the ENERGY lab

Carbon Dioxide Enhanced Oil Recovery

Untapped Domestic Energy Supply and Long Term Carbon Storage Solution

NATIONAL ENERGY TECHNOLOGY LABORATORY

U.S. DEPARTMENT OF ENERGY

Introduction

As the United States grapples with the twin challenges of reducing dependence on foreign energy sources and reducing emissions of greenhouse gases, the topic of carbon dioxide (CO_2) 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 CO_2 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 both of the challenges mentioned above.

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The Basics of Carbon Dioxide EOR

Why It Works

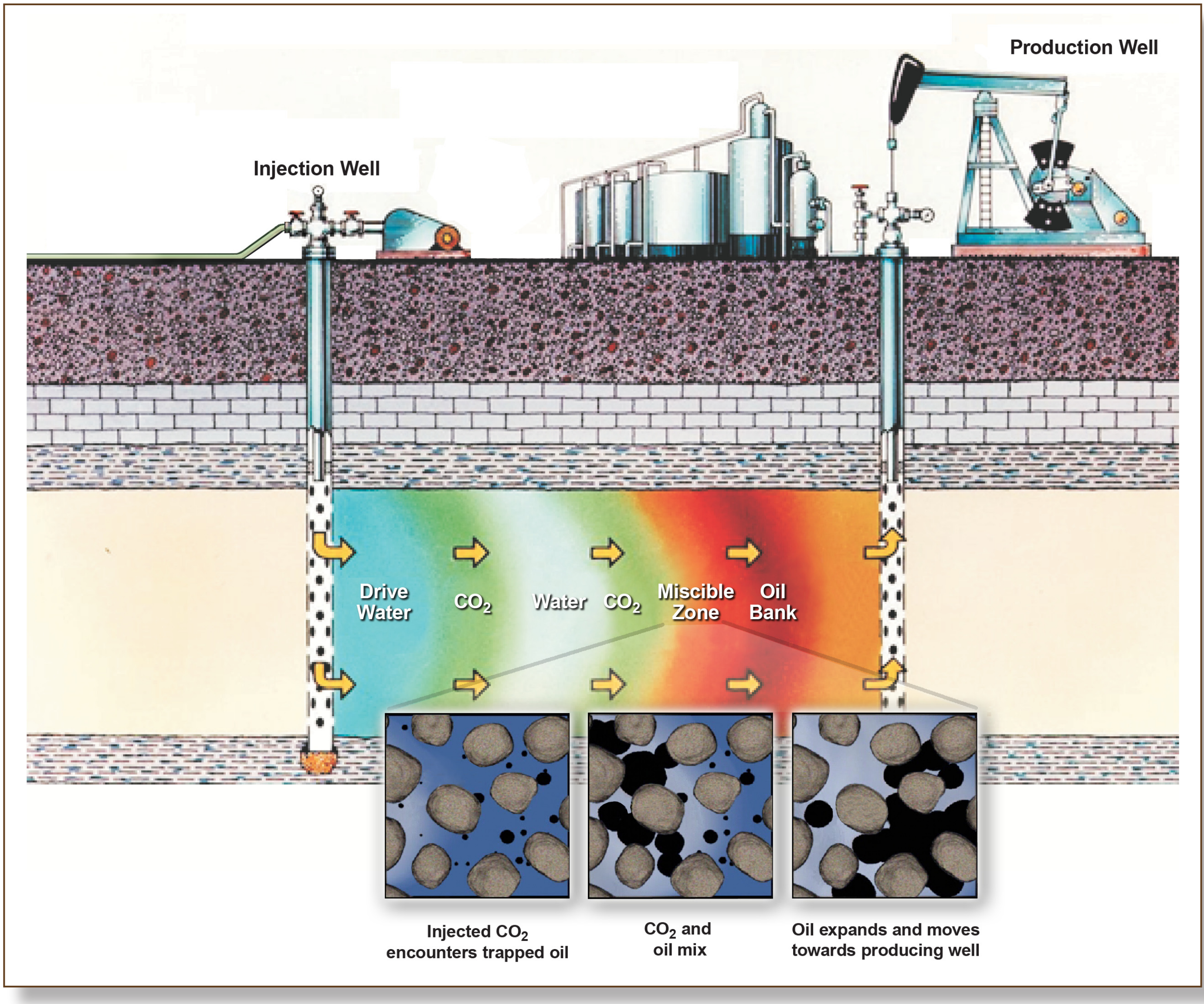
Oil and water form separate phases when mixed.

Why does injecting carbon dioxide (CO_2) into the pore spaces of a rock help move crude oil out? CO_2 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 homogeneous 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 CO_2 are relatively inexpensive, naturally occurring sources of the gas that can be extracted in large quantities, making it a more sensible choice. If CO_2 produced by human activities can be captured inexpensively, it could become a source as well.

Oily surfaces can be cleaned if a solvent is used that is completely miscible with the oil.

When we inject CO_2 into an oil reservoir, it becomes mutually soluble with the residual crude oil as light hydrocarbons from the oil dissolve in the CO_2 and CO_2 dissolves in the oil. This occurs most readily when the CO_2 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, CO_2 and oil will no longer be miscible. As the temperature increases (and the CO_2 density decreases), or as the oil density increases (as the light hydrocarbon fraction decreases), the minimum pressure needed to attain



Cross-section illustrating how carbon dioxide and water can be used to flush residual oil from a subsurface rock formation between wells

oil/CO_2 miscibility increases. For this reason, oil field operators must consider the pressure of a depleted oil reservoir when evaluating its suitability for CO_2 enhanced oil recovery. Low pressured reservoirs may need to be re-pressurized by injecting water (see page 6 sidebar on waterflooding).

When the injected CO_2 and residual oil are miscible, the physical forces holding the two phases apart (interfacial tension) effectively disappears. This enables the CO_2 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 CO_2 dissolves in the oil it swells the oil and reduces its viscosity; affects that also help to improve the efficiency of the displacement process.

Often, CO_2 floods involve the injection of volumes of CO_2 alternated with volumes of water; *water alternating gas* or WAG floods. This approach helps to mitigate the tendency for the lower viscosity CO_2 to finger its way ahead of the displaced oil. Once the injected CO_2 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.

How It Works

The physical elements of a typical CO_2 flood operation can be used to illustrate how the process works. First, a pipeline delivers the CO_2 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 CO_2 is directed to injection wells strategically placed within the pattern of wells to optimize the areal sweep of the reservoir. The injected CO_2 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 towards 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 CO_2 as the injected gas begins to break through at producing well locations, must be further processed. Any produced CO_2 is separated from the produced natural gas and recompressed for reinjection along with additional volumes of newly-purchased CO_2. In some situations, separated produced water is treated and re-injected, often alternating with CO_2 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, CO_2 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.

CO_2 pipeline metering

Production well pump jack

CO_2 injection wellhead

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 enhanced oil recovery is to minimize the amount of CO_2 that must be injected per incremental barrel of oil recovered, especially since CO_2 injection is expensive. However, if carbon sequestration 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.

