

CO-DEPLOYMENT OF CO₂-EGR AND GEOTHERMAL HEAT EXTRACTION IN GAS INFRASTRUCTURE: A REVIEW

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ABSTRACT

The accelerating global demand for energy, coupled with stringent climate targets, has intensified interest in innovative strategies that simultaneously enhance gas infrastructure performance and reduce carbon emissions. This review critically examines the technical feasibility, operational synergies, and environmental implications of co-deploying Carbon Dioxide Enhanced Gas Recovery (CO₂-EGR) and Geothermal Heat Extraction (GHE) within existing natural gas infrastructure. However, studies addressing their combined deployment as a unified and integrated system remain limited. CO₂-EGR is increasingly recognized as a dual-purpose approach that enhances gas production while sequestering carbon dioxide, thus mitigating greenhouse gas emissions. However, the high compressibility of CO₂ and associated thermodynamic behavior pose challenges to reservoir integrity, wellbore efficiency, and pipeline operations. Conversely, geothermal heat extraction harnesses subsurface heat resources to provide sustainable thermal energy that can optimize gas processing, reduce energy consumption in compression cycles, and improve overall system efficiency.

This review synthesizes recent advances in both technologies, highlighting successful pilot implementations, reservoir modeling developments, and engineering designs that support integrated operations. Key synergies between CO₂-EGR and geothermal systems are identified, including improved fluid mobility through temperature modulation, reduced gas viscosity via heat extraction, and enhanced thermomechanical stability of the reservoir. Critical technical barriers are also analyzed, such as CO₂ phase behavior under geothermal gradients, corrosion and scaling risks in multiphase flow, as well as economic considerations related to capital expenditure and energy pricing. Finally, this review provides a comprehensive foundation for researchers, industry practitioners, and policymakers aiming to unlock the combined benefits of CO₂-EGR and geothermal heat extraction in the transition toward low-carbon energy systems.

Keywords: CO₂ Enhanced Gas Recovery (CO₂-EGR), Geothermal Heat Extraction, Carbon Capture and Storage (CCS), Integrated Energy Systems, Gas Infrastructure

INTRODUCTION

The exploration, exploitation and utilization of the subsurface resource to meet energy demands, have been a critical activity in the 21st century with several oil and gas establishments. These resources can be fluid-based or rock-based in form. The fluid-based resources include the crude oil and natural gas, while the rock-based resources includes the in-situ heat present in the reservoir. For the fluid-based resources, the resources are produced by three stages viz; supplemental (natural), secondary and tertiary techniques [1]. The natural and supplemental approach only recovers 20-40% of the hydrocarbon (HC) reserves while tertiary recovery (TR) approach can only 60% of oil in place (OIP) [2]. The natural approach utilizes the reservoir's supplemental energy for production, whereas in the case of pressure decline, water or natural gas injection referred to as secondary recovery, is conducted for pressure maintenance of the reservoir [3]. When the secondary recovery becomes ineffective due to mobility ratio and capillary forces, the tertiary approach is then deployed [4]. The tertiary approach entails the introduction of approaches and /or reagents that excludes natural gas and water for trapped oil displacement [5]. It is grouped into miscible flood process, microbial flood process, thermal flood process and chemical flood process [4]. The miscible flood process is grouped into the multiple contact process and single contact, with the single contact process entailing the use of alcohol or inert gas for miscibility while multiple contact entails injection of methane which relies on phase chemical exchange to attain miscibility.

In the microbial flood process, micro-organisms are deployed for the formation of polymers or/and surfactants in the reservoir for EOR [6]. The thermal flood process makes use of hot water, in-situ combustion and cyclic steam injection to raise reservoir temperature for oil production. The chemical, microbial and miscible flood processes are viable in light crude oil bearing reservoirs, while thermal flood process is viable in heavy crude oil bearing reservoir. The density of crude oil plays a significant role in the application of these flooding techniques [4]. For the rock-based resources, the in-situ heat of the reservoir is harnessed and utilized for the generation of power, in what is called geothermal energy. Lately, its one of the fastest growing renewable energy source, with significant potential for harnessing heat from abandoned oil and gas wells [7].

Geothermal power generation system are used widely; however, their commercial viability is tied to several factors, including reservoir features, resource availability, drilling technology, durability and local energy cost [8]. Repurposing abandoned wells for geothermal energy extraction can reduce project costs by 42-95%, as these wells provide direct access to subsurface heat and eliminate the need for new drilling [9]. Oil and gas wells offer valuable geophysical, geological, and geochemical data, enabling efficient heat extraction from deep reservoirs [10; 11].

Globally, mature oilfields with high water cuts and declining production rates are prime candidates for geothermal energy exploitation [12]. For a well to be suitable, it must exhibit reliable wellbore integrity, high bottom-hole temperatures [13], and significant production potential. These requirements have spurred interest in retrofitting existing wells for geothermal applications. The extraction of heat are carried out using water vapour and supercritical carbon dioxide (CO₂) to enable them absorb and transport thermal energy [14]. This is due to their high thermal conductivity and low viscosity in supercritical condition [15]. Despite the individual merits of CO₂-EGR and GHE, their combined deployment within a unified gas infrastructure system remains underexplored. Integrating these technologies

presents significant synergies: geothermal heat can mitigate the thermodynamic challenges of CO₂ injection (e.g., phase behavior, high compressibility), while CO₂ can serve as an effective working fluid for heat extraction due to its favorable thermal properties in supercritical conditions.

LITERATURE REVIEW

Carbon Dioxide Utilization in Oil and Gas Operations

The injectant gas “carbon dioxide (CO₂)” have risen from pre-industrial concentration of 280 ppm in the 1750s, to about 407.8 ppm in 2018 [16], and such concentration rise is believed to be one of the major reasons for global warming [17]. The CO₂ capture, utilization and storage (CCUS) is regarded as one of the most important technologies for CO₂ emission control [18]. In CCUS, CO₂ is captured from sources of the emission, transported, and then permanently sequestered into underground formations, such as hydrocarbon reservoir and deep saline aquifer. The captured CO₂ can be utilized to improve the recovery of underground resources such as water-oil-gas-coalbed methane. In the oil and gas industry, several gases such as nitrogen and helium are introduced into the wellbore for the purposes of lightening up of the crude oil, but carbon dioxide is more preferred [19].

The choice of carbon dioxide is attributed to its enhanced gas recovery prospect, geothermal heat extraction and capture & storage prospects. Carbon dioxide is utilized for enhanced recovery, pressure maintenance and long-term geological storage. Its introduction into reservoir alters the thermodynamics of the reservoir, improves displacement efficiency and can be permanently trapped through residual, structural, solubility and mineral mechanism. Studies suggest sedimentary basins with well-characterized geology and existing infrastructure as prime candidates for carbon dioxide utilization [10].

ENHANCED GAS RECOVERY

Enhanced Gas recovery (EGR) is the approach utilized to improve gas recovery beyond primary depletion through the introduction of gases such as CO₂, nitrogen or flue gas [20]. CO₂ storage with enhanced gas recovery (CSEGR) yields the recovery of natural gas by permanently introducing CO₂ into gas reservoir. EGR is very attractive due to CO₂'s favourable compressibility, density and miscibility behaviour under reservoir conditions, which improves gas displacement and pressure support [21].

Figure 1 shows the schematic diagram for the process. CSEGR has several merits such as suitable geologic structure of the gas reservoir for long-term gas injection, availability of formation data and reservoir model, the potential repurposing of existing well infrastructure and the net revenue [21]. The CO₂ storage capacities in natural gas reservoirs are crucial, with global estimates for conventional natural gas reservoirs within 160-390 Gt [22]. Furthermore, simulations findings showed the prospect of natural gas production improving by 5-15% when CSEGR is applied [23]. Though the technical viability of CSEGR has been preliminary validated by practical projects and reservoir simulations [24], the technology has not been completely commercialized.

Table 1 shows the comparison of physical properties between CO₂ and natural gas. Simulation and field-scale evaluations shows that CO₂-EGR is very effective in depleted or late-life of natural gas reservoir with existing well and pipeline infrastructure [25].

