

Review

CO₂ Sequestration Overview in Geological Formations: Trapping Mechanisms Matrix Assessment

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Abstract: This review focuses on the consequences of the early and rapid deployment of carbon dioxide (CO₂) capture and storage (CCS) technologies, which is currently recognized as a critical problem in fulfilling climate change mitigation objectives and as a viable alternative for countries throughout the world. Currently, the geological storage of CO₂ is the most effective and, in many cases, the only viable short- to medium-term alternative for considerably moving towards CO₂ sequestration in geological sinks and, thus, lowering net carbon emissions into the atmosphere. Furthermore, this review explores the global and environmental measurements of CO₂ emissions, as well as the emphasis behind more efficient energy usage. The components of the CCS system are briefly examined, with an emphasis on the technologies that have been developed by previous scholars to support carbon capture, as well as the kinds of carbon geological formations that are suitable sinks for CO₂. Additionally, the importance of carbon interaction and sequestration in unconventional formations are examined through case studies that are applied to coalbed seams and shale gas reservoirs. Numerous trapping processes are grouped and introduced in a constructive matrix to easily distinguish the broad trapping mechanisms, which are (1) chemical, (2) physicochemical, and (3) physical trapping, and each of these categories are further classified in depth based on their contribution to CO₂ storage.

Keywords: CO₂ geological storage; CO₂ sequestration; trapping mechanisms; storage capacity



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1. Introduction

Carbon capture and storage (CCS) is a critical method for reducing human CO₂ emissions into the atmosphere [1]. Continuously growing CO₂ emissions have been identified as a major potential cause of global concern, whereas CO₂ geological sequestration (CGS) provides a viable strategy for addressing this massive environmental crisis that the world is now facing. Since the beginning of industrialization in the 19th century, the quantity of CO₂ in the atmosphere has been growing significantly at an alarming rate [2]. As a result of this incremental rise, the world's climate may be impacted, as shown by an increase in global temperatures and an increase in local weather extremes. Energy combustion and industrial processes contributed to a rise in global CO₂ emissions in 2021, resulting in the highest year of CO₂ emissions on record. The International Energy Agency's (IEA) detailed region-by-region and fuel-by-fuel analysis, which draws on the most recent official national data as well as publicly available energy, economic, and weather data, estimates that emissions will reach 36.3 gigatons (Gt) by 2030, representing a 6% increase from 2020. According to the IEA (2022), emissions rose by around 2.1 Gt compared to the baseline year of 2020. In absolute terms, this places the year 2021 above 2010 as the year with the biggest year-on-year growth in energy-related CO₂ emissions. The spike in emissions in 2021 more than negated the 1.9 Gt drop in emissions caused by the pandemic that occurred in 2020. CO₂ emissions increased by about 180 megatons (Mt) in 2021, compared to the pre-pandemic level in 2019.

The purpose of this research is to shed light on the crucial role of CCS in lowering CO₂ emissions by providing an in-depth examination of the relevant environmental and global metrics of CO₂ and the integrated role of the CCS system. Several examples are also provided with an emphasis on the geological sequestration of CO₂. Geological CO₂ sinks include ocean storage, deep saline formations, depleted oil and gas reservoirs, formations that require CO₂-enhanced oil recovery (CO₂-EOR), unmineable coal seams, and organic-rich shales. They may contain hundreds of gigatons of carbon (GtC) or more. There are many trapping mechanisms that may be utilized to store CO₂ in geologic formations, with the specific process depending on the kind of formation. These geological sinks have a wide range of potential capabilities, each of which is vastly different in terms of the storage capacity potential. As a result, a matrix evaluation of the CO₂-trapping processes is created, demonstrating its significance in understanding how these trapping mechanisms interact. These CO₂-trapping mechanisms play a crucial role in CO₂ storage potential from a constitutive standpoint, and yet they also provide a baseline for modeling CO₂ sequestration. Chemical trapping, physicochemical trapping, and physical trapping are the three main trapping mechanisms that set the fundamental baseline. Furthermore, there is a need for enhanced storage capacity estimations at the global, regional, and local levels, as well as a better knowledge of long-term storage, migration, and leakage processes, in order for CCS to be successful. In order to address the issue, it will be necessary to improve both our ability to track and verify the behavior of CO₂ that has been geologically stored as well as our knowledge of emerging concepts and enabling technologies for the role of CCS between now and the future.

1.1. Global Measures

The consumption of conventional energy sources results in CO₂ emissions, with power generation emitting the highest CO₂, followed by industry and transportation vehicles, as shown in Figure 1.

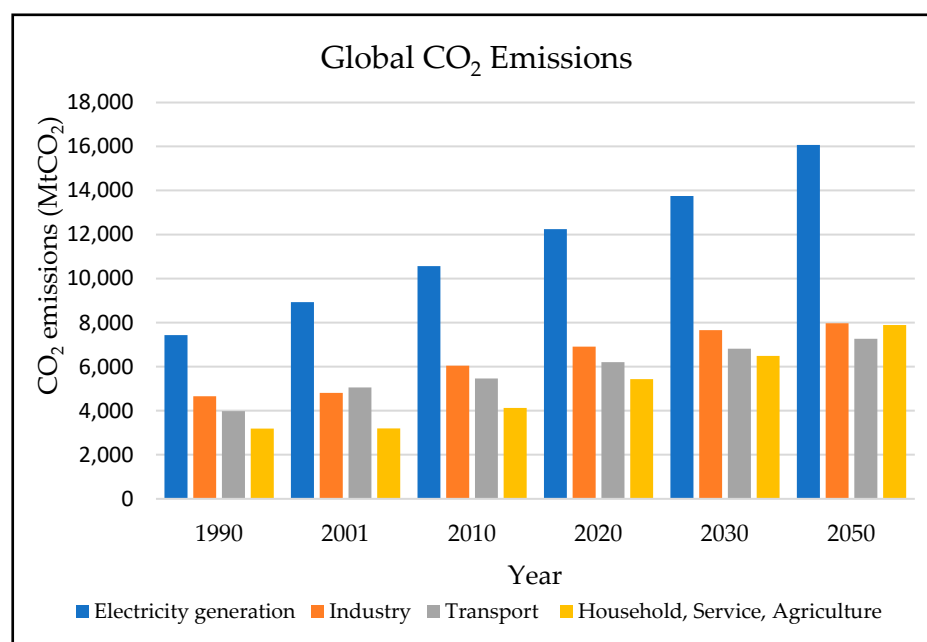


Figure 1. Global CO₂ emissions (data source: World Energy Technology Outlook 2050 [3]).

Lapillonne et al. [3] provided the data statistics on CO₂ worldwide emissions and sequestration. However, CO₂ emissions into the atmosphere could be reduced by reducing the need for fossil fuel combustion through more efficient energy use, substituting biofuel or hydrogen for fossil fuels in transportation and electric power generation, substituting

natural gas for coal in electric power generation, and capturing and sequestering CO₂ in geological formations.

1.2. Environmental Measures

CO₂ emissions are directly linked to rising environmental problems [4]. CO₂ levels have risen to their highest level in recent decades and are a significant contributor to global warming greenhouse gas emissions, making up over 55% of all emissions [5]. As a result, CO₂ emissions are a major contributor to global warming and climate change [6]. Climate change has become the greatest threat to human civilization in conjunction with the rise in CO₂ emissions. Excess CO₂ and other greenhouse gases in the atmosphere have already warmed the Earth's temperature by around 1.8 °F (1 °C) on average, and even if emissions were to halt immediately, more warming would still occur owing to existing greenhouse gases in the atmosphere [7]. Therefore, concerns about environmental protection prompted the introduction of CO₂ sequestration, which is expanding in conjunction with energy output, as seen in Figure 2. By 2050, it is expected that the CO₂ emissions will rise drastically due to increased utilization of transportation, electricity, manufacturing, constructions, and other sources of fugitive emissions [8]. As a result, the produced CO₂ must be captured and stored such that the whole process is almost free of CO₂ emissions into the environment. This may be accomplished by using advanced technologies and ensuring that leakage into the atmosphere is minimized. Another form that contributes to CO₂ reduction measures suggests combining electric vehicles (EVs) with renewable energy such as photovoltaics (PV), or wind power is yet another method that may be used to lessen the detrimental effects that CO₂ emissions have on the environment [9]. Furthermore, CO₂ emissions must be severely reduced in order to avoid the economic and human consequences of catastrophic climate change. Reduced mitigation costs and more adaptability in decreasing greenhouse gas emissions are also feasible results of CCS utilization [10].

