NATIONAL ENERGY TECHNOLOGY LABORATORY

Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology

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Disclaimer

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Storing CO_2 with Next Generation CO_2-EOR Technology

1.0 Executive Summary

The purpose of this report is to examine and quantify the benefits of integrating CO_2 storage with "next generation" enhanced oil recovery. This work builds on previous analyses of currently practiced CO_2-EOR technology, as reported in "*Storing CO_2 with Enhanced Oil Recovery*"[1] and a series of "*Ten Basin-Oriented Reports*" [2].

CO_2 enhanced oil recovery (CO_2-EOR) offers the potential for storing significant volumes of carbon dioxide emissions while increasing domestic oil production. However, a number of technical challenges have prevented operators from achieving the full theoretical potential offered by integrated CO_2 storage and CO_2-EOR.

In this report, we identify four "next generation" CO_2-EOR technology options that can address some of the issues faced by current CO_2-EOR practices. In so doing, these technology options could help unlock greater potential to sequester CO_2 and increase domestic oil production. Additionally, we quantify both the amount of oil these "next generation" CO_2-EOR technologies could recover and the amount of CO_2 they would use and store.

The four "next generation" CO_2-EOR technology options we identify are: (1) Increasing the volume of CO_2 injected into the oil reservoir; (2) optimizing well design and placement, including adding infill wells, to achieve increased contact between the injected CO_2 and the oil reservoir; (3) improving the mobility ratio between the injected CO_2/water and the residual oil; and, (4) extending the miscibility range, thus helping more reservoirs achieve higher oil recovery efficiency.

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[1] "*Storing CO2 with Enhanced Oil Recovery*" report prepared for U.S. DOE/NETL, Office of Systems, Analyses and Planning, DOE/NETL-402/1312/02-07-08, February 7, 2008. http://www.netl.doe.gov/energy-analyses/pubs/Storing%20CO2%20w%20EOR_FINAL.pdf

[2] The Advanced Resources completed series of ten "basin studies" were the first to comprehensively address CO2 storage capacity from combining CO2 storage and CO2-EOR. These ten "basin studies" covered 22 of the oil producing states plus offshore Louisiana and included 1,581 large (>50 MMBbls OOIP) oil reservoirs, accounting for two thirds of U.S. oil production. These reports are available on the U.S. Department of Energy's web site at: http://www.fe.doe.gov/programs/oilgas/eor/Ten_Basin-Oriented_CO2-EOR_Assessments.html.

If implemented, these practices could dramatically increase the performance of CO_2-EOR technology and increase the volume of CO_2 that could be stored in the reservoirs when compared to current practices. Table 1 shows the improvements that "next generation" technology would bring to a sample CO_2-EOR project. In this instance, incremental oil recovery is improved by 75% and CO_2 purchase and storage is increased by 28%. In other reservoir settings, operators can take greater advantage of recycled CO_2, the amount of additional CO_2 purchased and stored with "next generation" technology is much less*.

Table 1. Economic Comparison of Alternative CO_2-EOR Technologies – Light Oil San Joaquin Basin Oil Reservoir*

	Current Application of "Best Practices"	"Next Generation" Technology**
Oil Recovery (Million Barrels)	381	665
Oil Recovery (% OOIP)	16%	28%
Project Life (years)	31	43
CapEx ($/Bbl)	$1.11	$2.43
CO_2 Costs ($/Bbl)	$23.52	$21.84
OpEx ($/Bbl)	$4.17	$5.76

*Assumes long-term oil price of $70 per barrel, adjusted for gravity and location differentials with CO2 costs linked to the oil price.
**Includes extra costs for applying "next generation" CO_2-EOR technology.
Purchased and stored CO2 volumes are 178 million metric tons in the "next generation" case compared to 139 million metric tons in the "best practices" case.

Our analysis suggests three major benefits would accrue from using integrated "next generation" CO_2 storage and enhanced oil recovery:

* The analysis performed for this report shows that "Next Generation" CO_2-EOR technology, when applied to all large oil reservoirs with economically recoverable oil resource, increases the amount of CO_2 purchased for CO_2-EOR operations by 11% compared to the best practices case. For more information, see Table 13, below.

- Application of this technology would provide 119 billion barrels of additional technically recoverable domestic oil (40% more than can be accomplished with application of current "best practices" for CO2 EOR). Of this technically recoverable resource, 54 to 70 billion barrels would be economically recoverable under the range of prices investigated in the study (38-45% more than can be accomplished with current application of "best practices" CO_2-EOR)*.

- Employing "next generation" CO_2-EOR technology would create a demand for 9 to 13 gigatons of captured CO_2. This volume of CO_2 is roughly equal to captured CO_2 emissions from 50 to 70 GWs of coal-fired power plants over a 30 year life*. Importantly, power companies could be paid up to 60 $/ton for captured CO_2.

- Third, the oil produced with injection of captured CO_2 emissions is 50 to 80% "carbon-free", after accounting for the difference between the carbon content in the incremental oil produced by EOR and the volume of CO_2 stored in the reservoir. If operators were incentivized to change their CO_2-EOR and storage design as well as to continue injecting CO_2 at the end of the project, they could inject and store more CO_2 into the reservoir than was contained in the incrementally produced oil, resulting in over 100% carbon free ("green") oil. A case study of pursuing "second generation" CO_2-EOR and CO_2 storage is presented in Appendix C.

The results from the study are based on Advanced Resources data base of over 2,000 large domestic oil reservoirs of which 1,111 were screened using a streamline reservoir simulation and a detailed cost and cash-flow based economic model.

Another important opportunity for CO_2-EOR is the "left behind" oil in residual oil zones (ROZs) that underlie the primary oil-bearing formations. Currently, only limited

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* The low price case uses an oil price of $50/barrel and a CO_2 price of $35/metric ton. The high price case uses an oil price of $100/barrel and a CO_2 price of $60/metric ton.

* Assuming 85% capacity factor and 34% efficiency. A 1GW power plant with these specifications would generate 223 billion kWh of electricity in thirty years (1GW * 85% * 8.76 (conversion between GW and billion kWh/year) * 30 years). With a CO_2 intensity of .94 million tons CO_2/BkWh (thermodynamic equivalency based on efficiency of power plant and emissions profile of coal) and 90% capture, this power plant could supply 188 million tons of CO_2 in 30 years.

data exist on the nature and location of ROZs; due to their great depths and low oil concentrations, they have not been economically feasible to explore. However, we believe that the target is large, on the order of 100 billion barrels, and that the ability to receive credits for sequestering CO_2 into ROZs could change producer incentives, making these areas profitable targets for exploration. ROZs could be efficiently developed using the CO_2 transport, distribution, and injection infrastructure built for EOR in the primary oil bearing formation. Most important, pursuing the oil and pore space in ROZs would greatly increase the amount of CO_2 stored in the target reservoir. The quantification of the additional oil recovery and CO_2 storage potential in ROZs is an area for further work.

Additionally, advanced drilling and modeling technology have made vertical ("gravity stable") CO_2 floods more of a possibility. Generally speaking, vertical floods produce crude oil at a slower rate than conventional floods but enable a higher amount of oil in place to be recovered. Furthermore, this alternative method would allow a much greater amount of CO_2 to be stored within the oil reservoir. Vertical floods are also an area for future study.

The next generation EOR technologies discussed in this report, specifically the option for increased volumes of CO_2 injection, will result in increased electricity consumption per unit of oil produced (and per CO_2 stored). NETL is currently undertaking a follow-on study to quantify the increased power use and related greenhouse gas emissions of any "next generation" CO_2-EOR.

This study defines the magnitude of the opportunity and the impacts that advanced technology can have. We have not evaluated in detail the CO_2 pipelines that will be needed to connect sources of captured CO_2 and EOR flood. There are some cases where pipeline transport may present a barrier to EOR deployment. The cost and delays associated with CO_2 pipeline infrastructure is the topic of a separate NETL study currently underway.

Table 2. Economically Recoverable Domestic Oil Resources from Applying "Next Generation" CO_2-EOR: National Totals at Base Case Economics*

Basin/Area	Incremental Technically Recoverable Oil* (Billion Barrels)		Incremental Economically Recoverable Oil** (Billion Barrels)	
	"Best Practices"	"Next Generation"	"Best Practices"	"Next Generation"
1. Alaska	12.4	12.4	9.5	9.5
2. California	6.3	10.0	5.4	8.1
3. Gulf Coast (AL, FL, MS, LA)	7	7.4	2.2	2.7
4. Mid-Continent (OK, AR, KS, NE)	10.6	17.0	5.6	8.8
5. Illinois/Michigan	1.2	3.2	0.5	1.7
6. Permian (W TX, NM)	15.9	28.0	7.1	15.1
7. Rockies (CO,UT,WY)	3.9	7.1	1.9	3.8
8. Texas, East/Central	17.6	20.0	8.3	9.9
9. Williston (MT, ND, SD)	2.5	5.2	0.5	0.6
10. Louisiana Offshore	5.8	5.8	3.9	3.9
11. Appalachia (WV, OH, KY, PA)	1.6	2.6	0.1	0.1
Total	84.8	118.7	45.0	64.4

*Incremental technically recoverable oil resources after subtracting 2.3 billion barrels already being developed with CO2-EOR.
**Base Case Economics use an oil price of $70 per barrel (constant, real) and a CO2 cost of $45 per metric ton ($2.38/Mcf), delivered at pressure to the field.

