Chapter 10

Challenges Associated with CO_2 Sequestration and Hydrocarbon Recovery

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Additional information is available at the end of the chapter

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Abstract

In the near- and midterm future, carbon capture and storage (CCS), also called CO_2 geo-sequestration, is likely to play a significant role in the reduction of atmospheric greenhouse gas. By expanding the set of possible sequestration targets, it is expected that CCS will enable larger quantities of CO_2 to be sequestered, mitigating human activity-driven climate change. In general, oil and gas reservoirs are ideal geologic storage sites for CO_2 because they have successfully held hydrocarbon molecules for millions of years. In addition to the significant and reliable storage capacity of hydrocarbon reservoirs, there is a considerable body of knowledge related to the behavior of hydrocarbon bearing reservoirs, and significant amounts of data are often acquired during their exploitation, factors which improve the economics and safety of any CCS project. By making use of existing and future oil and gas projects, CCS can become a major contributor in the fight against global warming, as well as a sizeable contributor to energy production worldwide. The CCS sequestration targets discussed in this study are sandstones, coal beds, shales, and carbonates. The potential and challenges associated with each of them are discussed in detail, and suggested topics for future research work are provided.

Keywords: CO_2 EOR, CO_2 storage, sandstone, carbonate, shale, coalbed methane

1. Introduction

Global levels of CO_2 in the atmosphere have been steadily rising with the increase of hydrocarbon production and usage. It is estimated that CO_2 emissions in the United States were approximately 5.5 billion tons in 2015, the largest volume yet. Anthropogenic greenhouse gases, such as carbon dioxide (CO_2), are considered a major contributor to global warming [1]. Sequestration of power plant-generated CO_2 through injection into petroleum and gas reservoirs through a process called carbon capture and storage (CCS) or "carbon sequestration" has been proposed as a method for reducing greenhouse gas emissions. Research on the use of CO_2 for enhanced oil recovery (EOR) continues with growing interest; however, research concerning terrestrial sequestration of CO_2 for environmental purposes, such as CCS, is relatively recent. As a result, fundamental topics of interest in sequestration research are concerned with scientific and technical aspects, as well as practical concerns such as the economic feasibility, safety, and the maximum possible amount of CO_2 storage [1]. Therefore, fighting CO_2 emissions with EOR and CCS is a priority, leading to innovations within the petroleum industry.

The process of CCS involves pumping sizeable quantities of atmospheric CO_2 underground, where, under the right circumstances, it can remain safely sequestered for thousands or millions of years. The economics of CCS are often unfavorable, especially as CO_2 is generally an expense rather than a revenue stream, but by combining the end goal of CCS with enhanced oil recovery (EOR) techniques used in the oil industry, there is the potential that CCS can be made economical while also increasing the productivity and efficiency of existing oil resources.

CO_2 EOR generally involves the injection of CO_2 into an oil-bearing reservoir in order to decrease oil viscosity, decrease the interfacial tension between oil and water, and increase the elastic energy of the formation, generally resulting in improved oil production. In the case of methane-bearing formations, most notably coal beds, injected CO_2 has a far stronger affinity to the formation than methane, resulting in the replacement of adsorbed methane with adsorbed CO_2, both increasing methane production and resulting in the sequestering of large volumes of CO_2.

EOR and CCS projects are both complicated tasks that require a vast understanding of the target reservoir in order to enhance storage capacity and storage time of CO_2, as well as hydrocarbon production. These topics will be discussed in greater detail throughout this paper.

1.1. Trapping mechanisms

One of the primary considerations when approaching a CCS project is the different mechanisms by which CO_2 can become safely sequestered underground. Generally, there are four different trapping mechanisms employed in the sequestration of CO_2, each of which contributes differently to the duration and volume of CO_2 trapping (**Figure 1**). In the different time stage, those four trapping mechanisms will work together.

- Structural/stratigraphic trapping: These types of traps are formed from tectonic forces and generally involve physical barriers to flow. An example of this is a thick layer of low permeability rock (caprock), such as shale, where, assuming a favorable structure, rising CO_2 will become trapped and begin accumulating.
- Residual trapping: This phase of trapping starts as soon as the CO_2 is injected. While the CO_2 is being injected, it is displacing the fluids that are inside the pores of the formation. As the primary CO_2 volume migrates upward, small volumes of CO_2 remain inside these tiny

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pores due to capillary forces. This mechanism immobilizes the CO_2, potentially storing it in the formation for millions of years, just like the fluids it displaced.

- Solubility trapping: Solubility trapping refers to CO_2 being absorbed or adsorbed within the formation. Absorption occurs as CO_2 dissolves in the formation fluid, while adsorption occurs as CO_2 binds to the surface of the formation, like a piece of metal attaching to a magnet. After CO_2 has been adsorbed in the fluid, it will exist as a mixture, which will not be as buoyant as its gaseous form and will not migrate upward through the formation. This mixture will be denser than the surrounding fluids and will migrate downward over time.
- Mineral trapping: At the time of injection, this type of trapping is insignificant. Over a long period, after CO_2 has been dissolved in the formation fluids, it will begin reacting with the minerals in the surrounding formation and create solid carbonate minerals. These solid carbonate minerals will be attached to the rocks it reacted with and can be stored in the formation for millions of years.

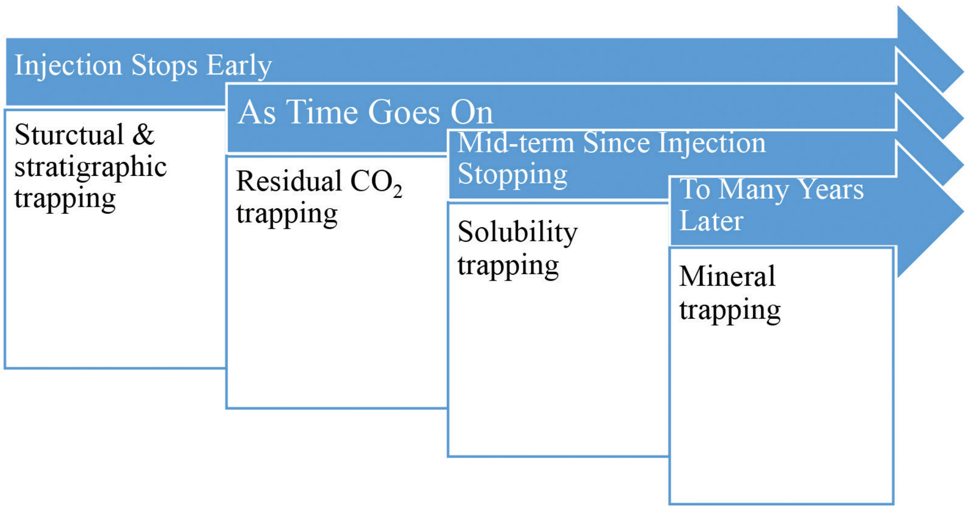

Figure 1. The four different mechanisms of CO_2 trapping.

Overall, these trapping mechanisms prevent carbon dioxide's upward travel and leakage while increasing the CO_2 storage potential and security of the desired formation. Assuming an ideal trapping mechanism, the temperature-related properties of a reservoir must be considered as well. The required temperature to store CO_2 underground should be less than the critical temperature of CO_2, making reservoirs such as those in Illinois Basin prime candidates. The critical temperature of CO_2 is 87.7°F; naturally, most geological formations exceed this temperature due to geothermal gradient [2].

1.2. Sandstone reservoirs

Sandstone reservoirs were the primary source of oil production during the early life of the oil industry. Many wells were produced and then abandoned long before the introduction of enhanced oil recovery (EOR) and other modern techniques that have enabled production from formations once thought of as nothing more than barriers to flow or geologic curiosities. In this modern day, sandstone reservoirs, once the workhorse of the oil industry but long since abandoned due to declining production, can be made to once again flow in economic quantities through the use of EOR techniques, such as CO_2 injection. While ensuring a renewed flow of oil to an energy-hungry world, CO_2 EOR in these old sandstone reservoirs may also play a major role in the preservation of our environment as injected CO_2 can be sequestered in subsurface formations for thousands of years. With these unique opportunities come unique challenges, ranging from the significant reservoir analysis required to ensure a safe sequestration to the infrastructure required to deliver such sizeable quantities of CO_2.

Sandstone reservoirs are particularly notable due to the sheer number of wells drilled in such formations that have been produced throughout the history of the oil industry and have since been abandoned. Due to their number, as well as how much time we have had to accumulate knowledge about their behaviors and the petrophysics involved in their production, sandstone reservoirs are likely to play a major role in any large-scale CCS program.