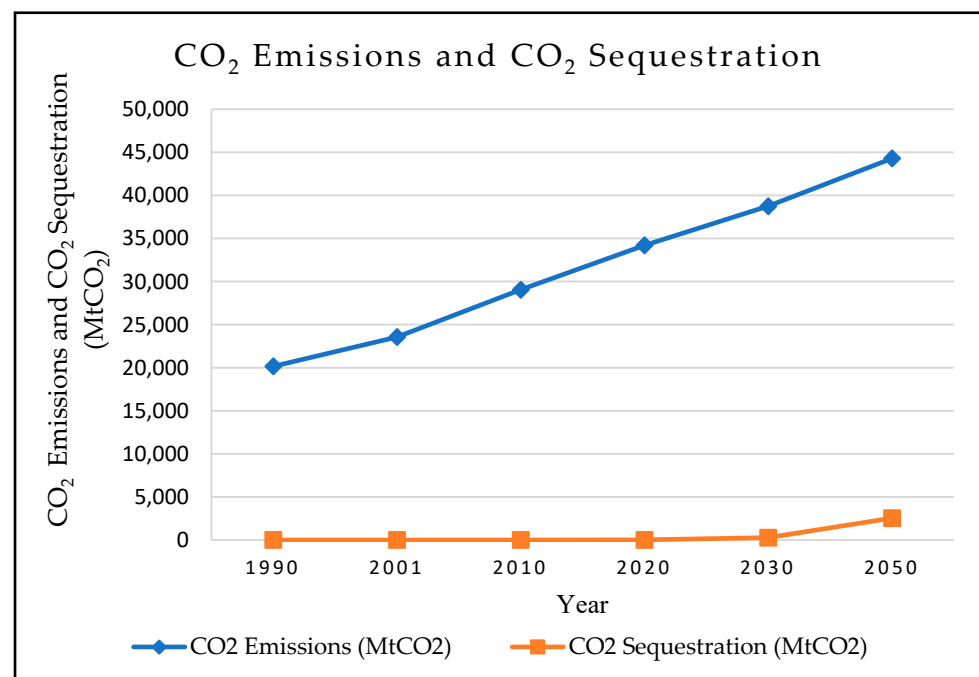


Figure 2. Global CO₂ emissions in conjunction with CO₂ sequestration from 1990 to 2050 (data source: World Energy Technology Outlook 2050 [3]).

1.3. Role of CCS

CO₂ capture, sequestration, and storage in geological formations may aid significantly in reducing the anthropogenic CO₂ emissions. CO₂ is extracted from a power plant's

flue gas (“capture”) and then compressed and transferred through pipelines. At a nearby location, the CO₂ is injected into a geological formation through a deep borehole (“sequestration” or “storage”). Carbon capture is technically accomplished through cryogenic separation, adsorption/absorption, and membrane separation [11], but one of the most cutting-edge methods for CO₂ storage is injection into deep saline aquifers, as well as deep coal-bed methane and ocean storage (all of which can be used to store CO₂). However, carbon capture is the most costly component of CCS, since the CO₂ extraction from flue gas and subsequent compression requires either modifying an existing power plant or altering the design of a new power plant. Whether converted or integrated into a new construction, this new equipment involves capital inputs and operating expenses that dramatically raise the price of the energy produced [12]. However, the widespread use of CCS would rely on the maturity of the technology, prices, overall potential, diffusion, and transfer of the technology to emerging nations and their ability to implement the technology, regulatory elements, environmental concerns, and public perceptions. CCS can only reduce emissions to the environment by a certain percentage depending on the amount of CO₂ it is able to capture, transport, and store, as well as any leakage that occurs during transportation and the amount of CO₂ that is able to be stored for an extended period of time [10]. Current CCS research aims to enhance the separation process and to produce innovative materials that can be employed as effectively as is feasible in the capture process. When it comes to carbon sequestration, a wide range of geological formations have the ability to trap significant amounts of CO₂ and are widely distributed and categorized according to the CO₂ sequestration varieties in Table 1. CO₂ geological sequestration options provide significant storage capacity potential for storing CO₂, and these geological sinks vary in terms of their location, type of the formation, and the types of trapping mechanisms that contribute to the CO₂ storage. Ocean storage, deep saline formations, depleted oil and gas reservoirs, formations that require CO₂-EOR, unminable coal seams, and organic-rich shales are all examples of geological CO₂ sinks. Collectively, they can hold hundreds of GtC. There is a variety of different trapping methods that may be used to store CO₂ in geologic formations, with the precise mechanism being dependent on the type of formation. These geological sinks provide a variety of potential capacities, each of which differs greatly from the others. At an estimated 40,000 GtC, the world’s oceans have the greatest storage capacity of any natural or manmade system, and have been demonstrated to have the greatest potential as a sink for anthropogenic CO₂. Marchetti [13] was the first to propose the method of direct injection of liquefied CO₂ into deep ocean waters to improve the degree of CO₂ isolation [14]. In addition, deep saline aquifers provide up to 10,000 Gt of potential CO₂ sequestration storage area on a global scale [15]. In the 1990s, Canada became the first country to inject CO₂ into a deep saline formation due to the need to dispose of “acid gas”, or H₂S and CO₂ mixes, from sour gas wells [16]. Furthermore, CO₂ sequestration as a concept for depleted oil and gas reservoirs emerged in the past as a result of the reservoirs’ proven reliability as long-term storage sites for hydrocarbons and acid gases. Up to 90% of the entire volume injected is composed of CO₂, making disposal of acid gas a primary goal. Acid gas is a byproduct of oil and gas extraction and refining that contains CO₂, H₂S, and other substances. In addition, CO₂-EOR was first used in 1983, and oil production stabilized shortly afterwards. To retrieve the oil, most EOR operations require “blowing down” the reservoir pressure, which releases CO₂, with some of the injected CO₂ remaining dissolved in the immobile oil [17]. This temporarily stores a large quantity of CO₂ that was injected into the reservoir. Another kind of geological sink is the sequestration of CO₂ in unmineable coal seams; the coal surface has a preferential chemical attraction for CO₂ adsorption over methane with a ratio of 2:1. As a result, coalbed methane (CBM) recovery may be improved using CO₂ sequestration. Furthermore, despite having relatively low porosities and permeabilities, several organic-rich shale formations are used as geological sinks for CO₂ and methane generation [18]. However, recent scientific developments have boosted the prospect of using shales and other tight formations to minimize fluid leak-off into the reservoir using the application of dual-porosity models, which can be applicable

for potential CO₂ storage [19]. Another kind of sequestration is terrestrial, in which CO₂ is absorbed by the trees and plants through photosynthesis and stored as carbon in soils and biomass [20]. Terrestrial sequestration is an example of biological sequestration. In addition to these options, a new technique known as direct air capture emerged in 2019, and the newest facility was already operational by September 2021 [21]. Direct air capture captures CO₂ from the environment using chemical processes. As air passes over the chemicals, they selectively react with and remove CO₂ while allowing the other components of air to flow through [22]. This form of CO₂ sequestration comes under using innovative technologies to reduce the anthropogenic CO₂ emissions. In addition to the research made by Herzog and Golomb [23], the following table has been modified to account for biological and technological options for CO₂ sequestration (see Table 1).

Table 1. Worldwide potential reservoir capacity for CO₂ sequestration.

CO ₂ Sequestration Options	Storage Capacity *	References
Geological CO₂ Sequestration:		
Ocean	1000–10,000 + GtC	[17,23]
Deep saline formations	100–10,000 GtC	[17,23]
Depleted oil and gas reservoirs	100–1000 GtC	[17,23]
CO ₂ -EOR	61–123 GtC	[17]
Coal seams	10–1000 GtC	[17,23]
Organic-rich shales	2.5–25 GtC	[18]
Biological CO₂ Sequestration:		
Terrestrial	10–100 GtC	[20]
Technological CO₂ Sequestration:		
Direct air capture (DAC)	<0.1 GtC	[21,22]

* 1 GtC = 1 billion tons of carbon.

