MEETING THE DUAL CHALLENGE

A Roadmap to At-Scale Deployment of CARBON CAPTURE, USE, AND STORAGE

CHAPTER EIGHT – CO_2 ENHANCED OIL RECOVERY

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Chapter Eight

CO_2 ENHANCED OIL RECOVERY

I. CHAPTER SUMMARY

Carbon dioxide enhanced oil recovery (CO_2 EOR) involves the injection of CO_2 into the reservoir rock of an existing oil field to recover more oil and natural gas than would otherwise have been produced. The injected CO_2 trades places with oil that is released from minute pore spaces within the reservoir rock. This exchange results in the CO_2 becoming trapped by capillary pressure within this same pore space, dissolving in the residual fluids present in the pore space, or eventually becoming mineralized. The trapping of CO_2 during the EOR process is incidental to the primary purpose of producing oil.

CO_2 EOR is a mature and regulated technology that has been applied for more than 40 years. The process benefits the environment when CO_2 from industrial sources—called anthropogenic CO_2—is captured, injected, and trapped underground, thereby reducing greenhouse gas emissions by providing large-scale CO_2 storage.

Enhanced oil recovery from existing fields requires fewer resources than its alternative, which is to install infrastructure and equipment to develop new oil field locations. Studies estimate that oil produced from existing fields using CO_2 EOR with anthropogenic CO_2 has 63% fewer emissions than oil produced without CO_2 EOR.[1] The CO_2 EOR process yields liquid fuels with a lower carbon emissions intensity, maximizes the efficient use of existing infrastructure, and reduces land and habitat disturbance.

The U.S. CO_2 storage capacity generated by EOR processes is estimated at 55 billion tonnes (Bt) to 119 Bt under "2019 View" in Table 8-1. Accessing this storage capacity could help produce 84 billion to 181 billion barrels of stranded oil. In 2018, CO_2 EOR used more than 30 million tonnes of natural CO_2 from underground deposits, which could be replaced with anthropogenic CO_2 if a pipeline infrastructure to transport it were available. A pipeline system is also needed to enable widespread deployment of CO_2 EOR for carbon capture, use, and storage (CCUS) projects that are included in the activation, expansion and at-scale phases described by the cost curve in Chapter 2, "CCUS Supply Chains and Economics," in Volume II of this report. This pipeline infrastructure system will involve many stakeholders and requires government incentives for support and construction.

Table 8-1 estimates the CO_2 storage capacity in the United States both for prevailing conditions (2019 View) and when economic CO_2 and advanced technology are available. With these factors considered, it is estimated that total CO_2 storage capacity in the United States could expand to between 274 Bt and 479 Bt. In the short-to-medium term, it is expected that CO_2 EOR could store between about 150 and 200 million tonnes per year. The storage capacity is widely distributed across the United States.

Historically, the retention of CO_2 during the EOR process has been incidental to the primary purpose of producing oil and is commonly

1 International Energy Agency, "Storing CO_2 through Enhanced Oil Recovery, combining EOR with CO_2 storage (EOR+) for profit," 2015, https://webstore.iea.org/insights-series-2015-storing-co2-through-enhanced-oil-recovery.

CO_2 EOR Category	CO_2 Storage Capacity (billion tonnes)	
	2019 View	With Economic CO_2 and Advanced Technology
Onshore Conventional	30-45	55-100
Residual Oil Zone (ROZ)	25-60	148-225
Offshore Conventional	0-14	14-28
"Design and Intent Focus"	0	2-43
Unconventional	negligible	55-83
Total CO_2 Storage Capacity	55-119	274-479

Note: Scenario columns are not additive.

Table 8-1. *Estimated CO_2 Storage Capacity in the United States Associated with CO_2 EOR*

referred to as associated CO_2 storage.[2] The amount of CO_2 that is stored in underground reservoirs during CO_2 EOR is specific to each oil field. This volume can be quantified and verified using either the Monitoring, Reporting, and Verification Plan from the U.S. Environmental Protection Agency (EPA), or other accepted standards combined with independently accredited verification.

There are more than 150 individual CO_2 EOR projects around the world that use either anthropogenic CO_2 or natural CO_2 from underground deposits. The primary factor that limits growth in the number of CO_2 EOR projects is the locally available and affordable CO_2 that can be delivered at a price below which CO_2 EOR projects can be economically financed. In 2018, Congress expanded and reformed the 45Q tax credit which has encouraged some U.S. companies to actively pursue the development of projects that will capture CO_2 from industrial sources for use in EOR.

During the CO_2 EOR process, 40% to 60% by volume of the injected CO_2 is produced with the oil, then recycled and reinjected back into the reservoir. This closed-loop process means that, at the end of the injection period, nearly all of the injected CO_2 is retained in the reservoir and less than 1% of the originally injected volume is lost to fugitive emissions and operational losses.[3]

During the injection process, brine water is commonly alternated with CO_2 in a process called water alternating gas (WAG), which minimizes the amount of CO_2 needed and enables the injected CO_2 to contact more of the reservoir area. Methods using foam or gel to thicken the injected CO_2 are also beneficial to oil recovery and increase the amount of CO_2 that is sequestered during the CO_2 EOR process. However, because these additives are expensive, they are rarely used.

Even when existing oil field infrastructure is in place, the incremental cost of developing a large CO_2 EOR project can be substantial. Such projects can be economically challenged because the increase in oil production may occur a year or more after initial CO_2 injection. This causes a delay in positive cash flow. In addition, large anthropogenic CO_2 sources are often hundreds of miles away from the oil and natural gas reservoirs that would benefit from CO_2 EOR. Reservoirs that can store CO_2 are called sinks, and the cost of transporting CO_2 from a source to a sink is a primary factor in deciding whether CO_2 EOR would be economical.

CO_2 can be transported over land by pipeline, rail, or truck. Pipeline transport is the preferred method of moving large volumes of CO_2 without interruptions. In certain areas of the United States, the CO_2 EOR industry has already installed local pipeline networks to move CO_2 from source fields to EOR projects (Figure 8-1). However, a larger superhighway-like CO_2 pipeline system is necessary to transport large volumes of anthropogenic CO_2 from sources to sinks. Incentives for pipeline infrastructure construction and tax credits, such as the Section 45Q tax incentive, would help ensure that investments in CCUS provide a sustained return on investment.

2 ISO 27916:2019, Carbon dioxide capture, transportation and geological storage—Carbon dioxide storage using enhanced oil recovery (CO2 EOR), International Organization for Standardization.

3 ISO 27916:2019.

Source: Melzer Consulting.

Figure 8-1. *Active U.S. CO_2 EOR Infrastructure and Projects*

The petroleum industry has considerable expertise in siting and operating CO_2 EOR projects in an environmentally responsible manner. CO_2 EOR has an excellent safety and environmental record. Leveraging CO_2 EOR industry experts for the development of more CO_2 storage sites is a logical choice for managing CO_2 emission reductions in a proven, safe, and environmentally sound way.

II. WHAT IS CO_2 EOR?

A. Understanding the EOR Process

CCUS, including transport, combines processes and technologies to reduce the level of CO_2 emitted to the atmosphere or remove CO_2 from the air. These technologies work together to capture (separate and purify) CO_2 from stationary sources so that it can be compressed and transported to a suitable location where the CO_2 is converted into useable products or injected deep underground for safe, secure, and permanent storage. Figure 8-2 is a schematic showing the CCUS technologies.

The CO_2 EOR process involves pumping CO_2 into reservoir rock where it trades places with the oil that is trapped in the minute pore spaces of the underground rock formation. This exchange releases oil but traps the injected CO_2 within the same pore space.

The trapping of CO_2 during the EOR process is incidental to the primary purpose of producing oil. For this reason, the result is often referred to as "incidental, or associated CO_2 storage," when long-term retention of the trapped CO_2 is verified. The text box titled "Certifying Secure Geologic Storage of CO_2 through EOR" provides an explanation of how CO_2 that is geologically trapped during CO_2 EOR is certified as being securely stored over the long-term.

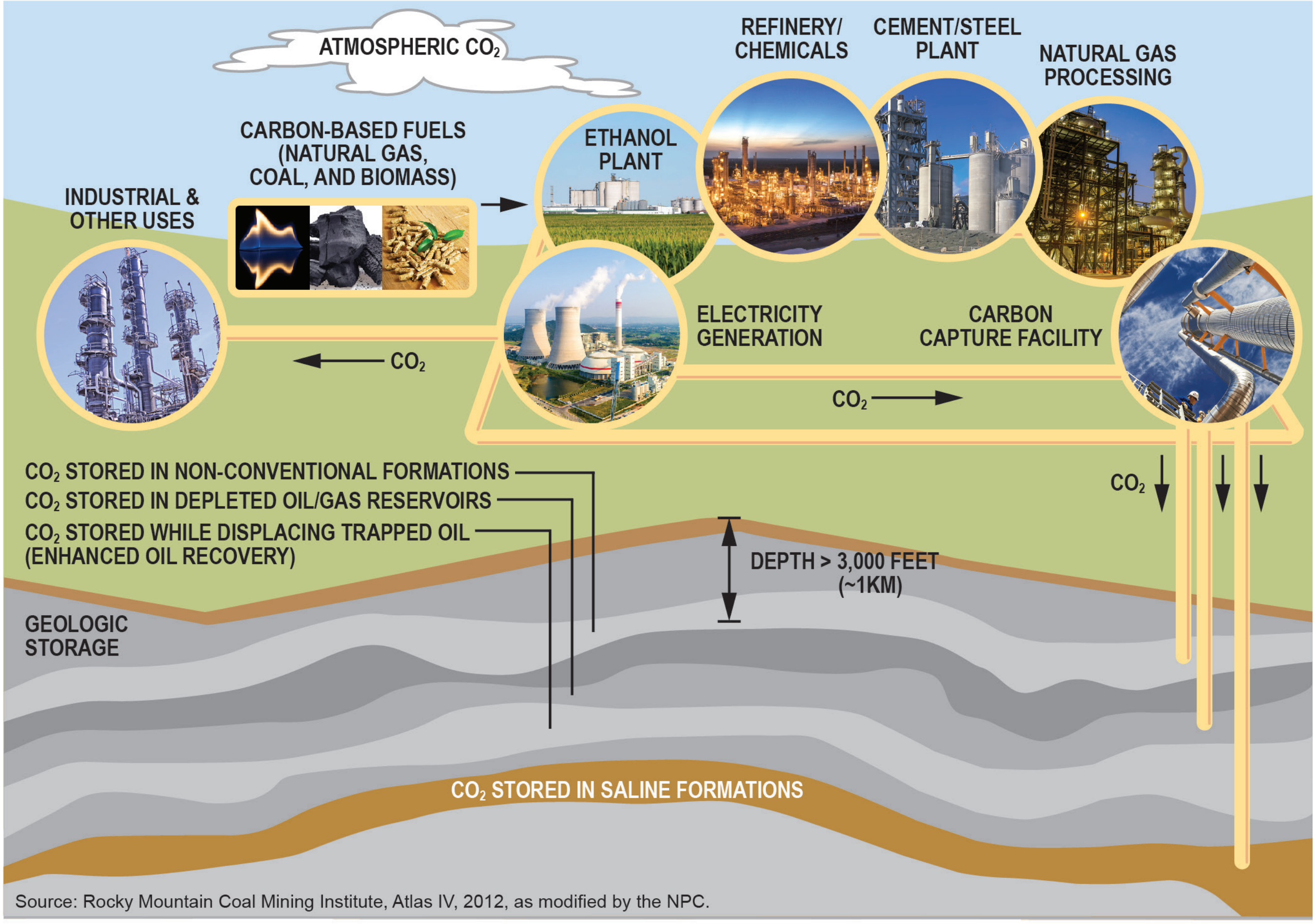


Figure 8-2. *Supply Chain for Carbon Capture, Use, and Storage*

CERTIFYING SECURE GEOLOGIC STORAGE OF CO_2 THROUGH EOR

CO_2 Geologically Trapped during CO_2 EOR Operations

Several natural forces cause CO_2 to be trapped in the reservoir during CO_2 EOR operations, including:

- A competent geologic seal to trap free CO_2
- Trapping in the pore space due to capillary pressure effects
- Dissolution in formation water that will not move to a shallower formation and come out of solution
- Mineralization (not a major factor except in the very long term).

