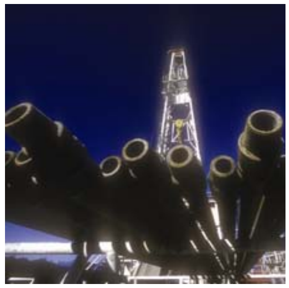
# U.S. OIL PRODUCTION POTENTIAL FROM ACCELERATED DEPLOYMENT OF CARBON CAPTURE AND STORAGE

## White Paper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**March 10, 2010**

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This report was prepared for the Natural Resources Defense Council.

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# EXECUTIVE SUMMARY

Key features of climate legislation being considered by the U.S. Congress, such as the American Clean Energy and Security Act (ACES) (H.R. 2454), are designed to stimulate and support rapid deployment of carbon capture and storage (CCS) in power generation and other industrial facilities that emit significant volumes of carbon dioxide ($CO_2$). In addition to reducing emissions, the captured $CO_2$ could be productively used to produce more domestic oil through the application of $CO_2$-enhanced oil recovery ($CO_2$-EOR) technology. Increasing domestic oil production will result in lower crude oil imports, enhanced domestic energy security, and significant economic and environmental benefits.

Specifically, the implementation of ACES could result in:

- By 2020, application of CCS technology in 13 to 14 gigawatts (GW) of coal power generation capacity, capturing 78 to 85 million metric tons (tonnes) of $CO_2$ per year (about 4 billion cubic feet per day (Bcfd)).
- By 2030, 69 to 109 GW of new coal and natural gas-fired power generation capacity equipped with CCS technology, reducing annual $CO_2$ emissions by 410 to 530 million tonnes in 2030.
- The productive use of this captured $CO_2$ for EOR could increase domestic oil production by 3.0 to 3.6 million barrels per day by 2030, *assuming all of the captured $CO_2$ is preferentially used for EOR*.[1] Cumulatively, from 12% to 19% of the economically recoverable $CO_2$-EOR potential in the Lower-48 would be produced by 2030.[2] The reduction of oil imports that could result from this increased domestic production would represent 33-40% of net crude oil imports in 2009 and 43-52% of net crude oil imports projected in 2030.[3]
- The cumulative reduction in oil imports that could result between now and year 2030 would improve the trade balance by nearly $700 billion, resulting in increased state and Federal revenues of $190 to $210 billion.

[1] This is not necessarily what is expected to take place as a result of the ACES.
[2] U.S. Department of Energy, National Energy Technology Laboratory, *Storing $CO_2$ with Enhanced Oil Recovery*, February 2008 (see Reference 4)
[3] Energy Information Administration, *Annual Energy Outlook*, April 2009.

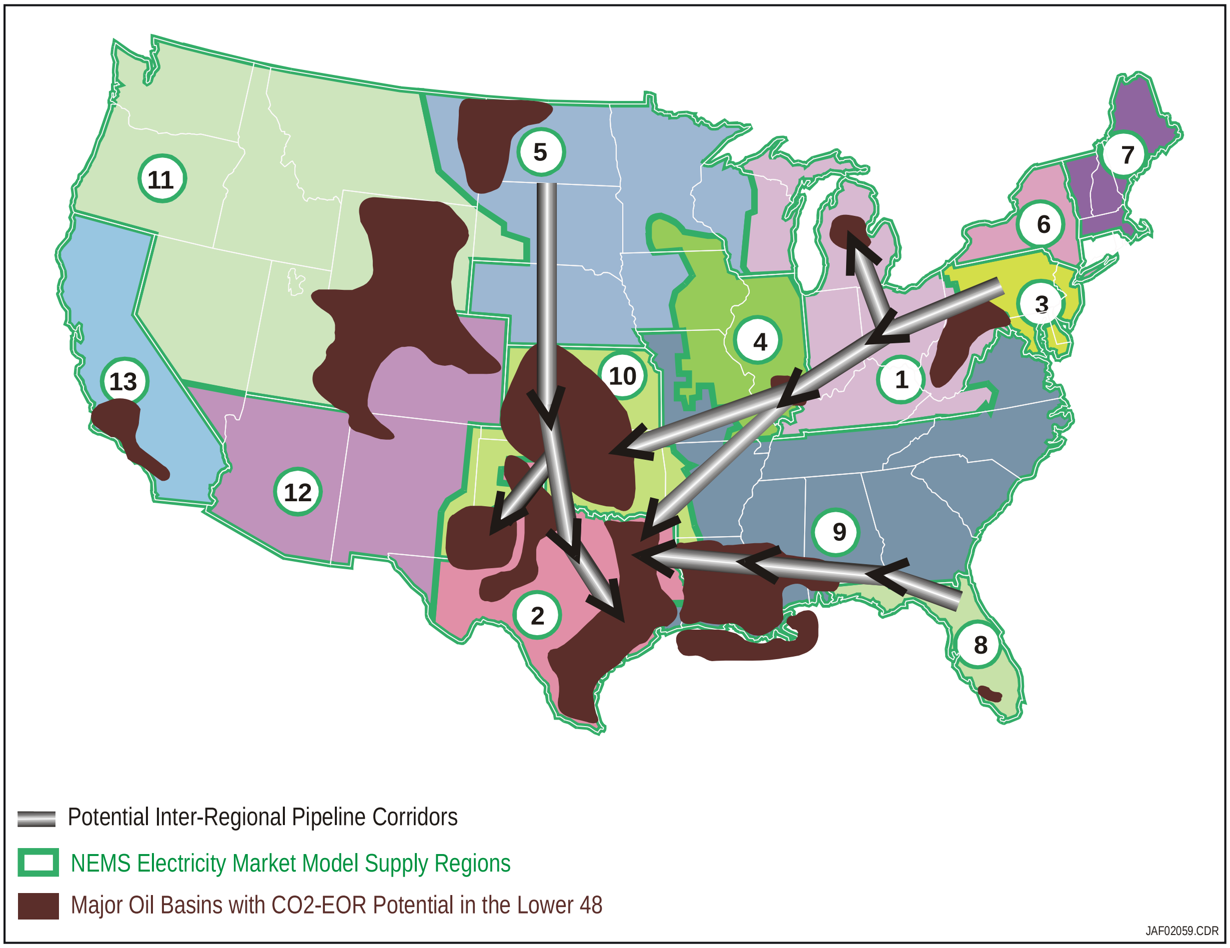
National Energy Market Model (NEMS) runs by the Natural Resources Defense Council (NRDC) and the Energy Information Administration (EIA) of the impacts of implementing ACES provide the foundation for the projected deployment of CCS-equipped power plants assumed in our study. In addition, NRDC modeled CCS deployment and $CO_2$-EOR production at the aggregate national level in MARKAL (acronym for MARKet ALlocation). The widespread deployment of CCS-equipped power plants and large supplies of captured $CO_2$ emissions would result in significantly lower $CO_2$ costs than assessed in previous reports on $CO_2$-EOR potential and enable the widespread and rapid expansion of $CO_2$-EOR production.[3,4]

Productively using $CO_2$ to enhance oil recovery is neither a new nor an exotic technology. Today, 105 $CO_2$-EOR projects provide over 250,000 barrels per day of incremental oil production in the U.S. Since 1986, about 1.5 billion barrels of domestic oil have been using $CO_2$-EOR, with another 1 billion barrels currently booked as proven reserves. However, the single largest deterrent to expanding production from $CO_2$-EOR today is the lack of large volumes of reliable and affordable $CO_2$. Most of the $CO_2$ used for EOR today comes from natural $CO_2$ reservoirs, which are limited in capacity. Thus, an attractive market exists for $CO_2$ emissions captured from industrial sources and power plants for expanding domestic oil production through the application of $CO_2$-EOR.

In the near-term, lower cost, high-purity $CO_2$ captured from the host of smaller industrial (non-power) sources would “kick start” the field pilots, demonstrate $CO_2$-EOR in new oil fields, and accelerate early $CO_2$-EOR market growth in underdeveloped oil basins. Captured $CO_2$ from power plants would provide the subsequent large volumes of $CO_2$ needed to scale up $CO_2$-EOR in these basins.

The captured $CO_2$ need not be adjacent to or near oil fields amenable to $CO_2$-EOR for this option to be economically viable. The vast majority of power plants projected to be equipped with CCS would be within 700 miles of oil basins with significant $CO_2$-EOR potential. This distance is comparable to existing and planned $CO_2$ pipelines, of which more than 3,500 miles exist today in the U.S. In fact, in this white paper, as shown in Figure ES-1, which illustrates *just one of the many possible ways* a $CO_2$ capture, transport and storage industry could evolve by 2030 in response to these regional imbalances and efficiently allow for captured volumes of $CO_2$ from CCS to be utilized to take advantage of $CO_2$-EOR opportunities. As shown, the transport network necessary to serve a CCS-oriented marketplace would be much less complicated than the current network utilized for natural gas.

Figure ES-1. Possible Way That U.S. $CO_2$ Capture/Transport/And Storage Could Evolve




The bulk of U.S. oil fields are amenable to $CO_2$-EOR. Application of today's "best practices"[4] $CO_2$-EOR technology to these oil fields could enable 85 billion barrels to become technically recoverable (over 72 billion barrels in the Lower 48). At an oil price of $70 per barrel and delivered $CO_2$ costs of $15 per metric ton, 48 billion barrels would be economically recoverable (over 38 billion barrels in the Lower 48), providing a large volume market for captured $CO_2$.

[4] "Best practices" in this assessment, assumes "State-of-the-Art" technology characteristics used in previous DOE/NETL studies. These represent the practices used by the most sophisticated operators today. (See discussion in the text of this report, as well as Reference 4)

Importantly, the use of "next generation"[5] $CO_2$-EOR technology would make 119 billion barrels technically recoverable (106 billion barrels in the Lower 48), with 66 billion barrels economic at $70 per barrel oil and $15 per metric ton $CO_2$ (57 billion barrels in the Lower 48).

The nation's oil reservoirs amenable to $CO_2$-EOR are more than adequate to make use of the projected supplies of captured $CO_2$ emissions to support increased domestic oil production of 3.0 to 3.6 million barrels per day, and to provide a high volume market for captured $CO_2$ emissions well past the year 2030. Higher production rates could be achieved with additional CO2 supplies from industrial (non power) sources, which will also be incentivized under proposed emission limits and CCS incentives.

Technically and Economically Recoverable Domestic Oil Resources from CO2-EOR*

| Region | Incremental Technically Recoverable Oil* (Billion Barrels) | | Incremental Economically Recoverable Oil** (Billion Barrels) | |
|---|---|---|---|---|
| | "Best Practices" | "Next Generation" | "Best Practices" | "Next Generation" |
| Lower 48 | 72.4 | 106.3 | 38.5 | 56.5 |
| TOTAL | 84.8 | 118.7 | 48.0 | 66.0 |

*Incremental technically recoverable oil resources after subtracting 2.3 billion barrels already being developed with $CO_2$-EOR.
**Assumes an oil price of $70 per barrel (constant, real) and a $CO_2$ cost of $15 per metric ton ($0.79/Mcf), delivered at pressure to the field.

[5] "Next Generation" in this assessment, assumes technology characteristics used in previous DOE/NETL studies. Specifically, it assumes: ((1) Increasing the volume of $CO_2$ injected into the oil reservoir; (2) optimizing well design and placement, including adding infill wells, to achieve increased contact between the injected $CO_2$ and the oil reservoir; (3) improving the mobility ratio between the injected $CO_2$/water and the residual oil; and, (4) extending the miscibility range, thus helping more reservoirs achieve higher oil recovery efficiency.(See discussion in the text of this report, as well as Reference 3).

## BACKGROUND AND OBJECTIVE

Implementation of the American Clean Energy and Security Act (ACES), or H.R. 2454, which was passed by the U.S. House of Representatives in 2009 (the "Waxman-Markey" bill), or similar legislation, would result in rapid deployment of carbon capture and storage (CCS) by new power generation and industrial facilities through the bill's extensive incentives for the technology.[6] As of the publication of this report, additional incentives are being considered by the U.S. Senate to further encourage CCS from both power generation facilities (including gas-fired facilities) and other industrial sources.

It has been alleged that requiring CCS for new power generation capacity would impose severe economic hardships on consumers and the nation's economy. In fact, this report demonstrates that CCS can provide both significant environmental and economic benefits; especially if value-added opportunities for productively using captured carbon dioxide ($CO_2$) are encouraged and pursued. In addition, large-scale CCS deployment could lead to significant increases in energy security. The captured $CO_2$, if stored in depleted oil fields with $CO_2$ enhanced oil recovery ($CO_2$-EOR) technologies, could result in significant increases in domestic oil production, with commensurate reductions in oil imports. Specifically, combining $CO_2$ storage with $CO_2$-EOR can help produce more oil from mature, already-developed oil fields in the U.S., while sequestering large quantities of $CO_2$, rather than emitting this greenhouse gas (GHG) to the atmosphere.

As such, $CO_2$-EOR can provide a "bridge" to a low-carbon energy future involving widespread market penetration of CCS technology. Revenues from $CO_2$ sales to the oil industry can offset some of the costs of $CO_2$ capture from both natural gas- and coal-fired power plants, as well as other industrial facilities producing large volumes of $CO_2$. In addition, $CO_2$-EOR can facilitate the construction of $CO_2$ pipelines and other infrastructure for transporting and storing $CO_2$ into other types of subsurface formations as well. Finally, the support provided by $CO_2$-EOR for early implementation of CCS will help drive down the costs of capture, the largest cost hurdle for CCS, through "learning by doing."

While previous reports by the U.S. Department of Energy (DOE), National Energy Technology Laboratory (NETL) have reported estimates of the overall national oil supply potential from $CO_2$-EOR, estimates of potential future oil production as a function of forecast deployment of CCS have not been

[6] Section 115 of the legislation contains an incentive program for CCS deployment subsidies that are estimated to amount to $150-200 billion, incentivizing up to 72 gigawatts equivalent of power generation and industrial capacity.

previously published. Recent work by the Natural Resources Defense Council (NRDC) and the Energy Information Administration (EIA) to assess the potential energy and economic impacts of implementing ACES provides projections of CCS deployment. Based on these projections, potential volumes of captured $CO_2$ emissions that would need to be stored, assuming all $CO_2$ captured from CCS deployment is used for $CO_2$-EOR, can be estimated. These projections of stored $CO_2$ emissions thus provide the essential link between available $CO_2$ supplies from captured anthropogenic sources and the projection of future oil production from the domestic application of $CO_2$-EOR.

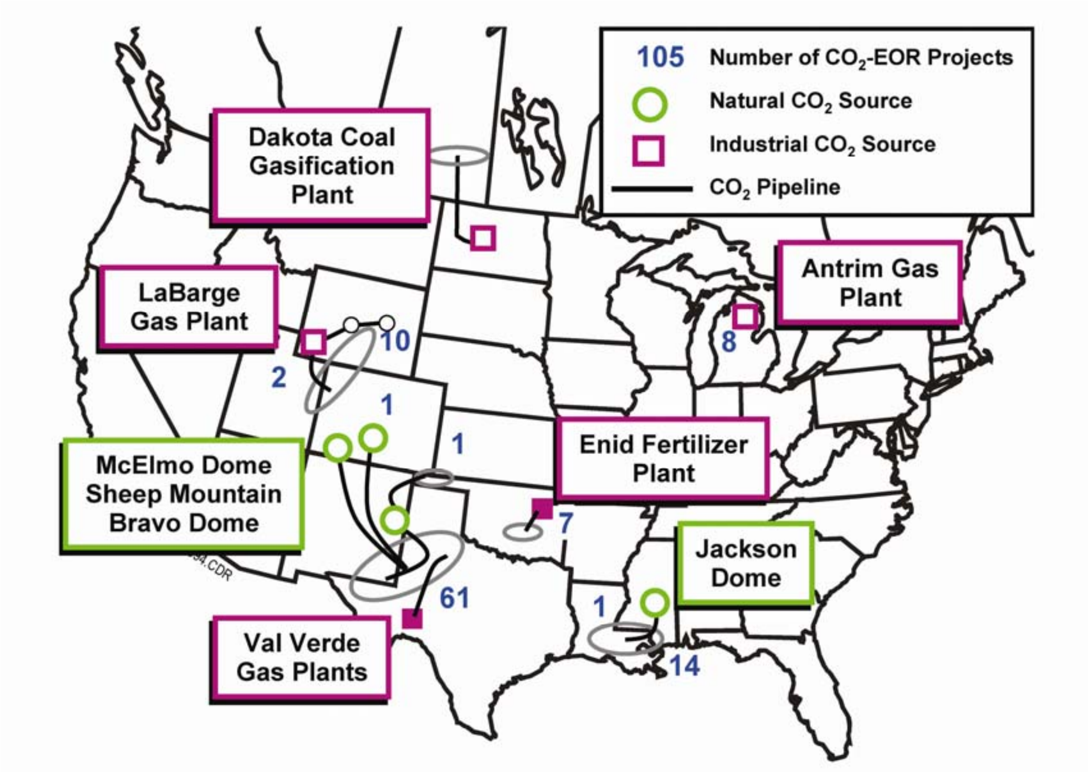
Therefore, the objective of this study is to estimate the oil production potential from $CO_2$-EOR, over time, as a function of forecast CCS deployment, and characterize some of the economic and environmental benefits that could result from this increased domestic oil production for the nation as a whole and for specific regions.