CO_2 processing plant where the gas is collected for re-injection

Separator for separating produced fluids (oil, water, and gas)

Well production manifold to allow individual testing of wells

Compressor for compressing gas prior to re-injection

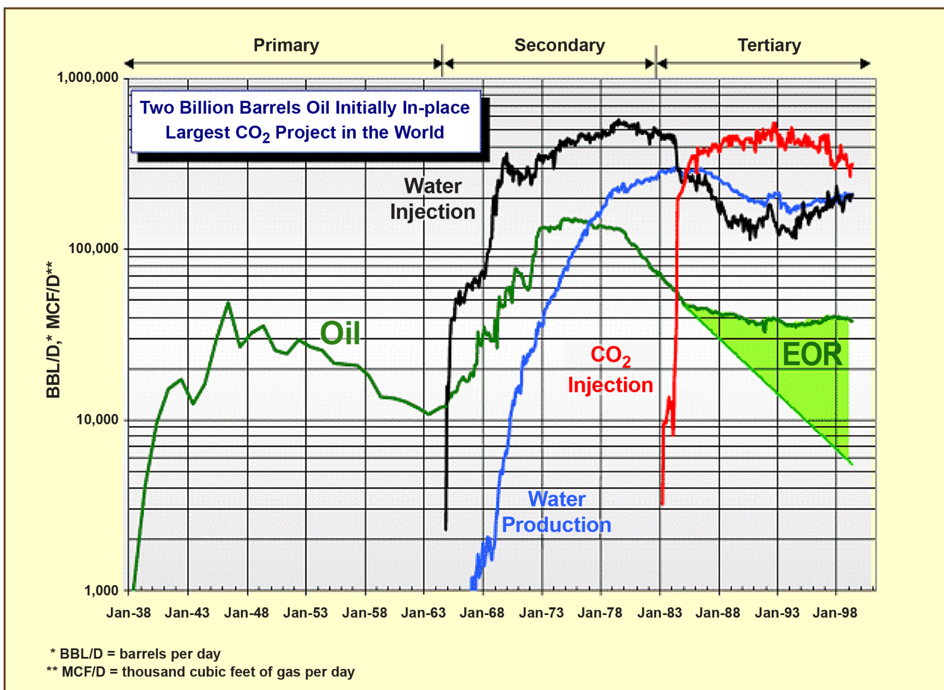
How Much Extra Oil Gets Produced

The Wasson Field's Denver Unit CO_2 EOR project has resulted in more than 120 million incremental barrels of oil thru 2008.

The production plot shown below illustrates how a field can respond to 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 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 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 CO_2 EOR by calculating the cumulative difference between the projected decline rate without 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 is incremental oil attributable to the CO_2 flood. The Wasson Field's Denver Unit CO_2 EOR project has resulted in more than 120 million incremental barrels of oil thru 2008.



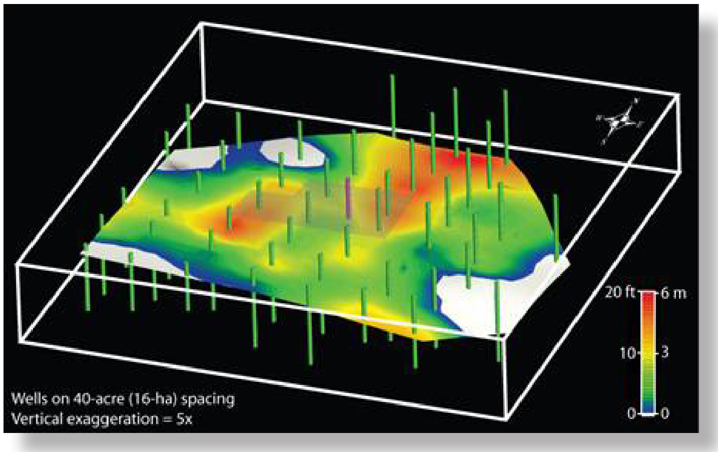
Plot showing oil production versus time for primary, secondary (waterflood) and tertiary (CO_2 EOR) oil production periods for the Denver Unit of the Wasson Field in West Texas. Incremental oil production due to EOR is represented by the green area under the curve at right.

Where It's Being Done

The United States leads the world in both the number of CO_2 EOR projects and in the volume of CO_2 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 CO_2 EOR activity for two reasons: reservoirs there are particularly amenable to CO_2 flooding, and large natural sources of high purity CO_2 are relatively close. However, a growing number of CO_2 EOR projects are being launched in other regions, based on the availability of low cost CO_2.

Screening Reservoirs for CO_2 EOR

What kinds of reservoirs are most suitable for CO_2 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 CO_2 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 CO_2 flood.



Depiction of reservoir model used for simulation of CO_2 flooding

Most of the large reservoirs in the Permian Basin 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 CO_2 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 CO_2 miscibility with the crude oil lower. Geologically, these reservoirs also exhibit a high degree of continuity between wells, and rock that is laterally and vertically uniform, and has relatively high permeability.

Criteria for Screening Reservoirs for CO_2 EOR Suitability

Depth, ft	< 9,800 and >2,000
Temperature, °F	<250, but not critical
Pressure, psia	>1,200 to 1,500
Permeability, md	>1 to 5
Oil gravity, °API	>27 to 30
Viscosity, cp	≤10 to 12
Residual oil saturation after waterflood, fraction of pore space	>0.25 to 0.30