2.0 Background

2.1 Updated Reservoir and Economics Data

In January 2008, Advanced Resources International, with sponsorship by the U.S. Department of Energy's Office of Fossil Energy, issued a study entitled, "*Storing CO_2 with Enhanced Oil Recovery.*" This study examined the domestic oil recovery and CO_2 storage potential offered by widespread application of currently used "best practices" CO_2-EOR technology (In the *Storing CO_2 with CO_2 Enhanced Oil Recovery* report, the term "State of the Art" is the synonymous with the term "best practices" used in this report). It also synthesized the analysis previously contained in a series of ten basin reports, noted above.

This report builds on the reservoir data and CO_2-EOR performance provided in the above cited study "Storing CO_2 with Enhanced Oil Recovery" and includes an updated cost model and field-by-field reservoir modeling of applying "next generation" CO_2-EOR technology to more than 1,000 domestic oil reservoirs.

A brief description of the updated data and analytical work contained in this report is set forth below.

- A significant number, nearly 500, of additional oil reservoirs have been added to the data base, including oil reservoirs in the Appalachian Basin. The assessment now includes 2,012 oil reservoirs accounting for nearly three-quarters of the U.S. oil resource base in 27 states, Figure 1. These new oil reservoirs were made available for this study from a proprietary database owned by Advanced Resources;

- Improvements and updates have been made to the well spacing and CO_2 injection portions of the model. Oil field cost data have been updated and indexed to mid-year 2007. These updates and improvements are based on internal work undertaken by Advanced Resources; and

- An expanded set of oil prices and a revised oil price/CO_2 cost relationship have been incorporated into the economic analyses.

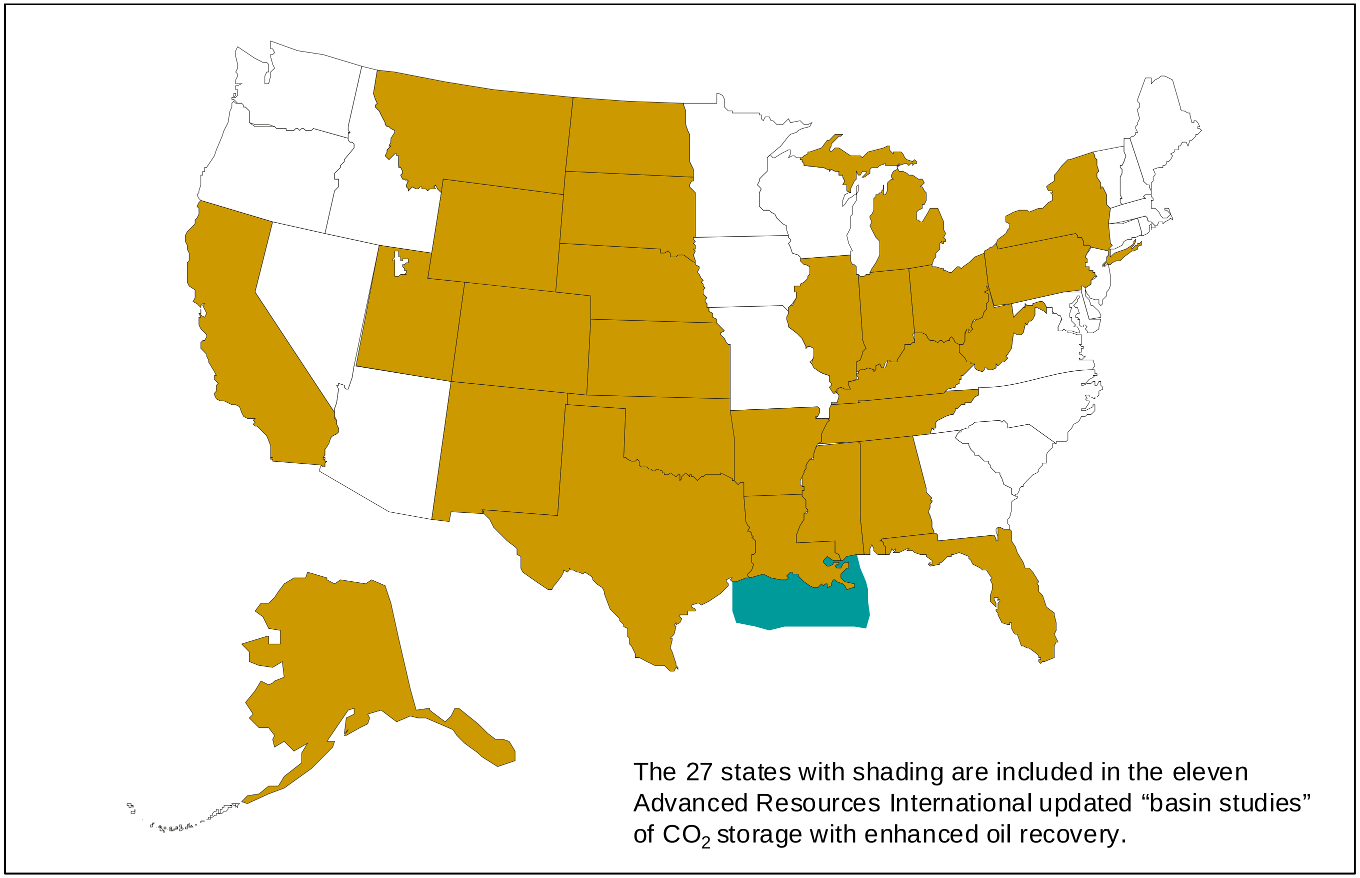

Figure 1. U.S. Basins/Regions Studied For Future CO_2 Storage and Enhanced Oil Recovery

2.2 Study Methodology

A six part methodology was used to assess the CO_2 storage and EOR potential of domestic oil reservoirs. The six steps were: (1) assembling and updating the Major Oil Reservoirs Data Base; (2) calculating the minimum miscibility pressure for applying CO_2 -EOR; (3) using minimum miscibility pressure and other criteria to screen reservoirs favorable for CO_2-EOR; (4) calculating oil recovery from applying “next generation” CO_2-EOR technology; (5) operating the updated cost and economic model; and, (6) performing economic and sensitivity analyses to understand how the combined effects of technology and oil prices impact the results of applying “next generation” CO_2-EOR storage technology.

To calculate the incremental oil produced by CO_2-EOR from the large domestic oil reservoirs, the study utilized the *CO_2-PROPHET* model. *CO_2-PROPHET* is a stream tube miscible flood predictive model that was first developed by the Texaco Exploration and Production Technology Department (EPTD) through a DOE Class I cost share program. The specific project was “Post Waterflood CO_2 Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir” (DOE Contract No. DE-FC22-93BC14960).

As part of ARI’s work on the series of Basin Studies reports mentioned above, the CO_2-PROPHET model was calibrated with an industry standard reservoir simulator, GEM. The primary reason for the calibration was to determine if alternative permeability distributions within a multi-layer reservoir and gravity override functionality, both absent in CO_2-PROPHET, might influence the calculation of oil recovery. *CO_2-PROPHET* assumes a fining upward permeability structure.

The models were calibrated by comparing their results from trial runs on the California San Joaquin Basin’ Elk Hills (Stevens) reservoir. The GEM model was run at alternate cases for reservoir permeability and oil gravity override to establish a range of oil recovery values against which the results from CO_2-PROPHET would be compared. The results indicated that that, in each case, oil recovery values from CO_2-PROPHET were between the oil recoveries from high and low cases run in the GEM model, suggesting the model was neither over nor under optimistic in its calculation of oil recovery.

Appendix A provides additional detail on the methodology used in this study.

2.3 Report Outline

The report begins with a summary presentation of the three topics central to analyzing the potential of integrated “next generation” CO_2-EOR and CO_2 storage technologies: (1) what is the size and nature of the domestic oil resource base; (2) how much of this resource base is recoverable with “next generation” CO_2-EOR; and, (3) what portion of this technically recoverable oil resource is economic under alternative oil prices and CO_2 costs? The report then examines the market demand for captured CO_2 emissions offered by the EOR industry.

A series of appendices provide supporting data and technical information for the analytical results discussed in the main report. Appendix A provides additional information on the study methodology. Appendix B contains additional detail on our cost and economics model. Appendix C provides a case study of “Second Generation” CO_2-EOR with advanced CO_2 storage.

3.0 The Domestic Oil Resource Base

The U.S. has a large oil resource base, on the order of 596 billion barrels originally in-place. About one-third of this oil resource base, 196 billion barrels, has been recovered or placed into proved reserves with existing primary and secondary oil recovery technologies. This leaves behind a massive target of 400 billion barrels of "technically stranded" oil, Figure 2*.

Table 3 provides a tabulation of the national in-place, conventionally recoverable and "stranded" oil in the eleven "basins" addressed by this study. The table shows that much of the "stranded" (remaining) oil resides in East and Central Texas (74 billion barrels), the Mid-Continent (66 billion barrels), and the Permian Basin of West Texas and New Mexico (62 billion barrels). California, Alaska, the Gulf Coast and the Rockies also have significant volumes of "stranded" oil.