1.3. Coalbed reservoirs

Another ideal medium in which to store CO_2 is coal beds. Generally used to produce coalbed methane or coal at shallower depths, coal beds have a dual porosity system, which can be classified as primary and secondary porosity system. The pores within the coal matrix make up the primary porosity, while the pore volume of the numerous fractures permeating the coal bed makes up the secondary porosity.

The methane that is the primary target of coalbed drilling is stored in the coal matrix via adsorption. Because CO_2 has a greater affinity for coal than methane does, CO_2 is the desired choice to enhance methane recovery, and coal beds are a good place to store CO_2. Coal beds are distinctively different from the conventional hydrocarbon reservoirs in production as well as gas storage mechanisms. In conventional oil reservoirs, CO_2 is dissolved in the oil to decrease the viscosity of the oil, resulting in a great deal of CO_2 being recovered at the surface along with the produced oil. The "sequestered" CO_2 is then only that which dissolves into residual oil or is trapped due to one of the other trapping mechanisms [3]. In the case of coal beds, the majority of CO_2 adsorbs directly to the surface of the coal bed, providing a more efficient mechanism of sequestration while also forcing methane off the coalbed surface, helping to release any residual gas production. For example, methane recovery was improved from 77 to 95% of original gas in place at the Allison Unit CO_2-ECBM pilot in the San Juan Basin [4]. Coal beds can act as a significant contributor to CCS through the excellent economics of CO_2-based EOR, as well as the quality of their sequestration.

1.4. Shale reservoirs

As technology has advanced throughout the years, oil and gas exploration in unconventional shale reservoirs has become the main focus of the oil industry. Horizontal drilling and the hydraulic fracturing of shale formations have allowed us to unlock vast reserves of oil and gas production. Considering shale formations have extremely low permeability (of nanoDarcy in some cases), primary production does not produce the maximum amount of oil possible out of the formation. In most cases, tertiary production or EOR will begin with gas injection, such as carbon dioxide (CO_2), instead of water flooding because of shale's low permeability and the risk of reactions between the clays and injected water. During this production enhancement, some of the injected carbon dioxide will be permanently stored in the formation with different storage mechanisms, while some will be produced with the oil stream and get recycled back into the formation. CCS in shale reservoirs is often more difficult as less is known about their geology and long-term behaviors.

Shale reservoirs will likely play an important part in future CCS projects due to the scale of many shale reservoirs, their quality as a seal, and the importance of EOR techniques in existing shale plays.

1.5. Carbonate reservoirs

CO_2 injection into carbonate reservoirs was first considered in the 1930s but did not become a reality until 1964 in the Mead Strawn field located in Texas. CO_2 injection has since been established as a reliable form of EOR, with results regularly matching or surpassing those of other EOR techniques. In the 1964 example with the Mead Strawn field, oil production was increased by up to 82% beyond the results of a standard water flood [5]. Like many sandstone reservoirs, carbonate reservoirs have a long history and will likely play a significant role in future CO_2 EOR and CCS projects.

Hill et al. [6] state carbonate CO_2 EOR now produces approximately 305,000 bbls worldwide with an accelerating growth rate. The areas targeted for carbonate CO_2 projects in the United States are as follows: Louisiana, Michigan, Mississippi, New Mexico, Oklahoma, Texas, and Wyoming. CO_2 production wells provide immense amounts of data on the reservoir response to a CO_2 flood compared to saline projects. Azzolina et al. [7] discuss how CO_2 EOR is an established method for extending the life of a hydrocarbon sustaining carbonate reservoir.

Dissolved CO_2 injection into carbonate subsurface formation increases geologic carbon storage integrity by avoiding dependence on trapping mechanisms. As a result, solubility trapping will dominate until mineral trapping occurs, which is dependent on the formation rock [56]. Izgec et al. observed that solubility storage of CO_2 is larger than mineral trapping [1]. Eke et al. [8] state geological CO_2 storage in carbonate formations for long timescales (sequestration) relies on the contribution of several CO_2 trapping mechanisms: physical trapping in a subsurface formation, solubility trapping, hydrodynamic trapping, and mineral trapping.

2. Existing field applications

With the need for the prompt reduction in CO_2 emissions, the development of CCS must be taken seriously, as it has the potential to make a major difference in the levels of atmospheric CO_2. At one time, it was believed that oilfield reservoirs did not have sufficient pore volumes to have a significant impact on CO_2 emissions, but it is now understood that not only are there massive pore volumes available for CCS in depleted major pay zones (MPZs) of reservoirs, but there also exist residual oil zones (ROZs) and transition zones (TZs) in hydrocarbon fields that can be depleted and used for sequestration through quaternary production.

Traditionally, residual oil zones (ROZs) are considered to be uneconomic by the end of their primary or secondary recovery phase due to their extremely low oil saturation. However, Advanced Resources International [9] analyzed the feasibility of using CO_2 EOR to recover hydrocarbons from the ROZ and determined that a total of 55 fields in the Permian Basin have the potential to become economic ROZ resources. Simulations using CO_2 PROPHET, a water and CO_2 flood prediction software available through the US Department of Energy (DOE) website, estimated the recoverable ROZ at 11.9 billion bbls of the 30.7 billion bbls of TZ/ROZ oil in place in these five Permian Basin oil plays [9].

Usage of CO_2 injection as a form of EOR has not been limited to pilot and research tests. Kinder Morgan estimated that in the past 37 years, 655 million tons of CO_2 have been injected, produced, and recycled back into EOR. This is an average of 17.7 million tons per year, which is enough to negate the yearly emissions of six 500 MW coal-fired electric power plants [10]. Examples of some of these different field applications are given below.

2.1. Permian Basin

The Permian Basin in West Texas is one of the largest areas employing CCS techniques in ROZ and TZ and is currently undergoing the largest CO_2-enhanced oil recovery (EOR) operation in the world. Most of the ROZs created in this area are due to lateral sweep by hydrodynamics and have thicknesses in excess of 300 feet [11]. While implementation of CO_2 floods is not particularly widespread due to the limited availability of CO_2, the Permian Basin has ready access to a pipeline of CO_2 originating in natural supplies in Colorado and New Mexico. Of the six CO_2 EOR projects in which recovery response has been published for Gulf Coast sandstone reservoirs, recovery factors are from 15 to 23% of original oil in place (OOIP) [12].

2.2. Port Neches

A CO_2 injection project in Port Neches, in a Texas Gulf sandstone, started in September 1993. The field had previously undergone water flooding, leaving a residual oil saturation of 30%. The goal of the project was to recover an additional 10% original oil in place (OOIP) [13]. A follow-up paper recorded that the production peaked at 500 barrels of oil per day (Bopd) (**Figure 2**) and later at 800 Bopd with CO_2 injection. The OOIP reduced from 12 to 7 million stock tank barrels (MMSTB) in the main fault block of the reservoir [14].

2.3. Bati Raman field

In 1986, the Turkish Petroleum Corporation started a large immiscible CO_2 injection project; the trend can be seen in **Figure 3**.

2.4. Ordos' Basin

The evaluation of Changqing oil field, Ordos' Basin, Northwest China, concluded that conducting a CO_2 flood after water flooding could produce 119 million tons of oil and sequestrate 273 million tons of CO_2 [16]. In 2000, the International Energy Agency Weyburn CO_2 Monitoring and Storage Project did a study on CO_2 storage in a partially depleted oil reservoir and found that a $1.5 billion, 30-year commercial CO_2 EOR produced an additional 130 million barrels of oil.

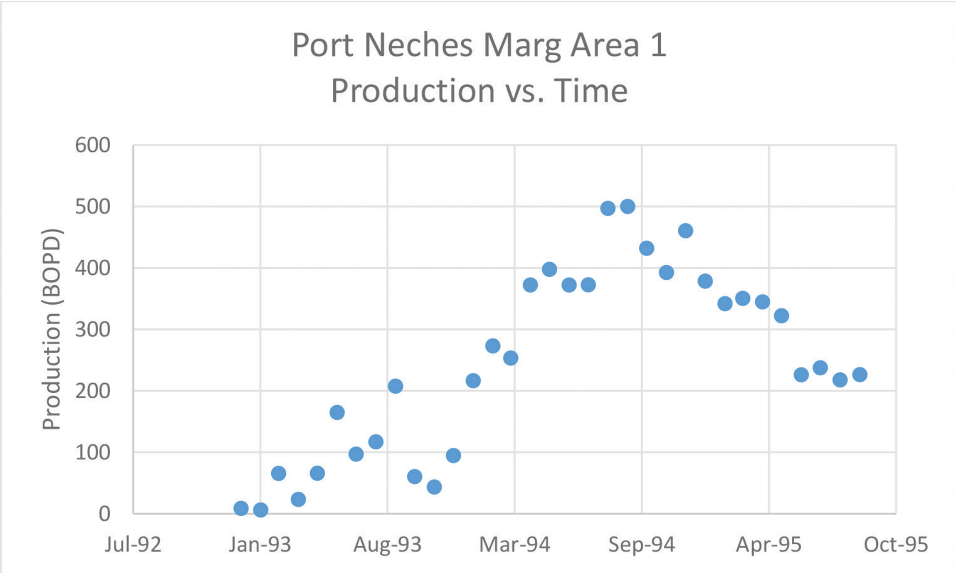

Figure 2. Production vs. time plot.