2. Components of the CCS System

CCS technology is expected to lower atmospheric concentrations of greenhouse gases. Compressing, transporting, and using the collected CO₂ for procedures such as injection into deep underground geological formations for long-term storage, and injection into existing oil fields for further hydrocarbon recovery, are all included in CCS [24]. The CCS system comprises many fundamental components, each of which must be understood in order to fully understand the technologies used in the CCS system. These components include the following: (i) capture, (ii) transport, (iii) injection, and/or (iv) storage, which is also known as “sequestration”, and (v) monitoring [25]. In 2009, Herzog [25] provided a concise description of the component of the CCS system as follows: capturing CO₂ from an effluent stream and compressing it to a liquid or supercritical state is known as capture. Currently, the resultant CO₂ concentration is more than 99% in the majority of situations; however, lesser amounts may be tolerable. Capture is often necessary in order to be able to transport and store CO₂ in an economically viable manner. The transportation of CO₂, which is defined as the transportation of CO₂ from its source to a storage reservoir, is considered the second component of the CCS system. CO₂ can be transported by trucks, rails, and ships; however, the most cost-effective method of moving big volumes is through pipelines. These transportation techniques are regarded as practical, but the sheer amount of CO₂ to be carried from the capture site will certainly require the building of local and regional infrastructure for appropriate transportation. This approach will lower the shipping cost substantially while also removing the concerns associated with hydrate crystallization [17]. Furthermore, carbon injection, the fourth CCS component, is defined as the act of injecting CO₂ into a storage reservoir. Geological formations are the primary

storage reservoirs now under consideration. The final component of the CCS system is associated with monitoring the CO₂ once it has been injected into the ground. Despite the fact that CO₂ is neither harmful nor combustible, it nonetheless presents a risk to the environment, as well as to health and safety. One of the primary goals of monitoring is to ensure that the CO₂ sequestration process is successful, which means that a substantial amount of the CO₂ is kept out of the atmosphere for hundreds of years or centuries.

2.1. Storage Capacity Assessment

It was determined that 17 countries have potential storage resources, and each country's prospective storage resource was analyzed by the Carbon Storage Resource Catalogue (CSRC) [26]. A categorized inventory of 715 prospective storage sites with a total aggregated storage resource of 12,958 Gt has been produced as a result of this process. The United States of America has the biggest storage potential capacity, with a potential storage resource that has been found in 36 US states, with 12 projects and 14 regional studies being carried out (see Figure 3).

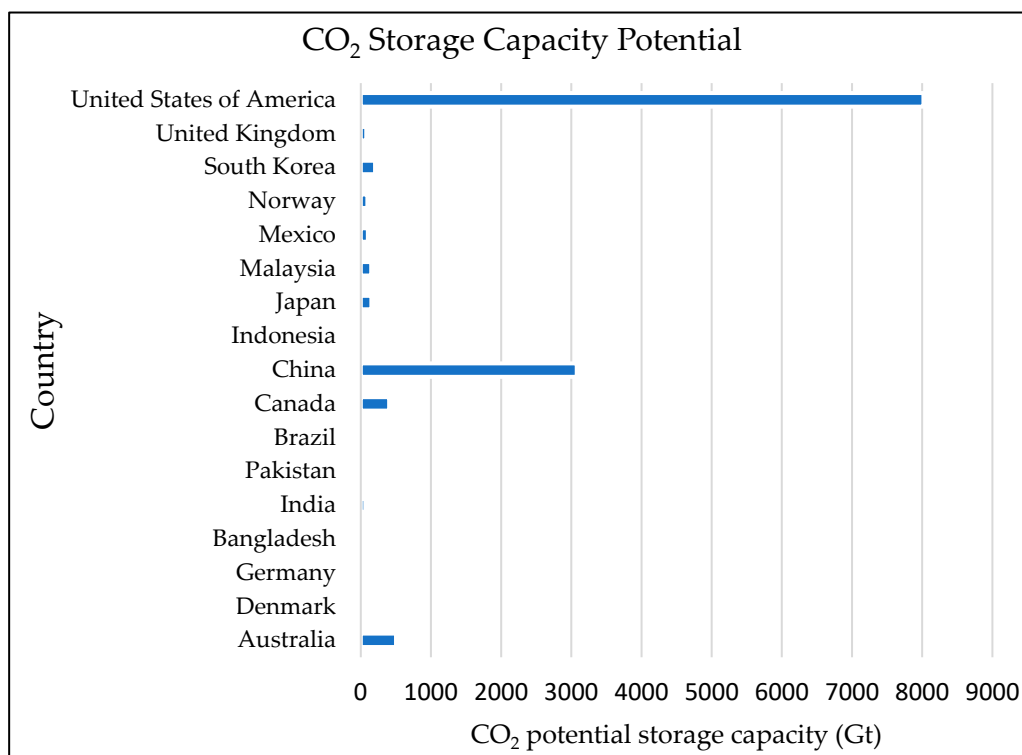


Figure 3. CO₂ potential storage capacity assessment across the countries (data source: CO₂ Storage Resource Catalogue Cycle 2 2021 [26]).

The undiscovered (95.7%) and sub-commercial (4.3%) classifications of storage resources predominate in the resource base's pre-commercial nature. Only 0.25 Gt, or less than 0.002%, of the total CO₂ inventory comes from commercial projects and those where CO₂ injection is permitted for development or is currently being injected and stored into the ground (Table 2). The data are gathered from the updated cycle 2 2021 CSR catalog and modified accordingly to include the storage resources and percentages of the potential amount of CO₂ in saline aquifers and oil and gas fields.

Table 2. Classification of CO₂ potential storage resources for the 17 countries (data source: CO₂ Storage Resource Catalogue Cycle 2 2021 [26]).

Classification	CO ₂ Storage Resource (Gt)	Percentage
Stored	0.037	0.00029%
Capacity	0.217	0.00167%
Sub-commercial	551	4.25%
Undiscovered	12,407	95.75%
Total	12,958.25	100%
Storage in saline aquifers	12,684	98%
Storage in oil and gas fields	274	2%

Furthermore, just 89.9 Gt (or 0.7%) of the whole aggregated potential resource is included within specific projects. Because of the huge storable volumes found in national and regional-scale atlases and studies, saline aquifers account for the majority of the resource inventory (12,684 Gt, or 98%). As a result, the resource estimates for the saline aquifers are highly dependent on volumetric calculations and, hence, should be viewed as significant high-level estimates of storage potential. According to the percentage of the aggregated storage resource, oil and gas fields account for just 2% (274 Gt) of the total.

2.2. Carbon Capture

Emissions from industrial facilities, power plants, and other locations of fuel burning would be decreased as a consequence of the utilized capture technologies. Estimated CO₂ emissions might be calculated by measuring the quantity of CO₂ captured and subtracting it from the total amount of CO₂ generated. Furthermore, the reduction of anthropogenic CO₂ emissions into the atmosphere may be done in a variety of ways. According to Professor Yoichi Kaya of the University of Tokyo, these measurements have the following reflectance [17]:

$$\text{CO}_2^\uparrow = \left[\text{POP} \times \frac{\text{GDP}}{\text{POP}} \times \frac{\text{BTU}}{\text{GDP}} \times \frac{\text{CO}_2^{\uparrow\uparrow}}{\text{BTU}} \right] - \text{CO}_2^\downarrow \quad (1)$$

where CO₂[↑] is the overall CO₂ being released into the atmosphere, CO₂[↓] is the quantity of CO₂ stored or isolated in biosphere and geosphere sinks, POP is the population level, GDP/POP is the per capita gross domestic product or the measure of standard living, BTU/GDP is the energy consumption per unit of GDP, reflecting the degree of energy intensity, and CO₂^{↑↑}/BTU is the quantity of CO₂ released per unit of energy consumed, reflecting the degree of carbon intensity.

