CARBON DIOXIDE ENHANCED OIL RECOVERY

Untapped Domestic Energy Supply and Long Term Carbon Storage Solution
Introduction

As the United States grapples with the challenge of reducing emissions of greenhouse gases, the topic of carbon dioxide (CO₂) enhanced oil recovery (EOR) has received increased attention. In order to help inform the discussion, the Department of Energy’s National Energy Technology Laboratory has published this “primer” on the topic. Hopefully, this brief introduction to the physics of CO₂ EOR, the fundamental engineering aspects of its application, and the economic basis on which it is implemented, will help all parties understand the role it can play in helping us meet the challenge mentioned above.

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The Basics of Carbon Dioxide EOR

Why It Works

Why does injecting carbon dioxide (CO₂) into the pore spaces of a rock help move crude oil out? Carbon dioxide has two characteristics that make it a good choice for this purpose: it is miscible with crude oil, and it is less expensive than other similarly miscible fluids. What does it mean to be miscible? Imagine that you get oil on your tools while working on your car’s engine. Water will get a little of the oil off, soap and water will do a better job, but a solvent will remove every trace. This is because a solvent can mix with the oil, form a homogenous mixture, and carry the oil away from the tool’s surface. Fluid pairs like ethanol and water, vinegar and water, and engine “degreasers” and motor oil exhibit miscibility, that is, the ability of fluids to mix in all proportions (see page 26 for a glossary). As we know, “oil and water don’t mix,” as they are immiscible; and as a result, completely removing oil from tools or engine parts requires a solvent.

We could use similar miscible solvents to clean the oil from underground reservoirs, but since these products are refined from crude oil and therefore relatively expensive, it does not make economic sense to do so, regardless of their effectiveness. The same goes for natural gas enriched with heavier hydrocarbons like propane; it is miscible with oil but it is also a valuable commodity. However, underground deposits of CO₂ are relatively inexpensive, naturally occurring sources of the gas that can be extracted in large quantities, making it a more sensible choice. If CO₂ produced by human activities can be captured inexpensively, it could become a source as well.

When we inject CO₂ into an oil reservoir, it becomes mutually soluble with the residual crude oil as light hydrocarbons from the oil dissolve in the CO₂ and CO₂ dissolves in the oil. This occurs most readily when the CO₂ density is high (when it is compressed) and when the oil contains a significant volume of “light” (i.e., lower carbon) hydrocarbons (typically a low-density crude oil). Below some minimum pressure, CO₂ and oil will no longer be miscible. As the temperature increases (and the CO₂ density decreases), or as the oil density increases (as the light hydrocarbon fraction decreases), the minimum pressure needed to attain oil/CO₂ miscibility increases. For this reason, oil field operators must consider the pressure of a depleted oil reservoir when evaluating its suitability for CO₂ enhanced oil recovery (EOR). Low pressured reservoirs may need to be re-pressurized by injecting water (see page 6 sidebar on waterflooding).
When the injected CO₂ and residual oil are miscible, the physical forces holding the two phases apart (interfacial tension) effectively disappear. This enables the CO₂ to displace the oil from the rock pores, pushing it towards a producing well just as a cleaning solvent would remove oil from your tools.

As CO₂ dissolves in the oil it swells the oil and reduces its viscosity; effects that also help to improve the efficiency of the displacement process.

Often, CO₂ floods involve the injection of volumes of CO₂ alternated with volumes of water; water alternating gas or WAG floods. This approach helps to mitigate the tendency for the lower viscosity CO₂ to finger its way ahead of the displaced oil. Once the injected CO₂ breaks through to the producing well, any gas injected afterwards will follow that path, reducing the overall efficiency of the injected fluids to sweep the oil from the reservoir rock.
Untapped Domestic Energy Supply and Long Term Carbon Storage Solution

CARBON DIOXIDE ENHANCED OIL RECOVERY

How It Works

The physical elements of a typical CO₂ flood operation can be used to illustrate how the process works. First, a pipeline delivers the CO₂ to the field at a pressure and density high enough for the project needs (>1200 pounds per square inch [psi] and 5 pounds per gallon; for comparison water density is 8.3 pounds per gallon), and a meter measures the volume of gas purchased. This CO₂ is directed to injection wells strategically placed within the pattern of wells to optimize the areal sweep of the reservoir. The injected CO₂ enters the reservoir and moves through the pore spaces of the rock, encountering residual droplets of crude oil, becoming miscible with the oil, and forming a concentrated oil bank that is swept toward the producing wells.

At the producing wells—and there may be three, four, or more producers per injection well—oil and water is pumped to the surface, where it flows to a centralized collection facility. The pattern of injectors and producers, which can change over time, will typically be determined based on computer simulations that model the reservoir’s behavior based on different design scenarios. A well manifold allows for individual wells to be tested to see how much oil, gas, and water is being produced at each location and if the concentration of oil is increasing as the oil bank reaches the producing wells.

The produced fluids are separated and the produced gas stream, which may include amounts of CO₂ as the injected gas begins to break through at producing well locations, must be further processed. Any produced CO₂ is separated from the produced natural gas and recompressed for reinjection along with additional volumes of newly-purchased CO₂. In some situations, separated produced water is treated and re-injected, often alternating with CO₂ injection, to improve sweep efficiency (the WAG process mentioned earlier).

Waterflooding and Residual Oil

When an oil reservoir is first produced, the pressure that exists in the subsurface provides the energy for moving the oil, gas and water that is in the rock to the surface. After a while, the pressure dissipates and pumps must be used to remove additional volumes of oil. Depending on the characteristics of the rock and the oil, a considerable amount of the original oil in place may be left behind (perhaps 60 percent or more) as residual oil. Waterflooding is a process whereby water is pumped down selected wells to push a portion of the remaining oil out of the rock towards the producing wells. In most cases, CO₂ enhanced recovery operations take place in oil reservoirs where this less expensive waterflooding option has already been implemented, although the remaining oil saturation in the post-waterflood reservoir is still significant, perhaps 50 percent of the original oil in place.
In WAG injection, water/CO\(_2\) injection ratios have ranged from 0.5 to 4.0 volumes of water per volume of CO\(_2\) at reservoir conditions. The sizes of the alternate slugs range from 0.1 percent to 2 percent of the reservoir pore volume. Cumulative injected CO\(_2\) volumes vary, but typically range between 15 and 30 percent of the hydrocarbon pore volume of the reservoir. Historically, the focus in CO\(_2\) EOR is to minimize the amount of CO\(_2\) that must be injected per incremental barrel of oil recovered, especially due to the high cost of CO\(_2\) injection. However, if carbon storage becomes a driver for CO\(_2\) EOR projects, the economics may begin to favor injecting larger volumes of CO\(_2\) per barrel of oil recovered, i.e., if the cost of the CO\(_2\) is low enough.
How Much Extra Oil Gets Produced

The production plot shown below illustrates how a field can respond to \( \text{CO}_2 \) injection. This example, for Shell Oil’s Denver Unit in the Wasson Field in West Texas, shows oil and water production, and water and \( \text{CO}_2 \) injection, over sixty years. The primary production portion of the field’s life lasted from 1938 through about 1965. The oil production rate peaked in the mid-1940s and then began to decline as reservoir pressure depleted. The operator initiated pressure maintenance with water injection (waterflooding) in 1965 and oil production rates responded quickly.

As the injected water began to break through at the production wells, the volume of water produced also rose rapidly in the 1970s. By the end of 1982, the volumes of water injected and produced were considerably more than the volume of oil produced. About two years after the operator initiated \( \text{CO}_2 \) injection in 1983, the oil production decline began to slow and eventually leveled off. At the end of 1998, one could determine the incremental oil attributable to \( \text{CO}_2 \) EOR by calculating the cumulative difference between the projected decline rate without \( \text{CO}_2 \) injection and the actual production rate.