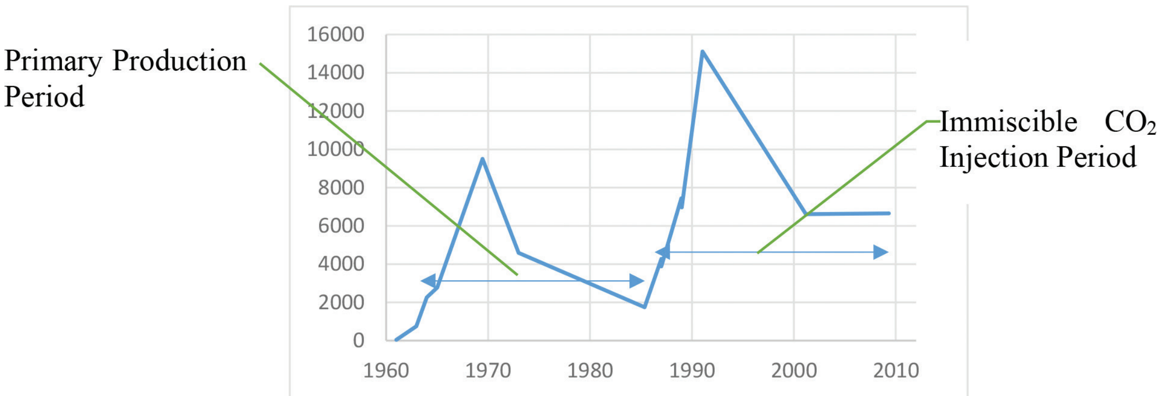

Figure 3. The Bati Raman field's production trend [15].

2.5. SECARB

The Southeast Regional Carbon Sequestration Partnership (SECARB) [17] operated a test for CO_2 sequestration at Black Warrior Basin in Alabama from 2006 to 2009 and determined that more than 360 million tons could be sequestered while increasing coalbed methane reserves by more than 20%. The SECARB set up monitoring systems in shallow boreholes and continues to monitor the local soil profile to determine if seepages of their test injection of 1000 tons of CO_2-injected gas occur and to facilitate the development of monitoring protocols that will ensure the safe conduct of CO_2 injection activities.

2.6. SWP projects

The Southwest Regional Partnership for Carbon Sequestration (SWP) indicates that over 2 million metric tons out of a total of 7 million metric tons retained CO_2 in the Scurry Area Canyon Reef Operators (SACROC) project were dissolved in the aqueous phase. That report does not include nor report CO_2 dissolution in oil, and therefore the numbers for CO_2 dissolution in the aqueous phase may be compromised. In addition to CO_2 dissolution in oil, the presence of a hydrocarbon phase can limit the contact between injected CO_2 and the aqueous phase even in depleted carbonate reservoirs. This work will, therefore, enhance estimates of predicted storage capacity both in depleted and producing oil reservoirs by revisiting and considering CO_2 solubility in the oil phase.

Additionally, rock wettability determines whether hydrolyzed CO_2 and the resulting acid in the aqueous phase can come into contact with the rock surface. When the rock is strongly oil wet such as in most carbonates, carbonate dissolution cannot take place; therefore, requirements for the mineralization trapping mechanism will not be met. In that case, the current estimation of CO_2 storage capacity in oil reservoirs because of the mineralization mechanism should be revisited. There is no indication of wettability measurement in the SACROC project. The SACROC project seeks to develop a subsurface geochemical-compositional flow model that incorporates the physics learned from lab-based measurements conducted throughout the course of its work, which will add considerably to the body of knowledge for carbonate reservoirs.

2.7. Existing exploited CO_2 sources

The majority of CO_2 injected into formation during operations is from natural reservoirs; however, problems arise such as climate change, diminished supply, and large demand. Innovation provides the solution by capturing CO_2 previously released to the atmosphere and using it for CO_2 EOR. During the production process, produced CO_2 is captured at the surface and reinjected, thus trapping the majority of injected CO_2 in formation. In Wyoming, natural gas processing plants produce approximately 716 Tcf of CO_2 while injecting 705 Tcf [7] in carbonate formations. In Michigan, an existing source of CO_2 provides the opportunity for carbonate CO_2 EOR in the NPRT; thus, Core Energy is using CO_2 emissions for EOR operations exploiting carbonate reef deposits [18]. These examples are helping reduce the emissions that would otherwise be vented to the atmosphere.

2.8. ECBM studies

Due to the effectiveness of CO_2 EOR and sequestration in coal beds, numerous studies have examined the usage of CO_2 sequestration in enhanced coalbed methane (ECBM) fields, and there are many field cases.

Mastalerz et al. [19] studied CO_2 sequestration and ECBM in unminable coal seams of the Illinois Basin. They found that approximately 271 billion tons of CO_2 could potentially be sequestered in the basin. Moreover, they found that potentially 1.6–4.6 billion tons of CO_2 could be sequestered in Illinois Basin coals and 70–280 billion m^3 (2.4–9.8 Tcf) of CH_4 is potentially recoverable as a result of CO_2 ECBM practices. The paper does suggest that volumetric strain due and coal swelling, which causes permeability damage, should be considered in any CCS or CO_2 EOR project.

Yu et al. [20] predicted in 2007 that the CO_2 sequestration throughout all ECBM projects (existing and potential) in China could result in over 3.751 Tm^3 of additionally recoverable methane, with a CO_2 sequestration capacity of around 142.67 billion tons.

2.9. Shale storage capacity (the United States and Canada)

The amount of available storage for CO_2 in oil and gas shale is currently unknown, but the vast volumes of shale formations indicate that the storage capacity is significant. A recent report has estimated between 1.85 trillion and 20.5 trillion tons of carbon dioxide storage capacity is available in oil and gas reservoirs just in the Unites States and Canada. These estimates suggest the availability for storing centuries worth of CO_2.

2.10. Additional possible locations and projects

Depleted oil and gas fields in the SECARB region could provide 29.7–34.7 billion tons of CO_2 storage with 24 million recovered oil barrels [21]. Almost 60% of the estimated volume relate to offshore fields. Coal and organic-rich shale formations can also offer a significant place for storage due to high absorption capacity of CO_2 in addition to potential EOR applications. A tertiary coal in the Gulf of Mexico is estimated to have 20–28 billion tons of CO_2 storage [18].

The potential storage capacity of the Barnett Shale is estimated to be 19–27 Gton, while other shale formation, Fayetteville Shale, is estimated to be capable of sequestrating 14–20 Gton of CO_2 [18]. There are still a lot more fields in the SECARB region to be evaluated on a possibility of a potential CO_2 storage and sequestration site. The SECARB region has a large annual CO_2 emission from coal-fired power generation and other fossil-fueled plants. In 2008 it was estimated to emit almost 2.9 [22] billion metric tons of CO_2.

An estimation of possible CO_2 sequestration volume was done by a "production replacement" principle, where for every volume of hydrocarbon, a 1:1 replacement ratio of CO_2 volume takes place. For the 2008 rates of CO_2 emission, SECARB region was capable of providing at least 28 years of CO_2 storage [18]. A case with a CO_2 EOR and sequestration in the Bell Creek oil field has a promising estimation of a recovery of additional 35 [23] million bbl of incremental oil through CO_2 flooding. Current plans exist to build a 232-mile pipeline from ConocoPhillips Lost Cabin gas producing plant to the Bell Creek field. This will help to integrate the large-scale storage of over 1 million tons of CO_2 per year.