From Equation (1), it can be seen that as the population rises, it is feasible to minimize energy intensity or carbon intensity by promoting the use of carbon-free fuels or increasing levels of carbon capture and sequestration. Carbon capture technologies that are moving towards reducing the degree of carbon intensity are dependent on the type of capture used. CCS systems may be divided into three primary categories: pre-combustion capture, post-combustion capture, and oxy-fuel combustion capture. Furthermore, pre-combustion capture is also the method of collecting CO₂ before it is discharged into the atmosphere. The gasification of fossil fuels produces syngas, which is subsequently transformed into CO₂ and H₂ in a process known as the water shift reaction. As a consequence, CO₂ may be readily separated. Moreover, post-combustion capture is a technique for collecting CO₂ from exhaust flue gas after the combustion process by utilizing chemical solvents. On the other hand, in the oxy-fuel combustion process, pure oxygen is utilized for combustion. This is known as recycled flue gas because it is created from a portion of the flue gas that has been recycled in order to lower the flame temperature. The exhaust flue gas has a high proportion of CO₂ and water vapor. Consequently, by condensing the water vapor, CO₂ may be easily separated from it [27].

2.3. Carbon Geological Storage

Carbon sequestration or storage has been used in a variety of applications across the world. Scientific and technological “focus areas” connected to carbon sequestration have been established since the 1990s. Furthermore, natural ways of storage are distinguished from man-made modes of storage, which may be divided into two categories. Natural ways of storage include terrestrial sequestration, and man-made modes of storage include storage in geologic formations through ocean sequestration and geologic sequestration [24]. The removal of CO₂ by photosynthesis and the inhibition of the release of CO₂ from terrestrial sources are the processes for terrestrial storage. It has been proposed to represent a significant mechanism for the storage of CO₂ [28,29]. The greatest sink for CO₂ storage, on the other hand, is ocean sequestration. It is predicted that ocean sequestration has the capacity to store 40,000 gigatons (Gt) of CO₂ [30], and to store over 90% of current CO₂ emissions. Using moving ships, stationary pipes, or offshore platforms, this technique involves injecting and depositing CO₂ into bodies of water as shallow as 1 km deep. At this level, water has a lower density than the injected CO₂ and the latter is predicted to dissolve and distribute throughout the water body [31]. When it comes to geological storage, it is currently widely recognized as the most viable option for storing the massive amounts of CO₂ required to successfully mitigate global warming and associated climate change [32,33].

When it comes to carbon geological storage, specific criteria must be understood, which necessitates an understanding of the chemistry and thermodynamic conditions that lead to successful CO₂ storage. The thermodynamic conditions present during CO₂ injection and storage in the target formation dictate whether the CO₂ is in a liquid, gaseous, or supercritical state at the time of injection and storage (see Table 3). CO₂ is in a supercritical state when temperatures and pressures are above the critical points, which are 31 °C and 7.38 MPa, respectively [34]. Because supercritical CO₂ is denser than gaseous CO₂, supercritical CO₂ leads to more efficient storage [35]. Moreover, the pressure and temperature rise with depth within a formation, while the density of CO₂ decreases as the depth increases, reaching a maximum density of 830 kg/m³ at the bottom of the formation [36]. Temperature and pressure in sedimentary basins may range between 40 °C and 200 °C and a few tens of megapascals to several hundreds of megapascals, depending on the regional geothermal gradient and pressure profile [37]. At depths below 800 m, CO₂ is anticipated to be in a supercritical state, according to common expectations [38].

Table 3. CO₂ supercritical state conditions for injection and storage.

CO ₂ Supercritical State Conditions	Values	References
Temperature	31 °C	[34]
Pressure	7.38 MPa	[34]
Density	850 kg/m ³	[36]
Depth	Below 800 m	[38]

Furthermore, different physical and chemical processes may trap millions of tons of CO₂ in a typical geological storage location [39]. It is possible to store CO₂ in geological formations such as deep saline aquifers, which have no other practical use, as well as in oil and gas reservoirs. It is necessary to carefully choose geological areas that are suitable for CO₂ storage [40]. The geological storage of CO₂ has a number of conditions, the most important of which are an adequate reservoir rock with sufficient porosity, thickness, and permeability [41], a caprock with excellent sealing capacity, and an environmentally stable geological environment. Requirements such as distance from the source of CO₂, effective storage capacity, paths for potential leakage, and general economic constraints may make it impractical to use a location as a carbon storage facility [40]. This was described in detail by Bachu [42] in terms of the criteria and approaches for selecting suitable geological sites

for CO₂ storage, which included factors such as the basin's tectonic setting and geology, its geothermal regime, the hydrology of formation waters, the presence of hydrocarbons, and the basin's maturity. Aside from these, economic considerations relating to infrastructure and sociopolitical factors will have an impact on the choice of location. Furthermore, although techniques for geological storage can be derived from existing processes, there is limited knowledge about the potential long-term environmental effects of storing large amounts of CO₂. Distinct geological settings have different criteria for determining their suitability as CO₂ storage regions, which are addressed in detail below.

2.3.1. Saline Aquifers

Deep saline aquifers offer more viable storage areas for potential CO₂ sequestration, with the potential to store up to 10,000 Gt of CO₂ globally [36]. The following are the trapping processes that keep the CO₂ molecules trapped in the aquifers in place: the trapping of water vapor includes hydrodynamic and residual trapping as well as pore-size trapping, solubility trapping, and mineral trapping [43]. The convection currents generated by the density and concentration gradients in the brine pockets have a significant impact on the storage dynamics of the brine pockets. Among the major elements that influence the effect of CO₂ migration in relation to brine are multiphase flow dynamics, geochemical interactions, geo-mechanical properties, porosity, and permeability [44]. When it became necessary to dispose of acid gas (a combination of H₂S and CO₂) from sour gas wells in Canada in the 1990s [16], injections started to be carried out in the country. Following that, commercially viable operations were created in the Sleipner field (in the Norwegian part of the North Sea), Snhvit (offshore Norway), and In Salah (Algeria), with around 15 million tons of CO₂ successfully injected between 1996 and 2007 [45,46]. A number of other pilot-sized and commercial projects have been proposed, including those in Gorgon, Australia, Nagaoka, Japan, and Ketzin, Germany, as well as efforts by the Department of Energy's Regional Carbon Sequestration Partnership (RCSP) [17]. Despite the fact that there is ambiguity about the environmental consequences of CO₂ storage in aquifers, the majority of the research shows that unfavorable effects may be reduced by selecting appropriate sites [47]. Aquifers that are suitable for this purpose will have an impermeable cap, which will prevent the release of injected CO₂, and a high permeability and porosity below the cap, which will enable huge volumes of injected CO₂ to be spread evenly [30]. The majority of such aquifers are salty and geologically isolated from shallower freshwater sources. Furthermore, the possibility of CO₂ leaking into groundwater drinking sources exists in theory, although the likelihood of this happening is very low. Various liquid and gaseous pollutants have been allowed to be stored in deep aquifers in certain states, and this is becoming more common. While it is anticipated that injected CO₂ would initially displace formation water, the CO₂ will gradually dissolve into the pore fluids. Ideally, chemical interactions between the absorbed CO₂ and surrounding rock would result in the creation of very stable carbonates, which might result in extended storage durations for the CO₂ [48].

2.3.2. Depleted Oil and Gas Reservoirs

Several factors make depleted oil and gas reservoirs ideal candidates for the long-term storage of CO₂. The first proof of integrity and safety is the fact that oil and gas initially gathered in traps (structural and stratigraphic) did not escape in some instances for many millions of years. Most oil and gas fields have been thoroughly analyzed for their geological structure and physical attributes. Third, oil and gas companies have created computer models to forecast hydrocarbon transport, displacement behavior, and entrapment. As a last option, some of the existing infrastructure and wells might be repurposed for CO₂ storage [49]. Furthermore, conventional oil and gas reservoirs, especially old and depleted oil and gas formations, have been one of the most popular targets for the carbon sequestration and storage operations: (1) they have been extensively geologically characterized; (2) the underground and surface infrastructure has already been developed; (3) EOR may be used because CO₂ reduces oil viscosity and IFT and, in some cases, becomes miscible with it;