Within this report, it is referred to as "trapped" or "retained" CO_2. Other reports may refer to this as "associated trapping," "associated storage," "geologic storage," or "incidental storage."

Certified Secure Geologic Storage

Geologically trapped CO_2 can be certified as being securely stored after an approved process is followed to determine that retention is demonstrated to be long term. Examples include the U.S. Environmental Protection Agency's Monitoring, Reporting and Verification Plan (MRV Plan) or any other approved and accepted standard. In this report, such storage is referred to as "secure geologic storage," "associated storage, when long term retention is verified," or "permanent storage." Other reports may also refer to this as "sequestration" or "permanent sequestration."

During the last 40 years, CO_2 EOR operations in the United States have injected more than 1 Bt of CO_2, and experience has shown that more than 99% of the CO_2 remains safely trapped underground after CO_2 injection is completed.[4]

All oil and gas wells produce a mixture of oil, natural gas, and brine fluids. During CO_2 EOR operations, some wells are dedicated to CO_2 injection and others to fluid production. In the producer wells, a portion of the CO_2 injected underground is produced back with the oil, natural gas, and brine mixture. The produced CO_2 is separated from the rest of the mixture in a closed-loop system and recycled back underground via reinjection (Figure 8-3). The brine produced is also separated from the oil and returned to an underground reservoir.

When describing the CO_2 EOR process, the amount of CO_2 trapped to produce a barrel of oil is called the CO_2 utilization factor (UF). The CO_2 UF number varies according to the specific geology, fluid characteristics, and design of each EOR project. The term is also used to determine the total amount of CO_2 that each field can store during EOR.

Most people understand that oil and water do not mix, but that honey and water will mix. Miscibility is a measure of how well two liquids will mix or dissolve together; if they will not mix, they are termed immiscible. CO_2 and oil can be miscible or immiscible depending on the pressure, temperature, and chemical makeup of the oil.

During the extraction of oil and natural gas, a reservoir's permeability describes how easily a fluid will flow through the rock. Permeability is measured in units called darcies or millidarcies. A higher permeability value means that fluid will flow through the rock more easily. In a reservoir, hydrocarbon pore volume (HCPV) is the fraction of the pore space, or void space, in the rock that contains oil or natural gas. To access the oil and natural gas in a reservoir, pipe is cemented into the well after it is drilled; this pipe is called "casing."

B. How CO_2 EOR Works

CO_2 EOR is a process where CO_2 is injected into oil fields to enhance the recovery of oil from

4 ISO 27916:2019.

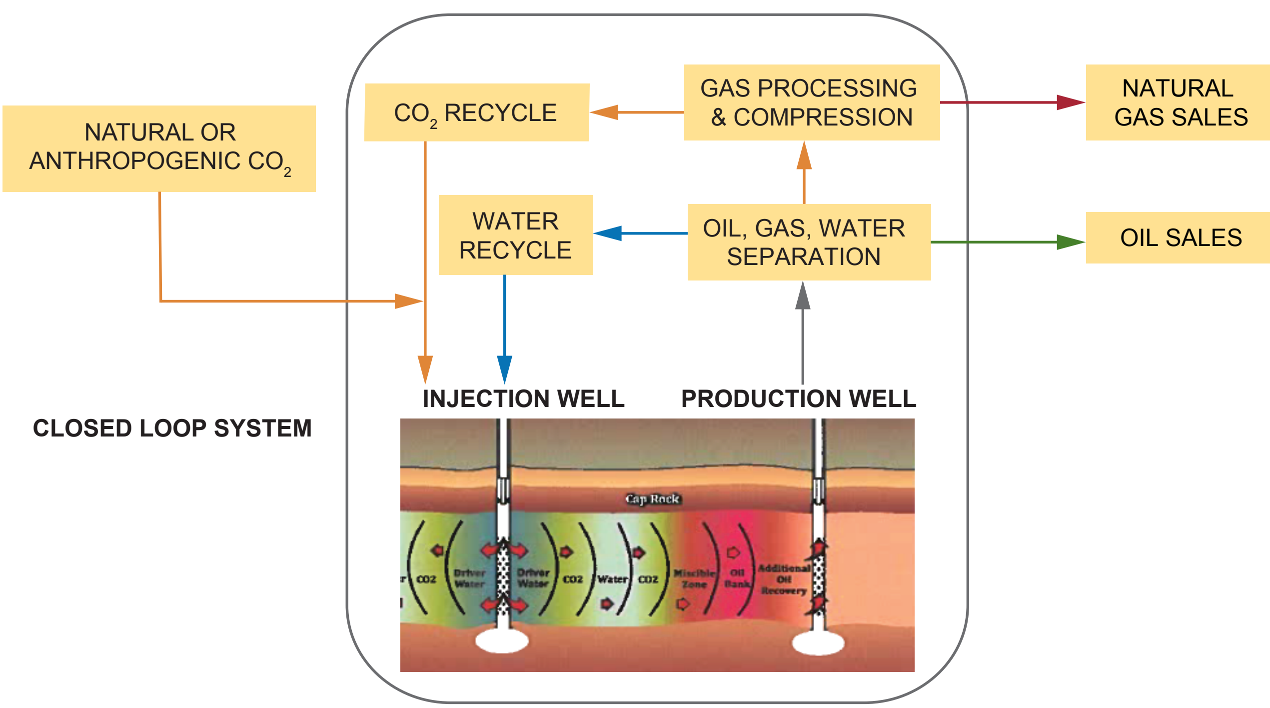


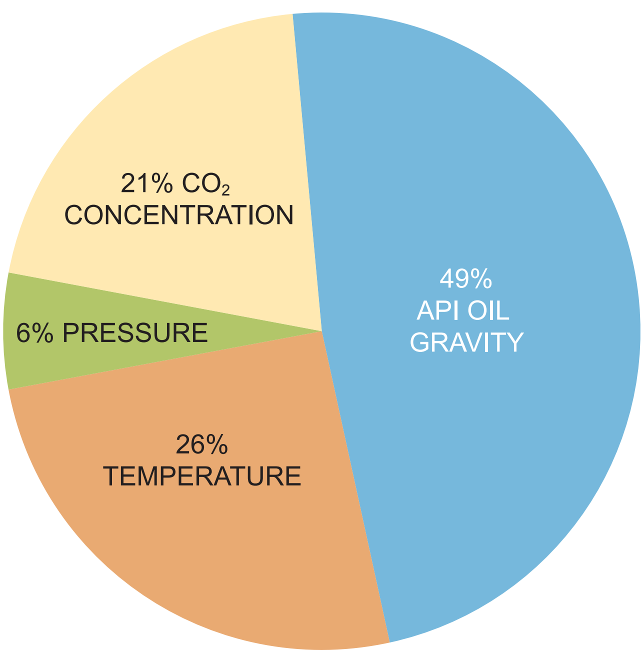
Figure 8-3. Typical Flow Diagram for CO_2 EOR

underground petroleum deposits. The injected CO_2 acts as a solvent to swell the volume of oil that sits in the reservoir's pore spaces. The swelling of the oil lowers its viscosity, which in turn enables the oil to flow more easily toward the producing wells.

CO_2 is usually injected into the reservoir under pressure as a dense phase. Fluids in the dense phase have a viscosity like that of a gas, but a density closer to that of a liquid. Four primary factors impact how much oil will swell when it comes into contact with CO_2 (Figure 8-4).[5]

CO_2 can also extract the intermediate components of oil (i.e., organic compounds, hydrocarbons with different molecular weights) through repeated contact, which results in vaporization of the oil into lean gas. This is the basis for the vaporizing gas drive mechanism that achieves multiple-contact miscibility between CO_2 and oil. If the CO_2 is sufficiently enriched with these intermediate components during vaporization such that miscibility results with the oil, then the CO_2 and oil are said to have achieved multiple-contact miscibility. CO_2 EOR projects can be conducted under miscible or immiscible conditions, but miscible projects are more commercially viable, hence more common.

5 Ahmadi et al., "Hybrid Connectionist Model Determines CO2-Oil Swelling Factor," *Petroleum Science*, April 2018, https://link.springer.com/article/10.1007/s12182-018-0230-5.



Source: Ahmadi et al., "Hybrid Connectionist Model Determines CO2-Oil Swelling Factor," *Petroleum Science*, April 2018.

Figure 8-4. *Relative Importance of the Independent Variables Affecting Oil Swelling in the Presence of CO_2*

1. Miscible CO_2 EOR Process

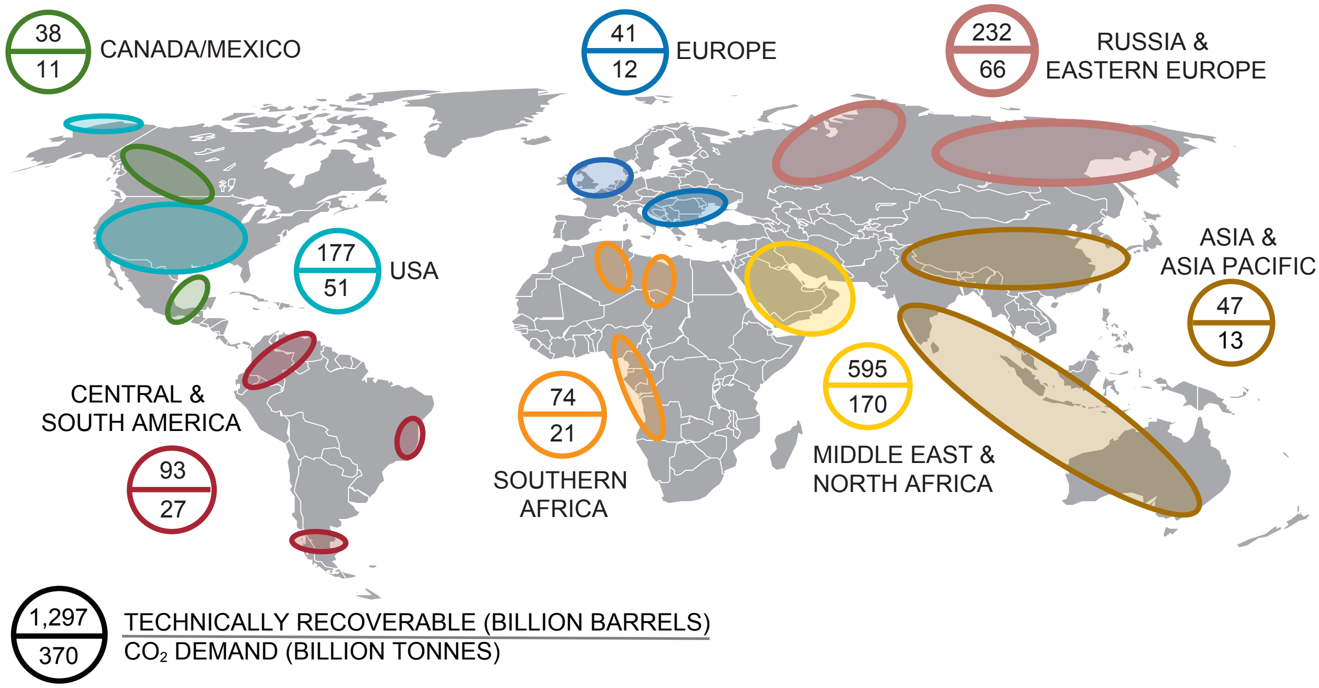
Miscibility between CO_2 and oil is required if the CO_2 is to act as a solvent to efficiently enhance the recovery of oil from underground reservoirs. The minimum miscibility pressure (MMP) is the reservoir pressure above which CO_2 and oil combine into a single-phase fluid. Miscibility can occur at first contact between the two fluids. If conditions are not ideal for first-contact miscibility, the fluids may still achieve miscibility through multiple contacts, during which the CO_2 and oil mix into a CO_2-rich phase.

