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Review

An Overview of Geological CO_2 Sequestration in Oil and Gas Reservoirs

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Abstract: A tremendous amount of fossil fuel is utilized to meet the rising trend in the world's energy demand, leading to the rising level of CO_2 in the atmosphere and ultimately contributing to the greenhouse effect. Numerous CO_2 mitigation strategies have been used to reverse this upward trend since large-scale decarbonization is still impractical. For multiple reasons, one of the optimal and available solutions is the usage of old depleted oil and gas reservoirs as objects for prospective CO_2 utilization. The methods used in CO_2 underground storage are similar to those used in oil exploration and production. However, the process of CO_2 storage requires detailed studies conducted experimentally and numerically. The main goal of this paper is to present an overview of the existing laboratory studies, engineering and modeling practices, and sample case studies related to the CCS in oil and gas reservoirs. The paper covers geological CO_2 storage technologies and discusses knowledge gaps and potential problems. We attempt to define the key control parameters and propose best practices in published experimental and numerical studies. Analysis of laboratory experiments shows the applicability of the selected reservoirs focusing on trapping mechanisms specific to oil and gas reservoirs only. The current work reports risk control and existing approaches to numerical modeling of CO_2 storage. We also provide updates on completed and ongoing CCS in oil and gas reservoir field projects and pilots worldwide.

Keywords: carbon dioxide storage; geological sequestration; oil and gas reservoirs; depleted reservoirs; numerical modeling

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1. Introduction

The fuels and technologies used to meet the growth in energy demand over the last century have changed considerably, since successive waves of technological innovations have affected the energy sector [1,2]. The first waves extensively expanded the use of oil. Subsequent waves increased the use of natural gas as a transient fuel, followed by the development of nuclear power and, more recently, non-hydro renewable energy power generation technologies. The transition to a sustainable low-carbon world requires a range of other energy sources and technologies, including low-carbon hydrogen, modern bioenergy, and carbon capture, use, and storage (CCUS) [3]. It should be noted that total energy demand growth has been faster than the progress made in clean energy technologies. According to the International Energy Agency's (IEA) forecasts, carbon dioxide CO_2 emissions from fossil fuel combustion will reach more than 37 billion tonnes (Gt) in 2025 [4]. For decades, the proportion of fossil fuels in the world's energy mix has remained persistently high, at over 80%. This value is predicted to decrease to only 60% by 2050 [4]. Carbon emissions increase air pollution, leading to increased health issues among the population (respiratory and cardiovascular diseases) and a hazard to the environment.

Deep decarbonization of the world's energy system requires many energy sources and technologies, such as electric vehicles, blue and green hydrogen, bioenergy, renewable energy, and carbon capture and storage (CCS) [5]. Major global economies are quickly aligning their policies and proactively adopting renewable energy technologies like wind and solar power. The growing societal inclination towards sustainability has further supported these initiatives [6]. On the other hand, developing countries need to catch up to the energy transition as they are challenged to grow their economies in a renewable energy environment, a challenge developed countries did not experience in the past [7]. A fact often overlooked is that meeting the projected demands for renewable-related materials and minerals requires massive mining operations, which pose major short- and long- term environmental threats [8]. Therefore, it is evident that the reduction in fossil fuel use will gradually decline over the next few decades, making it essential. Nevertheless, it has never been more apparent how important it is for the world to make a collective effort for a significant change toward a net-zero future [9–11].

Effective CO_2 geological sequestration is determined mainly by the capacity to ensure long-term secure confinement and the availability of many pore spaces and a capping rock [12,13]. Depleted oil or gas reservoirs (DOGR) and some deep saline aquifers are the most likely candidates to meet these needs. Many articles in the literature describe experimental [14] and numerical simulation [15,16] methodologies for saline aquifers, but only a few articles cover CO_2 storage in depleted reservoirs. Deep saline aquifers with confining layers are widely studied since they are believed to have a larger storage capacity than DOGR [17]. Despite this, DOGRs are desirable because of their proven capacity to store buoyant fluids securely across geologic time and without capital investments into new existing infrastructure [17–19]. In addition, CO_2 injection in depleted reservoirs provides the benefits of CO_2 storage co-optimization with oil and gas recovery.

The development of any CCS facility in DOGR is a complex project requiring a pre-feasibility study in both short and long-term planning [20], which should include risk assessment and laboratory and numerical research on capturing, transporting, and storing CO_2. For a CO_2 storage project to be successful, it is essential to gain a more thorough understanding of the mechanisms and processes that occur following the injection of supercritical CO_2 in both short- and long-term planning . As mentioned before, several factors make depleted oil and gas reservoirs good candidates for CO_2 storage [19,21,22]. Therefore, numerous research and review studies are devoted to detailed experimental studies of geological CO_2 sequestration [19,20,23–26]. However, various trapping mechanisms [27–30] are governed by multiple interdependent processes simultaneously, which, in turn, can vary depending on the type of target reservoir (oil sandstone, carbonate, shale, and tight). So, to successfully implement the CCS in DOGR, a full understanding of the reservoir specifics and important experimental parameters should be examined in detail. At the current state of the literature, experimental studies of the CCS in DOGR are mostly presented in separate narrow-targeted topics unsystematically, since many previous works focused on saline aquifers and other geologic types of storage. In our work, we attempt to prepare an integrated summary of available literature, group the main control parameters by their importance, and prioritize and simplify the existing operational checklists.

Another objective of this review is to examine the latest advances in CO_2 storage and sequestration simulations and describe the different numerical simulation approaches for the abovementioned reservoir types [31]. Also, a wide majority of literature reports focus on the simulation of CO_2 sequestration modeling in saline aquifers [12,13,26,32–35], but only a few publications focus on CO_2 storage in DOGR. According to [34], most existing simulators [13] broadly agree with each other, with some discrepancies resulting from the various fluid property models. A limited number of investigations were performed on the numerical simulation of geomechanical properties [36,37], the influence of oil/gas saturation [28], operational parameters for optimization [35,38,39], and the influence of reservoir heterogeneity [40,41]. The main challenge of CO_2 storage simulation is integrating a wide range of time and length scales and up-scaling that should be coupled with geochemical reactions [13].

Finally, a combination of laboratory and numerical studies [24,28,40] provides valuable background for CCS field projects [42–45]. Today's most used CCS technology utilizes CO_2 as an enhanced oil recovery (EOR) agent for hydrocarbon reservoirs. However, the global trend in CCS field development indicates that the majority of the proposed projects are less concerned with CO_2-EOR and more focused on dedicated geological storage (DGS) [46], attributed to the larger capacity for CO_2 storage offered by different types of geological reservoirs. Each DGS project is going through a detailed comprehensive investigation stage since the technology is new for the world, unlike EOR, and requires precision and accuracy before moving on to the pilot projects [47–49].

In the course of the main body of the manuscript, we review various research articles related to different technologies of CO_2 sequestration in oil and gas reservoirs and necessary experimental studies for defining the applicability of CO_2 storage. In summary, we highlight the most important experimental control parameters in applicability, sequestration, and leakage risk studies, discuss the limitations of current state numerical modeling, and analyze the existing trends and challenges of the CO_2 storage studies in DOGR. This research also details the general numerical simulation approaches and their limitations. Finally, the case study briefly describes the application of experimental and numerical results in the field.

2. Reservoir Screening and Experimental Investigations for CO_2 Sequestration

Geological sequestration combines various CO_2 storage sites: coalbed methane reservoirs, saline aquifers, including basalts, oil and gas reservoirs, and sedimentary basins. This study focuses on CO_2 storage in oil and gas reservoirs due to their favorable geostructural characteristics, extensive data availability, and reduced pressure after exploitation [19,21,22]. The reservoirs possess impermeable cap rocks, sufficient porosity/permeability, reduced pressure, and existing infrastructure, making them suitable for CO_2 storage with a reduced risk of cap-rock fracturing [18,19,21,22].

All oil and gas reservoirs as potential CO_2 storage sites can be classified into two main groups [50,51]. First, among the most suitable storage sites are the porous rocks of old (closed) and depleted gas or oil fields that have held fossil fuels for millions of years [19,21]. The second group includes active oil and gas fields which can become an option for successful CO_2 storage. Recent literature reports that CO_2 injection in active oil and gas fields can be performed as a part of an enhanced oil recovery technique where both miscible or immiscible displacement of hydrocarbons can be achieved [52]. The CO_2 can also be reinjected into DOGR after separating from target gaseous products in projects devoted to in situ hydrogen generation directly in hydrocarbon reservoirs [53–56]. More details on the geological CO_2 sequestration studies can be found in [19,20,23–26].

2.1. Preliminary Field Evaluation, Trapping Mechanisms and Control Parameters

Prior to initiating CO_2 injection, the control parameters must be extracted from geological data regarding the prospective storage site. To determine the suitability of each candidate reservoir, an evaluation must be performed that includes the following information relevant to the applicability criteria of the specific reservoir. These include, but are not limited to [57]:

- physical/stratigraphical applicability (presence of seal cap rock, logging data, and overall conditions);
- mechanical conditions of the target formations;
- the economic status of the field (calculated potential of storage), infrastructural (logistics and financial), reservoir properties;
- physicochemical interactions for the CO_2-rock-fluid system at each step of the CSS process.

Thibeau et al. [58] present a comprehensive review of the various approaches for estimating CO_2 storage capacity and provide a comprehensive overview of national and global preliminary assessments of CO_2 storage capacity in mineralized water-bearing layers. Research by [27] briefly reviews the reservoir quality and injectivity analysis for potential

CO_2 storage. It proposes the methodology for depleted storage site evaluation based on numerical and experimental studies. One of the latest reviews by [26] reports the current research progress and highlights such parameters as the depth of the reservoir, CO_2 density, rock porosity, thickness, permeability, pore size distribution, residual and condensate saturation, and lithology of the object. The paper by [59] highlights the importance of leakage control of CO_2 sequestration, providing a perspective on all sources of leakage. Injection parameters and pressure–temperature control are discussed in [60]. The main operational parameters related to storing CO_2 in heterogeneous oil reservoirs by numerical modeling are reviewed in [61].