In this example, the volumes of oil produced are significant because the Denver Unit flood is large, with more than 2 billion barrels of oil originally in place (OOIP) and a residual oil saturation after waterflooding of 40 percent. The typical well pattern is ten producing wells for every three injectors. Currently, the Denver Unit produces about 31,500 barrels of oil per day, of which 26,850 are incremental barrels of oil attributable to the \( \text{CO}_2 \) flood. The Wasson Field’s Denver Unit \( \text{CO}_2 \) EOR project has resulted in more than 120 million incremental barrels of oil thru 2008.
Where It's Being Done

The United States leads the world in both the number of CO₂ EOR projects and in the volume of CO₂ EOR oil production, in large part because of favorable geology. The Permian Basin, covering West Texas and southeastern New Mexico, has the lion’s share of the world’s CO₂ EOR activity for two reasons: reservoirs there are particularly amenable to CO₂ flooding, and large natural sources of high purity CO₂ are relatively close. However, a growing number of CO₂ EOR projects are being launched in other regions, based on the availability of low cost CO₂.

Screening Reservoirs for CO₂ EOR

What kinds of reservoirs are most suitable for CO₂ EOR? In theory, any type of oil reservoir, carbonate or sandstone, could be suitable provided that the minimum miscibility pressure can be reached, there is a substantial volume of residual crude oil remaining, and the ability of the CO₂ to contact the crude oil is not hindered by geological complexity. Typically, a reservoir that has undergone a successful waterflood is a prime candidate for a CO₂ flood.

Most of the large reservoirs in the Permian Basin, Depiction of reservoir model used for simulation of CO₂ flooding are carbonate formations—typically limestone or dolomite—that produce from depths of 3,000 to 7,000 feet, and have undergone extensive waterflooding. Post-waterflood recovery could be 30 to 45 percent of the OOIP, with relatively high residual oil saturation. A successful CO₂ EOR project could add another 5 to 15 percent of OOIP to the ultimate recovery.

In addition, the Permian Basin reservoirs tend to feature a low geothermal gradient (i.e., rate of increase in temperature with depth), which makes the pressure required for CO₂ miscibility with the crude oil lower. Geologically, these reservoirs also exhibit a high degree of continuity between wells, with rock that is laterally and vertically uniform, and has relatively high permeability.

Operators interested in enhancing recovery through CO₂ EOR will screen their reservoirs to determine the best candidates based on rock and fluid characteristics, past production behavior and response to waterflooding, and detailed geological assessments. The screening criteria used to identify favorable reservoirs are reservoir depth, oil gravity, reservoir pressure, reservoir temperature, and oil viscosity. A number of analysts have developed ranges for these screening criteria (see table), which operators can use to high-grade their reservoirs for further detailed technical and economic assessments. Perhaps the most critical factor for selecting candidates for CO₂ EOR is a growing consensus among experts that more detailed geophysical mapping of the remaining oil in a reservoir is needed, particularly in geologically heterogeneous formations.

In the 1980s the Department of Energy (DOE) helped develop software screening tools designed to quickly identify how key variables might influence CO₂ project performance and economics prior to performing a detailed numerical simulation. One such tool, CO₂-Prophet, was developed by DOE and Texaco. A number of other commercial screening tools are now available.

<table>
<thead>
<tr>
<th>Criteria for Screening Reservoirs for CO₂ EOR Suitability</th>
</tr>
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<tbody>
<tr>
<td>Depth, ft</td>
</tr>
<tr>
<td>Temperature, °F</td>
</tr>
<tr>
<td>Pressure, psia</td>
</tr>
<tr>
<td>Permeability, md</td>
</tr>
<tr>
<td>Oil gravity, °API</td>
</tr>
<tr>
<td>Viscosity, cp</td>
</tr>
<tr>
<td>Residual oil saturation after waterflood, fraction of pore space</td>
</tr>
</tbody>
</table>
CO$_2$ Availability

Although the large Permian Basin reservoirs were readily recognized as ideal candidates for miscible flooding through CO$_2$ injection, it was the ready availability of a low-cost source of CO$_2$ that drove the Permian Basin’s EOR boom in the 1970s and 1980s. The first commercial flood occurred in Scurry County, Texas, in 1972, in what was known as the SACROC Unit (SACROC stands for Scurry Area Canyon Reef Operators Committee). For this project, the operator (Chevron) recovered CO$_2$ from natural gas processing plants in the southern part of the basin (that would have otherwise been vented) and transported the gas 220 miles for injection at SACROC.

The technical success of this project, coupled with the high oil prices of the late 1970s and early 1980s, led to the construction of three major CO$_2$ pipelines connecting the Permian Basin oil fields with natural underground CO$_2$ sources located at the Sheep Mountain and McElmo Dome sites in Colorado and Bravo Dome in northeastern New Mexico (see map). Construction of the pipelines spurred an acceleration of CO$_2$ injection activity in Permian Basin fields. Today, operators inject more than 1.6 billion cubic feet per day of naturally-sourced CO$_2$ into Permian Basin oil fields to produce 170,000 barrels of incremental oil per day from dozens of fields.

North American CO$_2$ EOR operations and CO$_2$ sources.
(Source: Advanced Resources International, Inc., based on Oil & Gas Journal, 2012 and other sources.)
But even with CO₂ sources just a few hundred miles away, the cost of delivering and injecting the CO₂ is significant. Industry has spent more than $1 billion on 2,200 miles of CO₂ transmission and distribution pipeline infrastructure in support of CO₂ flooding in the Permian Basin. Typically, it costs $0.25-0.75 per thousand cubic feet to transport CO₂ to West Texas fields from the sources to the north. With a substantial CO₂ pipeline and distribution infrastructure in place, Permian Basin operators have spread the costs among several large fields, and the infrastructure in these “anchor” fields in turn has helped reduce the cost of delivered CO₂ to smaller fields in the basin. Still, analysts have estimated that there is as much as 500 million cubic feet (25,974 metric tons) per day of pent-up demand for CO₂ in the basin from oil field operators seeking to implement economic CO₂ EOR projects. Additional natural CO₂ resource has been discovered in the Arizona-New Mexico region and may be developed if the economics remain favorable.

To the east, Denbury Resources, a Plano, Texas-based independent, is developing a similar infrastructure in Mississippi, Louisiana, and southeastern Texas. Denbury owns a large natural CO₂ resource at Jackson Dome, Mississippi, which it describes as the largest CO₂ resource east of the Mississippi River. Jackson Dome already feeds CO₂ to EOR projects Denbury operates in Mississippi and Louisiana. Denbury plans to build a major extension from the southern terminus of its existing CO₂ pipeline in Louisiana to deliver CO₂ for injection at the Hastings Field in Texas. The company is also negotiating with industrial plants along the pipeline route, including four proposed gasification plants fed by coal or petroleum coke, to secure additional supplies of captured anthropogenic (man-made) CO₂ for EOR projects in all three states.

**Anthropogenic CO₂ Sources**

Much discussion has centered on methods to reduce or eliminate CO₂ emissions from industrial sources due to concerns over CO₂ as a “greenhouse” gas. Prominent in this discussion are concepts to capture and safely and permanently store anthropogenic CO₂ in underground formations, a process known as carbon storage. In CO₂ EOR projects, all of the injected CO₂ either remains sequestered underground or is produced and re-injected in a subsequent project, making the notion of using captured anthropogenic CO₂ for EOR in places far removed from natural sources of CO₂ a likely possibility. Companies have already launched several examples of this approach.

For years, ExxonMobil Corp. has sold CO₂ from its La Barge, Wyoming gas processing facility to area oil producers for use in CO₂ EOR projects (see map). The company currently captures 4 million metric tons of CO₂ per year for this purpose.

Another major CO₂ EOR project, the IEAGHG Weyburn-Midale CO₂ Monitoring and Storage Project in the Williston Basin reservoir, used industrially sourced CO₂ at the Weyburn oil field, just across the U.S. border in Saskatchewan, Canada. Encana Corp., a Canadian company, pumped about 95 million cubic feet (4,935 metric tons) per day of CO₂ into Weyburn, a 55-year-old field, to recover an incremental 130 million barrels of oil via miscible or near-miscible displacement. The CO₂ was sourced from the lignite-fired Dakota Gasification Company synthetic fuels plant in North Dakota, and delivered via a 205-mile pipeline. Encana estimates that as much as 585 billion cubic feet (30 million metric tons) of CO₂ was permanently sequestered underground through the project, which ran from 2000 to 2011, while the synfuels plant’s revenues rose by about $30 million per year and the Weyburn field’s life was extended by 20 to 25 years.