When the composition of gas and liquid phases become sufficiently alike, the interface between the two starts to disappear and lower interfacial tensions and miscibility occurs. The advantage of a miscible CO_2 process is that the oil's volume is increased through swelling and its viscosity is lowered, causing more oil to become mobile and travel to the producing wells.

2. Immiscible CO_2 EOR Process

In some fields, the MMP is greater than the pressure at which the reservoir seal, or caprock, could be compromised, possibly causing a leakage path for CO_2 and the reservoir fluids. In these fields, an immiscible CO_2 EOR process occurs at operating pressures below the MMP, which prevents reservoir pressure from falling by replacing the produced oil, water, and natural gas with CO_2. The CO_2 vaporizes and swells the oil by lowering the surface tension, and although it does so to a lesser extent than in the miscible process, it still enhances oil flow.

Because the immiscible process is less effective in producing oil and leaves more residual oil in the reservoir than does a miscible CO_2 EOR process, there are very few immiscible CO_2 injection projects operating today. The immiscible process can be quite effective in recovering oil



Source: IEA Greenhouse Gas R&D Programme, "CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery," December 2009.

Figure 8-5. *Worldwide CO_2 EOR Potential in Conventional Fields*

from what are called "tilted reservoirs." These reservoirs result when the geologic formations have been tilted over time to high angles relative to the horizontal positions at which they were deposited millions of years ago. Tilted reservoirs often benefit from the application of gravity drainage recovery mechanisms, where oil flows downward toward production wells when a buoyant fluid, such as CO_2, is injected at the top of the oil column.

III. CO_2 EOR STORAGE CAPACITY AND DEPLOYMENT ENABLERS

Onshore and offshore in the United States, there is an estimated 414 billion barrels of remaining oil in place that would be left in-situ without application of tertiary recovery operations such as CO_2 EOR.[6] Of this volume, 177 billion barrels of oil is technically amenable to recovery through CO_2 EOR. This would require injecting 51 Bt of CO_2, though only a portion of this is economical to pursue presently (Figure 8-5).[7] The CO_2 volume requirement increases to 370 Bt to recover nearly 1.3 trillion barrels of oil worldwide, with the United States, Middle East, North Africa, Eastern Europe, and Russia containing most of the potential for CO_2 EOR and its associated storage volume.

For example, the San Andres carbonate reservoir of the Permian Basin (West Texas and eastern New Mexico) supports conventional CO_2 EOR and is one of the largest residual oil zone (ROZ) complexes in the United States. A ROZ is an interval of oil that remains in a hydrocarbon reservoir after natural water flooding has occurred over geologic time. (More detail about how a ROZ is created is provided in the Residual Oil Zone section later in this chapter). A combination of detailed geophysical log and numerical modeling work and several ROZ EOR development projects have estimated that 43 Bt of associated CO_2 storage could be achieved through the recovery of 69 billion barrels of oil in the

6 Advanced Resources International, internal analysis, 2016.

7 IEA Greenhouse Gas R&D Programme (IEA GHG), "CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery," December 2009.

San Andres reservoir alone.[8] If other geographical areas with potential storage are included, total ROZ storage capacity in the United States would be 148 Bt to 225 Bt of CO_2.

The potential production associated with CO_2 EOR in unconventional oil reservoirs, also called shale or tight reservoirs, could be substantial because average recovery in these types of reservoirs is less than 10% of the original oil in place when using primary methods. However, the industry is only just beginning to understand how the CO_2 EOR process can be used in these complicated reservoirs. Although continuous injection, pattern-based CO_2 EOR (i.e., where dedicated injector wells push fluids to dedicated producing wells) has been challenging in unconventional reservoirs, there has been some success with cyclic CO_2 injection operations (i.e., where injection and production take place in the same well(s) at different times). The application of EOR in unconventional reservoirs could recover nearly the same volume of oil as is achieved with primary recovery techniques.

In 2019, the U.S. Energy Information Administration estimated that there were 113 billion barrels (bbl) of technically recoverable oil in shale oil reservoirs within the United States.[9] This equates to approximately 110 billion barrels of EOR production potential. Assuming net CO_2 UFs of 0.5 to 0.75 tonnes of CO_2 per barrel of oil recovered (10 Mcf/bbl to 15 Mcf/bbl) are achieved, the resulting CO_2 demand could add an associated storage volume of 55 Bt to 83 Bt in the United States.

Table 8-1, found earlier in this chapter, provides estimates of CO_2 storage capacities for several reservoir categories in the United States associated with CO_2 EOR. The table presents estimates for two different scenarios: a "2019 View" and when "Economic CO_2 and Advanced Technology" are available.

The 2019 View lists the CO_2 volumes that can be stored using currently available technologies. In this scenario, the total CO_2 storage capacity is 55 Bt to 119 Bt. The 2019 View suggests a negligible storage contribution from CO_2 EOR projects in unconventional (or shale) reservoirs because most unconventional efforts presently are at the research and development or small pilot stage. Furthermore, the 2019 View assumes no additional CO_2 capacity will result from CO_2 EOR projects designed with an intent to maximize storage of CO_2.

In Table 8-1, the midpoint of CO_2 storage capacity for onshore conventional (37 Bt) and the high point for offshore conventional (14 Bt) total 51 Bt. This sum corresponds with the 51 Bt shown in the bottom half of the circle associated with the United States in Figure 8-5, denoting CO_2 demand in billion tonnes.

In the Economic CO_2 and Advanced Technology scenario, the assumption is that there will be technological advances and affordable anthropogenic CO_2 will become available. Under this scenario, the total associated storage capacities could potentially increase to four to five times the volumes described by the 2019 View. Although offshore storage from CO_2 EOR is not expected to increase substantially in the near term, offshore CO_2 storage could occur where oil reservoirs are connected to large saline formations (see Chapter 7, "CO_2 Geologic Storage").

Given access to more affordable CO_2 and technological advances, and assuming a CO_2 utilization factor of 20 Mcf/bbl, onshore conventional storage opportunities could increase by as much as 50%. This would significantly increase the storage capacity of ROZ reservoirs, doubling the use of this commercial resource. Incremental additions to capacity due to new storage designs could also improve storage estimates from 1% to 20%. Finally, the development of new technologies could have a positive impact on unconventional reservoirs, adding significant CO_2 demand and associated storage capacity, which could enable total CO_2 EOR-associated storage to grow in range to between 274 Bt and 479 Bt.

Transporting large volumes of anthropogenic CO_2 in the United States from sources to sinks requires substantial expansion of the CO_2 pipeline infrastructure that currently exists.

8 Kuuskraa, V., "What's New for ROZ, CO2-EOR and CO2 Storage," presented at the CO_2 Flooding Conference, Midland, Texas, December 3, 2018.

9 U.S. Energy Information Administration, Assumptions to the Annual Energy Outlook 2019: Oil and Gas Supply Module, Table 3: U.S. unproved technically recoverable tight/shale oil and gas resources by play (as of January 1, 2017), January 2019.

Chapters 2 and 3 in Volume II present pathways and recommendations to progress development of interstate CO_2 pipeline infrastructure.

Expanding the application of CO_2 EOR in the United States can provide long-term storage of anthropogenic CO_2 that is less costly than many of the alternative CO_2 storage approaches, given the revenue that can be generated from incremental oil recovery, and leveraging of infrastructure that already exists in many locations.

The U.S. Internal Revenue Service (IRS) Section 45Q tax credit offers an incentive by which the economics of the CO_2 EOR process can be improved. The attributes of the Section 45Q tax credit are discussed in Chapter 3, "Policy, Regulatory, and Legal Enablers," in Volume II of this report.

The IRS also offers an EOR tax credit under Section 43 of the Internal Revenue Code to help offset the high upfront capital cost associated with a CO_2 EOR project. The credit was put in place in 1991 to incentivize the deployment of new and significantly expanded EOR projects during periods of low oil prices. Unfortunately, the Section 43 tax credit has been ineffective given the low floor price required for companies to use the incentive. Chapter 3 also discusses the Section 43 tax credit.

IV. FACTORS THAT AFFECT THE CO_2 EOR PROCESS

CO_2 EOR includes many factors that interact to increase the amount of oil that can be recovered while incidentally trapping the CO_2 used in the process. All these factors are considered and managed during the design and operation of CO_2 EOR projects to achieve technological and economical success. Some of these factors are summarized in this section.

A. Subsurface Considerations

From a reservoir standpoint, most medium-to-light (>22 degrees API gravity)[10] oil-bearing geological formations with sufficient matrix porosity and permeability can be used for CO_2 EOR. However, many conditions must be met to achieve a commercially successful CO_2 EOR project.

Achieving MMP is almost always needed for CO_2 to be an effective EOR agent.[11] When existing fields are converted to CO_2 EOR, it is sometimes necessary to repressurize the reservoir to increase reservoir pressure to a point above the MMP.

Injectivity is a measure of how easily CO_2 and water can move from an injection well into the reservoir over a given period. It is a function of the reservoir's total thickness, permeability, and the reservoir pressure differential relative to injection pressure at the wellbore. It also depends on the viscosity of the fluid used for injection. Better injectivity means that oil can be recovered more quickly, thereby improving project economics.

Understanding the reservoir's geology can make the difference between economic success and failure. The formation rock properties are never completely uniform throughout the reservoir. Yet the closer a reservoir is to having uniformity in static properties and dynamic flow characteristics, the better the CO_2 EOR process will perform in the reservoir.

B. Typical CO_2 EOR Field Performance Parameters

Several key factors control the success of CO_2 EOR projects. These include:

- Access to an affordable supply of CO_2
- The lateral sweep efficiency (within each pattern) of the project
- Whether the CO_2 is miscible at reservoir pressure
- The size of the target oil reservoir.

Lateral sweep efficiency describes the amount of the total reservoir area that is contacted (or

10 American Petroleum Institute, "Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR) Injection Well Technology," n.d., https://www.api.org/~/media/files/ehs/climate-change/summary-carbon-dioxide-enhanced-oil-recovery-well-tech.pdf.

11 Verma, Mahendra K. (2015). "Fundamentals of Carbon Dioxide-Enhanced Oil Recovery (CO_2 EOR) – A Supporting Document of the Assessment Methodology for Hydrocarbon Recovery Using CO_2 EOR Associated with Carbon Sequestration," U.S. Geological Survey Open-File Report 2015-1071.