3. Upcoming improvements to field applications

Kuuskraa, Godec and Dipeitro [24] analyzed primary and enabling next-generation technologies with applications in CO_2 sequestration, as shown in **Table 1**, and approximated the benefits of these technologies on a sample field area, as shown in **Table 2**. Notably, using their sample and estimates, they predict an increase in economically recoverable resource from 21.4 to 63.3 billion bbls.

Technologies		Technology implementation	The use of enabling technologies
I. Primary technologies			
1.	Improved reservoir conformance	Divert CO_2 from high permeability reservoir channels	Reservoir characterization and MDC
2.	Advance CO_2 flood design	Realign CO_2 flood pattern; drill additional wells to flood poorly swept zone(s)	Reservoir characterization and MDC
3.	Enhanced mobility control	Increase viscosity of drive water (WAG) to 2 cp	Enhanced fluid injectivity
4.	Increased volumes of efficiently used CO_2	Increase CO_2 injection from 1 HCPV to 1.5 HCPV; reduce sorm from 0.1 to 0.08	MDC and enhanced fluid injectivity
5.	Near-miscible CO_2 EOR	Apply CO_2 EOR to oil reservoirs with max pressure within 80% of MMP; reduce sorm based on reservoir pressure	–
II. Enabling technologies			
1.	Robust reservoir characterization	Advanced logging, seismic monitoring and core analysis	Essential for technologies 1 and 2
2.	Enhanced fluid injectivity	Effective near-wellbore stimulation methods	Essential for technologies 3 and 4
3.	Monitoring, diagnostics and control (MDC)	Downhole monitoring systems, real-time diagnostics, smart wells, etc.	Essential for technologies 1, 2, and 4

Table 1. Technologies used in next-generation CO_2 EOR [22].

Resource area	Economic oil recovery (billion bbls) *		Demand for CO_2 (billion metric tons)		Average CO_2 utilization (bbls/ $mtCO_2$)	
	SOA	Next generation	SOA	Next generation	SOA	Next generation
Miscible	19.6	60.8	8.4	15.4	2.3	3.9
Near miscible	1.8	2.6	0.5	0.8	3.9	3.3
Total	**21.4**	**63.3**	**8.9**	**16.2**	**2.4**	**3.9**

*At $90 per barrel oil price and $40 per metric ton CO_2 price, with 20% rate of return (before tax). Results compiled from simulations of CO_2 EOR floods at 1800 oil-bearing formations in the onshore continental United States. Reservoir characterization data drawn from the Big Oil Fields database, simulations conducted using the PROPHET stream tube model.

Table 2. Results from next-generation CO_2 EOR [22].

3.1. Simultaneous injection into pay zones and aquifers for ECBM

Ahmadi et al. [25] performed numerical modeling to investigate reasonable CO_2 injection scenarios, which were applied to CO_2 sequestration and ECBM. In their study, the main goal was to study different CO_2 injection methods and the effect of operational factors on the performance of each method by a numerical simulation model. There were three different strategies

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concentrated, which were soluble and insoluble CO_2 injection into the bottom aquifer, CO_2 injection into pay zone, and simultaneous CO_2 injection into aquifer and pay zone. The result was that simultaneous injection into aquifer and pay zone leads to higher final oil recovery in EOR schemes.

3.2. Modifications to shale CO_2 processes

Due to the low porosity of shale, capillary forces are not negligible. Furthermore, adsorption has to be carefully considered due to a large specific area in shale. Pu and Li [26] gave a new formulation that includes the capillary force and adsorption through pore size distribution. A local density optimization algorithm was used to the adsorption model. In the Bakken field, the results of their investigations reduced the soaking time of the CO_2 huff "n" puff process and increased the 18% OOIP ultimate recovery.

3.2.1. Shale heterogeneity needs to be considered

Most of the unconventional reservoirs are heterogeneous, which influences the application of the huff "n" puff method. Chen et al. [27] studied the relationship between the reservoir heterogeneity and CO_2 huff "n" puff recovery through running simulations in the Elm Coulee Field of the Bakken. Shale heterogeneity had a significant negative impact, reducing the final recovery rate of the well.

3.2.2. There have not been large-scale CO_2 sequestration projects with shale

Large-scale demonstrations to prove CO_2 storage capability and capacity for very long periods of time in shale have not yet occurred [28]. According to Global CCS Institute [29], only 15 large-scale projects on CO_2 storage are taking place around the world with CO_2 capture capacity volumes ranging from 0.7 to 7 million tons per annum (Mtpa) in countries such as Norway, Algeria, Canada, and the United States. These do not include smaller projects that use CO_2 injection and end up sequestering smaller volumes, i.e., CO_2 EOR projects.

3.2.3. Improving CO_2 sweep efficiency

To maximize the effectiveness of CO_2 sequestration and adsorption in shale, it is important for the injected carbon dioxide to come in contact with as much reservoir volume as possible, a phenomenon known as sweep efficiency. Again, not enough CO_2 sequestration projects in shale formations have taken place and been monitored to show what the most effective conditions are to keep carbon dioxide sequestered. An increase in recovery rate from CO_2 injection under specified conditions can be used to estimate the optimum requirements to achieve utmost levels of sweep efficiency, but this is not necessarily the ideal condition for sequestration.

The available knowledge suggests recovery factors increase drastically when carbon dioxide is injected around minimum miscible pressure (MMP) that is around 1500 psi [30]. MMP can change by a few percentages depending on reservoir pressure, permeability, heterogeneity, and pore geometry.

One of the advantages of carbon dioxide is that its MMP is much lower than other gases; therefore, CO_2 MMP injection is possible under a wide range of reservoir pressures [31]. At around MMP, carbon dioxide and oil are miscible which leads to a zero entry capillary pressure. This allows carbon dioxide to enter the oil filled tight pores of shale and increase sweep efficiency and storage with high displacement efficiency. Also, the required soaking time, the time needed for injected gas to pierce and spread throughout the formation, appears to have a significant effect on sweep efficiency because of exceedingly low permeability of shale formations. Longer shut-in periods after CO_2 injection show higher oil recoveries that indicate a greater sweep efficiency [28].

3.3. Carbonate potential

In the South Sumatera Basin, 98 carbonate oil fields represent 59% of total original oil in place (OOIP) [32]. A study ranked these reservoirs based on CO_2 EOR and sequestration.

3.3.1. Challenges in carbonates present opportunities in CCS

Carbonate hydrocarbon reservoirs remain poorly understood; opposed to other storage sites, carbonates are likely to be hydrophobic (2/3rd of the world's carbonate reservoirs are oil wetting). CO_2 dissolution in the oil phase is orders of magnitude higher than its solubility in brine as seen in **Figures 4** and **5**. In the context of CO_2 sequestration in carbonate hydrophobic storage sites, dissolution of CO_2 in the oil phase is favorable for the long-term CO_2 storage in comparison with free supercritical CO_2 storage or CO_2 dissolution in brines.

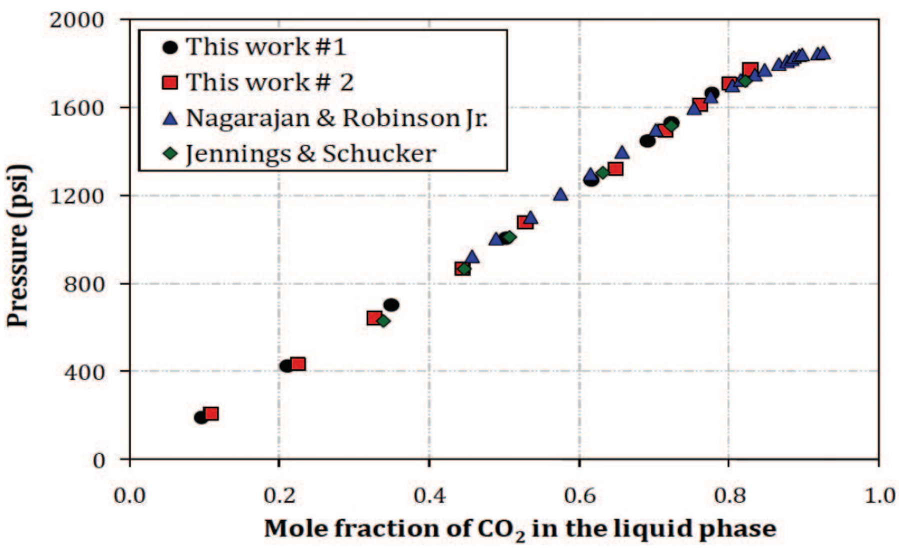

Figure 4. Pressure dependence of CO_2 dissolution in an oleic phase in 71°C [33].