Initial screening is a proxy for economic analysis. Source-sink matching is the first consideration in the initial screening stage. Criteria are the distance between CO_2 sources, potential sinks, and storage capacity. For the distance condition, a simple algorithm has been proposed in the literature [50]. In this report, authors employ straight geodesic distances (D) between the sources (L) and the potential reservoirs (R) where the acceptable reservoir meets the condition $D_{max} \leq |L–R|$, where D_{max} is a threshold defined by the engineer. The threshold $D_{max,}$ however, is usually not representative of the actual distance (D_{true}), and their ratio may vary up to the order of two. Therefore, additional consideration should be made for determining D_{max} to account for topographic terrain features and accessible infrastructure [50]. The second criterion is estimating the reservoir storage resource and the source CO_2 emissions. Similarly, like for D_{max}, the annual emission of CO_2 (E) and reservoir storage capacity (M_{CO_2}) are obtained, and their ratio ($A_{min} = M_{CO2}/E$) is calculated. The minimum requirement A_{min} is defined by the engineer. An initial estimate of CO_2 storage resource is based on original oil-in-place (OOIP) or original gas-in-place (OGIP). It can be performed using the USA Department of Energy (DOE) approximation [24,62].

$$M_{CO_2} = Ah_n\Phi_e(1 - S_{wi})B\rho_{CO_2std}E_{oil/gas} \tag{1}$$

where M_{CO2} is a mass estimate of CO_2 storage resources, A formation area, h_n formation net thickness, S_{wi} initial water saturation, Φ_e the average effective porosity, and B initial formation volume factor for oil or gas. Also, ρ_{CO2std} is a standard density of $CO_{2,}$ which converts standard CO_2 volume to mass. Lastly, $E_{oil/gas}$ presents the storage efficiency parameter obtained from CO_2 EOR projects in the vicinity or numerical reservoir simulations as a ratio of CO_2 volume and OOIP. Alternatively, the Carbon Dioxide Sequestration Leadership Forum (CSLF) approach can be used, which considers the original-oil-in-place (OOIP) or original-gas-in-place (OGIP) from the existing data together with pressure, temperature, and compressibility [51]:

Oil formation

$$M_{CO_2} = \rho_{CO_2r}R_f(1 - F_{IG})OGIP\left[\frac{P_sZ_rT_r}{P_rZ_sT_s}\right] \tag{2}$$

Gas formation

$$M_{CO_2} = \rho_{CO_2r}\left[\frac{R_fOOIP}{B}\right] - V_{iw} + V_{pw} \tag{3}$$

where R_f is a recovery factor, F_{IG} is an injected gas fraction, P and T are reservoir pressure and temperature, respectively, while V_{iw} and V_{pw} are injected and produced volumes of water. In case the geometry of the targeted formation should be considered, the authors provide an alternative model:

$$M_{CO_2} = \rho_{CO_2r}R_fAh_n\Phi_e(1 - S_{wi}) - V_{iw} + V_{pw} \tag{4}$$

Other considerations come into play to improve the understanding of CO_2 storage capacity further. Reservoir pressures and temperatures will significantly impact these terms, since these parameters directly influence the capability of the injected supercritical CO_2 to preserve its state [25].

The basic requirements of the potential reservoir are the temperature and the pressure of the reservoir. CO_2 is mainly injected in the supercritical state due to the higher density of supercritical CO_2. Therefore, the temperature should be higher than 31.1 °C and the pressure greater than 7.4 MPa (Figure 1). Although the CO_2 can be injected in liquid and gas states, the supercritical state is preferred in practice since its bulk compressibility is more significant than that of water, thus behaving like a gas and allowing CO_2 to flow into the smaller pores, while the increase in CO_2 density with the rise of pressure at greater depths incurs a liquid-like behavior resulting in a boost in storage capacity (Figure 1) [57]. Therefore, reservoirs at depths greater than 800 m are likely to have pressures and temperatures at which the phase stability of supercritical CO_2 should not be a concern.

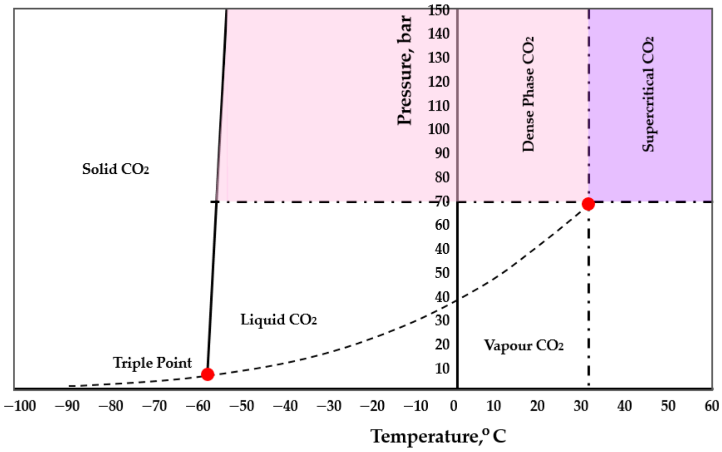


Figure 1. Phase diagram of pure CO_2 (modified after [63]).

According to the literature, various types of geological CO_2 storage candidates differ in terms of trapping mechanisms [24], structural properties of the reservoir, and geochemical conditions influenced mainly by reservoir lithology [57,64].

Two main CO_2 trapping mechanism groups can be distinguished (Figure 2). The first is a physical trapping, where buoyant CO_2 accumulates below a superimposed physical barrier, such as a low-permeable layer, and the trapping happens instantaneously in a geological timeframe [57]. Structural and stratigraphic trapping mechanisms are the first responsible for accumulating injected CO_2 into the target formation. Capillary or residual-gas trapping is a second physical mechanism where the CO_2 phase is immobilized in a pore system due to the capillary and viscous forces between wetting (usually water) and non-wetting phases (supercritical CO_2). Adsorption trapping is another physical trapping mechanism, predominantly occurring in shale reservoirs, based on the physical adsorption of CO_2 on the shale pore surface. In shale gas reservoirs, gas adsorption presents a primary trapping mechanism accounting for up to 50% of total gas volume. The storage capacity of shales largely depends on geochemical formation properties, the number of clay minerals, and pore size distribution [65].

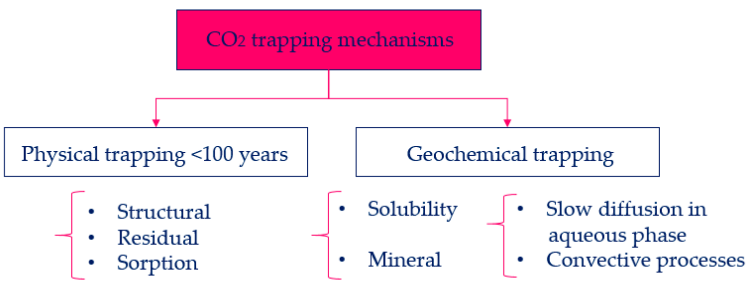


Figure 2. Schematics of CO_2 trapping mechanisms (modified after [24]).

The second trapping mechanism group is geochemical trapping, which occurs due to the chemical interaction between injected CO_2 and surrounding rocks and fluids, chemically locking it in place [66]. There are two main subcategories of geochemical trapping: solubility or dissolution trapping [14], which occurs when hydrocarbons and brines in depleted hydrocarbon reservoirs are exposed to injected CO_2 over prolonged periods (decades to centuries), and mineral trapping [18,24], in which CO_2 reacts with surrounding rock and is crystallized within the pore space due to various chemical reactions with minerals (a process that requires centuries to millennia) [67].

Specific control parameters for the selected object can be set depending on the targeted trapping mechanism. For instance, when capillary trapping is involved as the primary process, the detailed examination of the rock wettability, capillary pressure, and fluid-rock-CO_2 phase interaction is defined by experimental and numerical methods [24]. Adsorption trapping of CO_2 requires specific knowledge of CO_2 adsorption mechanisms and geochemical properties of the reservoir, including evaluation of the adsorption capacity by isotherms, organic matter properties, mineral composition, and porous structure of the rock [65,68]. As for the mineral trapping evaluation, apart from filtration parameters and lithology configuration of the reservoir, experimental findings in the literature show that the pH values of the reservoir fluids exhibit a strong relationship with the sequence of reactions [69,70]. Mineral dissolution is one of the crucial aspects to consider in carbonate reservoirs, which are subject to further CO_2 sequestration and storage. It should be noted that each of the listed trapping mechanisms involves multiple control parameters, and every study must report integrated data for the target reservoir.

2.2. Physicochemical Interactions in Rock–Fluid–CO_2 Systems

After the CO_2 is injected into the reservoir, it is crucial to account for CO_2 mitigation and all associated geochemical and geophysical aspects of this process [23]. When addressing the CO_2—rock, CO_2—fluid interactions, numerous parameters must be considered depending on the anticipated trapping mechanism and proposed object of the CO_2 sequestration, in our case, the type of reservoir [67,71].

Most parameters are impacted by the geochemical interactions between the reservoir fluids and the surrounding rocks, including the dissolution of CO_2 into the system, which alters the concentration of hydrogen ions (pH) and, as a result, modulates the rates of chemical reactions. Although these effects may enhance permeability and porosity in the short term, thereby improving well injectivity, literature reports have shown that in the long term, these effects may lead to pressure buildup and degradation of caprock stability, potentially resulting in fault reactivation and an increased risk of leakage [72]. For this reason, all the mentioned rock—fluid—CO_2 system parameters should be studied jointly.

Petrophysical control involves monitoring the changes in porosity and permeability of the target rock during and following CO_2 injection, both in the short- and long-term. The experiments are conducted under both ambient and reservoir conditions [73]. Porosity and pore size distribution of the screened formation for CO_2 injection is another important parameter that influences the dynamics of CO_2 migration. Geological formations with highly heterogenous porosities are a subject of intensive study. For instance, the migration of CO_2 plumes is heavily dependent on geological heterogeneity, since uneven and irregular pore sizes within the reservoir promote CO_2 fingering and flow localization [74,75]. Studies have revealed that in layered heterogeneous formations, CO_2 would more effectively permeate and diffuse into segments with higher injectivity.

In contrast, numerical and field studies suggest a more localized migration behavior of the CO_2 plume in homogeneous formations, such as large sections of sand or sandstone. Surprisingly, in such scenarios, the buoyant force of CO_2 will be so pronounced that most of its volume will elevate vertically towards the cap rock and spread erratically, resulting in the uneven occupation of surrounding pore volume [76,77]. Consequently, failing to adequately consider heterogeneity or homogeneity in pore size and permeability distribution within the formation may lead to unpredictable migration of CO_2 plumes, resulting in lower storage capacity estimates and presenting a risk of leakage, especially in unconfined sections of the reservoir.

Geomechanical control displays the condition of the well integrity and its monitoring during the field screening at the project stage, the CO_2 injection, and long-term storage [21]. To assess the potential long-term impact of CO_2 sequestration, it is crucial first to consider the presence and integrity of the cap rock, as well as its ability to withstand pressure. Additionally, key petrophysical and geomechanical properties, such as uniaxial strength, young's modulus, porosity, and permeability, should also be considered. An article by Yin et al. [78] reports the effect of CO_2 saturation on the mechanical properties of shales. Hence geomechanical control is essential for complex, unconventional objects such as organic-rich, low-permeability reservoirs.

The CO_2-induced effects on dissolution/precipitation and adsorption/desorption reactions were reviewed by Harvey et al. [79], since geochemical reactions of CO_2 should also be addressed within the complex studies of CO_2 sequestration in geological reservoirs. Figure 3 illustrates the effects of such reactions on the example of carbonate rock dissolution as a result of the CO_2 brine injection highlighting the destruction of the calcite grains.

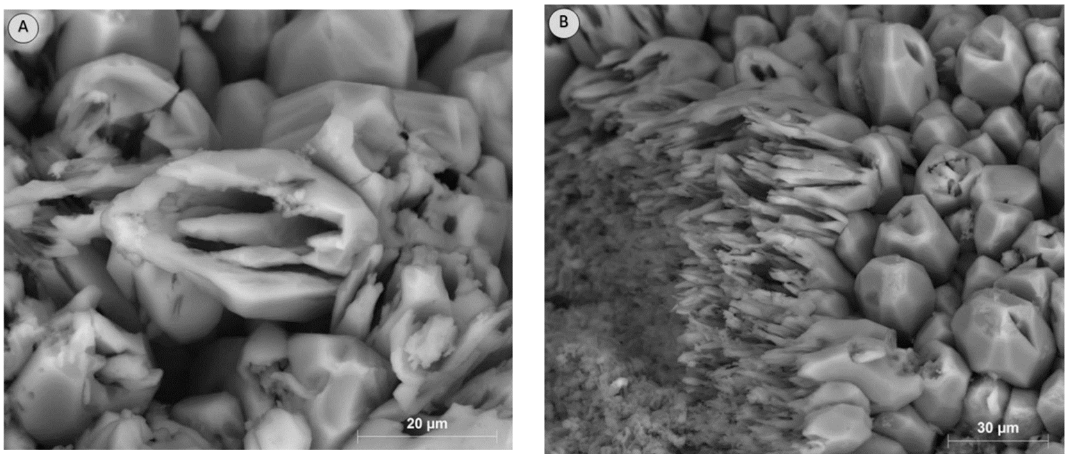


Figure 3. Calcite grain roughness alteration (**A**) and (**B**) after CO_2 brine injection ([80]).