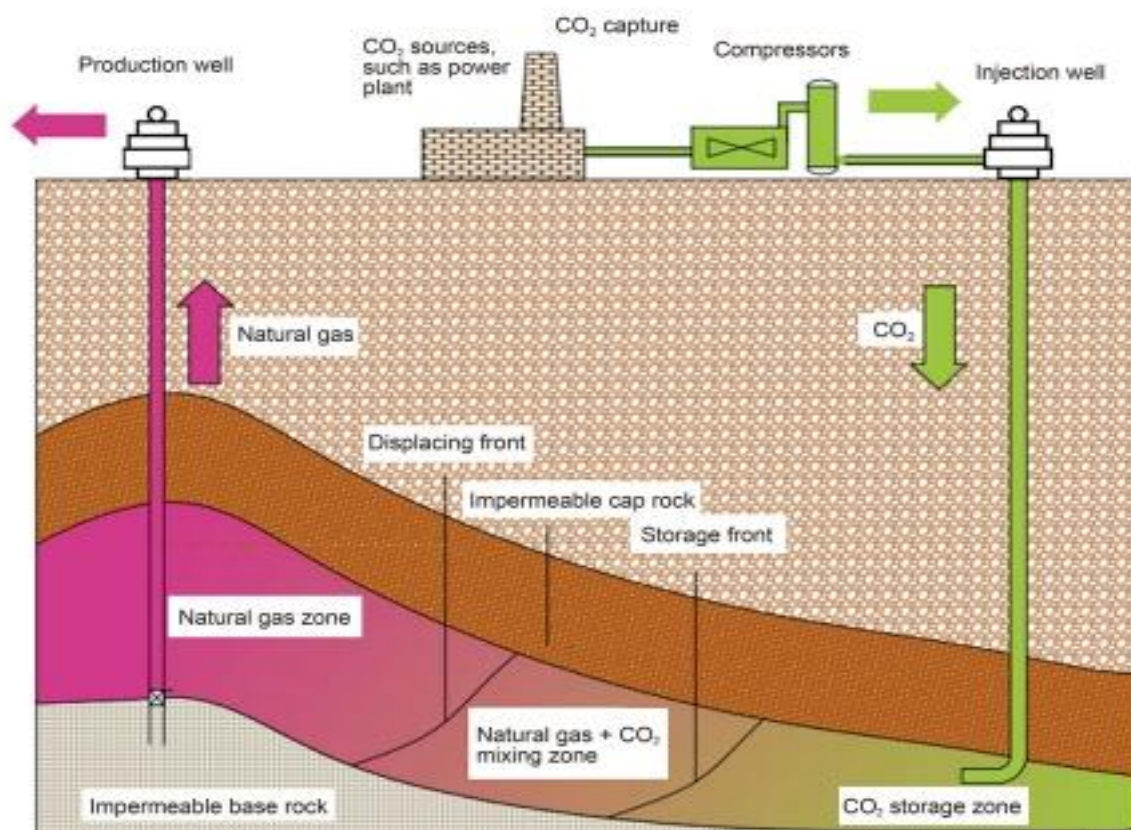


Figure 1. Carbon Dioxide-Enhanced Gas Recovery [22].

Table 1. Experiment studies of CO₂-Natural Gas displacement in consolidated cores for CSEGR

Research Focus	Studies	Core type and size	Porosity (Φ); Permeability (k, mD)	Pressure (P, MPa); Temperature ($T, ^\circ C$)
Technical Feasibility test of CSEGR	Mamora and Seo [27]	Carbonate	Φ : 0.23 k : 50	P: 3.5 - 20.8 T: 20 - 60
Impact of Impurity Composition	Nogueira [29]	Carbonate	Φ : 0.21-0.23	P: 10.3 T: 70
	Sadiq and Amin [30-32]	Sandstone	Φ : 0.143 k : 92.5	P: 40.679 T: 160
Gravity Effect and Entry/Exit effect on measurement of dispersion coefficient	Hughes et al [33]	Sandstone	Φ : 0.20, 0.16 k : 460, 12	P: 8-12 T: 40-80
	Li et al [34]	Sandstone, Carbonate	Φ : 0.20, 0.17 k : 100, 70	P: 10 T: 20, 40
Core dispersivity	Honari et al [38]	Sandstone, Carbonate	Φ : 0.2, 0.16, 0.15, 0.28, 0.22 k : 460, 12, 210, 2910	P: 8-14 T: 40-100

Impact of irreducible (residual) water	Turta et al [37]	Berea Core	Φ : 0.25 k : 500	P: 6.2 T: 70
	Honari et al [38]	Sandstone, Carbonate	Φ : 0.2, 0.16, 0.23 k : 460, 12, 2912	P: 10 T: 40
	Zecca et al [39]	Sandstone	Φ : 0.2, 0.15 k : 460, 12	P: 10 T: 36
	Abba et al [40-41]	Berea, Sandstone	Φ : 0.203 k : 217	P: 8.963 T: 40
CO ₂ horizontally displacing CH ₄	Abba et al [41-42]	Sandstone	Φ : 0.19-0.26 k : 200-315, 30, 350-600	P: 8.963 T: 50

Laboratory Experiment of CO₂-Natural Gas Displacement

Many laboratory investigations of CO₂-Natural Gas displacement in unconsolidated and consolidated cores showed the features of mixing between CO₂ and natural gas, CO₂ displacement and natural gas recovery. In the process of CO₂ displacing natural gas in underground reservoirs, the mix to yield a mixing zone due to diffusion and convection. The degree of mixing, and the mixing zone are vital to sweep efficiency, natural gas recovery and CO₂ storage in CSEGR [26]. The dispersion phenomenon which is tied to the dispersion coefficient and heterogeneity of the microscopic velocities inside the pore spaces is utilized to quantitatively describe the mixing degree [26]. Thus, dispersion formation in the process of a fluid displacing another within the pore spaces of the reservoir is influenced by diffusion and convection. The dispersion coefficient is usually evaluated by the convection-dispersion expression.

(1) **CO₂-natural gas displacement in consolidated cores:** The consolidated cores are closer to real reservoir condition. [27] and later [28] in their experimental study, noted that CH₄ recorded recovery of 73-87% prior to CO₂ breakthrough. The dispersion coefficient of CO₂-CH₄ was derived by fitting the convection-dispersion relation, and the coefficient rose with pressure and temperature. From [29] study, the introduction of dehydrated flue gas (CO₂ content of 13.574%) lowers CH₄ recovery by about 10%, and the dispersion coefficient improves by 20%-67% compared to that of CO₂ injection.

In contrast to the approach of convection-dispersion expression for dispersion coefficient derivation, [30] postulated a simple technique using a single point at the initial rise of a breakthrough plot. The dispersion coefficient is related to the displaced phase purity, and the dispersion coefficient drops with the rise in injection pressure. [31, 32] further focused on the impact of pore pressure on supercritical CO₂ displacing natural gas (90% CH₄ and 10% CO₂) within a sandstone rock with interstitial water. From the results, the greater variation in physical properties within a CO₂-CH₄ system under large pore pressure will yield limited interaction and improved recovery.

Hughes et al. [33] evaluated the impact of gravity and entry/exit on the dispersion coefficient measurement of CO₂-CH₄ displacement in sandstone cores. From their results, the entry/exit effect yielded apparent dispersion coefficient up to 63% larger than the internal one in the core. The gravity impact lowered vertical dispersion, but quickened

horizontal dispersion particularly at a low injection rate in a very permeable rock. Later, [34] utilized one-dimensional MRI to in-situ measure the dispersion process and arrived at similar to that of [33].

Honari et al. [35] enhanced the displacement experiments by deploying pulsed CO₂ introduction to derive dispersion coefficient. Their research evaluated the relation between Peclet number and dispersion to determine core dispersivity (representing the characteristic mixing length within a core). Furthermore, the phenomenon of early CO₂ breakthrough and tailing of the breakthrough curve was observed in heterogeneous carbonate cores in [36].

The dispersion coefficient derived by Mobile-Immobile Model (MIM) is much dominant in carbonates than in sandstones, and this is due to the more heterogeneous nature of carbonates to sandstones. Formation water largely impacts CO₂-Natural gas mixing and displacement features, as shown by recent research. With the existence of connate water, [37] demonstrated impact of CO₂ injection in significantly improving recovery factor. In addition, [38] demonstrated that the connate water occupies some flow channels, dissolved part of CO₂, and effectively lowers the bad impact of core heterogeneity on sweep. Thus, the CH₄ recovery factor was enhanced. Besides, [38] proposed that the delay of CO₂ transport causes a tailing in the breakthrough plot and non-Fick scenario, enhances the dispersion of CO₂-CH₄ displacement.

Zecca et al. [39] study showed that dispersivity increases greatly with the water saturation within the rock, and an empirical correlation was developed to that effect. [40] extended the study to account for the impact of connate water salinity. The results showed that the dispersion coefficient reduces with salinity increase. In this sense, connate water salinity after the mixing of the residual natural gas and CO₂ within the pore space of the reservoir. Also the above studies on vertical CO₂-CH₄ displacement, [41, 42] carried out the horizontal CO₂-CH₄ displacement on dispersion features in consolidated sandstones. The measured horizontal dispersion coefficient were overall 20-30% larger than the vertical ones. [42] indicated that the dispersion coefficient rises with dropping permeability. Furthermore, [43] proposed interfacial tension and interface during the displacement process of natural gas by CO₂. However, [33] proposed that the interfacial tension determined by [43] could occur due to Korteweg stresses, which is a transient stress within dynamic interfaces between miscible fluids induced by density gradient [44; 45].

Table 1 studies show consistent trends in CO₂-CH₄ displacement behavior in consolidated reservoirs. Porosity and permeability significantly affect dispersion and sweep efficiency. High-permeability carbonate cores showed greater dispersion coefficients and earlier CO₂ breakthrough due to preferential flow paths. Low-permeability sandstone systems had stable displacement fronts and delayed breakthrough. Carbonate heterogeneity caused significant tailing effects and non-uniform sweep behavior.

Pressure and temperature are critical parameters. Higher pressure improved CO₂ density and displacement efficiency, but excessive pressure gradients accelerated mixing and breakthrough in heterogeneous conditions. Higher temperatures enhanced molecular diffusion and dispersion coefficients, especially in supercritical CO₂ systems. Connate water studies showed residual water saturation can stabilize displacement fronts by blocking high-permeability channels and reducing fingering effects, though excessive water saturation may reduce methane recovery.