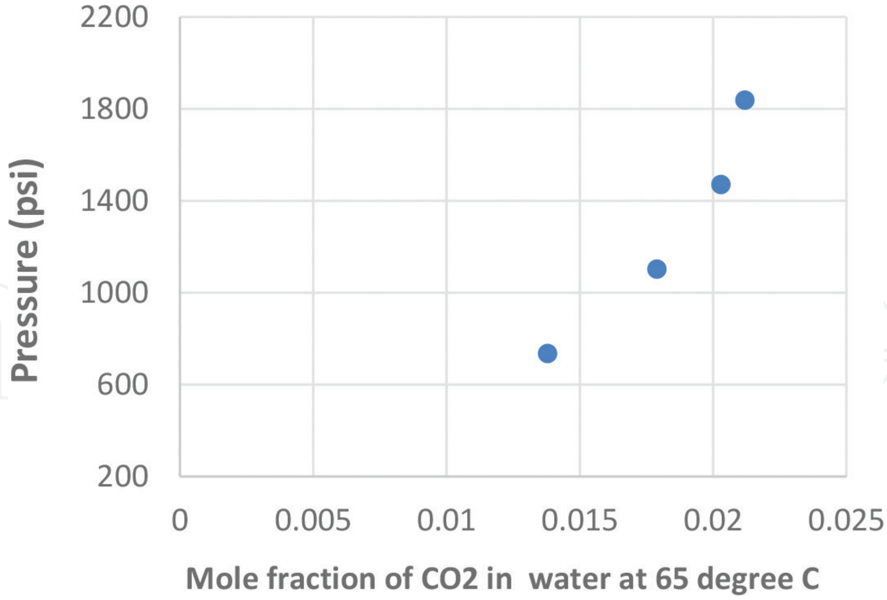

Figure 5. Pressure dependence of CO_2 dissolution in water at 65° [34].

4. Economics

One of the primary challenges facing CCS and CO_2 EOR is the cost of trapping and delivering CO_2. Large-scale injection of CO_2, for any purpose, can only reach its full potential when a supply chain and infrastructure are established, and most locations do not have access to a preexisting CO_2 infrastructure [16, 35].

For instance, while the impermeable shale barriers in an Illinois Basin are a perfect seal for a long-term sequestration of CO_2, the absence of a CO_2 delivery infrastructure, despite local electrical power facilities emitting over 255 [20] metric tons of CO_2 annually, still overcomes all the scientific potential in the area. The same scientific potential could allow low-temperature oil reservoirs to become sequestration targets, and to increase the local CO_2 storage capacity 20 times, at the same time, to enhance the oil recovery by another 6–18% (360–1100 MMSTB) [21].

In one case in the Gazran field, the costs to acquire CO_2 were approximately 11$/metric ton, with recycling costs of approximately 8$/metric ton [16]. In other areas, such as West Texas, prices can be as high as $40/ton with 18 billion tons of CO_2 required, making it very difficult to initiate large-scale CO_2 projects without a proper supply chain. Ghomian et al. [36] estimated that the total costs of CO_2 sequestration are in the range of $40–$60 per ton of CO_2 stored, primarily due to the costs of CO_2 capture and compression. In cases where a proper CO_2 infrastructure can be created, CO_2 transported via a pipeline with rates above 10 million tons of CO_2 per year often cost less than $1/metric ton of CO_2 per 100 km, with lower flow rates costing as much as double that amount [34]. This suggests that once a basic infrastructure has been created, the capture cost of CO_2 will become the limiting factor in CCS and CO_2 EOR projects.

4.1. Coal bed

No matter how efficiently CO_2 ECBM and CO_2 sequestration works when CO_2 is readily available, economic problems cannot be ignored. Robertson [37] provided the economic analysis of CO_2 sequestration and CO_2 ECBM of the Powder River Basin in Wyoming. He evaluated three production scenarios (no gas injection, flue gas injection, CO_2 injection). Strategies were analyzed using a discount rate of 10% and the rate of return on investment. A Monte Carlo model was used to analyze the CO_2 injection method and the mean value of the CO_2 injection scenario (**Figure 6**). It was found that for the mean case, a cost of CO_2 of approximately $4.81/Mg (or $4.81/metric ton) is required to maintain the economic viability [35].

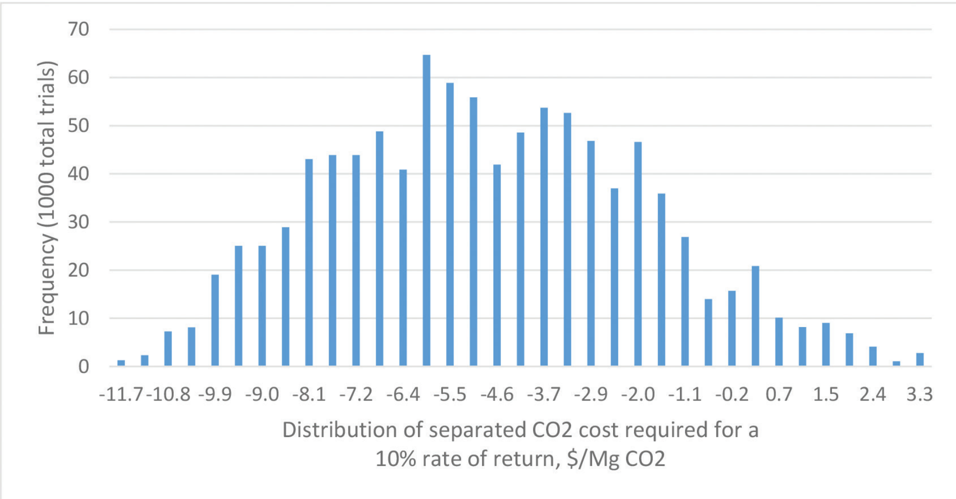

Figure 6. Distribution and mean value of the cost of CO_2 separation/capture required to yield a 10% rate of return [35].

Robertson also suggested that separating CO_2 from flue gas and injecting it into the unminable coal zones of the Powder River Basin seam, while currently uneconomical, can increase recovery of methane by 17% and could sequester over 86,000 tons CO_2/ac [35].

A 2009 economic analysis by Gonzalez et al. investigated the effectiveness of CO_2 EOR and sequestration on coal beds of different initial permeability values and determined that CO_2 storage was often quite economical on wells of moderate permeability (10 milliDarcy) and high permeability (100 milliDarcy). In their study, none of the low permeability cases were economical. It is worth to mention that high-rank coals (those containing higher levels of carbon) showed the strongest economics [38].

5. Injection and sequestration

Unlike in the oil industry where the inability to recover injected resources is often a cause for concern and additional economic strain, CCS inherently requires the permanent sequestration of CO_2 in the given reservoir. These conflicting intentions will need to be overcome

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for economic purposes if CCS and CO_2 EOR are to become major players in the fight against climate change. Once these challenges have been overcome, the effectiveness with which CO_2 can be sequestered into different formations becomes a major point of importance.

Examples of the effectiveness of CO_2 sequestration are fairly common. Yamaguchi et al. [39] investigated the Ishikari Coalfield in Japan, where a multi-well test was able to inject 600 tons of CO_2 with an estimated 96% of the CO_2 being successfully adsorbed into the coal bed. Mavor et al. [40] analyzed a project by the Alberta Research Council which operated a two-well pilot test, where they determined that the increase in CO_2 injectivity (owing ballooning and water saturation reduction) was able to overcome injectivity losses due to swelling. Results were greatly improved by reducing injection periods, which allowed for adsorbed gas in the coal bed to finish swelling and for CO_2 to diffuse throughout the reservoir. These results were mirrored by Wan and Sheng [41], who determined that in fractured reservoirs, cyclic gas injection could increase oil recovery to 29%, while primary production only produced about 6.5% of OOIP [39].

Sheng and Chen [42] compared CO_2 and water flooding and were able to achieve superior results for CO_2 injection both in the case of flooding and huff "n" puff scenarios, with the best results (production of 32.46% OOIP) occurring using the huff "n" puff method.

5.1. CO_2 EOR in gas condensate wells

Higher densities of CO_2 relative to the native gas condensate cause CO_2 to migrate downward; with an increase of viscosity, CO_2 will displace the hydrocarbon gas phase. CO_2 EOR is very effective in light and medium gravity reservoir oils, in addition to being effective at recovery of gas condensates [43]. The dissolution of CO_2 into the oil decreases its interfacial tension; this creates a chance for the capillary force to enhance the recovery of the residual oil. This aspect heavily depends on the pressure and thus the depth. The properties of depleted gas/condensate reservoirs make them favorable for repressurization and enhanced gas recovery using CO_2 [41].