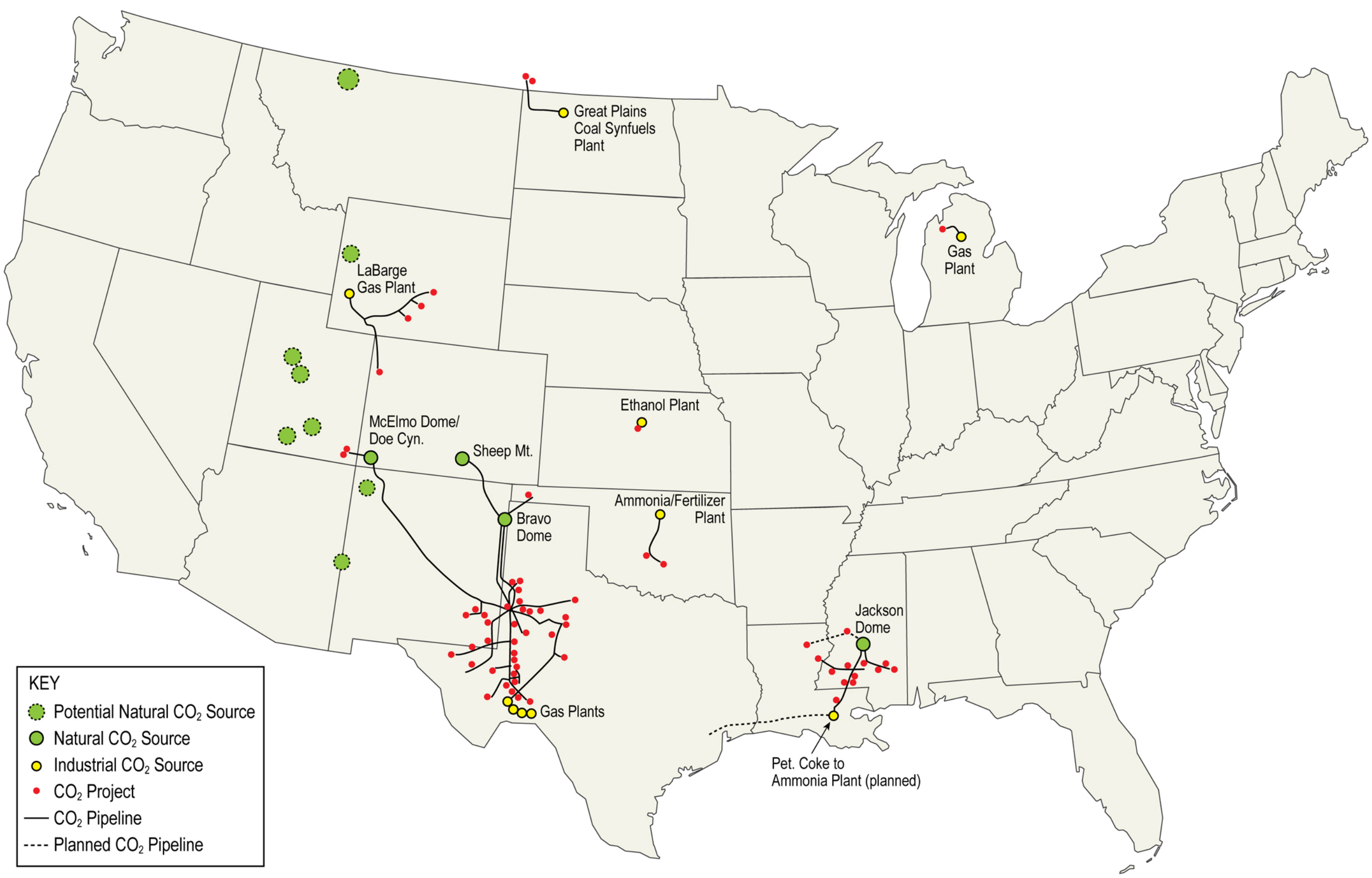
Operators interested in enhancing recovery through CO_2 EOR will screen their reservoirs to determine the best candidates based on rock and fluid characteristics, past production behavior and response to waterflooding, and detailed geological assessments. The screening criteria used to identify favorable 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 CO_2 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 CO_2 project performance and economics prior to performing a detailed numerical simulation. One such tool, CO_2-Prophet, was developed by DOE and Texaco. A number of other commercial screening tools are now available.

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.



Location of Current CO_2 EOR Projects and Pipeline Infrastructure

But even with CO_2 sources just a few hundred miles away, the cost of delivering and injecting the CO_2 is significant. Industry has spent more than $1 billion on 2,200 miles of CO_2 transmission and distribution pipeline infrastructure in support of CO_2 flooding in the Permian Basin. Typically, it costs $0.25-0.75 per thousand cubic feet to transport CO_2 to West Texas fields from the sources to the north. With a substantial CO_2 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 CO_2 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 CO_2 in the basin from oil field operators seeking to implement economic CO_2 EOR projects. Additional natural CO_2 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 CO_2 resource at Jackson Dome, Mississippi, which it describes as the largest CO_2 resource east of the Mississippi River. Jackson Dome already feeds CO_2 to EOR projects Denbury operates in Mississippi and Louisiana. Denbury plans to build a major extension from the southern terminus of its existing CO_2 pipeline in Louisiana to deliver CO_2 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) CO_2 for EOR projects in all three states.

Anthropogenic CO_2 Sources

Much discussion has centered on methods to reduce or eliminate CO_2 emissions from industrial sources due to concerns over CO_2 as a "greenhouse" gas. Prominent in this discussion are concepts to capture and safely and permanently store anthropogenic CO_2 in underground formations, a process known as sequestration. In CO_2 EOR projects, all of the injected CO_2 either remains sequestered underground or is produced and re-injected in a subsequent project, making the notion of using captured anthropogenic CO_2 for EOR in places far removed from natural sources of CO_2 a likely possibility. Companies have already launched several examples of this approach.

For years, ExxonMobil Corp. has sold CO_2 from its La Barge, Wyoming gas processing facility to area oil producers for use in CO_2 EOR projects (see map). The company currently captures 4 million metric tons of CO_2 per year for this purpose.

Another major CO_2 EOR project using industrially sourced CO_2 is located at Weyburn oil field, a Williston basin reservoir just across the U.S. border in Saskatchewan, Canada. EnCana Corp., a Canadian company, injects about 95 million cubic feet (4,935 metric tons) per day of CO_2 into Weyburn, a 55-year-old field, to recover an incremental 130 million barrels of oil via miscible or near-miscible displacement. The CO_2 is 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 CO_2 will be permanently sequestered underground through the project, while boosting the synfuels plant's revenues by about $30 million per year and extending the Weyburn field's life by 20 to 25 years.

Other industrially sourced CO_2 EOR projects are in the offing 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 CO_2 per year for use in CO_2 EOR operations. Proposals to capture CO_2 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

1 metric ton of CO_2 equals 545 cubic meters at standard conditions of 14.7 psi and 70 °F
1 metric ton of CO_2 equals 19.25 thousand cubic feet (Mcf) at standard conditions of 14.7 psi and 70 °F
The average American car emits about seven metric tons of CO_2 per year

A proactive technology transfer program led by NETL in the 1990s helped to transfer their CO_2 development concepts to the rest of the industry.

U.S. CO_2 EOR Demographics

Production from all United States CO_2 EOR projects grew to 240,000 barrels per day in 2008, according to the *Oil & Gas Journal's* biennial survey. CO_2 EOR production has jumped significantly since the early 1980s (see graph). At the same time, the demographics of CO_2 EOR operators have changed. Prior to the early 1990s, almost all CO_2 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 CO_2 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 CO_2 EOR operators (see table).