Consolidated carbonate systems exhibit more severe dispersion and mixing than sandstone formations due to stronger pore-scale heterogeneity. Reservoirs with moderate permeability, controlled heterogeneity, and optimized pressure management are most favorable for efficient CO₂-EGR deployment.

For CO₂-EGR projects, reservoir screening should prioritize formations with predictable permeability distributions, controlled water saturation, and sufficient structural integrity to minimize premature CO₂ breakthrough while maximizing methane recovery and CO₂ storage efficiency.

(2) **CO₂-natural gas displacement in unconsolidated porous media:** In addition to consolidated cores, some research studies of CO₂-Natural gas displacement were carried out in unconsolidated ones [42]. The utilization of unconsolidated porous media allows for the engineering of homogeneous core flooding apparatus, visualization of displacement process, evaluation of influential constraints, and in-situ measurement of dispersion. Before the idea of CSEGR was proposed, some experiment studies on the dispersion features in the displacement experiments were usually carried out using sand packed samples [26], with the mode of either CO₂ sweeping CH₄ or vice versa [46]. They are different from the settings of CSEGR.

For CSEGR, [47] and [48] analyzed the influential constraint of dispersion by conducting CO₂-CH₄ displacement experiments in a sand pack of glass beads. The results showed that the dispersion coefficient rose with both flow rate and temperature, and the pressure impact is complicated near the critical region. [47] also visually explained the CO₂-CH₄ displacement behavior by micro-X-ray CT. The in-situ visual observation validated that the presence of mixing transition zone at the displacing front as a limited zone, and no interface appeared in the process of supercritical CO₂ displacing CH₄.

Zhang et al. [49] proposed an in-situ measurement technique for dispersion coefficient of liquid/supercritical CO₂-CH₄ displacement. The component concentration of CO₂-CH₄ mixtures in the pore space of sand pack was derived by processing the grey value of CT image which describes the mixing degree of CO₂ and natural gas, and the Cranke-Nicolson approach was utilized to resolve the convection dispersion relation for the dispersion coefficient. They showed that the entry/exit artifacts yields an overestimation of the dispersion coefficients by 14%-23%.

Moreso [50] studied the entry/exit artifacts by utilizing the low-field MRI technology, which is in the range of 8%-32%, less than these in the consolidated core in [33]. The impact of gas compositions in the displaced or displacing fluid was also carried out in unconsolidated cores. [51] compared the performance CO₂ and N₂ in displacing CH₄ in sand-packed samples containing irreducible water. From the result of their evaluation CO₂ performed better than N₂ as it recorded higher recovery factor. The dispersion features however, were not evaluated. Later, [52] carried out the experiment of CO₂ horizontally sweeping a simulated natural gas (SNG, composed of 90% CH₄ and 10% CO₂). The presence of CO₂ in the SNG renders the SNG easier to be mixed with the injected CO₂, which yield in more significant horizontal dispersion.

Liu et al. [53] compared the apparent dispersion coefficient of CO₂-CH₄ displacement in both vertical and horizontal directions in a large range of temperature (60-150°C) and pressure (10e30 MPa). The results showed that the horizontal dispersion coefficients are

much higher than the vertical ones, which is similar to the phenomenon in consolidated cores.

The previous experiment studies reviewed above preliminarily verified the feasibility of CO₂ displacing natural gas for enhancing gas recovery due to the limited mixing. The in-situ CT and MRI visualization studies confirmed the mixing transition zone exists in the displacement. The mixability of CO₂-Natural gas displacement is quantitatively analyzed by the measurement of dispersion coefficient. Previous experiment studies of dispersion coefficient measurement reveal the basic changing rule of mixability of CO₂-Natural gas displacement in CSEGR. However, accurate dispersion measurements considering the complex condition of the gas reservoir, such as impure CO₂ injection, connate water, and heterogeneity, are still insufficient, and more related studies are essential to obtain the accurate mixing parameters for reservoir simulation.

Table 2 studies show that unconsolidated porous media offer valuable insights into dispersion mechanisms and displacement visualization under controlled laboratory conditions. Unlike consolidated cores, unconsolidated systems enable direct observation of displacement fronts and more accurate evaluation of flow instability and mixing-zone development.

Table 2. Natural gas displacement in unconsolidated cores for CSEGR.

Research Focus	Studies	Core type and size	Grain Size	Porosity (Φ); Permeability (k, mD)	Pressure (P, MPa); Temperature ($T, ^\circ C$)
Effects of various factors on dispersion	Liu et al. [47] Zhang et al. [48]	Glass beads sand-pack (BZ04, BZ06, BZ08, BZ1, BZ2) 1.5cm x 15cm	0.43, 0.60, 0.71, 1.19, 2.00 mm	Φ : 0.331-0.41 k : 22250-50900	P: 4-14 T: 29-60
In-situ approach of dispersion coefficient measurement	Zhang et al. [49]	Glass beads sand-pack (BZ01, BZ04) 1.5cm x 12cm	0.12, 0.40 mm	Φ : 0.324, 0.33	P: 10 T: 25, 40
	Honari et al. [50]	Borosilicate glass beads 2.9cm x 8.1cm	100 micrometer	Φ : 0.395	P: 4.5 T: 23
Impact of impurity compositions	Sim et al. [51]	Silica sand pack 4.14cm x 200cm	45-106 micrometer	Φ : 0.43 k : 2000	P: 0.69, 1.38, 3.45 T: Room Temp.
	Liu et al. [52]	Glass beads sand pack (BZ01) 1.6cm x 12, 20cm	0.1 mm	Φ : 0.324 k : 11200	P: 10, 14 T: 40, 55
CO ₂ horizontal displacing CH ₄	Liu et al. [53]	Glass beads sand-pack (BZ04, BZ06, BZ08, BZ1, BZ2) 1.6cm x 12, 21cm	0.12, 0.43, 1.19 mm	Φ : 0.331 k : 7800-42400	P: 10-30 T: 60-150

Key findings reveal that grain size and permeability strongly influence dispersion coefficients. Larger grains and higher permeability create wider mixing zones and greater dispersion due to reduced flow resistance and increased convective transport. Temperature significantly affects results, particularly under supercritical conditions where CO₂ mobility increases substantially. Dispersion behavior also depends on direction. Horizontal displacement consistently produces higher dispersion coefficients than vertical displacement because gravity stabilization is less effective horizontally. Additionally, irreducible water improves methane recovery by reducing channeling and enhancing sweep stability.

These findings emphasize the importance of reservoir orientation, permeability distribution, and saturation management in designing effective CO₂-EGR injection strategies. Results also confirm the need for accurate dispersion characterization in reservoir simulation to improve field-scale predictions.

CSEGR Numerical Simulation at Reservoir-Scale

Numerical simulation is an effective approach to study the mass transfer and flow during CO₂-Natural Gas displacement in reservoirs and thus aid assessment of a CSEGR project. Therefore, several studies of CSEGR simulations have been carried out. These studies include the evaluation of the effect of reservoir formation properties and CO₂ introduction properties and injection optimization approaches for both CO₂ sequestration and gas recovery.

(1) **CSEGR Feasibility Evaluation:** In the 1990s, [54] conducted a simulation study on CO₂ disposal process by introducing CO₂ into the depleted gas fields, in which CO₂ was captured from the coal-based IGCC's power plant and sequestered into the underground formation with enhanced natural gas production from the reservoir. [55] further proposed to blend hydrogen production from natural gas with CO₂ removal by compressing and injecting the separated CO₂ into the depleted gas reservoirs for CO₂ sequestration and enhancing natural gas recovery. [54] and [55] preliminarily studied the viability of CSEGR by simulation when they first proposed the original concept of CSEGR.

The technical and economic viability of CSEGR is the research aim at the beginning stage of the CSEGR study. [56, 57, 58, 59] carried out series of simulation studies to evaluate the economic and technical viability of CSEGR. [21, 57] explained the technical viability of CSEGR in the Rio Vista Gas Field within the central valley of California, US by qualitatively evaluating the difference in physical features (viscosity and density) between CO₂ and natural gas. Theoretically, the likelihood of mixing between supercritical CO₂ and natural gas is very little due to their wide variation in density and viscosity. Then the implementation of CO₂-EGR in the depleted Rio Vista gas field was simulated in a two-dimensional model. They discovered that additional CH₄ can be recovered from depleted gas reservoirs by CO₂ injection, which these validated the CSEGR's technical feasibility. Furthermore, [57] postulated the main criteria for a field site to implementing CSEGR: small reservoir volume and high permeability were considered very essential for pressure support and enhanced gas recovery over a reasonably short term.

Oldenburg & Benson [58] further extended the study of CSEGR's technical viability by utilizing a three-dimensional depleted gas reservoir model in the Rio Vista Gas Field. It's proposed that injecting CO₂ into the deeper zones and recovering natural gas from the higher zones of the gas reservoir can contribute to forming an efficient vertical CO₂-natural gas displacement due to the strong density contrast. Thus, the upwelling of the

mixing of CO₂ with the remaining natural gas in the reservoir was inhibited in this case. Furthermore, [56] suggested that it's technically practicable to implement CSEGR in the depleting gas reservoirs with considering CO₂ as a "cushion gas".

The study of [60] and [61] in the near depleted gas field Salzwedel-Peckensen, Altmark in North Germany, and [62, 63] in the Załęcze and Żuchłów Gas Fields in Poland also showed that the CSEGR was technically workable. [64] carried out CSEGR simulation applied in a high-pressure rock formation with temperature greater than critical point, and proved the technical viability of CSEGR, especially that CO₂ injection into the reservoir at a late stage of the field life and at high rate is more favorable. [65] study showed that CSEGR is technically viable especially that a higher CO₂ injection rate supports the significant improvement of CO₂ storage and gas recovery.

