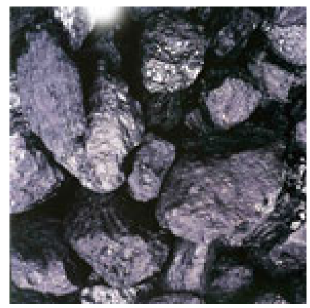
OPTIMIZATION OF CO_2 STORAGE IN CO_2 ENHANCED OIL RECOVERY PROJECTS





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SUMMARY FOR POLICYMAKERS

The combination of carbon dioxide enhanced oil recovery (CO_2-EOR) and permanent CO_2 storage in oil reservoirs has the potential to provide a critical near-term solution for reducing greenhouse gas (GHG) emissions. This solution involves the combined application of carbon capture and storage (CCS) from power generation and other industrial facilities with CO_2-EOR, which can provide the additional beneficial use of CO_2 injection for increasing crude oil production. On the other hand, some believe that increased oil production from CO_2-EOR is not an acceptable option for mitigating GHG emissions.

This study provides information on the opportunities for and potential benefits from increasing CO_2 storage associated with CO_2-EOR, to attempt to address the current lack of narrative in the international policy landscape around this issue.

This study starts with a review of traditional approaches for CO_2-EOR; these approaches have tended to optimize oil production efficiency, often by limiting the volume of CO_2 injected. This is contrasted with potential alternative approaches that optimize both oil production and CO_2 storage. Existing CO_2-EOR operations are described, highlighting those projects pursuing or considering the co-benefits of CO_2 storage and incremental oil production. Expanding on previous work, the world-wide incremental oil production and CO_2 storage potential from CO_2-EOR is assessed assuming the application of “next generation” CO_2-EOR technologies. Other “second generation” approaches to increase CO_2 storage in conjunction with CO_2-EOR are also identified and evaluated. Finally, life-cycle analyses are presented of the GHG emissions associated with various alternatives for CO_2-EOR development in combination with CO_2 storage.

The key findings of this study are summarized below.

CO_2-EOR has been demonstrated to be profitable in commercial scale applications for nearly 30 years. The bulk of the global application of CO_2-EOR comes from the Permian Basin of West Texas in the United States, which accounts for two-thirds of the world’s oil production from CO_2-EOR projects. CO_2-EOR has been deployed extensively in this basin since the 1980s. CO_2-EOR projects in the basin are largely injecting CO_2 obtained from natural CO_2 reservoirs; which provide CO_2 of high purity and that is readily available at low cost. An extensive CO_2 pipeline network has evolved to meet the CO_2 requirements of these projects. Anthropogenic sources, though currently accounting for a relatively small portion of CO_2 supply to CO_2-EOR projects, are steadily increasing, and are contributing greater volumes and a higher proportion of the CO_2 supplied for CO_2-EOR.

Additional growth in oil production from CO_2-EOR is limited by the availability of reliable, affordable supplies of CO_2. The main barrier to reaching higher levels of crude oil production from the application of CO_2-EOR, both in the U.S. and worldwide, is the lack of access to adequate supplies of affordable CO_2. Today, CO_2 production from current supply sources – both natural and industrial – is fully committed. Efforts are underway to alleviate to some degree the CO_2 supply shortage for CO_2-EOR, but current planned expansions in CO_2 supplies are insufficient to tap the bulk of the oil production potential from CO_2-EOR in most regions where production from CO_2-EOR is being pursued.

Traditionally, most CO_2-EOR projects have been designed to minimize the amount of CO_2 injected per incremental barrel of oil produced. In the past, since the purchased cost of injected CO_2 was often the largest cost component of a CO_2-EOR project, field operators attempted to optimize incremental oil production in individual CO_2-EOR projects by minimizing the amount of CO_2 injected per incremental barrel of oil produced. Therefore, assessments of CO_2 storage potential associated with CO_2-EOR based on historical ratios of CO_2 injected to incremental oil produced do not accurately characterize future potential. In a future characterized by controls on GHG emissions, the traditional concern about the high cost of CO_2 is replaced by the objective of taking full advantage of the potential value associated with sequestered CO_2. This likely will result in the use of greater volumes of CO_2 for CO_2-EOR.

The prospect of controls on CO_2 emissions is prompting some developers to consider projects that both utilize captured CO_2 for CO_2-EOR and subsequently continue to store CO_2 after CO_2-EOR operations have run their course. The importance of CO_2-EOR as a facilitator for CCS is particularly significant where there are no established requirements or financial incentives for sequestering CO_2. Without GHG emissions controls, CCS is generally not economically viable. Storing CO_2 in association with EOR can substantially reduce the overall costs associated with CCS, since oil producers will be willing to pay for the CO_2 to enhance recovery. This can encourage the application of CCS, primarily in the developing world, in the absence of other incentives for CCS. In fact, in developing countries, the availability of CO_2-EOR opportunities may be a prerequisite for the initiation of CCS projects.

Not only does CCS need CO_2-EOR to help ensure economic viability for CCS, but CO_2-EOR needs CCS to ensure adequate CO_2 supplies to facilitate growth in the number of and oil production from CO_2-EOR projects. Significant expansion of oil production utilizing CO_2-EOR will require volumes of CO_2 that cannot be met solely by natural sources. Therefore, many CO_2-EOR project developers are beginning to look to CCS projects as a long-term supply source of affordable, reliable CO_2. This a *fundamental change in the CO_2-EOR project paradigm*.

Programs that create economic incentives for reducing emissions are critical, either through emissions trading programs, carbon taxes, or other mechanisms.

Within any established framework for regulating and/or incentivizing emissions reductions from wide-scale deployment of CCS (with or without CO_2-EOR), storage must be established as a certifiable means for reducing GHG emissions. The fact that a sequestration project methodology has not been approved under the Clean Development Mechanism (CDM) as part of the Kyoto Protocol hinders CCS project deployment in developing countries. Without incentives provided under the CDM, CCS in developing countries will only take place sporadically in niche sectors. To encourage CCS deployment, with or without CO_2-EOR, standards and guidelines will need to be established to provide consistency and market acceptability about the reality of the emissions reductions claimed. This is true for frameworks like the European Trading Scheme, comparable national and/or regional programs in the U.S., and the CDM and/or any successor agreement to the Kyoto Protocol.

Other regulatory and legal issues and uncertainties currently associated with CCS and CO_2-EOR that are hindering wide-scale deployment must also be resolved. Encouraging economically viable CCS projects in association with CO_2-EOR may be a necessary but not sufficient condition for the ultimate "conversion" of a CO_2-EOR project to a storage project. Regulatory and legal uncertainties are also hindering the pursuit of CO_2-EOR, particularly because of the lack of regulatory clarity regarding the process and requirements associated with the transition from EOR operations to permanent geologic storage, and the long-term liability associated with the sequestered CO_2.

Potential approaches exist for optimizing and increasing CO_2 storage potential while also realizing additional oil production from CO_2-EOR. A substantial amount of information has already been developed by and acquired from operators and researchers to begin to evaluate how to optimize CO_2 storage in the context of the pursuit of CO_2-EOR.

The worldwide application of "next generation" CO_2-EOR technologies focused on increasing oil production could create between 160 and 370 billion metric tons of CO_2 storage capacity, while producing 700 to 1,600 billion barrels of incremental oil. Assuming emissions of 6.2 million metric tons per year for 40 years of operation per plant, this is equivalent to capturing and storing the emissions of 2,200 to 4,900 one-GW size coal-fired power plants. This capacity is sufficient to store 18% to 40% of global *energy-related* CO_2 emissions projected from 2010 to 2035. "Next generation" CO_2-EOR technology stores 14% to 18% more CO_2 and produces 47% to 50% more incremental oil than "state-of-the-art" technology. (See technology definitions in Table ES-1).

Table ES-1. Definitions of Alternative Technology Cases Assumed in this Study

Technology Case	Definition
"State-of-the-Art" CO_2-EOR Technology	Represents best practices used by operators today, which are much improved over traditional CO_2-EOR practices. Assumes injection of much larger volumes of CO_2, and rigorous CO_2-EOR monitoring, management and remediation activities that help assure that the larger volumes of injected CO_2 contact more of the reservoir's residual oil, 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	Represents technology applications that address some of the issues faced by best "state-of-the art" CO_2-EOR practices. These include increasing the volume of CO_2 injected into the oil reservoir from 1.0 to 1.5 hydrocarbon pore volume (HCPV)*; optimizing well design and placement, including adding infill wells to achieve increased contact between the injected CO_2 and the reservoir; improving the mobility ratio between the injected CO_2/water and the residual oil; and extending the miscibility range, helping more reservoirs achieve higher oil recovery efficiency.
"Second Generation" CO_2-EOR Technology and CO_2 Storage	Assumes a reservoir is developed with one or more "next generation" technologies, targeting both the main pay zone plus an underlying ROZ, with continued CO_2 injection into and storage in an underlying saline aquifer, including injecting continuous CO_2 (no water) after completion of oil recovery operations.

* Hydrocarbon Pore Volume (HCPV) is a measure of the volume of pore space in a reservoir available for the injection of fluids.

Recent developments in the Permian Basin indicate that vast, previously unrecognized opportunities for additional oil production from CO_2-EOR exist that can provide substantial additional capacity for permanently storing CO_2. This potential is associated with residual oil zones (ROZs) below the oil/water contact in oil reservoirs that are widespread and rich in unrecovered oil. In addition to the main pay portion of depleted oil fields, ROZs represent a second, potentially much larger CO_2 storage target. Field pilots are showing that applying CO_2-EOR in ROZs can be commercially viable. Pursuing this resource potential could result in a two-to-three fold increase in the potential CO_2 storage capacity associated with the application of CO_2-EOR. Preliminary work is indicating that the Permian Basin is not alone in possessing extensive ROZs. ROZs exist where formation water has encroached into oil entrapments due to tectonic readjustment in a post-entrapment phase. Many places in the world exist where such a subsidence and entrapment phase has been followed by a subsequent tectonic episode. Additional research would be invaluable in identifying where additional such potential exists globally.

Other approaches to increase CO_2 storage in conjunction with CO_2-EOR may further increase storage capacities. These primarily involve approaches that inject CO_2 earlier, inject CO_2 longer, and inject CO_2 instead of water (including producing residual water in oil reservoirs to "make more room" for CO_2). Additionally, after the injection and permanent storage of CO_2 from CO_2-EOR, CO_2 can be injected into and stored in other geologic horizons that can be accessible from the same CO_2 injection wells and surface infrastructure used for CO_2-EOR, allowing for the utilization of additional storage capacity.

Some approaches for CO_2-EOR that attempt to better increase CO_2 storage can store more CO_2 than is associated with the CO_2 emissions over the life cycle of the incremental oil produced from CO_2-EOR, including emissions from consumption. Numerous studies of the potential storage capacity show that basins have produced large volumes of oil, and that have significant potential for CO_2-EOR, also possess favorable opportunities for large capacity for non-EOR storage. Substantial opportunities are likely to exist for co-locating CO_2-EOR and CO_2 storage operations in deep saline formations utilizing the same CO_2 injection wells and surface infrastructure used for CO_2-EOR. Moreover, additional storage capacity should exist in reservoirs targeted for CO_2-EOR after CO_2-EOR operations are complete.

This is illustrated in one case study in the U.S. Gulf Coast that assumes that a reservoir is developed using gravity-stable, vertical CO_2 injection with horizontal production wells targeting the main pay zone, plus the ROZ and the underlying saline aquifer. It also assumes injecting continuous CO_2 (no water) and continuing to inject CO_2 after completion of oil recovery, Figure ES-1. In this example, under just "next generation" technology," CO_2 stored represents 74% of the life-cycle CO_2 emissions. With "second generation" CO_2-EOR, without additional post-CO_2-EOR storage, CO_2 stored represents 90% of the life-cycle CO_2 emissions. Including additional post-CO_2-EOR storage results in 29% more CO_2 stored than is associated with life-cycle CO_2 emissions for the project (Table ES-2).

Figure ES-1. Schematic Illustration of Coupling CO_2-EOR with Other Strategies to Maximize Cost-Effective CO_2 Storage

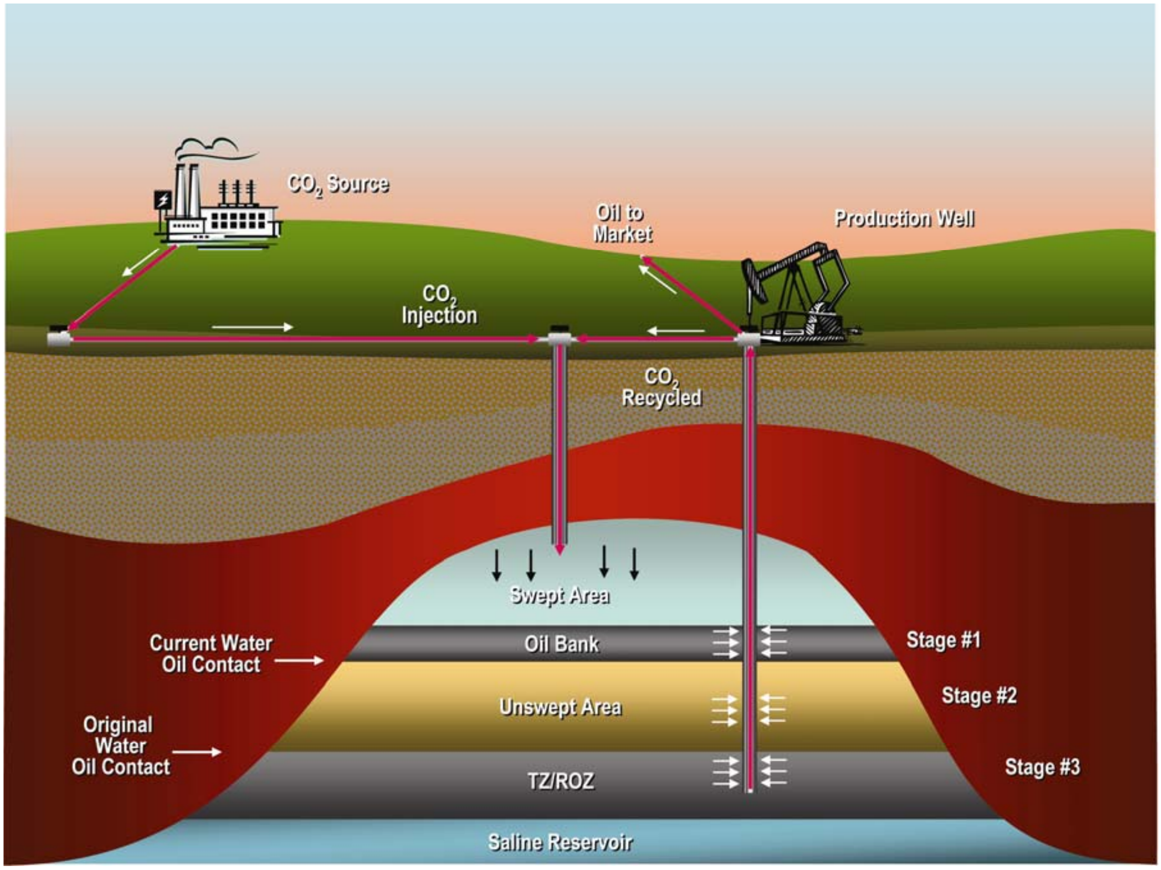


Table ES-2. Revised Case Study – Life Cycle Analyses of the Integration of "Next Generation" CO_2 Storage with EOR

	"Next Generation"	"Second Generation" CO_2-EOR & Storage		
	CO_2-EOR	CO_2-EOR	Storage	Total
CO_2 Storage (million metric tons)	32	76	33	109
Storage Capacity Utilization	22%	53%	23%	76%
Oil Recovery (million barrels)	92	180	-	180
% Carbon Neutral*	74%	90%	-	129%

* Includes the entire life-cycle CO_2 emissions, including those associated with CO_2-EOR operations, crude transport, refining, and the combustion of the incremental oil produced

Some believe that the emissions associated with processing and consuming the incremental volume of oil produced from CO_2-EOR operations should not be considered in life cycle emissions analyses of CO_2-EOR projects. They believe project life cycle emissions attributed to CO_2-EOR should include only fugitive emissions uniquely and directly related to the CO_2-EOR project, and not include downstream emissions common to all sources of oil supply, which would result regardless of the source of crude oil supply.

Even if only half of the emissions resulting from incremental oil production from CO_2-EOR are stored, and thus offset, this is still considerably better than none, which would be the case otherwise. In traditional CO_2-EOR projects, 50% to 60% of the total volume of emissions associated with oil production (from operations, transport, refining, and the ultimate consumption of the products refined from the produced crude) can be permanently stored. In other words, non-EOR oil production processes, when netting out the CO_2 stored with CO_2-EOR, produce twice the GHG emissions as CO_2-EOR projects.

A critical choice for society, at least in the near term, will be between a barrel of crude oil produced through application of CO_2-EOR, and that produced by other means, even as lower carbon alternatives such as wind and solar power 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 oil produced by most other means.

Achieving these environmental benefits will require that governments continue to work to ensure a policy, regulatory, and legal environment that encourages the application of CO_2-EOR in conjunction with CCS, as well as encouraging a long term, viable market for CO_2 in CO_2-EOR applications.

I. INTRODUCTION

Overview of this Report

This study provides additional information on the opportunities for and potential benefits from increasing CO_2 storage associated with CO_2 enhanced oil recovery (CO_2-EOR), to address the current lack of narrative in the international policy landscape around the issue of storage associated with CO_2-EOR.

The study starts with a review of traditional approaches for CO_2-EOR; these approaches tend to optimize oil production efficiency, often by limiting the volume of CO_2 injected. This is contrasted with potential alternative approaches that can optimize both incremental oil production and CO_2 storage. Existing worldwide CO_2-EOR operations are described, highlighting those projects pursuing or considering the co-benefits of CO_2 storage and incremental oil production. Expanding on previous work, the world-wide incremental oil production and CO_2 storage potential from CO_2-EOR is assessed assuming the application of "next generation" CO_2-EOR technologies. Other "second generation" approaches to increase CO_2 storage in conjunction with CO_2-EOR are also identified and evaluated. Finally, life-cycle analyses are presented that examine the potential greenhouse gas (GHG) emissions associated with various alternatives for CO_2-EOR development.

CO_2-EOR involves injecting CO_2 into an oil reservoir, often with intervening injections of water, with the aim of improving the flow of oil out of the reservoir. The injected CO_2 serves to decrease the viscosity of the oil and improve recovery efficiency of the remaining unproduced oil, thus enabling an increased amount of oil to be produced. Some of the CO_2 is recovered with the oil and can be separated and reused, and some remains permanently sequestered in the reservoir. Once the recoverable oil has been extracted, continued injection is possible to increase the amount of CO_2 than can be permanently stored in the reservoir. In addition, it may be possible to inject and permanently store CO_2 in other geologic horizons accessible from the same CO_2 injection wells and surface infrastructure used for CO_2-EOR.

Historically, most CO_2-EOR projects were designed to minimize the amount of CO_2 injected per incremental barrel of oil produced. This is because the purchased cost of injected CO_2 was often the largest cost component of a CO_2-EOR project. Consequently, assessments of CO_2 storage potential associated with the application of CO_2-EOR that are based on historical ratios of CO_2 injected to barrels of incremental oil produced probably do not provide an accurate characterization of this potential, especially in a future world characterized by controls on GHG emissions. In this world, the traditional concern of the high cost of CO_2 is replaced by the objective of taking full advantage of the potential value associated with permanently sequestered CO_2.

The combination of CO_2-EOR and permanent CO_2 storage in oil reservoirs has the potential to provide a significant, near-term solution for reducing GHG emissions, while also providing for the beneficial use of CO_2 injection for increasing crude oil production. Despite having less total estimated potential than deep saline aquifers, the CO_2 storage potential in depleted oil and gas fields is nonetheless thought to be significant. Experience to date indicates storage opportunities in depleted hydrocarbon fields can have much lower development costs than in deep saline formations because of the generally greater availability of geological data from exploration and production operations, as well as the accessibility of existing oil field infrastructure.

Moreover, pursuing CO_2 storage with CO_2-EOR offers significant potential to produce more oil from developed fields, while in the process, allowing for large quantities of CO_2 to be sequestered underground rather than emitted to the atmosphere. CO_2 storage in oil fields could be smaller in scale relative to deep saline aquifers, and the potential commercial benefits of utilizing CO_2 for EOR could provide an immediate economic value for implementation of such projects, particularly in a period of high oil prices.

On the other hand, some believe that increased oil production from CO_2-EOR is not an acceptable option for mitigating CO_2 emissions. And still others downplay the potential for CO_2-EOR in combination with CO_2 storage as a viable long-term option for storage because they claim the potential storage capacity for this option is limited.

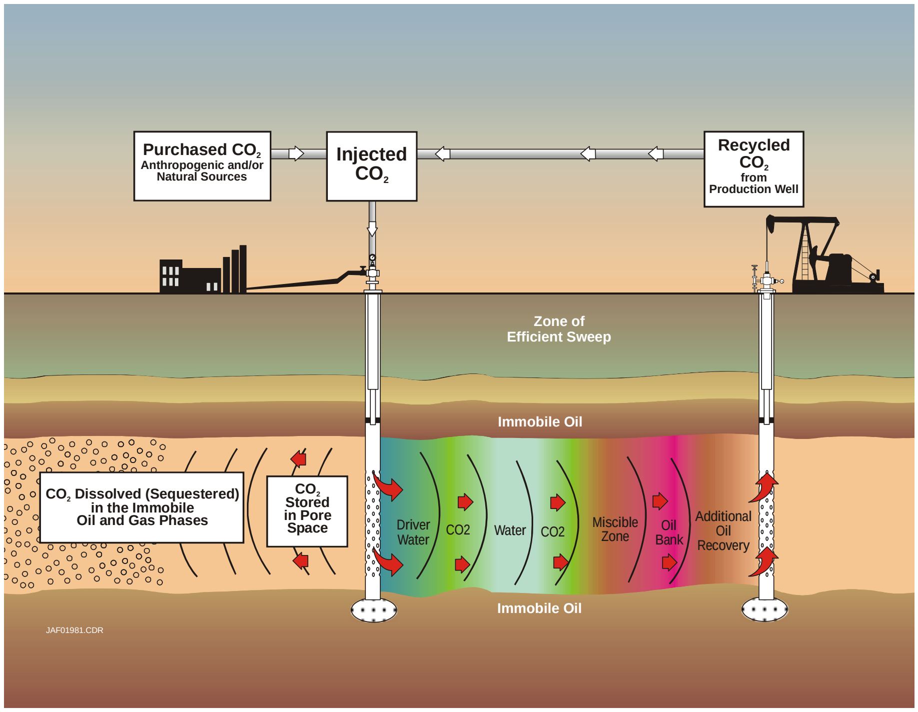
What is CO_2-EOR?

Enhanced oil recovery (EOR) is a term used for a wide variety of techniques for increasing the amount of crude oil that can be extracted from an oil field. Gas injection (primarily CO_2) is presently the most commonly used approach to enhance recovery. Sometimes, the CO_2 is mixed with H_2S. This gas stream, called acid gas or sour gas, can be the result of the separation of the desired hydrocarbon components in natural gas.