Other industrially sourced CO₂ EOR projects are in the works as well. Independent producers Sandridge Energy Inc. and Occidental Petroleum Corp. are developing a $1.1 billion natural gas processing plant in West Texas that will capture about 265 billion cubic feet (13.5 million metric tons) of CO₂ per year for use in CO₂ EOR operations. Additional proposals to capture CO₂ from coal-fired power plants, ethanol plants, and other industrial processes and use it to supply EOR projects, are being considered for funding in a number of states.

### Conversions

<table>
<thead>
<tr>
<th>Metric</th>
<th>Conversion</th>
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<tbody>
<tr>
<td>1 metric ton of CO₂</td>
<td>equals 545 cubic meters at standard conditions of 14.7 psi and 70 °F</td>
</tr>
<tr>
<td>1 metric ton of CO₂</td>
<td>equals 19.25 thousand cubic feet (Mcf) at standard conditions of 14.7 psi and 70 °F</td>
</tr>
</tbody>
</table>

The average American car emits about seven metric tons of CO₂ per year.
### U.S. CO₂ EOR Demographics

CO₂ EOR production has jumped significantly since the early 1980s. At the same time, the demographics of CO₂ EOR operators have changed.

Prior to the early 1990s, almost all CO₂ injection was undertaken by a small group of major oil companies—Amerada Hess, Amoco, ARCO, Chevron, Exxon, Mobil, Shell, and Texaco. A proactive technology transfer program led by DOE’s National Energy Technology Laboratory in the 1990s helped to transfer their CO₂ development concepts to the rest of the industry. That effort, together with a shift in major company investment overseas, led to the current situation where independent producers dominate the roster of CO₂ EOR operators (see table).

The SACROC Unit, where commercial CO₂ EOR got its start, is now in the hands of an independent. Kinder Morgan CO₂ Company, which is the second largest producer of oil in Texas and one of the nation’s largest owners and transporters of CO₂, has more than tripled SACROC production since acquiring a majority interest in the unit in 2000.

One of the most active CO₂ EOR operators is another independent producer, Occidental Petroleum (Oxy). Oxy operates more than half of the current CO₂ floods in the Permian Basin and is one of the dominant producers of CO₂ EOR oil, and the largest oil producer in Texas.

### Major U.S. CO₂ EOR Projects

<table>
<thead>
<tr>
<th>Project</th>
<th>Operator</th>
<th>Location</th>
<th>CO₂ Source</th>
<th>Size Mt/yr CO₂ Sink</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Denver Unit</td>
<td>Occidental Petroleum</td>
<td>Texas</td>
<td>Permian CO₂ Pipeline</td>
<td>1.1 EOR</td>
<td>Operational 1983</td>
</tr>
<tr>
<td>La Barge</td>
<td>ExxonMobil</td>
<td>Wyoming</td>
<td>Gas Processing</td>
<td>7 EOR</td>
<td>Operational 1986</td>
</tr>
<tr>
<td>Enid</td>
<td>Koch Nitrogen Company</td>
<td>Oklahoma</td>
<td>Fertilizer Production</td>
<td>0.68 EOR</td>
<td>Operational 1982</td>
</tr>
<tr>
<td>Val Verde</td>
<td>Multiple operators</td>
<td>Texas</td>
<td>Gas Processing</td>
<td>1.3 EOR</td>
<td>Operational 1998</td>
</tr>
<tr>
<td>Weyburn-Middale</td>
<td>Cenovus Energy &amp; Apache Canada</td>
<td>US/Canada</td>
<td>Coal Gasification</td>
<td>1 EOR</td>
<td>Operational 2000</td>
</tr>
<tr>
<td>Century Plant</td>
<td>Occidental Petroleum</td>
<td>Texas</td>
<td>Gas Processing</td>
<td>8.4 EOR</td>
<td>Operational 2010</td>
</tr>
<tr>
<td>Coffeyville</td>
<td>CVR Energy</td>
<td>Kansas</td>
<td>Fertilizer Processing</td>
<td>0.8 EOR</td>
<td>Operational 2013</td>
</tr>
<tr>
<td>Lost Cabin</td>
<td>ConocoPhillips</td>
<td>Wyoming</td>
<td>Gas Processing</td>
<td>0.9 EOR</td>
<td>Operational 2013</td>
</tr>
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</table>
CO₂ EOR Economics

Implementing a CO₂ EOR project is a capital-intensive undertaking. It involves drilling or reworking wells to serve as both injectors and producers, installing a CO₂ recycle plant and corrosion-resistant field production infrastructure, and laying CO₂ gathering and transportation pipelines. Generally, however, the single largest project cost is the purchase of CO₂. As such, operators strive to optimize and reduce the cost of its purchase and injection wherever possible.

Higher oil prices in recent years have significantly improved the economics of CO₂ EOR. However, oil field costs have also increased sharply, reducing the economic margin essential for justifying this oil recovery option to operators who still see it as bearing significant risk. Both capital and operating costs for an EOR project can vary over a range, and the value of CO₂ behaves as a commodity, priced at pressure, pipeline quality, and accessibility, so it is important for an operator to understand how these factors might change. Total CO₂ costs (both purchase price and recycle costs) can amount to 25 to 50 percent of the cost per barrel of oil produced. In addition to the high up-front capital costs of a CO₂ supply/injection/recycling scheme, the initial CO₂ injection volume must be purchased well in advance of the onset of incremental production. Hence, the return on investment for CO₂ EOR tends to be low, with a gradual, long-term payout.

Given the significant front-end investment in wells, recycle equipment, and CO₂, the time delay in achieving an incremental oil production response, and the potential risk of unexpected geologic heterogeneity significantly reducing the expected response, CO₂ EOR is still considered to be a risky investment by many operators, particularly in areas and reservoirs where it has not been implemented previously. Oil reservoirs with higher capital cost requirements and less favorable ratios of CO₂-injected-to-incremental-oil-produced will not achieve an economically justifiable return on investment without advanced, high-efficiency CO₂ EOR technology and/or fiscal/tax incentives for storing CO₂.

A 2008 study by INTEK for DOE sought to test the economics of a potential linkage between the most likely candidate CO₂ EOR reservoirs and their most likely matching industrial CO₂ sources. The study concluded that as much as 30 trillion cubic feet of CO₂—or 5 billion cubic feet per day at peak rates of injection—could ultimately be stored under this scenario, with a resulting incremental increase in U.S. oil production of 5.5 billion barrels over 25 years.

<table>
<thead>
<tr>
<th>Illustrative Costs and Economics of a CO₂ EOR Project</th>
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<tbody>
<tr>
<td><strong>Oil Price ($/Barrel)</strong></td>
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<tr>
<td><strong>Gravity/Basis Differentials, Royalties and</strong></td>
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<tr>
<td><strong>Production Taxes</strong></td>
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<tr>
<td><strong>Net Wellhead Revenues ($/Barrel)</strong></td>
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<tr>
<td><strong>Capital Cost Amortization</strong></td>
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<tr>
<td><strong>CO₂ Costs (@ $2/Mcf for purchase; $0.70/Mcf for</strong></td>
</tr>
<tr>
<td><strong>recycle)</strong></td>
</tr>
<tr>
<td><strong>Well/Lease Operations and Maintenance</strong></td>
</tr>
<tr>
<td><strong>Economic Margin, Pre-Tax ($/Barrel)</strong></td>
</tr>
</tbody>
</table>
Its Future Potential

Another study carried out by Advanced Resources International (ARI) for DOE-NETL concluded that CO₂ EOR could provide a large, value-added market for the sale of CO₂ emissions from new coal-fired power plants—about 7.5 billion metric tons between now and 2030. It puts the value of that market at $260 billion.