Patel et al. [66] also confirmed the technical feasibility of CSEGR with considering the dispersion between CO₂ and natural gas by conducting the high-fidelity reservoir simulations, and it emphasized that accurate reservoir simulations with high fidelity were important for CO₂-EGR. Moreover, [67] showed that the financial consequence of CSEGR deployed in the depleted and low-pressure Rio Vista gas reservoir is sensitive to several factors, such as CO₂ supply cost, wellhead prices of natural gas etc.

Generally, CSEGR will be highly favorable when CO₂ supply is low cost or carbon tax is imposed for CO₂ emission reduction. Similar to [66], simulation results of [23] and [64] validated that the economics of CSEGR is sensitive to CO₂ supply, market prices of natural gas, mixing of CO₂ and natural gas, etc. [65] postulated that CSEGR is more economically favorable while effective payments for CO₂ storage in the future carbon market will be more attractive. In summary, previous simulations showed that generally, CSEGR is technically feasible to be employed in gas fields, especially the depleted gas fields. From the view of the economic feasibility, CSEGR will be more economically feasible if implementing a carbon tax policy or effective payments for CO₂ storage. However, for a specific gas reservoir to apply CSEGR, the simulation is still needed to test the technical and economic feasibility.

- (2) **Study on the effect of reservoir properties and injection parameters:** The reservoir formation features and CO₂ injection parameters have a vital role in the underground sweeping of CO₂-natural gas, then significantly impact EGR and CO₂ storage when implementing CSEGR. [58] study, showed that permeability variations favors the formation of fast flow channels and tends to quicken CO₂ breakthrough. The CSEGR simulation in Altmark Field (Germany) of [60] and CO₂CRC Otway Project (Australia) of [68] also disclosed that CO₂ preferentially broke through in the geological strata with high permeability in the heterogeneous formations, which is not helpful to natural gas recovery. [69, 79, 71] arrived at similar conclusions.

Patel et al. [72] showed that the preferential pathway due to the fracture-induced has a dramatic effect on earlier CO₂ breakthrough and further impact the overall gas recovery. To stabilize the sweep process, [60], [23], and [70] suggested that the injected water or formation water in the high-permeability strata can slow down CO₂ breakthrough by efficiently obstructing the fast flow path and CO₂ dissolution. [73] research, showed that the inclusion of irreducible water has a large impact on changing the CO₂ flow field, causing a drop in CO₂ breakthrough time, and however, the connate water may result in a reduction in methane recovery. [73] indicated that these impacts of connate water were

sensitive to well perforation height, which should be evaluated comprehensively. [74] confirmed that low permeability, homogenous and isotropic reservoir is a good candidate for CO₂-EGR application.

To explore the optimal timing of CO₂ injection, [75] and [52] evaluated the effect of CO₂ injection on the natural gas recovery factor at various development stages of the gas field. It's found that to inject CO₂ when the gas reservoir was depleted can promote the maximum gas recovery. The premature injection of CO₂ at the early stage of gas field development was proved harmful to recovery. By conducting a simulation study of CSEGR in a sandstone reservoir in Northern West Virginia, [25] obtained similar results as [75]. In addition to injection timing, the injection rate of CO₂ is another major injection parameter on CSEGR. Recovery factor is observed to rise with injection rate within a certain range by [28]. [64] and [74] derived a similar conclusion that it is more economical for CH₄ recovery to introduce CO₂ into the reservoir in a high injection rate at the later stage of gas field life. The arrangements of CO₂ injection well and natural gas production well are two critical factors of injection strategy in CSEGR implementation. As for vertical wells, the simulation results of both [59] and [76] showed that increasing the distance between CO₂ injection wells and natural gas production wells can increase gas production before CO₂ breakthrough.

Kalra & Wu [69] evaluated the impact of injection/production well perforation placement by carrying out CSEGR simulations in a layered reservoir model with varying vertical permeability heterogeneity. The simulation results showed the placing of both the injection and production perforations in the lowest permeability layer can yield the best CO₂ storage capacity. The previous simulations showed that the preferential flow channel of CO₂ breakthrough was easy to form in the heterogeneous reservoir rock, which is not helpful to natural gas recovery. The connate water or injected water was confirmed to weaken the preferential CO₂ breakthrough to stabilize the sweep. The impact of CO₂ injection parameters and well placement on CSEGR were preliminarily evaluated in some previous simulations. However, more simulations on the impact of reservoir heterogeneity, well placements and CO₂ injection parameters, are still required to attain better performance of enhancing gas recovery and CO₂ storage before commercial utilization of CSEGR.

- (3) **Optimization of CO₂ injection strategies:** The optimization of CO₂ injection strategies plays an important role in determining the largest storage capacity of CO₂ and EGR in CSEGR. Thus, researchers carry out some simulation study on single or coupled optimization of CSEGR. To determine the optimal injection approach for CO₂ geological storage and utilization, Genetic Algorithms (GA) has already become one of the most promising and attractive optimization approaches with its rapid utilizations and good reliability. GA was respectively deployed for CO₂ sequestration in aquifer [77] and CO₂ geological utilization for enhanced recoveries of water [78], oil [79], natural gas [80, 81] and shale gas [82]. [80] deployed the combination of TOUGH2 and GA to optimize the injection rate for obtaining the best recovery of natural gas of CSEGR. The optimized constant injection rate of CO₂ can enhance the recovery factor by approximately 5%.

The optimization of time-dependent CO₂ injection scenarios (constant pressure injection) can attain higher production rates of natural gas without compromising the reservoir's structural nature. [83] validated that parameters like injected composition well

placements, CO₂ injection rates, and natural gas production rates are vital to the objective function by utilizing the GA optimizer in the CSEGR simulation based on a real gas field in the south of Iran, and the injection rate of CO₂ should be less than the production rate of natural gas to mitigate extra mixing of residual natural gas and injected CO₂. [80] optimized the well placement and CO₂ injection rates for CSEGR by employing the GA. The results proved that the horizontal injection well with accurate length and optimal injection rate can yield the best CO₂ storage and gas recovery factor. However, the exorbitant drilling cost of the horizontal well caused the above injection strategy with horizontal injection well not to be the best from economic standpoint.

Reusing a vertical production well with two suitably placed perforations for CO₂ injection with an optimized injection rate is economically superior due to reducing the drilling costs. The optimization of CO₂ injection strategies in CSEGR can promote the enhancement of natural gas recovery, which has been confirmed by the previous simulations. However, the optimization work of CO₂ injection strategies is relatively limited, especially lacking the optimization simulations with considering the comprehensive effect of natural gas recovery and CO₂ storage in CSEGR. In addition, [84, 85] proposed the production of geothermal in a depleted high-temperature gas reservoir. [86] Integrated CO₂-based enhanced natural gas recovery alongside geothermal energy utilization for electricity generation. Therefore, the CO₂-EGR simulations in gas reservoirs under high temperature and low pressure for enhanced gas recovery combined with the exploitation of geothermal will be more interesting and have scientific significance.

Analysis of the reviewed simulation studies shows that four key factors control CO₂-Enhanced Gas Recovery (EGR) performance: permeability heterogeneity, injection timing, reservoir pressure, and well configuration. Reservoir heterogeneity consistently creates preferred flow paths that speed up CO₂ breakthrough and lower methane recovery rates. As a result, uniform reservoirs with moderate permeability levels are typically better suited for long-term CO₂ storage and enhanced recovery projects [72].

The timing of injection significantly impacts displacement effectiveness. Research consistently demonstrates that introducing CO₂ during the late stages of depleted gas reservoir operations maximizes recovery while limiting unwanted gas mixing. Additionally, optimizing injection rates is crucial since excessively high rates increase dispersion and early breakthrough, while rates that are too low may compromise project economics [83]. A consistent finding across studies is the positive impact of connate or injected water in stabilizing the displacement front and reducing preferential flow channels. However, excessive water saturation can limit methane mobility and harm productivity. Moreover, strategic positioning of injection and production wells enhances sweep efficiency and improves CO₂ storage distribution patterns [79].

The reviewed studies demonstrate that successful Carbon Storage and Enhanced Gas Recovery (CSEGR) implementation requires comprehensive optimization of reservoir heterogeneity, fluid properties, injection timing, and well placement. These factors work together to determine displacement stability, recovery efficiency, and long-term CO₂ sequestration effectiveness.

Table 3 simulation studies show that reservoir heterogeneity, injection timing, permeability distribution, and well configuration are key factors controlling CO₂-EGR performance.

Table 3. Main simulation studies on the technical and economic feasibility CSEGR.