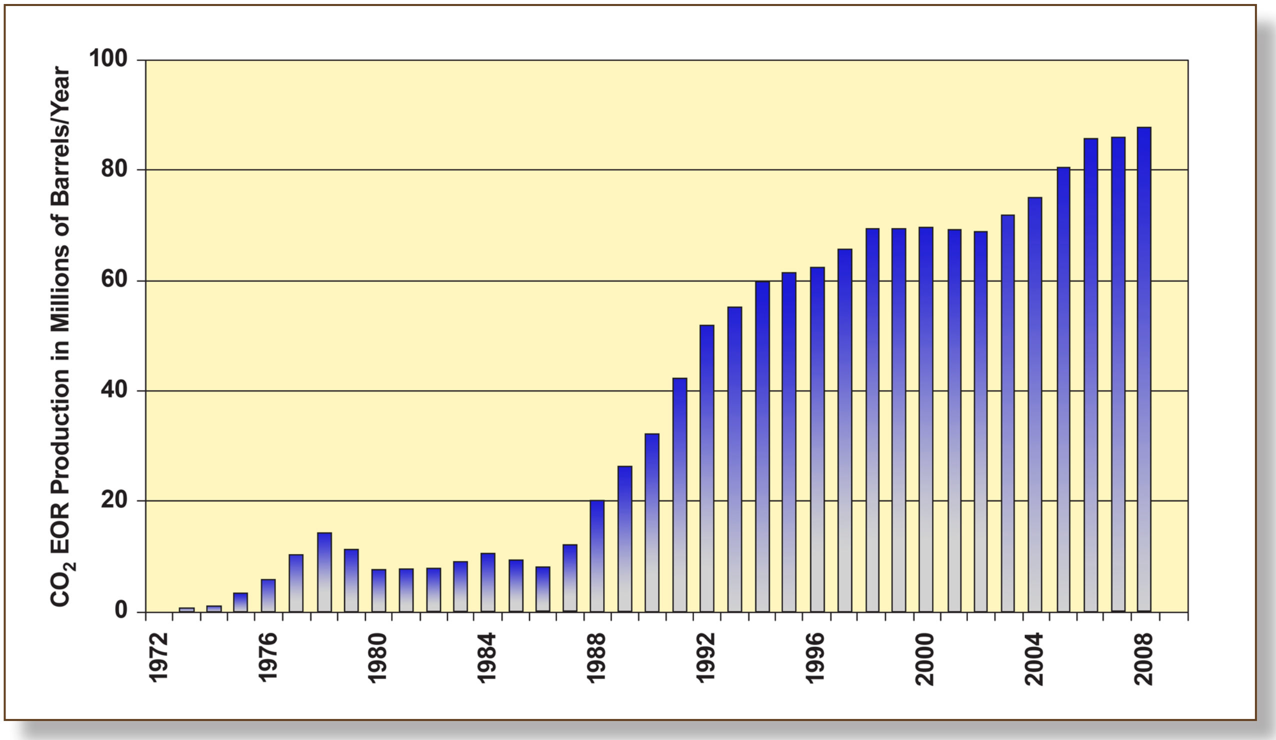
The SACROC Unit, where commercial CO_2 EOR got its start, is now in the hands of an independent. Kinder Morgan CO_2 Company, which is the second largest producer of oil in Texas and one of the nation's largest owners and transporters of CO_2, has more than tripled SACROC production since acquiring a majority interest in the unit in 2000.

One of the most active CO_2 EOR operators is another independent producer, Occidental Petroleum (Oxy). Oxy operates more than half of the current CO_2 floods in the Permian Basin and is one of the dominant producers of CO_2 EOR oil, and the largest oil producer in Texas.

Major U.S. CO_2 Operators (OGJ Biennial EOR Survey 2008)

Company	Miscible Projects	Locations	Incremental Production (MBO/D*)
Occidental	29	TX, NM	90.2
Hess	6	TX	25.3
Kinder Morgan	1	TX	24.2
Chevron	4	CO, TX, NM	21.3
Denbury Resources	13	MS, LA	17.8
Merit Energy	7	WY, OK	13.6
ExxonMobil	2	TX, UT	11.7
Anadarko	4	WY	9.0
Whiting Petroleum	3	TX, OK	6.9
ConocoPhillips	2	TX, NM	5.5
12 other independents	28	TX, OK. UT, KS, MI	14.9
Total	99		240.4

* thousand barrels of oil per day



U.S. CO_2 EOR Production

CO_2 EOR Economics

Implementing a CO_2 EOR project is a capital-intensive undertaking. It involves drilling or reworking wells to serve as both injectors and producers, installing a CO_2 recycle plant and corrosion resistant field production infrastructure, and laying CO_2 gathering and transportation pipelines. Generally, however, the single largest project cost is the purchase of CO_2. 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 CO_2 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 CO_2 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 CO_2 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 CO_2 supply/injection/recycling scheme, the initial CO_2 injection volume must be purchased well in advance of the onset of incremental production. Hence, the return on investment for CO_2 EOR tends to be low, with a gradual, long-term payout.

Illustrative Costs and Economics of a CO_2 EOR Project

Oil Price ($/Barrel)	**$70**
Gravity/Basis Differentials, Royalties and Production Taxes	($15)
Net Wellhead Revenues ($/Barrel)	**$55**
Capital Cost Amortization	($5 to $10)
CO_2 Costs (@ $2/Mcf for purchase; $0.70/Mcf for recycle)	($15)
Well/Lease Operations and Maintenance	($10 to $15)
Economic Margin, Pre-Tax ($/Barrel)	**$15 to $25**

Given the significant front-end investment in wells, recycle equipment, and CO_2, the time delay in achieving an incremental oil production response, and the potential risk of unexpected geologic heterogeneity significantly reducing the expected response, CO_2 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 CO_2-injected-to-incremental-oil-produced will not achieve an economically justifiable return on investment without advanced, high-efficiency CO_2 EOR technology and/or fiscal/tax incentives for storing CO_2.

Its Future Potential

Significant potential remains for additional growth in oil production from this process.

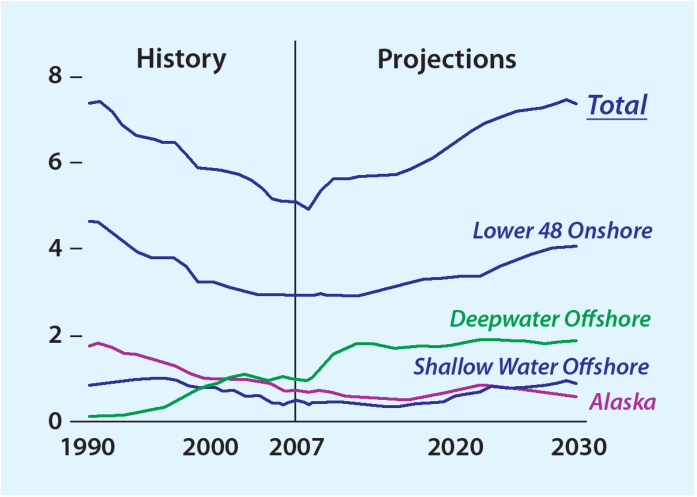
While CO_2 EOR has demonstrated significant success over nearly four decades, significant potential remains for additional growth in production from this process. This potential is further enhanced by the possibility of using captured anthropogenic CO_2 in fields that are good candidates for CO_2 EOR but far from natural CO_2 source reservoirs.

CO_2 EOR has increased recovery from some oil reservoirs by an additional 4 to 15 percentage points over primary and secondary recovery efforts that can account typically for about 30 to 35 percent of OOIP. However, some pilot projects have reported incremental recovery of as much as 22 percent, and studies have suggested that new “game-changing” technology innovations that bolster the efficiency of CO_2 floods or enhance geophysical mapping of residual oil pockets could push total ultimate oil recovery in some reservoirs to more than 60 percent of OOIP. CO_2 EOR currently is responsible for about 4 percent of U.S. oil production, displaying a long-term growth trend that stands in stark contrast to the long-term decline trend for U.S. oil production overall.