and (4) this results in enhanced CH_4 recovery due to CO_2 's preferential absorption over CH_4 . The majority of these oil and gas reservoir rocks are made of sandstone, limestone, and dolomite, and they have enough porosity and permeability to support huge CO_2 volume injections. They also feature well-defined low permeability caprocks, such as shale, anhydrite, or tight carbonates, which restrict leaking into shallower strata [50]. Moreover, hydrocarbons in depleted fields will not be negatively impacted by CO_2 , and a CO_2 storage strategy may be tailored to increase oil or gas output in hydrocarbon fields that are still producing. However, in many mature farms, wells were simply filled with a mud-laden fluid many decades ago. Nevertheless, Anderson et al. [49] argued that cement plugs had to be strategically placed in the wellbore, but without any regard for the fact that they may one day be depended upon to retain CO_2 . Since the caprock must be examined, so must the condition of the wells that penetrate the caprock [51]. Even identifying the wells may be challenging in certain circumstances, therefore pressure and tracer monitoring may be required to certify the integrity of the caprock. The reservoir's capacity is limited by the requirement to prevent damage to the caprock due to pressures that are too high. There should be no effect on reservoir permeability from near-injector clogging and changes in reservoir stress [52,53]. According to Ajayi et al. [24], geologic formations with the properties necessary for a storage site are existent and have been used for geologic sequestration. It is a significant advantage that they have already been well characterized. Additionally, the safe and secure character of these formations, which have been shown to be capable of storing large quantities of oil and gas for extended periods of time, makes them ideal candidates. It is possible to have more confidence in these formations by using numerical computer models that have already been history matched. The infrastructure and wells that were used in the construction of these fields are likewise accessible for CO_2 injection purposes. In depleted reservoirs, the storage capacity is greatly reduced owing to the necessity to prevent exceeding pressures that might fracture the caprock and because of the enormous leakage hazard provided by the abandoned wells, which must be avoided at all costs.

2.3.3. Enhanced Oil Recovery (EOR)

EOR by CO_2 flooding (injection) provides the opportunity for economic advantage from more oil output. Conventional primary production typically recovers 5–40% of the initial oil in situ [54]. Secondary recovery, which employs water flooding, produces an extra 10–20% of the oil in situ [55]. Various miscible agents, including CO_2 , have been used for enhanced (tertiary) oil recovery, or EOR, with additional oil recovery ranging from 7% to 23% (on average, 13.2%) of the original oil in situ [56,57]. Numerous CO_2 injection techniques, such as continuous CO_2 injection or alternating water and CO_2 gas injection, have been proposed [58,59]. The displacement of oil by CO_2 injection is based on the phase behavior of CO_2 and crude oil mixes, which is highly sensitive to reservoir temperature, pressure, and crude oil composition. Oil swelling and viscosity reduction for injection of immiscible fluids (at low pressures) to entirely miscible displacement in high-pressure applications are examples of these processes. More than half, and up to 67%, of the injected CO_2 returns with the produced oil in these applications [55], and is routinely separated and re-injected into the reservoir to save operating costs. The rest is retained in the oil reservoir by a variety of mechanisms, including irreducible saturation and dissolution in reservoir oil that is not produced, as well as in the pore space that is not linked to the flow channel for the producing wells. The majority of CO_2 -EOR projects temporarily store a large amount of CO_2 injected into the oil reservoir because the withdrawal of an EOR project usually requires the “blowing down” of the reservoir pressure to tap oil recovery, resulting in the release of CO_2 , with a small but significant amount of the injected CO_2 remaining dissolved in the immobile oil [17]. Oil reservoirs may need to fulfill extra requirements for greater CO_2 storage in EOR operations [59–61]. Typically, the depth of a reservoir must be at least 600 m. For oils with a gravity of 12–25 API, injecting immiscible fluids is usually sufficient. Light, low-viscosity oils (oil gravity 25–48 API) are suitable for the more desired miscible

flooding. Due to factors such as oil composition and gravity, temperature, and the purity of CO₂ in the reservoir, miscible floods need a greater reservoir pressure than the minimal miscibility pressure (10–15 MPa) [62]. Other recommended characteristics for both forms of floods are thin reservoirs (less than 20 m), a high reservoir angle, homogeneous formation, and limited vertical permeability to effectively remove the oil. The lack of natural water flow, a significant gas cap, and significant natural cracks are favored in horizontal reservoirs. The thickness and permeability of the reservoir are not important considerations. CO₂ storage efficiency is also affected by reservoir heterogeneity. The lower density of CO₂ compared to the heavier oil and water in the reservoir causes it to rise to the top of the reservoir, which reduces the storage capacity of the reservoir and reduces the amount of oil that can be recovered. By pushing CO₂ to spread laterally and delaying its ascent to the reservoir's top, reservoir heterogeneity might have a favorable influence on storage capacity by allowing the gas to invade the formation more completely [55].

2.3.4. Deep Ocean Storage

Oceans have the greatest potential as a sink for anthropogenic CO₂, with an estimated 40,000 GtC (billion metric tons of carbon) compared to atmospheric CO₂ levels of 750 GtC and 2200 GtC in the terrestrial biosphere. According to the statistical estimations, doubling the atmospheric concentration of CO₂ would only result in a 2% change in concentration if it is injected into the deep ocean, and would also reduce its pH by less than 0.15 units [17]. To better understand the mechanisms behind ocean CO₂ storage, a fundamental knowledge of CO₂ and seawater characteristics must be addressed. Furthermore, the discharge mechanism of CO₂ in its liquid phase is desirable for effective and economical delivery as it is injected at a depth of more than 3000 m to prevent it from ascending and being blended back into the atmosphere. Moreover, CO₂ creates a thick hydrate at such depths owing to the high pressure (>44.4 atm) and low temperature (10 °C). In addition, studies are being conducted to find alternate methods for injecting CO₂ as bicarbonate ions in solution. This would be inaccurate if it was suggested that CO₂ injection would not acidify marine water. However, procedures exist to limit the extent of the effect, such as dispersion of the injected CO₂ by an array of diffusers or the addition of powdered limestone to the injected CO₂ to buffer carbonic acid [46,63].

3. Carbon Sequestration in Unconventional Reservoirs

Unconventional reservoirs are most likely abundant, but their nature and distribution are not fully known. They are known to exist in vast quantities, but do not readily flow toward current wells for commercial recovery. Naik [64] added that unconventional reservoirs are less prevalent and less well known than traditional petroleum reservoirs such as sandstone and carbonate, fractured, or tight reservoirs. However, unconventional petroleum reservoirs are becoming an increasingly significant source of petroleum supply. Tight reservoirs do not have natural fissures, yet they are unable to be economically produced without the use of hydraulic fracturing. Unconventional reservoirs include tar, bitumen, and heavy oil reservoirs, as well as coalbed methane, shale, and basin-center gas reservoirs. In order to be economically viable, unconventional reservoirs must depend on evolving exploration tactics and novel production technology. All of these reservoirs are becoming more major contributors to the world's oil and gas reserves and production as a collective. It is a common perception that unconventional reservoirs, such as fractured and tight reservoirs, are more expensive and riskier than conventional reservoirs. In addition, geologists have discovered that techniques such as regional facies mapping and sequence stratigraphy, which are useful for locating and delineating conventional reservoirs, are often ineffective for locating and delineating fractured, tight, and unconventional reservoirs, according to their findings. Engineers are wary of them because they are difficult to analyze and because recovery strategies must be carefully selected and deployed in order to minimize production difficulties. As a result of recent technological developments, an increasing number of these accumulations are becoming economically viable. Coupling the

application of CO₂ and storage in unconventional formations could combine the potential to store the CO₂ underground and obtain the remaining bypassed oil or gas that has been left behind.

There are a number of CO₂-assisted recovery technologies, such as supercritical extraction, CO₂ injection via huff and puff, or CO₂ flooding, that take advantage of the favorable physical and chemical properties of CO₂ under reservoir conditions, where it typically exists above its critical point (31.1 °C, 7.38 mpa). Swelling of the oil phase, as well as the reduction of viscosity and interfacial tension (IFT), contribute to the improved displacement of residual oil that would otherwise remain unrecovered, especially with the high diffusivity, low viscosity, and higher miscibility of supercritical CO₂ (sc-CO₂) [65]. CO₂ preferentially adsorbs on organic matter in coalbeds, resulting in the desorption of CH₄ and so boosting methane recovery via increased gas recovery in unconventional organic-rich formations such as coalbeds [66]. In gas shale formations, this method has also been successful [67,68]. As a consequence, the geological storage of CO₂ in conjunction with EOR recovery might have the dual advantage of increasing hydrocarbon recovery factors while also reducing greenhouse gas emissions [69]. Conclusively, two examples of carbon sequestration in unconventional formations are described below that have gained recent research interest.