Research Focus	Studies	Simulator	Model Size (x,y,z)
Impact of permeability heterogeneity	Oldenburg et al. [21]; Rebscher and Oldenburg [59].	TOUGH 2	6.6km x 1km x 100m
	Ennis-King et al. [67]	TOUGH 2	/
	Feather and Archer [73].	ECLIPSE	1524m x 1524m x 30.48m
Impact of connate water or the injected water	Kalra and Wu [69].	CMC / GEM	2.286km x 22.86m x 91.5m
	Patel et al. [72]	COMSOL	201.19m x 201.19m x 45.72m
Impact of CO ₂ injection timing	Clement and Wit [74].	/	4km x 2km x 60m
	Jikich et al. [25]	UTCOMP	804.67m x 804.67m x 3.96m
Impact of CO ₂ injection rate	Seo and Mamora [28].	/	201.19m x 201.19m x 45.72m
Arrangement of CO ₂ injection well and natural gas production well	Oldenburg and Benson [58].	TOUGH 2	6.6km x 1km x 100m
	Hou et al. [76]	TOUGH 2 / FLA 3D	20km x 100m x 3km
	Luo et al. [68]	FLUENT	201.19m x 201.19m x 45.72m

Heterogeneous reservoirs with high-permeability streaks caused early CO₂ breakthrough and lower methane recovery due to preferential flow paths. Homogeneous formations showed better sweep efficiency and delayed breakthrough.

Late-stage CO₂ injection in depleted gas reservoirs performed better than early-stage injection, providing superior recovery and storage efficiency due to lower reservoir pressure and improved displacement stability.

Optimized injection rates are essential to balance recovery and storage. High rates increase breakthrough risk and mixing, while low rates reduce efficiency and economics. Strategic well placement and perforation design improve vertical sweep and storage distribution.

Successful CO₂-EGR deployment requires integrated optimization of reservoir properties, injection strategy, and operational controls. These parameters must be evaluated together during project design and feasibility assessment.

GEOTHERMAL HEAT EXTRACTION

In recent time, carbon dioxide has emerged as an alternative for water in geothermal heat extraction due to thermodynamic and hydrodynamic properties [87]. The utilization of CO₂ as working fluid has mainly three merits; higher mobility than water due to larger CO₂ density to viscosity ratio, drive can be influenced between injection well and production due to density variation of CO₂ under varying temperature, and CO₂ can be sealed in the formation due to CO₂ loss to the formation [88].

Properties and System Design

The concept of EGS consists of the hot dry rock (HDR). HDR comprises of extracting heat from rocks that naturally don't have low permeability fractures [90]. Generally, water is utilized as a working fluid that is introduced through ones of hot rock for the purpose of heat exchange [91]. Since the rocks don't have fractures, a process referred to hydro-fracturing is utilized to create ones of heat exchange between the working fluid and HDR. Seismicity is induced by the process due to the intentional exceedance of the critical fracture stresses [92]. Figure 2 shows the general design outline for a CO₂-plume geothermal system. Table 4 shows the advantages of CO₂ as a working fluid over water because of its key properties such as large expansibility and compressibility, and lower viscosity.

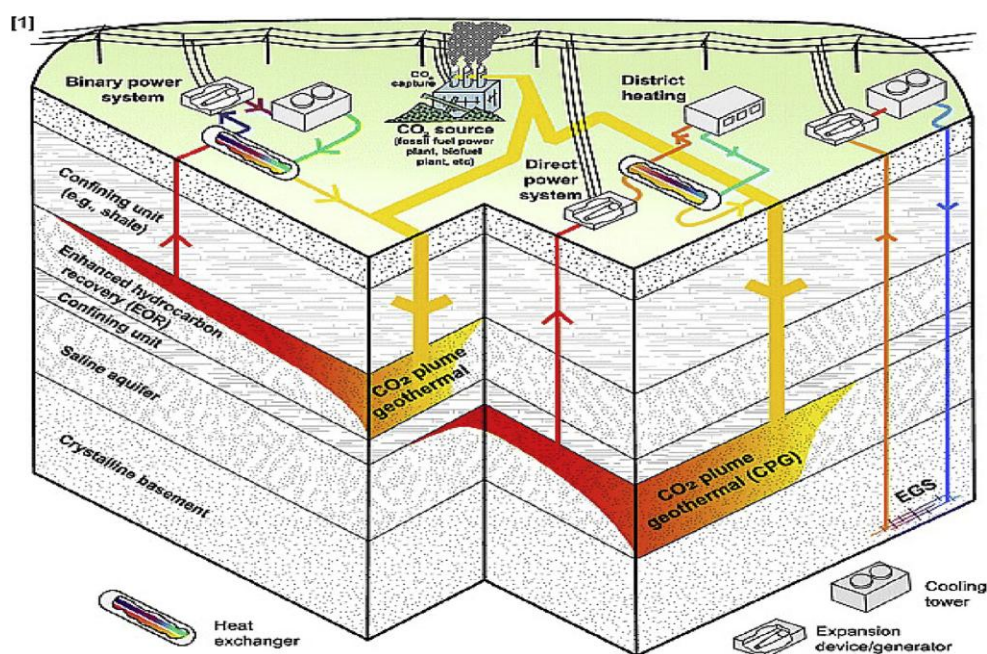


Figure 2. CO₂-plume geothermal systems [89].

Table 4. Merits of Carbon Dioxide over Water for Geothermal Heat Extraction.

S/N	Advantages of CO ₂ over Water
1	Large expansibility and compressibility that can generate buoyancy forces, which yields lower pumping consumption to manage the fluid in circulation
2	CO ₂ is not an ionic solvent, and is a poor solvent for rock minerals
3	CO ₂ has greater heat exchange than water
4	Lower viscosity which allows high flow velocities that would yield large mass extraction rates for a given pressure gradient.

As a disadvantage, CO₂ has a smaller specific heat; however, this is compensated by its lower viscosity [93; 94]. As the viscosity of CO₂ slightly increases with the temperature, most of the pressure can be utilized in the production wellbore instead of using for transporting the fluid [95]. When compared with water-EGS, CO₂-EGS takes advantages when: (i) the surrounding

formation has a high permeability; (ii) the average reservoir permeability is low; and (iii) the wellbores have a large radius, and the initial reservoir temperature is low [10]. On the other hand, CPG eliminates the need for hydro-fracturing since the recovery heat is gotten through large, naturally porous rock formation [96]. The major differences between CPG and CO₂-EGS are the permeability and the depth of the reservoir. CPG technology is applied to natural sedimentary reservoirs that have high porosity and permeability, which are overlain a low-permeability cap rock [97].

Simulation and Optimization

Several simulation studies were performed to evaluate different phenomena in CO₂ geothermal systems: (i) heat and mass transfer; (ii) the system performance with different geothermal working fluids; (iii) geochemical reactions, among others. For instance, [93] studied the effectiveness of the use of CO₂ instead of water through modelling of CO₂ energy production, injection, and fractured reservoir development using their thermo-physical properties. CO₂-EGS generate 50% more net heat extraction rates compared to water-EGS.

The use of CO₂ also presents merits in terms of hydraulics. Its large compressibility and expansibility reduce the parasitic power consumption of the fluid circulation system. The study of CO₂ geochemistry is also important due to the modification of porosity and permeability of the reservoir, affecting the heat extraction efficiency [89]. The optimization of carbon dioxide-based geothermal energy systems focuses on maximizing both heat extraction efficiency and CO₂ storage capacity while minimizing operational costs, pressure losses, and thermal degradation over time. Research analysis reveals that the optimization methodology typically encompasses four critical phases: (i) comprehensive reservoir characterization, (ii) detailed thermo-hydraulic modeling and simulation, (iii) systematic evaluation of operational parameters, and (iv) integrated economic and performance assessment.

Critical optimization parameters encompass injection pressure and temperature, CO₂ mass flow rates, reservoir permeability characteristics, geothermal temperature gradients, well spacing configurations, and production temperature decline rates [91]. Advanced multi-objective optimization methodologies, including Genetic Algorithm approaches, integrated thermo-hydraulic numerical modeling, and comprehensive sensitivity analyzes, are routinely implemented to identify optimal operating conditions. Research findings demonstrate that superior geothermal system performance is consistently achieved through moderate injection flow rates, maintained pressure gradient stability, and deployment in high-permeability reservoirs with advantageous geothermal gradients.

Contemporary optimization frameworks increasingly recognize heat extraction efficiency and long-term CO₂ sequestration performance as interconnected objectives requiring simultaneous consideration rather than independent operational goals. [10] compared CO₂-EGS and water-EGS for different parameters and simulated heat extraction and CO₂ sequestration simultaneously in a CO₂-EGS. Their study showed that the amount of sequestered CO₂ increased with the permeability of the surrounding formation. Besides, the cumulative amount of CO₂ increased with the geothermal gradient, and this value was two times higher than water losses.

Another important parameter to be studied is energy that represents the maximum amount of mechanical work that an energy carrying fluid at a given temperature and pressure can provide [98]. Depending on the temperature and pressure of the fluid, CO₂ can carry a total exergy 4.3 to 15.7 times higher than water. [99] studied the possibility of using other

geothermal fluids rather than water and CO₂ and studied which thermodynamic properties of geothermal working fluids are considered important for this application. In their study, they compared cyclopentane, acetone, hydrazine, carbon suboxide and nitrous oxide with CO₂ as a working fluid. The high performance of CO₂ as a working fluid compared to water was corroborated. The working fluid properties to take into account are: (i) high compressibility and expansibility; (ii) low viscosity and increase in viscosity for lower temperatures; and (iii) high mass heat capacity. Considering these properties, the nitrous oxide was also considered a potential alternative to the most studied working fluids (water and CO₂). However, the presented results depend on the considered parameters and assumptions. For different EGS plants, a new evaluation should be carried out.