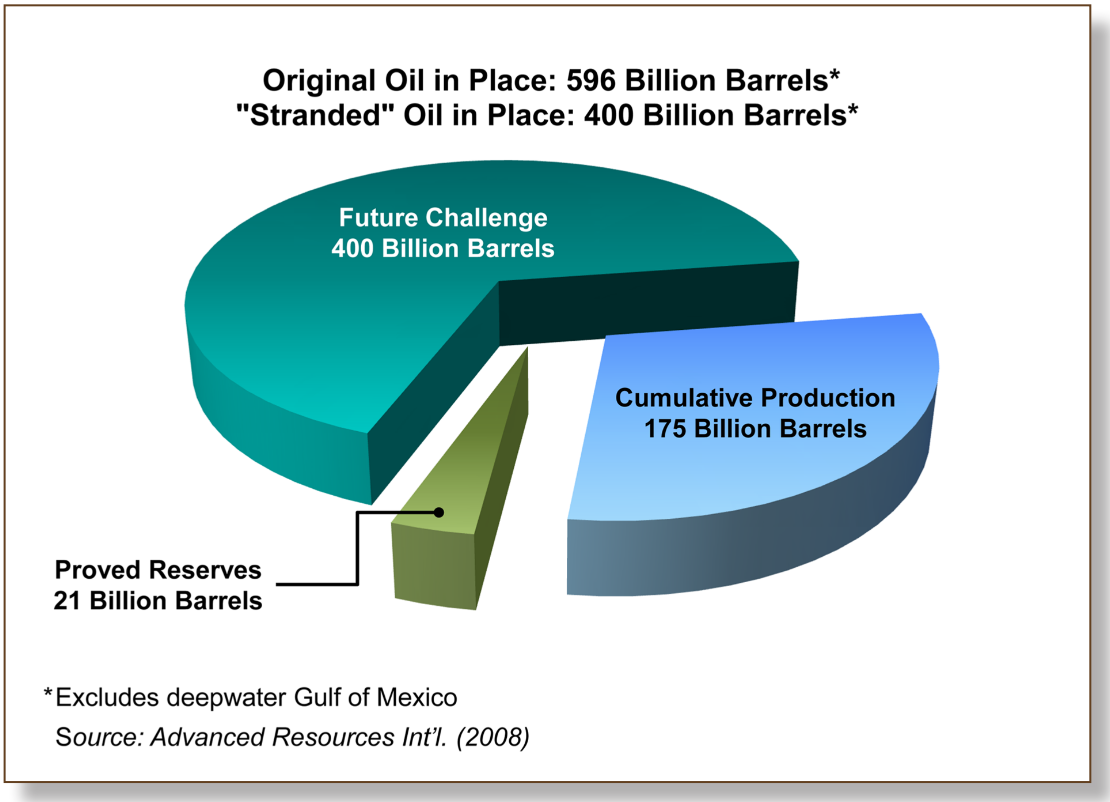
Production Outlook

In its 2009 Annual Energy Outlook the Department of Energy’s Energy Information Administration (EIA) notes that the long-term decline in U.S. crude oil production has slowed over the past few years as drilling activity responded to higher oil prices. Looking out to 2030, EIA forecasts that overall U.S. onshore oil production will increase to 3.8 million barrels per day from 2.9 million barrels per day in 2007, due in part to the increased application of CO_2 EOR (see graph). This increase helps boost Lower 48 oil production high enough to offset a flattening of the growth curve from deepwater oil production. EIA's assessment assumes that anthropogenic CO_2 will be available at a cost from just under $1 to just over $3 per Mcf, delivered to the field.

The projected rapid take-up of new technology, coupled with higher oil prices, could make a big difference in the outlook for CO_2 EOR's contribution to future U.S. oil production. Certainly, the volume of "stranded" oil left behind in U.S. reservoirs after conventional primary and second recovery techniques is massive—as much as two-thirds of all the oil discovered in the United States resides in this category (see remaining oil pie chart). However, laboratory tests, and a few selected field projects show that significant increases in CO_2 EOR oil recovery efficiency are possible.



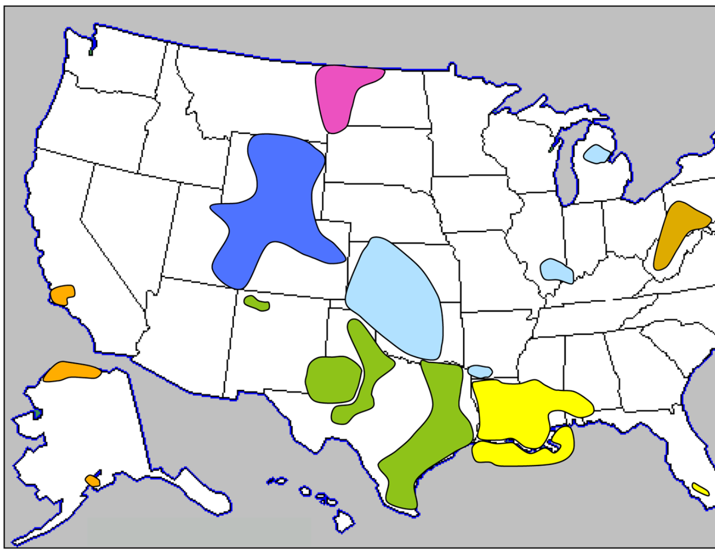
Domestic crude oil production by source 1990-2030 (million barrels per day)



Large volumes of domestic oil remain stranded after primary/secondary recovery.

A 2009 study by Advanced Resources International (ARI) for DOE assessed the role that "best practices" CO_2 EOR technologies could play in U.S. oil recovery. ARI 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, CO_2 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.

Potential Technically Recoverable Incremental Oil with "best practices" CO_2 EOR Technology



Source: ARI, February 2009

Remaining Oil in Place and Technically Recoverable Oil (BBls)

Region	ROIP*	Technically Recoverable
Alaska	45.0	12.4
California	57.3	6.3
Mid-Cont.	65.6	10.6
IL and MI	11.5	1.2
Rocky Mts.	22.6	3.9
Permian Basin	61.7	15.9
East/Cent. Texas	73.6	17.6
Williston Basin	9.4	2.5
Gulf Coast	27.5	7.0
LA Offshore	15.7	5.8
Appalachia	10.1	1.6
Total	**400**	**84.8**

* Remaining Oil in Place

Producible if costs, oil price and risks justify investment

However, many factors play a role in the suitability and economics of CO_2 EOR applications—not the least of which are the price of oil and the cost and availability of CO_2. Consequently, there can be a substantial gap between a "technically recoverable resource" and a proven reserve volume booked to an oil company's balance sheet. Still, the study points to the significant potential of CO_2 EOR to contribute to the nation's future oil supply. Increasing the volume of technically recoverable domestic crude oil could help reduce the Nation's trade deficit and enhance national energy security by reducing oil imports, add high-paying domestic jobs from the direct and indirect economic effects of increased domestic oil production and help to revitalize state economies and increase federal and state revenues via royalties, and corporate income taxes.