The Advanced Resources' Major Oil Reservoirs Data Base of 2,012 distinct oil reservoirs contains 74% (437.8 billion barrels of Original Oil in Place (OOIP) out of the national total of 595.7 billion barrels of OOIP) of the domestic oil resource, Table 4. We scale our data up to the national level based on the ratio of oil production from our large oil reservoir database to EIA national oil production data.

The data base coverage for individual basins/areas ranges from 59% for the Mid-Continent to 97% for Alaska. As such, the Major Oil Reservoir Data Base provides a solid foundation for estimating the national oil recovery potential from CO_2-EOR.

* When less established domestic oil resources, such as undiscovered oil, tar sands, and oil trapped in residual oil zones are included, the "stranded" oil resource approaches 1,000 billion barrels. For further information on this topic see Chapter 3 (pages 183 and 184) of the recently issued National Petroleum Council report "Hard Truths, Facing the Hard Truths about Energy" July, 2007, http://www.npchardtruthsreport.org/

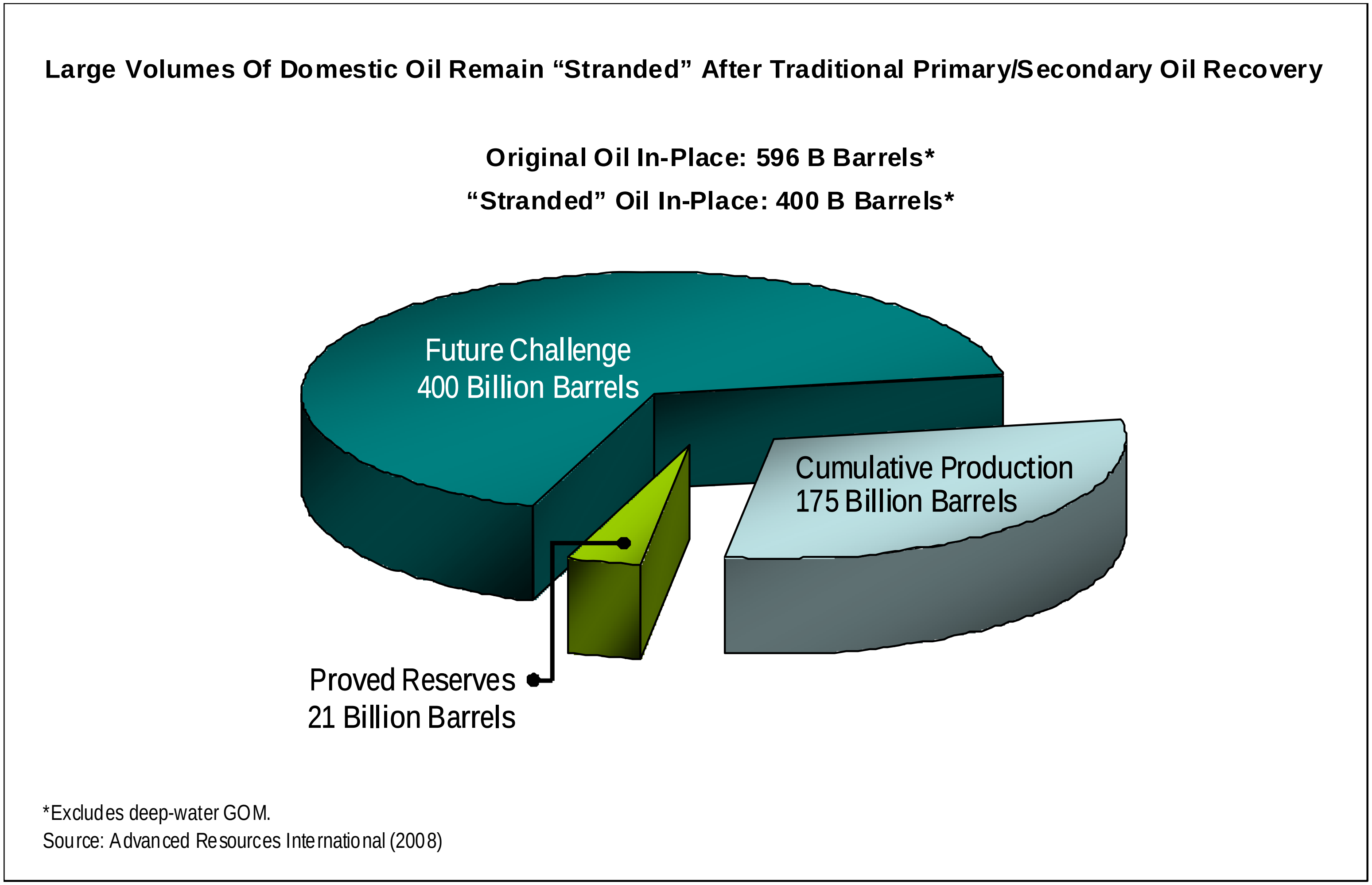

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Figure 2. The Domestic Oil Resource Base

Table 3. National In-Place, Conventionally Recoverable and "Stranded" Crude Oil Resources

Basin/Area	OOIP* (Billion Barrels)	Conventionally Recoverable (Billion Barrels)	Conventionally Recoverable % of OOIP	ROIP** "Stranded" (Billion Barrels)
1. Alaska	67.3	22.3	33%	45.0
2. California	83.3	26.0	31%	57.3
3. Gulf Coast (AL, FL, MS, LA)	44.4	16.9	38%	27.5
4. Mid-Continent (OK, AR, KS, NE)	89.6	24.0	27%	65.6
5. Illinois/Michigan	17.8	6.3	35%	11.5
6. Permian (W TX, NM)	95.4	33.7	35%	61.7
7. Rockies (CO,UT,WY)	33.6	11.0	33%	22.6
8. Texas, East/Central	109.0	35.4	32%	73.6
9. Williston (MT, ND, SD)	13.2	3.8	29%	9.4
10. Louisiana Offshore	28.1	12.4	44%	15.7
11. Appalachia (WV, OH, KY, PA)	14.0	3.9	28%	10.1
Total	595.7	195.7	33%	400.0

Table 4. Comparison of National and Data Base Domestic Oil Resource Base

Basin/Area	National Data OOIP* ** (Billion Barrels)	Major Oil Reservoirs Data Base OOIP* ** (Billion Barrels)	Data Base Coverage (%)
1. Alaska	67.3	65.4	97
2. California	83.3	75.2	90
3. Gulf Coast (AL, FL, MS, LA)	44.4	26.4	60
4. Mid-Continent (OK, AR, KS, NE)	89.6	53.1	59
5. Illinois/Michigan	17.8	12.0	67
6. Permian (W TX, NM)	95.4	72.4	76
7. Rockies (CO,UT,WY)	33.6	23.7	70
8. Texas, East/Central	109.0	67.4	62
9. Williston (MT, ND, SD)	13.2	9.4	71
10. Louisiana Offshore	28.1	22.2	79
11. Appalachia (WV, OH, KY, PA)	14.0	10.6	76
Total	595.7	437.8	74

*Original Oil In-Place, in all reservoirs in basin/area;
** Source: Advanced Resources Int'l, 2008. Figures are calculated from Advanced Resources' internal proprietary database of large domestic oil reservoirs. For more information, see Table 5 below.

Not all of the remaining domestic oil resource is technically amenable to CO_2-EOR. Favorable reservoir properties for CO_2-EOR include sufficiently deep formations with lighter (higher gravity) oil favorable for miscible CO_2-EOR. A portion of the shallower oil reservoirs with heavier (lower gravity) oil may be amenable to immiscible CO_2-EOR*. One of the "next generation" technology goals analyzed in this report is to help make more oil reservoirs suitable for miscible EOR.

Table 5 provides a basin/area level tabulation of the 2,012 reservoirs in the Major Oil Reservoirs Data Base, showing that 1,111 reservoirs (containing 319 billion barrels of OOIP) screened as being amenable to miscible and immiscible CO_2-EOR. More than half of the oil reservoirs in California, particularly the shallower heavy oil fields, are screened as unfavorable for CO_2-EOR while the great bulk (over 80%) of the oil reservoirs in the Permian Basin are screened as favorable for CO_2-EOR.

* For readers unfamiliar with the distinction between miscible and immiscible EOR, a more detailed description is given in section 4.1

Table 5. Major Oil Reservoirs Screened as Favorable for CO_2-EOR

Basin/Area	Major Oil Reservoirs Data Base	
	# of Total Reservoirs	# Favorable For CO_2-EOR
1. Alaska	42	32
2. California	187	86
3. Gulf Coast (AL,FL, MS, LA)	298	155
4. Mid-Continent (OK, AR, KS, NE)	246	102
5. Illinois/Michigan	172	72
6. Permian (W TX, NM)	228	190
7. Rockies (CO,UT,WY)	187	92
8. Texas, East/Central	213	161
9. Williston (MT, ND, SD)	95	54
10. Louisiana Offshore	156	99
11. Appalachia (WV, OH, KY, PA)	188	68
Total	2,012	1,111

4.0 Detailed Discussion of CO_2-EOR

4.1 Using CO_2-EOR to Recover "Stranded" Oil

Numerous scientific as well as practical reasons account for the large volume of "stranded" oil left unrecovered with primary and secondary methods. These include: oil that is bypassed due to poor waterflood sweep efficiency; oil that is physically unconnected to a wellbore; and, most importantly, oil that is trapped by viscous, capillary and interfacial tension forces as residual oil in the pore space.