## CURRENT $CO_2$-EOR ACTIVITY

The process of injecting $CO_2$ to enhance the recovery of oil is not new or exotic. $CO_2$-EOR technologies have been demonstrated at commercial scale for over 30 years in the Permian Basin of West Texas and Eastern New Mexico. Today, 105 $CO_2$-EOR projects provide nearly 250,000 barrels per day of incremental oil production in the U.S. (Figure 1). Since 1986, over 1.3 billion barrels of incremental oil has been recovered using this technology, with another 1 billion barrels remaining as proven reserves.[1] The technically and economically recoverable oil from $CO_2$-EOR, however, is orders of magnitude higher, as is documented in this report.

These current $CO_2$-EOR projects are, for the most part, injecting $CO_2$ sourced from natural $CO_2$ reservoirs; sources of $CO_2$ that are high in purity and accessible at relatively low cost. Over 80% of the $CO_2$ used for $CO_2$-EOR projects in the U.S. in 2008 came from four large natural $CO_2$ fields – Jackson Dome, Sheep Mountain, McElmo Dome, and Bravo Dome. The rest of the $CO_2$ used for $CO_2$-EOR projects – still amounting to over 500 million cubic feet per day (MMcfd) or 10 million metric tons (tonnes) per year – comes from natural gas processing plants, ammonia plants, and one large coal gasification facility (Table 1).

Figure 1. Major $CO_2$-EOR Activity in the U.S.




Source: Advanced Resources International, Inc., 2009

Table 1. Volumes of $CO_2$ Supplying EOR Projects in 2008

| State/Province (Storage location) | Source Type (location) | $CO_2$ Supply (million tonnes/year) | | $CO_2$ Supply (MMcfd) | |
|---|---|---|---|---|---|
| | | Natural | Anthropogenic | Natural | Anthropogenic |
| Texas-Utah-New Mexico-Oklahoma | Geologic (Colorado-New Mexico) Gas Processing (Texas) | 28 | 2 | 1,455 | 80 |
| Colorado-Wyoming | Gas Processing (Wyoming) | | 4 | | 230 |
| Mississippi | Geologic (Mississippi) | 15 | | 800 | |
| Oklahoma | Fertilizer Plant (Oklahoma) | | 1 | | 35 |
| Michigan | Gas Processing (Michigan) | | <1 | | 15 |
| Saskatchewan | Coal Gasification (N. Dakota) | | 3 | | 150 |
| **TOTAL** | | **44** | **10** | **2,255** | **510** |

Source: Brian Hargrove, L. Stephen Melzer, and Lon Whitman, "A Status Report on North American $CO_2$-EOR Production and $CO_2$ Supply, presented at the 14th Annual $CO_2$ Flooding Conference, Midland, TX, December 11-12, 2008

Despite the many projects in the U.S., $CO_2$-EOR activity elsewhere in the world is limited. Moreover, the vast majority of these projects were not initiated with eventual $CO_2$ storage in mind. One exception -- the "poster child" of an integrated $CO_2$-EOR and $CO_2$ sequestration project -- is EnCana's Weyburn $CO_2$ flood in Canada, where oil production from $CO_2$-EOR continues to increase. EnCana buys anthropogenic $CO_2$ from the Dakota Gasification Synfuels plant in Beulah, North Dakota. The project currently injects 2.4 million tonnes of $CO_2$ per year, and plans to store 23 million tonnes, to support its $CO_2$-EOR operations. With continued $CO_2$ injection after EOR operations have ceased, the ultimate expectation is to store 55 million tonnes of $CO_2$.[2] Substantial additional $CO_2$-EOR and associated $CO_2$ storage potential also exists in Apache's nearby Midale field.

The steady growth of $CO_2$ flooding in the Permian Basin, as well as in other areas, offers a case history for possible extrapolation to other regions. A review of the history of $CO_2$-EOR shows that it is generally successful in fields that meet the technical criteria for achieving miscibility (defined primarily in terms of reservoir depth and oil viscosity), that have a relatively large volume of unrecovered oil after primary and secondary recovery (water flooding), and where there is a good source of sufficient, predictable, sustainable volumes of high purity $CO_2$ supplies at affordable costs. Over time, other factors that contribute to success are operator knowledge, comfort and willingness to use $CO_2$-EOR technologies; the willingness and ability of the applicable regulatory regime to permit $CO_2$-EOR projects, and the availability of government financial incentives to promote $CO_2$-EOR.

In the past, $CO_2$-EOR project "failures" have generally resulted from either collapses in oil prices, such as was the case in 1986 and 1998, or the unwillingness of companies to "see the projects through." $CO_2$-EOR requires large up-front investments and is relatively slow in yielding financial returns on those investments. As a result, internal rates of return are traditionally not robust. The advantage of $CO_2$-EOR is that it has lower risks than exploration projects, can be deployed faster if the infrastructure is in place, and that large reserves associated with its application can be booked. Most oil companies are exploration-oriented and can be misled by the "unrisked" rates of return present in exploration projects. Historically, some companies have set unreasonable expectations on $CO_2$-EOR projects and, when these projects, in their view, underperformed, management made the decision to cut losses and abandon $CO_2$ injection. As a result, in some cases, the "potential" for $CO_2$-EOR was not realized in practice by those companies, whereas companies that acquired those fields managed to secure profitable operation in the long run.

## POTENTIAL DOMESTIC OIL RESOURCES FROM $CO_2$-EOR

In January 2009, the U.S. Department of Energy, National Energy Technology Laboratory published a report that quantified the potential benefits of integrating $CO_2$ storage with "next generation" $CO_2$-EOR technology.[3] This work built upon previous analyses of currently practiced, or "best practices" $CO_2$-EOR technology, in "*Storing $CO_2$ with Enhanced Oil Recovery*"[4] and a series of "*Ten Basin-Oriented*

*Reports*" [5]. The 2009 report involved individually assessing over 2,000 large oil reservoirs in eleven U.S. oil basins/areas,[7] of which, over 1,100 were amenable to the application of $CO_2$-EOR.

Considerable evolution has occurred in the design and implementation of $CO_2$-EOR technology since it was first introduced. Notable changes include: (1) use of much larger (up to 1.0 hydrocarbon pore volume (HCPV)) volumes of $CO_2$; (2) incorporation of tapered water alternating with gas (WAG) and other methods for mobility control; and (3) application of advanced well drilling and completion strategies to better contact previously bypassed oil. As a result, the oil recovery efficiencies of today's better designed "best practices" $CO_2$ -EOR projects have steadily improved. In this report, we assumed that such "best practices" were applied at a minimum to all prospective $CO_2$-EOR projects. Specifically, "best practices" in this assessment, assumes "State-of-the-Art" technology characteristics used in previous DOE/NETL studies. These represent the practices used by the most sophisticated operators today, which are much improved over the $CO_2$-EOR practices traditionally used by many operators.

Two key assumptions underlie the oil recovery performance estimated for "best practices" $CO_2$-EOR:

- The injection of much larger volumes of $CO_2$ (1.0 HCPV), rather than the smaller (0.4 HCPV) volumes used in the past;
- Rigorous $CO_2$-EOR monitoring, management and, where required, remediation activities that help assure that the larger volumes of injected $CO_2$ contact more of the reservoir's pore volume and residual oil rather than merely channel through high permeability streaks in the reservoir.

In addition to these two central assumptions, the estimated oil recovery under the "best practices" scenario also assumes appropriate well spacing (including the drilling of new infill wells), the use of a tapered WAG process, the maintenance of minimum miscibility pressure (MMP) throughout the reservoir, and the reinjection of $CO_2$ produced with oil.

"Next Generation" $CO_2$-EOR technology, in this assessment, again assumes technology characteristics used in previous DOE/NETL studies. Specifically, it assumes:

Innovative flood design and well placement by adding horizontal production wells and vertical $CO_2$ injection wells, enabling $CO_2$ to contact residual oil from poorly swept portions of the reservoir

[7] These 2,000+ large oil reservoirs account for 73% of the total U.S. oil endowment (original oil in-place).

Viscosity and miscibility enhancement by adding mobility control with viscosity enhancers and lowering MMP with miscibility enhancers

Increased volumes of $CO_2$ injection, assuming the injection of up to 1.5 HCPV of $CO_2$ (compared to 1.0 HCPV under "best practices")

Flood performance diagnostics and control through the use of instrumented observation wells, downhole sensors to monitor progress, periodic 4-D seismic, and pressure plus zone-by-zone flow tests (among others) to "manage and control" the $CO_2$ flood. ). (See Reference 3).

Because the deployment of "next generation" technologies is more costly than that for "best practices," it is not the economically preferred option in some settings.

Of the estimated 596 billion barrels of U.S. oil endowment (expressed as original volumes of oil in place, or OOIP), about two-thirds (395 billion barrels) is favorable for $CO_2$-EOR. Application of "best practices" $CO_2$-EOR would enable over 72 billion barrels to be technically recoverable in the Lower 48. At oil prices of \$70 per barrel and $CO_2$ costs of \$15 per tonne, over 38 billion barrels would be economically recoverable.[8] This is in addition to the estimated 2.3 billion barrels already being developed with $CO_2$-EOR in the U.S.

The use of "next generation" technology would add to these totals. Specifically, the application of this technology would provide over 106 billion barrels of technically recoverable domestic oil in the lower 48 (nearly 50% more than can be accomplished with current best practices for $CO_2$-EOR) (Table 2). About 70% of this technical potential exists in just four regions (California, Mid-Continent, Permian Basin, and East/Central Texas). Of this technically recoverable resource, over 57 billion barrels would be economically recoverable at these oil prices and $CO_2$ costs. *(For purposes of this assessment, the $CO_2$-EOR potential in Alaska was not included.)*

[8] The two primary factors that influence the economic viability of a $CO_2$-EOR project is the price of oil and the delivered cost of $CO_2$; thus the focus on these two factors. While average rates of return for the oil industry tend to average much lower, in practice, a 25% ROR hurdle rate was assumed in this assessment to represent the increased risks associated with the application of $CO_2$-EOR, especially for those operators not familiar with the technology.

Table 2. Economically Recoverable Domestic Oil Resources from $CO_2$-EOR*

| Region | Incremental Technically Recoverable Oil* (Billion Barrels) | | Incremental Economically Recoverable Oil** (Billion Barrels) | |
|---|---|---|---|---|
| | "Best Practices" | "Next Generation" | "Best Practices" | "Next Generation" |
| California | 6.3 | 10.0 | 5.5 | 7.8 |
| Gulf Coast (AL, FL, MS, LA) | 7.0 | 7.4 | 2.3 | 2.3 |
| Mid-Continent (OK, AR, KS, NE) | 10.6 | 17.0 | 5.6 | 8.7 |
| Illinois/Michigan | 1.2 | 3.2 | 0.5 | 1.7 |
| Permian (W TX, NM) | 15.9 | 28.0 | 9.4 | 15.0 |
| Rockies (CO,UT,WY) | 3.9 | 7.1 | 2.2 | 4.3 |
| Texas, East/Central | 17.6 | 20.0 | 8.4 | 12.1 |
| Williston (MT, ND, SD) | 2.5 | 5.2 | 0.5 | 0.5 |
| Appalachia (WV, OH, KY, PA) | 1.6 | 2.6 | 0.1 | 0.1 |
| Louisiana Offshore | 5.8 | 5.8 | 3.9 | 3.9 |
| Lower 48 | 72.4 | 106.3 | 38.5 | 56.5 |
| Alaska | 12.4 | 12.4 | 9.5 | 9.5 |
| TOTAL | 84.8 | 118.7 | 48.0 | 66.0 |

*Incremental technically recoverable oil resources after subtracting 2.3 billion barrels already being developed with $CO_2$-EOR.
**Assumes an oil price of $70 per barrel (constant, real) and a $CO_2$ cost of $15 per metric ton ($0.79/Mcf), delivered at pressure to the field; and a 25% investment hurdle rate of return

Table 3 provides a region-by-region tabulation of the volumes of $CO_2$ that would be needed to supply both "best practices" and "next generation" $CO_2$-EOR projects, assuming a $70 per barrel oil price and $15 per tonne $CO_2$ cost (delivered at pressure), excluding $CO_2$ demand from projects already underway. Under the "best practices" case, overall incremental demand in the Lower 48 for $CO_2$ in the "best practices" case is estimated to be 9.8 billion tonnes. Under "next generation" technology case, overall demand in the Lower 48 for $CO_2$ increases to 11.5 billion tonnes.

Table 3. Economically Feasible Market for $CO_2$ for "Next Generation" $CO_2$-EOR*

| Region | Gross Market for $CO_2$ (million metric tons) | | $CO_2$ Already Scheduled to be Injected (million metric tons) | Net New Market for $CO_2$ (million metric tons) | |
|---|---|---|---|---|---|
| | "Best Practices" | "Next Generation" | | "Best Practices" | "Next Generation" |
| California | 1,410 | 1,459 | - | 1,410 | 1,459 |
| Gulf Coast (AL, FL, MS, LA) | 721 | 721 | 250 | 471 | 471 |
| Mid-Continent (OK, AR, KS, NE) | 1,439 | 1,778 | 20 | 1,419 | 1,758 |
| Illinois/Michigan | 122 | 365 | - | 122 | 365 |
| Permian (W TX, NM) | 2,877 | 3,648 | 570 | 2,307 | 3,078 |
| Rockies (CO,UT,WY) | 568 | 809 | 74 | 494 | 735 |
| Texas, East/Central | 1,997 | 2,182 | - | 1,997 | 2,182 |
| Williston (MT, ND, SD) | 125 | 92 | - | 125 | 92 |
| Appalachia (WV, OH, KY, PA) | 41 | 18 | - | 41 | 18 |
| Louisiana Offshore | 1,386 | 1,386 | - | 1,386 | 1,386 |
| Lower 48 | 10,687 | 12,456 | 914 | 9,773 | 11,542 |
| Alaska | 2,094 | 2,094 | - | 2,094 | 2,094 |
| TOTAL | 12,781 | 14,550 | 914 | 11,867 | 13,636 |

*Assumes oil price of $70 per barrel; $CO_2$ cost of $15 per metric ton; and a 25% investment hurdle rate of return

Important to note in Table 3 that only a small portion (914 million tonnes) of the potential demand for $CO_2$ in $CO_2$-EOR projects will be met by existing CO2 supplies currently serving this market.