As part of the CO_2-EOR process, CO_2 is injected into an oil-bearing stratum under high pressure. Oil displacement by CO_2 injection relies on the phase behavior of the mixtures of gas and the oil, which are strongly dependent on reservoir temperature, pressure and oil composition. There are two main types of CO_2-EOR processes:

- *Miscible CO_2-EOR* is a multiple contact process involving interactions between the injected CO_2 and the reservoir's oil. During this multiple contact process, CO_2 vaporizes the lighter oil fractions into the injected CO_2 phase and CO_2 condenses into the reservoir's oil phase. This leads to two reservoir fluids that become miscible (mixing in all parts), with favorable properties of low viscosity, enhanced mobility, and low interfacial tension. The primary objective of miscible CO_2-EOR is to remobilize and dramatically reduce the residual oil saturation in the reservoir's pore space after water flooding. Figure 1 provides a one-dimensional schematic showing the dynamics of the miscible CO_2-EOR process. Miscible CO_2-EOR is by far the most dominant form of CO_2-EOR deployed.
- *Immiscible CO_2-EOR* occurs when insufficient reservoir pressure is available or the reservoir's oil composition is less favorable (heavier). The main mechanisms involved in immiscible CO_2 flooding are: (1) oil phase swelling, as the oil becomes saturated with CO_2; (2) viscosity reduction of the swollen oil and CO_2 mixture; (3) extraction of lighter hydrocarbon into the CO_2 phase; and, (4) fluid drive plus pressure. This combination of mechanisms enables a portion of the reservoir's remaining oil to still be mobilized and produced, and is commercial in many instances.

Figure 1. One-Dimensional Schematic Showing the Miscible CO_2-EOR Process



Potential Approaches for Optimizing CO_2-EOR and CO_2 Storage

A substantial amount of information has already been developed by and acquired from operators and researchers as part of previous efforts to evaluate methods to optimize CO_2 storage in the context of the pursuit of CO_2-EOR. This is based in large part by work sponsored by the U.S. Department of Energy/National Energy Technology Laboratory (DOE/NETL).

The potential approaches for optimizing incremental oil production from CO_2-EOR with CO_2 storage examined in this study include:

- "Next generation" CO_2-EOR technologies, which could dramatically increase incremental oil recovery over current best practices, as well as increase the CO_2 storage potential in depleted oil fields
- CO_2-EOR technology applied to the essentially immobile residual oil zones (ROZs) underlying the main oil pay zones in many reservoir settings
- Advanced drilling, monitoring and modelling technologies to make vertical ("gravity stable") CO_2 floods more of a possibility in some settings
- Deploying CO_2 injection earlier in field development; this can result in both incremental (and faster) oil recovery and greater utilization of storage capacity
- Pursuing straight CO_2 injection for CO_2-EOR, rather than more traditional water-alternating-gas (WAG) processes.
- Any of these approaches combined with the injection and permanent storage of CO_2 in other geologic horizons accessible from the same CO_2 injection wells and surface infrastructure used for CO_2-EOR.

II. GLOBAL STATUS AND DEVELOPMENTS IN CO_2-EOR/CO_2 STORAGE

Overview of this Section

This section reviews current CO_2-EOR operations globally, including design principles and operational practices associated with these operations. The main oil fields/basins currently supporting CO_2-EOR operations are identified and characterized, along with those that are in the process of planning operations for the future. This review also includes a summary of CCS projects that are being pursued with CO_2-EOR as the primary target for storage. The section concludes with some key findings to date on efforts to encourage combining CO_2-EOR operations with CO_2 storage, highlighting the policy, legal and regulatory barriers affecting the pursuit of CO_2-EOR in combination with CO_2 storage.

The key findings of this section include:

- CO_2-EOR technologies have been demonstrated to be profitable in commercial scale applications for nearly 30 years.
- Anthropogenic sources currently account for a relatively small, but steadily increasing, portion of this CO_2 supply to CO_2-EOR projects.
- Substantial additional growth in CO_2-EOR, both in North America and around the world, is possible, but is limited by the availability of reliable, affordable supplies of CO_2.
- To date, most CO_2-EOR projects have been engineered to minimize the amount of CO_2 injected per incremental barrel of oil produced, not the volume of CO_2 stored.
- Prospects of controls on CO_2 emissions is prompting developers to consider plans to both utilize CO_2 for CO_2-EOR and to subsequently store CO_2 after CO_2-EOR operations have run their course. This is a fundamental change in the CO_2-EOR project paradigm – i.e., not only does CCS need CO_2-EOR to help provide economic viability for CCS, but CO_2-EOR needs CCS in order to ensure adequate, affordable CO_2 supplies.
- Facilitating approaches to optimize CO_2 storage with CO_2-EOR require establishing a market for CO_2 in these applications, along with a legal and regulatory environment legitimizing CO_2 storage in association with CO_2-EOR.
- Critical are programs that create economic incentives for reducing emissions, either through emissions trading programs, carbon taxes, or other mechanisms. Within any established framework for regulating and/or incentivizing emissions reductions from wide-scale deployment of CCS (with or without CO_2-EOR), storage must be established as a certifiable means for reducing GHG emissions.

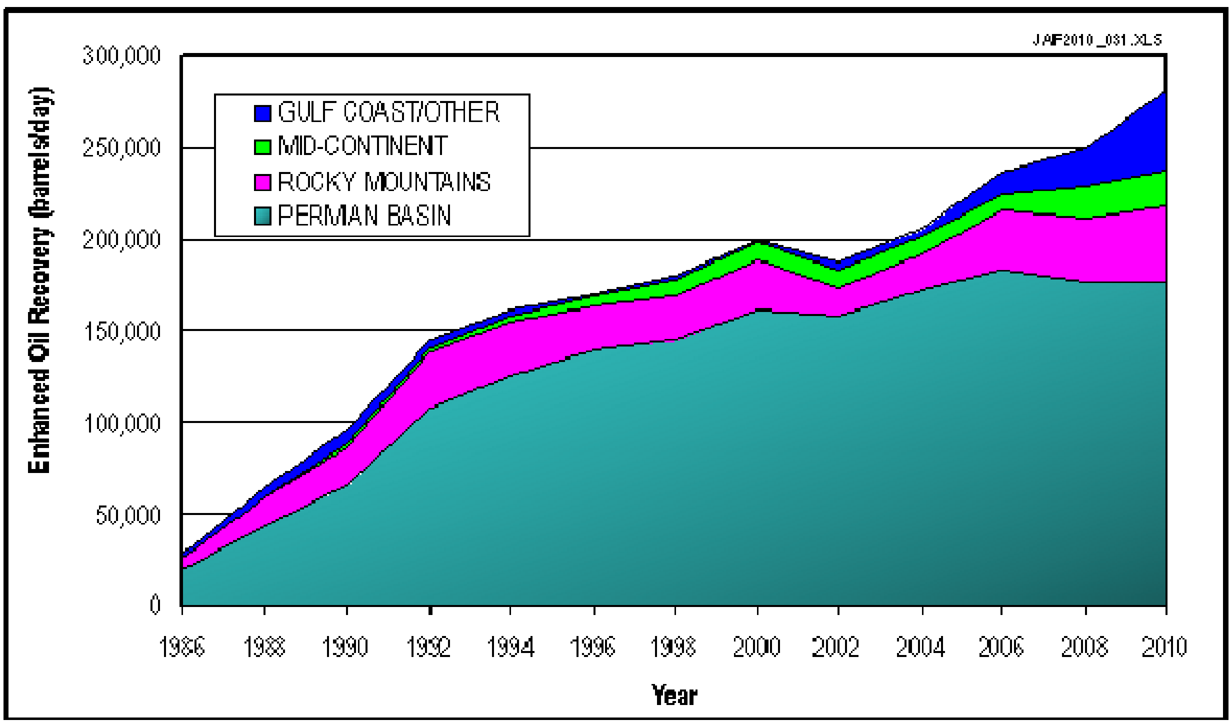
Overview of Current CO_2-EOR Activities

CO_2-EOR technologies have been demonstrated to be profitable in commercial scale applications for nearly 30 years. CO_2-EOR has been deployed extensively in the Permian Basin of West Texas in the U.S. since the mid-1980s. The projects in the Permian Basin are largely injecting CO_2 obtained from natural CO_2 reservoirs. These natural sources provide CO_2 supplies of high purity and that are available at low cost. An extensive CO_2 pipeline network has evolved in the region to meet the CO_2 requirements of these projects. Production from this region represents the majority of world's CO_2-EOR production.

United States

The most comprehensive review of the status of EOR projects around the world is the biennial EOR survey published by the *Oil and Gas Journal*, the most recent issue of which was published in April 2010.[1] This study reports that the number of CO_2-EOR projects and the level of production are increasing in the Permian Basin, as well as other regions of the United States, particularly in the Gulf Coast and the Rockies, Figure 2. Notably, this growth was sustained in spite of two oil price crashes. In fact, low oil prices did not deter this underlying historical growth in the CO_2-EOR industry, but only curtailed its acceleration.

Figure 2. U.S. CO_2-EOR Production (1986-2010)



[1] Koottungal, Leena, "SPECIAL REPORT: EOR/Heavy Oil Survey: 2010 worldwide EOR survey," *Oil and Gas Journal*, April 19, 2010

Natural CO_2 fields are the dominant source of CO_2 for the U.S. CO_2-EOR market, providing CO_2 supplies amounting to 45 million metric tons[2] per year (2.35 billion cubic feet per day (Bcfd)). However, anthropogenic sources account for steadily increasing volumes of this CO_2 supply, currently providing 10 million metric tons per year (529 million cubic feet per day (MMcfd)) of CO_2 for EOR, Table 1.[3] Nonetheless, *CO_2 reserves from natural sources have the potential of producing only a small fraction of the oil resource potential achievable with the application of CO_2-EOR*.

Table 1. Significant Volumes of Anthropogenic CO_2 Are Being Injected for EOR

State/Province (Storage Location)	Source Type (Location)	CO_2 Supply (MM Metric Tons/year)			CO_2 Supply (MMcfd)		
		Natural	Anthropogenic	Total	Natural	Anthropogenic	Total
Texas-Utah-New Mexico-Oklahoma	Geologic (Colorado-New Mexico) Gas Processing (Texas)	32	2	34	1,670	104	1,774
Colorado-Wyoming	Gas Processing (Wyoming)		4		-	230	230
Mississippi-Louisiana	Geologic (Mississippi)	13		13	683	-	683
Michigan	Ammonia Plant (Michigan)		0	0	-	15	15
Oklahoma	Fertilizer Plants (Oklahoma)		1	1	-	30	30
Saskatchewan	Coal Gasification (North Dakota)		3	3	-	150	150
Total		45	10	56	2,353	529	2,882

Source: Advanced Resources International, 2010; numbers do not add exactly due to rounding.
MMcfd of CO_2 can be converted to million metric tons per year by first multiplying by 365 (days per year) and then dividing by 18.9 Mcf per metric ton.

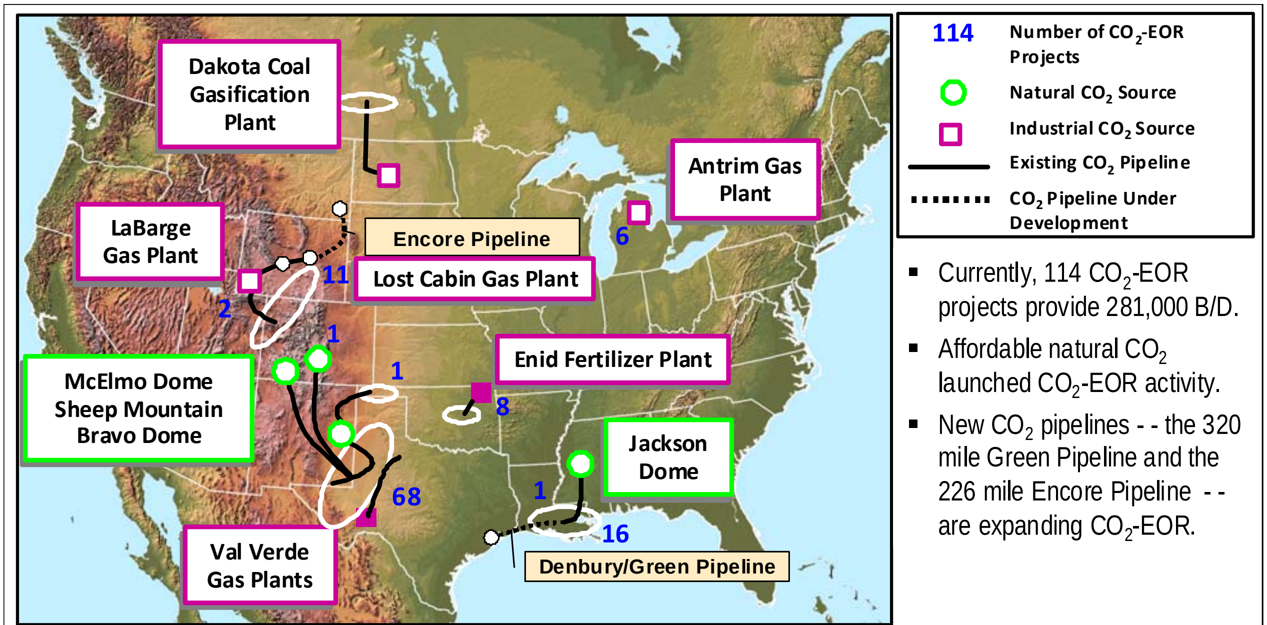
The largest single source of anthropogenic CO_2 used for EOR is the capture of four million metric tons per year (230 MMcfd) of CO_2 from the Shute Creek gas processing plant at the La Barge field in western Wyoming.[4] This is followed by the capture of about three million metric tons per year (150 MMcfd) of CO_2 from the Northern Great Plains Gasification plant in Beulah, North Dakota and its transport, via a 320 kilometer (km) (200 mile) cross-border CO_2 pipeline, to two EOR projects (Weyburn and Midale) in Saskatchewan, Canada (discussed in more detail below).[5]

New CO_2 pipelines and refurbished gas treatment facilities, such as Denbury's 512 km (320 mile) Green Pipeline along the Gulf Coast, ExxonMobil's expansion of the Shute Creek gas processing plant, the proposed 360 km (226 mile) Encore Pipeline and refurbished Lost Cabin gas plant in the

[2] The terms metric ton and tonne are used interchangeably in this report, and are assumed to be the same, as is the abbreviation – mt.
[3] Advanced Resources International internal data base, 2010.
[4] Skip Thomas, "LaBarge Field and Shute Creek Facility," presentation to the Wyoming Enhanced Oil Recovery Institute, 3rd Annual Wyoming CO_2 Conference, June 24, 2009
[5] Basin Electric Power Cooperative, 2009 Annual Report

Rockies, and the new Century gas processing plant in West Texas, are all due on-line in late 2010 or early 2011, Figure 3. These new facilities and pipelines will help connect existing, new, and expanded facilities providing CO_2 from both natural and anthropogenic sources, and facilitate expanded availability and use of CO_2 in U.S. oil fields, leading to increased oil production from CO_2-EOR.

Figure 3. Current U.S. CO_2-EOR Activity



Source: Advanced Resources International, Inc., based on Oil and Gas Journal, 2010 and other sources.

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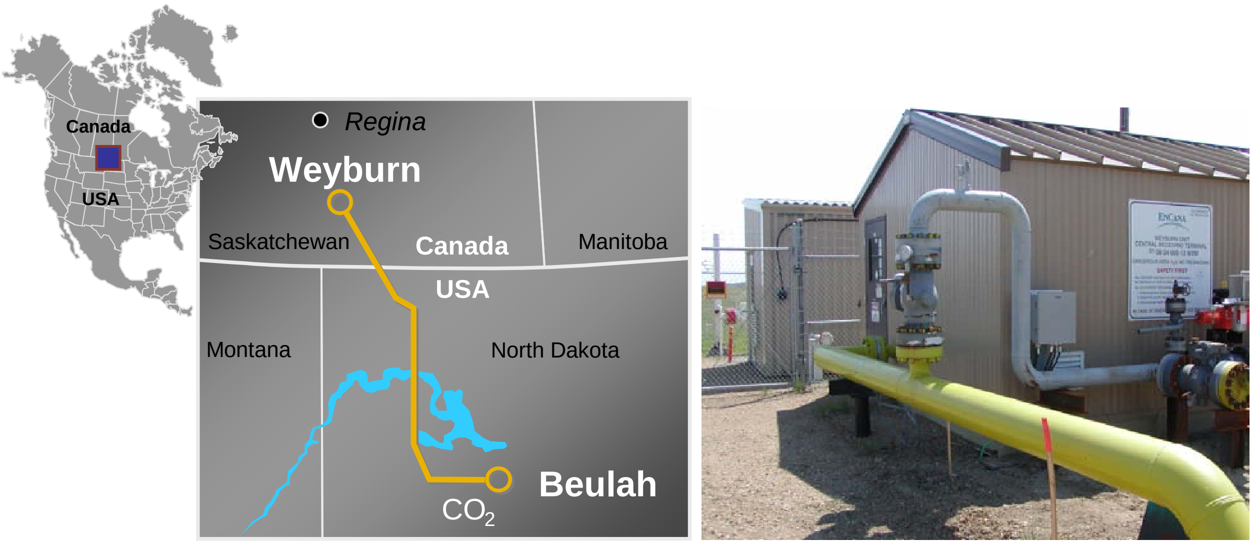
Canada

Seven CO_2 miscible projects and one acid gas miscible project are underway in Canada. The “poster child” of a combined CO_2-EOR and geologic storage project is Cenovus Energy’s (formerly EnCana’s) Weyburn CO_2 flood in Canada (Figure 4) where oil production from CO_2-EOR continues to increase. The CO_2 flood has been expanded to over 60% of the unit. The implementation of the CO_2-EOR project, along with the continued infill well development program, has resulted in a 65% increase in oil production. Cenovus buys anthropogenic CO_2 from the Dakota Gasification Synfuels plant in Beulah, North Dakota.[6]

[6] Moritis, Guntis, “SPECIAL REPORT: More US EOR projects start but EOR production continues decline,” *Oil and Gas Journal*, April 21, 2008

Figure 4. Weyburn Enhanced Oil Recovery Project



Source: EnCana

JAF028255.PPT

Currently, the Weyburn project is injecting 2.4 million metric tons per year, and plans to inject 23 million metric tons in association with CO_2-EOR (15 million metric tons have been injected to date).[7] The ultimate plan is to inject a total of 55 million metric tons, so that 32 million metric tons would be injected solely for purposes of CO_2 storage.[8]

Another CO_2-EOR project has been in operation by Apache Canada since 2005 in the nearby Midale field, using the same source for CO_2 as Weyburn.[9] In addition, a small CO_2-EOR project has been in operation at the Joffre field in Alberta since 1984, operated by Penn West, using CO_2 from a nearby petrochemical plant.

Other Countries

Only a few (mostly immiscible) CO_2-EOR projects are underway elsewhere in the world (in Brazil, Turkey, and Trinidad), according to the OGJ survey.[10]

CO_2-EOR pilots have been implemented in China in the Liaohe, Jilin, Dagang, Shengli, Zhongyuan, Daqing, Jiangsu, Songliao, Changqing, Huebei, and Xinli fields, though, at least in

[7] http://www.cenovus.com/operations/oil/weyburn.html
[8] See Law, David, et al., “Theme 3: CO_2 Storage Capacity and Distribution Predictions and the Application of Economic Limits,” in Wilson, M. and M. Monea, eds., *IEA GHG Weyburn CO_2 Monitoring and Storage Project Summary Report 2000-2004*, Petroleum Technology Research Center, Regina, Saskatchewan, Canada, 2004
[9] 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
[10] Koottungal, Leena, “SPECIAL REPORT: EOR/Heavy Oil Survey: 2010 worldwide EOR survey,” *Oil and Gas Journal*, April 19, 2010

some cases, the injection stream is a flue gas stream or other waste stream, often with a relatively low concentration of CO_2.[11,12]

In the North Sea, five hydrocarbon gas injection projects have been initiated, with some success, but none utilized CO_2.[13]

Petrobras recently started injecting high-pressure CO_2 into the Miranga onshore field in the state of Bahia in Brazil to test technologies that might contribute to future development projects for the Santos Basin's Pre-Salt cluster. The CO_2 produced at the future pre-salt fields will be reinjected into the reservoirs themselves to boost recovery. The Miranga field project foresees the geological storage of 370 metric tons of CO_2 per day, with the intention of also increasing the oil recovery efficiency in that field.[14]

Abu Dhabi Company for Onshore Oil Operations (ADCO) has initiated a CO_2-EOR project in a carbonate reservoir in the MENA region of Abu Dhabi. The pilot began operations in the fourth quarter of 2009. A continuous supply of 60 metric tons per day (1.2 million standard cubic feet per day) of CO_2 is being provided to ADCO and is being injected into one of the pilot wells.[15]

Based on the Prospect of Future Emissions Controls, a Number of Combined CO_2-EOR/CO_2 Storage Projects are Planned

As of April 2010, 12 CO_2-EOR projects were in various degrees of planning in the U.S, according to the *Oil and Gas Journal*.[16] These projects currently plan to only inject CO_2 for CO_2-EOR operations. Only one planned pilot CO_2-EOR project was reported by OGJ outside the U.S. in 2008; a project by Petrobras in the Miranga field in Brazil. No new planned CO_2-EOR projects were reported in the 2010 survey outside of the U.S.

In the first half of 2009, the Global CCS Institute commissioned a survey of the status of CCS projects worldwide. The survey was updated in April/May 2010 to ensure that this report included the most recent data available to track progress towards the G8's 2010 and 2020 goals. The survey identified 80 currently active or planned large-scale, fully integrated CCS projects for assessment against a set of criteria developed by the International Energy Agency (IEA), the Carbon Sequestration Leadership Forum (CSLF) and the Global CCS Institute. A review of the 80 projects indicates that approximately 15 are associated with or plan to provide their CO_2 to CO_2-EOR projects, all in North America.[17]

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[11] Dahowski, RT, X Li, CL Davidson, N Wei, JJ Dooley, and RH Gentile, "A Preliminary Cost Curve Assessment of Carbon Dioxide Capture and Storage Potential in China, " *Energy Procedia*, 1 (2009) 2849-2856

[12] Meng, KC, R.H. Williams, and M.A. Celia, "Opportunities for low-cost CO_2 storage demonstration projects in China," *Energy Policy*, 35, 2368-2378, (2007)

[13] Awan, A. R., R. Teigland, and J. Kleppe, "A Survey of North Sea Enhanced Oil Recovery Projects Initiated During the Years 1975 to 2005," *SPE Reservoir Evaluation and Engineering Magazine*, June 2008, pp. 497-512

[14] "Petrobras' CO_2 Injection Project to Serve As Test for Pre-Salt," *Rigzone*, October 02, 2009 (http://www.rigzone.com/news/article.asp?a_id=80962)

[15] http://www.pennenergy.com/index/petroleum/display/0080149715/articles/pennenergy/petroleum/exploration/2010/04/adco-starts_co2_injection.html

[16] Moritis, Guntis, "SPECIAL REPORT: More US EOR projects start but EOR production continues decline," *Oil and Gas Journal*, April 21, 2008

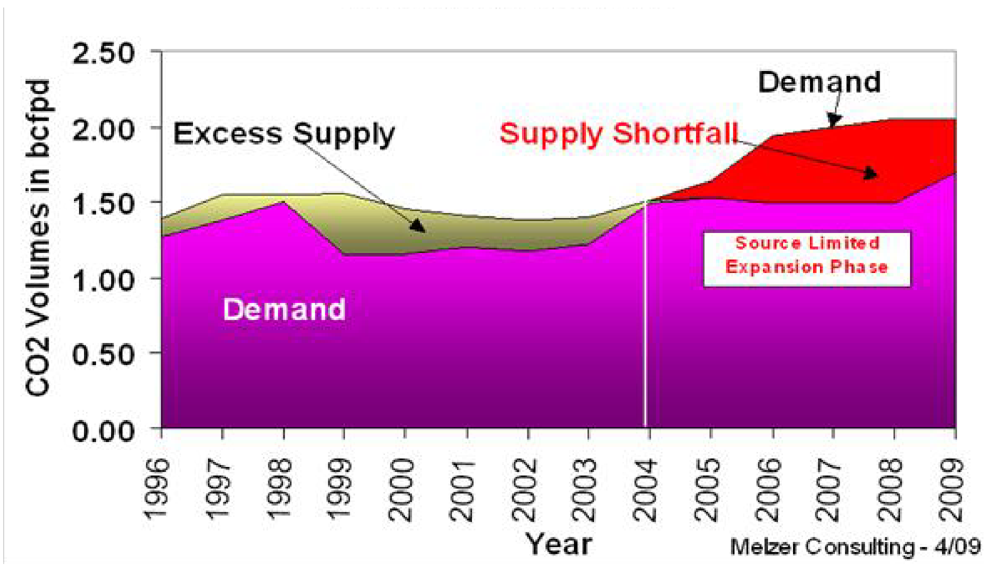
[17] International Energy Agency, *Carbon Capture and Storage, Progress and Next Steps, IEA/CSLF Report to the Muskoka G8 Summit*, 2010 (http://www.iea.org/papers/2010/ccs_g8.pdf)

"Demand Pull" on Anthropogenic CO_2 Capture

Based on a review of the historical application of CO_2-EOR,[18] the number one barrier to reaching higher levels of CO_2-EOR production, both in the U.S. and worldwide, is lack of access to adequate supplies of affordable CO_2. While affordable pricing of CO_2 is important, the successful pursuit of future CO_2-EOR projects depends upon sufficient and reliable CO_2 supplies.