The main mechanisms by which CO_2-EOR can recover this trapped oil is by creating, with the assistance of pressure, miscibility between the residual oil and the injected CO_2. Additional mechanisms such as viscosity reduction, oil swelling and improved reservoir contact further contribute to efficient oil recovery.

- Miscible CO2-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 after-waterflooding residual oil saturation in the reservoir's pore space. Figure 3 provides a one-dimensional schematic showing the various fluid phases existing in the reservoir and the dynamics of the CO_2 miscible process.

- Immiscible CO2-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 be mobilized and produced. In general, immiscible

CO_2-EOR is less efficient than miscible CO_2-EOR in recovering the oil remaining in the reservoir.

Currently available CO_2-EOR technologies, including both miscible and immiscible CO_2 injection, are in commercial use today. However, today's CO_2-EOR technologies still underperform compared to their theoretical potential as established by laboratory testing, reservoir simulation and a handful of forward-looking, highly instrumental projects. As evidence for underperformance, field data shows that currently practiced CO_2-EOR technology recovers only 5% to 20% of a reservoir's OOIP.

In response to the barriers faced by today's CO_2-EOR practices, we have set forth a set of "next generation" CO_2-EOR technology options that may help overcome some of the challenges faced by CO_2-EOR operators. These four options are: (1) increasing the volume of CO_2 injected into the oil reservoir to increase sweep efficiency; (2) optimizing well design and placement, including adding infill wells, to achieve increased contact between the injected CO_2 and the oil reservoir; (3) improving the mobility ratio between the injected CO_2/water and the residual oil; and, (4) extending the miscibility range, thus helping more reservoirs achieve higher oil recovery efficiency. If implemented, these practices could dramatically increase the efficiency of oil recovery from CO_2-EOR. They would also increase the amount of CO_2 that could be stored in the oil reservoirs. Reservoir analysis suggests that the combined application of, "next generation" technologies could increase the oil recovery from selected oil reservoirs by 50% (or more) relative to continued application of today's "best practices" CO_2-EOR technology.

The remainder of this section will discuss the performance of current CO_2-EOR technology, where it is being performed in the U.S. and how "next generation" technology could increase the amount of oil recovered from domestic fields.

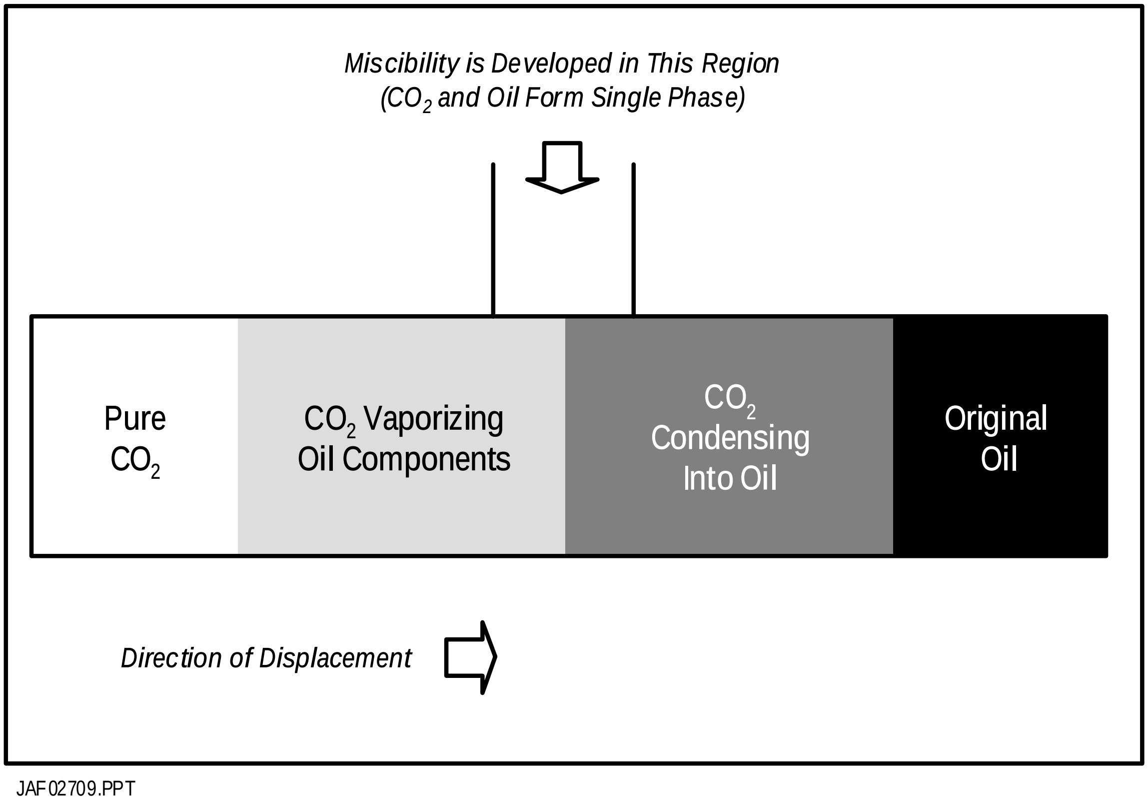

Figure 3. One-Dimensional Schematic Showing the CO_2 Miscible Process.

4.2 Current CO_2-EOR Activity and Production

According to the latest tabulation of CO_2-EOR activity in the U.S., in the 2008 EOR Survey published by the Oil and Gas Journal, approximately 250,000 barrels per day of incremental domestic oil is being produced by 100 CO_2-EOR projects, distributed broadly across the U.S. Since 1986, when comprehensive data were first made available about CO_2-EOR operations, over 1.3 billion barrels of incremental oil have been recovered using this technology.

Figure 4 provides the location of the currently active 101 CO_2-EOR projects (including the Weyburn project, in Canada), including their sources of CO_2 supply. For more detail on the CO_2 sources used by these operations, see Table 15. Figure 5 tracks the steady growth in CO_2-EOR production for the past 20 years, noting that although new activities are underway in the Gulf Coast and the Rockies, the great bulk of CO_2-EOR is still being produced from the Permian Basin.

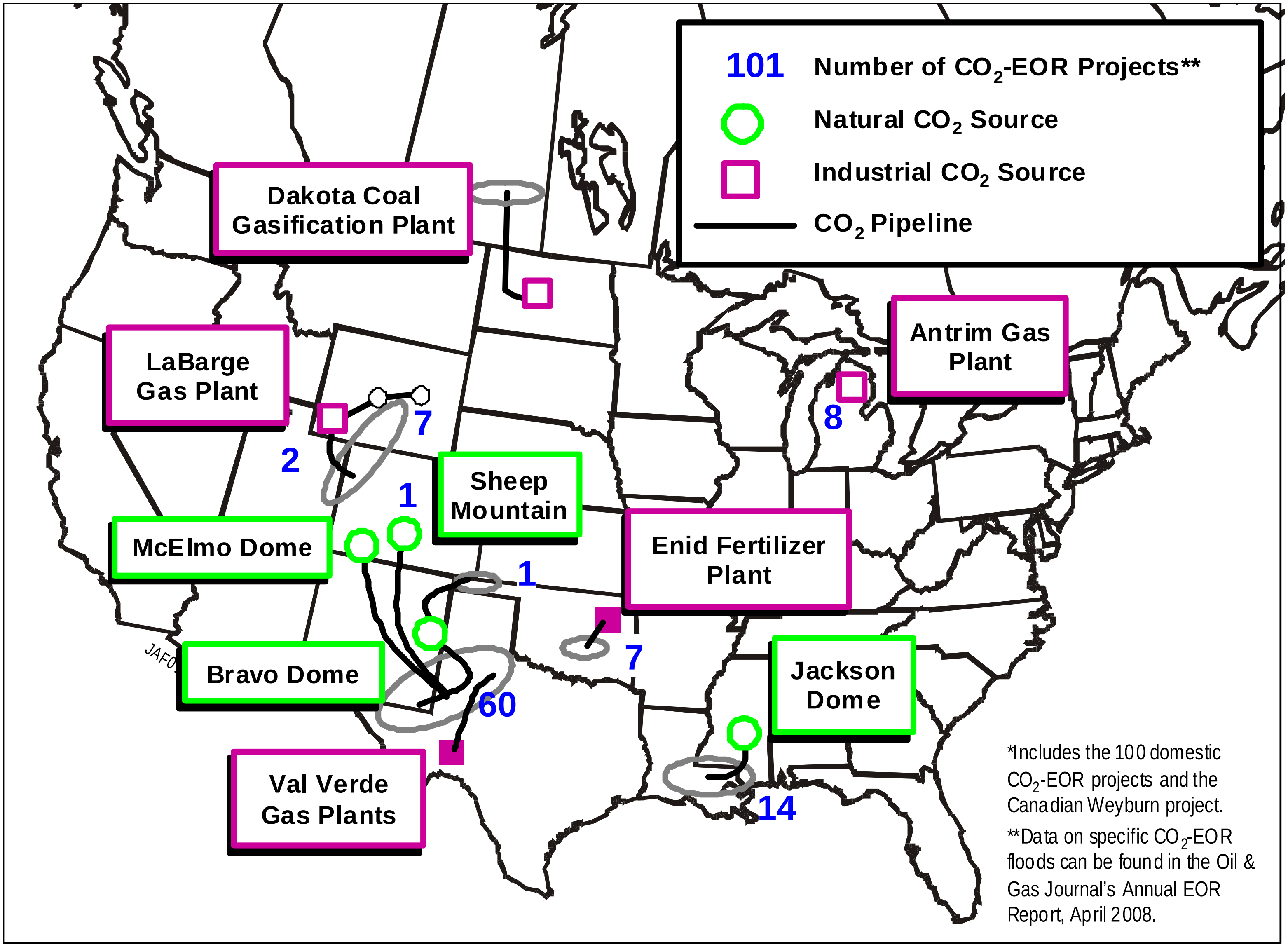

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Figure 4. U.S. CO_2-EOR Activity