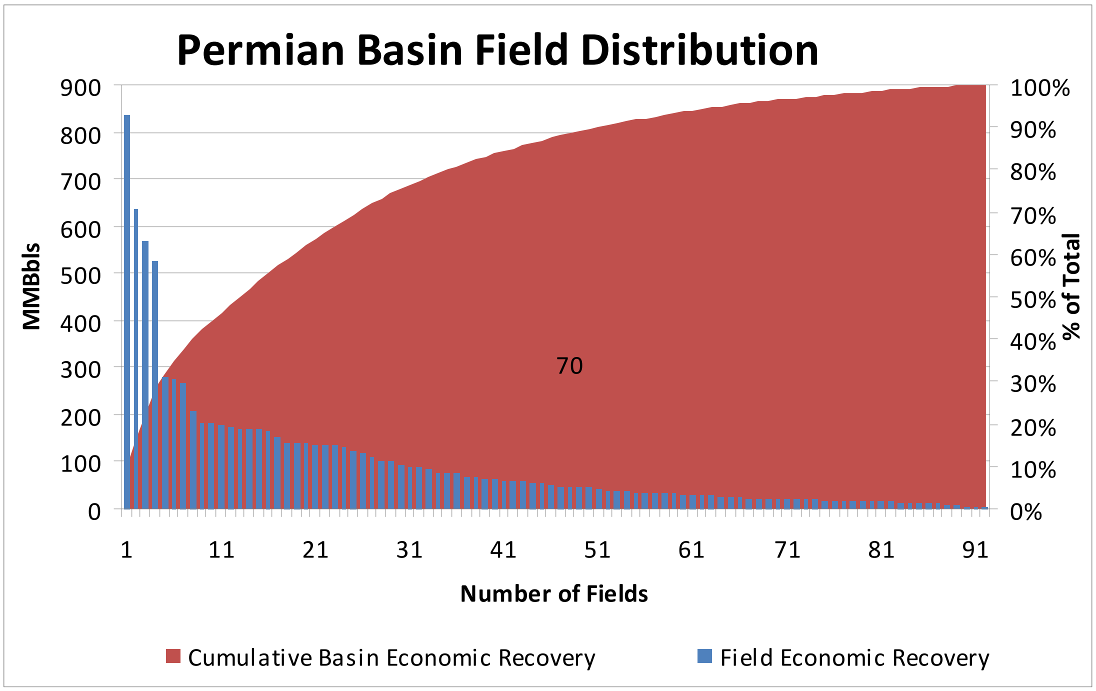
Moreover, if oil prices rise above $70 per barrel and/or if $CO_2$ costs drop below $15 per tonne, greater economic potential for $CO_2$-EOR exists. Likewise, if oil prices drop below $70 per barrel, and/or if $CO_2$ costs are greater than $15 per tonne, there would be less economic potential for $CO_2$-EOR.

Based on this characterization of economic potential for $CO_2$-EOR, it takes, on average, approximately 0.28 tonnes of $CO_2$ per incremental barrel produced for $CO_2$-EOR under the "best practices" scenario, and 0.22 tonnes of $CO_2$ per incremental barrel produced under the "next generation" technologies case.

## DISTRIBUTION OF ECONOMIC $CO_2$-EOR PROSPECTS

Within each region of the country, the majority of the economic $CO_2$-EOR potential generally exists in a relatively small share of the economic prospects. For example, as shown in Figure 2 for the Permian Basin of West Texas, of the 7.1 billion barrels of economic resource potential, consisting of 92 economic prospects (at an oil price of $70 per barrel), 70% of the economic resource potential exists in 25 economic prospects with 625 million barrels or more of original oil in place.

Figure 2. Distribution of Oil Production Potential by Field Size




Source: U.S. Department of Energy/National Energy Technology Laboratory

However, the nature of this distribution varies from region to region, as shown in Table 4 for the onshore regions of the U.S. For example, in Appalachia 70% of the economic resource potential exists in just 2 prospects (out of 6 total economic prospects) with a field size greater than 150 million barrels of original oil in place. In California, 70% of the resource potential exists in 17 large prospects, out of 75, with a field size of over 830 million barrels of original oil in place. In the region with the largest potential, East and Central Texas, of the 8.3 billion barrels of economic resource potential, consisting of 125 economic prospects, 70% of the resource potential exists in 21 prospects larger than 305 million barrels of original oil in place.

Table 4. Cumulative Probability Distribution for Onshore Economic $CO_2$-EOR Prospects

| $CO_2$-EOR Field Cumulative Probability Distribution | | | | | |
|---|---|---|---|---|---|
| Region | Field Size Cutoff for 70% of Economic Potential (MMBbls) | Fields > Field Size Cutoff | | Fields < Field Size Cutoff | |
| | | # | % of Total | # | % of Total |
| **California** | 830 | 17 | 23% | 58 | 77% |
| **Gulf Coast (AL, FL, MS, LA)** | 149 | 26 | 34% | 50 | 66% |
| **Mid Continent (OK, AR, KS, NE)** | 289 | 21 | 29% | 51 | 71% |
| **Illinois/Michigan** | 77 | 9 | 20% | 35 | 80% |
| **Permian (W TX, NM)** | 625 | 25 | 27% | 67 | 73% |
| **Rockies (CO, UT, WY)** | 135 | 21 | 30% | 49 | 70% |
| **Texas (East/Central)** | 305 | 21 | 17% | 104 | 83% |
| **Williston (MT, ND, SD)** | 96 | 9 | 41% | 13 | 59% |
| **Appalachia (WV, OH, KY)** | 150 | 2 | 33% | 4 | 67% |
| **Average** | 295 | 151 | 26% | 431 | 74% |

Source: U.S. Department of Energy/National Energy Technology Laboratory

Based on this, regions like Illinois/Michigan, with a small field size cut-off, would probably not be an attractive destination for a large scale $CO_2$ pipeline project, but may lend themselves to a local network of sources and sinks.

Thus, in the Lower-48 overall, 70% of the economic resource potential exists in 151 economic prospects (at an oil price of $70 per barrel), or 26% of the 582 *economic* prospects at these conditions (out of the over 1,100 prospects that are technically amenable to $CO_2$-EOR).

The importance of the characterization of this distribution is that, in the initial stages of growth of the $CO_2$-EOR/CCS market, these largest $CO_2$-EOR prospects will serve as the "anchors" for the establishment of $CO_2$ transport and storage infrastructure in the various basin regions. Once infrastructure is established around these "anchor" prospects, the development of the smaller prospects can subsequently occur more economically, adding both to the oil production and economic storage potential achieved within the region.

However, it is important to recognize that for a single large coal-fired electric power production facility, producing 5 to 8 million tonnes of $CO_2$ per year for as long as 50 years, a single $CO_2$-EOR prospect will generally not be sufficiently large to store all of the $CO_2$ emissions from the plant. However, a hydrocarbon basin, in general, will be able to accommodate, in aggregate, the output of a number of plants. Thus, given the nature of the field size distribution in a basin described above, in most cases, several $CO_2$ -EOR prospects will often need to be pooled together to accommodate the produced $CO_2$.

The largest fields will serve as anchors, with the smaller fields coming on line over time as the initial costs of $CO_2$ capture and transport infrastructure are covered.

## LIMITS TO AND PLANNED EXPANSION OF $CO_2$-EOR IN THE U.S.

The single largest barrier to expanding $CO_2$ flooding today is the lack of substantial volumes of reliable and affordable $CO_2$. The establishment of $CO_2$ sources and the resulting growth of $CO_2$ flooding in the Permian Basin, Wyoming, and Mississippi provide three independent case histories as testament to this observation. Today, all three areas are constrained by $CO_2$ supply, and $CO_2$ production from current supply sources is fully committed.

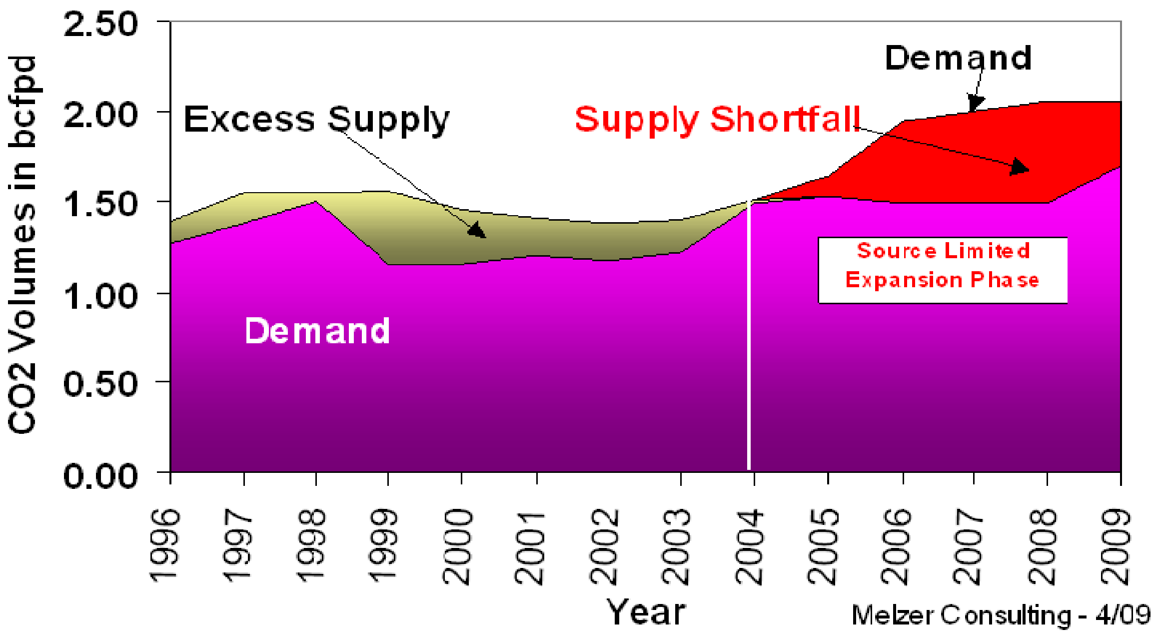
For example, after nearly a decade where $CO_2$ supplies in the Permian Basin outpaced demand in $CO_2$-EOR projects, since 2004 there has been a shortfall of $CO_2$ supply (Figure 3). Similarly, in other regions of the U.S. where $CO_2$ activity is currently taking place, most $CO_2$-EOR operators believe that the relatively scarce availability of $CO_2$ limits industry's ability to greatly expand the application of $CO_2$-EOR.

Some companies are taking steps to address, at least to some extent, this limitation. For example, in the Permian Basin:

- Kinder Morgan completed its Doe Canyon natural gas processing plant in southwestern Colorado in early 2008, adding 3.5 million tonnes per year of $CO_2$ supply availability to the Permian Basin. In addition, McElmo Dome has added another 3.5 million tonnes per year of $CO_2$ production capacity.
- Enhanced Oil Resources Inc. (EOR Inc.) announced a memorandum of understanding (MOU) for developing a pipeline with SunCoast Energy Corp. to transport 6 million tonnes per year of $CO_2$ nearly 350 miles from its St. Johns, Arizona helium and $CO_2$ field to the Permian Basin.[6]

- In June 2008, SandRidge Energy announced their agreement with Occidental to build a $CO_2$ treatment plant and associated $CO_2$ compression and pipeline facilities at the company's natural gas processing operations in Pecos and Terrell Counties in Texas, providing Occidental with a dedicated $CO_2$ stream for $CO_2$-EOR. The plant could ramp up to 8 million tonnes per year of $CO_2$.[7]

Figure 3. $CO_2$ Supply and Demand in the Permian Basin

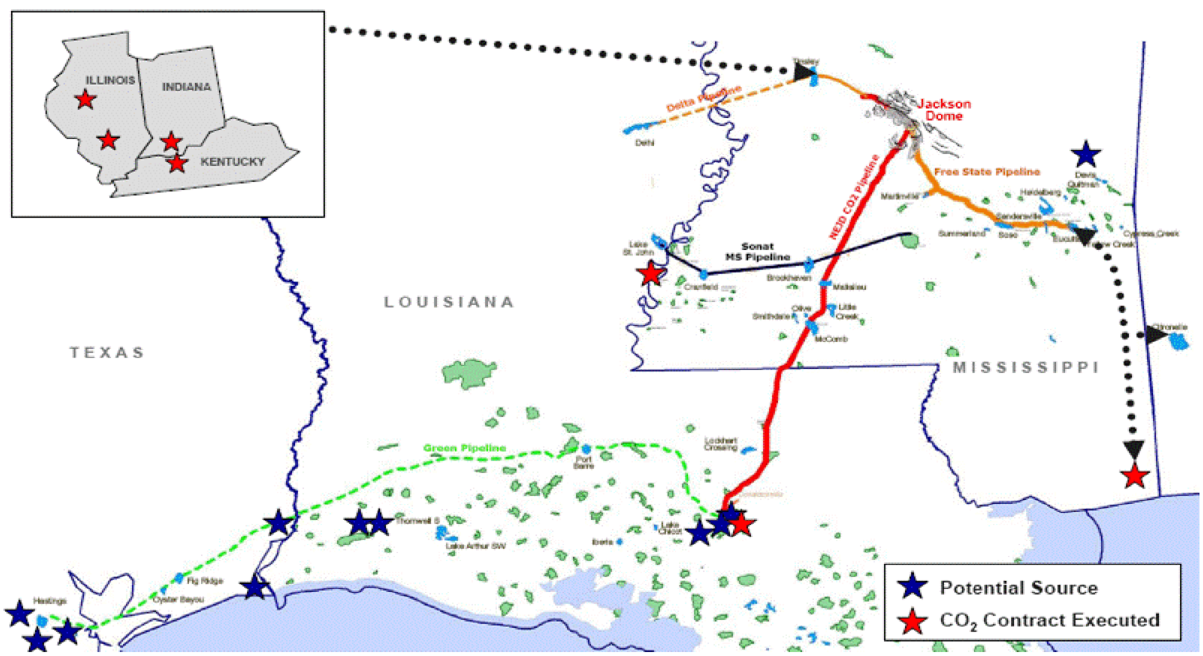



Similarly, in Wyoming, Anadarko has plans to extend to the Linch-Sussex area its 125 mile pipeline that currently transports $CO_2$ to the Salt Creek and Monell fields. The ExxonMobil La Barge gas plant is the source for this $CO_2$.[8] ExxonMobil is spending $70 million to expand the plant's capacity to capture $CO_2$ by 50%. Currently, its capacity is about 4 million tonnes of $CO_2$ per year; the plant's expansion, scheduled to be completed in 2010, will augment this volume to 6 million tonnes per year.[9] In July, 2009, Encore Acquisition Company announced that it would buy approximately one million tonnes per year (50 MMcfd) of $CO_2$ from the Lost Cabin Gas Plant for use in a $CO_2$-EOR project in the Bell Creek Field.[10] Several other projects are being considered that could further expand $CO_2$ supply in the region.[11]

Denbury Resources is going beyond just incremental increases in capacity by taking a long-term strategic approach to expanding $CO_2$-EOR development, and in supplying the $CO_2$ to facilitate this development, in Mississippi, Louisiana, and the Texas Gulf Coast.[12] Denbury plans to strategically expand its existing infrastructure to bring additional $CO_2$, captured from anthropogenic sources, to the $CO_2$-EOR market that already exists. The company has signed $CO_2$ purchase contracts with three planned chemical plants for a portion of their anthropogenic $CO_2$ supplies,[13] and is actively pursuing additional anthropogenic sources of $CO_2$ in the region to supplement its natural reserves (Figure 4); supplies which are projected to begin declining around 2015. In addition, the company has identified seven potential anthropogenic sources that could provide 30 to 36 million tonnes per year of $CO_2$ starting in 2013-2014.

Denbury also has plans to increase its $CO_2$ pipeline capacity, adding a $CO_2$ pipeline transporting $CO_2$ into East Texas. The approximately 510 kilometer (320 mile) "Green Pipeline" is designed to transport 13 million tonnes per year (800 MMcfd) of both natural and anthropogenic $CO_2$.