Tax Incentives

It is important to recognize that much of the CO_2 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 CO_2 EOR production growth subsequently grew rapidly. This incentive is a 15 percent tax credit that applies to all costs associated with installing a CO_2 flood, the purchase cost of CO_2, and CO_2 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. CO_2 EOR oil, provides a severance tax exemption on all the oil produced from a CO_2-flooded reservoir.

CO_2 EOR and Sequestration

Beyond its potential to augment U.S. oil production, CO_2 EOR is getting intensive scrutiny by industry, government, and environmental organizations for its potential for permanently storing CO_2. The thinking goes that CO_2 EOR can add value by maximizing oil recovery while at the same time offering a bridge to a reduced carbon emissions future. CO_2 EOR effectively reduces the cost of sequestering CO_2 by earning revenues for the CO_2 emitter from sales of CO_2 to oil producers.

Many experts look to geologic sequestration as one of the best alternatives for dealing with carbon emissions. The CO_2 EOR industry is an industry with a proven track record of safely injecting CO_2 into geologic formations. EOR operations account for 9 million metric tons of carbon, equivalent to about 80 percent of the industrial use of CO_2, every year. Although about 20 percent of CO_2 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 CO_2 emissions. However, industrial carbon capture and storage (CCS) offers the potential to significantly alter this situation.

Because of the cost of naturally sourced CO_2—roughly $10-15 per metric ton—a CO_2 flood operator seeks to recycle as much as possible to minimize future purchases of the gas. All of the injected CO_2 is retained within the subsurface formation after a project has ended or recycled to subsequent projects. After years of experience with CO_2 floods, oil and gas operators are confident that the CO_2 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.

The CO_2 EOR industry is an industry with a proven track record of safely injecting CO_2 into geologic formations.

One major oil industry operation that provides an example of such permanence is StatoilHydro's Sleipner CO_2 project in the North Sea off Norway. The company is developing a large gas field and must strip out CO_2 from the produced gas stream that is about 9 percent CO_2 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 CO_2 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 CO_2.

CO_2 EOR technology and equipment needs parallel those envisioned for sequestration, with similar surface infrastructure and wells, similar handling of supercritical (high pressure/low temperature) CO_2, 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 CO_2 use in EOR vs. maximizing it for sequestration) and regulatory concerns (monitoring, verification, and accounting of the CO_2 over the very long term).

Sequestration Potential in Oil Reservoirs

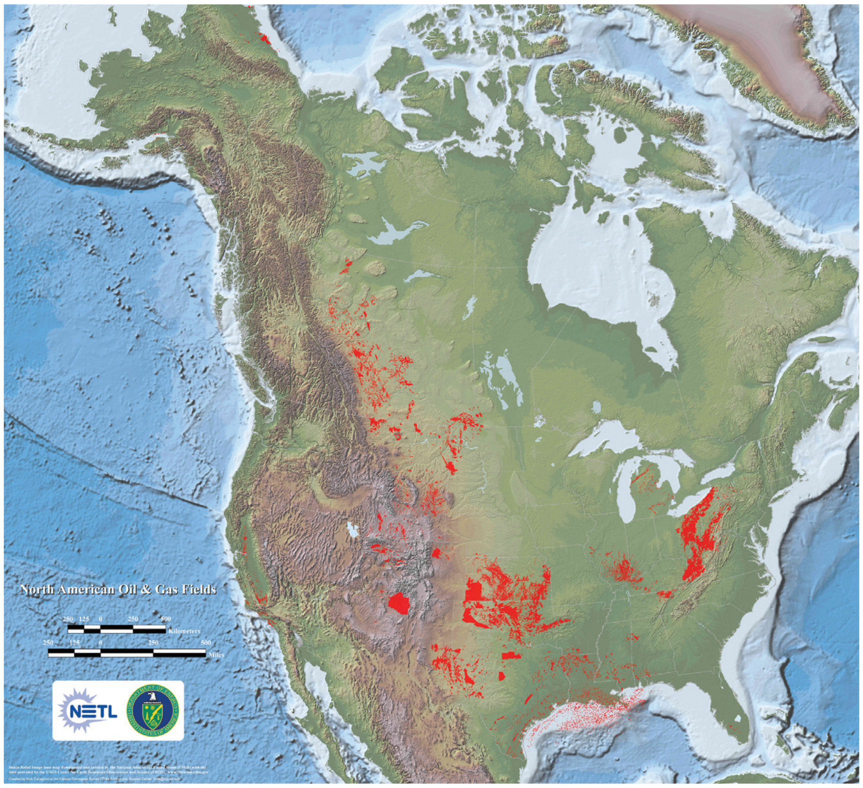
What is the potential for sequestration of CO_2 from EOR operations? The total volume of CO_2 consumed by U.S. CO_2 EOR to date has been about 11 trillion cubic feet (560 million metric tons). That pales in comparison with total U.S. CO_2 emissions from industrial sources alone of about 100 trillion cubic feet (5,090 million metric tons) per year. However, that does not mean that the potential demand for CO_2 for EOR will be insignificant; EOR could be an enabling catalyst for larger scale sequestration efforts.

EOR could be an enabling catalyst for large-scale sequestration efforts.

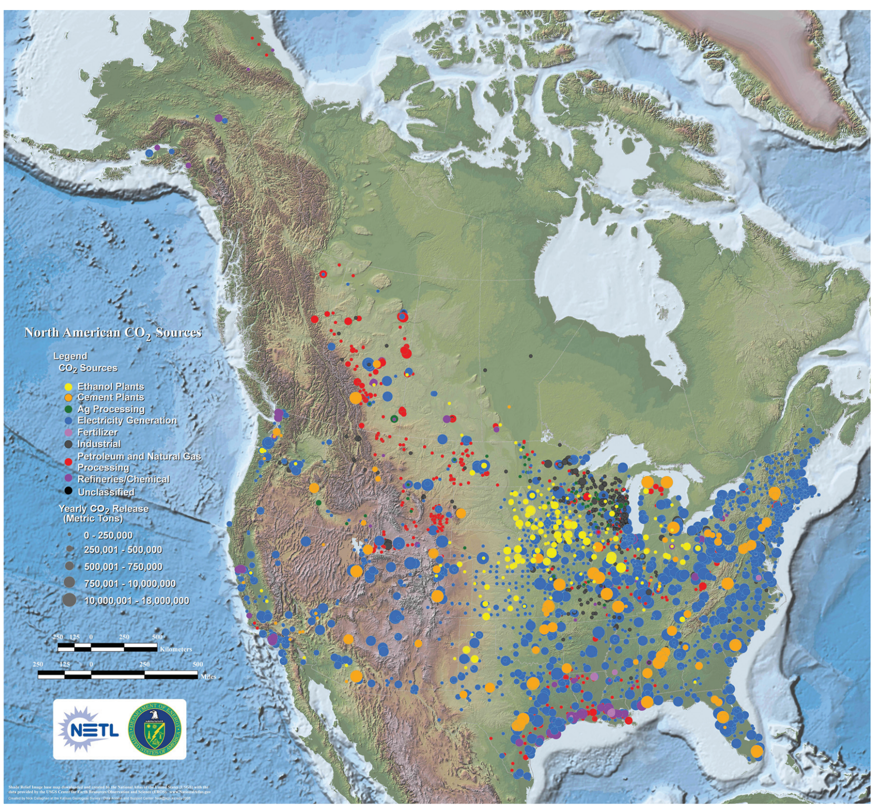
For example, a study by Montana Tech University found that CO_2 flooding of Montana's Elm Coulee and Cedar Creek oil fields could result in the recovery of 666 million barrels of incremental oil and the storage of 2.1 trillion cubic feet (109 million metric tons) of CO_2. All of the CO_2 required for the flood could be supplied by a nearby, coal-fired power plant, and would equate to 7 years of the plant's CO_2 emissions. Furthermore, installation of a pipeline and CO_2 capture equipment for the project could provide the basic infrastructure for subsequent storage of CO_2 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 Sequestration Atlas of the United States and Canada shows considerable overlap of the respective regional capacities for CO_2 storage in oil and natural gas fields and the major sources of CO_2 emissions.