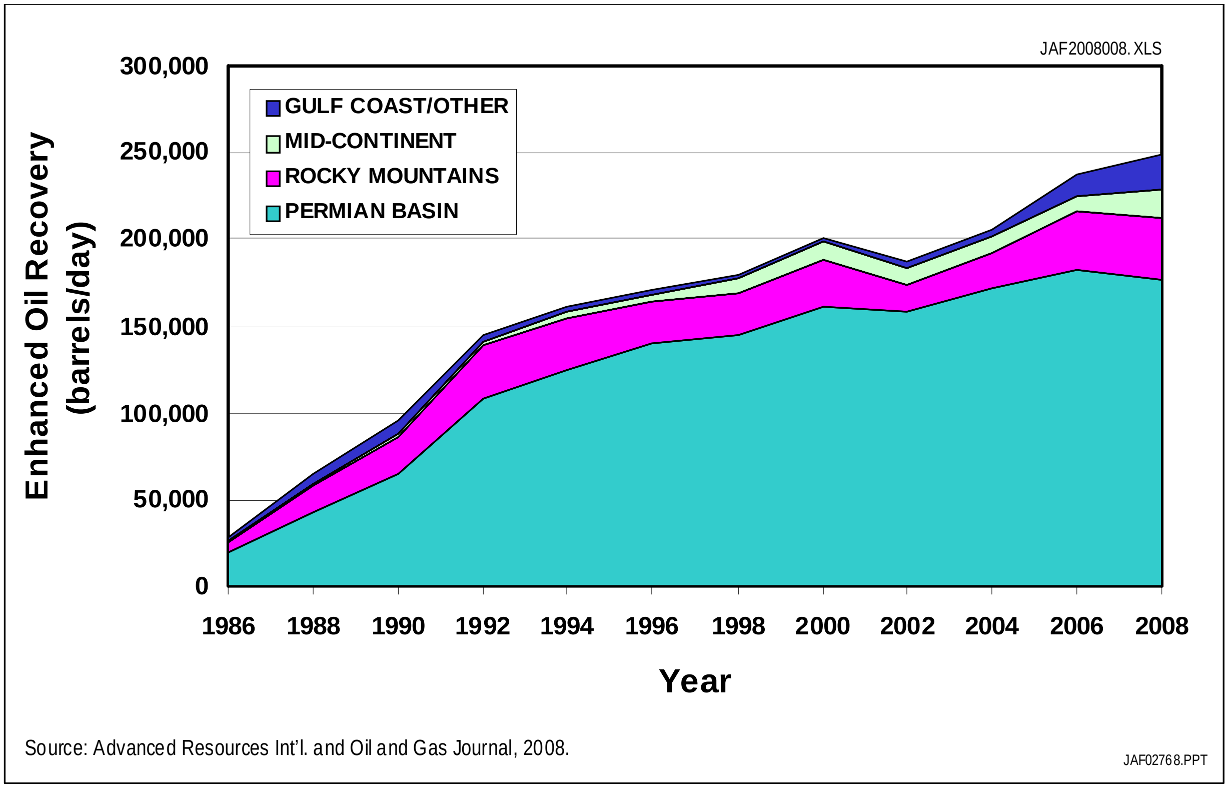


Figure 5. Growth of CO_2-EOR Production in the U.S.

4.3 Performance of Current CO_2-EOR Technology

Laboratory tests and reservoir modeling show that very high oil recovery efficiencies are theoretically possible using innovative applications of CO_2 enhanced oil recovery (CO_2-EOR). Under ideal conditions, gravity-stable laboratory core floods using high pressure CO_2 have recovered essentially all of the residual oil. Similarly, reservoir simulation models, using innovative well placement and process designs that facilitate contact of the majority of the reservoir's pore volume with CO_2, also show that high oil recovery efficiencies are possible.

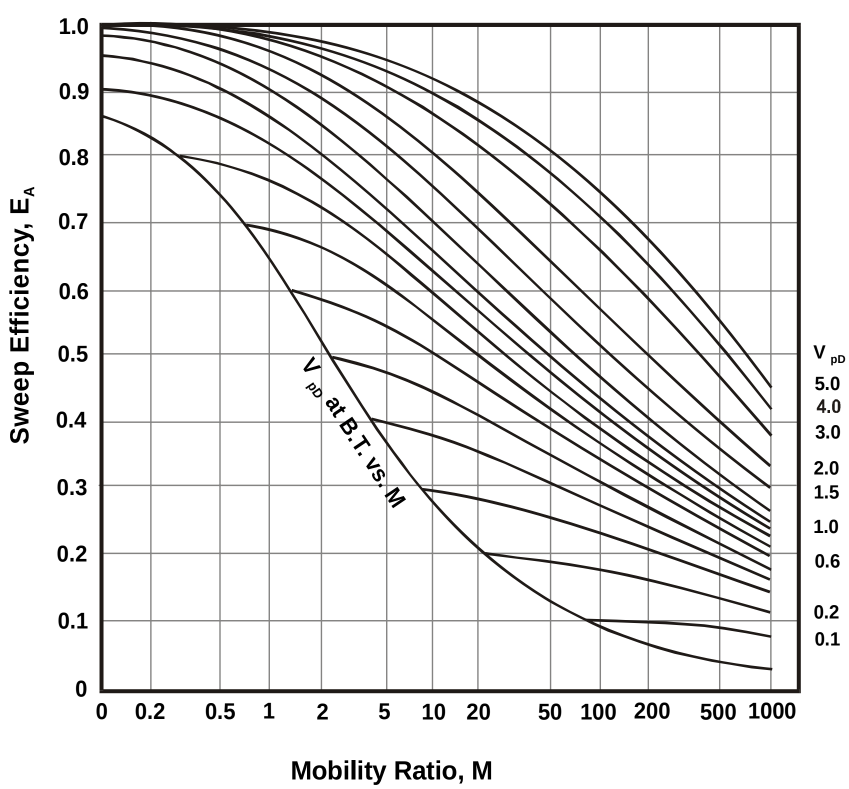
Though high oil recoveries are theoretically possible, they have not been reached in the field by ongoing CO_2-EOR projects. Geologically complex reservoir settings, combined with lack of reliable performance information or process control capability during the CO_2 flood, place serious barriers on achieving optimum oil recovery using CO_2-EOR.

4.3.1 Barriers to Improved CO_2-EOR Performance

The causes of less-than-optimum past-performance and modest oil recovery by currently used CO_2-EOR technologies include the following:

- The great majority of past CO_2 floods injected insufficient volumes of CO_2 for optimum oil recovery. This was due in part to high CO_2 costs relative to oil prices and the inability to control CO_2 flow through the reservoir. Figure 6 shows that low reservoir sweep efficiency results from using small volumes of CO_2 injection, particularly under conditions of high (unfavorable) mobility ratios. Table 6 provides an example of the relationship of CO_2 injection and oil recovery efficiency from an ideal, single layer oil reservoir, where CO_2 is used as the secondary recovery process.

Figure 6. Oil Recovery in Miscible Flooding for Five-Spot Well Patterns



Note: V_{pD} is displaceable fluid pore volumes of CO_2 injected.

Source: Claridge, E.L., "Prediction of Recovery in Unstable Miscible Displacement", SPEJ (April 1972).

Table 6. Example Oil Recovery Efficiency vs. HCPV of CO_2 Injection*

Injected CO_2 (HCPV)	Injected CO_2 (Barrels)	Reservoir Sweep Efficiency (Fraction)	Oil Recovery (Barrels)	Oil Recovery Efficiency (%)
0.40	156,400	0.345	117,300	32.2
0.60	234,600	0.440	149,600	41.1
0.80	312,800	0.515	175,100	48.1
1.00	391,000	0.570	193,800	53.2
1.50	586,500	0.670	227,800	62.6

Note: As a "rule of thumb", 2 Mcf of CO_2 at "typical" reservoir pressure and temperature conditions occupies one reservoir barrel of CO_2 .
*Oil recovery efficiency measures the amount of residual oil produced by CO2 flood
Source: Adapted by Advanced Resources Int'l from "Enhanced Oil Recovery", D.W. Green and G. P. Willhite, SPE, 1998.