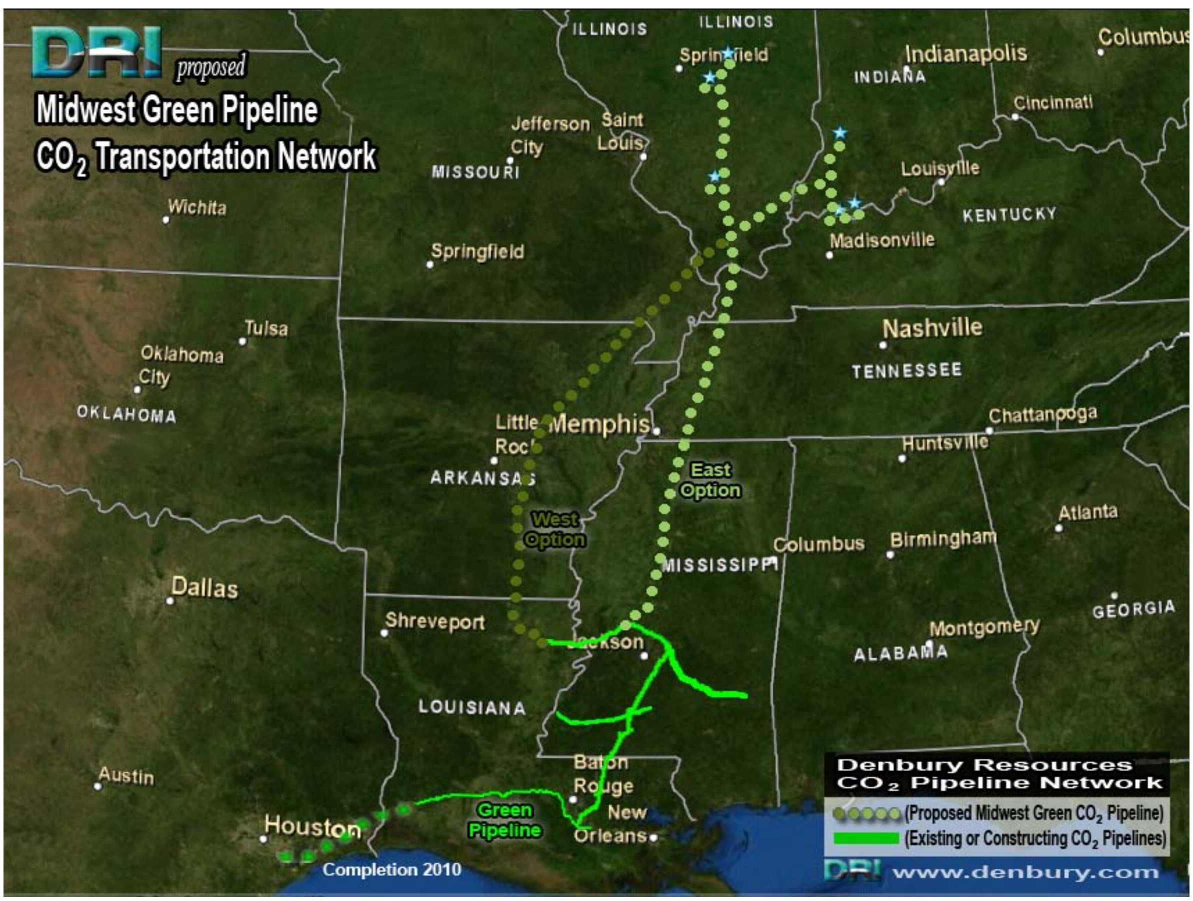
Figure 4. U.S Gulf Coast Potential Anthropogenic Sources of $CO_2$




Source: Denbury Resources Inc., June 2009 Corporate Presentation

But Denbury is also looking at bigger plans for moving $CO_2$ from areas where there are high concentrations of emissions, to areas where there is large potential for $CO_2$-EOR. In July 2009, the company announced that it has initiated a comprehensive feasibility study, in collaboration with the Illinois Department of Commerce and Economic Opportunity, of a possible long-term $CO_2$ pipeline project which would connect proposed gasification plants in the Midwest to its existing $CO_2$ pipeline infrastructure in Mississippi and/or Louisiana (Figure 5).[14] The feasibility study of the "Midwest Green Pipeline" is expected to determine the most likely pipeline route, the estimated costs of constructing such a pipeline, and review regulatory, legal and permitting requirements. Denbury's preliminary estimates suggest this would be a 500 to 700 mile pipeline system, with a preliminary cost estimate of approximately $1.0 billion. In addition to the feasibility study, Denbury has entered into contingent $CO_2$ purchase contracts with four planned Midwest facilities that would provide large volumes of captured $CO_2$.[15]

Figure 5. Denbury Resources' Strategic Vision for Moving Midwest $CO_2$ Supplies to the U.S. Gulf Coast $CO_2$-EOR Market




Source: Denbury Resources Inc., 2009

After this investment, further expanding $CO_2$ transportation capacity into East Texas and Oklahoma is also conceivable.

The bottom line is that, without substantial expansion of $CO_2$ supplies to serve $CO_2$-EOR projects in the U.S., expansion of domestic oil production from the application of $CO_2$-EOR will be limited. Moreover, given the current reserves and production of $CO_2$ from natural sources, significant expansion of supplies from these sources of $CO_2$ is also limited. Consequently, if substantial expansion in $CO_2$-EOR is to occur, additional $CO_2$ supplies will have to come from anthropogenic sources.

## POTENTIAL FOR CCS AND $CO_2$-EOR BY INDUSTRIAL EMISSIONS SOURCES

As described above, given the constraints on expansion of $CO_2$-EOR because of the scarcity of current natural sources of $CO_2$, expansion of production from $CO_2$-EOR will need to use $CO_2$ from anthropogenic sources, principally industrial facilities and power plants. Although this analysis focuses mainly on CCS adoption within the U.S. electric power sector, the influence of hundreds of industrial (non-power) $CO_2$ emission point sources needs to be considered as well.

These include a number of high purity $CO_2$ sources -- ammonia/fertilizer plants, ethanol and ethylene oxide plants, hydrogen plants, and natural gas processing plants -- which have lower capture costs than power plants and, consequently, could adopt CCS before such technologies begin to deploy broadly within the electric power sector. These high concentration $CO_2$ sources are some of the most likely earlier sources for expanded application for $CO_2$-EOR, even in the absence of enabling legislation like ACES. More than 500 of these types of industrial sources of $CO_2$ emissions exist in the U.S. Depending upon the portion of refinery emissions included, these sources can produce from 170 to 370 million tonnes of $CO_2$ per year, with perhaps a best estimate, including only $CO_2$ emissions from $H_2$ production at oil refineries, of about 200 million tonnes of $CO_2$ per year.[16]

In addition, energy intensive industries such as steel and cement production have significant potential for carbon capture, which could add an additional 90 million tonnes of $CO_2$ per year. Some of these industrial applications of carbon capture are capital intensive and would require state and federal incentives to be economic, even with potential revenue from selling captured $CO_2$ to EOR operations. In ACES, fifteen percent ($20-30 billion) of the incentive pool for CCS is reserved for a range of different industrial applications, which could support significant deployment on hundreds of additional sources.

Assuming the average value of $CO_2$ utilization for $CO_2$-EOR of 0.26 tonnes of $CO_2$ per incremental barrel produced,[9] the $CO_2$ produced from these industrial facilities could facilitate $CO_2$-EOR production of on the order of 2.1 million barrels per day assuming $CO_2$ utilization of 200 million tonnes per year.[10]

As discussed above, current sources of $CO_2$ for $CO_2$-EOR (both natural and anthropogenic) support production of over 250,000 barrels of oil per day. These sources, along with the planned expansions of $CO_2$ supply and transport capacity also discussed above, could support additional $CO_2$-EOR production for some time. Conservatively, assuming that about 300,000 barrels per day can be produced using $CO_2$ from these (predominately) natural sources, and that $CO_2$-EOR production ramps up uniformly over 18 years (from 2012 to 2030), 6 to 7 billion barrels of incremental oil could be produced using captured $CO_2$ from industrial sources, *assuming all of this $CO_2$ is utilized for $CO_2$-EOR*. This ranges from 16% to 18% of the economic Lower-48 oil production potential assuming "best practices" $CO_2$-EOR technology. This would result in 1.6 to 1.8 billion tonnes of stored $CO_2$ from "high value" industrial sources by 2030. Therefore, substantial $CO_2$-EOR oil production potential (along with the associated $CO_2$ storage potential) remains that could be the target for $CO_2$ captured via the application of CCS technologies for power plants.

[9] This is based on the combination of an average value of 0.28 tonnes of $CO_2$ per incremental barrel produced for "best practices" technology and a 0.22 tonnes of $CO_2$ per incremental barrel produced for "next generation" technology.

[10] For comparison, the latest forecasts for oil production for $CO_2$-EOR by the EIA, based on runs of NEMS, not counting that which would be attributable to natural sources of $CO_2$, range from 0.6 to 0.8 million barrels per day by 2030, depending on the scenario, without consideration of the potential contributions from CCS incentives. If $CO_2$-EOR production utilizing $CO_2$ from natural sources is included, forecast oil production from $CO_2$-EOR in the EIA forecasts ranges from 1.3 to 1.5 million barrels per day.

# FORECASTS OF POWER SECTOR CCS DEPLOYMENT FROM IMPLEMENTATION OF ACES

In this assessment, forecasts of the potential oil production from $CO_2$-EOR were based on assessments by EIA and NRDC on the energy and economic impacts of implementing ACES.[17] Included in these forecasts are estimates of deployment for coal and natural gas-fired power generation with CCS, assuming the legislation is enacted and signed more or less in the form passed by the House.

Two separate forecasts were developed by NRDC in September 2009, using two models: the National Energy Modeling System (NEMS)[18] and MARKAL (acronym for MARKet ALlocation).[19]

- NEMS is a forecasting model that is used by EIA to develop its annual long-term projections for energy supply, demand, and prices. It uses observed historical behavior in order to estimate how individual market participants will act going forward in response to changing market conditions and imposed constraints. NEMS results are presented on an annual basis through 2030.
- MARKAL is a long-term cost-optimization model with assumed perfect foresight that aims to minimize total societal costs through 2050 given imposed constraints. Originally developed by the International Energy Agency, MARKAL illustrates what could happen if all market participants had perfect information and behaved rationally. MARKAL results are presented in 5-year increments through 2050.

In the modeling runs based on both NEMS and MARKAL, NRDC used EIA's March 2009 Annual Energy Outlook (AEO) as its business-as-usual (BAU) reference case, with some modifications to reflect the extended renewable tax credits specified in the American Recovery and Reinvestment Act of 2009.[20] The April AEO 2009 updated release included changes to reflect stimulus bill provisions, as well as an updated economic forecast (reflecting the growing recession) and updated world oil prices.

The following provisions from ACES were reflected in the NEMS- and MARKAL-based assessments performed by NRDC:

- Declining emission limits
- Renewable electricity standards
- Carbon capture and storage incentives
- Energy efficiency provisions

- Vehicle efficiency standards

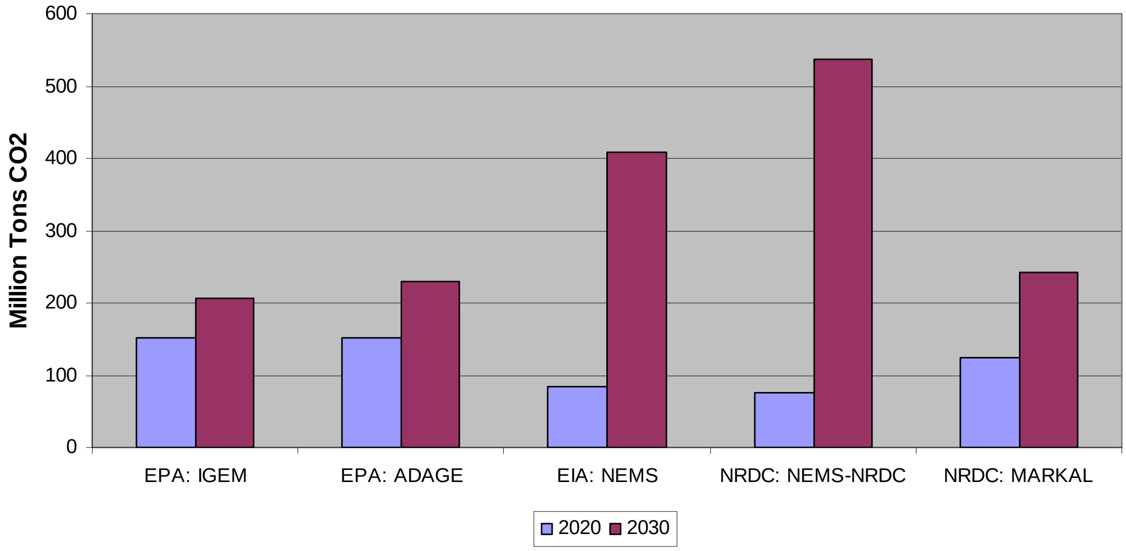
With regard to the assumed policy framework in ACES, the following policy and financial incentives relevant to CCS were addressed in these runs:

- A declining cap on 85% of U.S. emission sources of 17% below 2005 levels by 2020, increasing to 83% by 2050; oil and (residential and commercial) gas emissions are capped upstream at the refinery and distribution level, respectively;
- An initial allocation of 35% of emission allowances to electric and gas utilities, 9% to states and 15% to trade-exposed industries, transitioning to a full auction by 2036;
- A price floor for carbon allowances of $10/ton that increases 5% per year, and an allowance reserve to auction additional allowances in response to unexpected surges in allowance prices;
- Assumption that EPA establishes a comprehensive regulatory framework for CCS;
- A $10 billion demonstration program funded by a small wires charge on existing fossil generation;
- Allocation of 5% of the allowances to a commercial deployment program, 85% of which is for power plants and a maximum of 15% for industrial sources, with a total CCS capacity deployment of up to the equivalent of 72 gigawatts (GW) of coal-fired power plants. For power plants, the incentive starts at $90 per tone and transitions to a reverse auction or reverts to a fixed-value incentive that declines with installed capacity; and,
- An emission performance standard on all new coal plants built after 2009 that will likely require CCS for compliance.

In this analysis, forecasts of potential oil production and associated $CO_2$ stored (annual and cumulative) from the application of $CO_2$-EOR were based on forecasts of CCS deployment projections from the NRDC assessments (using NEMS and MARKAL[11]) of the economic and energy implications of implementing ACES. Similarly, Advanced Resources produced a forecast based upon the recent comparable assessment of ACES by EIA.[21] Figure 6 shows the range of modeled volumes of $CO_2$ captured in the power sector for geologic sequestration predicted in several forecasts.

[11] Advanced Resources also supplied $CO_2$_EOR oil supply curves as a function of oil price and $CO_2$ cost for incorporation into the MARKAL runs to simulate $CO_2$-EOR deployment due to CCS.

Figure 6. Carbon Dioxide Captured from Electricity Generation Technologies with CCS in 2020 and 2030




In the NEMS model runs by NRDC, ACES is forecast to stimulate 14 GW of coal fired power generation capacity with CCS by 2020, and 109 GW by 2030 (the last year of the forecast in NEMS). This would result in the annual storage of 78 million tonnes by 2020, and 530 million tonnes by 2030.

In the NEMS model runs by EIA, ACES is forecast to stimulate 13 GW of coal fired power generation capacity with CCS by 2020, and 69 GW by 2030. This results in the annual storage of 85 million tonnes by 2020, and 409 million tonnes by 2030.

In the MARKAL model runs, ACES is forecast to stimulate 17 GW of coal fired power generation capacity with CCS by 2020, 40 GW by 2030, and 201 GW by 2050. This would result in the annual storage of 124 million tonnes by 2020, 243 million tonnes by 2030, and 1,170 million tonnes by 2050.

These results are summarized in Table 5.