3.1. Coalbed Methane

In the enhanced coalbed methane (ECBM) recovery technique, CO₂ has been used to aid the recovery of methane from coal seams, which has been shown to be effective [70–72]. With a ratio of 2:1, the exposed coal surface has a preferential chemical attraction for CO₂ adsorption over methane, which supports its use in EOR. As a result, CO₂ may be utilized to boost the recovery of CBM, which may be highly cost effective or even free, since the increased methane removal can offset the expense of CO₂ storage operations. The overall global potential for CBM is estimated to be roughly 2 trillion scm, with around 7.1 billion tons of connected CO₂ storage capacity [17]. The methane produced from this source has the potential to be used as an energy source. Coalbeds feature very wide fracture networks, which allow gas molecules to flow into the matrix and desorb methane that has been strongly adsorbed to the coal. When compared to traditional procedures, CO₂ has been shown to increase methane recovery to around 90% from 50% when used in conjunction with them. After the methane has been retrieved from the formations, the CO₂ injected into the formations is stored. Storage in coalbeds may occur at lesser depths than in other formation types, and as a result, it is reliant on CO₂ adsorption on the coal surface to provide sufficient storage capacity [24]. However, the technical feasibility of this storage procedure is highly dependent on the permeability of the coal, which is determined by the depth variation of the coal combined with the effects of effective stress on coal cracks [31]. Furthermore, the San Juan Basin, which is the home to the world's first ECBM project, has reported on the viability of commercial CO₂ injection into coalbeds and seams after conducting laboratory and field tests [73]. Other improved CBM recovery initiatives reported throughout the world for laboratory and field testing include the Sydney Basin in Australia and deep coalbed methane in Alberta, Canada [74,75].

3.2. Shale Reservoirs

Carbon storage in unconventional reservoirs is thought to have two particularly appealing characteristics: (1) the presence of a fracture network that has developed over time, and (2) the possibility of using the injected CO₂ into the ground to increase the production of residual hydrocarbons. There are oil and shale gas deposits as well as organic-rich shale deposits in various places of the world. The trapping process for oil shale is similar to that for coalbeds, and it involves CO₂ adsorption onto organic material in the same way. It is possible that CO₂-enhanced shale gas production (such as ECBM) will result in lower storage costs. Although the potential for CO₂ storage in oil or gas shale is presently unclear, the huge quantities of shale available imply that the storage capacity

may be substantial. These shales may be restricted in volume if site-selection criteria such as minimum depth are created and applied to them, but the very poor permeability of these shales is likely to impede the injection of substantial amounts of CO₂ [49]. However, there are various advantages for CO₂ storage in shale gas [76]; CO₂ can enhance the recovery of shale gas, and the storage capacity is considered significant for storage. In addition, there is no possibility for CO₂ to leak due to the tight characteristics of shale formation. Furthermore, shale gas contains a lot of nanopores, and it can adsorb CO₂ strongly, which is propitious to CO₂ storage. It has also been proven that shale gas has a stronger affinity to CO₂ than to CH₄. There are several case studies and research that prove the success behind utilizing carbon storage in unconventional shale gas formations. In 2012, Khan et al. [77] studied the feasibility and economic benefits of shale gas produced by CO₂ based on numerical simulation. Then, Moinfar et al. [78] established a complex fracture model to simulate the improvement of shale gas recovery by injecting CO₂. After that, Sun et al. [79] proved that CO₂ sequestration with enhanced natural gas recovery can achieve CO₂ sequestration and enhance CH₄ recovery in shale gas reservoirs, and the injection pressure has a huge impact on the CO₂ storage and natural gas production rate. Moreover, it was proven that CO₂ storage in shale reservoirs is feasible; over 95% of the injected CO₂ is effectively sequestered instantaneously, with gas adsorption being the dominant storage mechanism [80]. In 2015, various research focused on the significance of the success of shale gas production through CO₂ sequestration. The first research was conducted by Li and Elsworth [81], who proved that injecting CO₂ into shale gas reservoirs is beneficial to increase the permeability of fracture. In the second study conducted by Bacon et al. [82], where they developed simulations of methane production and supercritical CO₂ injection, found that CH₄ desorption from clays is greater than that from organic matter after injecting CO₂. Then, in 2016, Sang et al. [83] proved that pressure is an important factor affecting the ultimate recovery of shale gas, and a pressure depletion scheme can affect the process of gas production in shale deeply. Furthermore, Liu et al. [69] presented a novel methodology based on nuclear magnetic resonance (NMR). It can be used to measure the enhanced gas recovery (EGR) efficiency caused by CO₂ injection. After that, in 2020, Sun et al. [76] developed an experimental study and proved that the pressure, temperature, and moisture have a relatively strong effect on the isothermal adsorption of shale gas. There has been substantial progress in CO₂ sequestration in unconventional reservoirs. This may be considered as an avenue to store CO₂ while simultaneously obtaining the remaining bypassed oil and gas.

4. Trapping Mechanisms

The ultimate distribution of CO₂ in a reservoir is the result of many factors. Structural or stratigraphic trapping, residual trapping, mobility trapping, and mineral trapping are some of the methods. These mechanisms kick in at various points during the CO₂ mitigation process's overall lifetime. For example, structural trapping is in charge of initial CO₂ containment and safe storage. Residual and solubility trapping are critical in the dispersion and migration of the CO₂ plume, and they help to accelerate geochemical trapping when the CO₂ comes into contact with more rock minerals as it expands outwards in the reservoir layer [31]. When geochemical trapping or mining starts, CO₂ will no longer be able to exit the reservoir in any way, and the CO₂ geological storage may be considered secure since leakage concerns are reduced [17]. The geological and petrophysical properties of the target formation influence CO₂ storage capacity, confinement, and injectivity. The supercritical CO₂ injected underground is safely trapped by three key trapping methods: (1) chemical trapping, (2) physicochemical trapping, and (3) physical trapping. The effectiveness of the storage process is decided by a combination of trapping processes to ensure long-term storage [31]. Figure 4 displays a matrix of the different CO₂-trapping systems, which is important for understanding how these trapping mechanisms interact. In terms of their mechanisms, the chemical and physical trapping methods have a common element, which includes physicochemical trapping. Hydrodynamic trapping is a type of physicochemical

trapping that occurs on both the chemical and physical scales. In the following sections, an in-depth explanation is provided for each kind of trapping mechanism.

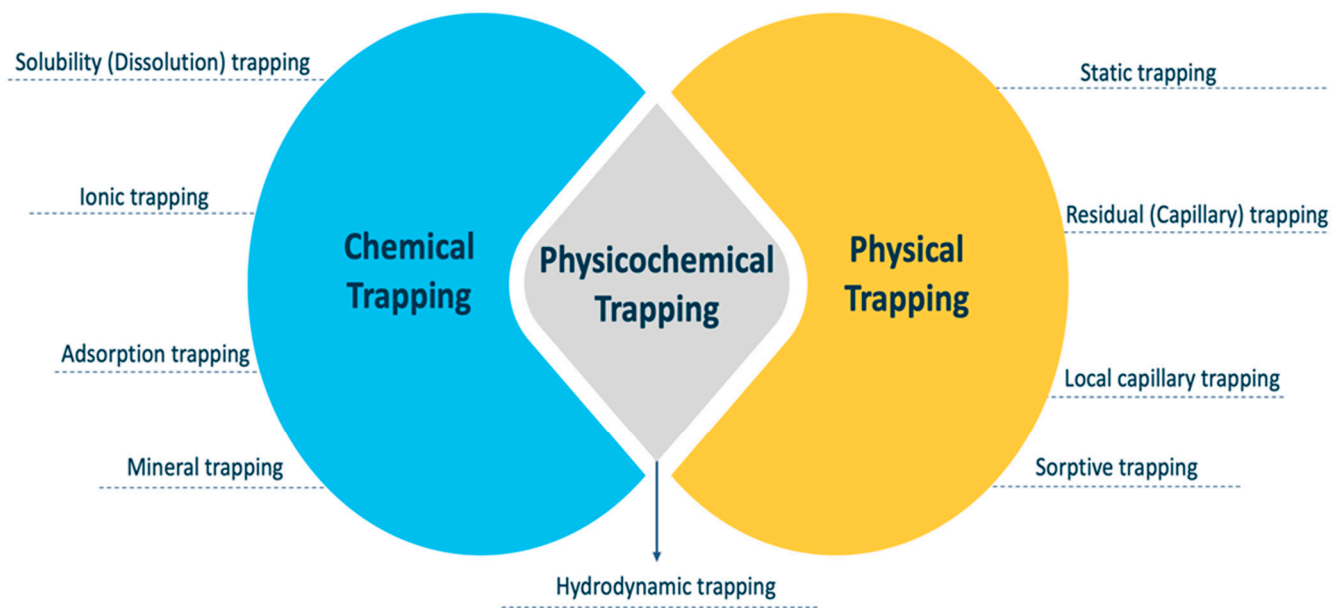


Figure 4. CO₂-trapping mechanisms in geological formations.