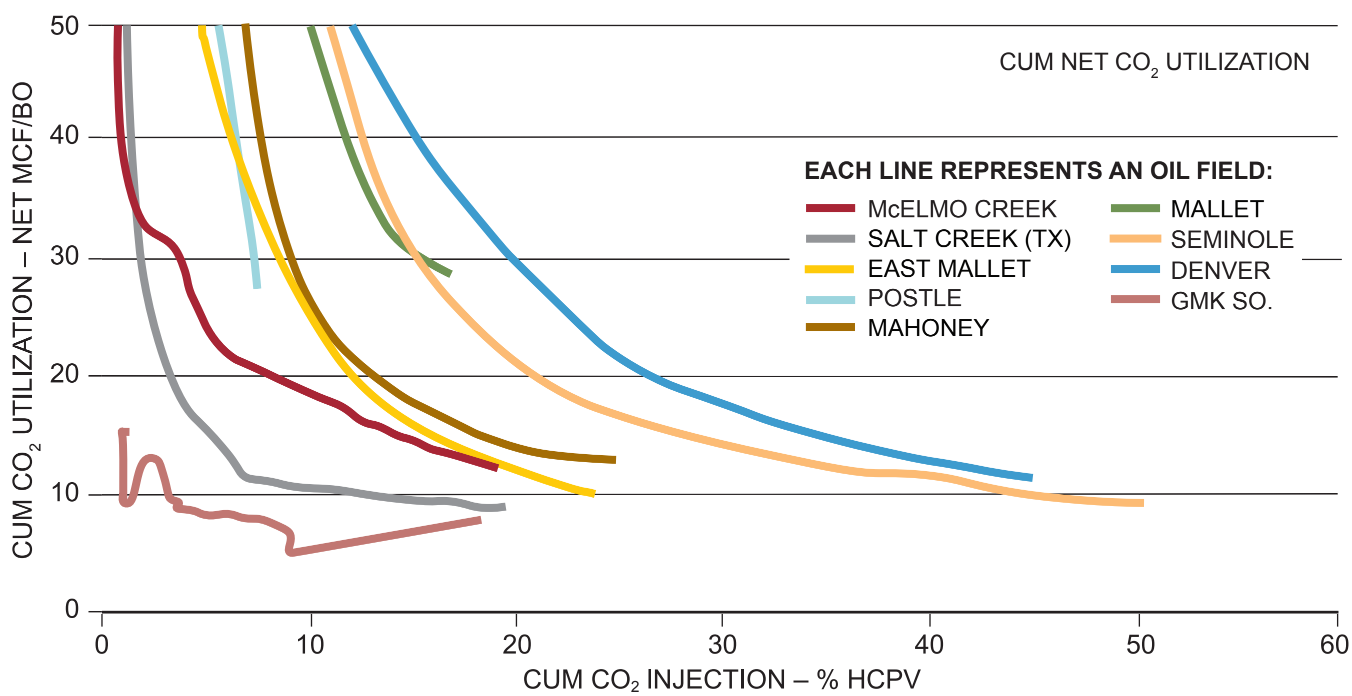
swept) by CO_2. Using WAG in the process is one way to increase lateral sweep efficiency. Efforts to maximize the lateral sweep efficiency are undertaken for each pattern of a CO_2 EOR project. Patterns refer to the manner in which injection and production wells are situated in relation to each other. Two common pattern types are line drive, where there are alternating lines of injection wells and production wells drilled in the field, and five-spot, where an injection well is drilled at or near the middle of a box with producing wells drilled at each of the four corners.

Once the CO_2 EOR project is operating, several metrics are used to manage and measure its technical and commercial performance. Oil production and CO_2 injection volumes are commonly monitored using a normalization technique where both the oil and CO_2 volumes are divided by the development area's original HCPV. Each of these volumes needs to be calculated using the densities of oil, water, and CO_2 at reservoir temperature and pressure. This enables comparison of one project's performance with another project, as well as the performance of individual well patterns within a project to other patterns in the same project.

As previously stated, the amount of newly sourced CO_2 required to produce a barrel of oil is called the utilization factor and is usually measured in thousands of standard cubic feet of CO_2 per produced barrel of oil (Mscf/bbl). A typical UF for a mature project might be 15 Mscf/bbl. When the project starts, the UF is infinite because no oil production can yet be attributed to the CO_2 contacting the oil in the reservoir. The UF decreases as cumulative CO_2 injection as a percent of HCPV increases (Figure 8-6). The UF can be stated using the newly sourced volumes (net utilization) or total volumes (gross utilization) of CO_2. Total volumes include the amount of CO_2 that is recycled.

C. Managing a CO_2 EOR Project

To optimize oil production while protecting reservoir integrity, injection pressure at the injection wellbore must be maintained below reservoir fracture pressure. During CO_2 EOR, injection and production volumes are managed to maintain



Note: Field Scale: Cum = cumulative, BO = barrels of oil under standard conditions.
Source: Melzer Consulting, personal communications.

Figure 8-6. *CO_2 EOR Project Performance Using Hydrocarbon Pore Volume (HCPV)* the desired reservoir pressure and to prevent CO_2 migration outside the intended patterns and zone. To achieve this, the pressures at injection and production wells are monitored, and the CO_2 injection volumes and produced fluids are carefully metered.

Injection and production well profile logs are used as monitoring tools to confirm how the CO_2 is vertically distributed across the formation. Production data serve as an additional monitoring tool to identify when CO_2 arrives at producing wells.

Near the end of a CO_2 EOR project, when CO_2 injection is no longer economically viable, reservoir simulation models and field experience have shown that more oil can be recovered by injecting water after the final CO_2 injection cycle. This is called the chase water phase of CO_2 EOR. The volume of oil that can be recovered in this manner ranges from 1% to 6% of the original oil in place. During this chase water phase, the small volume of CO_2 dissolved in the oil that is recovered may be used in another CO_2 EOR project, or it can be sequestered using other means.

D. Associated CO_2 Storage Incidental to CO_2 EOR

Several natural forces inevitably cause CO_2 to be retained in the reservoir during the CO_2 EOR process. Some CO_2 remains in the pore space previously occupied by oil or water that has been produced, some is trapped by capillary forces as an immobile residual phase, some is dissolved in the formation water, and some is dissolved with the remaining residual hydrocarbons. A portion of the injected CO_2 is also produced along with the reservoir fluids.

This produced CO_2 is separated from other products in surface production facilities and recycled for reinjection into the reservoir. This closed-loop process results in all of the supplied CO_2 being retained in the reservoir by the end of the CO_2 injection period, with the exception of minimal fugitive emissions and operational losses that are typically less than 1% of the original injected volume.[12] The amount of CO_2 that a reservoir can permanently trap is about 40% to 50% of the original hydrocarbon pore volume.[13]

E. Safety Performance

CO_2 EOR has been safely practiced in the United States for more than 40 years in thousands of wells in fields across a broad range of geological settings. Safe CO_2 EOR operations begin with careful site selection to ensure that the geology is secure and will trap CO_2. Potential pathways for leakage of CO_2 during EOR operations are evaluated and addressed, and mitigated if necessary, during the site selection phase of CO_2 EOR.

1. Risks

Risks associated with CO_2 EOR include the possibility of CO_2 finding a leakage pathway either into the atmosphere or underground sources of drinking water. Wellbores are a potential leakage pathway in CO_2 EOR projects. The next section, Well Construction, provides an explanation of how wells are constructed, maintained, and monitored under the supervision of governing agencies (see the CO_2 EOR Oversight section) to ensure safe and secure operations. Any problems that develop or occur with wells can generally be quickly resolved or remediated.

The Gulf Coast Carbon Center at the Bureau of Economic Geology studied the SACROC CO_2 EOR project for evidence of groundwater contamination. That study concluded that the shallow drinking water over SACROC has not been impacted by CO_2 injection, providing a strong case study to the ability to safely sequester CO_2 in deep subsurface reservoirs via this process.[14]

Operational safety risks are naturally present in the compression and injection of the CO_2.

12 ISO 27916:2019.

13 Lake, L. W., Lotfollahi, M., and Bryant, S. L., "Fifty years of field observations: Lessons for CO2 storage from CO2 enhanced oil recovery," presented at 14th International Conference on Greenhouse Gas Control Technologies, GHGT-14, October 21-25, 2018, Melbourne, Australia.

14 Gulf Coast Carbon Center, "SACROC Research Project," Bureau of Economic Geology, University of Texas, https://www.beg.utexas.edu/gccc/research/sacroc.

These risks were examined in a 2009 study by researchers at the Bureau of Economic Geology; the study concluded "the CO_2 EOR industry has an excellent safety record."[15]

2. Induced Seismicity

Seismicity induced through human activity is a public concern. Seismic events induced by injection into oil fields are rare but have occurred when large volumes of fluid are injected into underground zones near or within fault zones and when there is little or no fluid withdrawal. These conditions can create a localized pressure increase and reduce friction at fault surface interfaces, which can induce seismicity. Induced seismicity is usually associated with fields that produce large volumes of salt water concurrent with hydrocarbon production and that dispose of that water by injecting it into saline formations near basement rock. Basement rock is the rock layer below which hydrocarbon reservoirs are not expected to be found and are usually older, deformed igneous or metamorphic rocks.

CO_2 EOR projects mitigate the risks of induced seismicity by balancing fluid injection and withdrawal volumes to maintain the target reservoir pressure so it stays below the reservoir fracture pressure. Simulation models help to quantify this target reservoir pressure.

Some seismicity has been associated with CO_2 EOR activity, but this is rare. At the Cogdell CO_2 EOR project in the Permian Basin of West Texas, seismic events with a Richter Scale (RS) magnitude of 4.4 or less were reported during a period of gas injection from 2006 to 2011.[16] Seismic events were also recorded at that location when the field was undergoing brine water injection from 1975 to 1982, before CO_2 EOR operations commenced. Adjacent fields undergoing CO_2 EOR along the same structural geologic trend, such as Kelley-Snyder and Salt Creek, did not incur any seismic events during CO_2 EOR operations.[17] It has been suggested that the seismic events noted during CO_2 injection at Cogdell were reactivations of induced fractures formed during the period of brine water injection in 1975-82, and that the sudden large increases in CO_2 injection rates may have been the cause of the subsequent seismic events during 2006-11. To resolve this problem, injection rates were reduced, and the induced seismic events stopped.

Seismic events typically must be above a RS magnitude 3 for humans to feel them. Significant events are normally associated with seismic magnitudes above 5 or 6. Microseismic events, on the other hand, are typically associated with RS magnitudes near 0. Microseismic monitoring of the CO_2 EOR project in the Aneth Field, Paradox Basin, Utah, for example, shows that induced seismicity is not observed when there is no buildup of pressure in the reservoir. It has been concluded that microseismicity is largely absent in this CO_2 EOR project possibly due to the minimal change in net volume, defined as total injected fluid volume minus total produced-fluid volume, and the common practice of CO_2 EOR implementation after brine water injection, which allowed for the strain energy along preexisting fractures to be released through pressure recovery and maintenance of the brine water injection project.[18]

In summary, seismicity induced by CO_2 EOR has a very low statistical probability of occurrence. When induced seismicity does occur, it has been proven that methods exist to effectively mitigate (halt) the circumstances that lead to the seismicity.

F. Well Construction

CO_2 EOR projects require U.S. EPA Underground Injection Control (UIC) Class II permitted injection wells. UIC Class II wells must meet certain construction requirements. Thirty-four

15 Duncan, et al., "Risk Assessment for future CO_2 Sequestration Projects Based CO_2 Enhanced Oil Recovery in the U.S.," Bureau of Economic Geology, Jackson School of Geosciences, University of Texas at Austin, 2009.

16 White, J., and Foxall, W., "Assessing Induced Seismicity Risk at CO_2 Storage Projects: Recent Progress and Remaining Challenges," *International Journal of Green House Gas Control,* March 11, 2016.

17 Gan, W., and Frohlich, C., "Gas Injection May Have Triggered Earthquakes in the Cogdell Oil Field, Texas," *Proceedings of the National Academy of Sciences of the United States of America,* November 19, 2013.