Sales of captured CO₂ emissions would help defray some of the costs of installing and operating CCS technology. These sales, in turn, could support early market entry of as many as 49 one-gigawatt installations of CCS technology in the coal-fired power sector, according to the ARI study.

At the same time, concluded ARI, the ensuing CO₂ EOR boom would unlock an additional 39-48 billion barrels of oil prior to 2030, while building a CO₂ transportation infrastructure suitable for subsequent transport of CO₂ for sequestration in deep saline formations—which are likely to have the biggest ultimate CO₂ storage potential of all underground options. The synergies between CO₂ EOR and CO₂ sequestration may be strong enough to help both efforts happen faster. And there are clear energy, environmental, and economic benefits for America in that kind of future.

A 2009 study by ARI for DOE assessed the role that “best practices” CO₂ EOR technologies could play in U.S. oil recovery. The study noted that introducing “best practices” technology to regions where it is currently not yet applied; lowering risks by conducting research, pilot tests, and field demonstrations in...
geologically challenging fields; providing state production tax incentives, federal investment tax credits, and royalty relief; and establishing low-cost, reliable CO₂ supplies could result in an additional 85 billion barrels of technically recoverable oil from the 400 billion barrels of oil remaining in large reservoirs across 11 basins.

**Tax Incentives**

It is important to recognize that much of the CO₂ EOR development that has occurred in the U.S. might not have happened (or might not have happened as quickly) without the introduction of tax credits and other fiscal incentives to help offset the large financial risks. As a means to help boost domestic oil production, the federal tax code has had some sort of incentive for tertiary recovery since 1979, when crude oil was still under federal price controls. Incentives were codified with the U.S. Federal EOR Tax Incentive in 1986, and subsequently, CO₂ EOR production grew rapidly. This incentive is a 15 percent tax credit that applies to all costs associated with installing a CO₂ flood, the purchase cost of CO₂, and CO₂ injection costs.

In addition, eight states have introduced some form of tertiary oil production tax incentives related to the value of the incremental oil produced. Texas, which produces more than 80 percent of all U.S. CO₂ EOR oil, provides a severance tax exemption on all the oil produced from a CO₂-flooded reservoir.

**CO₂ EOR and Storage**

Beyond its potential to augment U.S. oil production, CO₂ EOR is getting intensive scrutiny by industry, government, and environmental organizations for its potential for permanently storing CO₂. The thinking goes that CO₂ EOR can add value by maximizing oil recovery while at the same time offering a bridge to a reduced carbon emissions future. CO₂ EOR effectively reduces the cost of storing CO₂ by earning revenues for the CO₂ emitter from sales of CO₂ to oil producers.

Many experts look to geologic storage as one of the best alternatives for dealing with carbon emissions. The CO₂ EOR industry is an industry with a proven track record of safely injecting CO₂ into geologic formations. EOR operations account for 9 million metric tons of carbon, equivalent to about 80 percent of the industrial use of CO₂, every year. Although about 20 percent of CO₂ used in EOR comes from natural gas processing plants, the majority used for EOR comes from natural underground sources and does not represent a net reduction in CO₂ emissions. However, industrial CCS offers the potential to significantly alter this situation.

Because of the cost of naturally sourced CO₂—roughly $10-15 per metric ton—a CO₂ flood operator seeks to recycle as much as possible to minimize future purchases of the gas. All of the injected CO₂ is retained within the subsurface formation after a project has ended or recycled to subsequent projects. After years
of experience with CO₂ floods, oil and gas operators are confident that the CO₂ left in the ground when oil production ends and wells are shut in will stay permanently stored there, assuming the wells are properly plugged and abandoned.

One major oil industry operation that provides an example of such permanence is StatoilHydro’s Sleipner CO₂ project in the North Sea off Norway. The company is developing a large gas field and must strip out CO₂ from the produced gas stream that is about 9 percent CO₂ by volume. Norway’s imposition of a tax on emitted carbon of $200 per metric ton—later reduced to $140 per metric ton—led StatoilHydro to compress the captured CO₂ and inject it into a deep saltwater formation below the seabed. The project, initiated in 1996, required an $80 million investment but has resulted in a tax savings of $55 million per year. Regular monitoring of the subsurface shows that the formation is retaining the injected CO₂.

CO₂ EOR technology and equipment needs parallel those envisioned for carbon storage, with similar surface infrastructure and wells, similar handling of supercritical (high pressure/low temperature) CO₂, and comparable subsurface simulation and characterization tools (well logs, three-dimensional [3-D] seismic, petrophysical analysis, etc.). The biggest differences between the two are intent (minimizing CO₂ use in EOR vs. maximizing it for storage) and regulatory concerns (monitoring, verification, and accounting of the CO₂ over the very long term).

**Storage Potential in Oil Reservoirs**

What is the potential for storage of CO₂ from EOR operations? The total volume of CO₂ consumed by U.S. CO₂ EOR to date has been about 11 trillion cubic feet (560 million metric tons). That pales in comparison with total U.S. CO₂ emissions from industrial sources alone of about 100 trillion cubic feet (5,090 million metric tons) per year. However, that does not mean that the potential demand for CO₂ for EOR will be insignificant; EOR could be an enabling catalyst for larger scale carbon storage efforts.

For example, a study by Montana Tech University found that CO₂ flooding of Montana’s Elm Coulee and Cedar Creek oil fields could result in the recovery of 666 million barrels of incremental oil and the storage of 2.1 trillion cubic feet (109 million metric tons) of CO₂. All of the CO₂ required for the flood could be supplied by a nearby coal-fired power plant, and would equate to 7 years of the plant’s CO₂ emissions. Furthermore, installation of a pipeline and CO₂ capture equipment for the project could provide the basic infrastructure for subsequent storage of CO₂ in other oil fields and in saline formations and unmineable coal seams elsewhere in the state.

A comparison of two maps in the National Energy Technology Laboratory’s Carbon Storage Atlas of the United States and Canada shows considerable overlap of the respective regional capacities for CO₂ storage in oil and natural gas fields and the major sources of CO₂ emissions.
Untapped Domestic Energy Supply and Long Term Carbon Storage Solution

North American oil field distribution and calculated capacities

North American CO$_2$ source distribution

What DOE is Doing

The need for federal investment in scientific data collection and technology development in enhanced oil recovery is driven by the following facts:

• While enhanced oil recovery has been successfully applied in some areas where circumstances are favorable (e.g., Permian Basin), in many other areas perceived risk keeps it just beyond reach. The development and demonstration of new EOR technologies and new ways to apply existing EOR technologies can help to accelerate its application.

• In mature fields that are the targets of EOR, small producers face challenges that are unique to their situation—low productivity wells, high water cuts, aging infrastructure and tight regulatory constraints. These operations are often low margin and are not targeted by the larger service companies’ R&D efforts.

• NETL has created a portfolio that is balanced and responsive to the issues facing operators. The data, technologies, and tools developed through this portfolio will help industry make decisions and optimize operations in ways that will advance the goal of environmentally sustainable CO$_2$ EOR.

• The Department of Energy’s Petroleum R&D Program aims to reduce the technology and cost barriers to increasing recovery from mature conventional oil reservoirs. There is also a significant effort targeting unconventional oil resources such as extra heavy oil, oil and tar sands, oil shale, and oil in unconventional reservoirs (like the fractured Bakken Shale of North Dakota).

• Economic extraction of these resources will require research to provide for a better understanding of the geologic nature of these reservoirs as well as new technologies for cost-effectively producing the oil. Yet the operators that are largely responsible for onshore domestic oil production are for the most part independent producers who do not invest in R&D.

To address these challenges and meet it’s goal of increased economic development of incremental reserves, particularly through the use of CO$_2$ EOR, NETL has created a substantial research portfolio focused on:

• Demonstration of CO$_2$ EOR technologies and results through the Regional Carbon Sequestration Partnership Initiative that created seven regional projects to demonstrate CO$_2$ EOR technologies in various geological settings.