Adsorption and desorption studies which are crucial in the case of the CO_2 sequestration investigation for DOGR, are reviewed by Hamza et al. [19]. The authors highlight the importance of the mineralogy that controls CO_2 adsorption in conventional and unconventional reservoirs. Questions related to CO_2 reactivity, kinetics, and CO_2-CH_4 interaction are of great interest in the case of gas reservoir studies as potential objects of CO_2 sequestration [81]. A study on shale CO_2 adsorption conducted by [82] investigated the long-term CO_2-rock fluid interaction. They identified that adsorption capacity decreases due to the changes in pore structure and oxygen-containing groups, which were identified as main adsorption sites in various kerogen species. Applied methods included scanning electron microscopy (SEM), thermogravimetric analysis (TGA), X-ray diffractometry (XRD), and other high-precision experimental measurements. Also, many reports perform an overview of chemical reaction characterization that may occur during long-term CO_2-fluid-rock contact in shale reservoirs caused by high-temperature and high-pressure conditions.

Wettability, capillary pressure, and the miscibility of the CO_2-oil system, which should be determined before any field study, are reported in detail in the overview by Mansour et al. [83]. Wettability is a critical parameter to monitor when evaluating changes in rock properties due to CO_2-fluid-rock interactions in depleted oil and gas fields and shale reservoirs [84]. Capillary pressure is a crucial parameter for the storage and injection dynamics of supercritical CO_2. It has two primary aspects for consideration: first, it determines the entry pressure required for non-wetting fluid (CO_2) to displace the wetting fluid (water) in a drainage-like manner; second, it impacts the probability and extent of physical immobilization of the CO_2 phase in pores through spontaneous imbibition or reentry of the wetting fluid into previously occupied pore space. Additionally, literature reports show that during these processes, the rock surface's wettability and interfacial tension between wetting and non-wetting phases can be altered due to the prolonged exposure of pore walls to the non-wetting phase, such as CO_2. Several works describe the effect of CO_2 on the wettability change of shales [78,82,85–87]. In three-phase systems with CO_2, water, and solids, the magnitude of capillary pressure is an essential indicator for CO_2 injectivity and capillary trapping/storage potential.

In summary of the current section, we provide some of the latest works related to the experimental research on potential CO_2 injection into the rock-fluid system and group them by the type of parameters (Table 1). The table also contains the main highlights of each research work. Due to the relatively low number of works devoted to the CCS in DOGR experimental examination and fragmentation of the control parameters, it is complicated to conduct a statistical evaluation and define the most critical properties. However, in the Summary section, we provide our suggestions on simplifying and reducing the load of to-do experimental work prior to the CO_2 injection launch on the field.

Table 1. Experimental programs for evaluating CO_2 injection impacts on different rock types, categorized by application area.

Study		Studied Parameters	Experiment Methods	P-T Conditions	Rock Type	Implications
			Geomechanical and Reservoir Properties			
Zhang et al., 2016 [88]	Geomechanical changes of limestone due to the sc-CO_2 injection	Young's modulus, indentation modulus, porosity, permeability	HP core flooding, nanoindentation test, ultrasonic test, gas porosity, and permeability, XRD, X-ray micro-CT.	P: 10 MPa T: 50 °C	Savonnieres limestone	After sc-CO_2 flooding Young's modulus decreased while the indentation modulus varied, most likely due migration of fines. Permeability and porosity also increased.
Sihai Li et al., 2022 [89]	Interaction of CO_2, rock and brine in carbonate rich shale systems	Mineral composition, dissolution, elastic modulus, hardness, tensile strength, porosity, permeability, and T_2 relaxation time.	Microidentation, Brazilian split, three-point bending test, HPHT soaking in sc-CO_2, XRD, SEM-EDS, gas porosity and permeability, 1D LF-NMR.	P: 35 MPa T: 90 °C	Limestone, dolomitic shale, silty dolomite	Carbonate samples' hardness and tensile strength are in strong inverse proportion with a soaking period, while permeability and porosity are in direct proportion (notably along the bedding planes). Dissolution of calcite occurs much faster than K-feldspar and albite.
Zhang et al., 2020 [90]	Mechanical response of carbonates to CO_2 flooding	Maximum compressive stress, Young's modulus, porosity	HPHT core flooding, CT scanning, UCS test	P: 10 MPa T: 50 °C	Savonnieres limestone	Maximum compressive stress decreases, Young's modulus decreases significantly after flooding with sc-CO_2 and CO_2-saturated brine, while porosity increases.
Park et al., 2022 [91]	Controlled CO_2 injection in North Sea reservoir rocks—study on induced sesimicity	Induced seismicity (acoustic emission (AE), microseismic events), Young's modulus, shear strength, and failure stress.	Uniaxial and triaxial loading and unloading tests, HPHT core flooding (sc-CO_2, sc-CO_2-brine, brine), ultrasonic velocity test.	P: 1–30 MPa T: 20–65 °C	Sandstone, siltstone, mudstone, shale	Experiments distributed by sample depth. A large temperature gradient between sc-CO_2 and sandstone with increased stiffness rises the likelihood of failure (micro-seismicity). Rocks saturated with sc-CO_2 show the highest strength and stiffness, and fracture reactivation pressure increases. Brine-sc-CO_2 injection produces large numbers of low magnitude AEs, while pure sc-CO_2 high magnitude AEs. The sc-CO_2-saturated samples have a lower dominant frequency compared to the brine-saturated samples. The elasticity of the sandstone samples varies from inelastic to non-linearly elastic. Shale and mudstone exhibit aseismic behaviour.

Table 1. *Cont.*

Study		Studied Parameters	Experiment Methods	P-T Conditions	Rock Type	Implications
			CO_2 solubility and alteration of flow parameters			
Lin et al., 2022 [92]	CO_2, rock and brine interactions and their influence on flow in porous media	Porosity, relative permeability, CO_2 solubility, mineral composition, T_2 relaxation time	HPHT core flooding, helium porosimetry, 1D LF-NMR, centrifuge test, relative permeability (by Darcy), XRD	P: 15–25 MPa T: 44–64 °C	Tight sandstone	Dissolution of calcite, dolomite, and K-feldspar. Pore size, pore throat size, and relative permeability increase over time, and irreducible water saturation decrease. The rise of pressure raises the CO_2 solubility in water/brine, while the rise of temperature causes it to decrease.
Kitamura et al., 2020 [93]	CO_2 injection speed influence on physical properties of sandstone and two-phase flow	Macroscopic capillary number, porosity, absolute permeability, CO_2 saturation, P-wave velocity, electrical resistivity, and fluid capillary and viscous limit.	HP core flooding, X-ray micro-CT, mercury injection capillary pressure, complex impedance four-electrode test, pulse transmission P-wave velocity.	P: 10 MPa T: 40 °C	Berea sandstone	CO_2 saturation in pores can be monitored using parameters such as macroscopic capillary number (N_c), P-wave velocity (V_p), and electrical resistivity (ρ). The flow rate or injection speed (represented by N_c) is directly related to CO_2 saturation. However, when N_c is low, the derived CO_2 saturation does not yield satisfactory monitoring accuracy, and resistivity measurements can be used instead.
Amarasinghe et al., 2020 [94]	Visualisation of CO_2 convective mixing (viscous fingering) and dissolution—effects of various permeabilities	Convective mixing fingers, Rayleigh number (Ra), permeability, dimensionless time (τ), CO_2 mixing rate	HPHT Hele-Shaw cell flooding (2D), digital and thermal imaging, synthetic sc-CO_2-brine	P: 10 MPa T: 50 °C	Hydrophilic micro glass beads (synthetic core)	In media with φ = 100%, CO_2 fingers and mixing occurs almost instantaneously seconds). The rate of CO_2 mixing is proportional to permeability. Permeability dictates the CO_2 dissolution pattern. For smaller permeabilities, fingering was not observed.
Agartan et al., 2015 [95]	Visualisation of CO_2 convective mixing—effects of mixed sand permeabilities	Permeability, heterogeneity, Rayleigh number (Ra), permeability, dimensionless time (τ), CO_2 mixing rate	2D flooding cell, digital imaging, synthetic sc-CO_2-brine	P: Ambient T: Ambient	Sand packs with varied heterogeneity	In homogenous sands with high permeability, convective mixing is more prevalent, whereas in low-permeable sections, diffusion mixing dominates. Heterogeneous permeability impacts the propagation of the brine- CO_2 phase and mixing mechanism. Transition zones between low and high permeability lead to lateral spreading of the injected phase, resulting in increased surface area between phases and enhanced diffusive mixing, promoting CO_2 dissolution in the long term.
Baban et al., 2023 [96]	Residual trapping evaluation of CO_2 in three-phase system	Water, oil, CO_2 saturations, recovery factors, wettability, oil displacement efficiency, spreading coefficient, T_1 and T_2 relaxation time	HPHT core flooding, wettability alteration (sample aging), 2D & 1D LF-NMR	P: 8 MPa T: 50 °C	San Sabo sandstone	CO_2 flooding generally improves oil recovery. Wettability plays an essential role in the residual trapping of injected CO_2: the oil-wet core had 12%, while the water-wet core had 20% residual CO_2 saturation. In both cases, CO_2 flooding yielded higher oil recovery than water flooding.
			Wettability and interfacial tension			
Fauziah et al., 2021 [97]	Effect of CO_2 flooding on sandstone wetabillity alteration	Advancing and receding contact angles, mineral composition, permeability, porosity	HPHT core flooding, SEM, drop shape analysis (contact angle), gas porosity, gas permeability, XRD	P: 10, 15 MPa T: 50 °C	Berea sandstone, Bandera grey sandstone	Advancing and receding contact angle changes are directly proportional to pressure change. Exposure of sandstone to CO_2 leads to wettability alteration to more hydrophobic (more CO_2 philic). Such alteration reduces residual trapping capacity but increases solubility trapping capacity.
Farokhpoor et al., 2013 [98]	CO_2 wettability alteration behaviour of reservoir rock minerals	Contact angle, CO_2 compressibility	Drop shape analysis (captive-needle drop)	P: 0.1–40 MPa T: 36, 66 °C	Quartz, fledspar, calcite, muscovite mica	Hydrophilic, quartz, feldspar, and calcite, their contact angle is not significantly affected by pressure variation. Muscovite mica, with increased pressure, increases its contact angles (from strongly water-wet to intermediate water-wet). The maximum contact angle is observed near critical pressure at 36 °C for feldspar calcite and quartz.