The establishment of CO_2 sources and the resulting growth of CO_2 flooding in West Texas, Wyoming, and Mississippi in the U.S. 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 5). 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.

Figure 5. CO_2 Supply and Demand in the Permian Basin

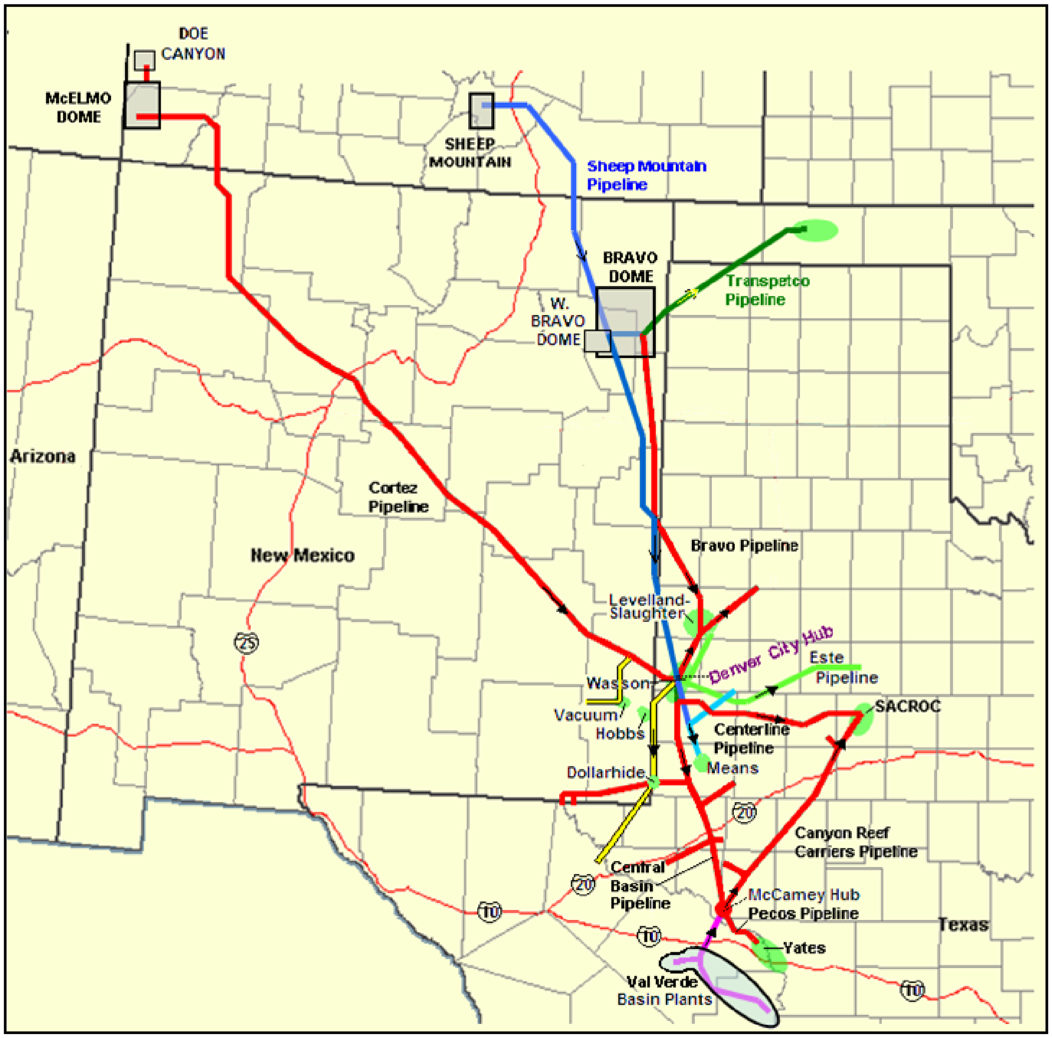


Efforts are underway to alleviate, at least to some degree, this CO_2 supply shortage for CO_2-EOR in the Permian Basin. For example, three pump stations have been added to the Cortez CO_2 pipeline from McElmo Dome natural CO_2 field (Figure 6) to upgrade throughput to enable transport of up to 25 million metric tons per year (about 1,300 MMcfd) of CO_2. The Doe Canyon CO_2 source field, just north of McElmo Dome, was drilled and volumes from that field were added to the enhanced volumes at McElmo Dome to keep the CO_2 pipeline full.[19]

[18] IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery,* Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009

[19] 2009 Annual Report and 10-K (pp. 24-25) for Kinder Morgan Energy Partners, Press Release, "Kinder Morgan Energy Partners Announces the Development of New CO_2 Source Field and Major Expansions to Existing CO_2 Operations" January 24, 2007, and 2010 KMP Analyst Conference Presentation, January 28, 2010, Tim Bradley presentation on "CO_2"

Figure 6. Planned CO_2 Pipeline Expansion Projects in the Permian Basin



In addition, a new area of Bravo Dome was developed by the Hess Corporation, called West Bravo Dome, and some upgrades at Bravo Dome were completed by Oxy to keep their CO_2 supplies from these natural source fields from declining, and to keep the CO_2 pipeline from this region full.

All these projects were completed by the end of 2009 and the aggregated Permian Basin CO_2 deliveries reached 34 million metric tons per year (1,800 MMcfd). These new supplies were absorbed quickly in the marketplace. Nonetheless, an estimated 6 million metric tons per year (300 MMcfd) of shortage still remains unsupplied as of mid-year 2010, not counting the pent-up demand volumes at Oxy. When the excitement of the immature ROZ phase of development gets moving (see discussion below), even more CO_2 may be required to facilitate EOR development in this region. The CO_2 price, with the ever-present caveat of healthy oil pricing, should remain solid for the foreseeable future.

Given the present situation, the Permian Basin may be the world's first example of a "demand pull" on anthropogenic CO_2 capture.[20]

Despite this, this expansion of CO_2 supplies predominantly from natural sources is still not foreseen as being sufficient for meeting the future demand of CO_2 for CO_2-EOR. Thus, legislative and regulatory activity in the State of Texas for CCS is also evolving to support increasing CO_2 supplies from anthropogenic sources to serve the CO_2-EOR market. This activity has focused on incentives for CO_2 capture from next generation coal power plants. In the State's 2009 session, a bill was passed with $100 million (U.S.) worth of franchise incentives for three qualifying coal plants. The state's oil and gas regulatory agency, the Texas Railroad Commission, was empowered to write rules for CO_2-EOR with "incidental CO_2 storage" and for CO_2 storage projects with "incidental production." Expectations for CO_2-EOR "business as usual" with a monitoring "overlay" for verifying storage volumes is to be drafted next.

This is creating a business environment that, together with the mature CO_2 market in Texas, has served to stimulate several new projects to increase anthropogenic CO_2 supplies for the West Texas CO_2-EOR market:

- The SandRidge/Occidental gas separation plant in Pecos County, Texas is moving forward with an expected start by the end of 2010. The industrial by-product CO_2 expected from this plant should exceed 4 million metric tons per year (200 MMcfd) and will be utilized in Occidental Permian's CO_2 flooding project portfolio.[21]
- Summit Energy's first-of-its-kind 400 MW integrated gasification combined cycle (IGCC) power/poly-gen plant in the Permian Basin could provide three million metric tons per year (150 MMcfd) for CO_2-EOR applications. The project has already received a $350 million (U.S.) award, including funds from the American Recovery and Reinvestment Act, from the DOE Clean Coal Power Initiative (CCPI) – Round 3 to demonstrate the commercial integration of large-scale IGCC with CCS. Summit said it chose this location for the facility due to the strong commitment of state and local elected officials, and the 30 years of experience importing natural CO_2 into the Basin for CO_2-EOR. The project's FEED team formally launched its study on June 30, 2010 and construction is currently scheduled to begin in the second half of 2011.[22]
- The Tenaska Trailblazer Energy Center will generate approximately 765 MW gross and 600 MW net, using best available supercritical steam, pulverized coal technology. This plant will be designed to capture 85% to 90% of the estimated 4.5 million metric tons per year of CO_2 (225 MMcfd) produced by combustion and deliver it via pipeline to Permian Basin oil fields for use in EOR and ultimately, geologic storage.[23]

Other Potential Sources of Anthropogenic CO_2 Supplies in the U.S.

A number of additional projects elsewhere in the U.S. are also known to be in the planning stages or under consideration to also help remedy, to some extent, current limits on CO_2 supply, by

[20] Tom Doll, Tracy Evans, L. Stephen Melzer, "North American CO_2 Status," presented at the EORI 3rd Annual CO_2 Conference, Casper, WY, June 2009

[21] SandRidge Energy, Presentation at Investor/Analyst Meeting, March 3, 2009 and Sandridge Energy, Inc., 2009 Annual Report

[22] "Summit Power begins FEED study for Texas IGCC-CCS project," *Carbon Capture Journal*, July 22,2010 (http://www.carboncapturejournal.com/displaynews.php?NewsID=603)

[23] http://www.tenaskatrailblazer.com/

bringing, perhaps, more anthropogenic sources to the CO_2-EOR market. These include the following:

- A joint CCS/CO_2-EOR project by Hydrogen Energy International, consisting of an IGCC power generating facility in Kern County, California. The project would gasify petroleum coke (or blends of petroleum coke and coal, as needed.) A gasification component would produce hydrogen to feed a 390 MW combined cycle plant, providing approximately 100 MW of peaking power. The gasification component would also capture approximately 90% of its CO_2 emissions, or two million metric tons per year (approximately 100 MMfd), which would be transported and used for CO_2-EOR and storage in the nearby Elk Hills Oil Field.[24] While the project received a $308 million (U.S.) Department of Energy grant in July 2009, the planners have struggled to acquire the necessary permits with the California state officials to permanently sequester the CO_2.
- Southern Company's Kemper County IGCC plant plans to provide 1.1 to 1.5 million metric tons per year of CO_2 to Denbury Resources for CO_2-EOR in oil fields in Louisiana and Mississippi.[25]
- Baard Energy's Ohio River Clean Fuels project, a 53,000 barrels per day coal- and biomass-to-liquids project, which plans to market the plant's CO_2 for EOR.[26]
- Rentech's 30,000 barrel per day coal- and biomass-to-liquids plant in Natchez, Mississippi, which will market the plant's CO_2 for EOR. The first phase of the project is expected in 2011.[27]
- DKRW Energy's 15,000 to 20,000 barrel per day coal-to-liquids plant in Medicine Bow, Wyoming, which will also market its CO_2 for EOR. The project is expected to begin operation in 2013. [28]

Denbury Resources has identified 17 million metric tons per year (approximately 900 MMcfd) of anthropogenic CO_2 potentially available for EOR in the Rockies, Table 2. The company has also entered into contingent purchase contracts for 18 million metric tons per year of anthropogenic CO_2 in the Midwest and for 14 million metric tons per year of anthropogenic CO_2 in the Gulf Coast.[29]

Finally, several oil field injection tests are being or have recently been conducted as part of the Phase II validation stage of the DOE Regional Carbon Sequestration Partnership Program.[30] These tests ultimately could lead to larger scale projects.

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[24] http://www.energy.ca.gov/sitingcases/hydrogen_energy/index.html and http://www.hydrogenenergycalifornia.com/embed/media/00000002/heca-printable-factsheet.pdf
[25] http://www.mississippipower.com/kemper/TRIGTechnology.asp
[26] http://www.baardenergy.com/orcf.htm
[27] http://www.rentechinc.com/natchez.php
[28] http://www.dkrwenergy.com/fw/main/Overview-46.html
[29] Denbury Resources corporate presentation, June 2010
[30] http://www.netl.doe.gov/technologies/carbon_seq/partnerships/validation.html

Table 2. Rockies New Anthropogenic CO_2 Sources

	Location	MMcfd	Million mt/yr	Comments
Natural Gas Treating Plants				
1. Exxon La Barge	SW Wyoming	100	1.9	Plant expansion
2. COP Lost Cabin	Central Wyoming	50	1.0	Under contract
3. Riley Ridge	SW Wyoming	-	-	Under discussion
	Subtotal	150	2.9	
Proposed Coal to Gas/ Liquids Plants				
1. DKRW/Medicine Bow	SE Wyoming	150	2.9	DOE Loan Guarantee
2. Refined Energy	SE Idaho	80-175	2.3	Diesel/Fertilizer
3. Gas Tech	NE Wyoming	115	2.2	UCG
4. Many Stars	C. Montana	250	4.8	Start in 2012
5. South Heart	SW N. Dakota	100	1.9	Coal to H_2
	Subtotal	695-790	14.1	
	TOTAL	845-940	17.0	

Potential Sources of Anthropogenic CO_2 Supplies Outside the U.S.

Outside of the United States, in addition to its planned project in California, Hydrogen Energy is also planning a project in Abu Dhabi that will convert natural gas to hydrogen and CO_2. The hydrogen power plant will generate approximately 400 MW. And while the CO_2 will not be used for EOR, up to 1.7 million metric tons of CO_2 per year will be transported to a producing oil field and used to replace natural gas that is currently being injected to maintain pressure.[31]

This project in Abu Dhabi was modeled after a similar project in Scotland -- the so-called "Peterhead site" – where a considerable amount of infrastructure was already in place, and land was available next to an existing, conventional gas-fired power plant. Pipelines were in place to transport the CO_2, and a North Sea oil field, BP's Miller field, had been identified as a suitable storage site. This project would have provided sufficient CO_2 for EOR to extend the life of the Miller oil field for 15 to 20 years with the production of more than 50 million barrels of additional oil. Unfortunately, the project promoters determined that the government financial incentives adequate to make such a first-of-its-kind CCS project economically viable would not be available in the time frame necessary to enable this project to proceed. By the time work stopped on the project, it had been fully permitted.[32]

In July 2010, Scottish and Southern Energy announced a new plan for the Peterhead site. The plan calls for the retrofit of an existing gas-fired plant for post-combustion carbon capture.[33]

Canada also has a number of CCS/CO_2-EOR projects in the planning stages:

- Alter NRG has announced Canada's first proposed coal-to-liquids project that will capture CO_2 for planned use in CO_2-EOR projects.[34]

[31] http://www.hydrogenenergy.com/42.html
[32] http://www.hydrogenenergy.com/41.html
[33] http://www.sse.com/SSEInternet/index.aspx?id=22800

- In Saskatchewan, after receiving $250 million (Canadian) from the Canadian government for carbon capture investment, SaskPower is proposing a retrofit system to the 139 MW Boundary Dam power plant; selling the CO_2 as an EOR source to offset retrofit costs.[35]
- Project Pioneer, a consortium of companies led by TransAlta, is constructing the 450 MW Keephills 3 coal plant with chilled ammonia, post-combustion capture technology. The project hopes to sequester one million metric tons of purified CO_2 per year in nearby fields. Over $1 billion (Canadian) in support has been awarded or pledged to Project Pioneer over the next 15 years from the federal CCS fund, the ecoENERGY Technology Initiative, and Alberta's CCS fund.[36]
- Bow City Power in Alberta is constructing two 500 MW coal plants that will utilize amine scrubbing to capture CO_2 for nearby EOR operations.[37]

Finally, the North Sea was identified by IEA GHG in an earlier study to have significant opportunity for CO_2-EOR.[38] Current plans under consideration in the North Sea include:

- In March 2006, Statoil and Shell launched a plan for a project to utilize CO_2 captured from a large natural gas-fired power plant and methanol production facility at Tjeldbergodden in Norway to be used in an offshore CO_2-EOR project at the Shell-operated Draugen field, and later at the Statoil-operated Heidrun field. A proposed capture facility plans to remove up to 2.5 million metric tons of CO_2 per year.
- Interest has been expressed in the idea of establishing a 'backbone' CO_2 supply system for North Sea oil fields (the CENS (CO_2 for EOR in the North Sea) project.[39]
- In the Netherlands, E.ON received €180 million from the EU and €150 million from the Dutch government to develop an 1,100 MW coal and bio-mass plant to capture 5 million tones of CO_2 per year in depleted gas fields, with potential enhanced gas recovery.[40]

Lessons Learned to Date

In general, what all of these proposed/planned projects illustrate is that the prospect of increasing controls on CO_2 emissions is prompting developers to increasingly consider projects that plan to both utilize CO_2 for CO_2-EOR and to subsequently store CO_2. Critical to any of this taking place are programs that create economic incentives for reducing emissions, either through emissions trading programs, carbon taxes, or other mechanisms. Nonetheless, within any established framework for regulating and/or incentivizing emissions reductions from wide-scale deployment of CCS (with or without CO_2-EOR), storage must be established as a certifiable means for reducing GHG emissions.

Since storing CO_2 in association with EOR can substantially reduce the extra costs associated with CCS,[41] it can encourage its application in both the United States and throughout much of the developing world in the absence of other incentives for CCS deployment.

34 "Alter NRG Announces Canada's First Coal to Liquids with EOR Project," *New Technology Magazine*, July 22, 2008
35 http://sequestration.mit.edu/tools/projects/boundary_dam.html
36 http://sequestration.mit.edu/tools/projects/transalta.html
37 http://sequestration.mit.edu/tools/projects/bow_city.html
38 IEA GHG Report PH4/10, *Opportunities for Early Application of CO_2 Sequestration Technology*, September 2002
39 http://www.co2.no/default.asp?uid=56&CID=56
40 http://www.reuters.com/article/idUSTRE64B2IN20100512

However, what is also becoming readily apparent is that significant expansion of oil production utilizing CO_2-EOR will require volumes of CO_2 that cannot be met by natural sources alone. Industrial sources of CO_2 will need to play a critical part. This is resulting in a *fundamental change in the CO_2-EOR project paradigm*; showing that not only does CCS need CO_2-EOR to help provide economic viability for CCS, but *CO_2-EOR needs CCS* in order to ensure adequate CO_2 supplies to facilitate growth in the number of and production from new and expanded CO_2-EOR projects.

The importance of CO_2-EOR as a facilitator for CCS is particularly significant where there is no established financial incentive for sequestering GHG emissions. Without GHG emissions controls, CCS is generally not economically viable. A report by the Belfer Center for Science and International Affairs, Harvard Kennedy School, Harvard University concludes that,

> "No single mechanism on its own appears to be sufficient to bridge the current cost gap between CCS and conventional fossil fuel generation. In practice, a bundle of several types of support mechanisms, both at federal and state levels, are likely to be needed to meet the different barriers facing deployment and commercialization of CCS technology. Such a bundle could include carbon pricing, operating cost support through the allocation of free emissions allowances, loan guarantees, capital grants, and investment tax credits."[42]

The inability of the United States to pass climate legislation will hinder CCS project deployment within its borders. Moreover, the inability of a CCS project methodology to be approved under the Clean Development Mechanism (CDM) seriously hinders CCS project deployment in developing countries.[43] The CDM is currently the only international incentive procedure for encouraging the reduction of GHG emissions in the developing world. The CDM allows industrialized countries required to reduce GHG emissions under the Kyoto Protocol (known as Annex I countries) to invest in projects that reduce emissions in developing countries, as partial fulfillment of their obligations. CCS projects are currently disallowed as CDM projects.

Without the potential incentives given by the CDM, CCS in developing countries will only take place sporadically in niche sectors.[44] In comments to the United Nations Framework Convention on Climate Change (UNFCC) encouraging inclusion of CCS in the CDM, the International Petroleum Industry Environmental Conservation Association (IPIECA) noted that CCS is being used to enhance oil recovery, and that over "… the past several decades have stored roughly half a billion metric tons of CO_2 in oil reservoirs."[45] Similarly, a report commissioned by the Global CCS Institute stated that "…in the absence of a mechanism such as the CDM it seems unlikely that

[41] Favreau, Didier, "Economics act against CCS retrofits," *Oil and Gas Journal*, October 4, 2010

[42] Al-Juaied, Mohammed A., "Analysis of Financial Incentives for Early CCS Deployment." Discussion Paper 2010-14, Cambridge, MA: Belfer Center for Science and International Affairs, October 2010.

[43] ERM, *Carbon Dioxide Capture and Storage in the Clean Development Mechanism*, Report No. 2007/TR2, prepared for IEA GHG Programme, April 2007 (http://www.co2captureandstorage.info/techworkshops/2007%20TR2CCS%20CDM%20methodology%20.pdf)

[44] de Coninck, Heleen, "Trojan horse or horn of plenty? Reflections on allowing CCS in the CDM," *Energy Policy*, Volume 36, pp. 929–936, 2008

[45] International Petroleum Industry Environmental Conservation Association (IPIECA), "International Petroleum Industry Environmental Conservation Association (IPIECA) submission on issues related to CO_2 capture and storage (CCS) projects in the CDM and interest in capacity-building activities", United Nations Framework Convention on Climate Change, May 31, 2007.

investment in CCS will be achieved in many developing countries within the timeframe proposed by the G8."[46]

Within any established framework for regulating and/or incentivizing emissions reductions (e.g., the CDM, the EU Emissions Trading Scheme, the Regional Greenhouse Gas Initiative (RGGI) in the U.S. Northeast), in order for geologic storage to achieve wide-scale deployment, it must be established as a certifiable means for reducing GHG emissions. In this regard, standards, guidelines, etc. need to be established to provide consistency and market acceptability about the reality of the reductions claimed.

However, supporting the factors contributing to successful, economically viable CO_2-EOR and/or CCS projects may be a necessary but not sufficient condition for the ultimate “conversion” of a CO_2-EOR project to a CO_2 storage project. In addition to the availability of affordable CO_2, numerous regulatory and liability issues/uncertainties are currently associated with CCS that are hindering wide-scale deployment. These uncertainties are also hindering the pursuit of CO_2-EOR, particularly because of the lack of regulatory clarity regarding the process and requirements associated with the transition from EOR operations to permanent geologic storage.[47,48]

A variety of organizations such as the IEA,[49] U.S. DOE,[50] Carbon Sequestration Leadership Forum (CSLF),[51] World Resources Institute,[52] and the U.S. Congressional Research Service[53] have identified the critical factors likely to influence the implementation of CCS projects. Moreover, while little or no existing policy or statutory authority specific to the operational aspects of geologic storage exists in many countries today, a number of countries have existing policies and statutes that may apply to related activities that could be extended to CO_2-EOR and, perhaps, geologic storage.