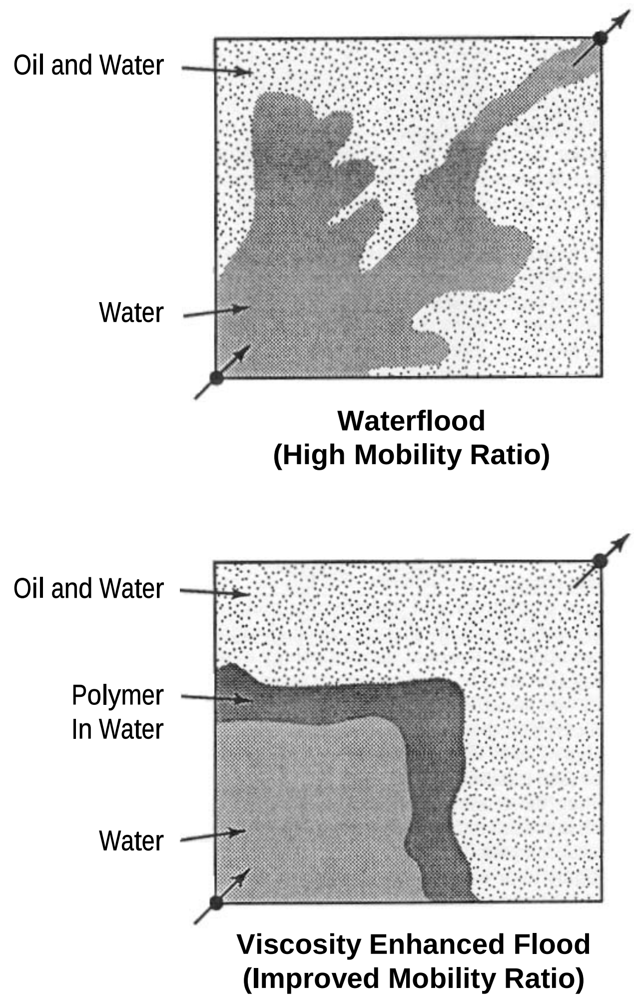
Table 6 provides a useful methodology for assessing how much CO2 to inject and what time period. While the case example, adapted from a classical reservoir engineering textbook, represents an ideal reservoir setting, it does illustrate that the injection of the final 0.5 HCPV of CO2, equal to 391,000 Mcf or 195,500 reservoir barrels of CO_2, leads to recovery of 34,000 additional barrels of oil with a CO2 to oil ratio of 11.5 Mcf per barrel. With the bulk of this injected CO_2 (80%) being recycled CO_2 (with a cost of \$0.70/Mcf), and the rest (20%) being purchased CO_2 (with a cost of \$2.58/Mcf), this would entail injecting about \$12 of CO2 to recover one barrel of \$70 oil (before royalties, taxes and incremental operating costs).

- In many of the previous CO_2 floods, the injected CO_2 achieved only limited contact with the residual oil in the reservoir (poor sweep efficiency). This was due to a variety of causes, including: gravity override by the less dense CO_2; viscous fingering of the CO_2 through the reservoir's oil; and channeling of the CO_2 in highly heterogeneous reservoirs. Figure 7 shows how a high mobility ratio for the

* Hydrocarbon Pore Volume (HCPV) is a measure of the volume in a reservoir available for hydrocarbon intrusion.

injected fluid can lead to viscous fingering and how addition of viscosity enhancers would help reduce this problem in a traditional waterflood.

Figure 7. Schematic of Macroscopic Displacement Efficiency Improvement with Polymer-Augmented Waterflooding (Quarter of a Five-Spot Pattern)



Source: Adapted by Advanced Resources Int'l from "Enhanced Oil Recovery", D.W. Green and G. P. Willhite, SPE, 1998.

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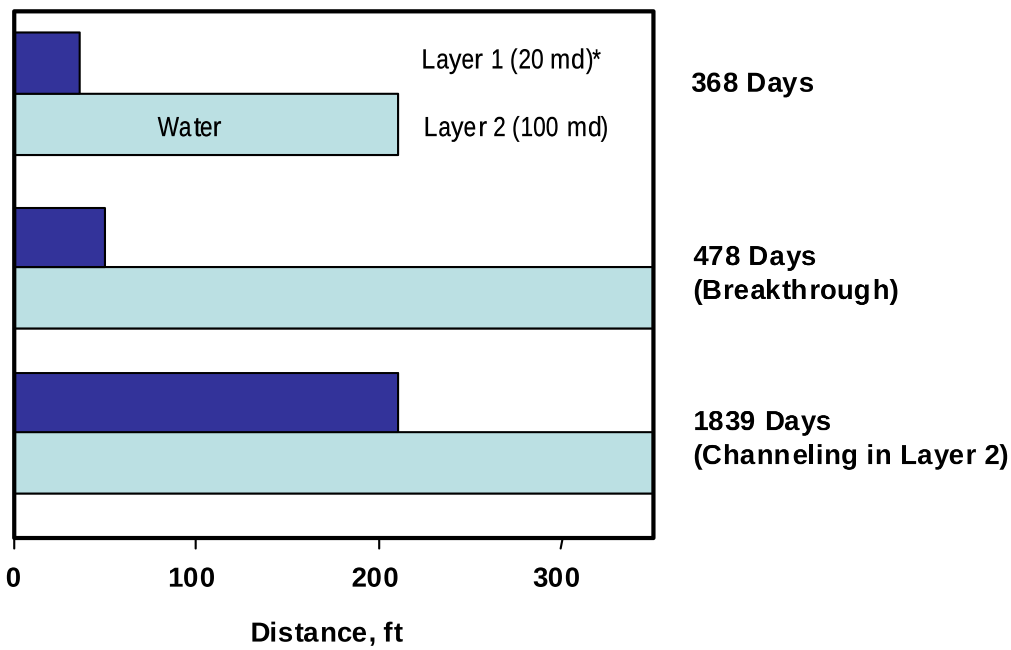
- Analysis of past CO_2 floods also shows that, in many cases, the CO_2-EOR project mobilized only a modest portion of the residual oil (poor displacement efficiency) due to lack of effective miscibility between the injected CO_2 and the reservoir's oil, caused by unexpected pressure declines in portions of the reservoir and limitations in injection and production well operating pressures.

- An often overlooked but important cause of poor CO_2-EOR performance is operators' inability to efficiently target injected CO_2 to preferred (high residual oil) reservoir strata and then capture and produce the mobilized oil. Figure 8 shows how the lower permeability portion of the reservoir strata (Layer 1) is less efficiently swept by a waterflood, leaving behind much higher residual oil saturations in this layer of the oil reservoir.

- Finally, a variety of other operating issues have contributed toward less-than-optimum performance, including the inability to "manage and control" the CO_2 flood for lack of real-time process and performance information from within the oil reservoir.



*Millidarcy (md) is a measure of permeability.
Source: Adapted by Advanced Resources Int'l from "Enhanced Oil Recovery", D.W. Green and G. P. Willhite, SPE, 1998.

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Figure 8. Relative Location of the Water Front in a Layered Reservoir

4.3.2 Evolution in CO_2 Flooding Practices

Considerable evolution has occurred in the design and implementation of CO_2-EOR technology since it was first introduced. Notable changes include: (1) use of much larger (up to 1 HCPV) volumes of CO_2; (2) incorporation of tapered WAG (water alternating with gas) and other methods for mobility control; and (3) application of advanced well drilling and completion strategies to better contact previously bypassed oil. As a result, the oil recovery efficiencies of today's better designed and operated CO_2-EOR projects have steadily improved.

- Figure 9 provides the scientific and practical basis for using larger volumes of injected CO_2.

- Figure 10, using information from Occidental Petroleum (Oxy Permian), provides a 17 year snapshot of the evolution of the "industry standard" for the most effective volume of CO_2 injection (the optimum "slug size").

- Figure 11, illustrates how rigorous monitoring and well remediation can be used to target injected CO_2 to reservoir strata with high remaining oil saturation, helping reduce ineffective CO_2 channeling.

The oil recovery calculations reported in our previous study, "*Storing CO_2 with Enhanced Oil Recovery",* are based on the practices of these forward thinking firms. As such, the calculated oil recovery efficiencies expected from CO_2-EOR are somewhat higher than have been achieved by older CO_2-EOR projects. However, they represent the "best practices" being employed by technically sophisticated operations and current CO_2-EOR projects. The "next generation" technology goals analyzed in this report build on the successes of these forward thinking firms such as Occidental Petroleum, to further address limitations of current CO_2-EOR performance

Actual field projects confirm that injection of higher volumes of CO_2 lead to higher oil recovery.

Source: SPE 24928 (1992)

The CO_2-EOR WAG project at Means (San Andres Unit) was implemented as part of an integrated reservoir development plan and involve the drilling of 205 new producers and 158 new injectors.

Initial objective was to inject 260 Bcf of CO_2, equal to 55% HCPV, (0.4 HCPV purchased; 0.15 HCPV recycled) at a 2:1 WAG ratio.

Latest objective is to inject 480 Bcf (~1 HCPV) of CO_2. Increasing the volume of injected CO_2 can also be achieved by increasing the rate of CO_2 injection (not shown in this chart).

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Figure 9. Science Behind Volume of CO_2 Injection and Oil Recovery Efficiency: Actual Practice

Eastern Denver Unit (Wasson Oil Field) CO_2-EOR Project	Started
Start of CO_2 injection in EDU with 40% HCPV CO_2 slug size	1984
EDU WAG & start off CO_2 injection in WAC, FIA, B8 FIA	1989
Non performing FIA patterns stopped (~20% HCPV CO_2 slug size)	1992
EDU 40% to 60% HCPV CO_2 slug size increase approved	1994
EDU 60% to 80% HCPV CO_2 slug size increase approved	1996
EDU 80% to 100% HCPV CO_2 slug size increase approved	2001

Source: OXY Permian 2006

Occidental Petroleum (Oxy Permian) is the industry leader for CO2-EOR, in terms of number of large projects, volume of CO_2 used and volumes of oil production.