Table 1. *Cont.*

Study		Studied Parameters	Experiment Methods	P-T Conditions	Rock Type	Implications
Baban et al., 2021 [99]	Wettabilitty alteraton due to CO_2, rock and brine interactions	Wettability indices, permeability, porosity, T_1 time, T_2 time, capillary pressure, capillary number	HPHT core flooding, gas permeability and porosity, 2D and 1D LF-NMR mapping	P: 8 MPa T: 60 °C	San Sabo sandstone	CO_2 reduces the hydrophilicity of sandstone and lowers water wetness, likely caused by the protonation of surface silanol groups on quartz. NMR measurements show preferential water displacement in large pores following sc-CO_2 flooding, with no change in smaller pores.
Cui et al., 2022 [100]	Determination of minimum miscibility pressure of CO_2 into oil	Interfacial tension (ITF), minimum miscibility pressure (MMP)	HPHT oil droplet volume measurement (ODVM), visual inspection techinque (VIT), pendant drop	P: 1, 5, 9 MPa T: 27-80 °C	Without porous medium	Two types of CO_2/oil phases were tested, with various molecular weights and densities. Newly propsed method MMP measurement method (ODVM) shows greater accuracy. MMP is heavily dependant from P-T conditions. Authors report MMPs in for specific P-T values.

2.3. *Advanced Laboratory Studies of CO_2 Sequestration and Storage in Reservoir*

Standard experimental research is often used for defining the most basic parameters of the reservoir (see Section 2.2) and fluid-rock-CO_2 interaction. In contrast, full-fledged research on CO_2 injection into rock requires a more advanced approach. Despite the provided information on CO_2 injection mechanisms and the kinetics of the process, such tests are comparatively laborious and expensive. However, CO_2 flooding tests are an irreplaceable step in CO_2 storage screening projects, since they provide information about dominating geochemical reactions and the response of host rock matrix to changes in hydrodynamic and chemical conditions, all of which are vital for further numerical simulations that precede the pilot projects. As depleted and semi-depleted hydrocarbon reservoirs are predominantly represented by clastic sediments like sands and sandstones, many CO_2 flooding reports in literature study their behavior [22,77,93,96,101]. Secondary minerals and grain cement types also play an essential role, since they impact the reaction dynamics, migration of fine components (fines), and, therefore, the evolution of porosity and permeability alteration.

One factor influencing CO_2 sequestration is the rate of CO_2 dissolution into brines and their migration dynamics. As previously discussed, the buoyant CO_2 tends to accumulate beneath the cap rock. Due to the molecular diffusion, CO_2 dissolves into formation brine. Consequently, the density of the brine increases with CO_2 dissolution, causing the gravitational differentiation of denser brine, which eventually results in natural convection mixing (i.e., fingering) driven by the density distinction from formation brines [102]. Researchers perform numerical and physical modeling to study the initiation and evolution of convection mixing. They determined that these processes are heavily influenced not only by a porous medium's porosity, permeability, and thickness, but also by brine mineralization and its initial density [95,103–105].

A popular technique for visualization of the convective mixing is the sc-CO_2 flooding experiments in the Hele-Shaw cell [87,94,103,104,106]. A Hele-Shaw cell is an experimental setup that consists of two parallel plates separated by a narrow gap through which a fluid flow can be introduced with or without the porous medium. The 2-D Hele-Shaw cell allows researchers to study fluid flow dynamics under controlled conditions. For instance, a paper by Jiang et al. [107] reports such a setup to study the effects of salinity and temperature on the rate and dissolution pattern of CO_2 solution with brine (Figure 4). Likewise, to study CO_2 convective mixing in reservoirs, the surrogate fluids are being used to simulate viscosity and, more importantly, the density of the CO_2.

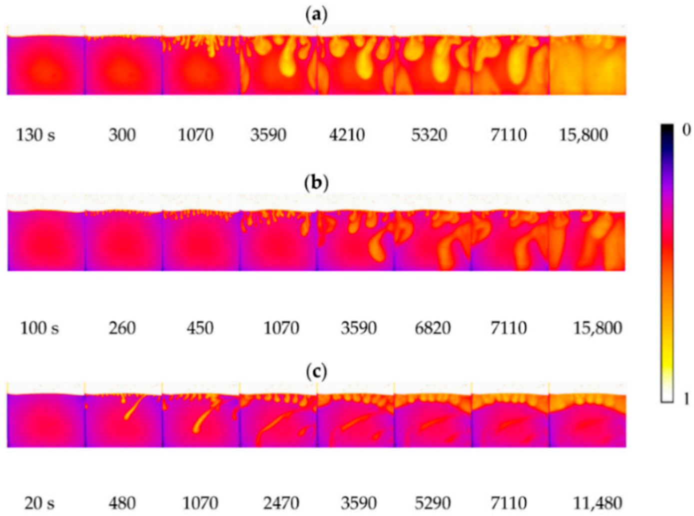


Figure 4. Time-lapse visualisation of CO_2 convective mixing (viscous fingering) into water, by Hele-Shaw setup at 33 °C at various salinities: (**a**) 0 wt%, (**b**) 0.25 wt% and (**c**) 1.00 wt% [107].

The exact properties are induced by the reservoir conditions based on pressure-volume-temperature (PVT) tests and corresponding diagrams. For instance, authors in [94] use a high-pressure Hele-Shaw cell to perform convection mixing experiments by injecting the dyed CO_2 surrogate into a brine-saturated cell, both with and without a porous medium. Monitoring of the mixing dynamics was performed using digital imaging. Literature reports show that in set-ups without a porous medium, the convective mixing takes place on a scale of a few seconds. In the porous medium, the rate increases proportionally with the increase in permeability [94]. The development of fingers is likely to be observed in mediums with homogeneous and high permeability. In a similar study [106], the authors performed a PVT cell test in addition to Hele-Shaw experiments to further study the CO_2 diffusion coefficient variability during the convective mixing. The results indicate that the highest values of CO_2 diffusion can be observed in the early stages of injection, thus confirming it to be a more pronounced mechanism than molecular diffusion.

An additional consideration is the permeability heterogeneity of the reservoir. For instance, Agartan et al., in their work, study the effect of reservoir heterogeneities on CO_2 dissolution into formation brine [95]. Their hypothesis states that the vertical variation in permeabilities and porosities in sand and sandstone reservoirs substantially impact the convective mixing rate. This hypothesis was tested through sc-CO_2 injection experiments performed in 2-D tanks with homogeneous and heterogenous sand packing configurations under varying pressure-temperature conditions.

Another recent trend in CO_2 injection studies is the utilization of the micro-computed X-ray tomography (micro-CT). Micro-CT scanning is used for 3D pore structure reconstruction, representation of fluid distribution, and determination of fluid migration patterns relative to the pressure and temperature variations and flow-influencing parameters, such as porosity, relative permeability, and wettability [25,108]. Once sample scans are obtained, properties can be evaluated by compiling the slices into 3D digital models. Subsequently, multiphase flow simulations can be conducted using software such as Geodict or Pergeos [109], including simulations of CO_2 or sc-CO_2 injection. However, the resolution of industrial micro-CT scanners typically ranges from 1–50 microns, resulting in poor resolution of nano-scale structures, where CO_2 can flow or dissolve (such as nanochannels and crystalline pore walls). To address this limitation, recent approaches in the literature have combined higher-resolution imaging tools, such as scanning electron microscopy (SEM), with micro-CT scans. 2D SEM slices are used to train convolutional neural networks (CNNs) to predict sub-resolved nanopores and structures on micro-CT slices [110]. SEM imaging also enables the qualitative analysis of micro and nanopore structures, allowing for visual inspection of rock material before and after CO_2 flooding [80].

Micro-CT scanning, therefore, is used for 3D pore structure reconstruction, representation of fluid distribution, and determination of fluid migration patterns relative to the pressure and temperature variations and flow parameters, such as relative permeability and wettability [25,108]. This information can be used to optimize the CO_2 flooding process, improve the understanding of the existing trapping mechanisms, and improve the overall assessment of potential CO_2 storage capacity.

Additionally, micro-CT imaging can be used to monitor the evolution of CO_2 plumes within the rock sample and to detect any changes in the rock structure that may occur due to CO_2 injection. Another advantage of this technology is the capability for visualization and even real-time observation of fluid displacement within the rock, as well as its chemical and mechanical behavior [111–114]. For instance, Garcia-Rios et al., in their work [114], use micro-CT to study the dissolution of calcite and gypsum in limestones as a function of variable CO_2 injection rate. The authors hypothesize that a CO_2 flow rate can substantially impact the pore and fracture geometry, and the rate of these alterations may change the hydrodynamic properties of the rock. Similarly, micro-CT imaging is used to characterize the geomechanical behavior of the reservoir rock relative to CO_2 flooding, mechanical alterations of rock, induced microseismicity, microstructural changes, and fracture propagation in shales [71,88,115–117]. For example, in a different work [90], the authors study the limestone's mechanical changes during the CO_2 injection, using micro-CT imaging with Discrete Element Method (DEM). The authors hypothesized that the dissolution of the primary limestone mineral, calcite, causes a substantial weakening of the limestone matrix, which raises a question about the mechanical stability of the potential carbonate reservoirs. Study findings show a substantial drop in the maximum compression stress of the limestone samples after their exposure to the injected fluids, a 14% drop in case of flooding by sc-CO_2, and a 54% drop in case of flooding by brine with dissolved sc-CO_2.

Thus, despite the costs and complicated experimental procedures required, advanced laboratory studies of CO_2 injection in a rock provide a wide range of information on CO_2 behavior and processes occurring at both a micro and macro resolution. In addition, the results of presented studies can be utilized for validation of the numerical models at the later stages of the target field evaluation.

2.4. Risks and Leakage Control

The risks associated with CO_2 leakage involve leakage from the storage zone to the upward subsurface zones or the atmosphere, with various consequences depending on the leakage and upward formations type, described in detail in [118–121]. There are geomechanical, well integrity, and other leakages (surface facilities leaks, seismicity), which could lead to the loss of CO_2 storage containment [21,24,122,123]. These risks may occur during the injection phase and afterward. Hence, risk management measures such as monitoring with various instruments, emergency responses, and remediation plans are necessary during CO_2 storage planning [24,118,124].

Most modeling and monitoring studies conducted in the planning and development, implementation, and monitoring phases of CCS are done primarily to avoid gas leakage into groundwater aquifers, shallow soil zones, overlying resource-bearing formations, and the atmosphere, to securely ensure the containment of gas.

The leakage of CO_2 might have different origins:

- Geomechanical leakages (caused by reservoir over-pressurization with the formation of cracks in the cap rock or out-of-zone hydraulic fracture or activation of pre-existing faults and fractures);
- Well integrity leakages (annular leak, cement degradation, casing degradation);
- Surface facilities leakages and leakages due to the induced seismicity.

The modeling also helps in monitoring because it can simulate various leakage scenarios. At the same time, the actual field measurement provides the critical inputs to refine the modeling work to define the risk and impact associated with each of the wells.

Various methodologies are available for evaluating the long-term integrity of wells, as described in [21,124]. These technologies are data mining, Free Energy Perturbation-based analysis, performance & risk management technology, CO_2-predictive engineering natural systems (CO_2-PENS), laboratory well integrity evaluation, and many more. Modeling requires many assumptions in a scenario, as existing old wells need more data to simulate the CO_2 leakage model.

Consequences of failed CO_2 geological storage projects can be local and global, as described in various reports [119,120,122,125,126]. Local consequences lead to the contamination of the upward formations with CO_2. The global consequence is associated with leakage back into the atmosphere, regardless of timing and rate, thus reducing the effectiveness of geological storage and contributing to increased CO_2 concentrations in the atmosphere.