In the past few years, significant progress has been made on the development of such legal and regulatory frameworks, most notably in Australia, the European Union and the United States. In the European Union, the *Directive on the Geological Storage of CO_2* and *the EU Emissions Trading Scheme Directive* provide a framework for legislation and regulation of CCS within the region, which must be transposed into individual member state law by 2011.[54] In Australia, CCS legislation has been put in place at the federal level by the Australia Ministerial Council on Mineral & Petroleum Resources to cover CCS offshore and onshore.[55]

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46 WorleyParsons Services Pty Ltd, *Strategic Analysis of the Global Status of CCS - Report 5, Synthesis Report*, Global Carbon Capture and Storage Institute, October 2009, page 137.
47 Marston, Phillip M., and Patricia A. Moore, “From EOR to CCS: The Evolving Legal and Regulatory Framework for Carbon Capture and Storage,” *Energy Law Journal*, July 1, 2008 (http://txccsa.org/From%20EOR%20to%20CCS.pdf)
48 Carbon Capture and Sequestration: *Framing the Issues for Regulation, An Interim Report from the CCSReg Project,* January 2009 (http://www.ccsreg.org/pdf/CCSReg_3_9.pdf)
49 International Energy Agency, *CO_2 Capture and Storage: A Key Carbon Abatement Option*, 2008
50 National Energy Technology Laboratory, *“International Carbon Capture and Storage Projects: Overcoming Legal Barriers*,” DOE/NETL-2006/1236, June 23, 2006
51 Carbon Sequestration Leadership Forum Policy Group, *Considerations on Regulatory Issues for Carbon Dioxide Capture and Storage Projects*, A report from the Legal, Regulatory, and Financial Issues Task Force, 13 August, 2004
52 World Resources Institute, *Capturing King Coal: Deploying Carbon Capture and Storage Systems in the U.S. at Scale*, May, 2008
53 U.S. Congressional Research Service, *Capturing CO_2 from Coal-Fired Power Plants: Challenges for a Comprehensive Strategy*, CRS Report to Congress, RL34621, August 15, 2008 http://opencrs.cdt.org/document/RL34621)
54 http://ec.europa.eu/environment/climat/ccs/dir_2009_31_en.htm
55 http://www.ret.gov.au/resources/Documents/ccs/CCS_Aust_Regulatory_Guiding_Principles.pdf

In the United States, some states have implemented CCS legislation, drawing primarily on the work of the Interstate Oil and Gas Compact Commission.[56] In parallel, on November 22, 2010, the U.S. Environmental Protection Agency (EPA) announced new standards for ground water protection associated with CO_2 injection,[57] as well as new requirements for reporting of GHGs from facilities that inject CO_2 for both the purposes of geologic sequestration and for CO_2-EOR.[58]

In addition, a number of other countries have begun the process of reviewing and amending legislation including Canada, Japan and Norway (implementing the EU legal guidelines). Finally, the World Resources Institute has developed guidelines for regulating the performance of geologic storage.[59]

Both the IEA and the Global CCS Institute have continuing work programs focused on CCS legislation and regulation. In 2009, the Global CCS Institute completed a comprehensive analysis of regulatory regimes supporting CCS to identify gaps in regulatory frameworks that need to be overcome for project deployment. This resulted in a number of recommendations to facilitate the development of comprehensive and effective CCS regulatory frameworks.[60]

Similarly, the IEA launched a CCS Regulators Network to help regulators around the world share case studies, challenges and solutions as authorities attempt to develop workable, effective and harmonized regulatory frameworks,[61] and is documenting progress in developing suitable geologic storage policy and regulatory frameworks.[62]

From this, the IEA has published its first *Carbon Capture and Storage Legal and Regulatory Review* that provides a knowledge-sharing forum to support national-level CCS regulatory development.[63] The Review collates contributions by national and regional governments, as well as leading organizations engaged in CCS regulatory activities. The review provides summaries of recent and anticipated CCS regulatory developments. To be produced bi-annually, this review is intended to serve as a key resource for policy makers and other stakeholders involved in developing CCS legal and regulatory frameworks worldwide.

Based on this review, the IEA has also recently published a its *Carbon Capture and Storage Model Regulatory Framework*, which seeks to assist governments to develop appropriate frameworks by drawing on CCS regulatory frameworks already in place to propose key principles for addressing the broad range of regulatory issues associated with CCS.[64]

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[56] Interstate Oil and Gas Compact Commission, *Carbon Capture and Storage: A Regulatory Framework for States - Summary of Recommendations*, Final Report under contract DE-FC26-03NT41994, January 24, 2005, www.iogcc.state.ok.us/PDFS/CarbonCaptureandStorageReportandSummary.pdf

[57] http://water.epa.gov/type/groundwater/uic/wells_sequestration.cfm

[58] http://www.epa.gov/climatechange/emissions/ghgrulemaking.html

[59] World Resources Institute, *CCS Guidelines: Guidelines for Carbon Dioxide Capture, Transport, and Storage*, Washington, DC, 2008 (http://www.wri.org/publication/ccs-guidelines)

[60] Global Carbon Capture and Storage Institute, *Policies and Legislation Framing Carbon Capture and Storage Globally,* Canberra, 2009

[61] For more information, see www.iea.org/Textbase/subjectqueries/ccs_legal.asp

[62] http://www.iea.org/work/workshopdetail.asp?WS_ID=444

[63] http://www.iea.org/ccs/legal/review.asp

[64] International Energy Agency, *Carbon Capture and Storage Model Regulatory Framework*, Information Paper, November 2010

III. OPPORTUNITIES FOR INCREASING CO_2 STORAGE WITH CO_2-EOR

Overview of this Section

This section identifies and assesses potential approaches for optimizing CO_2 storage for both the production of oil and for storage. Additional approaches for maximizing CO_2 storage in oil fields pursued using CO_2-EOR technologies could expand potential storage capacity, while also producing additional oil supplies from already developed fields and basins.

The key findings of this section are:

- **Realizing the potential through the global application of a set of "next generation" CO_2-EOR technologies, primarily focused on increasing oil production, could create between 165 and 366 Gt of CO_2 storage capacity, while producing 705 to 1,576 billion barrels of incremental oil.** Assuming emissions of 6.2 million metric tons per year over 40 years of operation per plant, this could result in storing the emissions associated with 2,200 to 4,900 one-GW size coal-fired power. This capacity is sufficient to store 18% to 40% of global energy-related CO_2 emissions from 2010 to 2035. Based on this global characterization, "next generation" CO_2-EOR technology stores 14% to 18% more CO_2, and produces 47% to 50% more oil than "state-of-the-art" technology.
- **Recent developments in the Permian Basin indicate that there may be vast, previously unrecognized opportunities for additional oil production from the application of CO_2-EOR, while also providing additional capacity for storing CO_2.** This potential exists in residual oil zones (ROZs) below the oil/water contact in traditional oil reservoirs that are widespread and rich in oil saturation. In addition to the traditional main pay portion of depleted oil fields, they represent a second potentially much larger, CO_2 storage option. Field pilots are showing that applying CO_2-EOR in ROZs appears to be commercially viable. Pursuing this resource potential could result in *a two-to-three fold increase in the potential storage capacity associated with the application of CO_2-EOR.* Preliminary work is indicating that the Permian Basin is not alone in possessing extensive ROZs. Additional research would be invaluable in identifying where additional such potential exists globally.
- **Other approaches to increase CO_2 storage in conjunction with CO_2-EOR may further increase storage capacities associated with such applications.** Examples of such technologies include vertical ("gravity stable") CO_2 floods, deploying CO_2 injection earlier in field development; and pursuing straight CO_2 injection for CO_2-EOR, rather than more traditional water-alternating-gas (WAG) processes. These approaches can be combined with the injection and permanent storage of CO_2 in other geologic horizons accessible from the same CO_2 injection wells and surface infrastructure used for CO_2-EOR to maximize storage.

Review of Concepts and Terminology

Before discussing the theoretical opportunities for optimizing CO_2-EOR and CO_2 storage, it is important to clarify how CO_2 is used in CO_2-EOR, and how it can ultimately be permanently stored.

In general, the fraction of pore space that can be filled with injected CO_2 is largely a function of the heterogeneity of the target storage formation, gravity segregation, and the efficiency with which the injected CO_2 displaces whatever fluids are in the pore space. Therefore, strategies to optimize CO_2 storage with CO_2-EOR need to take advantage of these characteristics. Simply, one strategy for increasing CO_2 storage with CO_2-EOR is to displace as much of the oil and water as possible, replacing it with the injected CO_2, within the pore space of the reservoir swept by the injected CO_2.

As discussed above, CO_2-EOR operations have traditionally focused on optimizing oil production, not the storage of the CO_2. In this context, storage (retention) is viewed as a negative factor, since it represents CO_2 that is no longer available to contact new oil and render it mobile within the reservoir.

This permanently "stored" CO_2 is most likely being retained in dead-end pores and channels where it is "popping" oil out into the flow streams. CO_2 that dissolves into the oil or water remains there permanently unless the reservoir fluids are depressured. Even then, depressuring can never be complete, and much of the CO_2 is literally stuck, never to be recovered.

Thus, CO_2-EOR can result in very effective storage, in spite of the industry's traditional objective to avoid retention of the valuable CO_2. In general, nearly 100% of the initially acquired/purchased CO_2 for CO_2-EOR operations (not that which is recycled) will be stored at the end of the period of active injection, with sufficient permanence of CO_2 storage.

Overview of Potential Approaches for Optimizing CO_2-EOR with CO_2 Storage

Storage of CO_2 with EOR is claimed by some to be a small niche opportunity. Many of these claims are based upon anecdotal evidence, outdated characterizations of CO_2-EOR performance, and past perceptions of the small oil recovery potential offered by CO_2-EOR using first generation CO_2-EOR technologies. However, redesigned CO_2-EOR projects could dramatically increase CO_2 storage, while further producing incremental oil.[65]

A variety of potential approaches for optimizing incremental oil production from CO_2-EOR with CO_2 storage are examined in this study. These include:

- "Next generation" CO_2-EOR technologies, which could increase incremental oil recovery over "state-of-the-art" technology, as well as increase the CO_2 storage potential in depleted oil fields.
- CO_2-EOR technology applied to the essentially immobile residual oil zones (ROZs) underlying the main oil pay zones in many reservoir settings.
- Advanced drilling, monitoring and modeling technologies to make vertical ("gravity stable") CO_2 floods more of a possibility in some settings

[65] Jessen, K., Kovscek, A, Orr, F.M. Jr., "Increasing CO_2 Storage in Oil Recovery", *Energy Conversion and Management*, 46, 2005, p. 293-311

- Deploying CO_2 injection earlier in field development; this can result in both incremental (and faster) oil recovery and greater utilization of storage capacity.
- Pursuing straight CO_2 injection for CO_2-EOR, rather than more traditional water-alternating-gas (WAG) processes.
- Any of these approaches combined with the injection and permanent storage of CO_2 in other geologic horizons accessible from the same CO_2 injection wells and surface infrastructure used for CO_2-EOR.

Key definitions for this study are summarized in Table 3.

Table 3. Definitions of Alternative Technology Cases Assumed in this Study

Technology Case	Definition
"State-of-the-Art CO_2-EOR Technology	Represent best practices used by operators today, which are much improved over traditional CO_2-EOR practices. Assumes injection of much larger volumes of CO_2, and rigorous CO_2-EOR monitoring, management and remediation activities that help assure that the larger volumes of injected CO_2 contact more of the reservoir's residual oil, 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	Represents technology applications that address some of the issues faced by "state-of-the-art" CO_2-EOR practices. These include increasing the volume of CO_2 injected into the oil reservoir from 1.0 to 1.5 HCPV*; optimizing well design and placement, including adding infill wells to achieve increased contact between the injected CO_2 and the oil reservoir; improving the mobility ratio between the injected CO_2/water and the residual oil; and extending the miscibility range, thus helping more reservoirs achieve higher oil recovery efficiency.
"Second Generation" CO_2-EOR Technology and CO_2 Storage	Assumes a reservoir is developed with one or more "next generation" technologies, targeting both the main pay zone plus an underlying ROZ, with continued CO_2 injection into and storage in an underlying saline aquifer, including injecting continuous CO_2 (no water) after completion of oil recovery operations.

* Hydrocarbon Pore Volume (HCPV) is a measure of the volume of pore space in a reservoir available for injection of fluids.

"Next Generation" CO_2-EOR Technologies

An assessment of the CO_2 storage and oil recovery potential in depleted oil fields in the U.S. that could be developed with both "state-of-the-art" and "next generation" CO_2-EOR, recently published by DOE/NETL, assessed U.S. CO_2 storage capacity based on a data base of over 6,000 U.S. oil reservoirs (over 1,800 in the onshore Lower-48), accounting for three-quarters of U.S. oil resources.[66] The study identifies over 1,700 large oil reservoirs (over 1,000 in just the U.S. Lower-48) with 305 billion barrels of remaining oil in-place (345 billion barrels of remaining oil in-place when extrapolated to national totals) as favorable for the application of CO_2-EOR technology. These large oil reservoirs were modeled to assess their potential for CO_2-EOR using Advanced Resource's adaptation of the streamline reservoir simulator *PROPHET2*.[67]

Considerable evolution has occurred in the design and implementation of CO_2-EOR technology since the technology was first introduced. Notable changes include the use of much larger

[66] U.S. Department of Energy/National Energy Technology Laboratory, *Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology: An Update*, report DOE/NETL-2010/1417 prepared by Advanced Resources International, April 2010 (http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&Source=Products&PubId=309)
[67] Dobitz, J.K., and John Prieditis, "A Stream Tube Model for the PC," SPE Paper No. 27750-MS presented at the SPE/DOE Improved Oil Recovery Symposium, 17-20 April 1994, Tulsa, Oklahoma

volumes of injected CO_2; the incorporation of tapered water alternating with gas (WAG) and other methods for mobility control; and the 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 "state-of-the-art" CO_2-EOR projects have steadily improved over traditional practices. Moreover, with reasonable assumptions about potential future advances in technology, even greater volumes of incremental oil production, and corresponding volumes of stored CO_2 could be realized by such "next generation" technologies.

In the DOE/NETL sponsored study, "state-of-the-art" technologies were assumed to be applied at a minimum to all prospective CO_2-EOR projects. These represent the best 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 "state-of-the-art" CO_2-EOR:

- The injection of much larger volumes of CO_2 (1.0 hydrocarbon pore volume (HCPV)),[68] rather than the smaller (on the order of 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 a "state-of-the-art" 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.

The application of "state-of-the-art" for CO_2-EOR was then contrasted with "next generation" technologies. Four "next generation" CO_2-EOR technology options were identified that can address some of the issues faced by "state-of-the-art" CO_2-EOR practices and result in more oil production and additional CO_2 utilization and storage:

- *Increasing the volume of CO_2 injected into the oil reservoir*, which involves increasing CO_2 injection volumes from 1.0 HCPV, currently used in "state-of-the-art", to 1.5 HCPV. Higher HCPV's of injected CO_2 enable more of the reservoir's residual oil to be contacted (and even multiple contacted) by the injected CO_2. Progressively longer CO_2 injection periods, longer overall project length, and higher gross CO_2-to-oil ratios are involved when greater volumes of CO_2 are injected. In the past, the combination of high CO_2 costs and low oil prices led operators to inject less CO_2 to maximize profitability. This low volume CO_2 injection strategy was also pursued because operators had very limited capability to observe and then control the sub-surface movement of the injected CO_2 in the reservoir. With adequate volumes of lower cost CO_2 and higher oil prices, CO_2-EOR economics today favor using higher volumes of injected CO_2. However, these increased CO_2 volumes need to be "managed and controlled" to assure that they contact, displace, and recover additional residual oil, rather than merely circulate through a high permeability interval of the reservoir.
- *Optimizing well design and placement*, including adding infill wells, to achieve increased contact between the injected CO_2 and the oil reservoir. The well design and placement objective is to ensure that both the previously highly waterflood-swept (with low residual oil) portions of the oil reservoir and the poorly waterflood-swept (with higher residual oil)

[68] Hydrocarbon Pore Volume (HCPV) is a measure of the volume of pore space in a reservoir available for the injection of fluids.

portions of the oil reservoir are optimally contacted by the injected CO_2. Examples of such well design and placement options include: (1) isolating the previously poorly swept reservoir intervals (with higher residual oil) for targeted CO_2 injection; (2) drilling horizontal injection and production wells to target bypassed or poorly produced reservoir areas or intervals; (3) altering the injection and production well pattern alignment; (4) using physical or chemical diversion materials to divert CO_2 into previously poorly contacted portions of the reservoir; and (5) placing the injection and production wells at closer spacing.

- *Improving the mobility ratio between the injected CO_2/water and the residual oil*. This assumes an increase in the viscosity of the injected water (as part of the CO_2-WAG process). (The viscosity of the CO_2 itself was left unchanged, although increasing the viscosity of CO_2 with CO_2-philic agents could theoretically further improve performance.) The viscosity of the injected water can be changed by adding polymers or other viscosity-enhancing materials. This was modeled by assuming the viscosity of injected water is increased to 3 cp,[69] or three times the viscosity of normal water.
- *Extending the miscibility range*, thus helping more reservoirs achieve higher oil recovery efficiency. This assumes that "miscibility extenders" are added to CO_2-EOR process that reduce minimum miscibility pressure requirements by 500 psi (pounds per square inch). Examples of miscibility enhancing agents would include addition of liquefied petroleum gases (LPGs) to the CO_2, although this would lead to a more costly injection process; addition of H_2S or other sulfur compounds, although this may lead to higher cost operations; and use of other (to be developed) miscibility pressure or interfacial tension reduction agents. Analytical modeling shows that extending the range of oil reservoirs applicable for miscible CO_2-EOR would significantly increase oil recovery efficiency, particularly when combined with higher volume injection of CO_2.

It is important to note that all of these technologies are currently being deployed, at least at pilot scale, in a few CO_2-EOR projects today. Moreover, it is also worth noting that these "next generation" technologies still focus primarily on recovering more oil, even though they still generally involve injecting, and ultimately storing, more CO_2.

Because the deployment of "next generation" technologies is more costly than that for "state-of-the-art," it may not be the economically preferred option in some settings.

The amount of CO_2 storage capacity and oil production potential offered by U.S. oil fields favorable for CO_2-EOR was evaluated in the DOE/NETL sponsored study as a function of technology and economics, as follows:

- The two technology scenarios: "State-of-the-Art" and "Next Generation".
- Two categories of recoverable oil resources: "Technical Potential" (without consideration of prices and costs) and "Economic Potential" (the volume of CO_2 the oil industry could buy at a specified oil price and CO_2 cost).

As shown in Figure 7, the volume of <u>technically recoverable</u> oil in the U.S. using CO_2-EOR is estimated to range from 81 billion barrels for "state-of-the-art" technology to 126 billion barrels for "next generation" technology. Similarly, the volume of <u>economically recoverable</u> oil (at an oil price of $70 per barrel, CO_2 costs of $45 per metric ton and a 15% before tax required financial return) ranges from 38 billion barrels for "state-of-the-art" technology to 58 billion barrels for "next generation" technology.

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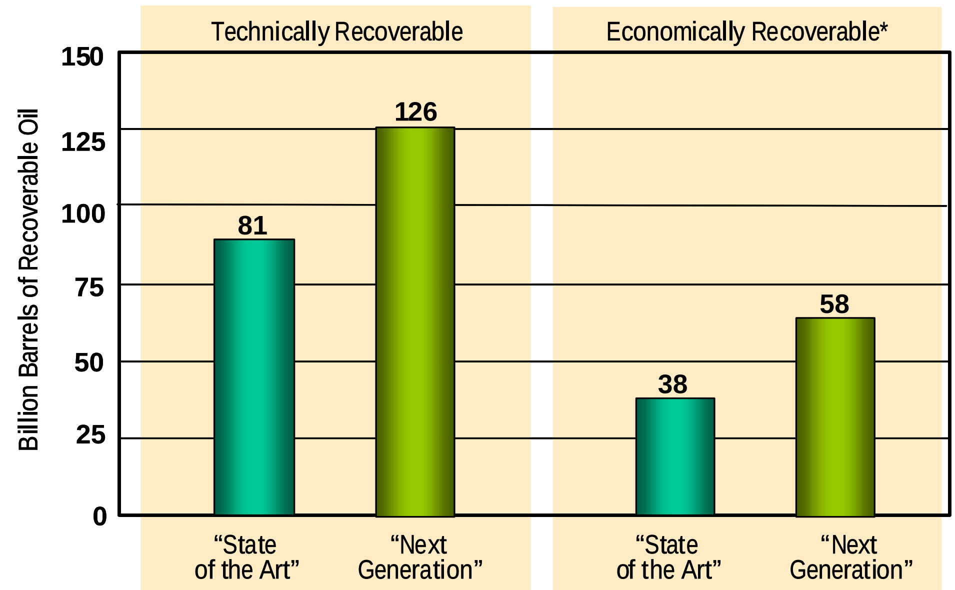
[69] A centipoise (cp) is the unit of measure for dynamic viscosity. Water has cp value of 1 at 20 degrees Celsius.

The associated volumes of CO_2 that will need to be purchased (this does not include the volume recycled) and subsequently stored[70] to recover the above volumes of oil was estimated in the DOE/NETL study to range from 12 billion metric tons for "state-of-the-art" technology to 28 billion metric tons for "next generation" technology, depending on technology and economics.

Figure 7. Potential New U.S. Oil Supplies from CO_2-EOR



*At an oil price of $70/B, CO_2 costs of $45/mt and 15% (BT) financial return.

Source: Advanced Resources Int'l (2010).

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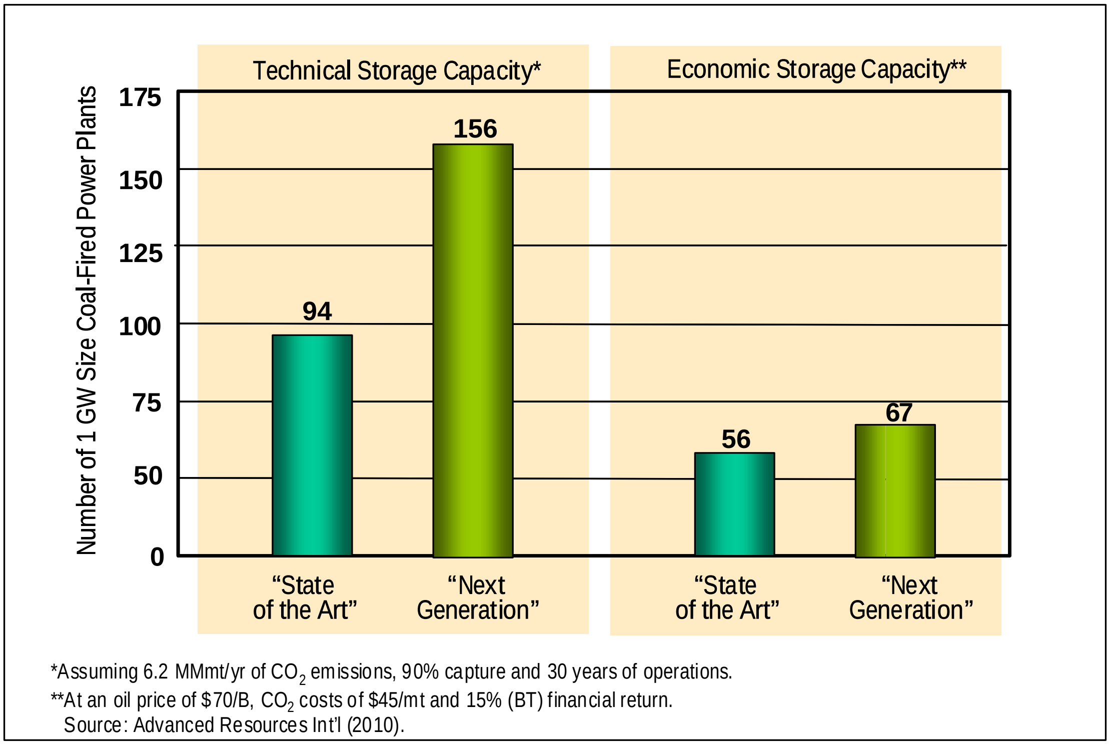
Figure 8 provides another way to characterize the CO_2 storage capacity offered by CO_2-EOR, where CO_2 storage capacity is defined in terms of the number of one-GW size coal-fired power plants that could rely on CO_2-EOR for storing their captured CO_2. The figure shows that, in the U.S., CO_2-EOR can offer sufficient technical storage capacity for the CO_2 captured from 94 to 156 one-GW size coal-fired power plants for 30 years of operation, depending on future CO_2-EOR technology. At the crude oil and CO_2 costs presented above, the economic CO_2 storage capacity offered by CO_2-EOR is smaller but still substantial, ranging from 56 to 67 one-GW size coal-fired power plants, again depending on CO_2-EOR technology.