18 Rutledge, J., and Soma, N., "Microseismic Monitoring of CO_2 Enhanced Oil Recovery in the Aneth Field, Geologic Demonstration at the Aneth Oil Field, Paradox Basin, Utah," submitted by New Mexico Institute of Mining and Technology, December 2010.

states and four territories have been granted primary enforcement authority (primacy) by the EPA to issue these Class II permits under state equivalency requirements. Some of these states and territories have adopted additional rules. For example, federal UIC rules require an owner or operator to case and cement wells to prevent movement of fluid into or between underground sources of drinking water.[19] Texas Railroad Commission rules require that CO_2 projects isolate and seal off all productive zones, potential flow zones, and zones with corrosive formation fluids in all wells, including Class II wells, to prevent the vertical migration of fluids, including gases.[20] The California Division of Oil, Gas, and Geothermal Resources has a similar requirement when a well is stimulated.[21]

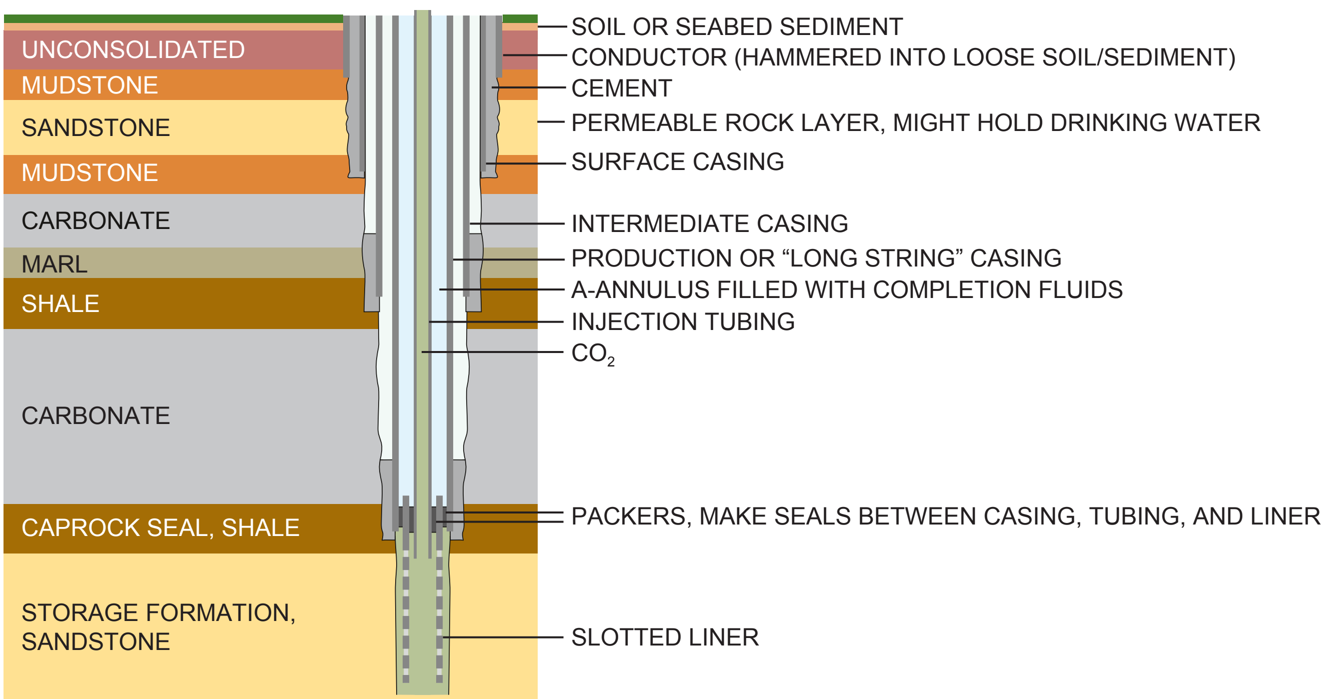
19 40 CFR § 144.28(e)(1), Requirements for Class I, II, and III Wells Authorized by Rule, Casing and cementing requirements. Code of Federal Regulations, U.S. Government Printing Office, 2010.

20 Title 16, Texas Administrative Code §3.13, "Casing, Cementing, Drilling, Well Control, and Completion Requirements," Railroad Commission of Texas, Oil and Gas Division, 2014.

21 California Code of Regulations, Title 14 – Natural Resources, § 1782(a)(3), California Office of Administrative Law, 2019.

Sealing is accomplished by deploying concentric pieces of steel pipe (casing strings) that are cemented into place underground (Figure 8-7). These casing strings and other well construction requirements protect underground sources of drinking water and facilitate vertical containment to the target zone of injected CO_2. To produce a well, the casing is perforated at the depth interval where the oil reservoir is located. A smaller diameter steel pipe string (tubing) is then lowered into the well through the production casing string. Injection and production take place by pumping or allowing fluids to flow through the tubing strings in injection and production wells, respectively.

CO_2 EOR well construction cementing requirements have proven sufficient to maintain long-term well integrity. Where temperatures and pressures are relatively low, specialized casing and tubing may be employed in newly drilled wells to resist corrosion. In addition, active corrosion inhibitor programs are a standard practice to prevent corrosion damage to the injection tubing. For example, in 2006 a team of researchers



Source: Owain Tucker. (2018). *Carbon Capture and Storage*, IOP Publishing.

Figure 8-7. *Typical Wellbore Construction Using Concentric Pipe Strings Cemented in Place to Provide Isolation Between Geologic Formations* at the Los Alamos National Laboratory recovered a core sample from the 30-year-old SACROC CO_2 EOR project to study long-term cement integrity in injector wells.[22] The sample included casing, cement, and the shale caprock. The study found that the cement had a permeability to air in the range of 0.1 millidarcy and thus had retained its capacity to provide isolation to fluid flow, including CO_2.

In the last decade, the use of horizontal wells has increased because of their ability to improve reservoir contact. These wells can be designed to access pockets of previously bypassed oil and to improve the sweep of oil toward existing production wells.

CO_2 EOR projects are usually conducted in oil fields that have already produced oil and contain large numbers of preexisting wells. Poorly plugged or damaged wells penetrating targeted formations could become pathways for injected CO_2 to leak into other formations or into the soil or the atmosphere. Care is taken before and during injection operations to prevent leakage. Before beginning a CO_2 EOR project, each well is reviewed to characterize its construction and remediate any identified issues. Well monitoring is also performed during operations to ensure that all well components continue to maintain integrity.[23]

G. CO_2 EOR Oversight

Carbon dioxide injection activities associated with enhanced oil recovery are regulated under Class II of the EPA's UIC program, and most of the oil and natural gas states have delegated primary enforcement authority, or primacy, over the activities which are also subject to federal oversight. Under this delegated authority, state regulations pertaining to CO_2 handling and injection are extensive. The UIC program and primacy are discussed further in Chapter 3.

Because groundwater is an important source of drinking water in the United States, the UIC program is designed to prevent potential contamination of underground sources of drinking water as a result of the operation of injection wells. States that have primacy must either meet the EPA's strict construction and conversion standards and regular testing and inspection requirements, or demonstrate that their program is effective in preventing endangerment of underground sources of drinking water while including requirements for permitting, inspections, monitoring, record-keeping, and reporting. Although the UIC program's focus is drinking water, compliance with UIC Class II requirements also ensures that properly designed and installed injection wells will prevent vertical movement of CO_2 through well casings, thus confining injected CO_2 to the intended target zones.

H. Residual Oil Zone

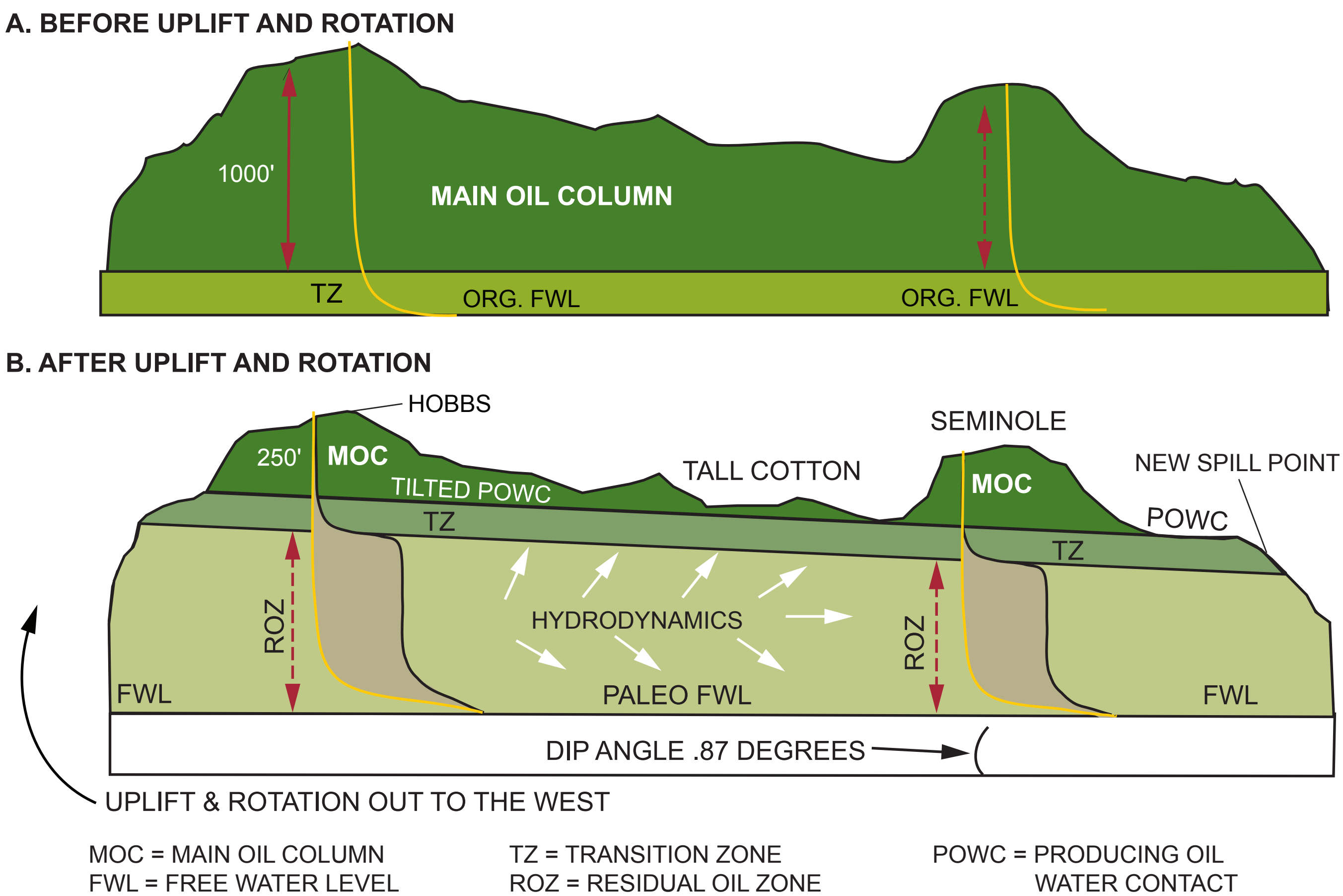
A residual oil zone is a remnant interval of oil that remains in a hydrocarbon reservoir after natural water flooding that occurs over geologic time. A ROZ is created when an oil reservoir is modified due to uplift, faulting, hydrodynamics, insufficient seal capacity, tilting, or a combination of these, resulting in previously mobile oil being displaced by encroaching water.