It should be noted that the leakage at the surface back into the atmosphere will be less probable than the leakage from the primary storage unit to the upward formations because some, if not all, of the CO_2 leakage from the latter will be most likely immobilized by various trapping mechanisms along the leakage pathway.

The integrity and safety of CO_2 geological storage are essential for the company's reputation, people, and environment. Thus, critical parameters that need to be investigated and monitored for successful CO_2 injection and long-term storage later on, include the upper and lower bounds of pressure and temperature experienced by the reservoir, the orientation and mechanical properties of existing faults, rock mechanical properties (e.g., strength and stiffness), in situ stresses, and reservoir depth and shape, safe upper limits on injection pressures, preferred injection well locations, review of historical records for stimulation treatments, drilling program design to mitigate rock yielding in new wells, and assessment of wellbore integrity indicators in existing wells.

3. Numerical Simulation

3.1. Primary Approaches

Reservoir modeling, which is based on data-constrained models that simulate the behavior of fluids, rock, and drive mechanisms inside the reservoir, is an essential instrument for addressing issues and difficulties in the context of geological storage of CO_2 in the deep subsurface. [127] Numerical simulators and mathematical models are essential for addressing problems with cost, safety, and viability. The creation of a legal framework that supports the broad use of CCS technology will undoubtedly also need such models [128].

Anxtensive numerical studies were performed to study the problems of CCS storage in saline aquifers in contrast with DOGR. Iskhakov et al. in [12] describe the main mechanisms of CO_2 sequestration in saline aquifers and list different numerical simulators developed for saline aquifers [13,32–34]. The problem of long-term CO_2 behavior in an aquifer with a sloping cap rock was studied through numerical simulation [32]. A first crude sub-grid model was developed to overcome the problems of the CO_2 plume. The article by [13] introduces the theoretical background behind CO_2 storage and governing equations, a comprehensive overview of the simulators available for geological carbon storage, and numerical issues and challenges. A paper by [26] presents the interrelations among laboratory experiments, theoretical analysis, and numerical simulations to study the mechanisms of failure of geological integrity of CO_2 storage, along with a summary of reported research on the CO_2-oil interaction mechanisms. Authors in [35], along with experiments studying the stability of geological storage, presented a numerical simulation of the stability of supercritical CO_2 storage. A numerical simulation of CO_2 sequestration with coupled EOR in a shale gas reservoir is presented in [129]. The CMG-GEM simulator is applied in this research to evaluate the feasibility of CO_2 sequestration in shale gas reservoirs with potential enhanced gas recovery (EGR). The necessity of effective fracking was discovered.

Generally, numerical models for CO_2 storage should take into account injectivity, storage capacity, security, and the long-term fate of the gas [130]. It is also essential to apply the appropriate gridding and upscaling of geological features for accurate representation of CO_2 plume behavior and the evolution of pressure over time while maintaining sufficient computational efficiency. The boundary conditions in the vicinity of the injection zone should also be carefully considered, which describes whether the flow is restricted on one or more sides as well as the top and bottom of the zone by stratigraphic or structural components [131].

Understanding the fundamental physical processes and incorporating them into mathematical and numerical models are prerequisites for translating laboratory results to the scale of application of the CCS technology [24]. Numerical models are helpful for CCS projects during the planning and approval phases, the actual injection process, and in the following steps. Numerical models should be used throughout a project's life cycle for a better decision-making process [128].

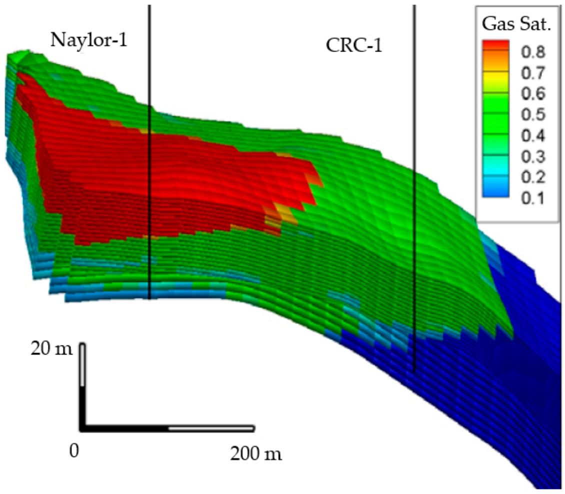
Due to the wide range of time and length scales involved, simulating geological CCS is exceptionally difficult [132]. Important computational difficulties include the numerical treatment of nonlinearity and the discretization of space and time. Accuracy, stability, and computational speed are the primary issues in the discretization and numerical solution to the discretized partial differential equations (PDE) [133,134]. Both geographical discretization and temporal discretization or integration are affected by these development concerns. The present simulators for geological CCS frequently leverage knowledge from the oil and gas sector to simulate multi-phase flow in porous media with and without geochemical reactions [135,136]. Simulators have also been created specifically for computing chemical processes. The performance of simulation models can vary significantly due to various discretization techniques, which result in varying levels of numerical precision and approximation in their modeling. Emphasis should be placed on the numerical difficulties of modeling long-term carbon storage [13].

This study focuses on DOGR, which are good candidates for geological sequestration but have been deemed uneconomical for continued hydrocarbon extraction. These fields include the necessary storage-site features as well as a developmental history, enabling historical modeling of the models. Using this history-matching method can increase prediction accuracy and confidence. The infrastructure and wells utilized to create these fields are also suitable for injecting CO_2. However, because of the necessity to minimize pressures that could break the cap rock and the significant leakage hazard provided by the abandoned wells, the storage capacity available in depleted reservoirs is significantly reduced, though there is a possibility of leaks behind well casings [24].

3.1.1. Numerical Models Differentiated by Scale

Generally, multi-phase, multi-component simulations can be used to describe physical systems, including non-isothermal phenomena that mostly appear in the vicinity of the injector as a result of the pressure drop and expansion of CO_2 (Joule–Thompson effect) [137]. Highly permeable vertical pathways, such as leaking wells, can also undergo rapid gas expansion connected with Joule-Thompson cooling [138]. Issues of this nature can be addressed through numerical or analytical simulations utilizing various models. The validation of these models is difficult, though, due to the lack of appropriate data on the relevant scales [128].

The integration of a wide range of time and length scales is the most notable aspect of the flow and transport phenomena in a porous medium for CO_2 storage [13]. Depending on the task, such models can be extended to large areas of interest, and various phenomena of interest can be observed over a long period of time. Figure 5 below provides an illustration of the visualization of gas saturation and CO_2 distribution during CO_2 injection into a depleted gas field.



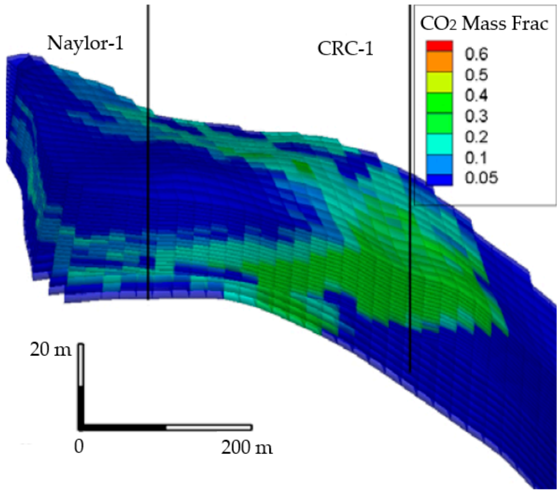


Figure 5. Simulation results of CO_2 injection in the depleted gas reservoir in CMG format (**a**)gas saturation distribution; (**b**) CO_2 mass-fraction distribution steps in 3D model modified after [139].

A multi-scale strategy is one way to handle such significant scale disparities. A multi-scale strategy refers to the division of the simulation process into multiple stages, each of which considers a specific scale and set of processes. A recent multi-scale model of CO_2 dispersion leakage from the seafloor was reported [140], in which a mesoscale hydrostatic model was coupled with a small-scale full 3D two-phase model, although the upscaling problem still has to be fully resolved. Multi-scale modeling to study CO_2 dispersion is an attractive option, since it can provide accurate predictions at a reasonable computational expense. [140]. The goal of multi-scale modeling of CO_2 dispersion is to simulate multi-phase, multi-species heterogeneous systems with complex local processes in an efficient computational manner. The macroscales will be handled on a coarse grid that might include a few fine-scale components that can be modeled using approximations or resolved using a fine resolution, i.e., a fine grid. An upscaling method must be used to build the governing equation on a coarse grid [141,142], where variables are divided into their coarse-grid averages and local fluctuating components, similar to how filtering works in large-eddy simulations of CFD. In contrast, fine-scale processes are only considered in a narrow zone of interest where phase interface exists or where mass-transfer processes have a significant impact. The upscaled equations are then solved on the coarse mesh. Although several types of methods have been proposed [143], the creation of such a formulation is still a work in progress. Additional issues with upscaling arise when the contributions of geochemical reactions must be fully considered [13].

3.1.2. Numerical Models Differentiated by Complexity

The number of fluid phases, the number of components considered, the discretization techniques employed, and other factors have a significant impact on the complexity of the simulators. A variety of physical models and numerical methods have been employed to study the complex process of CO_2 storage [128,134].

The model's level of complexity can range (see Figure 6) from strongly coupled, highly resolved three-dimensional simulations that demand powerful computing resources to straightforward, analytical solutions [144]. The third fluid phase (oleic phase) complicates CO_2 storage in DOGR in comparison to CO_2 storage in deep saline aquifers. In order to recreate complex physicochemical processes like the geological storage of CO_2, the resulting model must therefore incorporate multi-phase flow equations and multi-component equations. Due to various processes involved, the mathematical problem becomes very complex, involving strongly coupled non-linear PDEs. These problems, at least in their full complexity, cannot be resolved analytically [144].

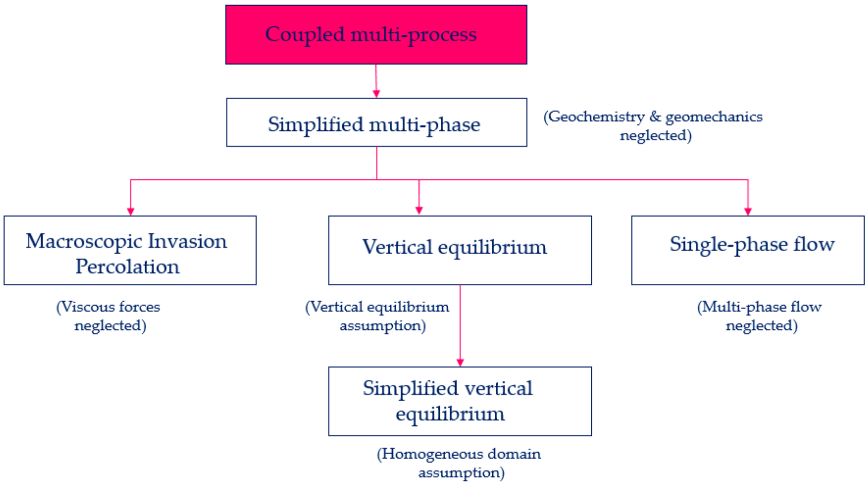


Figure 6. Hierarchy of model complexity (modified after [144]).