Concerning heat transfer of this system, [100] compared the convective heat transfer in a rough tortuous fracture with a smooth parallel-plate fracture. This study is crucial to forecast the heat transfer performance in EGS. The heat extracted was less in the rough and tortuous fracture than in a smooth parallel-plate fracture, with an equivalent hydraulic aperture (measured in volumetric flow and pressure drop based on a cubic law). The cause of the lower heat exchange efficiency was the disturbance (the Nusselt number increases for higher Reynolds number) and channeling (occurrence of a region of local stagnation where the fluid flow around) effects. Concerning the study of geochemical reactions, [101] performed batch experiments under in-situ reservoirs of the Songlian Basin (China) to evaluate fluid-rock interaction of a CO₂-EGS. Additionally, the experimental data were used to validate the numerical model. Experiments were performed at high temperature and pressure reactors. This study aimed to evaluate the change of minerals solubility due to the presence of water in CO₂-EGS, which can have an impact on reservoir longevity. Significant mineral composition changes were identified at CO₂-EGS reservoir, which changes the fluid flow. The injection of supercritical CO₂ led to the dissolution of primary minerals (e.g. calcite and K-feldspar) and the precipitation of secondary carbonate (e.g. calcite and ankerite). However, the numerical simulations were partially successful in the prediction of the laboratory results. Some factors were identified for the achieved deviations: (i) solubility and kinetic data using in the simulations; and (ii) impurities not considered in the minerals that could affect the solubility of other minerals.

The dissolution and precipitation of minerals were also identified as a result of the injection of supercritical CO₂ by [102]. In this study, reactive transport modelling was performed using thermal conditions and composition of minerals of two reservoirs: Songliao and Cranfield sites. Besides the evaluation of mineral dissolution and precipitation, the authors aimed to analyse the porosity change (affecting fluid and heat transfer) and CO₂ loss rates. Based on the simulations, the precipitation of carbonates did not affect the porosity and the fluid flow significantly and can contribute to the sequestration of CO₂. However, as in other referred studies, the results are specific to the considered conditions and parameters (e.g. salinity). [103] studied high-temperature and low-temperature geothermal reservoirs from western Anatolia (Turkey), trying to evaluate the mechanisms of CO₂ sequestration. Temperature showed to be an important variable for CO₂ stabilisation, as high values promote mineral trapping (by carbonate precipitation). At the low-temperature geothermal reservoir, carbonate precipitation is followed by its dissolution. In this case, base cations should be supplied to mineral trapping. [104] analysed the interactions between the CO₂ and the rocks around, using one and two-dimensional models and realised that the CO₂ had been sequestered in the rock.

By carbonate precipitation, a maximum of $50 \text{ kg CO}_2 \cdot \text{m}^{-3}$ of the medium was trapped. However, the precipitation and mineral alteration generally decreases the porosity, which reduces the heat transfer rate of the reservoir. Therefore, additional research studies should be performed to find a trade-off between geothermal energy production and CO_2 sequestration. [105] analysed the sequestration capacity of the Habanero geothermal field (Australia) and discovered that the major CO_2 sequestration mechanism is the storage in the stimulated reservoir. The existing Habanero 1–Habenero 4 doublet model estimated CO_2 storage of 94,500 tonnes per year and this value could increase to 572,000 tonnes of CO_2 per year in the next stage base project with a six spot well pattern (assuming of 5% fluid loss).

The use of supercritical CO_2 may require the water removal from the reservoir. CO_2 mixed with water form an acidic solution, causing dissolution and precipitation problems in the reservoir and corrosion of the pipes. [105] optimized a CO_2 -EGS system by numerical simulations, combining a genetic algorithm and a multi-phase flow solver TOUGH2 (Transport of Unsaturated Groundwater and Heat Version 2), designated as GA-TOUGH2. The GA-THOUGH2 optimized the CO_2 injection rate with constant mass and pressure to control the production temperature variation and to guarantee the heat extraction. The simulations were performed in a timeline of 35 years with an optimization baseline of 200 bar and 200°C for the injection of the CO_2 . The optimal constant mass injection rate was $34.92 \text{ kg} \cdot \text{s}^{-1}$, which gives a production temperature after 35 years slightly higher than 100°C . However, for a constant mass injection rate, the injection well pressure declines with time. Therefore, the temperature profile for a constant pressure injection was optimized, and the pressure drop between the injection and the production was 19.3 bar. For this optimized pressure injection, the reservoir has a slower temperature decline, which was kept above 100°C for the entire 35 years. Additionally, the heat extraction is less than the baseline case; however, the upgraded temperature profile results improve the sustainability of the EGS operation.

Randolph & Saar [106] compared the potential of using a hybrid system (a combination of a CO_2 -EGS and a closed-loop supercritical CO_2 Brayton cycles for solar thermal) with the two systems used separately. The hybrid system had equal or higher efficiency than the two separated systems. Additionally, there was no need for a compressor in a hybrid system due to the reduction of the operation pressure, which reduces the installation and maintenance costs. [88] evaluated the performance of the geothermal horizontal well and concluded that a larger mass flow rate and lower injection temperature are suggested to improve the energy extraction rate. Higher injection pressure might overload the equipment. The parameters to improve the economic performance of the horizontal well were also optimized [88], where a low injection rate and pressure were recommended.

Regarding CPG systems, [107] evaluated the hypothesis of considering the wellbore flow and heat transfer as an adiabatic process. The authors used a quasi-one-dimensional heat transfer model, assuming only radial heat transfer. The model was developed using the Engineering Equation Solver (EES) software in combination with MATLAB. The initial conditions for the CO_2 at the inlet of the well were fixed at 25 MPa, 100°C , and $80 \text{ kg} \cdot \text{s}^{-1}$. The authors concluded that adiabatic conditions are achieved approximately five days after the system operation and that the flow rate of $80 \text{ kg} \cdot \text{s}^{-1}$ will extract 9 MW of thermal energy. The authors recommended that new CPG studies should consider adiabatic flow in the well.

Cui et al. [96] performed a numerical simulation to analyze the effect of CO₂ geochemical reactions and salt precipitation on the heat mining rate of CPG. The evaporation induced by the negative gas-liquid capillary pressure gradient can result in salt precipitation, which its accumulation can reduce heat mining rate. Additionally, salt precipitation has a greater impact than CO₂ geochemical reactions because it can influence its flow and distribution, affecting heat mining rate up to 2/5. For the CPG application, geothermal reservoirs with high temperature, high porosity and permeability and low salinity should be selected first. Moreover, to solve the energy problem caused by the salt precipitation, injections of low salinity water prior CO₂ injection demonstrated to improve the production rate from 13 to 30 kg·s⁻¹ and the heat mining rate from 6 to 14 MW after 30 years.

Randolph & Saar [106] performed a numerical modelling to estimate the intensity of the thermosiphon effect at different depths and geothermal gradients for CO₂ and 20 wt% NaCl brine. CO₂ generates high convective mass flow rates than brine without mechanical pumping. With CO₂, a reservoir pressure drop of 3–12 times less than brine was achieved at the same flow rate, presenting a larger thermosiphon induced mass flow rate. The difference between the heat extraction rates became more significant for low-depth reservoirs (with a geothermal gradient of 35°C km⁻¹, the heat extraction rate is 300 times higher). The use of CO₂ as working fluid should be particularly more advantageous at depths between 0.5 km and 3 km. [105] compared the conventional water-based, the water-EGS and CO₂-EGS with CPG. Heat extraction when CO₂ was used as working fluid was significantly higher. The CPG compared to water-based and water EGS, show a superior geothermal heat energy extraction up to 2.9 and 5.0, respectively. Also, CPG may improve the economic viability of geothermal energy production and CO₂ capture and storage. Geothermal energy can be produced continuously or intermittently. Thus, this renewable energy can fulfil the energy requirement (peak demand) that is difficult to do with other renewable energies (solar and wind).

Gupta & Vashista [108] performed a numerical simulation to compare the CPG with CO₂-EGS and water-EGS. CPG provides a better heat extraction rate than CO₂-EGS, and the CPG system is economically and technologically more advantageous to produce electricity in regions with relatively low-moderate surface temperatures and heat flow rates (e.g. in India provinces). [111] analyzed the effects of multi-layered geothermal reservoirs on CPG system performance analyzing the CO₂ mass fraction in the produced fluid, pore-fluid pressure, and heat extraction rate. The geothermal reservoir was divided into two, three, or four horizontal layers and each layer had a different permeability. It was simulated two different scenarios: (i) low-permeability layers at the top; and (ii) high-permeability at the top. The CO₂ mass fraction is dependent on the high-permeability layers (at either the top or the bottom) and independent on the number of the layers. The pore-fluid pressure is affected by the permeability of the layers, which effect is more pronounced with low-permeability layers at the top and by the number of layers that decreases as the number increase. Regarding the heat extraction rates, it is constant for the low permeability layers at the top and decreases as the permeability of the bottom layers decrease.

Besides energy production, CPG was also proposed as an energy storage option, due to the intermittency of wind and solar energy production systems [112]. Using this renewable energy, CO₂ can be stored in geological reservoirs, and the energy produced by geothermal energy can be greater than the energy stored (ratio between produced and stored energy from 1 to 3).

The electrical energy is stored in the form of pressure and heat (with supercritical CO₂), enabling the temporal separation between power production and consumption. Also, this storage system can operate with any cycle duration that may be required by the intermittent renewable energy sources. Table 5 shows some of the significant research studies that are being considered in heat extraction.