Table 5. Comparison of Forecasts of CCS Deployment and Associated Benefits due to ACES

| | 2020 | 2025 | 2030 | Estimated Cum by 2030 | 2035 | 2040 | 2045 | 2050 | Estimated Cum by 2050 |
|---|---|---|---|---|---|---|---|---|---|
| **Coal with CCS Deployment - Capacity (GW)** | | | | | | | | | **(GW)** |
| **NRDC - MARKAL** | 16.9 | 36.9 | 39.8 | | 87 | 138 | 154 | 201 | **201** |
| **NRDC - NEMS** | 13.6 | 45.6 | 108.8 | | | | | | |
| **EIA - NEMS** | 13.1 | 31.4 | 68.9 | | | | | | |
| **Coal with CCS Deployment - $CO_2$ Stored (million tonnes)** | | | | **(Gt)** | | | | | **(Gt)** |
| **NRDC - MARKAL** | 124 | 226 | 243 | **2.4** | 521 | 809 | 902 | 1,170 | **96** |
| **NRDC - NEMS** | 78 | 224 | 530 | **1.6** | | | | | |
| **EIA - NEMS** | 85 | 190 | 409 | **1.5** | | | | | |
| **Incremental Oil Prod. from $CO_2$ Stored with CCS from Power Plants (MMBpd)*** | | | | **(Billion Barrels)** | | | | | **(Billion Barrels)** |
| **NRDC - MARKAL*** | 1.3 | 2.4 | 2.6 | **9** | 2.6 | 2.6 | 3.9 | 4.8 | **37** |
| **NRDC - NEMS** | 0.3 | 1.4 | 3.6 | **6** | | | | | |
| **EIA - NEMS** | 0.4 | 1.3 | 3.0 | **6** | | | | | |

* Assumes all $CO_2$ from CCS is stored in oil fields with EOR potential at a rate of 0.26 tonnes of stored $CO_2$ per barrel of oil.

** Assumes a price for captured $CO_2$ of $15/ton, which increases economic potential to between 38 billion barrels using "best practices" and 59 billion barrels using "next generation" technologies at oil prices ranging from $70 and $100 per barrel."

# NATIONAL FORECASTS OF OIL PRODUCTION FROM $CO_2$-EOR RESULTING FROM PROJECTED CCS DEPLOYMENT UNDER ACES

Also shown in Table 5 are estimates of the potential domestic crude oil production that could be realized *if all of the $CO_2$ captured from the power plants with CCS was injected into fields with oil production potential from $CO_2$-EOR*.[12] It is important to realize that it is unlikely that all captured $CO_2$ from CCS deployment will be used for EOR; some power plants may instead choose to sequester the captured $CO_2$ in deep saline formations instead, despite the economic advantages of CCS with $CO_2$-EOR. Our estimates therefore represent a maximum potential in that respect.

The estimates in this characterization were developed based on the previously discussed assumption that it takes 0.26 tonnes of $CO_2$ to produce an incremental barrel of oil from $CO_2$-EOR. Given this, and the amount of $CO_2$ forecast to be captured annually from power plants deploying CCS, estimates of incremental oil production from $CO_2$-EOR were developed, assuming all of the captured $CO_2$ is stored in oil fields with economic $CO_2$-EOR potential. To estimate annual and daily production rates, each year's new $CO_2$ supplies from CCS deployment are assumed to go to new floods and stay with them through a five year ramp up, to a peak production plateau for five years, after which that stream of $CO_2$ supply backs off over 5 years and goes to new floods (i.e. it is added as new $CO_2$ in the year it becomes available). Also, EOR production is assumed to start the year following the start of injection of new $CO_2$ from the CCS projects.

Given the range of forecasts of CCS deployment in Table 5, the $CO_2$ captured from CCS deployment could stimulate from 2.6 to 3.6 million barrels per day of incremental domestic oil production from $CO_2$-EOR by 2030. By 2030, from 6 to 9 billion barrels of incremental oil could be produced domestically as a result of using $CO_2$ captured from power plants. Combined with the 6 to 7 billion barrels of incremental oil could be produced using $CO_2$ from industrial sources, this represents from 32% to 39% of the economic Lower-48 oil production potential assuming "best practices" $CO_2$-EOR technology, and from 21% to 27% of the potential assuming "next generation" $CO_2$-EOR technology.

Specifically:

- In the NEMS model runs by NRDC, ACES is forecast to result in volumes of captured $CO_2$ sufficient to stimulate 0.3 million barrels per day of incremental oil production from $CO_2$-EOR by 2020, and as much as 3.6 million barrels per day by 2030. Cumulatively, if all this CO2

[12] This is not necessarily what is expected to take place as a result of the ACES.

were utilized for EOR, this could result in approximately 6 billion barrels of incremental oil production by 2030.

- In comparison, based on the EIA model runs, ACES could stimulate 0.4 million barrels per day of $CO_2$-EOR production by 2020, and 3.0 million barrels per day by 2030, again totaling approximately 6 billion barrels of incremental oil production by 2030.
- Finally, based on the NRDC model runs using MARKAL, which shows higher CCS deployment in the near term than NEMS, ACES would stimulate 1.3 million barrels per day of incremental $CO_2$-EOR production by 2020, and 2.6 million barrels per day by 2030. Cumulatively, this would result in approximately 9 billion barrels by 2030.[13]

As the volume of captured $CO_2$ from CCS continues to increase after 2030, rising to more than one billion tons per year by 2050 based on forecasts from MARKAL produced by NRDC, substantially more oil production from $CO_2$-EOR could be achieved. While not all of the captured $CO_2$ is likely to be stored in oil fields with $CO_2$-EOR potential, Advanced Resources' previous assessment of $CO_2$ storage indicate that there could be significant additional economic potential for CCS and EOR in U.S. oil fields as $CO_2$ infrastructure develops for capturing and transporting large volumes of $CO_2$ within and between oil producing regions. Moreover, as strategies evolve for optimizing $CO_2$ storage capacity as well as additional oil recovery potential, substantial additional volumes of $CO_2$ could be stored in fields targeted for $CO_2$-EOR.

The NRDC MARKAL model run, in which $CO_2$-EOR potential is limited to economic "best practices" and "next generation" techniques, forecasts that about 4.8 million barrels per day could be attributable to incremental oil production from $CO_2$-EOR by 2050. The MARKAL model forecasts that 37 billion barrels of additional crude oil could be produced by 2050, most of which is produced through "best practices" – as MARKAL forecasts oil prices to stay below $90 per barrel for the majority of the policy period (2010-2050). Up until 2030, MARKAL predicts that the value-added features of using the captured $CO_2$ for $CO_2$-EOR would result in most of the captured $CO_2$ from the forecast deployment of power generation with CCS being utilized for this purpose.

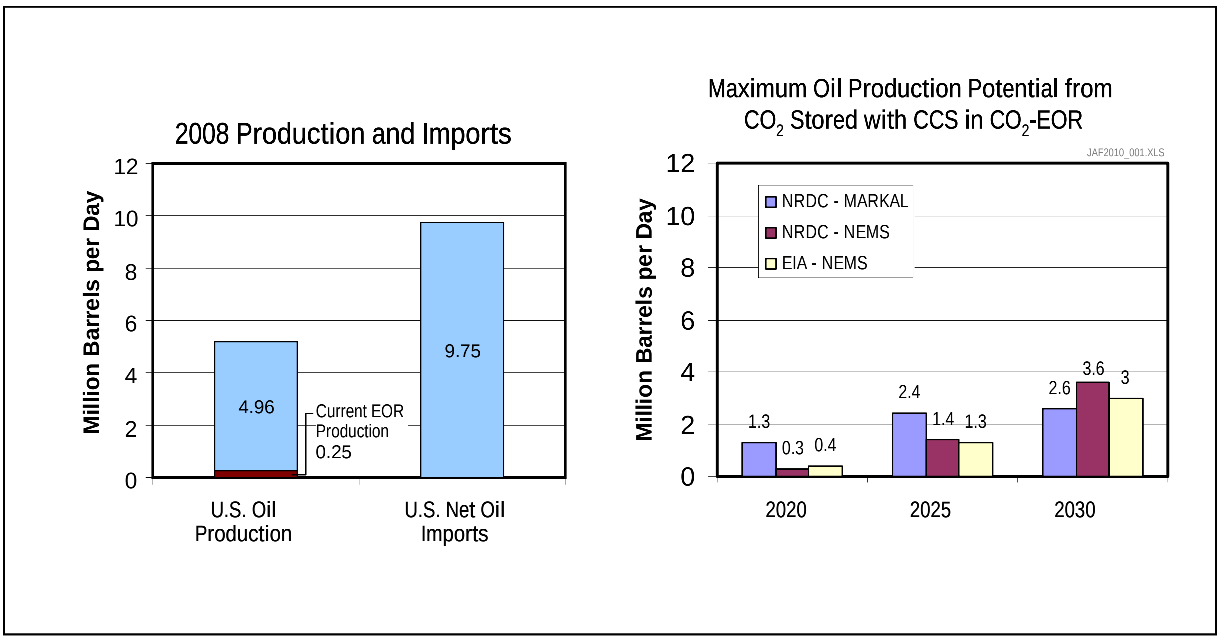
Finally, substantial additional oil production potential could be realized as $CO_2$-EOR technologies advance, as oil prices continue to rise, and delivered $CO_2$ costs continue to drop (as competition for storing $CO_2$ puts additional pressure on industrial facilities to deliver $CO_2$ to $CO_2$-EOR projects at lower

[13] Due to longer 5-year timeframes used in MARKAL, the overall average oil production rate was used to estimate oil production.

costs to ensure delivery), and as (discussed in more detail below) additional oil production potential is realized from the application of $CO_2$-EOR technologies to the essentially immobile residual oil transition/residual oil zone (TZ/ROZ) underlying the main oil pay zone in some basins. As there is insufficient characterization of this ROZ, the stranded oil potential for recovery was not included in our modeling of technical and economic $CO_2$-EOR potential and would be an additional opportunity for expanded $CO_2$-EOR production as $CO_2$ supplies develop and saturate EOR markets.

To provide some perspective as to the importance of this incremental oil production, in 2008, on average, the U.S. imported about 9.75 million barrels per day, and produced about 5 million barrels per day, Figure 7. At this rate, given these estimates of the potential production from $CO_2$-EOR in 2030 using captured $CO_2$ emissions from both the power plants deployed with CCS and high-quality $CO_2$ captured from industrial sources, this represents the potential for substantially reducing U.S. oil imports. [14]

Figure 7. Comparison of Potential Oil Production from CO2-EOR due to CCS Deployment to 2008 U.S. Oil Production and Imports

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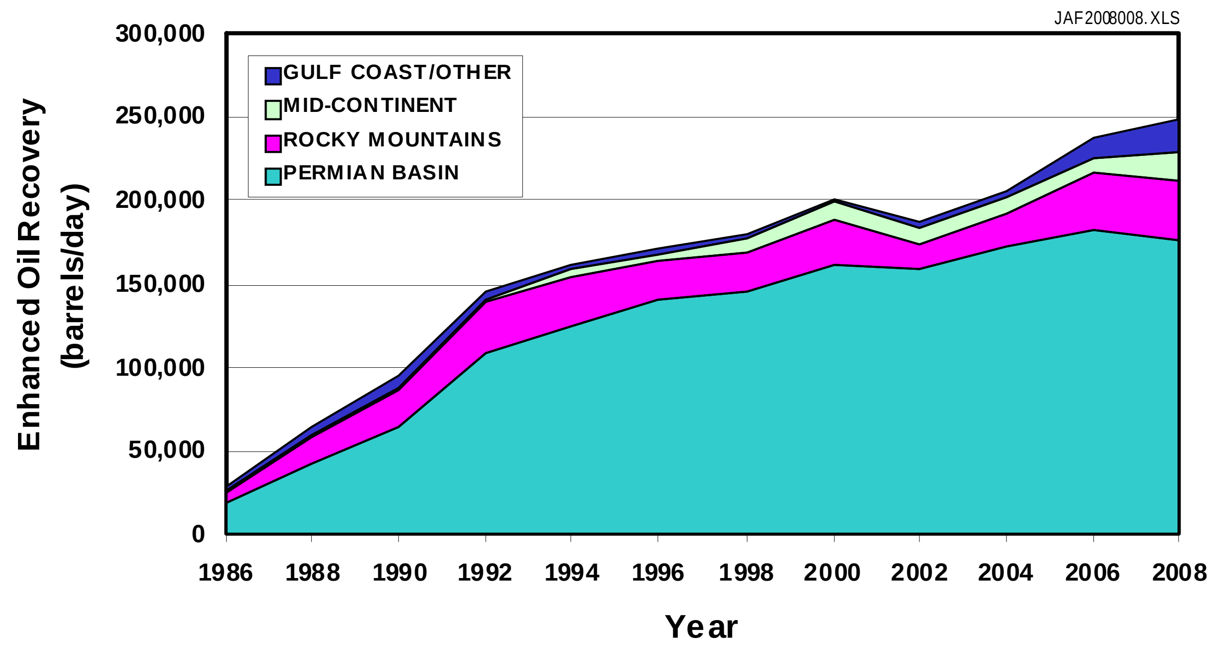
[14] NRDC also estimates that passage of ACES will also result in substantial reductions in the U.S. demand for oil, further reducing oil imports.

An important question that should be addressed relates to the feasibility of achieving this potential increase (over 12 fold) in oil production from $CO_2$-EOR by 2030. As shown in Table 3, 38.5 billion barrels are estimated to be economically recoverable in the Lower 48 assuming “best practices” technology. Assuming that this resource potential gets developed and fully converted into reserves over a 20 year time period, and assuming that these reserves are produced at an eight-to-one reserves-to-production ratio (the historical ratio in the U.S.), this corresponds to oil production rates from $CO_2$-EOR consistent with those forecast and summarized in Figure 8 and Table 5. Similarly, assuming 56.5 billion barrels are economically recoverable in the Lower 48 under “next generation” technology, converting this resource potential into reserves over a 30 year time period, at the same eight-to-one reserves-to-production ratio, corresponds to oil production from $CO_2$-EOR consistent with those forecasts.

The steady growth of $CO_2$ flooding in the Permian Basin and the other regions of the U.S., as shown in Figure 8, offers one case history for possible extrapolation to the future. Between 1988 and 2008, oil production from $CO_2$-EOR grew five-fold in the U.S. overall, while the growth in several of the individual regions grew even more, approaching levels comparable to the future potential production that could be achieved as the result of wide-scale CCS deployment. This occurred over a period where oil prices were much lower, in real terms, than is forecast over the next twenty years; and where the delivered costs of $CO_2$ were much higher than is forecast for the future if CCS results in ample supplies.

Figure 8. Growth of CO2-EOR Production in the U.S. (1986-2008)




Source: Advanced Resources Int'l. and Oil and Gas Journal, 2008.

As perhaps another perspective on comparable growth in U.S. production, between 1989 and 2001, U.S. coal bed methane (CBM) gas production increased from less than 100 billion cubic feet (Bcf) per year to over 1,500 Bcf per year, a 15 fold increase, or an average annual growth rate of over 23%. The forecast increase in oil production from CCS deployment in $CO_2$-EOR corresponds to a 12.25% annual growth rate over the 2008 to 2030 time period. Also, for reasons described below, in many ways CBM development is more resource- and time-intensive than $CO_2$-EOR, since CBM development, unlike $CO_2$-EOR, generally takes place in areas without as much established oil and gas industry infrastructure.

A recent study has shown that the average annual decline rate for the world's giant oil fields is roughly 6.5%, or about half of the forecast increase in $CO_2$-EOR production discussed in this white paper.[22] As more giant fields go into decline in the future, the average decline rates for these fields are expected to increase. Moreover, smaller fields often have larger decline rates than the world's giant fields. Thus, at least in part, increases in oil production from $CO_2$-EOR, which will use much of the same infrastructure currently used by oil production facilities, and will offset declines in oil production that would otherwise occur from U.S. oil fields without the implementation of $CO_2$-EOR. This will allow production from $CO_2$-EOR to use existing production facilities that would be otherwise substantially underutilized.