DOE's Regional Carbon Sequestration Partnership Initiative is the world's most comprehensive field program dedicated to the assessment and validation of carbon sequestration technologies in saline formations, oil fields and



North American oil field distribution and calculated capacities



North American CO_2 source distribution

CO_2 Storage Resource Estimates by Regional Carbon Sequestration Partnership (RCSP) for Oil and Gas Reservoirs

RCSP	Billion Metric Tons	Trillion Cubic Feet
BSCSP*	1.5	29
MGSC*	0.4	8
MRCSP*	8.4	165
PCOR*	24.1	473
SECARB*	31.1	611
SWP*	65.0	1,277
WESTCARB*	7.7	151
TOTAL	138	2,714

* RCSPs:

BSCSP–Big Sky Carbon Sequestration Partnership

MGSC–Midwest Geological Sequestration Consortium

MRCSP–Midwest Regional Carbon Sequestration Partnership

PCOR–Plains CO_2 Reduction Partnership

SECARB–Southeast Regional Carbon Sequestration Partnership

SWP–Southwest Partnership on Carbon Sequestration

WESTCARB–West Coast Regional Carbon Sequestration Partnership

Source: "Carbon Sequestration Atlas of the United States and Canada," DOE/Office of Fossil Energy/NETL, November 2008.

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 (see table).

The RCSPs are carrying out DOE-funded R&D field projects designed to validate and develop the potential for carbon capture and storage within their respective areas. A number of these projects combine CO_2 storage with EOR. Ten field projects are being supported throughout the United States and Canada. Seven of the projects have completed injection operations while three are injecting with plans to complete injection by the end of 2010.

The Midwest Geological Sequestration Consortium (MGSC) has evaluated the potential for CO_2 storage in a sandstone oil reservoir in the Loudon field of Fayette, Co., Illinois, and is currently conducting another test in the Sugar Creek field near Madisonville, Kentucky and a third injection test in Mumford Hills, Indiana. The Southeast Regional Sequestration Partnership (SECARB) is testing the potential for CO_2 storage in Denbury's Cranfield Unit near Natchez, Mississippi. The Plains Carbon Dioxide Reduction Partnership (PCOR) continues to carry out research associated with monitoring the fate of CO_2 in a pinnacle reef in Northeastern Alberta. Other RCSPs projects are in the Aneth Field in Utah; Permian Basin in Texas; the Williston Basin in North Dakota. The DOE also supports Encana's Weyburn project in Saskatchewan, Canada. Details about these field projects can be found online at (http://www.netl.doe.gov/technologies/carbon_seq/index.html).

A 2008 study by INTEK for DOE sought to test the economics of a potential linkage between the most likely candidate CO_2 EOR reservoirs and their most likely matching industrial CO_2 sources. The study concluded that as much as 30 trillion cubic feet of CO_2—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.

Another study carried out by Advanced Resources International (ARI) for DOE-NETL concluded that CO_2 EOR could provide a large, value-added market for the sale of CO_2 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 CO_2 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.

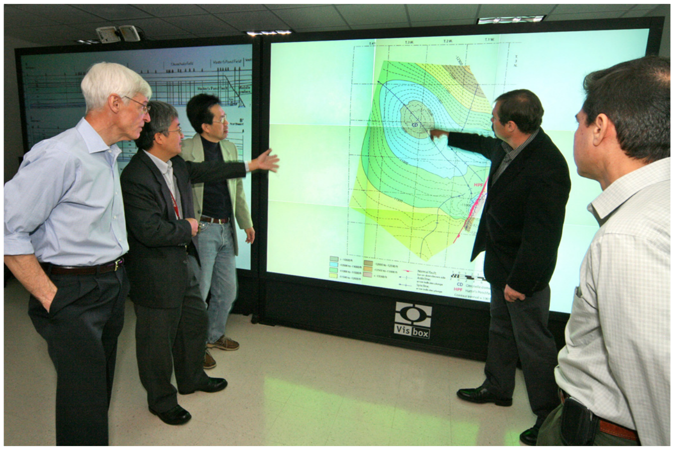
At the same time, concluded ARI, the ensuing CO_2 EOR boom would unlock an additional 39-48 billion barrels of oil prior to 2030, while building a CO_2 transportation infrastructure suitable for subsequent transport of CO_2 for sequestration in deep saline formations—which are likely to have the biggest ultimate CO_2 storage potential of all underground options. The synergies between CO_2 EOR and CO_2 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.

What DOE is Doing

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).

Several trends highlight the need for continued research into ways to improve recovery from conventional domestic oil reservoirs.

- Energy demand continues to grow, and the need to slow the growth in oil imports for economic and energy security reasons remains strong.
- Onshore domestic oil production is declining, but there are significant amounts of oil left in conventional reservoirs in mature oil fields.
- 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.



NETL is investigating the potential for recovering incremental oil from the Citronelle Field in Alabama using carbon dioxide 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 carbon dioxide flooding through sweep improvement (Louisiana State).
- Improve CO_2 flooding sweep using CO_2 gels (SBIR-RTA Systems Inc.)
- Conduct CO_2 injection tests in the Citronelle oilfield in Mobile County, AL to improve the reliability of computer simulations of oil yield from CO_2-EOR and calculations of sequestration capacity (University of Alabama at Birmingham).
- Determine the economic and technical feasibility of using CO_2 miscible flooding to recover oil in a Lansing-Kansas City formation oilfield in central Kansas (U. Kansas).
- Employ molecular modeling and experiments to design inexpensive, environmentally benign, CO_2-soluble compounds that can decrease the mobility of CO_2 at reservoir conditions (U. Pittsburgh).
- Develop a neural network model for CO_2 EOR (University of Louisiana at Lafayette).
- Develop a novel, low cost method to install geophones for CO_2 monitoring (SBIR-Impact Technologies).