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Figure 10. Evolution of "Industry Standard" for Volume CO_2 Injection ("Slug Size")

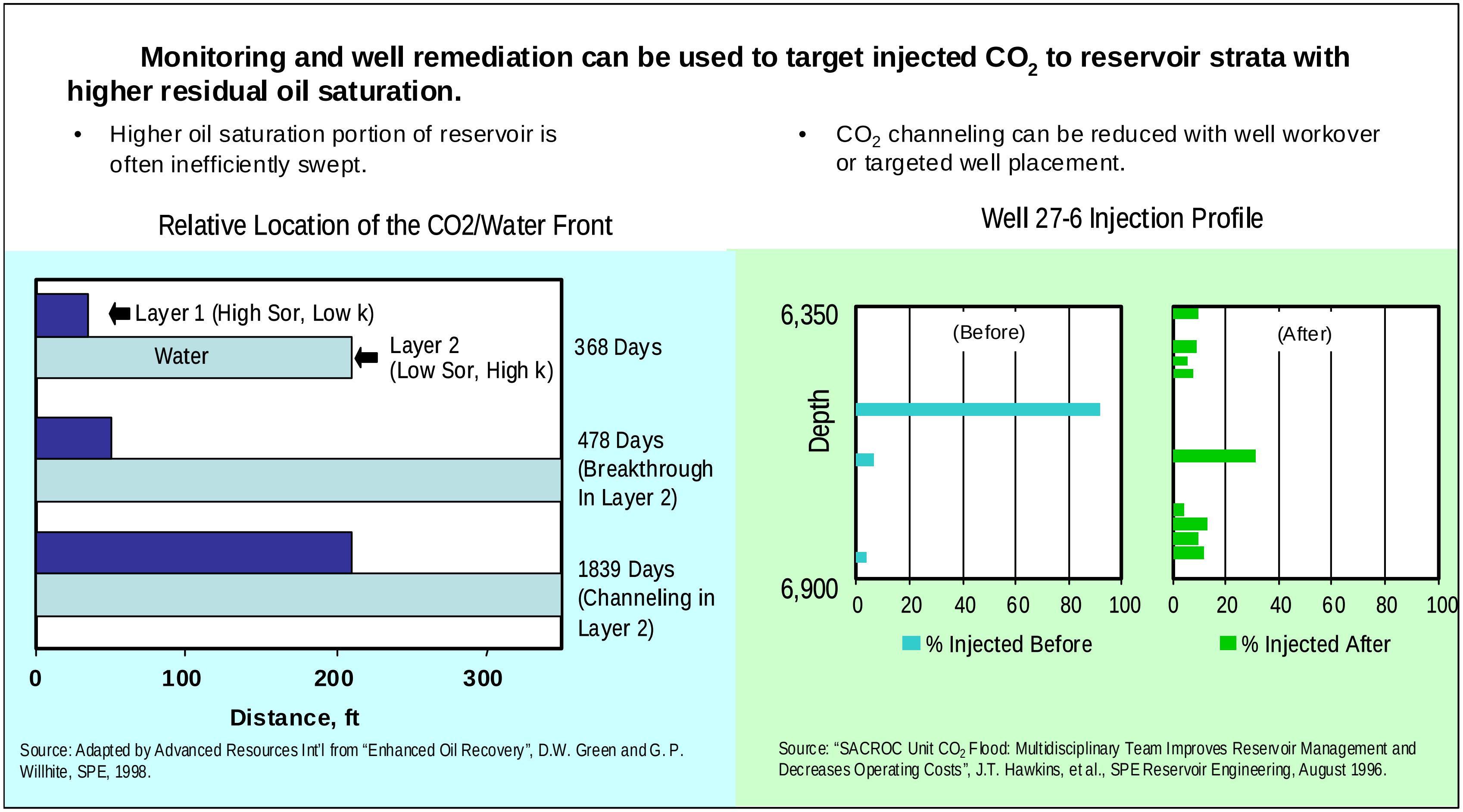

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Figure 11. Overcoming the Effects of Geologic Complexity on CO_2-EOR Performance

4.4. "Next Generation" CO_2-EOR Technology

For this report, we examine four specific "next generation" CO_2-EOR technology options. These options involve: 1) Increasing the volume of CO_2 injected, 2) Optimizing well design and placement, 3) Improving the mobility ratio, and 4) Extending miscibility. For each case, there is a posited "achievable level of process performance", such as contacting more of the reservoir's pore volume using innovative flood and well design (including conducting a gravity-stable CO_2 flood); increasing the viscosity of the injected water used in the CO_2-WAG process; and, reducing the minimum miscibility pressure for deep, heavy oil and shallow, light oil reservoirs. Below, we discuss each technology application in detail and investigate how these options increase the performance of existing CO_2-EOR technologies.

Importantly, each of these improved levels of process design and field performance represents a topic for substantial future R&D in CO_2-EOR.

4.4.1 Overview of Next Generation Technology Performance

Technology Option #1. Increasing CO_2 Injection.

The first "next generation" technology option involves increasing CO_2 injection volumes from 1.0 HCPV, currently used in "best practices", to 1.5 HCPV. Higher HCPV's of injected CO_2 enable more of the reservoir's residual oil to be contacted (and even multiply contacted) by the injected CO_2. However, progressively longer CO_2 injection periods, longer overall project length and higher gross CO_2 to oil ratios are involved in the higher volume CO_2 injection cases. Field operators will need to carefully consider this option to evaluate its cost effectiveness.

In the past, the combination of high CO_2 costs and low oil prices led operators to use small-volume injections of CO_2 (traditional 0.4 HCPV) to maximize profitability. This low volume CO_2 injection strategy was also selected because field 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 CO_2. However, these increased CO_2 volumes would 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.

Technology Option #2. Innovative Flood Design and Well Placement.

Technology Option # 2 assumes that through optimized well design and placement more of the residual oil in each reservoir would be contacted. More specifically, 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) portions of the oil reservoir are optimally contacted by the injected CO_2.

Examples of such innovative 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 spacings.

To model Technology Option #2, we assume that one new vertical production well would be added to each pattern. This well would produce from previously bypassed or poorly contacted portions of the reservoir. (The “basic” model assumes that each CO_2-EOR pattern has one production and one injection well. The “next generation” version of the model adds one well to the pattern that targets the poorly contacted reservoir area in the “basic model”).

Technology Option #3. Improving the Mobility Ratio.

Technology Option # 3 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, such as those being pursued in the joint DOE/University of Pittsburgh research program*, could theoretically further improve performance.) The viscosity of the injected water can be changed by adding polymers or other viscosity-enhancing materials.

To model Technology Option # 3, we assume the viscosity of injected water is increased to 3cps*, or three times the viscosity of normal water.

Technology Option #4. Extending Miscibility.

Technology Option # 4 assumes that "miscibility extenders" are added to CO_2-EOR process which reduce minimum miscibility pressure requirements by 500psi (pounds per square inch). Examples of miscibility enhancing agents would include: addition of Liquefied Petroleum Gasses (LPG) 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 (using *PROPHET**) 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. Our findings show that successful application of Technology Option # 4 could allow 21 previously immiscible fields to become suitable for miscible CO_2-EOR operations.

Technology Option # 5. Integrating Application of "Next Generation" Technology Options

The maximum benefits, in terms of increased oil recovery, accrue when these four individual "next generation" technology options are applied jointly, part of an integrated field operations strategy.

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* DOE Program Reference Number: DE-FC26-01BC15315
* A centipoise (cp) is the unit of measure for dynamic viscosity. Water has cp value of 1 at 20 degrees Celsius.
* For more information on the PROPHET model, see Appendix A

4.5. Examining the Costs and Benefits of Using "Next Generation" CO_2-EOR Technology

Insights on the costs and benefits of conducting an integrated "next generation" CO_2-EOR flood may be gained by examining the changes in oil production, capital investment, CO_2 requirements, and operating costs between using today's "best practices" and using, in an integrated fashion, "next generation" CO2-EOR technologies. The example set forth is a light oil field in the San Joaquin Basin in California, Table 7. Additional project detail is given in Table 8. An abbreviated project cashflow, showing the first 10 years of the project's operation, is shown in Figures 12 and 13.

Appendix B provides discussion of the cost and economic model that underlies the cost and performance information presented in Tables 7 and 8.

Table 7. Economic Comparison of Alternative CO_2-EOR Technologies – Light Oil San Joaquin Basin Oil Reservoir

	Current Application of "Best Practices"	"Next Generation" Technology*
Oil Recovery (Million Barrels)	381	665
Oil Recovery (% OOIP)	16%	28%
Project Life (years)	31	43
CapEx ($/Bbl)	$1.11	$2.43
CO_2 Costs ($/Bbl)	$23.52	$21.84
OpEx ($/Bbl)	$4.17	$5.76

*Includes extra costs for applying "next generation" CO_2-EOR technology.
**Assumes long-term oil price of $70 per barrel, adjusted for gravity and location differentials, and $45/metric ton of CO_2 .