For example, Figure 8-8 shows how a ROZ formed from uplift due to compressional tectonics to the west of the Permian Basin during the Laramide Orogeny, between 80 million and 35 million years ago, exposing large reservoir outcrops at the surface. Part A shows the formation after oil seeped into it from a source rock and became trapped in a large main oil column. In Part B, note the tilted producing oil-water contact and original main oil column (MOC) in the structural highs after uplift and rotation have occurred. Also, note in Part B, the ROZ resides between a transition zone below the MOC and the free water level.[24] Uplift between A and B led to the migration of water down along the dip from west to east through the subsurface strata, displacing or flushing large volumes of trapped oil in the adjacent Grayburg, San Andres, and Clearfork oil reservoirs. This flushed zone in Part B is the ROZ. The result of this flushing process over

22 Carey, J. W., Wigand, M., Chipera, S. J., Gabriel, G. W., Pawar, R., Lichtner, P. C., Wehner, S. C., Raines, M. A., and Guthrie, Jr., G. D., "Analysis and Performance of Oil Well Cement with 30 Years of CO_2 Exposure from the SACROC Unit, West Texas, USA," *Science Direct*, December 28, 2006.

23 ISO 27916:2019.

24 Occidental internal communication: Jim Cooper, Technical Lead Petrophysics, Permian EOR.



Source: Occidental internal communication (Jim Cooper, Technical Lead Petrophysics, Permian EOR); and "Enabling Large-scale CCS using Offshore CO_2 Utilization and Storage Infrastructure Developments," Carbon Sequestration Leadership Forum, November 2017.

Figure 8-8. *The Creation of a Residual Oil Zone After Tilting and Hydrodynamic Sweep*

geologic time yields a result that is very similar to a modern-day brine water injection project.

CO_2 EOR functions the same when applied in a ROZ as it does in the main oil column and transition zones of a given oil field or area. The CO_2 becomes miscible with any residual oil, causing the oil volume to swell and lowering its viscosity. This enables oil still trapped in a ROZ to become mobile and move to producing wells while the CO_2 trades places with the oil and is subsequently trapped in the reservoir.

CO_2 EOR is successfully being used to develop ROZs, in particular in the Permian Basin. However, using CO_2 EOR in a ROZ is not widely practiced due to the lack of large volumes of affordable CO_2 and because CO_2 EOR in higher oil saturation main oil columns is usually more economically attractive to recover. This suggests that more ROZs could become viable investment opportunities for CO_2 EOR when affordable CO_2 is made available.

I. Offshore

There are no offshore CO_2 EOR projects in the United States, although five CO_2 EOR pilot projects were conducted in the Gulf of Mexico during the 1980s. The first at-scale offshore CO_2 EOR project started at the Lula Field offshore Brazil in 2011 and is still active.[25] Downhole processes are similar for onshore and offshore CO_2 EOR settings. If offshore CO_2 EOR can be implemented economically in the United States, it will provide an untapped resource for producing additional oil and storing significant volumes of anthropogenic CO_2. The incremental challenges for offshore

25 "Enabling Large-scale CCS using Offshore CO2 Utilization and Storage Infrastructure Developments," Carbon Sequestration Leadership Forum, November 2017.

implementation compared with onshore projects may include the following:

- Offshore operations are conducted either from a surface-piercing structure or platform, or from subsea facilities tied back to a platform, all of which typically have higher development and operating costs than onshore facilities.
- Well patterns for producing reservoirs differ significantly between onshore and offshore projects. This is due to the higher well densities typically associated with onshore developments relative to offshore, and the common requirement for special drilling or well spacing considerations offshore. Offshore wells tend to be drilled horizontally or at high angles from the vertical because they need to reach distant areas of the reservoir from a central platform. More widely spaced wells offshore leads to longer lag times between injection and production responses, and to less efficient reservoir sweep by the injected CO_2.
- The financial investment required to modify existing platforms, wells, and other installations for CO_2 EOR will be higher offshore than onshore, and lost revenue during the facility modification process can be a significant factor. Most existing platforms will not have been designed in anticipation of CO_2 EOR operations and there is limited space to accommodate the equipment required to maintain the closed-loop system used in CO_2 EOR.
- Operational maintenance is costlier offshore than onshore.
- In an offshore CO_2 EOR operation, CO_2 will be delivered by ship or offshore pipeline, which creates additional costs when compared with onshore operation. The CO_2 may be injected directly into the wells or temporarily stored in floating storage vessels, enabling a choice of injection strategies.

Despite these challenges, the advantageous aspects of offshore CO_2 EOR include the following:

- Offshore leases are owned by single (federal or state) licensing authorities, whereas onshore projects often require the cooperation of multiple leaseholders.
- Frequently larger field sizes offshore may offer significant potential for higher additional production from CO_2 EOR.

Data from international offshore CO_2 saline formation injection projects will be helpful in designing the transport and injection components of the facilities for offshore CO_2 EOR. There are at least 10 offshore CO_2 injection projects operating, under construction, or undergoing advanced study according to the Global CCS Institute.[26] Several injection facilities are operational in the Barents Sea, North Sea off the coasts of Norway and the Netherlands, and offshore Japan.

J. Unconventional Reservoirs

In 2017, oil production from unconventional shale reservoirs was nearly 5 million barrels per day, or about 50% of total U.S. production supply.[27] These reservoirs are under primary production, but their ultra-low permeabilities will result in primary recovery factors ranging from 3% to 10% of the original oil in place. This leaves a significant volume of hydrocarbons underground. Research efforts for improving oil recovery in unconventional reservoirs are being undertaken by universities, industry, and the Department of Energy. New research suggest that use of CO_2 could improve recovery factors by as much as 3% to 5% through the application of various primary and secondary EOR processes, such as CO_2 stimulation and CO_2 repressurization, respectively.

Unconventional reservoirs are very different from the conventional reservoirs typically used for CO_2 EOR. The primary difference is in reservoir permeability. Unconventional oil reservoirs often have permeability values in the nanodarcy range but conventional reservoirs have permeabilities in the millidarcy range. Because of these ultra-low permeabilities, unconventional oil reservoirs are often drilled in blocks of 80 acres and completed with horizontal wellbores of 1 to 3 miles in length, and requiring several hydraulic

26 Global Status of CCS, Global CCS Institute, Melbourne, Australia, 2018.

27 U.S. Energy Information Administration, "How much shale (tight) oil is produced in the United States?" Frequently Asked Questions, https://www.eia.gov/tools/faqs/faq.php?id=847&t=6, updated September 4, 2019.

fracture treatments along the wellbore to unlock the oil. The combination of closely spaced horizontal wellbores and hydraulic fracturing creates injection conformance and lateral sweep efficiency challenges for continuous pattern-based CO_2 injection.

EOR models for conventional reservoirs do not describe well what happens in unconventional reservoirs. Instead of pushing fluids through the rock, as is the recovery mechanism for CO_2 EOR in conventional reservoirs, in unconventional reservoirs the injected CO_2 engages with the oil in rock local to the injection well, liberating it so that it can be produced back with the CO_2 via the injection will itself, now functioning as a producing well. In the lab, attempting to push oil through a tight formation core does not work, but when a shale sample is left to soak in gas or surfactant, oil can be produced. This has resulted in the industry's testing of cyclic, or "huff-n-puff," EOR methods for unconventional reservoirs where injection and production occur using the same well.

One major review assessed the status of unconventional (tight oil) activity for five major producing basins.[28] The review identified the major challenges and gaps to be addressed by research and development that could lead to more efficient recovery of tight oil using EOR, which included:

- Rigorously characterizing and defining the natural and induced fracture systems in unconventional oil formations
- Establishing CO_2 injectivity and its entry into the unconventional oil reservoir's matrix
- Establishing the relative importance of unconventional oil EOR mechanisms
- Achieving increased reservoir conformance by the injected EOR fluid
- Defining reservoir conditions and well completion methods favorable for EOR in unconventional reservoirs
- Achieving pattern-based CO_2 EOR in unconventional reservoirs
- Addressing the unique challenges of conducting EOR in low-permeability unconventional oil sands
- Improving EOR monitoring and diagnostic technologies and practices for unconventional oil
- Conducting fully integrated laboratory research, reservoir modeling, and pilot EOR projects in each tight oil basin or formation.

Research from entities such as the National Energy Technology Laboratory (NETL) is needed to develop methods that may result in commercial CO_2 EOR opportunities in unconventional reservoirs. This research should start soon so that the results can be put into use within 5 to 10 years. A specific R&D investment recommendation is quantified in the Research and Development Needs section of this chapter as well as in Chapter 3.

V. COMMERCIAL EXPERIENCE AND PERFORMANCE

CO_2 EOR has proven to be technically and economically viable in a variety of fields in the United States and abroad. The tools and knowledge to select reservoirs for CO_2 EOR and to design successful projects are well established. Examples of these are shown in Appendix G of this report, "CO_2 EOR Case Studies," where case studies of the Denver Unit in the Permian Basin of West Texas, the Bell Creek Field in the Powder River Basin of Montana, and the Northern Niagaran Pinnacle Reef Trend in the Michigan Basin of Michigan are highlighted.

These examples show that CO_2 EOR has been applied in diverse reservoir types in the United States with successful and predictable results. The case studies also show that although every CO_2 EOR project is different, the basic principles of geologic characterization, well and facility construction, and monitoring and management have been successfully applied for each project. The result is that more oil is produced out of existing fields while the CO_2 used in the process is subsequently trapped underground. The oil produced from CO_2 EOR has 63% lower carbon emissions intensity than oil produced by other methods.

28 U.S. Energy Information Administration, *Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

A. Infrastructure Needs for CO_2 EOR

CO_2 EOR projects require infrastructure to handle the injection, production, separation, and recycling of CO_2 in a closed-loop system. This infrastructure includes equipment within the oil field and outside the field. Infrastructure outside the field is commonly shared among several CO_2 EOR projects, creating economies of scale.

1. Within the Field

The addition of new facilities and equipment within the field is needed when developing CO_2 EOR projects. Figure 8-9 presents a simplified schematic that shows the key components and stages of a CO_2 EOR operation. This infrastructure is used to receive CO_2 that is delivered to the field and to distribute it to the injection wells located throughout the field. On the production side, well testing and fluids separation equipment, often located at centralized processing facilities called central tank batteries, must be modified to accept the gaseous CO_2 that is produced, then to recompress the CO_2 so that it may be reinjected in the closed-loop process.