6. Possible geomechanical problems

EOR through CO_2 sequestration provides great opportunities for improving hydrocarbon recovery and the reduction of the greenhouse effect. Yet there are still problems about CCS that need to be addressed. A study on a pressure-depleted gas reservoir in the southern North Sea provided insight on CO_2 sequestration in depleted hydrocarbon reservoirs [60]. Their sequestration led to multiple geomechanical problems during drilling, completion, and CO_2 injection.

These depleted reservoirs have a narrow window of drilling mud weights that will not result in reservoir problems, and well completions can be affected by potential solid flow back when the injection of CO_2 is interrupted, while the temperature changes near the wellbore can lead to thermal fracturing and reactivation of faults. CO_2 sequestration can sometimes require drilling additional injection wells, which can be a problem with a narrow mud weight window because of the increased chance of a wellbore collapse.

The narrow mud weight window can make it nearly impossible to avoid falling out of the ideal range of mud weights, leading to a number of risks and an increase of nonproductive time and additional costs. During the injection stage, if there are problems with CO_2 supply, resulting in an interruption of CO_2 injection, solids will flow back into the well, resulting in a risk of rock failure or erosion of a pipeline.

Well integrity is the achievement of fluid containment and pressure containment within the well throughout its whole life cycle. The CO_2 injection can lead to the corrosion and degradation of the injection tubing, injection casing, and cement and packer material. The trickiest part is keeping the well leak-free. A CO_2 sequestration well has to be designed for over 40 years of continued well integrity. Some potential methods of protecting well integrity include the injection of supercritical CO_2 fluid, as it is dry and noncorrosive, protecting a well for a much longer period [44]. Usage of supercritical CO_2, unfortunately, increases costs and can increase issues with temperature changes, which can hydraulically and thermally fracture a rock in a near-wellbore region. This risk can be mitigated by keeping the fluid pressure that acts on a caprock outside of its fracturing pressure. Most other well failure problems can be reduced by keeping a well straight instead of inclined [60].

6.1. Offshore leak issues

Offshore injections of CO_2 for EOR and sequestration lead to alterations and deformations of caprock, affecting seal integrity. A break in a cap rock can result in a large burst of CO_2 from a reservoir and ultimately the seabed. When evaluating long-term caprock integrity, it is important to note the intrinsic caprock properties, chemical conditions at reservoir/caprock interface, and injection-induced pressure perturbation [61].

The caprock properties to look for are fracture normal stiffness, bulk concentration, and carbonate-forming cations. The enhancement or degradation of a caprock is related to the reduction and widening of microfracture apertures. During an injection process, initial mineral trapping takes place, which can have a significant impact on maintaining initial CO_2 injectivity and can delineate and partially self-seal plume boundaries while also reducing caprock permeability. Many CO_2 migration and sequestration processes in saline aquifers are equally applicable to CO_2 flood EOR in shale-capped water-wet oil reservoirs [21]. The CO_2 storage capacity is inverse proportional on reservoir permeability, which, in pure sequestration scenarios with high injection pressure, benefits from an increased storage and delayed migration, providing a noncompromised caprock performance.

Injection could also lead to pressures exceeding the formations natural fracturing pressure, resulting in the reactivation of a fault or the reservoir rock becoming hydraulically and thermally fractured. This creates a potential breach in the caprock that prevents CO_2 migration to the surface or flow into an adjacent formation [60]. An injection is followed by a change of reservoir temperatures that result in expansion and contraction of materials and ultimately result in changes of the field stresses, which creates a risk of breaching the caprock over time.

All geomechanical problems impose a great risk on CO_2 storage, which means the caprock integrity must be addressed when selecting a storage well site. The sealing efficiency is dependent on many factors, including caprock, well cement, capillary threshold pressure, and chemical reactivity to CO_2. A proper geological evaluation is required to investigate the possible paths for CO_2 migration to the surface through the faults and fractures. Well sites with microseismic activity are generally poor candidates for the long-term containment of CO_2. Topography has to be addressed in the same manner, in the case of CO_2 leakage; the surface has to be well ventilated to prevent an accumulation of CO_2 cloud.

6.2. Risks and examples of CO_2 leakage

Equipment degradation is a big problem in abandoned wells, as well as currently operating wells. Individual wells have to be monitored in order to spot a leakage of CO_2 through the annulus of a wellbore. Leakage can result in not only a migration of CO_2 to the surface but also a contamination of surrounding reservoirs and aquifers [43]. This can happen because of wellbore expansion and contraction due to temperature and pressure changes.

Nygaard et al. [45] wrote a paper regarding wellbore well leakage and found that 95 out of 1000 wells near Wabamun Lake in Alberta identified as potential leakage pathways caused by an immediate caprock penetration. This sort of issue is common in poorly plugged wells which can leak CO_2 at the cement-rock interface or through a cement plug. Any mechanical load during a completion or stimulation can affect the integrity of the cement, in addition to corrosion and chemical reactions near the wellbore. Issues such as those found in this study must be considered during the life and abandonment of well to ensure a reliable seal.

6.3. Actions to prevent future CO_2 leakage

There are multiple options for sealing abandoned wells, but all of them require at least 8 m of cement inside the casing. Most abandoned wells after 1995 have sufficient integrity. In order to improve the seal integrity, it is suggested to remove the casing steel from abandoned wells before the final cement plug, and an injection of the CO_2-resistant polymer is executed [44]. The cement samples from 30- to 50-year-old wells kept a good sealing integrity and prevented leakage of CO_2, even though they contained a degree of carbonation [10]. It is not suggested to squeeze the cement into an opening in the casing, but a melted alloy can fill most openings, and its expansion will mitigate microfissures [44].

CO_2 injection affects the mineralogy and structural heterogeneity of the reservoir, which will have an impact on the porosity, permeability, and storage stability of the well. Better predictions of reservoir response to CO_2 injection are a necessary step in the evaluation of possible long-term sequestration of CO_2. A well-proven method for CO_2 testing is Hassler cell core testing, but unfortunately, there is no standard protocol for CO_2 testing, which can lead to errors in results [10].

6.4. Selection of readings on stress and possible leakage in ECBM wells

As ECBM reservoirs often do not have a standard caprock to prevent leakage, their long-term viability as CO2 sequestration targets must be carefully considered. Numerous papers have explored this question and are briefly listed and summarized below:

- In the report of Myer [46], geomechanical factors that risk CO_2 leakage in sequestration, as well as the risk of CO_2 leakage from drilling and completion, production, and repressurization, are discussed.
- Mitra and Harpalani [47] investigated the matrix strain resulting from a CO_2 injection.
- Chen et al. [48] investigated how the effective stress factor and methane CO_2 counter-diffusion work on the CO_2 recovery using a finite element model that coupled coal deformation, gas flow, and methane-CO_2 counter-diffusion. Through their study, it was found that permeability loss/gain is influenced by effective stress and methane CO_2 counter-diffusion and that the gas pressure distribution is related to gas composition [47].
- Fathi and Akkutlu [49] investigated counter-diffusion and competitive adsorption effects according to the new one-dimensional theoretical model they created. Compared with the conventional model, they created a new triple porosity dual permeability multi-continuum model to describe the gas release from macro-pores and micro-pores to the fracture.

6.5. CO_2 monitoring

Due to the quantities of CO_2 being sequestered in large CCS projects and the importance of keeping that CO_2 permanently underground, monitoring is a very important part of any CCS project. 3D seismic survey has proven to be effective at monitoring CO_2 storage but is prohibitively expensive. Gasperikova and Hoversten [50] investigated using a combination of gravity inversion, electromagnetic (EM), and amplitude vs. angle (AVA) monitoring analysis to detect changes in CO_2 saturation. Gravity inversion detects density changes in the injected layer. EM and AVA can be used to estimate CO_2 saturation changes. Macdonald [51] provided field and lab measurements of CO_2 using Raman spectroscopy, which improved monitoring of the prevised amounts of CO_2 dissolved in reservoir brine. Through the Saptharishi and Makwana [52] study, various monitoring techniques are summarized, which include but are not limited to techniques for coal beds.

6.6. Risks of CO_2 injection, possible failure modes

Carbon dioxide storage is not a risk-free task. As years go by after CO_2 has been injected into a formation, it is possible for the CO_2 to begin migrating upward and leak out of the ground back into the atmosphere through openings in the caprock or fractures, faults, and poorly completed preexisting wells [53]. This problem can be prevented or reduced if the formation of interest for CO_2 storage has a caprock with ideal qualities.