[70] For purposes of this study, and consistent with a number of rigorous assessments, the volume of CO_2 purchased (not recycled) for CO_2-EOR is assumed to be equivalent to the estimated volume of CO_2 ultimately stored.

Figure 8. Volumes of CO_2 Storage Capacity Available for CO_2-EOR in the U.S.



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In a recent study published by the International Energy Agency Greenhouse Gas Programme (IEA GHG),[71] a data base of the largest 54 oil basins of the world (that account for approximately 95% of the world's estimated ultimately recoverable (EUR) oil potential) was developed. From this, a high-level, first-order assessment of the CO_2-EOR oil recovery and CO_2 storage capacity potential in these basins was developed using the U.S. experience as determined in the DOE/NETL study as analogue, assuming the application of "state-of-the-art" CO_2-EOR technology. These basin-level, first-order estimates were compared with detailed reservoir modeling of 47 large oil fields in six of these basins, and the first-order estimates were determined to be acceptable.

The IEA GHG study concluded that CO_2-EOR offers a large, near-term option to store CO_2. Even with "state-of-the-art" technology, the 54 largest oil basins of the world have the potential to produce 470 to 1,070 billion barrels of additional oil, and store 140 to 320 billion metric tons of CO_2. Using a metric similar to that applied above, assuming emissions of 6.2 million metric tons per year over 40 years per plant, this is equivalent to the lifetime emissions of 1,900 to 4,300 one-GW size coal-fired power plants.

The original methodology used in the IEA GHG study was then modified for this study to provide an assessment of the global capacity for the application of "next generation" CO_2-EOR technology, to compare with that originally resulting from the assumption of "state-of-the-art" CO_2-EOR technology.

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[71] IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recover,* Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009

The results of this assessment suggest that the worldwide application of "next generation" CO_2-EOR technology to the world's largest oil basins could create between 165 and 366 Gt of CO_2 storage capacity. Again using the metric applied above, this is equivalent to the lifetime emissions of 2,200 to 4,900 one-GW size coal-fired power plants over 40 years of operation. This can be achieved while producing 705 to 1,576 billion barrels of incremental oil. These results are summarized in Table 4 by region, and are also illustrated in Figure 9.

Based on this characterization, "next generation" CO_2-EOR technology stores 14% to 18% more CO_2, and produces 47% to 50% more oil than "state-of-the-art" technology. This storage capacity is sufficient to store 18% to 40% of global energy-related CO_2 emissions forecast to result over the 2010 to 2035 time period.[72]

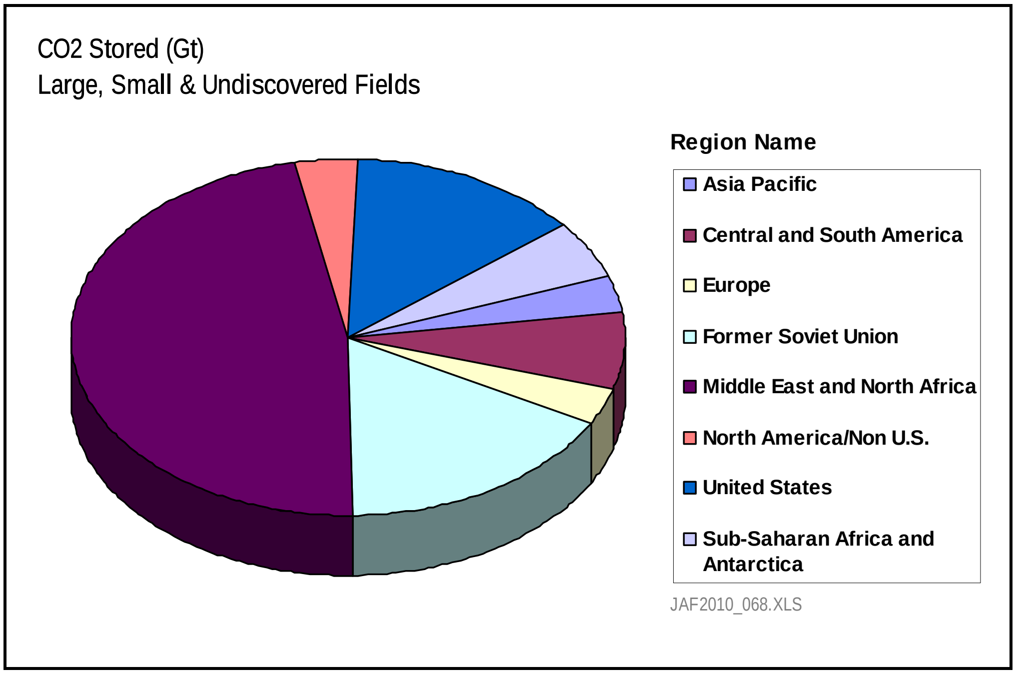
Areas with the highest capacity include the Middle East, Former Soviet Union and the United States, which together contain 68% of the total CO_2 storage capacity potential.

Table 4. CO_2 Storage and Oil Production Potential of "Next Generation" CO_2-EOR Technology

Region Name	CO_2 EOR Oil Recovery (MMBO)		CO_2 Storaged (Gt)	
	Large Fields	Large, Small & Undiscovered Fields	Large Fields	Large, Small & Undiscovered Fields
Asia Pacific	29,864	47,068	6	10
Central and South America	49,229	92,560	11	21
Europe	24,032	41,179	6	10
Former Soviet Union	123,465	231,550	27	50
Middle East and North Africa	342,160	594,683	82	142
North America/Non U.S.	24,776	38,363	7	11
United States	89,209	177,036	21	41
South Asia	-	-	-	-
Sub-Saharan Africa and Antarctica	22,536	74,073	5	16
Reserve Growth		279,951		65
Total	705,270	1,576,464	165	366

[72] The 2010 International Energy Outlook reports forecast global energy related emissions from 2010 through 2035 of 923 billion metric tons.

Figure 9. Worldwide CO_2 Storage Potential of "Next Generation" CO_2-EOR Technology



The Extension of CO_2-EOR Technology to Residual Oil Zones

Two recent discoveries in the Permian Basin of West Texas in the United States indicate that there may be vast, previously untapped opportunities for additional oil production from the application of CO_2-EOR, while also providing substantial additional capacity for permanently storing CO_2. The enormity of the prize is just beginning to be understood and is opening minds to the possibility of large-scale concurrent CO_2-EOR and CO_2 storage. These two discoveries are summarized below.

- Discovery #1: Zones below the Oil/Water Contact in Traditional Oil Reservoirs are Widespread and Rich in Residual Oil Saturation. Beyond the CO_2 storage capacity offered by the traditional, main pay portion of depleted oil fields, a second potentially much larger, CO_2 storage option is offered by residual oil zones (ROZs) – essentially saline formations underlying oil reservoirs that contain residual oil. Work originally sponsored by the DOE/NETL has demonstrated both the origin and now the distribution of what have come to be known as ROZs. While the full volume of CO_2 storage capacity offered by ROZs is still to be defined, the ground breaking conceptual framework for this option has been established.[73]
- Discovery #2: The Application of CO_2-EOR Recovery Technologies below the Oil/Water Contact is Being Demonstrated to be Commercially Viable. The above described on-going science and resource characterization is accompanied by commercial demonstration projects. Nine CO_2-EOR projects and one chemical EOR project are currently being pursued, and two operators of these demonstrations have been especially generous about sharing results.

[73] "Stranded Oil in the Residual Oil Zone", prepared by Steven L. Melzer, Melzer Consulting for Advanced Resources International and the U.S. Department of Energy, Office of Fossil Energy - Office of Oil and Natural Gas, February 2006.

A recent DOE/NETL sponsored study estimates that the hydrodynamic ROZ fairways in the Permian Basin could add 12 to 18 billion metric tons of additional CO_2 storage capacity in these fairways in the basin.[74] In comparison, the "traditional" CO_2 storage capacity offered by CO_2-EOR in the Permian Basin is 6.4 billion metric tons. Therefore, this represents (at least) a two-to-three fold increase in the potential storage capacity associated with the application of CO_2-EOR in this one basin.

This is further breaking down the often-cited myth that CO_2-EOR applications are small targets for sequestration. However, all of the detailed knowledge and the above work are currently concentrated in the Permian Basin's San Andres Formation. Preliminary work is underway to evaluate other formations in the Basin, including the Grayburg, Glorieta, Clearfork and Abo/Wichita Albany. These potential new large targets below the oil-water contact have not been considered in resource assessments of the past.

While it is true that these resources will be regional and volumetrically case-specific, at least one area of the world has moved out of the theoretical realm to proven category. Privately sponsored work is also underway to examine other areas of the U.S. and Europe. It could be true that the uniqueness of the ROZ oil resource in the Permian Basin will overwhelm these other formations and regions, but evidence is coming in that the Permian Basin is not alone in possessing extensive ROZs.

ROZs are developed where formation water has encroached into oil entrapments due to tectonic readjustment in a post-entrapment phase. There are many regions in the world where the subsidence and entrapment phase has been followed by a subsequent tectonic episode. The Permian Basin region is far from unique in that regard.

However, some believe that since the ROZ is the result of tectonic tilting after hydrocarbon migrated into the traps, then the very reason for the existence of an ROZ is because of leakage and change in the spill points of the reservoirs. Because of this, they claim the secure storage of CO_2 may be problematic. (This, however, is the same situation as exists in deep saline aquifers that are not structurally contained.)

Additional research would be invaluable in identifying where additional such potential exists globally, whether or not that potential is recoverable, and whether or not the storage of CO_2 associated with recovery of this oil can be secure and permanent.

The first step of such research would be to consult with structural geologists that have studied the geological history of a basin to determine if the geologic history matches the two episode test. The second step would be to look within the areas of current oil entrapments to determine if a particular formation is noted for good oil "shows," but produces only water when drilled and completed. The third step would be to determine whether secure CO_2 storage can be achieved with the application of CO_2-EOR to pursue this resource potential in the ROZ.

Taking advantage of the oil recovery opportunity provided by ROZs could result in substantial economic, energy security, and environmental benefits, specifically:

- It can result in a substantial increase in production, often in areas with already existing oil development and production infrastructure.

[74] "White Paper: Establishing the Viability of Storing CO_2 in Deep Saline Formations Containing Residual Oil", prepared by Advanced Resources International, Inc. and Melzer Consulting for the U.S. Department of Energy, National Energy Technology Laboratory, September 8, 2009.

- Because these resources generally coexist with already developed resources, it results in minimal incremental environmental impacts relative to new developments in frontier or pristine areas.
- Relative to storage in deep saline aquifers, ROZs provide the opportunity to store substantially greater volumes of CO_2 within a given geographical area, since producing the oil provides additional void space within which to store CO_2.
- Since oil is produced while the CO_2 is being stored, existing regulatory and legal regimes can be used as a framework to oversee operations, allowing frameworks more specific to geologic storage time to evolve and be vetted.

Other Alternatives to Enhance CO_2 Storage with CO_2-EOR

To date, most studies of the potential for CO_2-EOR (and the potential for CO_2 storage associated with CO_2-EOR) assume that CO_2 injection begins near the end of water flood operations. Moreover, the CO_2-EOR operations are assumed to proceed by deploying a water-alternating gas (WAG) process. WAG processes have generally been pursed in the past to reduce the CO_2 requirements for CO_2 flooding. These are usually deployed in a traditional five-spot pattern flood utilizing vertically drilled injection and production wells.

In theory, early initiation of CO_2 injection, at least in some circumstances, may increase the ultimate recovery efficiency, reduce the need for water injection and handling, and accelerate oil production, thus improving overall project economics. Alternatively, straight CO_2 injection, rather than a WAG process, could result in improved recovery efficiency and lower costs where CO_2 supplies and costs are less constraining. Alternative development approaches such as line drives or vertical, gravity stable, CO_2 floods may have merit in some situations. Taking advantage of the increased applicability and lower costs of horizontal drilling technology, the use of horizontal wells may also be conceivable in some settings. Finally, producing residual water left in the reservoir, if feasible, could free up additional pore space for storing additional volumes of CO_2.

In appropriate settings, the application of alternative development approaches for CO_2-EOR could result in considerable additional oil production and the ability to use, and permanently store, greater volumes of CO_2. Finally, in any of these applications, pursued individually or in some combinations, it is often possible to pursue additional injection and permanent storage of CO_2 in other geologic horizons accessible from the same CO_2 injection wells and surface infrastructure used for CO_2-EOR.

The potential viability of these alternative CO_2-EOR approaches is highly dependent on reservoir properties and the development history of the reservoir, field, and/or basin.

Some potential options are described below. However, it is important to note that these 'case studies' are specific to the reservoir and operating conditions assumed. Alternative outcomes are likely given alterative conditions.

Vertical ("Gravity Stable") CO_2 Floods

Where the geologic structure of a reservoir permits, the use of crestal or up-dip injection can be used to more efficiently recover oil left behind in an oil reservoir following conventional recovery operations. This tertiary recovery mechanism can be gravity stable, where injection volumes equate to production volumes and recovery factors can approach 90% of the OOIP. This can result in a substantial improvement over a simple, less stable horizontal flood.

Generally speaking, vertical floods produce crude oil at a slower rate than conventional floods, but enable a higher amount of the OOIP to be recovered, particularly in reservoirs with favorable geological characteristics and a development history that allows the pursuit of this option. Nonetheless, through the top-down flooding methodology employing mostly CO_2, this process holds a great deal of promise for increasing CO_2 storage volume while increasing oil production. In some situations, it can also be used to recovery heavier crudes,[75] which would otherwise not be viable for the application of CO_2-EOR.

Successful application of a gravity stable CO_2 flood requires good vertical permeability and a dip angle large enough so that CO_2 front is relatively horizontal. Vertical continuity of the formation is a key characteristic when determining the viability of the process. However, reservoir fluid properties, such as density and viscosity, also play a key role. These types of floods can be very successful in high-angle reservoirs and reef structures.

One often-cited example of this type of application is the Weeks Island “S” Sand Reservoir B pilot gravity stable flood, conducted in the late 1970s through mid 1980s in Iberia Parish, Louisiana.[76] This CO_2 injection project mobilized nearly 90% of the residual oil, and recovered 80% of the mobile oil and 28% of OOIP. Simulation studies have been conducted of this approach in other settings as well.[77]

Using the Weeks Island data set, two reservoir models were constructed for this study to demonstrate the utility of gravity stable CO_2-EOR and storage technology. The first involved “matching” the pilot project to ensure a strong fundamental understanding of this flooding mechanism is reflected in the model. Once a history “match” was satisfactory obtained, the model was extended to also include consideration of the lower-lying residual oil zone. In addition, the use of horizontal wells to encourage more fluid injection and production, and to speed up the recovery process, was also considered.

To represent this situation, a simplified 162,000 square meter (40 acre) reservoir was simulated. The reservoir was subdivided into three subzones reflecting different oil saturations: a main pay zone (MPZ), a residual oil zone (ROZ) and an underlying saline aquifer (water zone (WZ)) below the water table. The main properties of these zones are shown in Tables 5 and 6.

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[75] Sohrabi, Mehran, et al., “Mechanisms of Extra-Heavy Oil Recovery by Gravity-Stable CO_2 Injection,” paper presented at the International Symposium of the Society of Core Analysts held in Abu Dhabi, UAE 29 October-2 November, 2008 (http://www.scribd.com/doc/11545625/MECHANISMS-OF-EXTRAHEAVY-OIL-RECOVERY-BY-GRAVITYSTABLE-CO2-INJECTION)

[76] Cole, Lance, E., Howard H. Ferrell, and David Miller, *An Evaluation of the Weeks Island “S” Sand Reservoir B Gravity Stable CO_2 Displacement Project, Iberia Parish, Louisiana*, performed for the U.S. Department of Energy, Bartlesville Project Office, under Contract No. AC19-85BC10830, February 1989

[77] Tiffin, D.L. and Y.J. Kremesec Jr., “Production Co-Mechanistic Study of Gravity-Assisted CO_2 Flooding,” SPE of Reservoir Engineering Journal, Volume 3, Number 2, May, 1988, pp. 524-532; and Wo, S., et al., “Simulation Evaluation of Gravity Stable CO_2 Flooding in the Muddy Reservoir at Grieve Field, Wyoming,” SPE Paper No. 113482 presented at the 2008 SPE/DOE Improved Oil Recovery Symposium, Tulsa, Oklahoma, April 19-23, 2008

Table 5. Main Reservoir Parameters in Each Simulated Zone

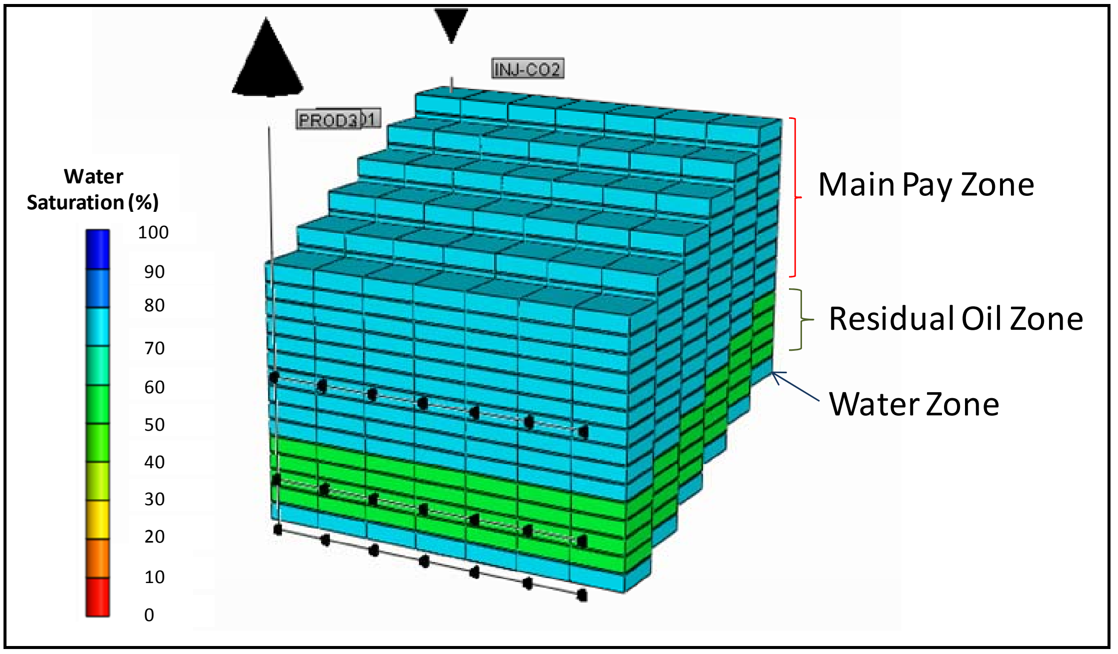
Parameters	Net Sand Thickness, ft	Elevation, ft	Water Saturation, %
Main Pay Zone	325	14,000	73.75
Residual oil Zone	130	14,325	60
Water Zone	32.5	14,455	80

Table 6. Reservoir Parameters Similar In All Zones

Parameters	Value
Dip, deg	26
Reservoir Pressure Gradient, psia/ft	0.43
Porosity, %	29
Horizontal Permeability, mD	1,000
Vertical Permeability, mD	100
Oil Gravity, API	33
Residual Oil Saturation to water, %	30.3
Residual Oil Saturation to CO2, %	6.56

A well injection pattern was assumed with a vertical CO_2 injection well located up dip, and one or more producers located down dip, in different zones. To reduce the running simulation time, only a quarter well was modeled, as shown in Figure 10. In this figure, three horizontal producers were assumed: one producer was completed at mid-distance inside the MPZ; one producer was completed at the bottom of the ROZ; and one producer was completed in the WZ. However, as described below, several different configurations for the placement of these wells was considered.

Figure 10. Three Dimensional View of the Reservoir Model Used for the Vertical ("Gravity Stable") CO_2 Flood Cases, Colored by Initial Water Saturation



In this simple assessment, we evaluated four different CO_2 injection/oil production strategies for this vertical, gravity-stable flood. These were:

- Case 1:
  - 1 producer is located at the middle of the MPZ
  - 1 producer is located at the bottom of the MPZ
  - 1 producer is located at the bottom of the ROZ
- Case 2:
  - 1 producer is located at the middle of the MPZ
  - 1 producer is located at the top of the ROZ
  - 1 producer is located at the bottom of the ROZ
- Case 3
  - 1 producer is located at the middle of the MPZ
  - 1 producer is located at the top of the ROZ
- Case 4
  - 1 producer is located at the middle of the MPZ
  - 1 producer is located at the bottom of the ROZ

Well spacing for CO_2 injection was determined so that the oil mobilized by miscible CO_2 injection would be produced in a timely manner to ensure project economic viability. It also was assumed that the front should reach the first producer within the first two years of injection, thus generating significant incremental oil recovery early in the project.

Well injection and production rates were optimized using Advanced Resources' enhanced, proprietary version of the *PROPHET* software[78] to ensure a gravity stable CO_2 displacement front during injection. Front stability is an important factor to avoid oil bypass, CO_2 fingering, and maximize oil recovery. A maximum per well injection rate of about 18 MMcfd was assumed for the project, and the maximum production rate assumed was 9,000 barrels per day. These rates were found to provide a stable front for achieving good incremental oil recovery.

Since this particular reservoir is dipping 26 degrees, injection was implemented up dip; due to very high reservoir horizontal and vertical permeability (1,000 millidarcies (md) and 100 md, respectively). Given this geologic setting, super-critical injected CO_2 migrates down dip, pushing oil towards the 200 meter (660 feet) long horizontal production wells located down dip.

After the start of injection, the simulation monitored the quantity of CO_2 being reproduced to keep the oil cut higher than 50% (CO_2 production lower than 50% of the total production stream). When CO_2 production exceeded 50% of the total volume produced, the producer was closed, and a second producer, located deeper in the reservoir, was open. This allowed the optimization of both oil production while monitoring CO_2 storage for the different development scenarios considered.