• Funding of CO$_2$ EOR research projects at six U.S. universities to improve understanding of CO$_2$ EOR resources and develop technologies to exploit them.
Regional Carbon Sequestration Partnerships

DOE’s Regional Carbon Sequestration Partnership (RCSP) Initiative is the world’s most comprehensive field program dedicated to the assessment and validation of carbon storage technologies in saline formations, oil fields and coals seams. DOE has been leading the efforts of the RCSPs to identify the volumes of carbon dioxide that could be stored in oil fields throughout the United States and Canada.

The RCSPs are carrying out DOE-funded R&D field projects designed to validate and develop the potential for CCS within their respective areas. A number of these projects combine CO₂ storage with EOR. Four EOR field projects are being supported throughout the United States. Three of the projects have completed injection operations while one is currently injecting with plans to complete injection and post-injection monitoring by the end of 2018.

NETL is investigating the potential for recovering incremental oil from the Citronelle Field in Alabama using CO₂ EOR. The first stage is developing an improved understanding of the geology using state-of-the-art interpretation techniques. Fields like Citronelle can demonstrate the potential for recovering domestic oil using carbon dioxide captured from industrial sources.

R&D Objective (Performer)

- Evaluate and enhance CO₂ flooding through sweep improvement (Louisiana State).
- Improve CO₂ flooding sweep using CO₂ gels (SBIR-RTA Systems Inc.).
- Conduct CO₂ injection tests in the Citronelle oilfield in Mobile County, AL, to improve the reliability of computer simulations of oil yield from CO₂ EOR and calculations of storage capacity (University of Alabama at Birmingham).
- Determine the economic and technical feasibility of using CO₂ miscible flooding to recover oil in a Lansing-Kansas City formation oilfield in central Kansas (University of Kansas).
- Employ molecular modeling and experiments to design inexpensive, environmentally benign, CO₂-soluble compounds that can decrease the mobility of CO₂ at reservoir conditions (University of Pittsburgh).
- Develop a neural network model for CO₂ EOR (University of Louisiana at Lafayette).
- Develop a novel, low cost method to install geophones for CO₂ monitoring (SBIR-Impact Technologies).
## Current or Final Injection Volumes for Each Phase III Partnership Project

<table>
<thead>
<tr>
<th>Project Name</th>
<th>RCSP</th>
<th>Project Type</th>
<th>Injection Formation(s) (Reservoir)</th>
<th>CO$_2$ Injected (Metric Tons)</th>
<th>CO$_2$ Stored (Metric Tons)</th>
<th>Recorded Date for Injection Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>Development Phase Large Scale Field Project¹</td>
<td>MRCSP</td>
<td>EOR</td>
<td>Niagara Pinnacle Reefs (Shallow Shelf Restricted)</td>
<td>1,519,090</td>
<td>596,282</td>
<td>09/30/2016</td>
</tr>
<tr>
<td>Cranfield Site “Early Test”¹</td>
<td>SECARB</td>
<td>EOR/Saline</td>
<td>Lower Tuscaloosa (Fluvial Deltaic)</td>
<td>4,743,898</td>
<td>4,743,898</td>
<td>Final injected amount</td>
</tr>
<tr>
<td>Farnsworth Unit EOR Field Project²</td>
<td>SWP</td>
<td>EOR</td>
<td>Morrow Sandstone (Fluvial Deltaic)</td>
<td>927,235</td>
<td>490,720</td>
<td>09/30/2016</td>
</tr>
<tr>
<td>Bell Creek Demonstration Site³</td>
<td>PCOR</td>
<td>EOR</td>
<td>Muddy (Fluvial Deltaic)</td>
<td>4,863,587</td>
<td>2,982,000</td>
<td>Final injected amount</td>
</tr>
<tr>
<td>Fort Nelson Demonstration²¹</td>
<td>PCOR</td>
<td>Saline</td>
<td>Elk Point Group (Carbonate Barrier Reef)</td>
<td>0</td>
<td>0</td>
<td>N/A – no injection to date.</td>
</tr>
<tr>
<td><strong>All Sites</strong></td>
<td></td>
<td></td>
<td></td>
<td><strong>12,053,081</strong></td>
<td><strong>8,812,900</strong></td>
<td></td>
</tr>
</tbody>
</table>

¹ Late stage reefs (Category 1): 271,144 injected, 364,365 stored; 
² Active EOR reefs (Category 2): 1,247,946 injected; 331,917 stored; Early stage reefs (Category 3): No injection

² Injected amount includes 530,700 tons purchased + 396,535 tons recycled

³ Volumes injected and stored after 03/31/2016 are not counted toward totals for DOE project

⁴ Injection has not yet been initiated. The project seeks to inject 1,000,000 metric tons of CO$_2$. 
DOE Funded CO₂ EOR Research

**BELL CREEK FIELD PROJECT**

Beginning in 2010, characterization efforts began to better understand the associated CO₂ storage at the Bell Creek Field. The target injection horizon in the Field is an oil-bearing sandstone reservoir in the Muddy Formation at a depth of about 4,500 feet. One of the project goals was to demonstrate that CO₂ storage can be safely and permanently achieved on a commercial scale in association with an enhanced oil recovery operation and that oil-bearing sandstone formations are viable regional storage formations for CO₂. Another goal of the project was to show that monitoring, verification, accounting (MVA) and assessment methods can be used to effectively monitor CO₂ storage in association with commercial-scale CO₂ EOR projects.

The Bell Creek project began CO₂ injection in May 2013. The CO₂ is transported to the site via pipeline from the Lost Cabin and Shute Creek gas processing plants in Wyoming, where it is separated from the process stream during natural gas refinement. The CO₂ is delivered at a target rate of more than 50 million cubic feet per day to the Bell Creek oil field and injected into the oil-bearing zone of the Muddy Formation. Injection is occurring in a staged approach with nine planned developmental phases, injection is currently underway in phases 1–4. The reservoir is suitable for miscible flooding conditions and is expected to meet the incremental oil production target of 40 to 50 million barrels.

A robust and iterative site characterization program was initiated in 2010 to provide data necessary to establish baseline reservoir characteristics and modeling and simulation activities. Characterization activities continue to provide a solid foundation for other critical elements of the Bell Creek project like risk assessment, modeling and simulation and MVA that create an increased confidence in predicting and tracking CO₂ movement.

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**Project Highlights**

- Injection of CO₂ began in May 2013. As of August 2015, over 2,980,000 cumulative metrics tons of CO₂ have been stored.

- A pulsed-neutron logging campaign was completed at the project site. This survey was conducted as part of an overall MVA strategy to demonstrate and validate more technologies based on site-specific technical risks, to better understand sweep efficiency, effective storage capacity, and vertical and lateral flow boundaries in the Bell Creek Field.

- A 40-mi², 3-D seismic survey was collected in August 2012 to aid in structural interpretation and to provide a baseline data set for future time-lapse CO₂ monitoring. A repeat 3-D seismic survey was collected in 2014.
Untapped Domestic Energy Supply and Long Term Carbon Storage Solution

Cranfield Project

The Cranfield Project is located approximately 12 miles east of Natchez, Mississippi. Denbury Onshore, LLC, is currently operating a commercial CO₂ flood of the field (using the subsurface injection of CO₂ for EOR). The SECARB Cranfield team characterized the surface and subsurface of the Cranfield site. Numerical models were developed and used to quantify the response of the reservoir to injection and migration of fluids. Monitoring was used to validate the conceptual and quantitative predictions made in the models and to support project goals.

Normally, CO₂-EOR operations occur in active fields that are in the late stages of water flood, but the wells at the Cranfield site had been abandoned for over 40 years. This project demonstrates the value of using old oil fields for storage, and highlights their immense research value.

SECARB’s study operations occur in four integrated research program areas within Cranfield field: (1) the High Volume Injection Test area (HiVIT); (2) the Detailed Area of Study (DAS); (3) the Geomechanical area; and (4) the near-surface observatory, also called the “P-site.” Carbon dioxide injection activities occur at the HiVIT and the DAS. Carbon dioxide from Jackson Dome, a natural source, is delivered to the Cranfield oilfield via pipeline.

SECARB partners and researchers worldwide use the data collected at Cranfield to further refine reservoir models for similar geological settings.