4.1. Chemical Trapping

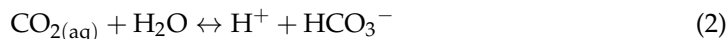
Chemical entrapment occurs when CO₂ undergoes a sequence of geo-chemical interactions with the formation brine and the rock, causing it to alter its physical and chemical characteristics and to cease to exist in either the mobile or immobile phase. This interaction guarantees that CO₂ is no longer present as a distinct phase and boosts storage capacity significantly, making it an appropriate characteristic for long-term storage [24]. There are several trapping mechanisms that fall under geo-chemical trapping, including:

- Dissolution (solubility) trapping;
- Ionic trapping;
- Adsorption trapping;
- Mineral trapping.

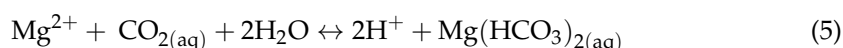
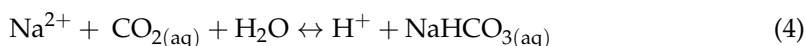
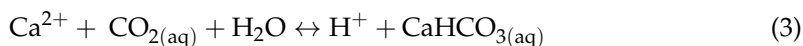
4.1.1. Solubility (Dissolution) Trapping

CO₂ dissolves in other fluids in either the supercritical or gaseous phase in the same way as sugar dissolves in tea [24]. Solubility trapping occurs as a consequence of CO₂ dissolution in brine, resulting in thick CO₂-saturated brine. Thus, it no longer exists as a distinct phase at this moment, which removes any buoyancy impact. After injection, CO₂ would travel upwards to the interface between the reservoir and caprock, and then spread laterally beneath the caprock as a distinct phase. When CO₂ comes into contact with the ambient formation brine and hydrocarbon, mass transfer takes place, with CO₂ dissolving into the brine until an equilibrium condition is attained. In addition, CO₂ solubility in water is affected by the salinity, pressure, and temperature of the formation water [84]. Furthermore, CO₂ dissolves into water by molecular diffusion at the boundary of the free gas phase and formation water. When water comes into contact with CO₂, it becomes saturated with CO₂, and the CO₂ concentration gradient forms. Because the molecule diffusion coefficient is minimal, this process is significantly slow, where the CO₂ will take millions of years to dissolve entirely in brine [85]. Hence, CO₂-saturated brine becomes denser than the surrounding reservoir fluids and sinks to the formation's bottom over time, resulting in more secure CO₂ trapping. CO₂ dissolution in the aqueous phase

produces weak carbonic acid, which decomposes over time into H^+ and HCO_3^- ions (Equation (2)) [24]:

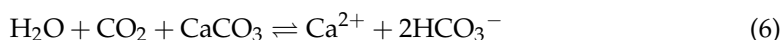


It may also be combined with other cations in the formation brines to generate insoluble ionic species, as shown in Equations (3)–(5). The solubility of CO_2 in formation water reduces as the temperature and salinity rise [24]:



4.1.2. Ionic Trapping

Ionic trapping is the process by which dissolved CO_2 reacts with reservoir minerals to form carbon-bearing ionic species (i.e., HCO_3^- and CO_3^{2-}). This process, called ionic trapping, takes from hundreds to thousands of years to occur [31]. An ionic trapping reaction is common in reservoirs containing calcite and dolomite. In this reaction, $H_2CO_3^-$ reacts with carbonate minerals (e.g., $CaCO_3$), resulting in dissolved Ca^{2+} and two HCO_3^- ions in the reservoir brines, with half of the carbon obtained from injected CO_2 and the other half from the carbonate mineral. This reaction is known as the ionic trapping of the injected CO_2 as HCO_3^- [86]:

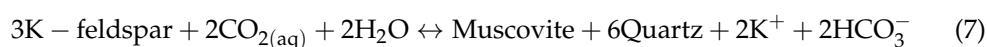


4.1.3. Adsorption Trapping

This trapping mechanism occurs when CO_2 adsorbs onto organic materials contained on coals and shales. Particularly in shale gas reservoirs, adsorption trapping may be the predominant mechanism taking place. Furthermore, gas occurs in shale reservoirs in two forms: as free gas and as adsorbed gas. The total organic carbon concentration (TOC) in shales may range from 0.5% to 50%, depending on the kind of shale [87]. Therefore, the quantity of adsorbed gas rises in proportion to the increase in TOC. Furthermore, the adsorption capability of shales increases with the amount of clay present [88,89]. Given the heterogeneity of shale gas reservoirs, the adsorption capacity may vary from 20% to 85%, depending on the TOC and clay concentration [90]. In shale gas reservoirs, intermolecular interactions exist between gas molecules (mostly CH_4 and its impurities, or CO_2 if it is sequestered) and the solid surface of shales, resulting in the formation of gas bubbles (including organic materials and clays). The process of gas accumulation on a solid surface is known as adsorption when the intermolecular interactions between gas molecules are stronger than the forces between the gas molecules in the surrounding medium [91]. The gas molecules that have been adsorbed are referred to as “adsorbate,” and the solid substance is referred to as “adsorbent” [92]. Adsorption rises in response to a fall in temperature or a rise in pressure. Adsorbed gas is released during desorption, which occurs in the opposite scenario [93]. The adsorption process is exothermic, whereas the desorption process is endothermic [92]. Adsorption and desorption become critical for generating gas from shale gas reservoirs or sequestering CO_2 into shale gas reservoirs, depending on TOC and clay concentration. In the event that horizontal wells and hydraulic fracturing are successfully completed, desorption will occur from shale surfaces to matrix pores and fractures, due to a decrease in reservoir pressure as a result of increased production [94]. Desorbed gas and free gas move into the matrix and subsequently into the wellbore, respectively. If CO_2 is sequestered in a shale gas reservoir, the process is reversible. Therefore, understanding flow dynamics in shale gas reservoirs requires an understanding of the adsorption and desorption processes [95].

4.1.4. Mineral Trapping

Mineral entrapment is the process by which CO₂ is incorporated into a stable mineral phase via interactions with other minerals and organic materials in the formation. Over time, the CO₂ injected into the formation water will dissolve and trigger a range of geological processes. Some of these reactions may be advantageous, assisting in chemically containing or “trapping” CO₂ as dissolved species and the production of new carbonate minerals; others may be detrimental, assisting in CO₂ migration [96]. It is critical to comprehend the cumulative effect of these opposing processes. However, these processes will be influenced by the structure, mineralogy, and hydrogeology of the existing lithologies [97]. CO₂ in the aqueous phase generates a weak acid that combines with rock minerals to form bicarbonate ions with a variety of cations depending on the formation’s mineralogy. The following is an example of such a process using potassium basic silicate (Equation (7)) and calcium (Equation (8)) [24]:



According to the mineralogy of the rock formations, precipitation of CO₂ minerals is inevitably generated by chemical interactions with the rock formations themselves [24]. The feasibility of CO₂ sequestration forecasts is thus dependent on the accuracy of the geochemical modeling of these events [98]. Because of the dependence of this trapping process on the minerals in the rock, the pressure of the gas, the temperature, and the porosity of the rock, it has been discovered to cause considerable variations in the permeability and porosity of the rock [99].

4.2. Physicochemical Trapping

The bridge between the chemical and physical pathways is physicochemical entrapment. It is important to note that the hydrodynamic trapping aspect is present in all of these methods. The process of storing the CO₂ via the interaction of all of the many processes that might occur along a migration route is referred to as hydrodynamic trapping [100].