The cases considered highlighted the trade-offs associated with optimizing for oil production versus CO_2 storage. In summary, the results of these cases are as follows:

- In Case 1, with two producers in the MPZ, and one producer in the ROZ, 6.4 million barrels of oil were produced, mainly from the MPZ. Production takes place for nearly four years, while injection continues for over seven years. Ultimately, the project stores 1.7 Gt of CO_2. This is an example of a case that is optimized for oil production, rather than CO_2 storage.
- In Case 2, with only one producer in the MPZ, and two producers in the ROZ, oil production is about the same as Case 1, with more oil proportionally produced from the ROZ. The duration of injection and production are comparable to Case 1, as is the durations for injection and production.
- In Case 3, with only one producer each in the MPZ and the ROZ, substantially less oil is produced than Case 1 (4.7 compared to 6.4 million barrels), but significantly more CO_2 is stored (2.8 Gt compared to 1.7 Gt).
- Finally, Case 4 is the same as Case 3, except that the producer in the ROZ is at the bottom of the zone, rather than at the top. This case results in more oil production (6.8 million barrels) and more CO_2 stored (3.4 Gt) than any of the other cases, with CO_2 injection occurring over a considerably longer period of time.

These results are summarized in Table 7.

[78] A publicly accessible version of the software can be obtained at http://www.netl.doe.gov/technologies/oil-gas/software/software_main.html.

Table 7. Summary of Results for the Vertical ("Gravity Stable") CO_2 Flood Cases

Case 1

	Cumulative Oil Produced		Stored CO_2	Prod. Period	Inj. Period
	(MMSTB)	(% OOIP)	(Gt)	(Years)	(Years)
Main Pay Zone	5.2	16.5	N/A	N/A	N/A
Residual Oil Zone	1.1	3.6	N/A	N/A	N/A
TOTAL	6.4	20.1	1.7	3.7	7.3

Case 2

	Cumulative Oil Produced		Stored CO_2	Prod. Period	Inj. Period
	(MMSTB)	(% OOIP)	(Gt)	(Years)	(Years)
Main Pay Zone	3.1	9.7	N/A	N/A	N/A
Residual Oil Zone	3.2	10.2	N/A	N/A	N/A
TOTAL	6.3	20.0	1.7	3.8	7.3

Case 3

	Cumulative Oil Produced		Stored CO_2	Prod. Period	Inj. Period
	(MMSTB)	(% OOIP)	(Gt)	(Years)	(Years)
Main Pay Zone	3.1	9.7	N/A	N/A	N/A
Residual Oil Zone	1.6	5.1	N/A	N/A	N/A
TOTAL	4.7	14.8	2.8	3.7	9.9

Case 4

	Cumulative Oil Produced		Stored CO_2	Prod. Period	Inj. Period
	(MMSTB)	(% OOIP)	(Gt)	(Years)	(Years)
Main Pay Zone	3.1	9.7	N/A	N/A	N/A
Residual Oil Zone	3.7	11.6	N/A	N/A	N/A
TOTAL	6.8	21.4	3.4	3.8	17.0

MMSTB = Million Stock Tank Barrels
Gt = gigatonnes, or billion metric tons
N/A = Not available

Other Alternative Strategies for CO_2-EOR

A number of assessments have been made of the potential to deploy CO_2 injection earlier in field development. Laboratory work has long been able to demonstrate that the earlier the injection of CO_2 is implemented, the better the hydrocarbon recovery will be. Primary reasons for this are reducing the blocking of oil by introduced water (secondary recovery) and the maintenance of reservoir pressure, particularly in the case of "live" oil, thereby mitigating negative relative permeability effects due to gas.

In conventional CO_2-EOR operations, water-alternating-gas (WAG) flooding is the common approach for CO_2 injection. In many cases, this scheme has been implemented to conform the injection of CO_2 vertically and mitigate faster processing layers (higher permeability) from thieving the injection stream, thereby spreading the CO_2 across the oil interval. Where this is applicable, it precludes the injection of water and ultimately increases the amount of CO_2 injected and processed by the reservoir due to the removal, via production, of reservoir hydrocarbons and waters.

Denbury Resources is currently developing some fields in Mississippi using this approach. They have found that continuous injection with 100% CO_2 (no water) stores almost double the CO_2 of WAG methods.[79] Denbury's experience with continuous injection in CO_2-EOR projects leads them to conclude that one can inject from 0.52 to 0.64 metric tons of CO_2 for every recovered barrel of oil (which releases approximately 0.42 metric tons of CO_2); therefore, storing 24% to 52% more CO_2 than the recovered oil will emit when consumed.

This study builds upon previous, preliminary work by Advanced Resources to assess the potential of deploying such CO_2 injection earlier in field development on incremental (and faster oil recovery) and greater utilization of storage capacity. [80] A representative model (i.e., a pattern element model for the Wasson Denver Unit – San Andres reservoir) was constructed and tuned to prior primary, secondary and expected tertiary recovery. This model was then re-initialized, with injection of CO_2 varied across the timeline to include the following CO_2-EOR cases (in addition to a Base Case):

- Injection of CO_2 (with WAG) in lieu of secondary production with water fill up – called the "Water Fill Up Case"
- Injection of CO_2 (with WAG) in lieu of secondary production with CO_2 fill up – called the "CO_2 Fill Up Case"
- Injection of CO_2 (with WAG) at the start of project (replacing primary and secondary recovery) – called the "Early CO_2 WAG Case"
- Injection of straight CO_2 (instead of a WAG) at the end of primary and secondary production – called the "Tertiary CO_2 Only Case."
- Injection of CO_2 at the start of project (replacing primary and secondary recovery), but with no WAG – called the "Straight CO_2 Case"

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[79] http://docs.nrdc.org/globalWarming/files/glo_09031101f.pdf

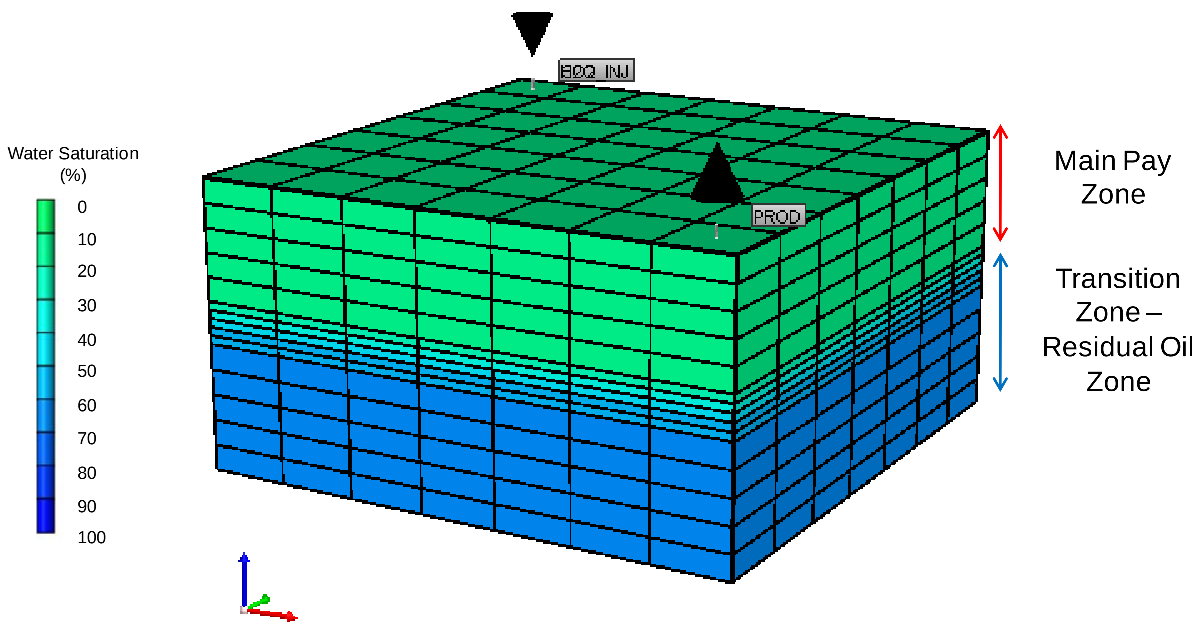
[80] IEA Greenhouse Gas R&D Programme, *CO_2 Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery,* Report IEA/CON/08/155, Prepared by Advanced Resources International, Inc. and Melzer Consulting, August 31, 2009

These scenarios were compared with a traditional CO_2-EOR project where CO_2 injection commences after both primary and secondary recovery operations have run their course. For each of these cases, CO_2 recovery and oil recovery potential where assessed for three scenarios for the cumulative volume of CO_2 injected: 1 HCPV, 2 HCPV and 2.4 HCPV. For the two cases with no WAG injection, continued injection beyond 2.4 HCPV was also considered.

The model setup assumed for these examples was identical for all cases. A 162,000 square meter (40 acre) 5-spot injection pattern was modeled. The model dimensions are 7 by 7 by 15 grid blocks (735 total grid blocks), that was 200 meters (660 feet) wide by 200 meters (660 feet) long. The Denver unit reservoir is 150 meters (491 feet) thick, with 43 meters (141 feet) in the Main Pay Zone (MPZ). The Main Pay Zone was subdivided into five layers to provide better granularity for modeling.

Using the pattern element of symmetry, only a quarter-well model was built to reduce model run time requirements: the reservoir area only covers 40,500 square meters (10 acres), Figure 11.

Figure 11. Three-Dimensional View of the Model Structure for the Alternative Strategies Cases, Colored by Initial Water Saturation

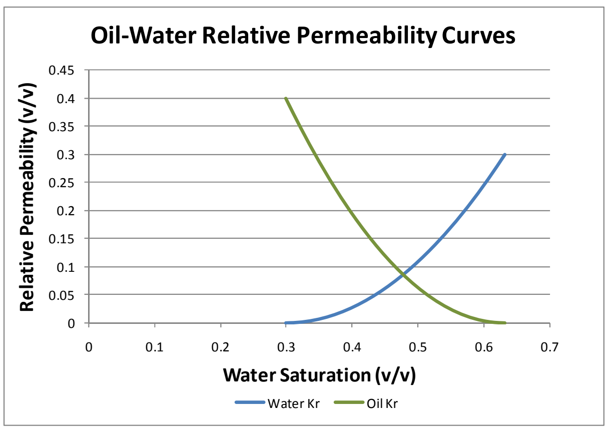


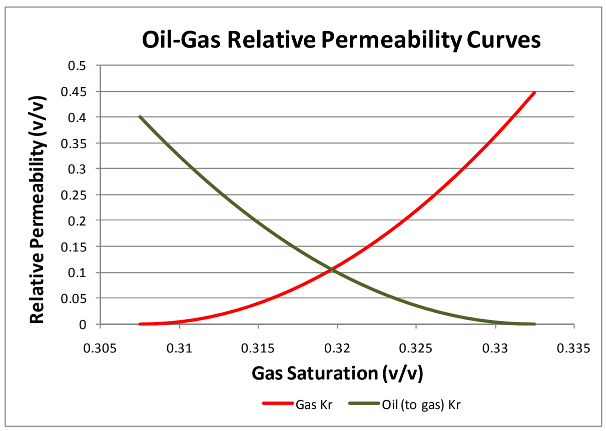
Model inputs were based on those from a previous history matched model of Wasson Field, Denver unit, and are summarized in Table 8. The relative permeability curves assumed in the model are shown in Figure 12.

Table 8. Model Inputs for History Matched Model of Wasson Field, Denver Unit

Parameters	Value	Units
Reservoir Top Elevation	5,200	ft
Reservoir Net Thickness	491	ft
Main Pay Zone Net Thickness	141	ft
Reservoir Initial Pressure Gradient	0.35	psia/ft
Porosity	12	%
Horizontal Permeability		mD
Layer 1 (Top MPZ)	0.6	mD
Layer 2	1.5	mD
Layer 3	2.7	mD
Layer 4	4.9	mD
Layer 5 (Bottom MPZ)	11.8	mD
Horizontal Permeability Anisotropy	1	Kx/Ky
Vertical Permeability	0.001	mD

Figure 12. Relative Permeability Curves Assumed for the Alternative Strategies Cases





The production and injection programs assumed were case specific, and were designed and optimized using PROPHET. These are described in the paragraphs below.

- _Base Case (Primary-Secondary-Tertiary Recovery)._ The production well was operated at a maximum bottom hole fluid rate of 175 stock tank barrels per day, with a minimum bottom hole operating pressure of 500 psia. The reservoir was produced on natural depletion (primary production) for a total of 20 years. The water flood program was designed to inject two HCPV at a maximum injection rate of 120 barrels per day. The waterflood was implemented for 25 years. The WAG CO_2-EOR program was then implemented and designed to inject 3 HCPV of water and CO_2, with a WAG ratio of 1:2. Water injection was operated at a maximum injection rate of 50 barrels per day, whereas CO_2 injection was operated at a maximum injection rate of 200 thousand cubic feet per day (Mcfd) (~100 barrels equivalent).
- _Water Fill-up Case._ The production well was operated at a maximum bottom hole fluid rate of 175 barrels per day, with a minimum bottom hole operating pressure of 500 psia. The reservoir was produced on natural depletion for a total of 20 years. The water fill up program

was designed to achieve reservoir re-pressurization back to initial conditions within one year. To do so, water injection was operated at a maximum injection rate of 500 barrels per day. The WAG CO_2-EOR program was designed to inject a total of 3 HCPV of water and CO_2, with a WAG ratio of 1:2. Water injection was operated at a maximum injection rate of 50 barrels, whereas CO_2 injection was operated at a maximum injection rate of 200 Mcfd.

- *CO_2 Fill-up Case.* The production well was operated at a maximum bottom hole fluid rate of 175 barrels per day, with a minimum bottom hole operating pressure of 500 psia. The reservoir was produced on natural depletion for a total of 20 years. The CO_2 fill up program followed and was designed to achieve reservoir re-pressurization back to initial conditions within a year. To do so, CO_2 injection was operated at a maximum injection rate of 2.5 MMcfd. The WAG CO_2-EOR program was then implemented and designed to inject a total of 3 HCPV of water and CO_2, with a WAG ratio of 1:2. Water injection was operated at a maximum injection rate of 50 barrels per day, whereas CO_2 injection was operated at a maximum injection rate of 200 Mcfd.
- *Early CO_2 WAG Case.* The production well was operated at a maximum bottom hole fluid rate of 175 barrels per day, with a minimum bottom hole operating pressure of 500 psia. The WAG CO_2-EOR program was implemented from day one and designed to inject a total of 3 HCPV of water and CO_2, with a WAG ratio of 1:2. Water injection was operated at a maximum injection rate of 50 barrels per day, whereas CO_2 injection was operated at a maximum injection rate of 200 Mcfd.
- *Tertiary CO_2 Only Case.* The production well was operated at a maximum bottom hole fluid rate of 175 barrel per day, with a minimum bottom hole operating pressure of 500 psia. The reservoir was first produced on natural depletion for a total of 20 years. The water flood program was designed to inject two HCPV at a maximum injection rate of 120 barrels per day. The water flood was implemented for 25 years.
- *Straight CO_2 Case.* The reservoir was produced under CO_2 injection from day one. CO_2 injection was then implemented and designed to inject 5 HCPV of straight CO_2 (no WAG). Injection was operated at a maximum injection pressure of 0.5 psia per foot to avoid reservoir pressurization and loss of injectivity. The CO_2 injection was conducted for a total of nearly 89 years. The production well was operated at a maximum bottom hole fluid rate of barrels per day, with a minimum bottom hole operating pressure of 500 psia.

Like that for the vertical (“gravity stable”) CO_2 floods cases considered above, these alternative CO_2-EOR development cases also highlight the trade-offs associated with optimizing for oil production versus optimizing for CO_2 storage.

As shown in Figure 13 and summarized in Table 9, relative to traditional CO_2-EOR practices represented in the Base Case, all of the alternative development scenarios result in more incremental oil production earlier. For this single pattern example, cumulative oil production reaches a maximum of about 3 million barrels within about 35 years of production, while this same level of cumulative production takes twice as long if the project goes through each of the traditional three stages of production – primary, secondary, and tertiary (CO_2-EOR), utilizing a WAG process.

This is particularly important for two reasons: (1) earlier incremental oil production results in much better economic viability; and (2) the many oil field development projects around the world that are not at the stage of depletion characteristic of most projects in the U.S. will not necessarily need to wait for primary and secondary production to run their course before deploying CO_2-EOR.

Figure 13. Cumulative Oil Production over Time for Alternative CO_2-EOR Development Strategies (Incremental Production per Pattern)

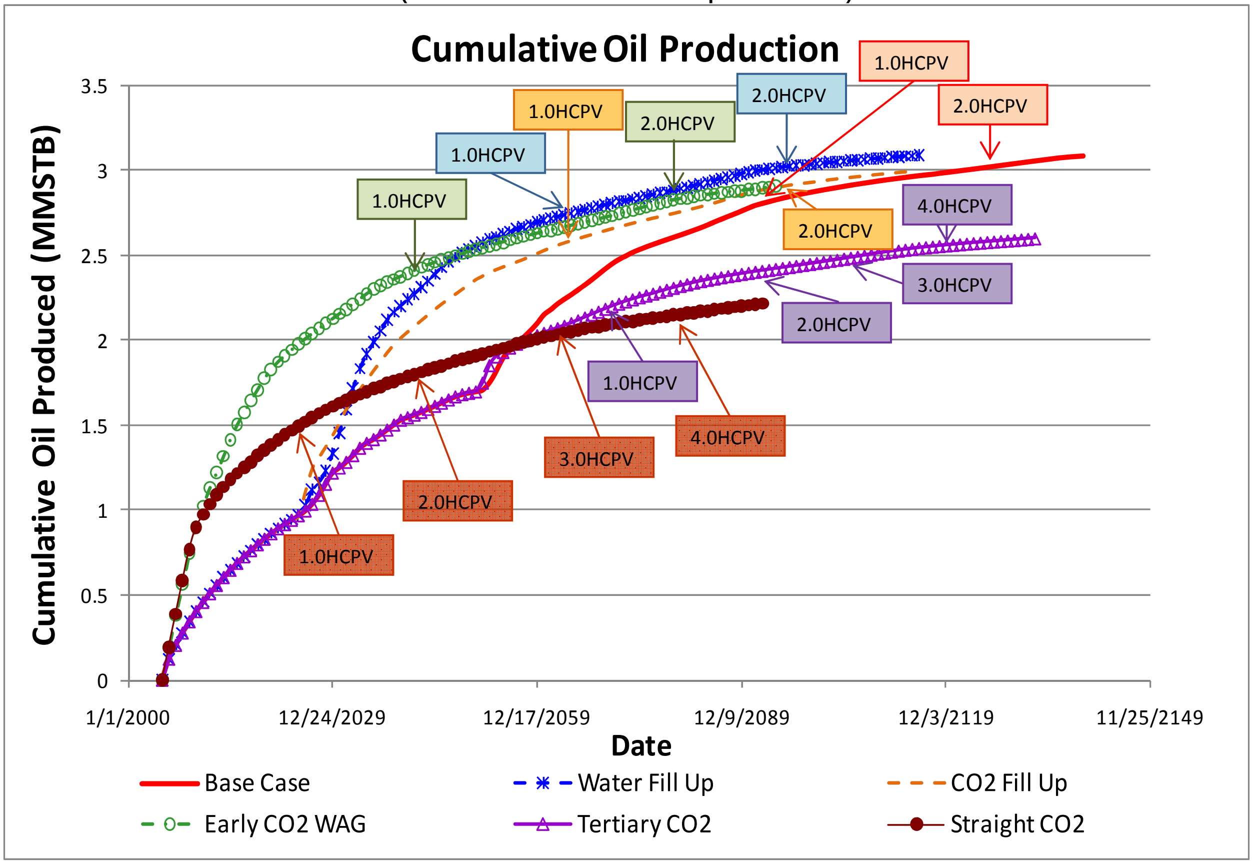


Table 9. Cumulative Oil Production over Time for Alternative CO_2-EOR Development Strategies (per Pattern)

	Cumulative Oil Production (Thousand Barrels)							
	Primary	Secondary	CO_2-EOR			Total		
			1 HCPV	2 HCPV	2.4 HCPV	1 HCPV	2 HCPV	2.4 HCPV
Base Case	969	722	1,026	1,319	1,393	2,717	3,009	3,084
Water Fill Up	969	0	1,761	2,069	2,118	2,730	3,037	3,087
CO_2 Fill Up	969	0	1,594	1,965	2,035	2,563	2,933	3,004
Early CO_2 WAG	0	0	2,415	2,821	2,906	2,415	2,821	2,906
Tertiary CO_2 Only	969	722	431	650	699	2,122	2,341	2,390
Straight CO_2	0	0	1,428	1,770	1,869	1,428	1,770	1,869

However, despite the early deployment of CO_2-EOR for the WAG cases, ultimate CO_2 storage is not impacted much. As shown in Figure 14 and in Table 10, essentially the same amount of ultimate storage is achieved for these cases. However, it is important to note that the length of time to get to that ultimate level of storage varies; basically, the earlier one begins CO_2 injection, the earlier one achieves the ultimate storage capacity available.

In contrast, the situation changes somewhat when only CO_2 is injected; that is, when the CO_2 is not injected alternatively with water in a WAG process. In those cases, while the ultimate oil recovery potential may not be as high, substantially larger volumes of CO_2 can be stored, again as shown in Figure 14. In particular, for the "Tertiary CO_2 Only" case, more CO_2 can be stored than the CO_2 emission associated with the incremental oil produced, including when it is consumed.

Figure 14. Cumulative CO_2 Stored over Time for Alternative CO_2-EOR Development Strategies (per Pattern)

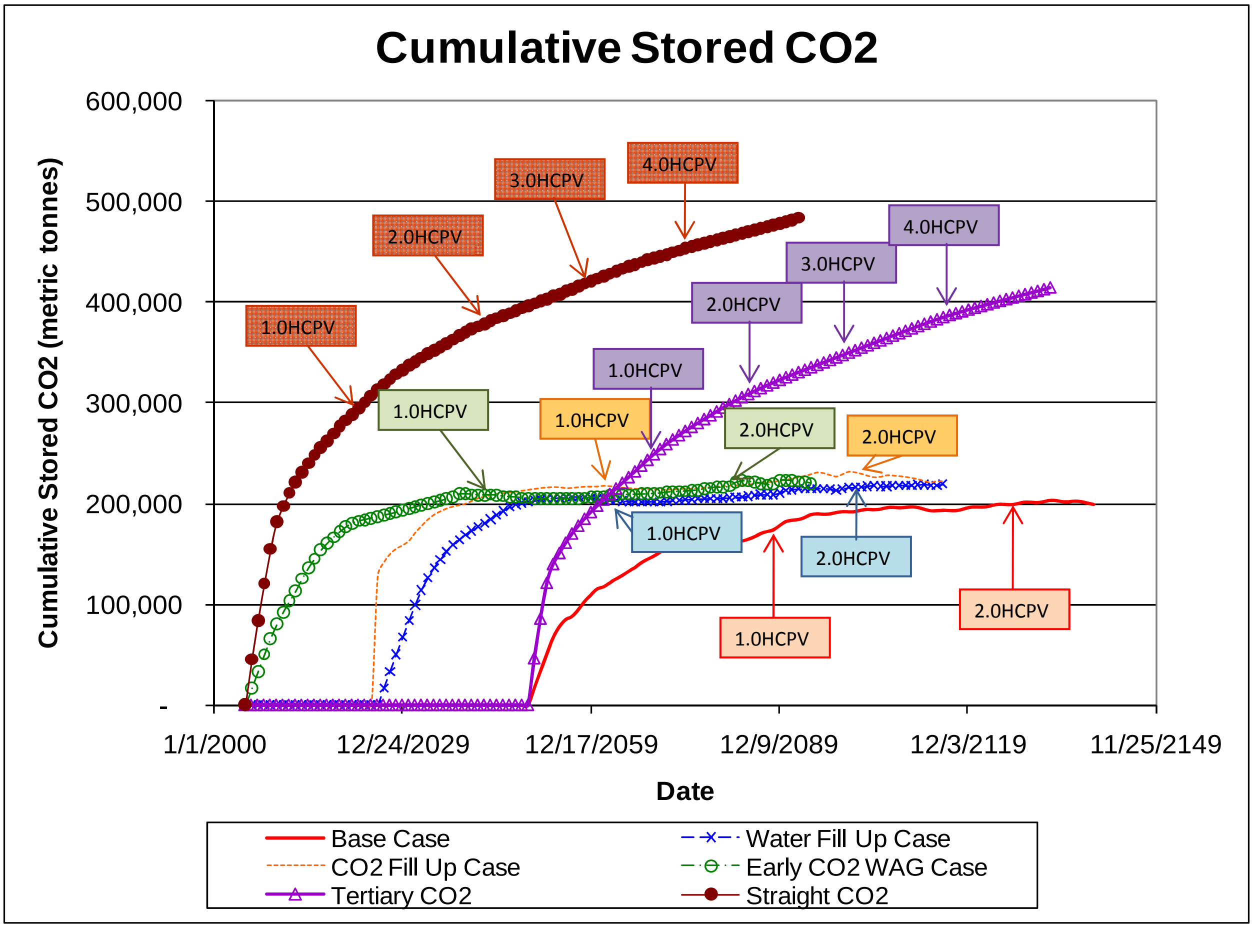


Table 10. CO_2 Stored and CO_2 Emissions Associated with Incremental Oil Production for Alternative CO_2-EOR Development Strategies

Cum. Incremental Oil Production (Thousand Barrels)			
	CO_2-EOR		
	1 HCPV	2 HCPV	2.4 HCPV
Base Case	1,026	1,319	1,393
Water Fill Up	1,761	2,069	2,118
CO_2 Fill Up	1,594	1,965	2,035
Early CO_2 WAG	2,415	2,821	2,906
Tertiary CO_2 Only	431	650	699
Straight CO_2	1,428	1,770	1,869

Cumulative CO_2 Stored (Thousand Metric Tons)			
	CO_2-EOR		
	1 HCPV	2 HCPV	2.4 HCPV
Base Case	167	192	199
Water Fill Up	200	209	219
CO_2 Fill Up	95	107	223
Early CO_2 WAG	206	209	220
Tertiary CO_2 Only	231	308	329
Straight CO_2	283	375	399

Finally, none of these cases assumes that additional residual water remaining in the reservoir is produced to "make room" for more CO_2. Producing residual water left in the reservoir, if feasible, could free up additional pore space for storing additional volumes of CO_2.