Project Highlights

- SECARB injection into brine leg below and east of oil-water contact started in November 2009 and concluded field work on January 31, 2015. During that time, they successfully injected, stored, tracked, and monitored 4,743,898 metric tons of CO₂.

- Natural and introduced geochemical program with U-tube sampler was implemented to observe evolving flow field as plume matured and injection rate increased. Methane exsolved as a CO₂ dissolved, which is an important indicator of CO₂-brine contact and dissolution. CO₂ developed preferred non-radial flow paths following sinuous channels.

- Performed extensive simulations of the injection and history matched results with actual field data to produce best match simulations for oil production, water production, and gas production. Additionally, 4D seismic results were comparable to fluid flow simulation results.

- High frequency real-time observation well parameters were on-going for the duration of the project. Observations included bottom-hole pressure and temperature at the injection zone (before instrument failure), tubing pressure, and temperature at surface, casing pressure and temperatures, casing deployed bottom-hole pressure and temperature at the above-zone monitoring interval.

SECARB partners and researchers worldwide use the data collected at Cranfield to further refine reservoir models for similar geological settings.
FARNSWORTH UNIT PROJECT

The project targets an incised valley-fill coarse sandstone in the Anadarko Basin that produced more than 19 million barrels of oil and 44 billion cubic feet of gas. Preliminary estimates of CO₂ storage capacity of the Farnsworth Unit (FWU) exceed 25 million metric tons. The Farnsworth Unit has 13 active CO₂ injection wells. Three wells were drilled by the SWP that are dedicated to characterization and monitoring injected CO₂. The Farnsworth Unit project serves as a blueprint for future commercial-scale CCS projects.

The CO₂ injected is 100 percent anthropogenic. It is captured, compressed, and transported via pipelines from a fertilizer plant in Texas and an ethanol plant in Kansas. The SWP maintains a detailed inventory of the CO₂ delivered to and stored at the Farnsworth Unit for use as carbon offsets. Approximately 461,000 metric tons of anthropogenic CO₂ has been permanently stored in the subsurface—more than 1,000,000 metric tons will be injected by 2018.

Stakeholders are private industry, non-government organizations, the general public and government entities. Stakeholders are kept informed of the technical benefits of CCS, which include: increased resolution of reservoir characterization; direct and frequent sampling and fluid analyses; collection of core and detailed logging suites; petrophysical, geochemical and geomechanical core testing; and optimization of CCS methods through monitoring and simulation.

The project also provides educational excellent experience for students, including college level courses, internships with national laboratories, and hands-on fieldwork. SWP members participate at regional, national and international meetings and provide expertise and information to industry, trade associations, and other interested organizations.
Project Highlights

- Completed baseline geologic characterization and acquisition of monitoring data from the site. The effort included wireline logging, gravity meter logging, vertical seismic profiling, microseismic monitoring, remote sensing, and reservoir testing.

- Performed a gravity meter survey assessment at the early stage EOR site as part of an effort to model the site. Results predicted that the injection would provide a detectable gravity response in the northern/center portion of the reef but not in the southern portion.

- Performed five walk-away vertical seismic profiles at the injection well of the late stage EOR effort. Results indicate that the resolution is greater than surface seismic imaging.

**MICHIGAN BASIN PROJECT**

The large-scale CO₂ injection project is being carried out across oil-bearing pinnacle reefs in differing oil production life cycles, including early stage CO₂-EOR flood (two reefs), active CO₂-EOR (six reefs), and late stage (one reef). The CO₂-EOR operation in these nine reefs behaves as a closed-loop recycling system where produced CO₂ is compressed and dried, co-mingled with pure CO₂ from the natural gas processing facility, and re-injected back into the early stage and active reefs. The Michigan Basin Project encompasses 11 injection wells and 11 active producing wells.

Since monitoring operations began in February 2013, MRCSP has successfully injected and monitored the storage of more than 590,500 metric tons of new CO₂.

MVA technologies are collecting data before, during, and at the end of the active injection phase. The reservoir provides an ideal system to test the ability of MVA technologies to track and monitor CO₂ in the subsurface and improve understanding of using depleted hydrocarbon reservoirs for permanent CO₂ storage.

The MRSCP region has many large stationary CO₂ sources located in close proximity to geologic storage resources. Geologists from MRCSP member states are collaborating to define carbon storage formations suitable for existing and future sources of CO₂, collaborating with oil and gas drillers and operators to fill-in data gaps, and supporting industry in evaluating CO₂ storage options. The research will benefit the regional economy by helping to develop a robust and cost-effective means for reducing greenhouse gas emissions.
DOE-Funded CO₂ EOR Research and Development Projects

<table>
<thead>
<tr>
<th>Project Title</th>
<th>Development of Swelling-Rate-Controllable Particle Gels to Enhance CO₂ Flooding Sweep Efficiency and Storage Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Number</td>
<td>DE-FE0024558</td>
</tr>
<tr>
<td>Recipient</td>
<td>Missouri University of Science and Technology</td>
</tr>
<tr>
<td>Project Budget</td>
<td>Total: $1,240,396; DOE: $990,575; Recipient: $249,821</td>
</tr>
<tr>
<td>Project Duration</td>
<td>36 Months</td>
</tr>
<tr>
<td>Description</td>
<td>The objective of the project is to develop a novel environmentally-friendly and swelling rate controllable particle-based gel technology that can be used to enhance CO₂ sweep efficiency while improving CO₂ storage in oil reservoirs. These particle gels will have particle sizes ranging from nanometer to millimeter level. The project consists of the synthesis and evaluation of larger particles (micro-millimeter level) for filling in high permeability streaks, channels, or fractures, and of smaller particles (nanometer level) for plugging areas at an increased distance from the injection site. The recipients will also perform core-flooding experiments on multiple types of cores to understand the transport behavior and mechanisms of the particle gels in CO₂.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Project Title</th>
<th>Improved Characterization and Modeling of Tight Oil Formations for CO₂ Enhanced Oil Recovery Potential and Storage Capacity Estimation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Number</td>
<td>DE-FE0024454</td>
</tr>
<tr>
<td>Recipient</td>
<td>University of North Dakota</td>
</tr>
<tr>
<td>Project Budget</td>
<td>Total: $2,500,000; DOE: $2,000,000; Recipient: $500,000</td>
</tr>
<tr>
<td>Project Duration</td>
<td>36 Months</td>
</tr>
<tr>
<td>Description</td>
<td>The project is developing improved tools and techniques to assess and validate fluid flow in tight, fractured reservoirs resulting in an ability to better characterize and determine the storage capacity for CO₂ and EOR potential of tight oil formations. Specifically, the project is developing methods to better characterize fractures and pores at the macro-, micro-, and nanoscale levels, identifying potential correlations between fracture characteristics and other rock properties of tight oil formations, correlating core characterization data with well log data to better calibrate geocellular models, and evaluating CO₂ permeation and oil extraction rates and mechanisms.</td>
</tr>
</tbody>
</table>
## DOE-Funded CO₂ EOR Research and Development Projects (continued)