The development of mathematical models must take into account the relevant subsurface processes, such as the flow [145] and transport behavior [146] of multiple phases, geo-chemical reactions, as well as geomechanical effects [144]. The characteristics of the porous media, such as permeability and porosity, have a significant impact on the hydraulics of the fluid flow of CO_2 dispersion. Furthermore, constitutive relationships, such as those for capillary pressure and relative permeability as functions of saturation, are required to describe the interaction between fluid phases and the rock matrix [147]. The geological input, the kinetic modeling of geochemical reactions, and the fluid characteristics all affect how accurate a numerical simulation is. Given the extraordinarily long duration of some reactions (e.g., mineral carbonation), the kinetic modeling aspect is not fully investigated. In various kinds of simulations, these input parameters also have diverse functions. Geochemical modeling, for example, will be less significant in simulations of the "short-term" injection process than the one in simulations of the "long-term" storage process. In summary, constraints and uncertainties inherent in the mathematical formulations must be addressed, in addition to any numerical difficulties that may arise when solving these equations [144].

3.2. Existing Simulators

In order to accurately simulate the behavior of fluids during CO_2 storage in DOGR, interdependent processes must be considered to represent the behavior of fluids in the injection formation. The creation of the model must take into account a variety of physical and chemical factors in order to be accurate and reliable [144]. As previously mentioned, these processes involve molecule transport and diffusion, chemical reactions, heat transfer, mechanical stress and strain, fluid characteristics and phase behavior, and multiphase fluid movement. It should be highlighted that currently there is no single model able to simulate all the connected processes concurrently, and such a model is not required for practical applications. Models that take into consideration flow, chemical processes, and geomechanics are frequently combined [34]. Thus, the choice of the simulator is greatly dependent on the specific applications and the nature of the process that needs to be modeled.

Several research teams are developing numerical simulators for geologic CO_2 sequestration [24]. The performance of the simulators, including both computational accuracy and costs, can be significantly influenced by the numerical techniques utilized in the simulation models, such as finite difference, fine element, and finite volume [13,148].

A comprehensive overview of currently used simulators developed for geological CO_2 storage is presented in literature [13,24,149]. In addition, the interrelations between laboratory experiments, theoretical analysis, and numerical simulations are well described in [26], along with a synopsis of the reported research on the mechanisms underlying the loss of the geological integrity of CO_2 storage.

Pruess et al. [34] performed numerical modeling of CO_2 in saline aquifers. An algorithm for phase transition from supercritical to sub-critical CO_2 was also developed by Pruess et al. to simulate the possible leakage process of CO_2 escaping from deep reservoirs [33]. In addition, carbonate precipitation was modeled in TOUGHREACT using batch reaction modeling. The GEM-GHG, developed by CMG [150], is a fully coupled simulator that models convective transport and chemical reactions for the purpose of simulating greenhouse gas sequestration. In addition to phase equilibrium, GEM-GHG includes mineral dissolution and precipitation kinetics. Other codes were also modified or used directly for CO_2 sequestration modeling. Examples include UTCOMP [151], NUFT [152], Eclipse 100 [153], Eclipse 300 [154], and CMG-STARS [155]. A thorough study of these numerical simulators was performed by [34] and concludes that current simulators broadly agreed with each other while some discrepancies resulted from the different fluid property models.

Injection of CO_2 for the purpose of a coupled sequestration-EOR process is appealing because both goals of ultimate recovery enhancement and greenhouse gas reduction would be established by employing this scheme [156]. Some authors have published works addressing economic analysis CO_2-EOR projects [157].

Despite all comprehensive studies on the CCS process in saline aquifers, there is little work published considering the CO_2-EOR scheme. In the current work, we highlighted some relevant research with the main parameters affecting the CO_2 storage in DOGR.

3.3. Model Design Considerations and Application Examples

The study objectives, the quantity and quality of available reservoir characterization data, geological description, the development strategy, time and cost restrictions, and simulator accessibility and its capabilities must be taken into account while designing the reservoir model. Models can range from intricate single-well mechanistic models for determining injectivity for basins to regional-scale models for determining the capacity and movement of long-term CO_2 storage [127].

In order to make decisions during the early stages of CCS projects, risk assessment is required, and CO_2 injection performance and sequestration efficiency should be considered. Screening criteria for CO_2 storage are listed in [158] and include reservoir characteristics such as capacity, pore pressure gradient, location, seals, oil, or gas characteristics such as composition, surface facilities and pipelines, corrosion and synergy. Storage capacity is thus a crucial factor for candidate reservoirs in CO_2 storage projects, but stability is just as critical. Over-injecting CO_2 into the reservoir based on reservoir capacity and rock strength is bad for the reservoir integrity [36]. A breach of the original stable geologic structures, natural hydraulic fracturing of the seal, or the slide of sealing faults, among other things, might result from the overpressurization of fluids in rock pore space, which can produce heaving and dilatation of the reservoir rocks. Geomechanical characteristics' significance is discussed in [36,37]. The most significant variables in the investigation of CO_2 long-term behavior [16] are layer thickness, capillary pressure permeability, and relative permeability (STAR general-purpose multiphase geothermal reservoir simulator). Limited information on kinetic studies is provided in the literature [149] for CO_2 storage in DOGR and should be studied further along with mineralization. Table 2 provides a summary on software applications of the CO_2 sequestration modeling in DOGR and highlight main takeaways from each study.

Table 2. Summary on numerically studied parameters affecting CO_2 storage in DOGR.

Study		Studied Parameters	Software	Implications
Li, 2016 [36]	CO_2 storage simulation using geomechanical-fluid coupling model	Geomechanical (stress) and reservoir properties (porosity), operational parameters (pressure)	CMG 2012	(1) Maximum ground uplift was predicted depending on the amount of injected CO_2 (2) Limited and small changes in porosity due to pressure and total mean stress variation (3) Limited pore pressure ensures the absence of rock damage due to tensile deformation, and conservative value of calculated storage capacity
Sharma et al., 2022 [37]	Simulation of CO_2 injection into DOGR using geomechanically coupled and non-coupled simulation models	Geomechanical properties (stress, Poisson's ratio, and Young's modulus)	CMG	(1) Substantial influence of geomechanical rock properties on simulation results (2) Proposed coupled model exhibited more realistic pressure and saturation profiles in comparison to the simple, non-geomechanically-coupled model and improved cost of computation time (3) Iterative (i.e., two-way coupling) simulation models can provide greater accuracy in predictions, but multiphase two-way models can significantly increase the computational efforts (4) Detailed and accurate geological modeling prior to reservoir simulation can lead to greater accuracy in the reservoir behavior
Raza et al., 2018 [28]	Simulation of CO_2 storage accounting the effect of residual gas saturation	Operational parameters (injection rate) and reservoir properties (residual saturation)	Eclipse (E300)	(1) The amount of remaining gas is important to achieve a high effective storage capacity with sustainable injection rates (2) Direct relationship between residual gases and the capillary trapping, and inverse correlation of the injection rate and structural and dissolution trappings and storage capacity were identified (3) High residual gas saturation can lead to a high-pressure buildup and elevated security risk. (4) Low injection rate are favorable when the level of remaining gas in the reservoir is significant.
King et al., 2011 [139]	History matching of the CO_2 storage simulation models accounting heterogeneity	Operational parameters (arrival time), downhole pressure	TOUGH2/EOS7C	(1) Significant influence of geological uncertainty determined by means of multiple geostatistical realizations. (2) Pressure data from downhole gauges has significant impact on precision of simulation and ability to adjust the bulk reservoir properties in the model
Kopp et al., 2010 [39]	Implicit simulation of CO_2 leakage risks through abandoned wells	Operational parameters (injection time, distances between wells) and reservoir properties (permeability anisotropy, geothermal gradient, relative permeability, irreducible water saturation)	MUFTE_UG	(1) Statistics of reservoir properties gathered can be used as selection criteria for future decision-making (2) The depth of the reservoir and the geothermal gradient have shown the greatest influence on risks, while anisotropy plays a role only for short distances. Risks are independent of porosity in the given study (3) Optimized placement of wells determined analytically
Raza et al., 2018 [38]	Numerical simulation of depleted reservoirs suitability for CO_2 storage	Operational parameters (injection rate), reservoir properties (permeability)	Eclipse (E300)	(1) Condensate gas formations are more suitable for CO_2 storage than gas reservoirs (dry and wet) due to slight remaining gas volume, phase behavior of the condensate gas-CO_2 mixture, good injectivity, and the smaller amount of methane mole fractions present in the medium (2) Injection rate has great impact on medium storage behavior and optimum injection rate (depending on the reservoir) can lead to high storage potential in gas reservoirs (3) The reduction in the permeability of the storage site enhances the overall storage capacity by boosting the residual and dissolution trappings after the injection period
Sun et al., 2021 [35]	Numerical study of the stability of CO_2 storage	Operational parameters (injection rate, pressure, temperature)	CMG	(1) Supercritical CO_2 injection can lead to high gas storage rate, storage stability, and also improvement of gas recovery (EOR) (2) Temperature does not affect the displacement and storage effects of supercritical CO_2 in gas reservoirs (3) The increase in the injection pressure and reasonable control of the injection rate can delay the breakthrough of supercritical CO_2 displacement

Table 2. *Cont.*

Study		Studied Parameters	Software	Implications
Akai et al., 2021 [40]	Comparison of numerical simulation of CO_2 storage and analytical solution	Reservoir properties (porosity, permeability, aquifer size, saturation, rock compressibility)	Eclipse (Version 2019.2)	(1) Effect of heterogeneity (porosity, permeability and saturation factors has negligible effect on CO_2 storage capacity (2) The reversibility of rock compaction has the most significant factor influencing the storage capacity
Lei et al., 2019 [41]	Field scale numerical simulation of CO_2 storage of four different gas fields	Operational parameters (injection rate, pressure, development scheme) and reservoir properties (permeability, depleted pressure)	TOUGH2/EOS7	(1) Optimal operational parameters were defined (2) Reservoir thickness, permeability, boundary conditions, effect of formation water and water-rock-gas interactions remain as uncertainty and affect the accuracy

4. Field Projects: Application of Laboratory and Computational Experiments

4.1. Potential of Geological CCS and Its History

Ongoing carbon capture, utilization, and storage (CCUS) projects aim to determine the fate of carbon dioxide, either by utilizing it through CCU projects or storing it via CCS projects. The CCU projects currently meet global CO_2 demand of about 270 million tons of CO_2 per year [159,160]. Utilization technologies are divided into direct and indirect use of CO_2. The primary technology for direct consumption of CO_2 is CO_2-EOR technology [46,161,162], associated with CCS projects. The prevailing technology of indirect utilization via transformation is the carboxylation process resulting in the production of urea or carbonates, consisting of about 60% of all CO_2 use projects [160,163,164]. The most significant number of CCU projects are launched in the USA, Germany, and the UK [160]. According to various model predictions, the estimated CO_2 utilization potential ranges from 80 million tons to 6.5 Gt per year in the near future [165–167].

The potential for CCS projects is much more attached to the geographic area of candidate oil field and its geological characteristics. In theory, the capacity of global geological resources can provide storage for the entire volume of emitted CO_2 to achieve net-zero emissions. As stated before, saline aquifers and oil and gas fields are the most suitable geological formations for CO_2 storage. The global storage capacity is estimated at ~55,000 Gt of CO_2 [30,46,168], with the vast majority located in the US and China [169]. Although the overall capacity of oil and gas fields is significantly inferior to saline aquifers (estimated up to 300–400 Gt [170]), they can be more attractive for CCS projects due to factors mentioned above.