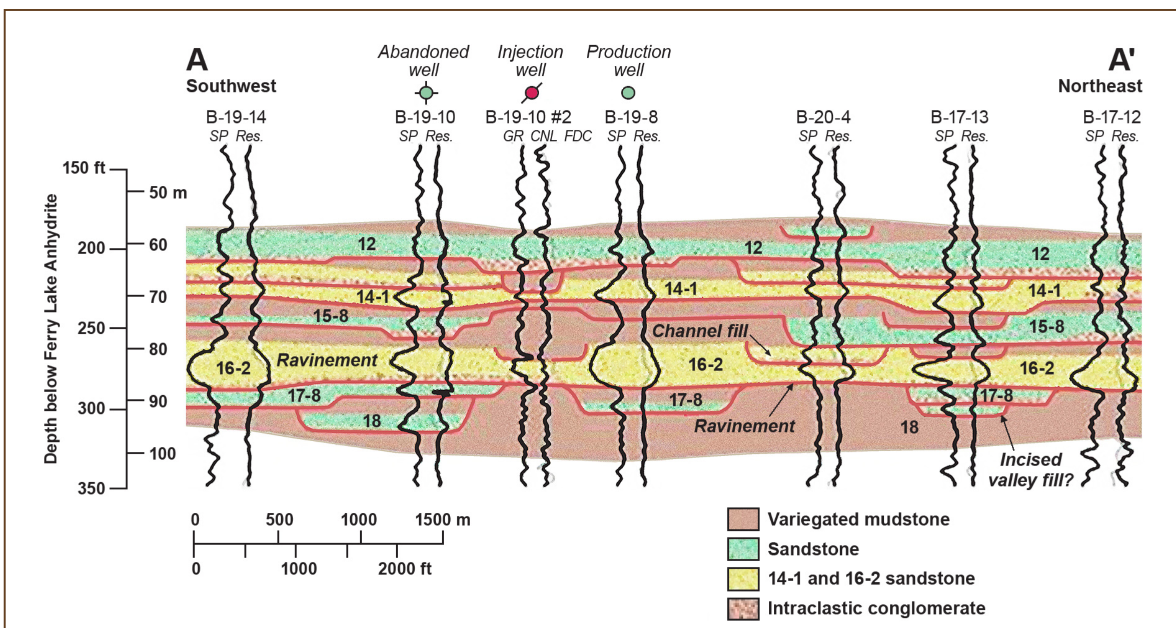
NETL is demonstrating carbon dioxide flooding EOR in the Hall-Gurney field in Russell, Kansas, using carbon dioxide recovered from a nearby ethanol plant.

The need for federal investment in scientific data collection and technology development 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.

Currently there are 26 funded projects in petroleum R&D portion of NETL's program that have either just been completed or are scheduled to continue through 2012. Of these, seven projects are directed at problems related specifically to CO_2 EOR. In addition to these extramural projects, an effort funded through the program instituted by Section 999 of the Energy Policy Act of 2005 aims to evaluate the potential for near-miscible CO_2 flooding in midcontinent reservoirs where circumstances preclude re-pressuring to minimum miscibility pressure. Another project is looking at ways to increase the viscosity of injected CO_2 to improve sweep efficiency.

Together, these projects form 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.



Cross-section through the pilot test area of the Citronelle Field shows the challenge of geologic complexity in fields where CO_2 flooding is being considered. Well B-19-10 #2 is the CO_2 injection well.

What's Next?

The potential impact of CO_2 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 carbon dioxide available from a variety of sources. The speed with which CO_2 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 sequestration credits
- Cost of carbon dioxide capture from anthropogenic sources
- Pilot project results
- Speed of technology advancement and dissemination

Insulated CO_2 source wellhead

These factors can be hard to predict. Nevertheless, as the regulatory picture begins to become clearer, more CO_2 EOR projects are likely to be implemented.

There is also an important public relations and regulatory aspect to the speed with which CO_2 flooding spreads beyond its current boundaries. Although the places CO_2 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 carbon dioxide injection is not well understood. It is important that stakeholders (citizens, investors, regulators, landowners, elected representatives) understand the science behind CO_2 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 CO_2 that is produced along with oil and natural gas is captured and re-injected. The company operating the EOR project bought the CO_2 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 CO_2 EOR flood is finished, the CO_2 that remains underground, stays there. Monitoring efforts can be put into place to make sure that is true.

The potential of CO_2 EOR is not so much a matter of whether but of when.

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 CO_2 for over 1000 years. At the Weyburn Project in Weyburn, Saskatchewan, Canada has determined that the likelihood of any CO_2 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 CO_2 underground. The investors want to know where it is going more than anyone does.

How 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.

How 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 CO_2 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 CO_2 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—CO_2 has properties midway between a gas and a liquid. If the conditions changed to room temperature and pressure, the supercritical CO_2 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 CO_2 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 CO_2 EOR and CO_2 sequestration.

Some useful links:

National Energy Technology Laboratory (http://www.netl.doe.gov/index.html)

Natural Resources Defense Council (http://www.nrdc.org/energy/eor.pdf)

Kinder Morgan (http://www.kne.com/business/co2/)

Oxy (http://www.oxy.com/Pages/default.aspx)

Denbury Resources (http://www.denbury.com/)

Enhanced Oil Recovery Institute (http://eori.gg.uwyo.edu/)

Glossary

$$\text{API gravity} = \frac{141.5}{SG} - 131.5$$

where SG = specific gravity at 60 °F

$$SG_{oil} = \frac{\text{density of oil}}{\text{density of water}}$$

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.

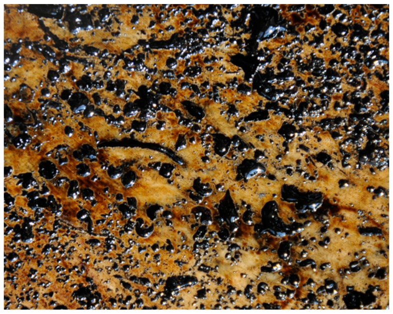
carbonate rock – Sedimentary rock formed primarily from calcium carbonate ($CaCO_3$) deposited in a marine environment; most commonly limestone. Many of the carbon dioxide floods found in the Permian Basin of West Texas are in oil reservoirs in carbonate formations deposited during the Permian Period.

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."

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 constitutents (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 (CH_4) 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.

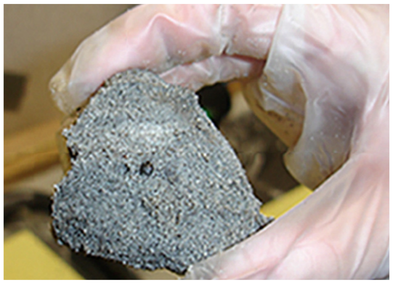
permeability – The ability of a rock to allow fluids (oil, water, and gas) to flow through it by virtue of the interconnectivity of its internal porosity. Fluids move through reservoir rock and into a well due to a pressure gradient (higher pressure out in the reservoir compared to the pressure at the 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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Page 7: plant *(Hess Corp.)*, manifold *(Denbury Resources)*, separator *(Whiting Petroleum Corp.)*, compressor *(Steve Melzer)*

Page 9: reservoir model *(Denise J. Hills, Geological Survey of Alabama)*

Page 21: contour map of Citronelle *(Jack C. Pashin, Geological Survey of Alabama)*

Page 22: stratigraphic cross section *(Jack C. Pashin, Geological Survey of Alabama)*

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