<table>
<thead>
<tr>
<th>Project Title</th>
<th>Identification of Residual Oil Zones (ROZs) in the Williston and Powder River Basins</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Number</td>
<td>DE-FE0024453</td>
</tr>
<tr>
<td>Recipient</td>
<td>University of North Dakota</td>
</tr>
<tr>
<td>Project Budget</td>
<td>Total: $6,505,998; DOE: $2,499,671; Recipient: $4,006,327</td>
</tr>
<tr>
<td>Project Duration</td>
<td>36 Months</td>
</tr>
<tr>
<td>Description</td>
<td>The project team will identify and evaluate ROZs in the Williston and Powder River Basins through comprehensive reservoir basin evolution modeling, simulation, temperature and saturation logging, and fairway mapping. The presence, extent, and oil saturation of ROZs in the Williston and Powder River Basins will be identified and the oil in place (OIP) and the CO₂ storage potential will be determined. The research has a strong potential to identify many ROZs in both basins that could promote further domestic oil production and encourage further CO₂ capture for utilization in recovering oil from these and other sedimentary basins.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Project Title</th>
<th>A Non-conventional CO₂ EOR Target in the Illinois Basin: Oil Reservoirs of the Thick Cypress Sandstone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Number</td>
<td>DE-FE0024431</td>
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<tr>
<td>Recipient</td>
<td>University of Illinois</td>
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<tr>
<td>Project Budget</td>
<td>Total: $2,737,670; DOE: $2,181,663; Recipient: $556,007</td>
</tr>
<tr>
<td>Project Duration</td>
<td>36 Months</td>
</tr>
<tr>
<td>Description</td>
<td>This research will undertake detailed geologic reservoir characterization to define CO₂ storage potential, residual oil saturation, and CO₂ EOR feasibility in oil reservoirs within the Cypress Sandstone of the Illinois Basin. Through careful reservoir characterization, geocellular modeling, and reservoir simulation based on actual reservoir parameters and formation fluid properties, methods for improved sweep and storage efficiency through injection will be developed. Cursory economics will be completed so that the relatively high storage component anticipated from these formations can be understood in terms of the magnitude of the CO₂ EOR.</td>
</tr>
</tbody>
</table>
DOE-Funded CO\textsubscript{2} EOR Research and Development Projects
(continued)

<table>
<thead>
<tr>
<th>Project Title</th>
<th>Optimize CO\textsubscript{2} Sweep based on Geochemical and Reservoir Characterization of the Residual Oil Zone of Hess Seminole Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Number</td>
<td>DE-FE0024375</td>
</tr>
<tr>
<td>Recipient</td>
<td>The University of Texas at Austin</td>
</tr>
<tr>
<td>Project Budget</td>
<td>Total: $1,820,611; DOE: $1,454,752; Recipient: $365,859</td>
</tr>
<tr>
<td>Project Duration</td>
<td>36 Months</td>
</tr>
<tr>
<td>Description</td>
<td>This project will perform a detailed characterization and produce a new reservoir model of the largest producing ROZ in the Permian Basin, Hess’s Seminole San Andres Unit, based on core logging, petrography, and stratigraphic correlation of facies using core and wireline logging results. The new ROZ model will be used to design sophisticated multiphase fluid flow simulations to test different injection strategies. The team will compare the cost effectiveness of using a range of different strategies (such as use of horizontal injector wells, strategies to modify the viscosity of CO\textsubscript{2} such as foam, and various strategies to alternate CO\textsubscript{2} and water during injection) to optimize both oil production and incidental CO\textsubscript{2} storage. Recommendations to optimize the sweep of CO\textsubscript{2} in the reservoir will be presented to the operator of the reservoir for potential future implementation and testing.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Project Title</th>
<th>Carbon Life Cycle Analysis of CO\textsubscript{2} EOR for Net Carbon Negative Oil (NCNO) Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Number</td>
<td>DE-FE0024433</td>
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<tr>
<td>Recipient</td>
<td>The University of Texas at Austin</td>
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<tr>
<td>Project Budget</td>
<td>Total: $1,049,868; DOE: $836,183; Recipient: $213,685</td>
</tr>
<tr>
<td>Project Duration</td>
<td>36 Months</td>
</tr>
<tr>
<td>Description</td>
<td>The objective of the project is to develop and apply a universal methodology for estimating the carbon balance of a CO\textsubscript{2} EOR operation and making the determination of whether the operation can be classified as NCNO. As the carbon balance of an EOR operation depends significantly on the volumes of CO\textsubscript{2} ultimately stored in the formation, the project team will consider multiple injection scenarios, such as direct CO\textsubscript{2} injection (DI) and water alternating gas (WAG). In addition, the researchers will consider energy intensive components of the operation not typically included in carbon life cycle analyses and similar studies, such as compression and fluid handling. The team has selected the Cranfield site in Mississippi (an active CO\textsubscript{2} EOR field) as the ideal case study field.</td>
</tr>
</tbody>
</table>
What’s Next?

The potential impact of CO₂ EOR is not so much a matter of whether but of when. The process works, there is plenty of residual oil in many reservoirs, and there is plenty of CO₂ available from a variety of sources. The speed with which CO₂ EOR is applied to recover the oil in U.S. oilfields will depend on economic decisions that in turn depend primarily on the:

- Price of oil
- Cost of capital (interest rates) and capital infrastructure construction (drilling, gas processing, pipelines)
- Cost of carbon emission taxes, or conversely, the value of carbon storage credits
- Cost of CO₂ capture from anthropogenic sources
- Pilot project results
- Speed of technology advancement and dissemination

These factors can be hard to predict. Nevertheless, as the regulatory picture begins to become clearer, more CO₂ EOR projects are likely to be implemented.

There is also an important public relations and regulatory aspect to the speed with which CO₂ flooding spreads beyond its current boundaries. Although the places CO₂ flooding will be applied are by definition places where oil has already been produced and people are familiar with oil production activities, in some of these areas the concept of CO₂ injection is not well understood. It is important that stakeholders (citizens, investors, regulators, landowners, elected representatives) understand the science behind CO₂ flooding, so that decisions can be made based on facts. Some potential stakeholder questions are listed below.

**Won’t the carbon dioxide be released when the oil is produced?**

No. Any CO₂ that is produced along with oil and natural gas is captured and re-injected. The company operating the EOR project bought the CO₂ and expects to re-inject it if any is produced to maximize its value. It only has value when it is used to remove oil from the rock formation underground, so there is a strong economic motivation to collect it for re-injection, either in the current project or another. When a CO₂ EOR flood is finished, the CO₂ that remains underground stays there. Monitoring efforts can be put into place to make sure that is true.
Won’t the carbon dioxide leak from underground and cause problems?

No, this is very unlikely. For well-selected, designed, and managed geological storage sites, experts calculate that the rock formations are likely to retain over 99 percent of the injected CO₂ for over 1,000 years. At the Weyburn Project in Weyburn, Saskatchewan, Canada, it has been determined that the likelihood of any CO₂ release is less than one percent in 5,000 years. There is a strong economic motivation for the operating company to fully understand the geology of the subsurface reservoir before it makes a multi-million dollar investment in infrastructure and pumps millions of dollars of CO₂ underground. The investors want to know where it is going more than anyone does.

What about the pipelines on the surface, can’t they leak?

Yes, any pipeline can leak. But just as with natural gas pipelines (which criss-cross the nation and are commonplace in practically every residential neighborhood), there is a strong economic (and regulatory) motivation for operators to keep them from leaking.

What about the old wells in an old oilfield; can’t they leak?

Yes, but again there is a strong economic (and regulatory) motivation to make sure that the casing in these wells is still strong, that it is well cemented in place, and that there is no opportunity for communication between the deep formation being flooded and any shallower formations at lower pressure. The loss of CO₂ to unintended places costs money and reduces the efficiency of the process. Every year, natural gas is reinjected at high pressure into gas storage fields around the country, particularly in northeastern states. These fields, many of which are located in populated areas, are developed in the same way that CO₂ projects are developed, by carefully checking old wells to prevent leakage, monitoring them after injection has begun, and repairing or replacing them if necessary.

But isn’t the carbon dioxide that is being injected “supercritical?” That sounds dangerous.

Supercritical is a term physicists use to define the physical state of a substance; it has no negative connotation. Carbon dioxide can exist as a gas (what you exhale with each breath), as a liquid (similar to the liquid nitrogen that you remember from science class experiments), and as a solid (the “dry ice” that you sometimes find keeping ice cream cold), depending on its temperature and pressure. At high pressure and low temperature—as a supercritical fluid—CO₂ has properties midway between a gas and a liquid. If the conditions changed to room temperature and pressure, the supercritical CO₂ fluid would shift to the gas phase and dissipate, just as dry ice does.
Can’t injecting carbon dioxide into the old oil fields cause earthquakes?

No. Oil companies have been injecting CO₂ in West Texas for decades and have not caused any earthquakes. Large volumes of water have been re-injected into oil fields all over the country without any evidence of the injection having caused earthquakes.

There are a number of places online where additional information can be obtained about CO₂ EOR and CO₂ storage.