Integrated Approaches for Maximizing CO_2 Storage with CO_2-EOR

Numerous studies of potential CO_2 storage capacity show that basins that have produced large volumes of crude oil, and that have significant additional potential for CO_2-EOR, also possess substantial favorable opportunities for non-EOR storage.[81] One area where this is particularly true is in the Gulf Coast region of the southeastern United States, where some CO_2-EOR operations are underway, where additional CO_2-EOR potential exists, and where large capacity saline reservoirs also are present as a target for CO_2 storage. On top of that, in this region, large CO_2 emitting sources tend also to be in relatively close proximity to this large storage capacity.[82] Thus, substantial opportunities are likely to exist for co-locating CO_2-EOR and CO_2 storage operations in deep saline formations utilizing the same CO_2 injection wells and surface infrastructure.

Moreover, additional storage capacity should exist in reservoirs targeted for CO_2-EOR after CO_2-EOR operations are complete. As discussed above, the "poster child" of a combined CO_2-

[81] Department of Energy, *Carbon Sequestration Atlas of the United State and Canada, 2008* (http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/)

[82] Esposito, R. A.; J. C Pashin,.and P.M. Walsh, "Citronelle Dome: A Giant Opportunity for Multi-Zone Carbon Storage and Enhanced Oil Recovery in the Mississippi Interior Salt Basin of Alabama," *Environmental Geosciences*, Volume 15, No. 2, pp.53–62, June 2008

EOR and CO_2 storage project is Cenovus Energy's (formerly Encana's) Weyburn CO_2 flood in Canada (shown previously in Figure 4). The Weyburn project plans to ultimately inject 23 million metric tons in association with CO_2-EOR (15 million metric tons have been injected to date), and another 32 million metric tons solely for purposes of CO_2 storage after CO_2-EOR operations are complete. In total, this amounts to 55 million metric tons of CO_2 ultimately stored.

Detailed simulation work has documented the expected trapping mechanisms in the Weyburn field for the stored CO_2, which have achieved fairly good correlation with results to date.[83] Predicted economically viable storage volumes were estimated based on various factors, including the price of oil and the value of potential future emission reduction credits. Based on this, the Weyburn project is expected to produce at least 122 million barrels of incremental oil. Roughly speaking, the project plans to inject about 113% of the CO_2 that would be associated with the estimated incremental oil, when burned.

Another previously cited case study[84] involves a large Gulf Coast oil reservoir with about 340 million barrels of OOIP in the MPZ pursued using the gravity stable CO_2-EOR flood design shown in Figure 15. This reservoir is assumed to hold another 100 million barrels in 130 feet of a ROZ, and has an underlying saline aquifer 195 feet thick within the spill point of the anticline structure of the reservoir.

The reservoir properties of the main pay zone are assumed to be as follows:

- Depth – 14,000 feet
- Oil gravity – 33 degrees API
- Porosity – 29%
- Net pay – 325 feet
- Initial reservoir pressure – 6,620 psi
- Miscibility pressure – 3,250 psi.

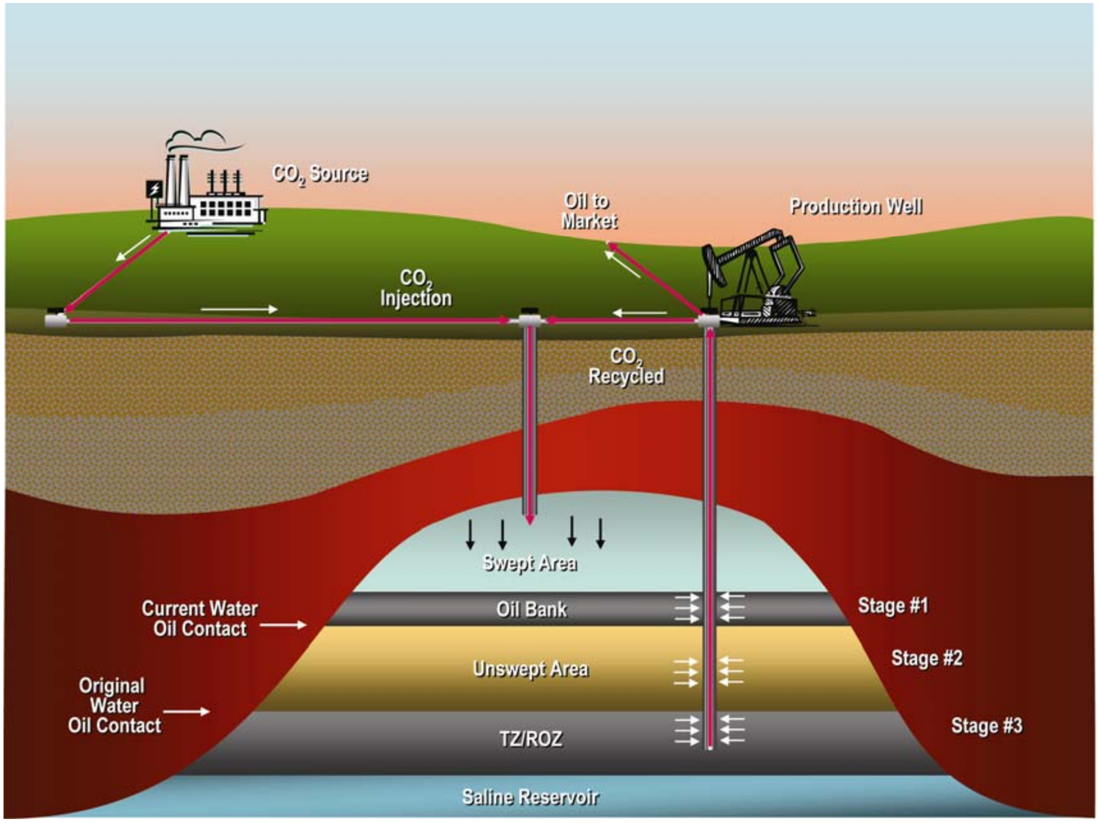
The primary/secondary oil recovery in this oil reservoir is favourable at 153 million barrels, equal to 45% of OOIP in the main pay zone. Even with this favourable oil recovery using conventional practices, 181 million barrels is left behind ("stranded").

This reservoir was assumed to be developed using "state-of-the-art" CO_2-EOR technology, including vertical wells, one HCPV of CO_2 injected (including both purchased and recycled CO_2) and one-to-one WAG ratio.

[83] See Law, David, et al., "Theme 3: CO_2 Storage Capacity and Distribution Predictions and the Application of Economic Limits," in Wilson, M. and M. Monea, eds., *IEA GHG Weyburn CO_2 Monitoring and Storage Project Summary Report 2000-2004*, Petroleum Technology Research Center, Regina, Saskatchewan, Canada, 2004

[84] U.S. Department of Energy/National Energy Technology Laboratory, *Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology: An Update*, report DOE/NETL-2010/1417 prepared by Advanced Resources International, April 2010 (http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&Source=Products&PubId=309)

Figure 15. Schematic Illustration of Coupling CO_2-EOR with Other Strategies to Maximize Cost-Effective CO_2 Storage



Next, this was compared to “next generation” CO_2-EOR and CO_2 storage, including gravity-stable, vertical CO_2 injection with horizontal production wells targeting the main pay zone, plus the ROZ and the underlying saline aquifer, along with injecting continuous CO_2 (no water) and continuing to inject CO_2 after completion of oil recovery.

Based on the above, the theoretical CO_2 storage capacity of this oil reservoir and associated structural closure is 143 million metric tons (2,710 Bcf). Assuming there is value to storing CO_2 with gravity stable CO_2-EOR and sequestration technology, much more CO_2 can be stored relative to “next generation” technology and more oil becomes potentially recoverable (Table 11):

- CO_2 storage increases by 3 to 4 fold to 109 million metric tons with 76% of the theoretical storage capacity utilized.
- Oil recovery is increased by two fold, to 180 million barrels, containing 72 million metric tons of CO_2 (when combusted). Importantly, 109 million metric tons of CO_2 is injected and stored during the EOR flood.
- Thus, in this example, over 50% more CO_2 is stored than is contained in the produced oil when burned.

Table 11. Case Study: Integration of "Next Generation" CO_2 Storage with EOR

	"Next Generation"	"Second Generation" CO_2-EOR & Storage		
	CO_2-EOR	CO_2-EOR	Storage	Total
CO_2 Storage (million metric tons)	32	76	33	109
Storage Capacity Utilization	22%	53%	23%	76%
Oil Recovery (million barrels)	92	180	-	180
% Carbon Neutral*	87%	106%	-	151%

* In these cases, only the emissions associated with combustion of the refined incremental oil was considered.

Reconsidering the Applicability of CO_2-EOR in Offshore Settings

Conventional wisdom has been that the high costs associated with challenging settings such as that in the offshore make the applicability of CO_2-EOR in such settings generally uneconomic.

Recent work sponsored by DOE/NETL indicates that this may not always be the case, at least in the U.S. Gulf of Mexico (GOM), though CO_2-EOR projects in such settings will nonetheless face both economic and logistical challenges.[85] The GOM, including the Shelf (Shallow Water) and Slope (Deep Water), has been endowed with a large, geologically attractive oil resource with 46 billion barrels of OOIP. Of this, 19 billion barrels have been produced or booked as recoverable reserves, with 27 billion remaining unrecoverable or "stranded".

This DOE/NETL study assessed the potential of storing CO_2 and producing incremental oil in the offshore GOM with the integrated application of CO_2-EOR. One of the principal features of this assessment was the recognition that offshore reservoirs in the GOM typically consist of a series of stacked sands that may be vertically aligned in a structural trap or fault block setting. These reservoirs are typically produced with as few wells as possible, and these wells are often completed in multiple sands.

In order to model this approach, the sands within a field were assumed to be vertically stacked. The largest area sands were assumed to drive the spacing and development pace of the field. All other sands within a field were assumed to be developed on the same spacing as the largest sand. Existing producers within a field were assumed to be reworked as CO_2-EOR producers which can produce from any sand. Alternatively, all injection wells were assumed to be newly drilled to ensure that they can properly deliver CO_2 to the sands. CO_2 injection wells were also assumed to be completed in each of the stacked sands.

A detailed, up-to-date Offshore CO_2-EOR Cost Model was developed for this study that included costs for: (1) drilling new wells or reworking existing wells; (2) providing surface equipment for new wells on an existing platform; (3) installing the CO_2 recycle plant on the existing platform; (4) constructing a CO_2 spur-line from a main CO_2 trunk line to the oil platform; and (5) various

[85] U.S. Department of Energy/National Energy Technology Laboratory, *Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO2-EOR Technology: An Update*, report DOE/NETL-2010/1417 prepared by Advanced Resources International, April 2010 (http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&Source=Products&PubId=309)

other miscellaneous costs. The cost model also accounted for normal well operation and maintenance (O&M), for lifting costs of the produced fluids, and for costs of capturing, separating and reinjecting the CO_2.

Analyses were performed where the recovery potential of offshore GOM reservoirs were simulated assuming a WAG flood injecting 1.0 HCPV of CO_2. Another case was considered where 1.5 HCPV was assumed to be injected, but it was determined that the incremental oil recovery associated with injecting an additional 0.5 HCPV of CO_2 did not improve the economic return for these fields for the following reasons:

- Smaller “stranded” oil target and high primary and secondary recovery efficiencies yield low incremental oil
- Injecting an additional 0.5 HCPV of CO_2 requires greater CO_2 purchases, CO_2 recycling, and operating expenditures, which worsens economic returns.

The study concluded that the integrated application of CO_2-EOR and CO_2 storage in the GOM could technically recover 5.8 billion barrels of oil and store 1,700 million metric tons of CO_2. Over half of this potential resides in the Louisiana shallow water (shelf) federal offshore oil fields.

However, the offshore GOM is a high-cost operating area. At an oil price of $70 per barrel and CO_2 cost of $45 per ton, only 730 million barrels of this stranded oil resource was determined to be economically recoverable, and would result in the storage of about 200 million metric tons of CO_2, with all of this potential in the shallow federal waters of the GOM. For half or more of the technically recoverable oil and associated CO_2 storage potential in the GOM to be economically viable, it was determined that higher oil prices ($100 per barrel), lower CO_2 costs ($35 per ton) and/or other incentives such as reduced royalties or credits for storing CO_2 would be necessary.

The GOM has many of the same challenges for CO_2-EOR as that in the North Sea. A considerable amount of work has been done identifying the best CO_2-EOR prospects in the North Sea. BP, Shell, ConocoPhillips, and Statoil have investigated CO_2-EOR potential at fields like Forties, Miller, Draügen and Gullfaks; but have not pursued these opportunities. Initial evaluations of these prospects concluded that CO_2-EOR oil yields are disappointing, and together with escalating capital costs for the conversion of offshore installations, including facilities and wells for CO_2 injection, potential CO_2-EOR prospects were determined unlikely to be economic.

Further studies by Herriot Watt University and the Norwegian Petroleum Directorate have also deemed CO_2-EOR development in the North Sea area uneconomic without financial incentives.[86] The authors cite as causes a lack of regulatory guidance, poor sweep efficiency (and hence low oil recovery efficiency), high oil recovery rates from secondary recovery techniques (compared to onshore fields), high costs of offshore platform retrofits, the lack of availability of sufficient and cheap volumes of CO_2, and the costs to establish a region-wide CO_2 supply infrastructure.

[86] See, for example, Guntis Moritis , “Norway study finds CO_2 EOR too expensive, risky” *Oil and Gas Journal*, Volume 103, Issue 30, August 8, 2005

A number of other studies have come to the same basic conclusion -- that without substantial government incentives, CO_2-EOR is unlikely to be an economic means of supporting CCS in the North Sea. [87,88,89,90,91,92]

In contrast, a recent study by Durham University concluded that using CO_2-EOR in existing North Sea oil fields could yield an extra three billion barrels of oil over the next 20 years, and be worth £150 billion ($240 billion U.S) -- but only if the current infrastructure is enhanced now.[93] In other words, some potential exists, but time is running out. They conclude that time is of the essence to make best use of the UK's remaining oil reserves, since vital infrastructure is lost as the oil fields decline and are abandoned, and would then be unavailable for deploying CO_2-EOR in the future.

For the most part, these studies did not consider more aggressive development scenarios for CO_2-EOR, nor did they examine in detail potential approaches for CO_2 storage beyond that directly associated with CO_2-EOR, especially in a world characterized by mandated controls on GHG emission. Finally, these studies did not thoroughly investigate ways that CO_2-EOR can be more cost-effectively pursued in offshore environments.

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[87] Department of Business Enterprise and Regulatory Reform, *Development of a CO_2 Transport and Storage Network In The North Sea*, Report to the North Sea Basin Task Force, In Association with Element Energy Pöyry Energy and British Geological Survey, (http://www.berr.gov.uk/files/file42476.pdf)

[88] See: Markussen, P., Austell, J.M. and Hustad, C-W., "A CO_2-Infrastructure for EOR in the North Sea (CENS): Macroeconomic Implications for Host Countries", Sixth International Conference on Greenhouse Gas Control Technologies, 30 Sept - 04 Oct, 2002, Kyoto. Paper No. 324, pp.8; 2003;

[89] Matthiassen, O.M. "CO_2 as Injection Gas for Enhanced Oil Recovery and Estimation of the Potential on the Norwegian Continental Shelf", Trondheim/Stavanger, Norwegian University of Science and Technology Department of Petroleum Engineering and Applied Geophysics, Trondheim, Norway, 2003

[90] Holt, Torlief, Erik Lindeberg, and Dag Wessel-Berg, "EOR and CO_2 disposal – economic and capacity potential in the North Sea", *Energy Procedia*, 2009, 4159-4166; and

[91] Scottish Center for Carbon Storage, *Opportunities for CO2 Storage around Scotland – An Integrated Strategic Research Study*, April 2009, (http://www.geos.ed.ac.uk/sccs/regional-study/)

[92] Tzimas, E., Georgakaki, A., Garcia Cortes, C. and Peteves, S.D., "CO2 Storage Potential in the North Sea via Enhanced Oil Recovery," EU Commission DG-Joint Research Centre, Institute for Energy, Petten, The Netherlands, Paper 03-20-09 presented at Eighth International Conference on GHG Technologies, Trondheim, Norway, pp.6, 19-22 June 2006

[93] http://www.sciencedaily.com/releases/2010/10/101013193533.htm, and http://www.computescotland.com/north-sea-oil-decommission-or-prime-recovery-3729.php

IV. ENVIRONMENTAL IMPLICATIONS OF CO_2-EOR PROJECTS

Overview of this Section

A critical consideration is where the balance lies in terms of the potential climate benefits associated with the integrated application of CO_2 storage with CO_2-EOR, especially in comparison to other sources of crude oil supplies. This section builds upon the alternative approaches for the integrated application of CO_2 storage with CO_2-EOR developed in Section III. The section presents the results of life-cycle analyses of the CO_2 emissions associated with the production of oil using CO_2-EOR, with those associated with transporting and refining the incremental oil produced, and with the emissions associated with consuming the crude, once it has been ultimately refined into its various products. These life-cycle emissions are then assessed as applied to some of the potential approaches for optimizing CO_2 storage with incremental oil production from CO_2-EOR examined in this study. Finally, the section offers some perspectives on other possible environmental benefits associated with CO_2-EOR in comparison to other options for developing crude oil supplies.

The key findings of this section are:

- **Some believe that the emissions associated with consuming the incremental volume of oil produced from CO_2-EOR operations should not be considered in life cycle emissions analyses of CO_2-EOR projects.** They believe project life cycle emissions attributed to CO_2-EOR should include only fugitive emissions directly related to the CO_2-EOR project and not include downstream emissions common to all sources of oil supply. They believe oil not otherwise produced using CO_2-EOR would just get supplied to the market, as demanded, by other sources of crude oil.
- **Nonetheless, some approaches for CO_2-EOR development that maximize CO_2 storage can permanently store more CO_2 than the CO_2 emissions associated with the incremental oil produced, when considered over its entire life cycle.**
- **However, even CO_2-EOR projects that are not optimized for storage, 50% to 60% of the total volume of emissions associated with oil production (from operations, transport, refining, and the ultimate combustion of the products refined from the produced crude) could be permanently stored.** In other words, even if only half of the emissions resulting from incremental oil production from CO_2-EOR are stored, this is still considerably better than none, which would be the case otherwise.
- **Thus, a critical choice for society, at least in the near term, will be between a barrel of crude oil produced through the application of CO_2-EOR, and that produced by other means,** even as lower carbon alternatives such as wind and solar power 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 oil produced by most other means.

Consideration of CO_2 Emissions Associated with CO_2-EOR

One of the questions surrounding CO_2-EOR operations is whether there can be, in fact, an overall net reduction in CO_2 emissions over the life of a strategically planned and executed CO_2-EOR project, when considering the CO_2 emissions associated with the entire life cycle of the incremental oil produced, including ultimate consumption. Such strategically planned and executed CO_2-EOR projects would strive to optimize the volume of CO_2 stored, not just the volume of incremental oil produced.

Some believe that the emissions associated with transporting, refining, and consuming the incremental volume of oil produced from CO_2-EOR operations should not be considered in life cycle emissions analyses of CO_2-EOR projects. They believe project life cycle emissions attributed to CO_2-EOR should include only fugitive emissions directly related to the CO_2-EOR project itself, and not include downstream emissions common to all sources of oil supply. They believe that these emissions (primarily from refining and consumption) are not incremental to the EOR project, because they would occur even if the EOR project was not executed. They believe that world oil production is determined by world oil demand, and if CO_2-EOR projects were not undertaken, some other source of oil would be produced to meet the demand and those emissions would still result.[94]

And in most cases, these alternative sources of oil supply would have greater net emissions than that associated with CO_2-EOR.

While a number of stages with varying levels of complexity can be considered when assessing the life cycle CO_2 emissions of a CO_2-EOR project, for this study, the four largest sources of CO_2 emissions will be examined. Those stages include the emissions generated from: (1) the electricity needed for the CO_2-EOR operation itself, (2) the transportation of the crude oil to the refinery, (3) the emissions associated with refinery operations, and (4) the emissions generated by the consumption of the refined products produced from the incremental oil produced by the CO_2-EOR project. Not included is the emissions generated from acquiring and providing that CO_2 to the field, or the transportation of the consumer products from the refinery to the market.

In this study, particular focus is given to understanding the CO_2 emissions associated with CO_2-EOR operations. Several studies have analyzed the potential CO_2 emissions associated with CO_2-EOR,[95,96,97,98,99] and the approaches used and the corresponding results are varied. The studies also vary on what components are considered part of the CO_2-EOR project life cycle and, as a result, these studies are often difficult to compare. Nonetheless, most consider the

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94 Faltinson, John, and Bill Gunter, "Net CO_2 Stored in North American EOR Projects," SPE Paper No. CUSG/SPE 137730-PP, presented at the Canadian Unconventional Resources & International Petroleum Conference, Calgary, Alberta, Canada, October 19–21, 2010.