Perhaps most importantly, $CO_2$-EOR produces incremental oil from fields that have already been explored and developed, and are in production. The incremental investment associated with the deployment of $CO_2$-EOR in these fields generally involves installing the additional equipment, pipelines, and facilities necessary for $CO_2$ injection and recycling (converting production wells to injection wells, constructing a $CO_2$ processing/recycling facility, installing the $CO_2$ transportation and in-field distribution and gathering system, and, in some cases, the drilling of some additional new wells to reconfigure field development patterns to make them more appropriate for $CO_2$ flooding. These investments, and the length of time associated with their implementation, are considerably smaller, however, than that which would be associated with developing and producing comparable volumes of oil from areas that are not currently under development. As a result, at least in theory, $CO_2$-EOR production could ramp up at a rate much faster than most other types of energy resources, and with far greater certainty about the magnitude of reserves.

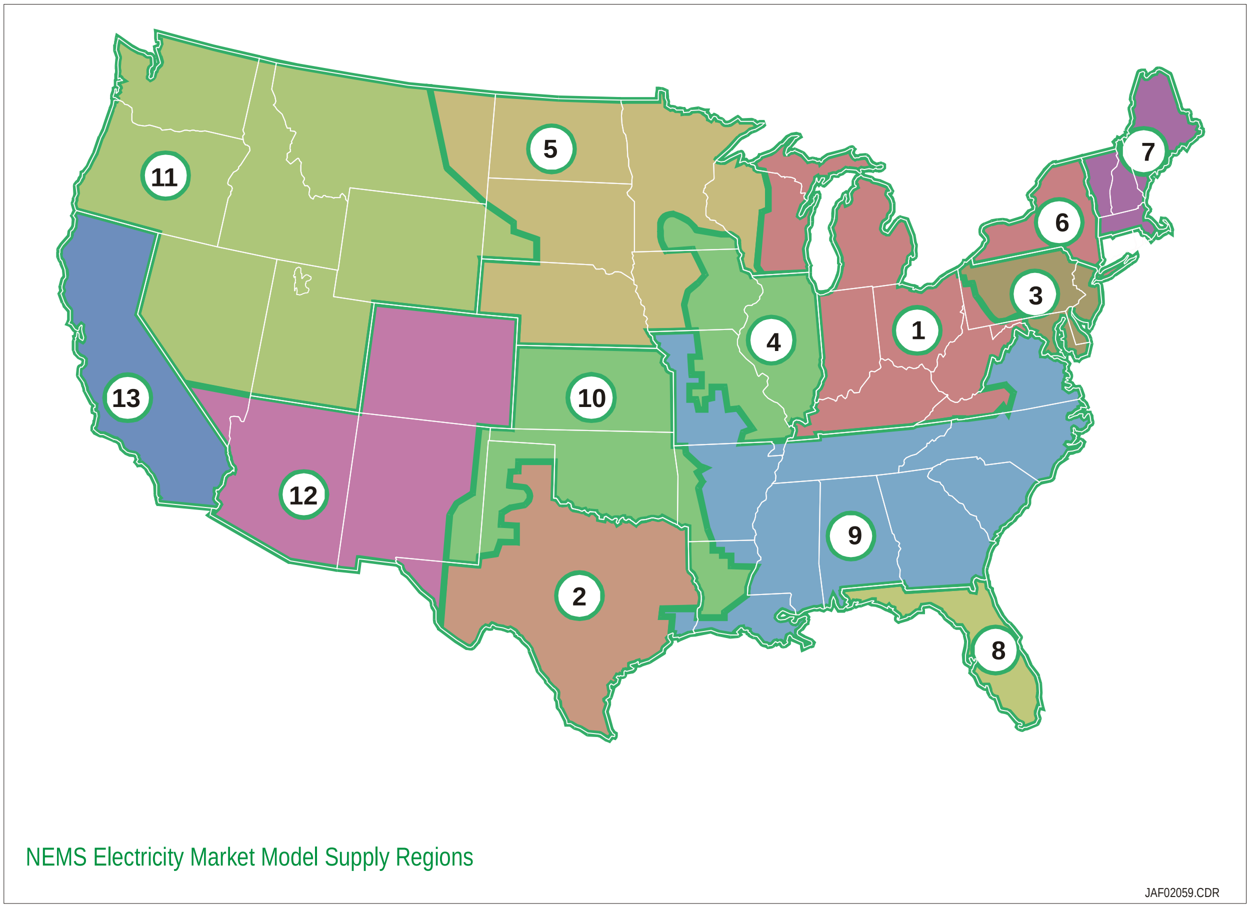
## REGIONAL DISTRIBUTION IMPACTS OF CCS DEPLOYMENT OF $CO_2$-EOR POTENTIAL

Also important to consider is the regional distribution of CCS deployment, and the resulting benefits from that deployment, due to implementation of ACES. Table 6 shows the forecast deployment of power generation capacity with CCS in the NEMS runs by NRDC, by power market regions represented in NEMS, for the years 2020, 2025, and 2030 (the NEMS Electricity Market Model Supply Regions are shown in Figure 9). The greatest CCS-equipped capacity additions are forecast in the regions associated with the Southeastern Electric Reliability Council (SERC), East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), and the Mid-America Interconnected Network (MAIN). These four regions make up well over 70% of the $CO_2$ supply from forecast CCS deployment.

Table 6. NEMS Forecasted Deployment of Power Generation Capacity with CCS

| | | **CCS Capacity Deployed (GW)** | | |
|---|---|---|---|---|
| **NEMS Power Region** | | **2020** | **2025** | **2030** |
| **1** | ECAR (coal) | 2.1 | 7.2 | 19.9 |
| | ECAR (gas) | 1.0 | 5.5 | 9.3 |
| **2** | ERCOT (coal) | 0.0 | 0.0 | 7.8 |
| | ERCOT (gas) | 0.0 | 0.0 | 1.2 |
| **3** | MAAC | 3.9 | 6.3 | 11.7 |
| **4** | MAIN (coal) | 0.0 | 0.0 | 2.9 |
| | MAIN (gas) | 0.0 | 1.2 | 6.8 |
| **5** | MAPP | 2.3 | 2.4 | 7.4 |
| **6** | NPCC-NY | 0.7 | 1.3 | 3.7 |
| **7** | NPCC-NE | 0.0 | 0.0 | 0.0 |
| **8** | FRCC | 1.0 | 1.0 | 1.0 |
| **9** | SERC | 2.6 | 19.4 | 26.2 |
| **10** | SPP | 0.0 | 1.2 | 7.0 |
| **11** | WECC-NW | 0.0 | 0.0 | 0.9 |
| **12** | WECC-RM/SW | 0.0 | 0.0 | 1.2 |
| **13** | WECC-CA | 0.0 | 0.1 | 2.0 |
| **TOTAL COAL CCS** | | 12.6 | 38.8 | 91.6 |
| **TOTAL GAS CCS** | | 1.0 | 6.7 | 17.2 |
| **TOTAL GW CCS** | | **13.6** | **45.6** | **108.8** |

Figure 9. NEMS Electricity Market Model Supply Regions




1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6 New York (NPCC-NY)
7 New England (NPCC-NE)
8 Florida Reliability Coordinating Council (FRCC)
9 Southeastern Electric Reliability Council (SERC)
10 Southwest Power Pool (SPP)
11 Northwest Power Pool (WECC-NW)
12 Rocky Mountain Power Area (WECC-RM/SW)
13 California (WECC-CA)

The NEMS model was developed by the EIA to assess market dynamics and policy impacts at the power region level, which can be aggregated nationally. The model incorporates fuel availability and costs, electricity supply and demand data to model optimal utility decisions by electric power region, thereby providing market-based projections for new capacity additions, including CCS-equipped power plants (for coal and natural gas units). At this time, the NEMS model does not include geological information relevant to the siting of carbon sequestration plants, such as access to saline aquifers or oil and gas reservoirs. As a result, NEMS may project more or less CCS deployment than if such data were included. For example, less CCS deployment might be projected in the Mid-Atlantic region (Region 3, see Figure 11), due to lack of available storage options in that region compared to the Rocky Mountain Power Area (Region 12), which has access to both saline formations as well as active $CO_2$-EOR markets.

The estimates of captured $CO_2$ associated with this power generation capacity with CCS are summarized by NEMS power market regions in Table 7. Similarly, estimates of maximum oil production potential from $CO_2$-EOR utilizing captured $CO_2$ associated with power generation capacity with CCS is shown in Table 8.

It is important to understand of the dynamic between regional CCS deployment in the power sector and its ability to take advantage of the $CO_2$-EOR potential of various regions, since the areas of CCS deployment do not overlap simply in the prospective regions of $CO_2$-EOR potential. Figure 10 overlays the NEMS Electricity Market Model Regions with the major oil basins with $CO_2$-EOR potential.

Table 7. Estimates of Captured $CO_2$ Associated with Power Generation Capacity with CCS

| NEMS Power Region | | Captured $CO_2$ from CCS (million tonnes) 2020 | 2025 | 2030 | Cum (MMt) |
|---|---|---|---|---|---|
| 1 | ECAR | 15.6 | 53.0 | 129.9 | 668 |
| 2 | ERCOT | 0.0 | 0.0 | 44.5 | 111 |
| 3 | MAAC | 23.4 | 33.3 | 61.5 | 438 |
| 4 | MAIN | 0.0 | 3.3 | 33.6 | 100 |
| 5 | MAPP | 13.6 | 12.7 | 38.9 | 229 |
| 6 | NPCC-NY | 3.9 | 6.7 | 19.7 | 102 |
| 7 | NPCC-NE | 0.0 | 0.0 | 0.0 | 0 |
| 8 | FRCC | 5.9 | 5.2 | 5.2 | 69 |
| 9 | SERC | 15.7 | 102.1 | 138.2 | 935 |
| 10 | SPP | 0.0 | 6.1 | 37.0 | 123 |
| 11 | WECC-NW | 0.0 | 0.0 | 4.6 | 11 |
| 12 | WECC-RM/SW | 0.0 | 0.0 | 6.2 | 16 |
| 13 | WECC-CA | 0.0 | 0.7 | 10.3 | 29 |
| **Total** | | **78.2** | **223.1** | **529.6** | **2,830** |
| | **COAL CCS SEQ** | 75.2 | 204.5 | 482.7 | |
| | **GAS CCS SEQ** | 2.9 | 19.4 | 47.2 | |
| | **TOTAL CCS SEQ** | 78.1 | 223.9 | 529.9 | |

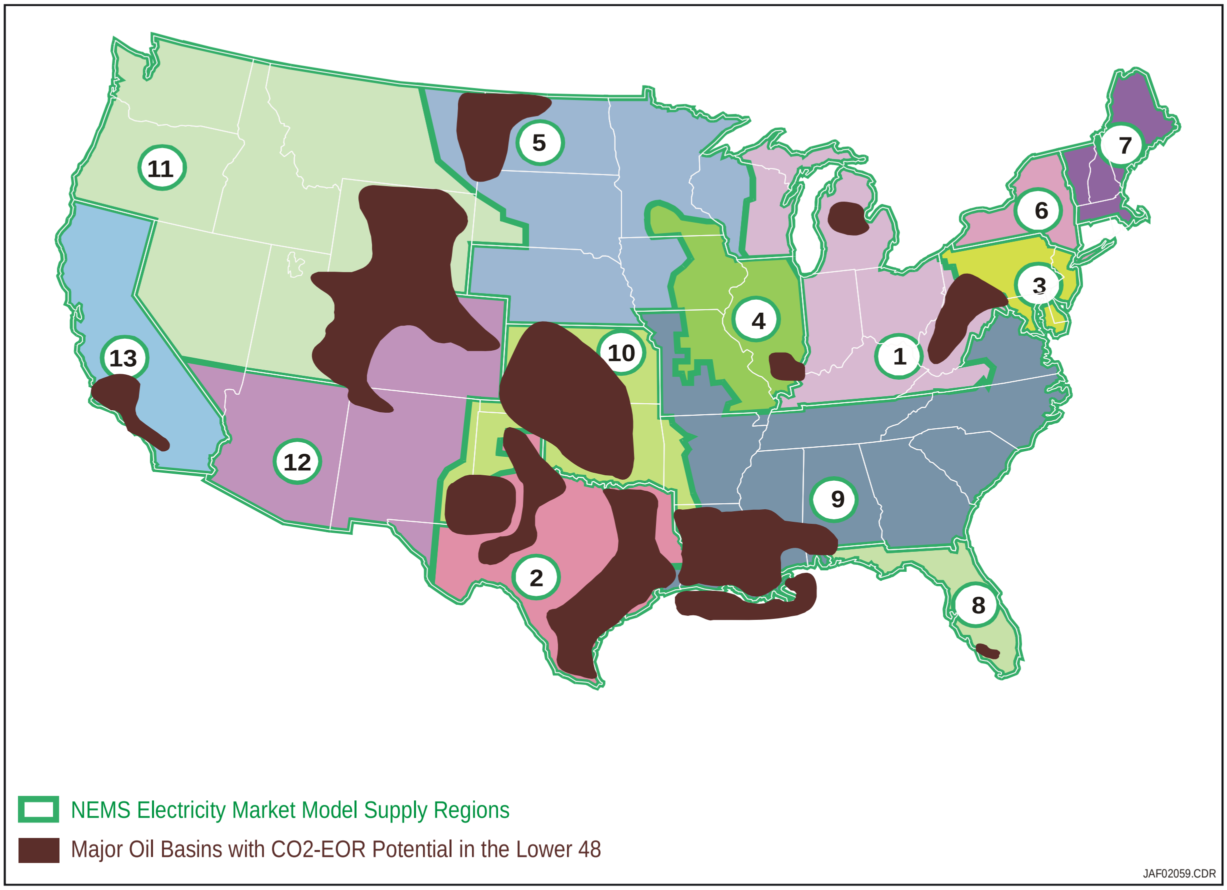
Table 8. Estimates of Maximum Oil Production Potential from $CO_2$-EOR Utilizing Captured $CO_2$ Associated with Power Generation Capacity with CCS

| NEMS Power Region | | Potential $CO_2$-EOR Prod from $CO_2$ Captured via CCS (MMB/day) 2020 | 2025 | 2030 | Cum (Billion Barrels) |
|---|---|---|---|---|---|
| 1 | ECAR | 0.1 | 0.3 | 0.9 | 1.5 |
| 2 | ERCOT | 0.0 | 0.0 | 0.3 | 0.3 |
| 3 | MACC | 0.1 | 0.2 | 0.4 | 0.9 |
| 4 | MAIN | 0.0 | 0.0 | 0.2 | 0.2 |
| 5 | MAPP | 0.0 | 0.1 | 0.3 | 0.5 |
| 6 | NPCC-NY | 0.0 | 0.0 | 0.1 | 0.2 |
| 7 | NPCC-NE | 0.0 | 0.0 | 0.0 | 0.0 |
| 8 | FRCC | 0.0 | 0.0 | 0.0 | 0.1 |
| 9 | SERC | 0.1 | 0.6 | 0.9 | 2.1 |
| 10 | SPP | 0.0 | 0.0 | 0.2 | 0.3 |
| 11 | WECC-NW | 0.0 | 0.0 | 0.0 | 0.0 |
| 12 | WECC-RM/SW | 0.0 | 0.0 | 0.0 | 0.0 |
| 13 | WECC-CA | 0.0 | 0.0 | 0.1 | 0.1 |
| **Total** | | **0.3** | **1.4** | **3.6** | **6.2** |

* Assumes all stored $CO_2$ with CCS is in oil fields with EOR potential

** Assumes 0.26 tonnes of $CO_2$ stored per incremental barrel produced

Figure 10. NEMS Electricity Market Regions and Major Oil Basins with CO2-EOR Potential




The SERC Electricity Market Model Supply Region has the largest amount of CCS capacity deployed, and thus the highest volumes of captured $CO_2$ that could be used for $CO_2$-EOR. Fortunately, the SERC region also corresponds with a region with some of the largest potential for $CO_2$-EOR (the Gulf Coast Region). By 2030 the SERC region is forecast to generate nearly 940 million tonnes of captured $CO_2$. The Gulf Coast Region, with 2.2 to 2.7 billon barrels of economic $CO_2$-EOR recovery potential, would require 650 to 690 million tonnes to develop. Thus, from 250 to 290 million tones of excess $CO_2$ would be available for pursuing $CO_2$-EOR opportunities in other regions.