Table 5. Research Consideration for Heat Extraction.

Reference	Material	Research Consideration
Pruess [93]	CO ₂ ; Water	Energy Production; Energy Injection; Fractured Reservoir Development
Xu et al. [18]	CO ₂	CO ₂ sequestration
Randolph and Saar [107]	Water; CO ₂	Compared Water-EGS and CO ₂ -EGS with CPG
Randolph et al. [105]	CO ₂	Numerical simulation wellbore flow and heat transfer model using Engineering Equation Solver (EES) software and MATLAB, for CPG system
Adams et al. [106]	CO ₂	Numerical modeling to estimate the intensity of the thermosiphon effect at different depth and geothermal gradient.
Garapati et al. [109]	CO ₂	Impacts of multi-layered geothermal reservoir on CPG system performance analyzing the CO ₂ mass fraction in the produced fluid, pore-fluid pressure and heat extraction rate
Xu et al. [102]		Reactive transport modelling using thermal conditions and mineral composition
Biagi et al. [80]	CO ₂	Numerical Simulation using combination of Genetic Algorithm and a Multi-phase Flow Solver TOUGH2 (Transport of Unsaturated Groundwater and Heat Version 2)
Na et al. [101]	CO ₂	Geochemical reactions between fluid and rocks
Gupta and Vashistha [108]	Water; CO ₂	Numerical Simulation between Water-EGS, CO ₂ -EGS and CPG.
Xu e al. [103]	CO ₂	CO ₂ sequestration
Jiang et al. [104]	CO ₂	Hybrid system (a combination of a CO ₂ -EGS and a closed-loop supercritical CO ₂ Brayton cycles for solar thermal)
Phuoc et al. [98]	Water; CO ₂	Maximum amount of mechanical work that can be carried out.
Zhang et al. [100]	CO ₂	Convective heat transfer in a rough tortuous fracture and smooth parallel-plate fracture.
Cui et al. [96]	CO ₂	Numerical simulation model to evaluate CO ₂ geochemical reactions and salt precipitation on the heat mining rate of CPG.

Olasolo et al [99]	Cyclopentane; Acetone; Hydrazine; Carbon Suboxide; Nitrous Oxide; Water; CO ₂	Utilization of other alternate fluids based on their working properties
Sun et al. [88]	CO ₂	Performance of the Geothermal Horizontal Well
Wang et al. [71]	CO ₂ ; Water	Simultaneous heat extraction and CO ₂ sequestration

CARBON CAPTURE AND STORAGE

The carbon dioxide capture and storage (CCS) entail the separating CO₂ from an emission primary gas, transporting it into a storage system, and the securing it in long-term isolation from the atmosphere [113].

Carbon Capture and Storage Approach

The CCS approaches include biological and artificial approaches as follows:

1. **Biological Approach:** Biological carbon capture and storage (CCS) strategies are generally classified into natural (biological) and engineered (artificial) approaches. Among the biological pathways, two primary methods are widely recognized. The first involves harnessing photosynthesis in organisms such as microalgae, cyanobacteria, and higher plants to absorb atmospheric CO₂ and transform it into energy-rich organic biomass [114]; However, this approach remains largely impractical for large-scale industrial deployment [115-117]. The second approach involves the application of thermo-alkali-stable carbonic anhydrase (CA, EC 4.2.1.1) to catalyze CO₂ hydration and promote biomineralization.

In this process, an aqueous solution containing immobilized CA captures CO₂ from high-temperature flue gas streams, converting it into bicarbonate ions, with an absorption capacity reported to be up to 25 times greater than that of non-catalyzed systems. Furthermore, during biomineralization, CA facilitates the conversion of CO₂ into thermally stable calcium carbonate (calcite), making it suitable for long-term storage. Electron microscopy analyses have revealed distinct differences in the crystal morphology of calcium carbonate formed in the presence versus absence of the enzyme. Despite these advantages, large-scale implementation remains challenging. The production of thermo-alkali-stable CA relies on specialized microorganisms and advanced biotechnological processes, including genetic optimization. Additionally, strict operational requirements such as controlled temperature, pH, and oxygen conditions make enzyme production and process scalability difficult to achieve at an industrial level.

2. **Artificial Approach:** Artificial approaches to carbon capture and storage (CCS) primarily encompass two key components, CO₂ capture and geological storage. Carbon Capture, Utilization, and Storage (CCUS) refer to a suite of technologies that separate CO₂ from emission sources using various engineering techniques, followed by compression for either subsurface storage or practical utilization in industrial and commercial applications.

The overarching objective is to ensure the long-term isolation of CO₂ from the atmosphere. It is important to note that CO₂ utilization and storage, although often integrated, are

fundamentally distinct processes. The CO₂ streams employed in CCUS systems are typically sourced from the combustion of fossil fuels and biomass in power generation facilities, as well as from industrial operations such as cement production, steel manufacturing, and ammonia synthesis. Additional sources include associated gas separation during crude oil production and CO₂ removal processes in natural gas processing plants [118].

Geological storage of CO₂ is a complex and multidisciplinary process that involves several critical stages, including site selection, understanding the mechanisms of CO₂ trapping within subsurface formations, evaluating storage capacity, and implementing long-term monitoring strategies after injection. Prior to selecting a suitable storage site, key factors such as the reservoir's storage and injection capacity, as well as local environmental conditions and regulatory requirements, must be carefully assessed. Typically, geological formations used for CO₂ storage consist of porous and permeable rock structures that contain fluids such as water, oil, or gas. The storage capacity of these formations is provided by pore spaces within the rock matrix and by natural or induced fractures that enhance fluid flow and storage potential. The techniques employed for CO₂ capture in geological storage systems can generally be classified into five main categories [119]:

- a. **Structural Trapping:** Structural trapping is considered the dominant mechanism for CO₂ storage in geological formations. When CO₂ is injected in its gaseous or supercritical state (scCO₂), it is less dense than the surrounding formation fluids, giving it a buoyant tendency to migrate upward through the porous and permeable rock. This upward movement continues until the CO₂ reaches an impermeable cap rock or sealing layer that prevents further migration. At this point, the CO₂ accumulates beneath the cap rock, forming stable, immiscible, and effectively immobile plumes, thereby ensuring its containment within the reservoir over long time scales.
- b. **Residual Trapping:** Residual trapping, also referred to as capillary trapping, occurs when CO₂ is immobilized within the pore spaces of the reservoir rock due to capillary forces, preventing its further movement [120]. During CO₂ injection, the fluid migrates through the porous rock, displacing the resident formation fluids in the pore spaces. As injection continues and the flow regime evolves, these fluids can subsequently re-enter and displace portions of the CO₂. Owing to the heterogeneity and discontinuities within the pore structure, some of the CO₂ becomes immobilized as disconnected, residual droplets. This trapped CO₂ remains stationary due to capillary forces, contributing to long-term storage security.
- c. **Solubility Trapping:** Solubility and mineral trapping occur when CO₂ is injected into water-bearing formations such as saline aquifers. Over time, structurally and residually trapped CO₂ gradually dissolves into the pore water, forming carbonic acid and altering the fluid's chemical composition. This acidified environment promotes the dissolution of reactive minerals, such as feldspars, within the reservoir and cap rock. Subsequently, chemical reactions between dissolved CO₂ and released ions lead to the precipitation of stable carbonate minerals, effectively converting the CO₂ into solid form and enhancing long-term storage security.
- d. **Adsorption Trapping:** Adsorption trapping is predominantly employed for CO₂ injection into coal seams. In this mechanism, CO₂ moves freely through the natural fractures of the coal and becomes adsorbed onto the surfaces of the coal's micro-porous matrix [121]. The adsorption of CO₂ onto the coal matrix simultaneously displaces methane (CH₄), enabling

the recovery of coalbed methane. Under optimal pressure and temperature conditions, approximately 95% of the injected CO₂ can remain in the adsorbed state within the coal seam, ensuring effective long-term storage.

In combined CO₂-Enhanced Gas Recovery (EGR) and geothermal systems, carbon capture and storage (CCS) serves both operational and environmental purposes. While providing a long-term solution for storing greenhouse gasses, the injected CO₂ simultaneously functions as an underground working fluid that enables enhanced methane recovery and geothermal heat extraction. This dual-purpose approach sets integrated CO₂ systems apart from traditional standalone CCS operations. In depleted or mature gas reservoirs, injected CO₂ helps restore reservoir pressure and improves methane displacement efficiency due to its beneficial density, viscosity, and compressibility characteristics under reservoir conditions. Additionally, the thermodynamic properties of supercritical CO₂ make it highly effective for geothermal heat transfer, allowing it to transport underground thermal energy with reduced pumping requirements compared to water-based systems.

As a result, combining CCS with CO₂-EGR and geothermal extraction creates a synergistic system where carbon storage, hydrocarbon recovery, and renewable energy production occur simultaneously within the same geological framework. The examined trapping mechanisms also directly impact integrated deployment systems. Structural and residual trapping mechanisms ensure immediate containment security during CO₂ circulation and injection processes, while solubility and mineral trapping enhance long-term storage stability over extended operational timeframes.