An ideal caprock is a layer of the formation with very low permeability that can prevent oil and gas from migrating upward and out of the reservoir formation. In any case of CO_2 storage, a thick shale layer is the most desirable type of caprock. Due to shale's extremely low permeability, causing a more tortuous flow path, CO_2 migration vertically is tremendously limited [54]. The degradation of cement and metal casing with a presence of CO_2 is currently a topic that needs extensive investigation [52]. As the **Figure 7** shows, there are five possible leakage pathways in an abandoned well. Label a and label b are the pathway between casing and cement wall and plug, respectively. Label c shows leakage through cement plugs. Label d represents leakage through casing. Label e shows leakage through the cement wall. Label f represents leakage pathways between the cement wall and the formation [52].

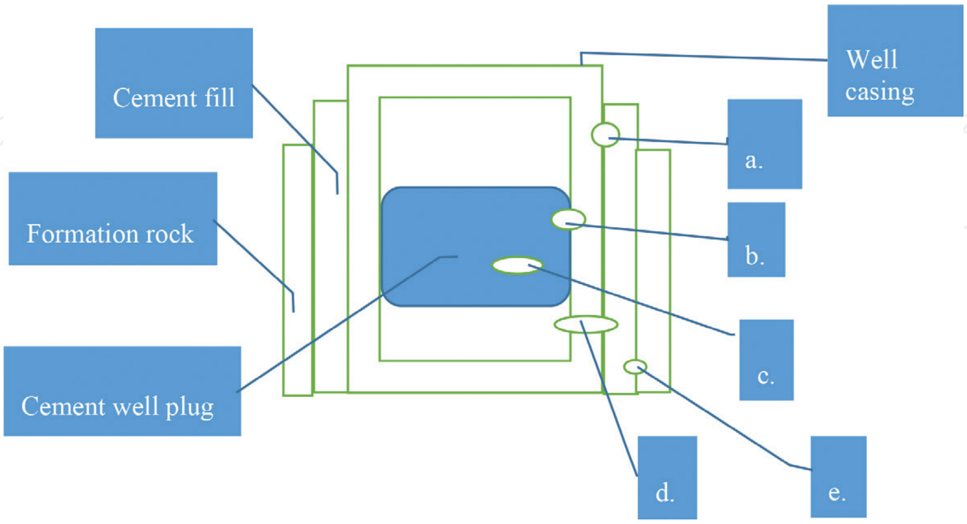

Figure 7. CO_2 leakage pathways.

The Sleipner Project, located in Norway, is currently storing more than 2700 tons of CO_2 per day below an extensive and thick shale layer [27]. Monitoring the injected CO_2 during the past 13 years is showing that the gas has spread out nearly two square miles below the shale layer without moving upward or leaking out of the reservoir storage [55]. This is one of the most significant evidence that proves how effective shale formations can be as CO_2 storage reservoir and caprock, where carbon dioxide will be trapped and immobile. In short, the ultimate geological storage reservoir should have sufficient capacity, be a thick shale layer acting as a caprock simultaneously, and be a stable storage environment maintaining the original characteristics of the reservoir.

6.6.1. Overcoming the high risk of CO_2 leakage in carbonate reservoirs

Carbonate reservoirs do not generally possess an impermeable boundary or caprock, and therefore permanent trapping of CO_2 through geomechanical means is unrealistic [57]. Solubility storage decreases potential leakage in carbonate formations, as the dissolution of CO_2 into water promotes mineralization, but this will need to be studied further before carbonate reservoirs can be relied upon to properly sequester large volumes of CO_2 [56].

Agada et al. [57] did extensive research on how fracture network geometry affected oil recovery and CO_2 storage in carbonate reservoirs. They noted that many of the problems associated with high fracture-matrix connectivity, such as bypassing of oil, early water breakthrough, and rapid CO_2 migration, could be mitigated by foam flooding. Sehbi et al. [58] proposed a low injection rate, longer in-reservoir CO_2 retention time, and good pore structure to improve the efficiency in carbonate reservoirs. Carbonate formations showed an increase in effective permeability resulting from chemical dissolution in the matrix, thus enhancing pore connectivity [59].

6.6.2. Examples of natural carbonate sequestration

The Colorado Plateau-Southern Rocky Mountains region contains natural CO_2, which has been discovered during exploration for oil and gas fields (**Figure 8**), thus providing a natural laboratory for studying the effects of long-term, subsurface CO_2 storage in carbonate reservoirs. These laboratories yield information such as that injecting CO_2 separated from flue gases ensures the subsurface migration path is long, thereby yielding optimal sequestration. Despite the number of carbonate CO_2 reservoirs in the region and active flux of CO_2 to the surface, no hazards from CO_2 surface accumulations are known. The nature and rate of CO_2 surface leakage in carbonate formations are still unknown [60].

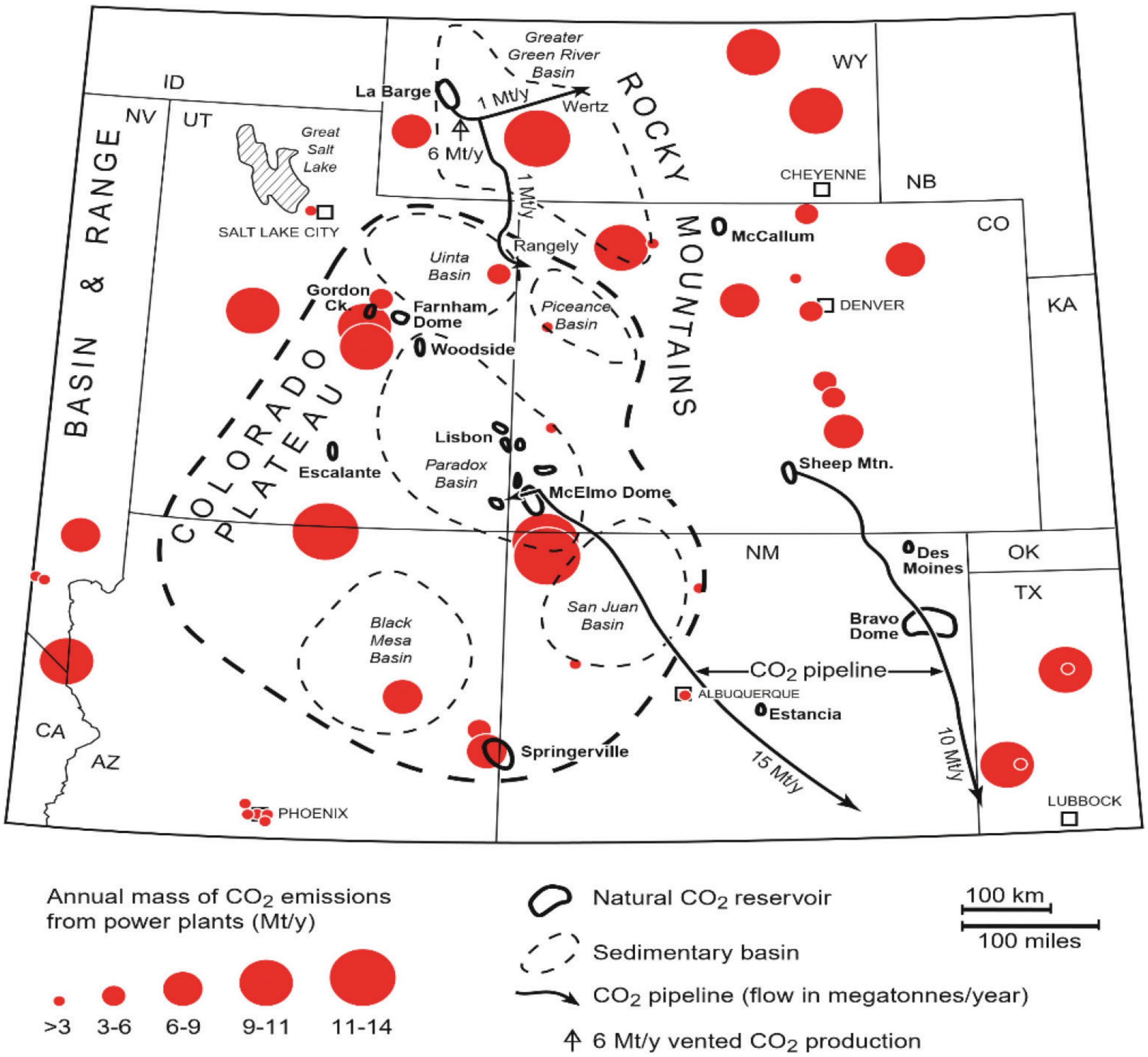

Figure 8. Synthesis of data relating to CO_2 fluxes and concentrations around the Colorado Plateau [8].