95 U.S. Department of Energy, National Energy Technology Laboratory, *An Assessment of Gate-to-Gate Environmental Life Cycle Performance of Water-Alternating-Gas CO_2-Enhanced Oil Recovery in the Permian Basin*, Report No. DOE/NETL-2010/1433, September 30, 2010 (http://www.netl.doe.gov/energy-analyses/pubs/CO2_EOR_LCA_093010.pdf)

96 Aycaguer, Anne-Christine, Miriam Lev-On, and Arthur M. Winer, "Reducing Carbon Dioxide Emissions with Enhanced Oil Recovery Projects: A Life Cycle Assessment Approach," *Energy Fuels*, 2001, 15 (2), pp 303–308 March 1, 2001

97 Khoo, H.H.; Tan, R.B.H., "Life cycle investigation of CO_2 recovery and sequestration," *Environmental Science and Technology*, Volume 40, No. 12, pp. 4016-4024, 2006

98 http://mrgreenbiz.wordpress.com/2009/10/04/study-questions-lifecycle-emissions-benefits-of-using-co2-for-enhanced-oil-recovery-as-a-method-for-carbon-sequestration/

99 Jaramillo, Paulina., W. Michael Griffin, and Sean T. McCoy, S., "Life Cycle Inventory of CO_2 in an Enhanced Oil Recovery System," *Environmental Science and Technology*, Vol. 42, No. 21, 2009

compression and injection of CO_2, and the production, transport, refinement, and end-use combustion of the incremental oil produced. Finally, the studies differ on the amount of CO_2 assumed to be stored in the reservoirs from the application of CO_2-EOR; the quantity against which offsetting CO_2 emissions is compared.

Each of the sources of CO_2 emissions associated with CO_2-EOR operations and subsequent oil process, transport, and use are described in more detail below.

CO_2 Emissions Associated with Electricity Generation

Electricity requirements are important to consider for any emissions sensitive project because of the amounts of CO_2 emitted by the power plants that generate the power needed. Although electrical power can come from both fossil and non-fossil fuel sources, the most prevalent are coal, petroleum, and natural gas. Other fossil fuel sources can include municipal waste that emits CO_2 when burned for electricity. Non-fossil fuel power can include nuclear, solar, hydroelectric, and other sources with net-zero CO_2 emissions. While non-fossil fuel sources are preferable to lower the emissions profile, they are not as common today as fossil fueled plants.

Table 12 illustrates the different CO_2 emissions per kilowatt-hour for various types of fossil-based power stations.

Table 12. CO_2 Emissions from Fossil Fuel Plants

Type of Power Plant	Output Rate
Coal	0.960 kg CO_2 / kWh
Petroleum	0.869 kg CO_2 / kWh
Gas	0.596 kg CO_2 / kWh
Other	0.625 kg CO_2 / kWh

Source: DOE, EPA, Carbon Dioxide Emissions from the Generation of Electric Power in the United States, 2000

This study's emissions estimates are based on electricity provided to the CO_2-EOR project using coal-fired power both because of its prevalence, especially in the United States, and the ability to utilize CO_2 emissions streams from coal burning power stations. This also represents a "worst case" for the emissions associated with power generation.

Life-Cycle Emission Stages and Sources for CO_2-EOR Operations

During the operations of a CO_2-EOR project, the primary sources of emissions are associated with the electricity demands of the operations. In general, these are related to the volumes of fluids injected, processed, and produced, along with the complexity and length of the project's life.

Much of the material presented in this study on the electricity requirements of CO_2-EOR operations draws from previous work by Advanced Resources. [100]

CO_2-EOR projects have a number of processes requiring equipment and infrastructure that require electricity, and thus could have associated CO_2 emissions. Figure 16 provides a simplified diagram of the various facets or activities associated with a CO_2-EOR project. On the surface, equipment and facilities associated with compression, natural gas liquid (NGL) separation and processing, oil/brine handling, and artificial lift mechanisms are shown, which are typical of most CO_2-EOR operations.

Figure 16. Simplified Diagram of a CO_2-EOR Flood

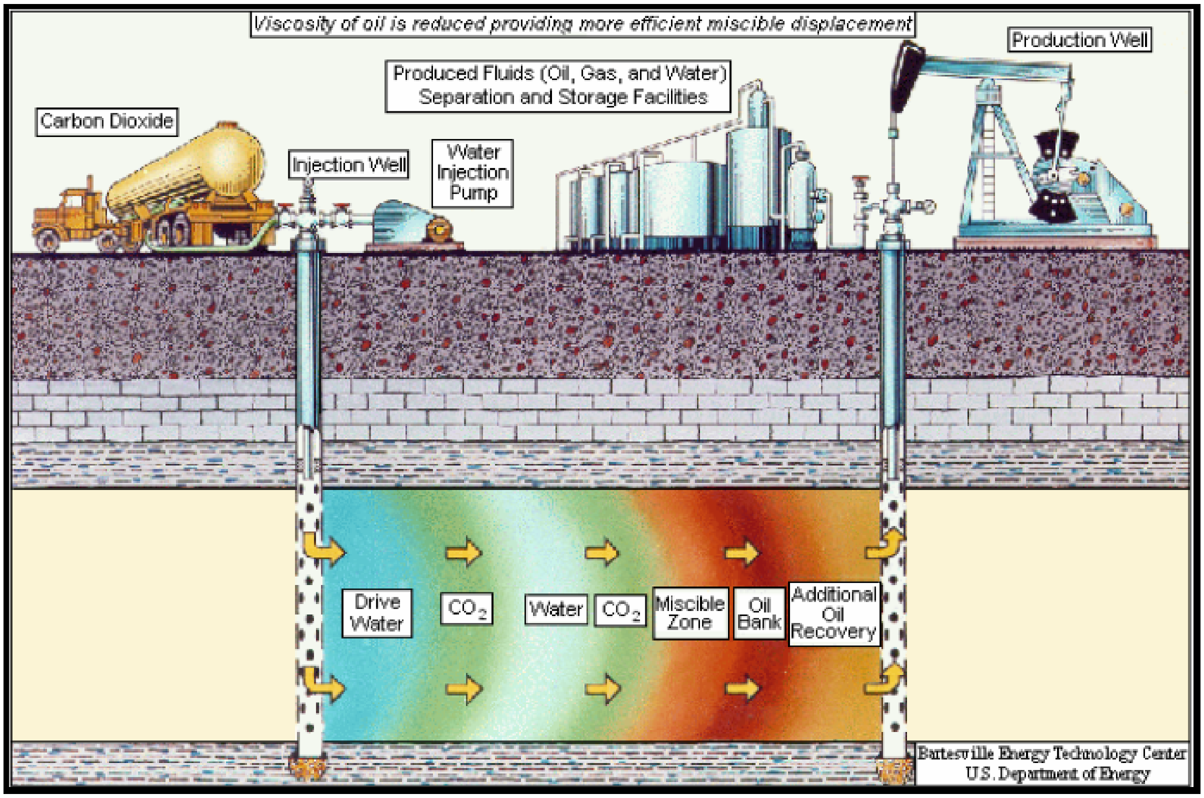

Image Source: U.S. Department of Energy

The energy demands and associated emissions corresponding to each of the major aspects of a CO_2-EOR operation are discussed below.

CO_2 Compression

While each aspect of a CO_2-EOR operation requires energy, compression of the CO_2 requires the largest amount, so most of the emissions associated CO_2-EOR operations can be attributed to the power demands of CO_2 compression. Because of the high injection pressures required, boost compression is required for both new CO_2 sources (unless those sources are already delivered at injection pressure, which is generally the case today) and recycled CO_2 being produced from the reservoir.

[100] National Energy Technology Laboratory, *Electricity Use of Enhanced Oil Recovery with Carbon Dioxide (CO_2-EOR)*, report DOE/NETL-2009/1354 prepared by Advanced Resources International, January 26, 2009 (http://www.netl.doe.gov/energy-analyses/pubs/Electricity%20Use%20of%20CO2-EOR.pdf)

CO_2 compression power requirements depend on the differential between the pressure of the produced CO_2 and the required field injection pressure. This range is directly affected by the pressure of the source CO_2 and the characteristics of the reservoir that dictate the injection pressure (porosity, permeability, thickness, etc.) In general, the higher the pressure of the source CO_2, the lower the compression energy usage, and thus the lower the CO_2 emissions associated with this usage.

While these pressure differentials vary depending on reservoir characteristics, in general, CO_2 needs to be injected at a minimum of about 1,800 pounds per square inch absolute (psia), and it is typically produced at around 50 psia – an implied compression ratio of 36. This range of pressures would require four-stage compression. Additionally, the CO_2 stream needs to be dehydrated before compression, a process that also requires some electricity.

Using CO_2 compression power consumption equations compiled by McCollum and Odgen,[101] an estimated 56 kWh are needed to compress one metric ton of CO_2 for the range of pressures mentioned above.

Fluid Lifting

In addition to compression equipment, many CO_2-EOR projects require artificial lift equipment as the primary reservoir drive is depleted. An estimated 80% of all current CO_2-EOR operations require artificial lifting. Notable exceptions exist, such as Anadarko's Monell and Salt Creek fields and portions of Kinder Morgan's SACROC field, where operators have converted to free-flowing wells. Lifting power consumption is estimated to make up 10% to 30% of the electricity use of a CO_2-EOR project.

Electricity consumption by artificial lift equipment is highly dependent upon the depth of the production wells and the composition and volume of the produced fluids. Shallower wells with lighter oil may only require 1 to 4 kWh per barrel to lift the produced fluids, which is generally the case for CO_2-EOR projects.[102] In this study, the energy requirements for artificial lift were estimated to be about 1.25 kWh per barrel lifted (accounting for both the oil and water produced, adjusting for the relative densities). This estimate is based on typical parameters for fluid composition and depth for CO_2-EOR projects in the U.S.

The amount of power required to lift the produced fluids in a CO_2-EOR reservoir is likely to change over time. In the beginning years of the project, before the CO_2-mobilized oil bank has reached the production wells, lift power consumption is likely to be quite high. At this stage, reservoir pressure has likely been depleted by primary and secondary production, and wells may produce high volumes of water.

As injected CO_2 and water (in the case of WAG floods) increase reservoir pressure, lifting electricity requirements will decrease. High concentrations of CO_2 in the produced oil stream will also decrease lifting power consumption by reducing the density of the produced fluid. At the end of the project, if the operator injects a large slug of water to flush the reservoir, lifting power requirements could rise again.

Under favorable circumstances, it is possible for wells that begin a CO_2 flood using artificial lift to be converted to free flowing wells later in the project. Indeed, whenever feasible, reservoir

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[101] McCollum, D., Ogden, J. Techno-Economic Models for Carbon Dioxide Compression, Transport and Storage. Institute of Transportation Studies, University of California, Davis

[102] QRod Rod Pumping Design Application, available at http://www.echometer.net/qrod/ .

operators will attempt to minimize the electricity and mechanical operating costs of a project by converting wells to flow freely. This decision is made on a reservoir-by-reservoir basis, and is dependent on site-specific geologic, operational and economic factors.

Hydrocarbon Fluid Separation

In oil fields that also produce considerable volumes of hydrocarbon gases and NGLs, operators may need equipment to separate and capture some of these valuable hydrocarbons for sale. Hydrocarbon separation can be performed using a Ryan Holmes process or membrane separation.

Ryan Holmes facilities separate NGLs from the produced CO_2 stream by exploiting the dew point differential of different types of hydrocarbons. Produced gas is pumped through a vertical, temperature-polarized column and NGLs are separated as they condense out of the gaseous stream. Ryan Holmes facilities can be scaled to separate all of the produced hydrocarbons from a produced stream, or a selected few, depending on project economics

Ryan Holmes facilities require additional compression of refrigerant liquids to maintain the temperature differential of the separation column. This additional refrigerant compression adds to the electricity consumption of the plant. Though significant amounts of CO_2 compression are required to drive the low pressure produced CO_2 stream through the separation process, the CO_2 compression requirements are no larger than those of a CO_2-EOR operation of similar size.

The propane recovery column at Chevron's Buckeye Processing Plant at the Vacuum Field uses two 1,750 horsepower (HP) compressors to cool the separation tower. These compressors use approximately 63,000 kWh per day, or 10 kWh per produced barrel of oil. To compress the produced CO_2 stream, four 3,000 HP compressors are used, which use approximately 215,000 kWh per day, or 35 kWh per produced barrel of oil.

Membrane permeation systems separate various components of gas produced with oil based on molecular size. A CO_2 molecule permeates a filter-like material more quickly and with less force than a hydrocarbon molecule. As a result, membranes create a permeate stream (CO_2-rich) and a non-permeate stream (hydrocarbon rich).

During the process, the permeate stream loses more pressure than the non-permeate stream and additional compression is required to recompress this stream to its initial pressure. The electricity consumption from membrane separation systems comes from this additional CO_2 compression requirement. The compression and resulting electricity requirements can vary widely, depending not only on the volume of throughput in the process, but also the starting and desired finishing CO_2 concentrations. In this study, the energy requirements for hydrocarbon fluid separation was assumed to be 3 kWh/Bbl of oil produced.

Other Electricity Uses

In addition to the major sources of electricity consumption discussed above, there are other smaller, but non-trivial, components that contribute to CO_2-EOR electricity demand. This includes electricity use for injecting water into disposal wells and as part of the CO_2-WAG process, where applicable. Water injection electricity requirements are dependent on the injection pressure and volume of fluid being injected.[103] Water injection electricity requirements range from 4 to 8 kWh per barrel of oil produced. In addition, small amounts of electricity are used by field automation and CO_2 dehydration equipment. For this study, it was assumed that these components would require no more than 2 kWh per barrel of oil produced.

Table 13 summarizes the energy use assumptions used for CO_2-EOR projects in this report.

Table 13. Electricity Use Assumptions for CO_2-EOR Operations, by Source

Project Component	Electricity Consumption** Estimates Assumed in this Study
Compression	56 kWh /tonne CO_2
Artificial Lifting	1.25 kWh/Bbl of fluids (oil and water)
NGL Separation	3 kWh/Bbl oil
Other	2 kWh/Bbl oil

Converting all of these uses to a barrel of oil equivalent produced from CO_2-EOR results in an average CO_2 emission rate associated with CO_2-EOR operations of about 0.04 metric tons per barrel of oil produced.

Emission Sources and Stages Subsequent to CO_2-EOR Operations

Crude Transport

Once the produced oil has been separated from the production stream, it must be transported to a refinery for conversion into marketable products. It is important to remember that only the CO_2 emissions associated with the incremental production from CO_2-EOR be considered, not those that are a result of the pre-existing (if-any) production of the field. The emissions attributed to this stage are small, less than 1% of the overall project, and are difficult to estimate due to the different methods and varying distances that the crude must travel. Transportation usually takes place through a pipeline network that takes the oil from the field to the refinery, but can also be done using tanker and carrier trucks. Previous work by the U.S. DOE examined the different methods and estimates that emissions from crude oil transport in the United States averages 4.09 kg CO_2 per barrel of oil transported,[104] or 0.004 metric tons per barrel.

103 The equation is: $BHP = \frac{Q \times (P_d - P_s)}{1714 \times ME}$ Where: BHP is the horsepower of the pump, Q is the amount of fluid compressed in gallons/minute, P_d is the discharge pressure, P_s is the initial pressure and ME is the mechanical efficiency of the pump (typically between 65-75%). Horsepower can be converted into kilowatts by multiplying by 0.747. Source: http://www.pumpcalcs.com/calculators/view/81/

104 National Energy Technology Laboratory, *Electricity Use of Enhanced Oil Recovery with Carbon Dioxide (CO_2-EOR)*, report DOE/NETL-2009/1354 prepared by Advanced Resources International, January 26, 2009 (http://www.netl.doe.gov/energy-analyses/pubs/Electricity%20Use%20of%20CO2-EOR.pdf)

Crude Refining

With some exceptions, unprocessed crude oil is not a useful product. Oil refineries are needed to process the crude into a variety of useful, marketable consumer and industrial products. Upon reaching the refinery, the raw crude undergoes a distillation process to refine the oil and separate into the products, yielding an assortment of gases, light, medium and heavy fuels, and residual products such as lubricants, waxes, and asphalt. The U.S. Energy Information Administration (EIA) monitors and releases energy and emissions data, including monthly refinery yields.[105] The two categories with the highest yields, motor vehicle gasoline and distillate (diesel) fuels, together make up almost 75% of the product refined from a barrel of crude. The remaining is made up of smaller yields of the other products including aviation fuel, liquefied refinery gases, petroleum coke, and the various waxes and lubricants.

Although the same refinery generates different products, the processes and energy requirements for each vary. Because of this, CO_2 emissions the refinery generates are rooted in a refinery's output, not the input of crude. In 2008, one DOE study examined the GHG emissions of refinery operations and provided a CO_2 emissions factor for each of the major products produced from crude oil. By weighting those emissions factors based on the EIA's refinery yield, in June 2010, overall U.S. refinery emissions averaged 40 kg CO_2 per barrel of crude.

However, on average, a barrel of crude oil produced from an EOR project tends to be of higher gravity and easier to refine that the U.S. average barrel, with contains a significant portion of heavier, lower gravity crudes. For this reason, a somewhat lower emissions factor for refining oil produced from CO_2-EOR was assumed in this study, amounting to 0.03 metric tons per barrel.

Crude Consumption

The final and largest stage of CO_2-EOR life-cycle emissions as defined in this study is the combustion of the refined products once they make it to market. According to the EIA, a 100% combusted barrel of crude oil releases 432 kg of CO_2.[106] However, a small percentage of residual refinery products are not intended for combustion including asphalt, lubricants, waxes, and chemical feedstock used for the manufacturing of plastics and synthetic materials. As a result, a portion of the crude's original carbon content remains unburned in these products, effectively trapped. One study estimates that 93% of the carbon in a barrel of refined crude to be converted into emissions released when the gasoline, diesel, and other fuel products are burned.[107] As a result, an estimated 0.40 metric tons of CO_2 are emitted per barrel of oil (0.93*0.432 metric tons/barrel = 0.40) was assumed for this study.

Assuming coal-fired electricity generation, the total life-cycle emissions for CO_2-EOR operations amount to about 0.47 metric tons per barrel of oil produced, summarized as follows:

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105 Energy Information Administration, U.S. Refinery Yield Table, June 2010 (http://www.eia.doe.gov/dnav/pet/pet_pnp_pct_dc_nus_pct_m.htm)

106 Energy Information Administration, Voluntary Reporting of Greenhouse Gases Program Fuel and Energy Source Codes and Emission Coefficients, 2010 (http://www.eia.doe.gov/oiaf/1605/coefficients.html)

107 Jaramillo, Paulina., W. Michael Griffin, and Sean T. McCoy, S., Life Cycle Inventory of CO_2 in an Enhanced Oil Recovery System," Environmental Science and Technology, Vol. 42, No. 21, 2009

	Emissions (metric tons/bbl)
CO_2 Operations	0.04
Transport	0.00
Refinery	0.03
End use	0.40
	0.47

Assessment of Selected Case Studies

In this report, net CO_2 emissions for CO_2-EOR are examined in terms of the CO_2 emissions reduction benefits associated with selected approaches for jointly pursuing optimal CO_2-EOR and CO_2 storage. Benefits are characterized in terms of the life-cycle CO_2 emissions associated with the incremental oil produced from CO_2-EOR, compared to the volume of CO_2 stored as part of those operations.

Vertical (“Gravity Stable”) Flood Case Studies

In Section III, the use of crestal or up-dip injection to more efficiently recovery oil left behind following primary and/or secondary recovery operations was investigated. Four different CO_2 injection/oil production strategies for this vertical, gravity-stable flood were considered, highlighting the trade-offs associated with optimizing for oil production versus optimizing for CO_2 storage. As shown in Table 14, CO_2-EOR strategies that optimized oil production tended to store 55% to 60% of the life-cycle CO_2 emissions, while those that tended towards optimizing CO_2 storage were able to store more CO_2 than that emitted over the life cycle of the incremental production, with a total ratio of CO_2 stored to CO_2 emitted as high as 125%.

Table 14. Summary of Life-Cycle Analyses for the Vertical Flood Cases

	Cumulative Oil Produced	Stored CO_2	Total CO_2 Emissions*	CO_2 Stored/CO_2 Emitted
	(MMSTB)	(Gt)	(Gt)	(%)
Case 1	6.4	1.7	3.0	55%
Case 2	6.3	1.7	3.0	58%
Case 3	4.7	2.8	2.2	125%
Case 4	6.8	3.4	3.2	106%

* Includes emissions from operations, transport, refining, and consumption

Integrated Approaches Case Study

As discussed above, the combined CO_2-EOR and CO_2 storage project in Cenovus Energy's Weyburn CO_2-EOR project in Canada to ultimately inject 23 million metric tons in association with CO_2-EOR and another 32 million metric tons solely for purposes of CO_2 storage, totaling 55 million metric tons ultimately stored. Current estimates are that the Weyburn project is expected to produce at least 122 million barrels of incremental oil. Assuming 0.47 metric tons of CO_2 emitted per incremental barrel of oil produced, this amounts to about 57 million metric tons of CO_2 emitted. Based on these conditions, the project is forecast to store about 96% of the CO_2 that would be associated with the emissions from the production, transport, refining, and ultimate consumption of the incremental oil produced.

The other case study previously examined the combination of a vertical, gravity stable CO_2 flood with additional storage in an underlying aquifer. In previous presentation of this example, only the emissions associated with the combustion of the incremental oil were considered. Revising that assessment to include all of the life cycle CO_2 emissions from producing this oil from CO_2-EOR, which adds the emissions associated with CO_2 operations, crude transport, and refining (Table 15):

- Under just "next generation technology," CO_2 stored represents 74% of the life-cycle CO_2 emissions
- With "second generation" technology," without additional post-CO_2-EOR storage, CO_2 stored represents 90% of the life-cycle CO_2 emissions
- Including additional post- CO_2-EOR storage with "second generation" technology results in 29% more CO_2 stored than emitted.

Other Considerations

Finally, there should also be consideration to the advantages of producing oil using CO_2-EOR operations in an existing field, relative to oil produced using other technologies in other settings. Preparing an existing oilfield for CO_2-EOR operations does not require as large an energy (and capital) investment, since a significant portion of the infrastructure is already in place. This infrastructure can include existing wells and surface equipment, and an existing transportation network to handle the incremental oil production.

Table 15. Revised Case Study – Life Cycle Analyses of the Integration of "Next Generation" CO_2 Storage with EOR

	"Next Generation"	"Second Generation" CO_2-EOR & Storage		
	CO_2-EOR	CO_2-EOR	Storage	Total
CO_2 Storage (million metric tons)	32	76	33	109
Storage Capacity Utilization	22%	53%	23%	76%
Oil Recovery (million barrels)	92	180	-	180
% Carbon Neutral*	74%	90%	-	129%

* Includes the entire life-cycle CO_2 emissions, including those associated with CO_2-EOR operations, crude transport, refining, and the combustion of the incremental oil produced.

In fact, reduced 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 on production. The incremental development activities associated with CO_2-EOR include installing additional infrastructure necessary for CO_2 injection and recycling, and some additional new wells. The incremental environmental impacts associated with this additional development 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, project siting, infrastructure installation and field development.

Finally, 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. This local focus in environmental impact assessments tends to ignore the global benefits associated with the efficient use of existing operational infrastructure that can be achieved by maximizing development in existing oil-producing regions.[108] 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.

Thus, a critical choice for society in this context, at least in the near term, will be between crude oil produced through the application of CO_2-EOR and oil produced by traditional means. CO_2-EOR contributes to permanently storing CO_2 that would otherwise be emitted to the atmosphere, and has other environmental benefits.

[108] Hargis, Dean, "Environmental Resource Value of Industrial Infrastructure – The Hidden Environmental Cost of Restrictive Environmental Regulations in Existing Developing Areas," SPE Paper No. 73966 presented at the SPE International Conference on Health, Safety, and the Environment in Oil and Gas Exploration and Production, Kuala Lampur, Malaysia, March 20-22, 2002