Some useful links:

- National Energy Technology Laboratory (http://www.netl.doe.gov)
- Natural Resources Defense Council (http://www.nrdc.org/sites/default/files/eor.pdf)
- Kinder Morgan (http://www.kindermorgan.com/pages/business/co2/eor/)
- Oxy (http://www.oxy.com/Pages/default.aspx)
- Denbury Resources (http://www.denbury.com/)
- Enhanced Oil Recovery Institute (http://www.uwyo.edu/eori/)
Glossary

**API gravity** – Crude oil is commonly referred to in terms of its “API gravity,” a reference established by the American Petroleum Institute that relates the density of a crude to the density of water at standard conditions. The API scale inverts and increases the numerical value of specific gravity (e.g., oil with a specific gravity of 0.93 relative to water has an API gravity of 20, while an oil with a specific gravity of 0.83 has an API gravity of 40). A “light,” less dense crude with lighter weight hydrocarbons has a higher API number than a “heavy” crude oil. If a crude’s API gravity is less than 10, it is heavier than water and will not float. Mathematically API gravity has no units, but is referred to as “degrees API.”

**areal sweep** – Percentage of the total oil reservoir geographical area which is within the area being swept of oil by a displacing fluid, as in the case of a water flood or carbon dioxide flood. Combined with the vertical sweep, it provides a measure of the total volumetric sweep of the reservoir.

**carbonate rock** – Sedimentary rock formed primarily from calcium carbonate (CaCO₃) deposited in a marine environment; most commonly limestone. Many of the carbon dioxide floods found in the Permian Basin of West Texas are in oil reservoirs in carbonate formations deposited during the Permian Period.

**casing** – The tubular steel pipe that is used to line the wellbore as a well is drilled. Casing is cemented in place by pumping cement down the inside of the casing and up the annulus between the outside of the casing and the wall of the hole. It comes in a variety of diameters and as a well is drilled, smaller and smaller diameter strings of casing are placed concentrically into the well and cemented in place, forming a protective barrier between deep and shallow rock formations.

**density** – A measure of how much mass is contained in a unit volume of a substance. It can be expressed in kilograms per cubic meter, grams per cubic centimeter, pounds per gallon, or other units. Oil density expressed relative to that of water, and natural gas density expressed relative to that of air, at standard pressure and temperature conditions, is termed “oil specific gravity” and “gas specific gravity.”

API gravity = \(\frac{141.5}{SG} - 131.5\)
where \(SG\) = specific gravity at 60 °F

\(SG_{oil} = \frac{\text{density of oil}}{\text{density of water}}\)
**heterogeneous** – Consisting of dissimilar elements or parts; not homogeneous. Heterogeneous rock formations are not uniform in terms of their properties but instead vary widely both vertically and laterally. This variation can result in poor sweep efficiency as reservoirs are flooded with water or carbon dioxide, and less than optimal recovery of remaining oil.

**high water cut** – When an increasingly high percentage of the total fluid produced from a well is water rather than oil (perhaps as high as 99 percent or greater). This tends to be the case as water floods reach the end of their economic life.

**hydrocarbon pore volume** – The pore volume of a porous, sedimentary rock is that portion of a unit volume of the rock that is pore space rather than solid mineral constituents (often in the range of 10, 20 or 30 percent). The pore volume is naturally filled with fluids: water, oil and gas. The *hydrocarbon* pore volume is that portion that is filled with hydrocarbons, rather than water.

**interfacial tension** – A phenomenon at the surface separating two immiscible liquids caused by intermolecular forces. The tendency of an interface to contract in order to minimize the interfacial area leads to a state of tension. Reducing interfacial tension allows fluids to mix more intimately and can allow a displacing fluid to more effectively move a displaced fluid.

**light hydrocarbons** – Lower molecular weight hydrocarbons (fewer carbons). Methane (CH₄) is the lightest hydrocarbon. Other paraffinic series hydrocarbons (ethane, propane, butane, etc.) each successively have one additional carbon atom. High density (low gravity) crude oils typically contain molecules with many carbon atoms.

**manifold** – A system of pipes and valves that allow for the commingling and/or redirection of flowing fluids from many individual wells at a central production processing facility.

**metric ton** – Also referred to as a *tonne*, is a measurement of mass equal to 1,000 kg or 2204.6 pounds, or approximately the mass of one cubic meter of water. A U.S. ton is a measurement of mass equal to 2000 pounds. Carbon dioxide is often measured in metric tons. One metric ton of carbon dioxide is equal to a volume of 556.2 cubic meters of the gas at standard conditions of temperature and pressure.
minimum miscibility pressure – The minimum pressure at which a crude oil will be miscible with carbon dioxide at reservoir temperature.

miscibility – The condition where two fluids can be mixed in all proportions; where there is no interface between them.

original oil in place – The volume of oil originally in place in a reservoir before production commences, expressed as a total volume at surface conditions of temperature and pressure (typically in “stock tank barrels” in the U.S.). Oil in place must not be confused with oil reserves, which are the technically and economically recoverable portion of the oil volume in the reservoir. Recovery factors for oil fields around the world typically range between 10 and 60 percent of the original oil in place.

permeability – The ability of a rock to allow fluids (oil, water, and gas) to flow through it by virtue of the interconnectivity of its internal porosity. Fluids move through reservoir rock and into a well due to a pressure gradient (higher pressure out in the reservoir compared to the pressure at the bottom of the well). Higher permeability rock will allow a higher flow rate, all other things being equal. Permeability is a constant in the flow equation for fluid flow through porous media, with units known as Darcies.

primary production – Oil production that is driven by the natural pressure of the reservoir, before any energy is added through water injection (secondary production or secondary recovery) or post-waterflood enhanced oil recovery processes like carbon dioxide injection (tertiary recovery).

reservoir – The rock formation and its fluid contents of water, oil, and gas that make up a hydrocarbon accumulation in the subsurface. An oil reservoir generally is bounded by seals, either structural barriers like faults or lithological barriers like low permeability rocks, that act to trap the hydrocarbons and prevent their migration over geologic time.

residual oil – The oil that remains in a reservoir after primary, secondary or tertiary production (or all three) has taken place. Typically expressed as a percentage of the pore volume.

reworking wells – The act of re-entering a well bore after the well has been producing for some time, generally using a drilling or “workover” rig, to effect repairs or otherwise enhance the ability of the well to produce at commercial rates.
sandstone – A sedimentary rock composed mainly of sand-size mineral or rock grains. Sandstones can result from a variety of depositional environments and can exhibit a range of values for permeability and porosity. Most sandstone is composed of quartz and/or feldspar because these are the most common minerals in the Earth’s crust.

secondary recovery – Oil production that is driven by water injection in a waterflood.

supercritical conditions – Combined conditions of temperature and pressure that place a substance at a point above its critical point. When in a supercritical state, a substance can exhibit properties of both a liquid and a gas (e.g., it may diffuse through solids like a gas, and dissolve materials like a liquid).

tertiary recovery – Oil production that is post-waterflood and driven by enhanced oil recovery (EOR) processes like carbon dioxide injection (other processes include chemical and thermal).

viscosity – Measure of the internal resistance of a fluid to being deformed by either shear stress or extensional stress. With common fluids and terminology, viscosity is though of as “thickness” (e.g., water is “thin,” having a lower viscosity, while honey or molasses is considered as “thick,” having a higher viscosity. Viscosity describes a fluid’s internal resistance to flow and may be thought of as a measure of fluid friction. In general, heavier crudes are highly viscous and thus more difficult to displace using a lower viscosity fluid (like water, or carbon dioxide).

waterflooding – The practice of pumping (injecting) water into selected wells in an oil field, in order to sweep remaining oil from the rock formation and push it towards producing wells were it can be pumped to the surface. Waterflooding is typically (but not always) initiated some time after a field has been significantly depleted under the primary production phase.

well pattern – The pattern of wells in a field; their location relative to each other and the spacing (drainage area per well) that pattern implies. In a waterflood or carbon dioxide flood, the pattern can also indicate the ratio of injectors to producers and their relative position to one another.
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CARBON DIOXIDE ENHANCED OIL RECOVERY