6.7. Additional potential concerns

Despite the many benefits of CO_2 EOR and CCS programs, it must be remembered that these are complicated projects being undertaken in complex geological environments. A 2004–2008 project in Algeria stored over 2.5 [61] million tons of CO_2 in a carboniferous sandstone reservoir. During the shut-in process, the CO_2 injection was unexpectedly interrupted, and the wellbore pressure went lower than the reservoir pressure, risking rock failure, sand production, and possible blowout.

Potential concerns also include preventing potentially catastrophic failure of the reservoir seal. For instance, if injection pressures exceed the breakthrough pressure of the sealing caprock, the CO_2 would break through and risk flowing back to the surface [60]. Reactive transport modeling shows that for a typical shale caprock, geochemical processes continuously improve isolation performance, and geomechanical processes first rapidly degrade and then improve isolation performance over time. There is a possibility for a counterbalancing of geomechanical and geochemical effects, but they must be carefully monitored [62].

Some issues are more minor, not directly threatening the safety of the operation, but nonetheless affecting the economics of a combined CO_2 EOR and CCS project. Bou-Mikael [14] wrote about the performance of a CO_2 flood at Port Neches in the Gulf of Mexico, with a partnership of Department of Energy and Texaco E&P. The CO_2 flood underperformed [13], with 500 bbl/day instead of 800 bbl/day; with this underperformance was attributed to the following reasons: reservoir characterization, oil saturation, water blockage, and wellbore mechanical problems. After a careful evaluation of the project, it was determined that in ideal circumstances and if related criteria are met, CO_2 injection can accelerate production two to three times compared to unassisted primary production [13].

6.7.1. Potential coalbed problems

Coal beds, despite offering unique opportunities, also offer unique challenges. In particular the coal matrix swells during CO_2 adsorption. Coal matrix swelling can cause reductions in permeability. Bustin et al. [63] experimented on the volumetric strain from three western Canadian coals and found that a mixture of N_2 and CO_2 injection would improve CO_2 injection rates greatly but that CO_2 sequestration capacity decreased wildly. However, pure CO_2 injection could cause the reduction of permeability by two orders of magnitude. The applicability of the CO_2-ECBM process in any coal seam is mainly governed by the seam's permeability and its adsorption process [62]; therefore, these concerns must be explored further.

7. Conclusion

Numerous studies support the potential of major sequestration projects, and due to the negative impacts of atmospheric CO_2, CCS will continue to be an important part of protecting our environment. While EOR through CO_2 sequestration has proved to be valuable, there are still challenges that need to be addressed in the future. Reservoir properties must continue to be carefully considered for all CCS projects due to their impact on successful EOR and CO_2 sequestration.

The major challenges currently facing CCS projects are primarily those of economics and transportation. Limited CO_2 transportation supply chains act as a barrier for CO_2 EOR utilization in the oil industry. When this barrier has been removed and a large network of CO_2 capturing mechanisms have been created, it will open the petroleum industry to a breadth of new possibilities both in terms of improved recovery and environmental sustainability.

For the purposes of having a significant impact on atmospheric CO_2 levels, the simple merging of CO_2 EOR and CCS may not be enough. In every reservoir type, in every circumstance, there are diminishing returns as far as incremental production as additional CO_2 is injected into a well. As such, as long as CO_2 remains an expense, rather than a revenue stream, the full potential of CCS will not be realized. In the meantime, however, there are numerous projects that hold a good deal of promise and are economical under current conditions due to the benefits of CO_2 injection on ultimate hydrocarbon recovery.

7.1. Closing notes on shale reservoirs

Shale reservoirs still hold a great deal of promise for CCS and CO_2 EOR, as the benefits for production are significant, and the formations themselves provide excellent seals against any risk of CO_2 migration. Unfortunately, a great deal of research and monitoring is still required in order to ensure that shale beds maintain the quality of their seals over time and to maximize CO_2 sequestration. Knowledge gaps such as lack of information on available storage capacity, lack of 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 and EOR still exist [52]. Many questions regarding this topic will remain unanswered until additional, large, in situ field tests take places.

7.2. Closing notes on carbonate reservoirs

The future of CO_2 EOR and sequestration in carbonate reservoirs will steadily improve due to the statistical data being acquired from existing field tests. The United States' carbonate formations provide the foundation for CO_2 injection in carbonate reservoirs [64]. The Bati Raman reservoir provides a significant opportunity to further carbonate CO_2 EOR operations. Sahin et al. [65] state this reservoir could easily yield a billion dollars in revenue as a CO_2 EOR project. Hydrocarbon fuels can supply relatively pure CO_2 for EOR allowing the byproducts of the industry's previous production to add in new production while also creating a more environmentally friendly outcome. CO_2 that cannot be used for EOR can be stored in depleted carbonate formations, thus furthering the climate-friendly initiative [66]. Recent estimates of future CO_2 demand suggest that large volumes will be required to meet the promise of next-generation EOR including the development of residual oil zones [7].

7.2.1. Specific challenges in carbonate reservoirs

As previously discussed, dissolved CO_2 injection is recommended for reactive fractured formations and formations with uncertain caprock integrity [7]. The challenges of the carbonate pinnacle reef data analysis are as follows: an increase in pressure with CO_2 injection, the presence of multiple reservoir fluids, and unique CO_2 phase behavior due to changing pressure and temperature.

Izgec et al. [1] discuss challenges of mineral trapping, the effects of changing rock properties, and the residual impact on CO_2 CCS in carbonate reservoirs. Puon et al. [67] state that other challenges in carbonate formations include CO_2 tendency to bypass a large percentage of pore volume, yielding an early breakthrough, and reductions in recovery efficiency. As a result, CO_2 flooding is not economically feasible without improved mobility control. Several mobility control methods have been attempted with limited success; therefore, concepts for CO_2 mobility control are required to increase the overall recovery efficiency and economics in carbonate reservoirs [66]. Eke et al. [8] suggested the injection of denser CO_2 saturated brine in carbonate formations, which should be capable of eliminating much of buoyancy force. Thus, CO_2 brine surface mixing strategy is recommended due to the enhancement and secure storage of CO_2 in subsurface carbonate formations.

8. Suggestions for future study

For sandstone and coalbed reservoirs, the last major remaining barrier to large-scale implementation of CO_2 EOR and CCS is the economic burden of CO_2 capture and transportation. Research into improving capture and transport techniques, as well as how to structure intelligent government incentives, will go a long way in increasing CO_2 sequestration rates.

Unlike with sandstone and coalbed reservoirs, the primary barrier to CO_2 sequestration in shale reservoirs is a lack of research and monitoring work after CO_2 injection. The lack of research is in fact only aggravated by the lack of monitoring and in situ data.

At last, the study of CO_2 sequestration in carbonate reservoirs needs to expand to include the effects of CO_2 on carbonate rock properties. Issues ranging from an early breakthrough, to low sweep efficiency, to structural problems within the formation, all, limit the viability of large-scale carbonate projects. Future experiments will need to be performed using a high-pressure carbonate core flooding system optimized for use within different lab apparatus so that experiments can be conducted to better understand the complications and benefits of supercritical CO_2 [57].

There is no doubt that CCS and CO_2 EOR/ECBM will play a major role in the future of the energy industry. However, besides the economic issues with many CO_2 implementations, legal risks must also be considered as well. Unitization is important for CO_2 EOR in order to avoid the trespass claim [68]. In addition, different states and regulators treat CO_2 differently, sometimes as a pollutant, other times as a natural gas [67]. Despite not being research-based concerns, the legal climate of the United States must also change for a truly successful CCS program to take hold and to make the best use of what could become a CO_2 revolution.

Nomenclature

AVA	Amplitude vs. angle
bbl	barrel
CCS	Carbon capture and storage
CO_2	Carbon dioxide
DOE	Department of Energy
ECBM	Enhanced coalbed methane
EM	Electromagnetic
EOR	Enhanced oil recovery
MMP	Minimum miscible pressure
MPZ	Major pay zone
ROZ	Residual oil zone
SACROC	Scurry Area Canyon Reef Operators
SECARB	Southeast Regional Carbon Sequestration Partnership
SWP	Southwest Regional Partnership for Carbon Sequestration
TZ	Transition zones

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