The key specific equipment needed for CO_2 EOR are:

- Injection manifolds capable of accommodating a WAG process.
- Injection well instrumentation and metering capable of measuring the two separate fluids associated with WAG injection—water and dense phase CO_2—each with different volumetric properties.
- Producing well instrumentation and metering to measure the amount of gas, oil, and water of each producer well.
- Produced-fluid handling systems, including a remote well testing facility (satellite) and a central tank battery designed to separate oil, water, and gas streams and that can accommodate high concentrations of CO_2. Before entering the high-pressure, three-phase separator, the EOR fluid production mixture is typically treated with demulsifiers, scale inhibitors, and corrosion inhibitors to aid the fluids separation process and protect the process equipment.
- Reinjection Compression Plant (RCP) for produced gas from the high-pressure three-phase separator (that contains CO_2 and hydrocarbon

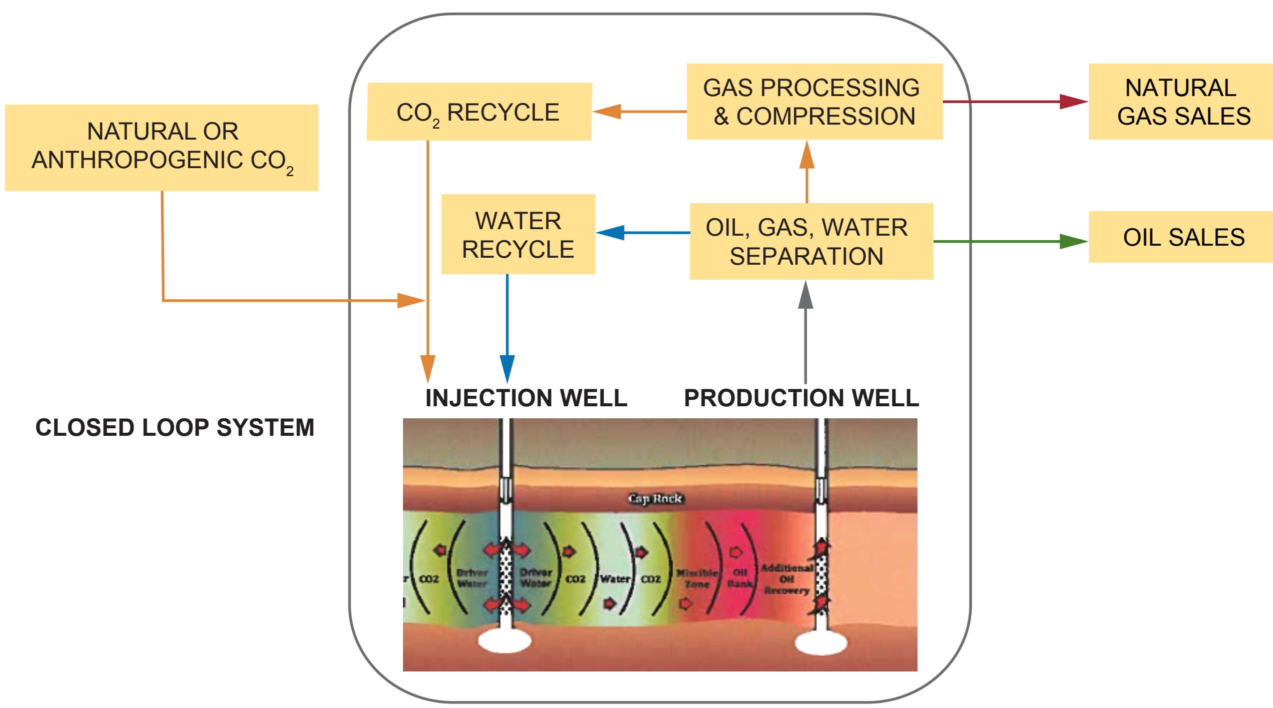


Figure 8-9. Typical Flow Diagram for CO_2 EOR

gas) to compress the mixture for transmission to a gas recovery plant where CO_2 will be separated from hydrocarbon gases for recycling. The CO_2 content in the gas stream impacts compressor operation and requires careful monitoring and adjustments. Sensors may be located upstream of this compressor to quantify the amount of CO_2 being produced.

- CO_2 recovery plant capable of separating out a pure CO_2 stream from the produced gas for recompression and reinjection, and the collection of natural gas liquids for sale. There are several CO_2 separation options available (chemical solvents, physical solvents, membranes, cryogenic processes, etc.) depending on the nature of the produced gas, the throughput rate, and other factors. Each has advantages and disadvantages, and sometimes a combination of these is required.[29] An alternative to building a CO_2 recovery plant is to reinject the produced gas stream using the RCP, which is only viable if the gas composition would not adversely affect the MMP.
- High-volume artificial lift systems capable of handling high volumes of liquid before gas breakthrough in the reservoir and CO_2 in the produced gas after breakthrough. One option is to use compressed, recycled CO_2 as a gas lift fluid.[30]

An overview of facilities supporting the supply, distribution, and injection of the CO_2 for EOR follows.

a. Supply

CO_2 is generally supplied to CO_2 EOR projects via transmission pipelines. Volumes are measured through a custody transfer meter that enables CO_2 ownership to transfer from the CO_2 supplier to the CO_2 user (the field). The CO_2 is in dense phase and typically at a density above 35 lbs/cu ft. This higher density minimizes pressure drops in the supply pipeline and enables the use of centrifugal pumps (versus more costly compressors) to add pressure to the fluid en route to the user.

Often the supply pressure is in the 2,000 psig range and is sufficient to enable direct distribution to the wellheads through the distribution system discussed below. Typical supply specifications include 95% CO_2 purity with most of the non-CO_2 components being hydrocarbons and nitrogen. The water content specification is usually 30 lbs H_2O/MMscf to eliminate corrosion concerns from using internally bare carbon steel piping materials at the temperatures and pressures the supply system operates.[31] Oxygen concentration should generally be below 10 parts per million by volume to avoid conflicts with the reservoir.

b. Distribution

The CO_2 distribution system is generally the point where CO_2 supply pipeline regulatory requirements end and the field operations begin. The distribution system connects the CO_2 supply to the CO_2 injection wells. After the field begins to produce CO_2, the distribution system is where the produced, separated, and compressed CO_2 (recycled CO_2) is combined with the CO_2 supply stream. Generally, the CO_2 supply and recycle streams are combined before reaching the first injection well so that CO_2 injection composition and temperature are consistent across all wells at a given point in time.

c. Injection

The distribution system terminates at an injection well. Injection may be controlled by pressure or rate. Injection pressure is regulated to not exceed the maximum allowable surface injection pressure to ensure reservoir integrity is maintained regardless of control methodology. The injection well may also inject water if the system is designed for WAG.

d. Closed Loop

Some injected CO_2 is incidentally trapped on the first pass through the reservoir. Some is produced via the production wells where it is then

29 Saadawi, H. (2011). "A Study to Evaluate the Impact of CO2 EOR on Existing Oil Field Facilities," SPE 141629.

30 Gray, L., and Geoffrey, S. (2014). "Overcoming the CO2 Supply Challenge for CO2 EOR," SPE-172105-MS, Society of Petroleum Engineers.

31 Havens, K. (2007). "CO_2 Transportation and EOR," Houston, TX: Kinder Morgan CO_2 Company.

recycled to be trapped on subsequent passes through the reservoir. The production wells produce hydrocarbon liquids and water, along with any returned CO_2 and hydrocarbon gas. On the surface, liquid components are separated from the gases, and the returned CO_2 is subsequently separated from hydrocarbon gases, thereby enabling the produced CO_2 to be reinjected (recycled). This represents a closed-loop system where all CO_2 is ultimately stored in the reservoir once long-term retention is verified.

2. Outside the Field

The proximity of neighboring fields with CO_2 EOR operations or potential will sometimes drive the siting of the RCP and CO_2 plant so that the facilities may be shared between several fields to take advantage of economies of scale. For isolated developments, the well test satellites, RCF, and CO_2 plant may be developed as a single complex. In certain areas of West Texas, for example, the population density of fields undergoing CO_2 EOR justifies the pipeline costs associated with gathering production from multiple fields and using shared RCP and a single CO_2 plant.

Facilities for new CO_2 EOR projects typically require several years to design and construct, be they sited inside or outside the field. There is also a relatively large investment made in the construction of these facilities. Once built and commissioned, these facilities can have a useful life of more than 20 years.

B. Economic Factors and Considerations

CO_2 EOR development costs are an important driver in the economics of CO_2 EOR projects. These costs are difficult to generalize since they are highly dependent upon the type, size, and location of the project being developed, and the depth of the play.[32] Costs can also vary considerably due to well configurations and whether or not existing wells and equipment can be repurposed for CO_2 EOR operations. Most CO_2 EOR plays have their own set of idiosyncrasies that can impact overall project economics in positive and negative ways.

There is, however, a broad set of costs that are common to most CO_2 EOR applications. These include:

- Cost of the supply of CO_2 for injection purposes
- Cost to drill a series of CO_2 injection wells, and/or converting selected producing wells to injection wells
- Cost to install surface facilities needed to separate, measure, recycle, and transport the CO_2 into the subsurface
- Cost of added compression
- Cost to provide additional surface equipment that is needed.

In addition, there are other economic factors that impact overall CO_2 EOR profitability, particularly those associated with financing these types of projects. Appendix H explores each of these factors and examines how the component costs vary and change CO_2 EOR project economics.

VI. OPTIMIZING CO_2 STORAGE IN CO_2 EOR

In general, contacting the maximum amount of oil-saturated reservoir rock with CO_2 will also result in maximization of the CO_2 trapped in the subsurface. However, in a business context where CO_2 supply can represent a substantial cost, CO_2 EOR operators often prefer to minimize CO_2 supply purchases, hence, to minimize net CO_2 utilization. Net CO_2 utilization is derived by dividing the amount of newly provided or acquired CO_2 in thousands of cubic feet by the barrels of oil production, both measured at standard conditions.

A consequence of this practice has been to leave a portion of the oil reservoir uncontacted by CO_2 due to the cost of contacting hard-to-reach areas. If cost were not an object, technologies such as CO_2 thickeners or CO_2 foams would be used more frequently to contact more of the oil-saturated reservoir area. These products make the fluid properties of CO_2 closer to those of the oil so that it will spread away from the injection wells and contact more of the in-situ rock volume, thereby resulting in the recovery of additional oil and the associated storage of additional CO_2.

32 Godec, M. (2011). "Global Technology Roadmap for CCS in Industry: Sectoral Assessment CO_2 Enhanced Oil Recovery," United Nations Industrial Development Organization.

When CO_2 EOR projects reach the post-CO_2 injection phase, it is common to continue injecting water during what is called the chase water phase. The primary purpose of chase water is to produce additional oil and recover any still-mobile CO_2 for use in another CO_2 project.

However, if the value of leaving the mobile CO_2 volume in the reservoir were higher than the value of recovering the injectant for use in subsequent projects, there would be an incentive to eliminate the chase water phase and to continue to inject CO_2. Additionally, produced CO_2 could be reinjected in lieu of the chase water. If the economics of the continuing production process were positive, the removal of additional oil and water from the reservoir would enable additional CO_2 to be injected and trapped.

Following are several alternatives to increasing the amount of CO_2 trapped during CO_2 EOR operations:

- Use geomodeling and reservoir engineering configured in a way to improve subsurface characterization. The WAG schedule can also be optimized to maximize CO_2 sequestration.
- Relax the gas oil ratio (GOR) constraints and/or EOR efficiency target. Most CO_2 EOR WAG projects have been designed with a tapering policy when reaching a high GOR or a low EOR efficiency because of the marginal added net present value, and thus a better CO_2 cost allocation. Increasing the CO_2 injection per pattern requires parallel optimization of infill well locations. Infill wells are new wells drilled to form the selected injection pattern when installing a CO_2 EOR project in an existing field where the wells are in a different pattern.
- Revive and enhance methods for improving the mobility ratio between CO_2, water, and residual oil by using CO_2 foam, stabilizing foam agent (polymer, nanoparticles), CO_2 direct thickener, or polymer in water.
- Lower the oil miscibility pressure with CO_2 by incorporating additives (i.e., liquefied petroleum gas) to target heavier oils or de-gassed oil from primary recovery.

Any enhancements that would intentionally target increasing CO_2 trapping and that would not result in more efficient recovery of hydrocarbons at the same time, would have to be properly vetted to ensure that mineral estate and surface estate interests are taken into consideration.

VII. RESEARCH AND DEVELOPMENT NEEDS

The first CO_2 EOR projects implemented in the United States in the early 1970s operated with a combination of high CO_2 costs and low oil prices.[33] Because of the limited capability to monitor and control the subsurface movement of the injected CO_2, operators were encouraged to inject relatively small volumes of CO_2. Advances in monitoring and control techniques, and more readily available volumes of affordable CO_2, led to the injection of larger volumes of CO_2. These injected volumes are monitored and controlled to ensure that they contact, displace, and recover oil rather than simply circulating CO_2 through the reservoir's higher permeability zones.