ERCOT and SPP, with combined cumulative capture of 234 million tonnes, are near the large $CO_2$-EOR potential in Texas, Oklahoma, and Kansas. The combined $CO_2$-EOR potential of these states is estimated to be 21 to 34 billion barrels, requiring 5.5 to 7.0 billion tonnes of $CO_2$ to develop.[15] Clearly, to develop all of the $CO_2$-EOR potential of this region, substantial $CO_2$ supplies from outside the region would be needed.

MAPP, forecast to generate 229 million tonnes of captured $CO_2$ by2030, is coincident with the region containing the Williston Basin, which has 0.5 to 0.6 billion barrels of $CO_2$-EOR potential. The Williston Basin potential would require 120 to 130 million tonnes to develop; less than the forecast $CO_2$ emissions captured. From 100 to 110 million tones of excess $CO_2$ could be available for $CO_2$-EOR opportunities in other regions.

The next four largest supply regions in terms of forecast volumes of captured $CO_2$ from CCS (ECAR, MAAC, and MAIN) exist in the Midwest and Northeast, which are not located near large $CO_2$-EOR potential. Collectively, these three regions are forecast to produce over 1.3 billion tonnes of captured $CO_2$ by 2030. To develop the $CO_2$-EOR potential in the oil basins nearest to these regions (the regions of Appalachia and Illinois/Michigan) would require only as much as about 350 million tonnes. Clearly, most of the $CO_2$ volumes captured in this region would need to be transported elsewhere to facilitate increased production from $CO_2$-EOR.

[15] Volumes based on “best practices” and “next generation” technologies.

# CONNECTING $CO_2$ SUPPLY WITH EOR DEMAND

Figure 11 illustrates *just one of the many possible ways* a $CO_2$ capture, transport and storage industry could evolve by 2030 in response to these regional imbalances and efficiently allow for captured volumes of $CO_2$ from CCS to be utilized to take advantage of $CO_2$-EOR opportunities. The specific volumes of $CO_2$ that could get transported along each corridor, from electricity market model supply regions to the defined oil basins, are summarized in Table 9. The pipeline corridors indicated in Figure 10 are based on the NEMS model forecast of CCS deployment. If an alternative regional distribution of CCS deployment takes place, obviously, these corridors could evolve differently.

Figure 11. Possible Way That U.S. $CO_2$ Capture/Transport/And Storage Could Evolve

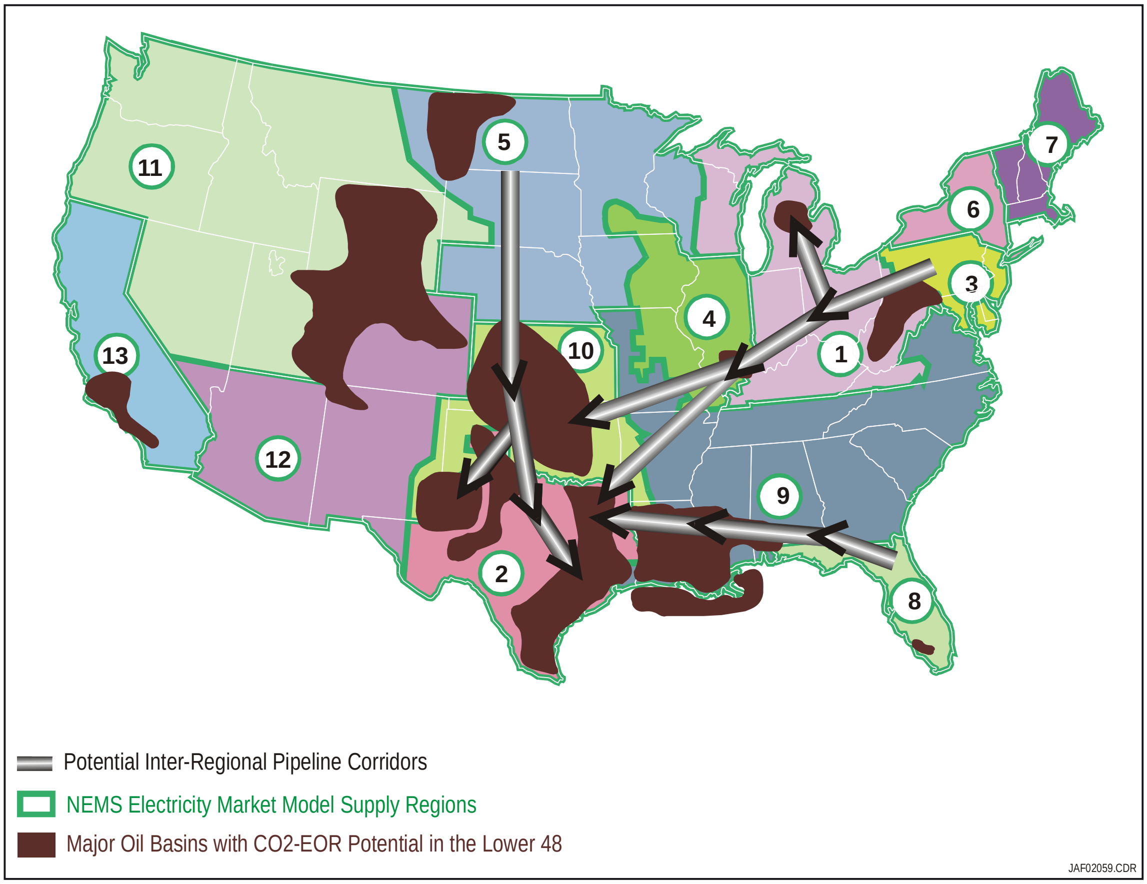


Table 9. Tabulation of Possible Movement of $CO_2$ from CCS Deployment from Electricity Market Supply Regions to Oil Regions

| NEMS Electricity Market Model Supply Region | Volume of $CO_2$ Supply (MM tonnes) | $CO_2$-EOR Oil Basin | "Best Practices" $CO_2$ Market for $CO_2$-EOR (MM tonnes) |
|---|---|---|---|
| SERC | 940 | | |
| | | Gulf Coast | 650 |
| | | Texas, East/Central | 290 |
| | | | 940 |
| ECAR | 670 | | |
| | | Illinois/Michigan | 130 |
| | | Texas, East/Central | 540 |
| | | | 670 |
| MAAC | 440 | | |
| | | Appalachia | 40 |
| | | Texas, East/Central | 400 |
| | | | 440 |
| MAPP | 230 | | |
| | | Williston | 130 |
| | | Midcontinent | 100 |
| | | | 230 |
| SPP | 120 | | |
| | | Midcontinent | 120 |
| ERCOT | 110 | | |
| | | Texas, East/Central | 110 |
| MAIN | 100 | | |
| | | Midcontinent | 100 |
| NPCC-NY | 100 | | |
| | | ? | |
| FRCC | 70 | | |
| | | Texas, East/Central | 70 |
| WECC - CA | 30 | | |
| | | California | 30 |
| WECC - RM/SW | 20 | | |
| | | Rockies | 20 |
| WECC-NW | 10 | | |
| | | Rockies | 10 |
| **TOTAL** | **2,840** | | **2,740** |

Nonetheless, as shown in Table 10, even just assuming today's state-of-the-art $CO_2$-EOR (and not next generation technology), the market for $CO_2$ for EOR far exceeds the volumes of $CO_2$ forecast to be captured from CCS deployment through 2030.

Table 10. Tabulation of Possible Movement of $CO_2$ from CCS Deployment to Oil Regions from Electricity Market Supply Regions

| $CO_2$-EOR Oil Basin | "Best Practices" $CO_2$ Market for $CO_2$-EOR (Lower-48 Onshore) (MM tonnes) | NEMS Electricity Market Model Supply Region | Volume of $CO_2$ Supply (MM tonnes) |
|---|---|---|---|
| Gulf Coast | 650 | SERC | 650 |
| Texas, East/Central | 1,940 | SERC | 290 |
| | | ECAR | 540 |
| | | MACC | 400 |
| | | ERCOT | 110 |
| | | FRCC | 70 |
| | | | 1,410 |
| Williston | 130 | MAPP | 130 |
| Illinois/Michigan | 130 | ECAR | 130 |
| Appalachia | 40 | MACC | 40 |
| Midcontinent | 1,420 | MAPP | 100 |
| | | SPP | 120 |
| | | MAIN | 100 |
| | | | 320 |
| California | 1,380 | WECC-CA | 30 |
| Permian | 2,140 | | |
| Rockies | 500 | WECC-RM/SW | 20 |
| | | WECC-NW | 10 |
| | | | 30 |
| Louisiana Offshore | 1,370 | | |
| ? | | NPCC-NY | 100 |
| **TOTAL** | **9,700** | | **2,840** |

Important to this characterization of the potential evolution of a future CCS/$CO_2$-EOR marketplace and supporting infrastructure, and supported by Denbury's plan for its "Midwest Green Pipeline" discussed above, is the fact that the sources of captured $CO_2$ do not necessarily need to be near $CO_2$-EOR prospects for such "source-sink" matching to be economically viable. In fact, most of the captured $CO_2$ associated with the forecast power generation capacity with CCS predicted to be built is located within a distance to oil basins with significant $CO_2$-EOR potential that is comparable to the anticipated distance of the "Midwest Green Pipeline" (500 to 700 miles), or is comparable to the current Cortez pipeline shipping $CO_2$ from southwest Colorado to the Permian Basin for use in current $CO_2$-EOR projects (500 miles).

The anticipated $CO_2$ supplies projected to flow from areas of carbon capture deployment to areas with $CO_2$-EOR potential are comparable to current volumes of $CO_2$ transported from natural sources for use for $CO_2$-EOR. For example, the largest interregional $CO_2$ transport volume shown in Table 11 would likely flow from the ECAR power region to the East and Central Texas hydrocarbon regions, amounting to 540 million tonnes cumulatively. Assuming that this volume flows over 20 years, this would amount to a flow capacity of about 1.5 Bcf per day, which is just slightly more than the capacity of the existing Cortez $CO_2$ pipeline (about 1.3 Bcf per day).

Traditionally, the timing for development of $CO_2$-EOR projects has been highly dependent on the timing of availability of the $CO_2$. This applies both to the development of new $CO_2$-EOR projects within a basin, as well as the timing of pattern development within an individual field project and basin region. Moreover, project development is also often highly dependent on the availability of investment capital, field services like drilling and workover rigs, and materials and construction workers for development of $CO_2$ processing, recycling, compression, and distribution facilities.

Nonetheless, in general, a "typical" project would require 2 to 3 years for conversion of an oil field under waterflood to one ready for $CO_2$ flooding (including well drilling and workover and the construction of $CO_2$ processing, recycling, compression, and distribution facilities). Once flooding begins, the early years (the first 5 to 10 years) are dominated by the use of $CO_2$ acquired from external supplies, after which an increasing proportion of the $CO_2$ injected is that which is recycled as it is produced in association with the oil.

Therefore, it is anticipated that the timing of development of $CO_2$ transport infrastructure and $CO_2$-EOR projects, in a world characterized by GHG emissions controls, will be comparable to, if not less than, that associated with the installation of CCS facilities associated with coal-fired electric generation facilities.

Finally, as more $CO_2$-EOR prospects are added to the network over time, more $CO_2$ can flow from sources of captured $CO_2$ emissions. The flow rate in a $CO_2$ pipeline depends, in large part, on the length of the pipeline, the size (internal diameter) of the pipeline, how many spur (branch) lines are added, and the pressures on both ends of the pipeline. Pipeline operations are managed by regulation of pressure and volume over the system. The delivery pressure is maintained at nearly constant levels while demand can vary significantly throughout the day. Pressure is controlled by compression. Thus, adding more $CO_2$-EOR prospects to the network over time results in a reduction in downstream pressure, which must be offset by either an increase in compression, and/or the input of more $CO_2$ from more sources of $CO_2$ emissions. The 24-inch Green Pipeline under construction initially will have a capacity of 800 million cubic feet per day (MMcfd) (13 million tonnes per year); the addition of spur lines to supply $CO_2$ to southern Louisiana fields could expand the pipeline's capacity to as much as 1,600 MMcfd (26 million tonnes per year).

Moreover, by raising and lowering the pressure on any pipeline segment, the pipeline itself can be used to store $CO_2$ during periods when there is less demand at the end of the pipeline than there is supply at the source.

## ECONOMIC BENEFITS OF INCREASED DOMESTIC OIL PRODUCTION

The increased domestic production of crude oil from $CO_2$-EOR can reap substantial economic benefits to the U.S. economy. These benefits include a decrease in the U.S. trade deficit due to decreased crude oil imports, assuming every barrel of domestic production offsets a barrel that would otherwise be imported. Moreover, every barrel of domestically produced oil results in economic value to Americans, such as royalty payments to U.S. landowners, and increased U.S. government revenues – at the local, state, and federal level. All of these economic benefits would not accrue if the domestic demand for oil would otherwise be met by imports, which, in at least the near term, is the only alternative to domestic oil.

For every dollar of profit going to the producer of domestic oil in a $CO_2$-EOR project, an almost equal or greater amount goes to various U.S. government treasuries. To illustrate this benefit, we assumed the average forecast oil price in the NRDC's NEMS run -- approximately $112 per barrel over the 2016 to

2030 time period. In this example, shown in Table 11, which assumes that an operator purchases $CO_2$ at $15 per tonne, for every incremental barrel produced by $CO_2$-EOR, ), the operator earns about $30 in net profit, the private mineral owner again earns about $8, and local, state, and federal governments earn about $34, as shown in Table 12. This estimate also assumes representative industry values for royalty and tax rates, and $CO_2$-EOR project costs derived from Advanced Resources' $CO_2$-EOR cost and economic models.

Similarly, as shown in Table 12, if the $CO_2$ costs the operator $45 per tonne, then the operator earns nearly $26 in net profit, the private mineral owner earns nearly $8, and local, state, and federal governments earn nearly $31.

These benefits would not accrue to Americans if this oil was otherwise imported.

Assuming forecast oil prices in the two NEMS-based assessments (NRDC and EIA), and assuming that the increased domestic production from $CO_2$-EOR offsets, on a one-to-one basis, crude oil that would otherwise be imported, the U.S. could reduce its foreign trade deficit by $11 to $15 billion dollars (2007 dollars) in 2020, and by $120 to $150 billion by 2030. Cumulatively, by 2030, the U.S. would save over $600 billion in reduced oil import purchases.

Similarly, American landowners (both private and public) would benefit as a result of this increased domestic production. These landowners would collect an additional $1.4 to $1.9 billion in increased royalties from production from $CO_2$-EOR 2020, and $15 to $19 billion more in 2030, again based on today's royalty, tax, and CO2-EOR cost structures. Again, by 2030, these landowners could receive $80 to $90 billion in increased royalties.

State, local and federal government would also benefit significantly. State and local governments could receive $0.5 to $0.6 billion in increased revenues from production taxes in 2020, and $5 to $6 billion by 2030. By 2030, they could cumulatively collect $25 to $30 billion in production tax receipts for their state and local treasuries. Moreover, as much as $3 to $4 billion in 2020 and $30 to $36 billion by 2030 could be collected in additional income taxes by both state government and the federal government, with as much as $150 to $170 billion collected by 2030 cumulatively.

These economic benefits are summarized in Table 13 for the NRDC NEMS-based assessment and Table 14 for the comparable EIA assessment.