In geothermal reservoirs, higher temperatures may accelerate mineralization reactions and improve permanent CO₂ fixation within the formation structure. This interaction between geothermal conditions and geochemical trapping mechanisms represents a significant benefit of integrated CO₂-geothermal systems. Additionally, existing gas infrastructure including depleted reservoirs, production wells, pipelines, and monitoring systems can potentially be repurposed for integrated CCS operations, reducing capital costs and improving economic viability. The combined deployment strategy also supports broader energy transition goals by decreasing greenhouse gas emissions while extending the productive lifespan of mature gas assets and enabling sustainable geothermal energy utilization. Consequently, CCS should be recognized not merely as a passive storage mechanism within this analysis, but as an essential enabling component for successfully integrating CO₂-EGR and geothermal heat extraction technologies within low-carbon energy systems.

CCS application challenges

The analysis of CO₂ storage methods shows that successful long-term carbon capture in combined CO₂-EGR and geothermal systems requires multiple trapping processes working together. These include structural, residual, solubility, mineral, and adsorption trapping mechanisms. Each mechanism works at different time periods and locations, and together they determine how securely the injected CO₂ will remain stored. During the initial phases of CO₂ injection and circulation, structural and residual trapping serve as the primary containment methods [103]. Structural trapping provides immediate protection by keeping CO₂ beneath sealed rock layers, while residual trapping captures isolated CO₂ droplets in rock pores through natural forces. These mechanisms prove especially critical during active CO₂-EGR operations, where ongoing injection and production activities can affect reservoir pressure and fluid movement. As operations continue over extended periods, solubility and

mineral trapping gain importance [97]. When CO₂ dissolves into underground water, it reduces upward movement and increases storage stability. Mineral trapping permanently secures dissolved CO₂ by converting it into stable carbonate minerals through chemical reactions with reservoir rocks. In geothermal settings, higher underground temperatures may speed up these mineral formation processes and enhance long-term storage effectiveness. Adsorption trapping proves especially valuable in coal-containing formations, where CO₂ absorption can support both methane extraction and carbon storage simultaneously. However, its effectiveness depends heavily on rock composition and pressure conditions [121].

From an engineering standpoint, having multiple trapping mechanisms working together improves storage dependability in integrated CO₂-EGR and geothermal systems. Reservoirs chosen for combined operations should feature strong cap-rock integrity, adequate permeability, sufficient underground heat gradients, and reactive mineral compositions that support long-term mineral formation reactions. Additionally, understanding how thermal processes, fluid flow, and chemical reactions interact remains crucial for predicting reservoir performance, reducing leakage risks, and maximizing both energy recovery and CO₂ storage efficiency.

Projections for carbon capture and storage (CCS) suggest that by 2025, global patent applications in this field are expected to reach 16,156. Among countries, the United States leads in CCS technology development and competitiveness [122]. Despite its potential, CCS faces two major challenges: high costs and safety concerns [123]. The stages of CO₂ separation, capture, purification, compression, transportation, and storage involve significant capital and operational expenditures. Among these, CO₂ capture and compression are the most expensive, accounting for approximately 50–80% of the total CCS costs, which poses a major barrier to the widespread adoption of the technology [124-125]. Therefore, optimizing the transport of CO₂ from emission sources to storage or utilization sites in an efficient and cost-effective manner is essential [126]. Further research and development are required to develop more cost-effective CO₂ capture technologies [127].

Geological storage is the primary method for CO₂ sequestration, involving injection into deep saline aquifers, oil or gas reservoirs, coal seams, or seabed sediments. Integrating CO₂ storage with hydrocarbon production through processes such as CO₂-enhanced oil recovery (CO₂-EOR) or gas recovery (CO₂-EGR) can help offset costs and improve the economic feasibility of CO₂ storage [128]. Deep saline reservoirs represent a promising option for CO₂ storage; however, large-scale injection can lead to significant increases in reservoir pressure. If this pressure exceeds critical limits, it may drive the migration of saline water through leaking wellbores into overlying freshwater aquifers, posing environmental and safety risks [129]. Extracting saline water from the reservoir is an effective strategy to reduce pressure and mitigate the risks associated with CO₂ injection [130-131]. However, the extracted saline water typically contains high levels of dissolved salts, suspended solids, and potentially toxic substances, which pose challenges for disposal or treatment [132]. Consequently, implementing this approach introduces new environmental concerns and increases operational costs. Moreover, storing CO₂ in deep saline aquifers, depleted oil and gas reservoirs, or seabed sediments carries an inherent risk of leakage.

In offshore settings, such leakage could disrupt the surface sediment layer, potentially affecting circulation within the top 5cm [133-134]. Additionally, the interaction of acidified sediments with seawater can lead to the leaching of contaminants into the sediment, releasing

potentially toxic elements such as zinc (Zn), lead (Pb), cadmium (Cd), nickel (Ni), and arsenic (As) [135]. Prolonged, large-scale, and continuous CO₂ leakage onto the seabed could cause significant environmental damage [136]. In onshore geological storage, large-scale industrial injection of CO₂ into depleted oil and gas reservoirs or saline aquifers can increase reservoir pressure and promote lateral CO₂ migration. This pressure buildup may drive CO₂ and/or saline plumes through natural fractures, fault zones, or poorly sealed injection wells. Subsequent vertical migration can lead to leakage, potentially contaminating overlying shallow aquifers and freshwater resources [137-139]. During the leakage process, as the fluid moves across heterogeneous interfaces with low-permeability layers, it experiences discontinuous flow and flow constriction. This can cause CO₂ dissolved in the saline water to degas, potentially allowing it to escape into the soil or even the atmosphere [140].

Direct mineralization and the industrial utilization of captured CO₂ present attractive alternatives, particularly in light of the potential risks of leakage from geological storage sites. However, these approaches are limited by high costs and significant energy requirements. Another promising strategy involves injecting CO₂ into mafic and ultramafic rock formations, such as basalts, where it reacts with calcium or magnesium oxides to form stable carbonates. In this way, CO₂ is permanently fixed within the rock matrix, preventing migration to shallow aquifers or the atmosphere and significantly enhancing the long-term safety of storage [141].

Several commercial-scale and pilot projects have already been implemented to investigate this form of CO₂ storage, including the CarbFix Project, the Wallula Project, and the Oman Drilling Projects, among others [142]. In Iceland's CarbFix Project, over 95% of the injected CO₂ was successfully mineralized into stable carbonates within just two years [143]. The Wallula Project demonstrated that iron (Fe) and manganese (Mn) were enriched in the carbonates formed within the basalt following CO₂ injection. This suggests that the partial carbonation observed in the injection zone results from the dissolution of the basalt itself [144]. Building on the concept of CO₂ storage through mineral carbonation, this study explores an alternative approach for geological CO₂ sequestration: the CO₂-enhanced geothermal system (CO₂-EGS). In this method, CO₂ serves a dual role as both a working fluid for heat extraction and a medium for long-term carbon storage.

The reviewed storage mechanisms confirm that integrated CO₂-EGR and geothermal systems can deliver both sustainable energy production and secure long-term carbon management when reservoir conditions and operational parameters receive proper optimization.

CONCLUSIONS

This comprehensive review examined the combined use of Carbon Dioxide Enhanced Gas Recovery (CO₂-EGR) and geothermal heat extraction in existing gas infrastructure systems. The research shows that combining these technologies creates significant technical, environmental, and economic benefits for advancing sustainable and low-carbon energy systems. Laboratory studies and large-scale reservoir simulations confirmed that CO₂ has excellent properties for enhanced gas recovery, including high compressibility, density changes, and mixing behavior under reservoir conditions. The success of CO₂-EGR operations depends heavily on reservoir characteristics such as rock variation, permeability patterns, water content, injection timing, injection rates, and well design. Research consistently demonstrated that injecting CO₂ into depleted reservoirs during later stages improves methane recovery while increasing long-term CO₂ storage capacity.

The analysis revealed that CO₂-based geothermal systems offer multiple benefits compared to traditional water-based geothermal systems. The low thickness and high expansion properties of supercritical CO₂ improve fluid movement, reduce pumping needs, and increase underground heat extraction efficiency. Additionally, geothermal heat extraction helps address temperature-related challenges from CO₂ injection and improves overall system performance.

Carbon capture and storage (CCS) methods, including structural, residual, solubility, mineral, and adsorption trapping, were recognized as essential elements for ensuring secure long-term storage. Combining CCS with CO₂-EGR and geothermal operations improves the economic viability of carbon management by linking greenhouse gas reduction with enhanced oil and gas recovery and renewable geothermal energy generation.

While these benefits are substantial, several technical and operational challenges still need solutions. These include early CO₂ breakthrough, reservoir variation effects, corrosion and scaling problems, chemical interactions, temperature decline, monitoring needs, and uncertainties in long-term reservoir performance. Economic success also depends on CO₂ transportation costs, infrastructure availability, carbon pricing policies, and energy market conditions.

Future research should therefore emphasize integrated thermal-hydraulic-chemical reservoir modeling, field-scale testing programs, advanced monitoring technologies, and multi-objective optimization of combined CO₂-EGR and geothermal operations. Additional studies are needed to establish reliable reservoir selection criteria, assess long-term storage security, and improve the commercial feasibility of integrated deployment approaches.

In conclusion, the combined deployment of CO₂-EGR and geothermal heat extraction offers a promising approach for simultaneously improving gas recovery, reducing greenhouse gas emissions, utilizing geothermal resources, and extending the operational life of existing gas infrastructure within the global energy transition framework.

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