The development history of CCS and the first pilot projects date back to the early 1970s, and the progress has been subject to fluctuations in the past decade. In 2010, the capacity of CCS projects was estimated to reach 140 million tons of CO_2 per year, but most projects in the development stage were never launched [170]. However, today, tremendous growth in the number and capacity of CCS projects is observed. While the number of operational projects is growing relatively slowly, the number of projects under development is rising rapidly. Thus, in 2020, the average estimate of planned projects was at most 75 Mtpa. At the beginning of 2022, it rose to 125 Mtpa. According to recent studies, the predicted capacity of the planned CCS facilities is estimated at ~200 Mtpa in addition to the 42.5 Mtpa capacity of operational facilities (Figure 7).

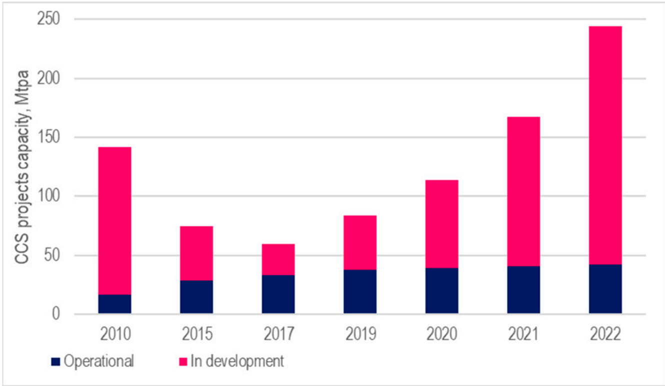


Figure 7. Capture capacity of ongoing and planned CCS projects adapted from [46,170].

At the same time, recent research [171] shows an overall optimistic trend for CCS project expansion, predicting growth of up to 550 Mtpa by 2030. More than 80% of the projects are expected in North America and Europe, considering the current global situation. A substantial part of CO_2 is planned to be stored or used as an EOR agent in oil or gas reservoirs [46].

Today, most CCS projects use natural gas processing as the primary source of CO_2 [46]. Plans are, in turn, focused on the generation of ethanol and hydrogen. Hydrogen is considered to be among the cleanest fuels, which is why demand for it is growing rapidly [172]; however, CO_2 produced during H_2 poses additional emission challenges requiring implementation of CO_2 capturing systems. One of the most advanced technologies for hydrogen synthesis in depleted hydrocarbon reservoirs involves utilizing in situ combustion (ISC), as described in recent literature [56,173]. This approach is also considered an exceptional alternative for CCS or CCS-EOR, provided the produced CO_2 remains sequestered within the reservoir while hydrogen is simultaneously released [174].

As reported by the Global CCS Institute [46,175], deployment of ~170 CCS facilities was planned globally by the end of 2022, but only 30 commercial CCS projects, 21 CO_2-EOR projects, and nine DGS projects were operational. Notably, CO_2-EOR projects outnumbered DGS projects, with the first CCS facility launched in 1972 using CO_2-EOR technology, while DGS projects gained momentum only in the last five years (Figure 8). It is also worth mentioning that most of the planned projects are focused on DGS.

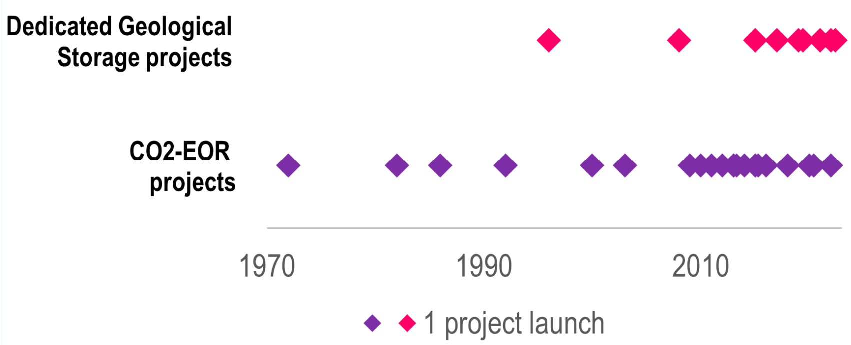


Figure 8. Distribution of the operational CCS projects in time by type based on [46].

All this indicates that EOR is still viewed as a preferable technology used for the pilot CCS method. In contrast, DGS projects may offer greater storage capacity, which therefore justifies the growing interest in this technology.

At the same time, DOGRs cannot be easily classified into a single group, since CO_2 storage in different oilfields is often combined with enhanced oil or gas recovery (EOR or EGR) [24,44]. This combination is often preferred since reservoir pressure changes are typically well-recorded over time, which can aid in assessing the effectiveness of the CO_2 storage.

IEA Greenhouse Gas Research & Development programme reports [45,48] suggest the main screening criteria for a successful CCS project in DOGR:

- the reservoir depth preferably over 1 km;
- cap rock integrity confirmed by retention of hydrocarbons;
- injectivity and capacity of 25–50% more than required by preliminary calculations;
- low heterogeneity of the reservoir;
- low residual water saturation;
- the presence of a nearby/underlying aquifer;
- the presence of active and relatively new infrastructure, well-recorded exploration and production data for the reservoir.

More information on the requirements for potential reservoirs is presented in Section 2.1.

However, determining standard operational parameters for specific DOGRs is challenging due to the complexity and uniqueness of hydrocarbon reservoirs [44,45]. These factors include whether the production was performed offshore or onshore, whether reservoirs contain gas or oil, the type of rock, the depth, the presence of water, and the level of depletion. That is why exploring hydrocarbon reservoir potential by applying laboratory study and computational modeling is essential. The main objective of these studies is to quantify parameters such as injection rate and pressure, as well as storage capacity, so that the optimal injection dynamics can be defined to ensure long-term containment of CO_2.

For instance, injectivity can be predicted with reasonable accuracy from the production data and well logs. These predictions are then validated or adjusted from core-flooding tests as described in Section 2. The results are then history-matched and upscaled in a computational model intended to predict injectivity on a field scale, as described in Section 3 [176]. Several examples of CCS projects in DOGR have been selected from previous studies [24,44,48,175] to illustrate how these studies can either help to realize a CCS project or lead to its termination.

4.2. Selected CCS Field Projects

Jilin Oilfield is a CO_2-EOR and storage project in China that was evaluated to achieve a storage capacity of ~71 Mt of CO_2. This field is heterogeneous, buried at of 2–2.5 km depth, and characterized by ultra-low permeability of 0.5–3 mD [177]. Today, five CCS facilities are operating in the field with a total CO_2 injection of 2.5 Mt [162], which was preceded by extensive preliminary research, including laboratory studies, numerical modeling, and pilot tests. Petrophysical studies, core and fluid analysis, and well logging confirmed the suitability of the reservoir for CCS-EOR [178]. A few research articles were dedicated to the experimental investigation of CO_2 behavior in the reservoir to fulfill the ongoing CCS project. This research included a laboratory slim tube test for minimum miscibility pressure determination [179], pilot field tests for CO_2 injection and water-alternating-gas performance [178], simulation studies on optimization of EOR methods in Eclipse software [180] and assessment of CO_2 storage potential [181]. Additionally, microseismic monitoring of the CO_2 sweeping and migration [42] and a CO_2 dynamic miscible flooding test in a 2-layered heterogeneous reservoir model was performed [182]. The main findings from the experimental studies include the following:

- CO_2 storage capacity of 71 Mt was evaluated;
- most of the CO_2 should be maintained at a supercritical state and trapped structurally (>60%);
- the remaining volume was predicted to be dissolved in brine and oil;
- CO_2 plumes were likely to be unevenly distributed within the reservoir due to reservoir heterogeneity;
- reservoir and bottom-hole pressures were identified as key parameters in controlling the CO_2 flooding performance, channeling, and breakthroughs;
- the near-miscible flooding mode was found to be preferable for storage measures due to the better sweep efficiency;

- the higher injection pressure was associated with increased risk for re-opening of the pre-existing natural fractures in the reservoir, which could lead to changes in the CO_2 flow pattern and leakages;
- gas absorption in high permeable zones was found to be greater than in low permeable zones, which could have adverse effects on the sweeping efficiency and the distribution of remaining oil and gas.

All the outcomes are intended to be considered during the continuation of CCS-EOR projects in Jilin Oilfield [44], allowing the adoption of an injection-production scheme.

Another example is the Goldeneye—a completely different offshore depleted gas field proposed for pure CO_2 storage. The site appeared suitable for CCS projects upon initial assessment. The depth of the reservoir is 2.5 km under the North Sea floor, and its permeability varies between 700 and 1500 mD. The estimated CO_2 capacity of the reservoir is 20 Mt. The site was an industrial gas field until 2011, and it still has preserved infrastructure such as pipelines, wells, and a platform [43,44]. One additional advantage was the proximity of a nearby power station, which made it a convenient source for CO_2. The reservoir characterization was robust, owing to extensive geophysical surveying, exploration drilling, and a vast database of production data gathered over years of operation and monitoring. The primary evaluation method for assessing the CCS efficiency at this site was computational modeling. Several studies, analyzing the potential benefits, drawbacks, and risks of the proposed project, have been published in recent years [183–187], including the results of various modeling simulations.

Unfortunately, the risks discovered by continuous simulation studies were too high to continue the CCS project, despite all the site's advantages. The most recent information on the Goldeneye field reveals that the CCS project is no longer progressing due to funding withdrawal, and the decommissioning of the infrastructure is planned [188]. However, there are still chances for future re-use of the pipelines [189,190]. Moreover, the nearby Hewett gas field with similar properties may also be considered for CO_2 storage given that the integrity of the wells is satisfactory [44,191].

The last example is the much more successful Lacq-Rousse—a CCS demonstration pilot in France. The Rousse is an onshore depleted carbonate gas reservoir 4.5 km deep operated from 1972 to 2008. Approximately 1.5 Mt of gas was produced from the reservoir which defines the estimated capacity of the CO_2 storage [45]. The CCS project was carefully planned starting with the first studies in 2006 [49]. In addition, the integrity of wells was confirmed by well-logging. Particular consideration was given to the characterization of the reservoir to verify its integrity and suitability for safe CO_2 storage—first, by collecting data on reservoir properties by applying well logging and laboratory studies, followed by geological and hydrodynamic modeling to simulate CO_2 behavior within the reservoir, and finally, by monitoring and calibrating the injection parameters during the operation phase [49]. Several studies were published highlighting the results of creating a transparent environment around the project. The structure of the target formation is isolated with lateral and top seals.

The main findings of mineralogical, geochemical, petrophysical, and geomechanical studies of the rocks, along with the subsequent geomechanical modeling, have revealed several important characteristics of the reservoir. These include an average porosity of 3%, permeability of up to 1 mD, the presence of sealed fractures, and the absence of any damage or deformation of the cap rock. Additionally, the studies have identified the maximum reservoir capacity at which the sealing competency is maintained, the boundary pressure for CO_2 injection, and the evolution of the mineralogical composition of the seal during CO_2 injection. It is highly significant that these studies have shown that the overall reservoir properties remain unaffected during CO_2 injection [49,192–194].

The numerical study applying Petrel and CMG-GEM with an equation of state (EOS) based model with 16 components (13 HC components, N_2, H_2S, and CO_2) was performed to match historical data (pressure, gas production) of the reservoir [47]. The model was then used to evaluate the optimal CO_2 injection pressures, and to simulate the evolution of pressure profiles throughout the injection period, CO_2 migration pathways, water behavior, and sealing integrity. The injection strategy was selected based on similar studies in the literature [48,49]

The injection of CO_2 in the field lasted from 2010 till 2013, ~51 kt of CO_2 was permanently stored during this period. The post-injection micro-seismic monitoring indicated that the isolated structure of the reservoir was allowed to confine the CO_2 phase within the reservoir safely, while maintaining reservoir, caprock, and well integrity [191,195]. Despite the small amount of CO_2 stored in the Rousse field, it is still one of a few fully completed CO_2 storage projects, which helped to develop the experience and show the reliability of the technology required for future larger-scale projects.