Hydrodynamic Trapping

This trapping mechanism refers to the interaction of various processes when CO₂ is injected into the reservoir or saline formations. It may move extremely slowly for a long time before being trapped by residual, solubility, or mineral trapping. It is the link between chemical and physical trapping mechanisms. In saline formations, hydrodynamic trapping may happen even if there is not a definitive closed trap; it only has to be in an area where fluids move extremely slowly over a very long distance. Because CO₂ has a lower density than water, it is able to displace the salty formation water when it is injected into a formation. It then migrates upwards buoyantly because it is lighter than the water. When it reaches the top of the formation, it continues moving as a distinct phase until it is either trapped as residual CO₂ saturation or in local structural or stratigraphic traps inside the formation that is sealing it. Over the course of a longer period of time, considerable amounts of CO₂ will dissolve in the formation water and subsequently move with the groundwater [31]. When there is a large distance between the deep injection site and the end of the overlaying impermeable formation, such as when there are hundreds of kilometers between them, the amount of time it takes for fluid to travel from the deep basin to the surface may be measured in millions of years [101]. Many researchers and academics are of the opinion that hydrodynamic trapping may be placed in either the category of chemical or physical trapping. Nevertheless, it refers to the common bridging point between the systems that were previously discussed. When the CO₂ is injected into the reservoirs, it has the potential to linger there for a significant amount of time while only moving extremely slowly. Eventually, it may get trapped due to residual (physical trapping), solubility, or mineral entrapment (chemical trapping).

4.3. Physical Trapping

Physical entrapment is a method in which CO₂ retains its physical properties after being injected into an aquifer or reservoir, and the flow of CO₂ is impeded by a physical low-permeability barrier. The physical trapping mechanisms may be subdivided into the following [24,102]:

- Static trapping;
- Residual (capillary) trapping;
- Local capillary trapping;
- Sorption trapping.

4.3.1. Static Trapping

Static trapping refers to structural trapping, which is the most common kind of trapping seen during geological sequestration, and a similar process has kept oil and gas safe below for centuries. Anticlines coated with caprocks (an ultra-low-permeability layer), stratigraphic traps with/without sealed faults, are used for CO₂ storage as a mobile phase or supercritical fluid. It is critical to maximize this storage mechanism in order to guarantee that the injected CO₂ stays underground for up to dozens of years after injection [102,103]. Viscous forces are the dominating factors for CO₂ migration throughout the injection procedure in the desired formation; CO₂ is then stored as a function of depth in either the supercritical or gas phase at the corresponding pressure and temperature [24]. When the injection is stopped, the supercritical CO₂ tends to migrate upward through the porous and permeable rock due to the buoyancy effect caused by its density difference compared to other reservoir fluids, and laterally via preferential pathways until it reaches a caprock, fault, or other sealed discontinuity [104], which will eventually inhibit additional CO₂ movement.

4.3.2. Residual (Capillary) Trapping

During residual capillary trapping, when CO₂ is first introduced into the reservoir, it initially displaces the brine. However, when the injection is stopped, the CO₂ moves in two directions: upward due to density differences and laterally due to viscous forces. Thus, the wetting phase (brine) is introduced into the pores through the less-wetting phase (CO₂). Then, the brine starts displacing the CO₂, resulting in considerable CO₂ saturation that becomes trapped in tiny clusters of pores [24]. CO₂ that has been detached is then locked in an immobile phase. This technique of trapping is referred to as residual trapping or capillary trapping [96]. Furthermore, as reported by Saadatpoor et al. [105], the surface tension between the CO₂ and brine serves to block CO₂ transport, resulting in a greater capillary entry pressure than the normal rock pressure. Therefore, CO₂ becomes trapped in the pores at this moment due to residual gas saturation. The snap-off and gas trapping occurs as a result of the existence of an imbibition saturation path, as the plume leaves behind a trail of immobile CO₂ as it rises [106]. Additionally, residual trapping is often encountered in rocks with microcapillary heterogeneities. Recent research indicates that capillary trapping is a more efficient short-term CO₂-trapping process than other short-term CO₂-trapping mechanisms [107,108]. Its effectiveness is owed to the presence of stronger capillary forces than buoyant forces, which results in CO₂ appearing as pore-scale bubbles rather than being trapped by a slightly weakened caprock. Additional findings show that the residual trapping may severely restrict the mobility of injected CO₂, leading to a considerable proportion of CO₂ trapping in the hysteresis model. Furthermore, residual gas was shown to have a significant impact on CO₂ storage [96].

4.3.3. Local Capillary Trapping

CO₂ is trapped by local capillary barriers in a process known as local capillary trapping (LCT). It occurs when a saline aquifer's permeability and capillary entry pressure are spatially variable, allowing bulk-phase CO₂ to move across it due to buoyancy [109]. This trapping mechanism is considered when addressing the inherent heterogeneity of capillary

pressure in a specific storage formation [105]. LCT is a type of trapping mechanism that takes place when CO₂ is held in place by capillary walls. The saline aquifer with spatially variable characteristics experiences buoyancy-driven bulk-phase CO₂ migration, resulting in this phenomenon (permeability and capillary entry pressure). Furthermore, the saturation of the stored CO₂ is greater than that of the residual phase, making it ideal for CO₂ sequestration [105].

4.3.4. Sorptive Trapping

Sorptive trapping occurs when CO₂ is sorbed into an accessible pore space bulk due to a weak physical interaction. Sorption and structural entrapment are two processes that are considered complementary, despite the fact that they take place in the same pore spaces. It is important to note that a sorbed layer will cover a certain volume of the pore space depending on its physical parameters (density and volume). Because of this, the amount of pore space that is accessible to bulk CO₂ is decreased. If the sorbed phase density is greater than the bulk density, any storage capacity will benefit from this trapping process, since part of the injected CO₂ will not contribute to pressure building and will instead improve the total storage capacity, regardless of the storage capacity [110]. Furthermore, while utilizing manometric and gravimetric sorption devices, as well as neutron diffraction methods, it has been shown in various investigations [70,111] using high pressures (>10 MPa) that the excess sorption capacity may turn negative. This indicates that the average density of the sorbed layer is lower than the average density of bulk CO₂, and thus, the same quantity of fluid in the sorbed layer will occupy a greater volume than the average density of bulk CO₂. In addition, Busch et al. [110] argued that an immediate practical implication is that the same amount of injected CO₂ will result in greater pressures in a reservoir with negative excess sorption capacity.

5. Conclusions

CCS is an important approach for lowering CO₂ emissions into the atmosphere. Continuously increasing CO₂ emissions have been highlighted as a significant potential source of global concern, while CGS presents a plausible solution for tackling the world's current huge environmental concern. The threat of global warming has become a real concern. Several governments have acknowledged that our planet is in danger of losing its atmosphere, and that this must be handled. The issue is not just scientific, but also has ramifications in other areas of human activity. We present the reader with the most recent information on CO₂ storage science and technology in this review. From a scientific standpoint, the knowledge of the mechanisms involved in the process has substantially improved over time. There are three basic types of trapping mechanisms: (1) chemical, (2) physical, and (3) physicochemical. Each of these categories has been further categorized in detail depending on the contribution they make towards CO₂ storage in this review. Each CO₂-trapping mechanism is vital and serves a function that is unique to the type of formation. The trapping technique that ensures long-term CO₂ capture, storage, and security with minimal leakage is crucial from a variety of perspectives. For instance, mineral trapping is the safest means of storage, but it might take hundreds of years or even thousands of years for it to occur. Therefore, understanding how these trapping mechanisms work in terms of their physics and chemistry would establish a baseline towards:

- Utilizing the science to understand the trapping mechanisms' contribution to maximize the CO₂ storage capacity;
- Taking a significant step forward in modeling multi-phase flow systems for carbon storage by integrating the chemical, physical, and physiochemical interactions via a thorough investigation of the parameters that optimize storage capacity potential;
- Examining the dynamics of CO₂ plumes and their contribution to different trapping mechanisms in unconventional depleted shale reservoirs or coal seams;

- Developing an integrated model that incorporates all of the aforementioned trapping processes and evaluates their trapping storage capability, particularly in tight unconventional formations such as shale or coal seams.

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