Table 11. Estimated Distribution of Economic Value of Incremental Oil Production from $CO_2$-EOR by 2030
(Assuming $CO_2$ costs of $15 per tonne)

| Notes | | Oil Industry | Private Minerals | Federal/State |
|---|---|---|---|---|
| 1 | **Domestic Oil Price ($/B)** | **$112.00** | | |
| 2 | Less: Royalties | $16.80 | $14.00 | $2.80 |
| | **Operating Revenues** | **$95.20** | | |
| | **Operating Expenses** | **($28.40)** | | |
| 3 | Production Taxes | ($4.80) | ($0.80) | $5.60 |
| 4 | $CO_2$ Purchase Costs | ($3.90) | | |
| 5 | $CO_2$ Recycle Costs | ($11.70) | | |
| 6 | O&M Costs | ($8.00) | | |
| | **Capital Expenses** | **($16.40)** | | |
| 7 | CapEx | ($6.00) | | |
| 8 | Cost of Capital | ($10.40) | | |
| | **Income, Before Tax** | **$50.40** | **$13.20** | **$8.40** |
| 9 | **Income Taxes** | **($20.20)** | **($5.30)** | **$25.50** |
| | **Net Income ($/B)** | **$30.20** | **$7.90** | **$33.90** |

1 Assumes $112 per barrel: the average oil price for the NRDC-NEMS run
2 Royalties are 15%, with about 1 of 6 barrels assumed to be produced from federal and state lands.
3 Production taxes including ad valorem taxes of 5% from FRS data.
4 $CO_2$ cost of $15/tonne for transport and compression; 0.26 tonne $CO_2$ acquired per barrel of oil.
5 $CO_2$ recycle O&M cost of $15/tonne/Mcf; 0.78 tonne recycled $CO_2$ per barrel of oil.
6 Other O&M expenses from ARI $CO_2$-EOR cost models; includes site and MMV costs for CCS
7 Capex and return on capital from ARI $CO_2$-EOR cost models; includes site and MMV costs for CCS
8 Assumes cost of capital/hurdle rate of return of 25%; to account for increased risk
9 Effective combined federal and state income taxes on domestic production of 40% based on FRS data.

Table 12. Estimated Distribution of Economic Value of Incremental Oil Production from $CO_2$-EOR by 2030

(Assuming $CO_2$ costs of $45 per tonne)

| Notes | | Oil Industry | Private Minerals | Federal/State |
|---|---|---|---|---|
| 1 | **Domestic Oil Price ($/B)** | **$112.00** | | |
| 2 | Less: Royalties | $16.80 | $14.00 | $2.80 |
| | **Operating Revenues** | **$95.20** | | |
| | **Operating Expenses** | **($36.20)** | | |
| 3 | Production Taxes | ($4.80) | ($0.80) | $5.60 |
| 4 | $CO_2$ Purchase Costs | ($11.70) | | |
| 5 | $CO_2$ Recycle Costs | ($11.70) | | |
| 6 | Other O&M Costs | ($8.00) | | |
| | **Capital Expenses** | **($16.40)** | | |
| 7 | CapEx | ($6.00) | | |
| 8 | Cost of Capital | ($10.40) | | |
| | **Income, Before Tax** | **$42.60** | **$13.20** | **$8.40** |
| 9 | **Income Taxes** | **($17.00)** | **($5.30)** | **$22.30** |
| | **Net Income ($/B)** | **$25.60** | **$7.90** | **$30.70** |

1 Assumes $112 per barrel: the average oil price for the NRDC-NEMS run
2 Royalties are 15%, with about 1 of 6 barrels assumed to be produced from federal and state lands.
3 Production taxes including ad valorem taxes of 5% from FRS data.
4 $CO_2$ cost of $15/tonne for transport and compression; 0.26 tonne $CO_2$ acquired per barrel of oil.
5 $CO_2$ recycle O&M cost of $15/tonne/Mcf; 0.78 tonne recycled $CO_2$ per barrel of oil.
6 Other O&M expenses from ARI $CO_2$-EOR cost models; includes site and MMV costs for CCS
7 Capex and return on capital from ARI $CO_2$-EOR cost models; includes site and MMV costs for CCS
8 Assumes cost of capital/hurdle rate of return of 25%; to account for increased risk
9 Effective combined federal and state income taxes on domestic production of 40% based on FRS data.

Table 13. Estimated Economic Impacts of Oil Production from $CO_2$-EOR Utilizing Captured $CO_2$ Associated with Power Generation Capacity with CCS

**NRDC NEMS Based Assessment**

**ESTIMATED ECONOMIC BENEFITS OF INCREASED DOMESTIC OIL PRODUCTION FROM $CO_2$-EOR --- NRDC-NEMS Case**

| | Units | 2020 | 2025 | 2030 | Cum to 2030 | Notes |
|---|---|---|---|---|---|---|
| **Incremental oil production due to $CO_2$-EOR** | (MMBbls per day) | 0.3 | 1.4 | 3.6 | 6.3 | 1 |
| **Crude oil price (2007 dollars)** | ($/bbl, avg WH) | $109.91 | $110.90 | $118.95 | $112.36 | 2 |
| **Reductions in U.S. crude oil imports** | (MMBbls per day) | 0.3 | 1.4 | 3.6 | 6.3 | 3 |
| **Reduction in trade deficit due to reduced imports** | (Billion dollars) | $11.0 | $55.5 | $154.9 | $703.3 | |
| **Royalty payments to public and private leaseholders** | (Billion dollars) | $1.4 | $6.9 | $19.4 | $87.9 | 4 |
| **Private** | (Billion dollars) | $1.2 | $6.0 | $16.9 | $76.7 | |
| **State** | (Billion dollars) | $0.1 | $0.6 | $1.8 | $8.0 | |
| **Federal** | (Billion dollars) | $0.1 | $0.3 | $0.7 | $3.3 | |
| **Increased revenues from production taxes** | (Billion dollars) | $0.4 | $2.3 | $6.3 | $28.7 | 5 |
| **Increased revenues from income taxes** | (Billion dollars) | $2.6 | $13.3 | $37.1 | $168.3 | 6 |
| **State** | (Billion dollars) | $0.2 | $1.1 | $3.1 | $14.0 | |
| **Federal** | (Billion dollars) | $2.4 | $12.2 | $34.0 | $154.3 | |
| **Total to Government** | (Billion dollars) | **$3.3** | **$16.4** | **$45.9** | **$208.2** | |

**Notes**

1. Cumulative oil production in billion barrels
2. From April 2009 EIA Annual Energy Outlook Reference Case
3. Assumes increased domestic production offsets an imported barrel on a one-to-one basis
4. Assumes a national-average royalty rate on production of 15%
5. Based on ratio of production taxes to revenues in EIA Performance Profiles of Major Energy Producers 2007, for 2000-2007
6. Based on ratio of income taxes to revenues in EIA Performance Profiles of Major Energy Producers 2007, for 2000-2007

Table 14. Estimated Economic Impacts of Oil Production from $CO_2$-EOR Utilizing Captured $CO_2$ Associated with Power Generation Capacity with CCS

**EIA NEMS Based Assessment**

| | Units | 2020 | 2025 | 2030 | Cum to 2030 | Notes |
|---|---|---|---|---|---|---|
| **Incremental oil production due to $CO_2$-EOR** | (MMBbls per day) | 0.4 | 1.3 | 3.0 | 5.7 | 1 |
| **Crude oil price (2007 dollars)** | ($/bbl, avg WH) | $113.09 | $111.48 | $116.59 | $110.72 | 2 |
| **Reductions in U.S. crude oil imports** | (MMBbls per day) | 0.4 | 1.3 | 3.0 | 5.7 | 3 |
| **Reduction in trade deficit due to reduced imports** | (Billion dollars) | $14.8 | $51.8 | $125.7 | $628.1 | |
| **Royalty payments to public and private leaseholders** | (Billion dollars) | $1.9 | $6.5 | $15.7 | $78.5 | 4 |
| **Private** | (Billion dollars) | $1.6 | $5.6 | $13.7 | $68.5 | |
| **State** | (Billion dollars) | $0.2 | $0.6 | $1.4 | $7.1 | |
| **Federal** | (Billion dollars) | $0.1 | $0.2 | $0.6 | $2.9 | |
| **Increased revenues from production taxes** | (Billion dollars) | $0.6 | $2.1 | $5.1 | $25.6 | 5 |
| **Increased revenues from income taxes** | (Billion dollars) | $3.5 | $12.4 | $30.1 | $150.3 | 6 |
| **State** | (Billion dollars) | $0.3 | $1.0 | $2.5 | $12.5 | |
| **Federal** | (Billion dollars) | $3.2 | $11.4 | $27.6 | $137.8 | |
| **Total to Government** | (Billion dollars) | **$4.4** | **$15.3** | **$37.2** | **$186.0** | |

**Notes**

1. Cumulative oil production in billion barrels
2. From April 2009 EIA Annual Energy Outlook Reference Case
3. Assumes increased domestic production offsets an imported barrel on a one-to-one basis
4. Assumes a national-average royalty rate on production of 15%
5. Based on ratio of production taxes to revenues in EIA Performance Profiles of Major Energy Producers 2007, for 2000-2007
6. Based on ratio of income taxes to revenues in EIA Performance Profiles of Major Energy Producers 2007, for 2000-2007

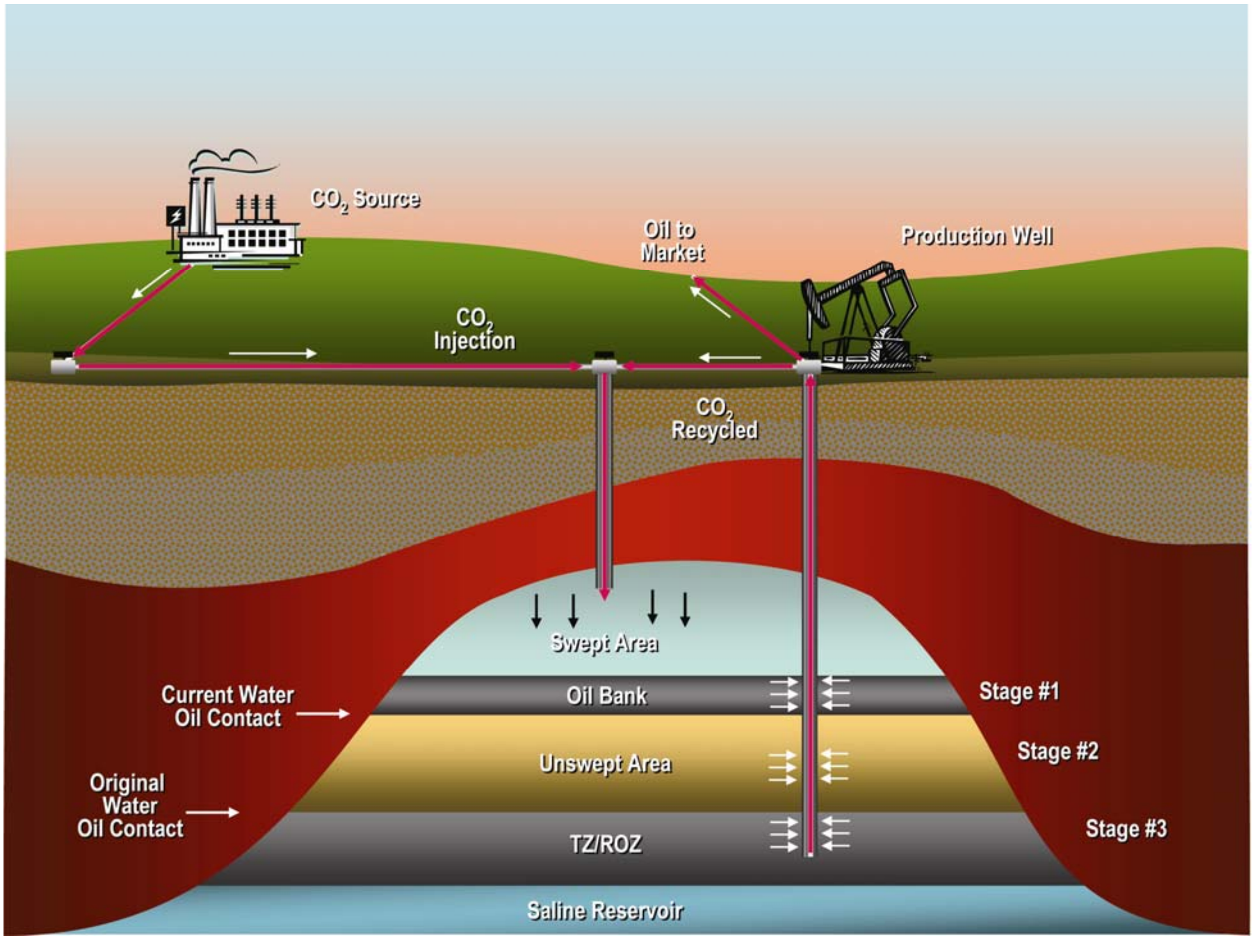
# ENVIRONMENTAL BENEFITS OF INCREASED DOMESTIC OIL PRODUCTION WITH $CO_2$-EOR

Despite what is assumed about increased efficiencies in transportation, it is important to realize that a critical choice for society, at least in the near term, will be between a domestically produced barrel of crude oil and an imported barrel, even as lower carbon alternatives become more available. $CO_2$-EOR contributes to permanently sequestering $CO_2$ that would otherwise be emitted to the atmosphere, and has other environmental benefits over imported oil, or even domestically produced oil by traditional means.

As referenced in this report, a quarter tonne or more of purchased $CO_2$ is sequestered over a project's life, on average, for every barrel of oil produced in the enhanced oil recovery process. At sufficient pressures, the $CO_2$ becomes miscible (fully mixed) with the oil, and some is produced with the oil, separated, compressed and re-injected into the oil field for further oil recovery. At each step of the process, the $CO_2$ can be carefully monitored to ensure minimal process losses of the $CO_2$. In accordance with anticipated CCS incentives and regulations, $CO_2$-EOR operators will be required to ensure that the remaining $CO_2$ is permanently sequestered in the oil field after further oil production becomes uneconomical. In fact, in some cases, more $CO_2$ could be stored in the reservoir than would be associated with the incremental oil produced, as the $CO_2$ also displaces water that is present in the oil zone as a result of secondary recovery and/or the WAG process associated with most $CO_2$-EOR operations. Some $CO_2$-EOR operators use 100% $CO_2$ flooding, which can result in even higher volumes of sequestered $CO_2$.

$CO_2$ storage potential in depleted oil fields could increase substantially beyond the original oil recovery target, with an even greater volume of potential incremental oil recovery. In addition to the additional $CO_2$ injected as a part of "next generation" $CO_2$-EOR, it could also include the result of $CO_2$-EOR technology applied to the essentially immobile residual oil transition/residual oil zone (TZ/ROZ) underlying the main oil pay zone, as well as the underlying saline reservoir that exists below the TZ/ROZ, as illustrated in Figure 12.

Figure 12. Schematic Illustration of Coupling $CO_2$-EOR with Other Strategies to Maximize Cost-Effective $CO_2$ Storage




Source: U.S. Department of Energy/National Energy Technology Laboratory

Reduced atmospheric $CO_2$ emissions are not the only environmental benefit resulting from increased production from $CO_2$-EOR. $CO_2$-EOR produces incremental oil from fields that have already been explored and developed and are in production. The incremental environmental impacts, at least at the surface, associated with $CO_2$-EOR would include installing additional infrastructure necessary for $CO_2$ injection and recycling, and some additional new wells. These additions and their associated disturbances would be minimal, however, compared to producing these same volumes of oil from areas that are not currently under development, which would require full-scale prospecting, infrastructure siting and development.

Although the strategic and economic implications of future oil and gas supplies are often discussed from a national or global perspective, environmental considerations are generally evaluated and discussed in terms of local effects. While CO2-EOR will need to meet all relevant existing environmental regulations as well as future standards and regulations for ensuring permanent sequestration, the use of existing industrial infrastructure to support the further development of existing fields, or even the development of newly discovered oil and gas resources in existing developed areas, allows for new oil supplies without the environmental impacts associated with the development of resources in relatively undeveloped areas, requiring new infrastructure, and resulting in new environmental impacts.

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