In addition to larger volumes of injected CO_2, the implementation of tapered WAG injection schemes has become common practice to better control CO_2 mobility, to improve conformance and sweep efficiency, and to avoid bypassing areas of the reservoir that contain residual oil. Tapered WAG is when the size of the water and/or CO_2 volumes in each successive cycle is changed in a tapered manner. These control measures, along with the application of more advanced well drilling and completions strategies to improve the contact of bypassed oil, have led to steady improvements in residual oil recovery efficiencies.[34]

Expanded application of CO_2 EOR in conventional reservoirs will most likely not result from the development of entirely new tools or technologies. Instead, it will be through the advancement

33 While the first patent for CO_2 EOR was granted in 1952, the first large scale commercial EOR project began operations in 1972 at SACROC field in West Texas (Meyer, J. P., "Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR) Injection Well Technology," American Petroleum Institute, https://www.api.org/~/media/Files/EHS/climate-change/Summary-carbon-dioxide-enhanced-oil-recovery-well-tech.pdf).

34 Global CCS Institute, "The Evolution of CO2 EOR Technology," https://hub.globalccsinstitute.com/publications/global-technology-roadmap-ccs-industry-sectoral-assessment-CO2-enhanced-oil-recovery-3.

of existing methods and their application to a larger number of reservoirs in basins with existing CO_2 EOR projects and in basins where CO_2 EOR has not yet been implemented.

Research is needed to develop methods that may result in commercial CO_2 EOR opportunities in unconventional reservoirs. More generally, R&D investment of $100 million per year is recommended, to be directed to better understanding CO_2 trapping mechanisms and magnitudes in unconventional and conventional CO_2 EOR reservoirs, as well as in nonconventional storage opportunities (basalts and coal seams).

Two particular CO_2 EOR technologies that would benefit from further research include vertical and horizontal conformance controls to maximize sweep efficiency, and advanced compositional modeling techniques to better predict and enhance performance.

A. Vertical and Horizontal Conformance Controls to Maximize Sweep Efficiency

Methods for improving sweep efficiency include the WAG process, the surfactant alternating gas (SAG) process, and the use of stabilized CO_2 foams created with surfactants.

Adding a surfactant to the injected water used in the WAG process helps to reduce the trapping of oil in small pores through wettability alteration (wettability is the ability of a liquid to maintain contact with a solid surface—in this case the formation rock). Application of SAG can improve recovery over WAG alone.[35] Gel-based polymer solutions that crosslink in-situ and preformed particle-gel dispersions are also used in the water injection stage of the WAG process to counter high-permeability flow paths.

The use of CO_2-water foam stabilized with soluble surfactants can increase CO_2 viscosity and improve the mobility ratio in a CO_2 EOR project, leading to improved sweep efficiency. There have been many successful laboratory-scale tests involving water-soluble surfactants capable of stabilizing CO_2-in-brine foams.[36] Thirteen reports of pilot tests conducted between 1984 and 1994 have been published, most of which were aimed at attaining conformance control, and five of which were considered successful technically. However, it appears that polymer and surfactant additives coupled with WAG have largely replaced the use of foams as a conformance-control technique, especially in extremely high-permeability flow paths where foams are generally ineffective. Recently, however, laboratory-scale testing of foam stabilization with water-dispersible nanoparticles has been carried out in an attempt to address surfactant-to-rock adsorption losses and chemical instability of the surfactant.[37] Additional research into the development of robust and cost-effective nanoparticle-stabilized CO_2 foams coupled with field testing is needed to help determine whether or not this option has potential for both conventional and unconventional reservoirs.

Another method that has been investigated involves the thickening of injected CO_2 using a variety of chemicals. Developing cost-effective, reliable thickening agents for CO_2 using polymers has been a challenge.[38] High molecular weight polymers only dissolve in CO_2 at pressures much higher than the MMP. Smaller molecule thickeners designed to form macro-molecular structures did not produce a significant viscosity increase. Research into this area would help to expand the already large storage capacity of CO_2 EOR.

B. Compositional Modeling Techniques for Unconventional Reservoirs

There are about 29 reservoir simulators available to better predict and enhance the performance of CO_2 EOR in unconventional reservoirs. Only a subset of these simulators is suitable for predicting performance of miscible EOR processes. Accurate modeling of miscible EOR processes using natural gas or CO_2 as an injectant

35 Salehi, M. M., et al., "Comparison of oil removal in surfactant alternating gas with water alternating gas, water flooding and gas flooding in secondary oil recovery process," *Journal of Petroleum Science and Engineering,* August 2014, 120:86-93.

36 Enick, R. M., et al., "Mobility and Conformance Control for CO2 EOR—Thickeners, Foams, and Gels: A Literature Review of 40 Years of Research and Pilot Tests," SPE 154122 prepared for the 2012 SPE Improved Oil Recovery Symposium, Tulsa, April 14-18, 2013.

37 Enick et al., 2013.

38 Enick et al., 2013.

requires a simulator that can represent the various physical processes underway. Compositional simulators predict the phase behavior of the fluids in the reservoir as well as the sweep behavior. This enables the prediction of incremental oil recovery and solvent utilization efficiency to optimize variables such as solvent composition, operating pressure, slug size, WAG ratio, injection-well placement, and injection rate.

A 3D compositional reservoir simulator calculates the flow of solvent, oil, and water phases in three dimensions as well as the flow of multiple components in the solvent and oil phases. It also computes the phase equilibrium of the oil and solvent phases (i.e., the equilibrium compositions and relative volumes of the solvent and oil phases) in each gridblock of the simulator. In addition, it computes solvent- and oil-phase densities.[39] The equilibrium compositions and densities are calculated with an equation of state. Using the calculated phase compositions and densities, the solvent and oil viscosity and other properties such as interfacial tension are estimated from correlations.[40]

The primary disadvantages of a compositional simulator are the degree of grid refinement often required to compute oil recovery accurately and the computing time required for fine-grid simulations. These factors generally preclude using a compositional simulator directly for full-field simulations unless a scaling-up technique is used to transfer the information developed from fine-grid reference-model simulations on a limited reservoir scale to coarse-grid simulations on the full-field model scale.

DOE has funded the development of a CO_2 EOR model that was designed to aid in accelerating CO_2 EOR technical studies for small- to mid-sized oil field operators within the United States. The objective was to develop a tool that includes a capability for addressing all the significant physical and chemical factors that impact the flow and recovery of reservoir fluids, yet make the simulation model building and evaluation process fast enough that an integrated feasibility study could be completed in a fairly short time period. The software integrates a user interface (COZView) for pre- and post-processing of simulation results with a 3D, 3-phase, 4-component reservoir simulator (COZSim) capable of modeling CO_2 EOR in oil reservoirs. The product enjoyed some use following its release in 2012 and has been used to perform screening studies and then incorporated into subsequent models.

There are opportunities for improving the use of compositional modeling for CO_2 EOR in unconventional reservoirs. These improvements include adding the ability to model adsorption and vaporization mechanisms to track oil movement in the reservoir, determining specific drive mechanisms by which oil makes its way to the producing wellbores, and the coupling of wellbore and subsurface modeling to predict conditions where condensate deposition in the wellbore would occur.

VIII. CONCLUSIONS

CO_2 EOR is a process that can trap significant volumes of CO_2 and help produce more crude oil from existing oil fields. This results in oil that may be produced with a lower carbon footprint than conventional oil. CO_2 EOR has increased oil recovery from existing fields for more than 40 years and traps the CO_2 that is used during a closed-loop CO_2 injection and recycle process. Once injected into a reservoir, CO_2 acts as a solvent to swell the volume of oil, lower its viscosity, and enhance its ability to move through a reservoir from injection wells toward production wells. It is a proven technique to maximize hydrocarbon recovery from new oil fields and extend the life of mature oil fields.

Industry and academia have developed a thorough understanding of how CO_2 interacts with hydrocarbons, gas, water, and reservoir rock to predict the extent of the CO_2 plume, ensuring safe and secure associated storage of CO_2 in EOR projects. The fraction of injected CO_2 that is produced can be compressed and recycled back into the reservoir using a closed-loop system such that nearly all of the CO_2 brought to the project is ultimately trapped in the reservoir.

39 Society of Petroleum Engineers, "Compositional simulation of miscible processes," PetroWiki, https://petrowiki.org/Compositional_simulation_of_miscible_processes, updated June 4, 2015.

40 Society of Petroleum Engineers, 2015.

The availability of affordable CO_2 from anthropogenic sources, combined with advances in the technologies used in CO_2 EOR, would significantly increase the associated CO_2 storage potential in the United States to a range between 274 Bt and 479 Bt. Much of this potential storage capacity is accessible now, and more can be made available with proper planning and with government assistance through tax credits and support for building a pipeline infrastructure system. The following list of actions would enable a wider scale deployment of CO_2 EOR in the United States.

A. Near Term (0 to 5 Years)

The share of oil production from CO_2 EOR projects in the global oil production mix is not high and is predominantly located in the midwestern United States. The economic model of CO_2 EOR is reservoir- and site-specific, and the pace of development is constrained by the amount of CO_2 that can be sourced affordably in close proximity to oil fields that are amenable to CO_2 EOR.

1. CO_2 EOR is an effective and safe CCUS process, but many of the anthropogenic sources of CO_2 are located far away from the regions where CO_2 EOR projects are currently operating and other areas where it is suitable for deployment. Work remains to develop pipeline infrastructure in the United States to move CO_2 from point sources, where capture technologies can be applied, to the geographic locations of oil-bearing formations where CO_2 EOR can be used to increase oil production and safely store the CO_2. More information about constructing CO_2 pipeline infrastructure can be found in Chapter 6, "CO_2 Transport."
2. The Internal Revenue Code Section 45Q tax credit was put in place to incentivize the capture and storage of anthropogenic CO_2. The Section 43 credit was intended to incentivize investment in EOR projects during periods of low oil price. The ways that both of these tax credits can be enhanced to enable more CO_2 EOR in the future are described in Chapter 3.
3. Unconventional reservoirs account for 50% of U.S. crude oil production. These reservoirs have ultra-low permeability, which limits a conventional CO_2 EOR process where CO_2 and water are injected into dedicated injection wells to push oil to producer wells. Congress should encourage research managed by NETL in the next five years to develop methods that can be used to apply CO_2 EOR commercially to unconventional reservoirs and to understand the associated CO_2 retention potential. This is needed so that widespread CO_2 EOR operations in unconventional reservoirs can begin within 5 to 10 years.

B. Mid Term (5 to 10 Years)

1. Offshore CO_2 EOR would benefit from further research and testing to bring down the cost of implementation. The high cost of offshore development has resulted in fewer wells being drilled offshore relative to a comparable onshore development. Fewer wells negatively affects oil recovery efficiency, leaving a large amount of oil in offshore reservoirs that could be targeted by CO_2 EOR. In addition to lower well costs, the development of smaller, lower-cost compression equipment used for recycling the produced gas in a CO_2 EOR project would help overcome the economic hurdles that are necessary to make offshore projects viable from an investment standpoint.
2. Existing and future CO_2 EOR projects could increase the efficiency of oil recovery, and trap larger volumes of CO_2, if the viscosity of the injected CO_2 could be increased. Research into identifying low-cost thickeners and/or foaming agents for CO_2 could result in an increase in the amount of CO_2 stored in CO_2 EOR projects.

C. Long Term (10+ Years)

Reducing global CO_2 emissions while delivering increased energy supplies will require efforts from many stakeholders. CO_2 EOR offers the means of delivering this energy while also offering substantial incidental CO_2 storage capacity in service of both objectives. Expanding the application of CO_2 EOR processes globally will support the uptake of CCUS, while leveraging the skills, experience, and knowledge developed in the United States over the past 40 years.