The presented case studies highlight and conclude that regardless of the initial knowledge of the potential CO_2 storage reservoir, the target studies, such as computational modeling and laboratory research, are invaluable and must be performed during the preparation of any CCS project. Otherwise, the lack of information may lead to a worst-case scenario and, consequently, the risk of getting restrictions for starting a CCS project.

5. Summary

In our work, we present a summary of available studies devoted to the laboratory and numerical studies of the potential CO_2 injection and storage in oil and gas reservoirs and discuss the existing field case studies.

Multiple experimental studies highlight the importance of a detailed investigation of the rock-CO_2 and fluid-CO_2 interaction parameters prior to the launch of the field projects. Many proposed works, however, are expensive and time-consuming. It is especially notable in the case of DOGR with non-heterogeneous porous and lithological structures and shale reservoirs. In addition to the limited material of rocks and fluids, the cost of detailed experimental tests can be overestimated. Therefore, one of the goals was to review the published literature, get an overview of the latest trends in experimental studies of the CCS in DOGR, and define the key control parameters (Table 1).

In the first section, the most common and latest experimental methods used in different reservoir characterization categories are summarized to establish the interrelated relationships between CO_2-rock-fluid interaction. Some of the reviewed parameters are related to geomechanical properties and wettability alteration of the rock and operational parameters such as flow parameters alteration and CO_2 injection speed (Table 1). Experimental programs for DOGR CO_2 storage candidate reservoir formations have to be structured in such a way as to address most critical processes during CO_2 injection and to answer questions about anticipated storage capacity, how nearly wellbore and further parts of the formation interact with CO_2 and CO_2 brine, to what extent porosity, permeability, and wettability change, and whether there are leakage risks associated with these changes. At the stage of the potential field screening, however, the minimal set of parameters can be limited to information on stratigraphical and reservoir properties of the reservoirs, which is often available for depleted reservoirs and does not require additional laboratory studies and, thus, extra costs. The expanded set of experimental studies describing the CO_2-rock and CO_2-fluid interaction (including geochemical and petrophysical aspects) must be determined according to the candidate reservoir's geological and lithological aspects (Table 3).

While the data availability for DOGR is a significant advantage, actual CO_2 injection experiments are the only way to obtain a realistic view of CO_2 storage feasibility, making them a critical step in CO_2 injection storage projects. Additionally, a well-designed experimental program is essential, as it is necessary to obtain all the results needed to create realistic numerical models and validate them. According to [19], molecular simulation tools can help describe the displacement mechanisms in gas reservoirs. Complex physicochemical interactions, including the CO_2 reactivity, its adsorption and dissolution, and kinetics of the process of the minerals, are actively studied by molecular simulation for gas reservoirs, coals, calcite, and artificial systems [28,35,40]. Also, multiple numerical studies confirm the applicability of simulation tools in evaluating the prospective CO_2 storage in oil and gas reservoirs [35]. Numerical simulation is the final step, where all the previously obtained and analyzed field and experimental information is incorporated to provide insight into time-dependent factors of prolonged CO_2 injection. Notably, most of the problems solved by numerical simulation are related to engineering problems, while geomechanical modeling for CO_2 storage remains crucial. Also, the replacement of gas hydrates by CO_2 needs to be studied further.

Therefore, simulation delivers crucial perspectives on the interchanging dynamics between dominant trapping mechanisms, reservoir pressure and temperature response over time, migration pathways of CO_2 plumes, rock and mineral dissolution rates, and optimal CO_2 injection dynamics. Creators of CO_2 storage models should consider a wide range of time and length scales to ensure long-term CO_2 storage efficiency and fluid behavior. It is also important to accurately model the reservoir fluid displacement and changes in pressure by covering locations outside of the primary storage target. The models must span longer time scales because regulations will likely call for prolonged post-injection monitoring. A review of research articles on numerical simulations presented in Table 1 highlighted the main factors that should be included during the field-scale simulation and designing a reservoir model for CO_2 storage in DOGR, as they have distinctive features from oil and gas fields:

- Heterogeneity of reservoir properties can affect the storage capacity, while proper characterization of the geological model can increase the accuracy of the prediction models and significantly decrease the risks [38,41];
- Geomechanical properties should carefully consider the voidage replacement ratio, ground uplift, possible rock damage, and formation of fractures [36,37];
- Operational parameters greatly affect medium storage behavior and storage stability, and optimal injection pressure/rate can lead to high storage potential [35,38];
- Simulation of field-scale projects in DOGR has several advantages, since these models feature the storage-site characteristics with greater accuracy and have a development history. The history-matching method can increase prediction accuracy and confidence [139].

Despite the many publications devoted to the CCS study in geological objects, the process of the CO_2 injection, storage, and safety control in DOGR is not studied as extensively as in saline aquifers. That can be explained by the absence of existing field projects and the less attractive potential of DOGR. Also, many oil and gas reservoirs, including DOGR, are regulated by the government and the petroleum industry, which imposes certain limitations. Among these are restricted data availability, confidentiality, and the high costs of the CCS in DOGR, despite the existing infrastructure and logistics of the field. For oil and gas companies, the potential application of CCS technology is often constrained by the additional costs, bureaucracy, and a new cycle of laboratory and numerical studies.

One of the main objectives, therefore, in planning the CO_2 storage in DOGR is to simplify the process and define the critical parameters that can be used for modeling. Typically, each process of the CCS in geological objects, as in our case, is performed in accordance with a certain framework of steps that provides the carbon risk assessment [196,197]. For DOGR, we shortened the workflow and presented the main actions to be taken in Figure 9.

It is important to note that the specifics of the experimental workflow as well as the numerical modeling at all stages of the research, depend on the type of the target reservoir. Stratigraphical, lithological, and reservoir properties, and the specifics of CO_2-fluid interaction should be carefully considered at the earliest stage of the CCS project. In Table 3, we list the trends and challenges for selected reservoir types derived from recent articles published no later than 2017.

Table 3. Main trends in the most recent studies.

Reservoir Type	Challenges	Author, Year
Oil (sandstones)	Influence of heterogeneity of the reservoir porosity and permeability on the storage capacity	Akai et al., 2021 [40]
	Estimation of the post injection pore pressure distribution and it's influence on the storage integrity	Li et al., 2022 [26]
	Geomechanical modeling for storage integrity (cap-rock poroelastic behavior, cap-rock stability, reactivation of faults, formation of fractures), estimation of reversibility of rock compaction using different modeling approaches	Song et al., 2023 [198]
	Evaluation of the theoretical reservoir equilibrium conditions among several phases and reconstruction of physico-chemical variations of different phases at non-equilibrium conditions	Khan et al., 2018 [199]
	Influence of CO_2 induced precipitation reactions on the pore space evolution and thus the physical properties and the need for the development of coupled flow, geochemical and geomechanical models	Khan et al., 2020 [200]
	Limited information on catalyzation and imbibition of CO_2-rock interaction reactions	Rahman et al., 2022 [201]
Shales, tight reservoirs	Limited information on available storage capacity, formation and reservoir data that specifies favorable sequestration settings, understanding long-term CO_2 interaction in shale, and testing different strategies for CO_2 injection and well patterns to achieve efficient carbon dioxide sequestration complications in the estimation of the storage capacity	Li et al., 2022 [26]
	Alteration of the limestone and calcite matrix, which raises a question about the mechanical stability of rocks	Monghanloo et el., 2017 [202]
	Solubility trapping in carbonates that will dominate until mineral trapping occurs	Monghanloo et el., 2017 [203]
Gas and gas condensate (sandstones)	Understanding and mitigating Joule Thomson effects to avoid the possible formation of ice and gas hydrates	Li& Laloui, 2017 [204]
	Geomechanical modeling for storage integrity (cap-rock poroelastic behavior, cap-rock stability, reactivation of faults, formation of fractures), CO_2–rock interaction that causes mineral dissolution	Harding et al., 2018 [205]
	Mechanism and effect of CO_2-rock-brine interaction on reservoir properties in gas reservoirs with aquifers	Tang et al., 2020 [206]

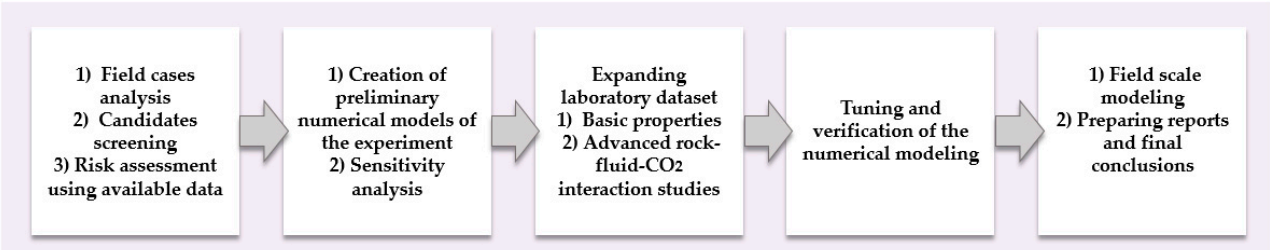


Figure 9. Workflow of the CO_2 storage implementation in DOGR.

6. Conclusions

Accurate site selection, characterization (storage capacity estimation, plume modeling) and monitoring are crucial for any CCS project in oil and gas reservoirs. Experimentally determined control parameters are applied in field screening and numerical modeling of the process. In turn, through the use of modeling and simulation tools, the site will be successfully characterized, and the model will be verified for future predictions. Thus, in the current article, we collected and summarized the latest information on CO_2 storage in DOGR evaluation and provided a summary of the main control parameters and modeling tools. We report standard experimental parameters, which are actual for oil and gas reservoirs, and discuss more advanced laboratory studies. Currently, available modeling tools covered in this article can cover part of expensive and laborious research. In addition, we report examples of field case studies and planned CCS projects, which will be implemented in oil and gas reservoirs.

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Nomenclature

CCS	Carbon capture and storage
CO_2	Carbon dioxide
CCUS	Carbon capture, use and storage
DOGR	Depleted oil and gas reservoirs
CCU	Carbon capture and utilization
IEA	International Energy Agency
EOR	Enhanced oil recovery
CMG	Computer modelling group
GEM	General equation model
EGR	Enhanced gas recovery
OOIP	Original oil in place
OGIP	Original gas in place
DOE	USA Department of Energy
CSLF	Carbon Dioxide Sequestration Leadership Forum
SEM	Scanning electron microscopy
TGA	Thermo-gravimetric analysis
XRD	X-ray diffraction
HP	High pressure

Micro-CT	Micro computed tomography
HPHT	High pressure & high temperature
EDS	Energy dispersive spectroscopy
NMR	Nuclear magnetic resonance
LF-NMR	Low-field nuclear magnetic resonance
UCS	Unconfined compressive strength
AE	Acoustic emission
PVT	Pressure, volume, temperature
DEM	Discrete element method
FEP	Free energy perturbation
PENS	Predictive engineering natural systems
CFD	Computed fluid dynamics
GHG	Greenhouse gas
ISC	In situ combustion
PDE	Partial differential equation
EOS	Equations of state

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