Table 8. Economic Comparison of Alternative CO_2-EOR Technologies Applied to the San Joaquin Light Oil Field*

	Currently Used "Best Practices"	Application of "Next Generation" CO_2-EOR Technologies
OIL RECOVERY (Million Barrels)	381	665
% OOIP	16%	28%
Project Life (years)	31	43
CAPITAL INVESTMENT		
Basic Cap Ex	$423	$423
Additional Wells	-	$1094
Larger CO_2 Recycle Plant	-	$17
Process Control Measurements and Feedback	-	$80
Total	$423	$1614
CO_2 COSTS		
Purchased CO_2	$6,239	$7,985
Recycled**	$4,040	$6,465
Total	$10,279	$14,450
CO_2 USAGE		
CO_2 Purchased/Barrel of Oil Produced (tons/barrel)	0.36	0.27
OPERATING AND MAINTENANCE		
Basic Op Ex	$1,561	$1,561
Additional OpEx and Fluid Lifting	-	$1,127
Viscosity Enhancement and Mobility Control	-	$1,080
Integrated Project Management Team	-	$65
Total	$1,561	$3,833

* Figures in millions of 2006 dollars, unless otherwise noted

* Both the "best practices" and "next generation" are injecting 100% recycled CO_2 by the end of the project. For information about total volumes of CO_2 used and recycled in this example, see below.

Field Cashflow Model		Next Generation	Pattern		Field				
State	CA	San Joaquin	Active Injectors Used	1.00	Active Injectors Used	125			
Field	ELK HILLS		Active Producers Converted	-	Active Producers Converted	0	0	Total Injectors Required	
Formation			New Injectors Needed	-	New Injectors Needed	0		125	
Depth	5500		New Producers Needed	-	New Producers Needed	0		Total Producers Required	
Distance from Trunkline	10	miles	Active Producers Used	1.19	Active Producers Used	148		148	
# of Patterns	125.00		In-active Injectors Used	-	In-active Injectors Used	0		Total Next Gen Injectors Required	
Miscibility:	Miscible		In-active Producers Converted	-	In-active Producers Converted	0	0	0	
			In-active Producers Used	-	In-active Producers Used	0		Total Next Gen Producers Required	
			Plugged and Abandoned Wells	6.85	Plugged and Abandoned Wells	856		148	

		0	1	2	3	4	5	6	7	8	9	10
CO2 Injection (MMcf)			76,134	152,266	228,400	304,531	380,666	380,666	380,666	380,666	380,666	380,666
H2O Injection (Mbw)			15,205	30,408	45,613	60,815	76,020	76,018	76,020	76,018	76,020	76,018
Oil Production (Mbbl)			4,177	10,527	21,514	29,993	37,669	40,919	41,095	35,530	31,846	28,721
H2O Production (MBw)			39,548	75,303	98,951	119,541	138,450	116,896	97,979	91,220	87,221	85,130
CO2 Production (MMcf)			-	59	9,647	36,420	70,448	107,814	151,563	190,369	215,450	233,780
CO2 Purchased (MMcf)			76,134	152,206	218,753	268,111	310,217	272,852	229,103	190,297	165,216	146,886
CO2 Recycled (MMcf)			-	59	9,647	36,420	70,448	107,814	151,563	190,369	215,450	233,780
Oil Price ($/Bbl)	**$ 70.00**		$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00
Gravity Adjustment	**35**		$ 68.25	$ 68.25	$ 68.25	$ 68.25	$ 68.25	$ 68.25	$ 68.25	$ 68.25	$ 68.25	$ 68.25
Gross Revenues ($M)			$ 285,071	$ 718,492	$ 1,468,329	$ 2,047,024	$ 2,570,918	$ 2,792,744	$ 2,804,708	$ 2,424,937	$ 2,173,499	$ 1,960,185
Royalty ($M)	**-12.5%**		$ (35,634)	$ (89,812)	$ (183,541)	$ (255,878)	$ (321,365)	$ (349,093)	$ (350,589)	$ (303,117)	$ (271,687)	$ (245,023)
Severance Taxes ($M)	**-2.0%**		$ (4,989)	$ (12,574)	$ (25,696)	$ (35,823)	$ (44,991)	$ (48,873)	$ (49,082)	$ (42,436)	$ (38,036)	$ (34,303)
Ad Valorum ($M)	**0.0%**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ 244,448	$ 616,107	$ 1,259,092	$ 1,755,323	$ 2,204,562	$ 2,394,778	$ 2,405,037	$ 2,079,384	$ 1,863,775	$ 1,680,858
Capital Costs ($M)												
New Well - D&C		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
New Well - Next Generation D&C		$ (165,817)	$ (165,817)	$ (165,817)	$ (165,817)	$ (165,817)	$ -	$ -	$ -	$ -	$ -	
Reworks - Producers to Producers		$ (3,116)	$ (3,116)	$ (3,116)	$ (3,116)	$ (3,116)	$ -	$ -	$ -	$ -	$ -	
Reworks - Producers to Injectors		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Reworks - Injectors to Injectors		$ (2,625)	$ (2,625)	$ (2,625)	$ (2,625)	$ (2,625)	$ -	$ -	$ -	$ -	$ -	
Surface Equipment (new wells only)		$ (7,136)	$ (7,136)	$ (7,136)	$ (7,136)	$ (7,136)	$ -	$ -	$ -	$ -	$ -	
CO2 Recycling Plant	2	$ -	$ (262,068)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (3,150)										
Plugging Costs		$ (64,173)										
Capital Costs		$ (246,017)	$ (440,762)	$ (178,694)	$ (178,694)	$ (178,694)	$ -	$ -	$ -	$ -	$ -	$ -
Next Generation Capex	**10%**	$ (24,602)	$ (44,076)	$ (17,869)	$ (17,869)	$ (17,869)	$ -	$ -	$ -	$ -	$ -	$ -
Cap Ex G&A	**20%**	$ (54,124)	$ (96,968)	$ (39,313)	$ (39,313)	$ (39,313)	$ -	$ -	$ -	$ -	$ -	$ -
Total Capex		$ (324,742)	$ (581,806)	$ (235,876)	$ (235,876)	$ (235,876)	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)												
CO2 Purchased ($M)			$ (181,200)	$ (362,251)	$ (520,632)	$ (638,104)	$ (738,317)	$ (649,387)	$ (545,265)	$ (452,907)	$ (393,213)	$ (349,589)
CO2 Recycled ($M)			$ -	$ (42)	$ (6,753)	$ (25,494)	$ (49,314)	$ (75,470)	$ (106,094)	$ (133,258)	$ (150,815)	$ (163,646)
Total CO2 Cost ($M)			$ (181,200)	$ (362,292)	$ (527,385)	$ (663,598)	$ (787,631)	$ (724,857)	$ (651,359)	$ (586,165)	$ (544,028)	$ (513,234)
O&M Costs ($M)												
Operating & Maintenance ($M)	1		$ (3,323)	$ (6,647)	$ (9,970)	$ (13,293)	$ (16,616)	$ (16,616)	$ (16,616)	$ (16,616)	$ (16,616)	$ (16,616)
Operating & Maintenance Next Gen	**10%**		$ (332)	$ (665)	$ (997)	$ (1,329)	$ (1,662)	$ (1,662)	$ (1,662)	$ (1,662)	$ (1,662)	$ (1,662)
Lifting Costs ($M)			$ (19,402)	$ (38,226)	$ (54,385)	$ (68,558)	$ (81,844)	$ (75,313)	$ (68,626)	$ (64,229)	$ (61,488)	$ (59,626)
G&A	**20%**		(4,545)	(8,975)	(12,871)	(16,370)	(19,692)	(18,386)	(17,049)	(16,169)	(15,621)	(15,249)
Total O&M Costs			$ (27,603)	$ (54,512)	$ (78,223)	$ (99,550)	$ (119,814)	$ (111,977)	$ (103,953)	$ (98,676)	$ (95,387)	$ (93,153)
Net Cash Flow ($M)		$ (324,742)	$ (546,161)	$ (36,573)	$ 417,608	$ 756,299	$ 1,297,117	$ 1,557,945	$ 1,649,725	$ 1,394,543	$ 1,224,360	$ 1,074,471
Cum. Cash Flow		$ (324,742)	$ (870,903)	$ (907,476)	$ (489,867)	$ 266,432	$ 1,563,549	$ 3,121,493	$ 4,771,218	$ 6,165,762	$ 7,390,122	$ 8,464,593
Discount Factor	**25%**	1.00	0.80	0.64	0.51	0.41	0.33	0.26	0.21	0.17	0.13	0.11
Disc. Net Cash Flow		$ (324,742)	$ (436,929)	$ (23,407)	$ 213,816	$ 309,780	$ 425,039	$ 408,406	$ 345,972	$ 233,966	$ 164,331	$ 115,370
Disc. Cum Cash Flow		$ (324,742)	$ (761,671)	$ (785,077)	$ (571,262)	$ (261,482)	$ 163,557	$ 571,963	$ 917,936	$ 1,151,901	$ 1,316,232	$ 1,431,603
NPV (BTx)	25%	$1,748,197										
NPV (BTx)	20%	$ 2,600,608										
NPV (BTx)	15%	$ 3,928,813										
NPV (BTx)	10%	$ 6,145,737										
IRR (BTx)		54.23%										

Figure 12: Abbreviated Sample CO_2-EOR Project Cashflow

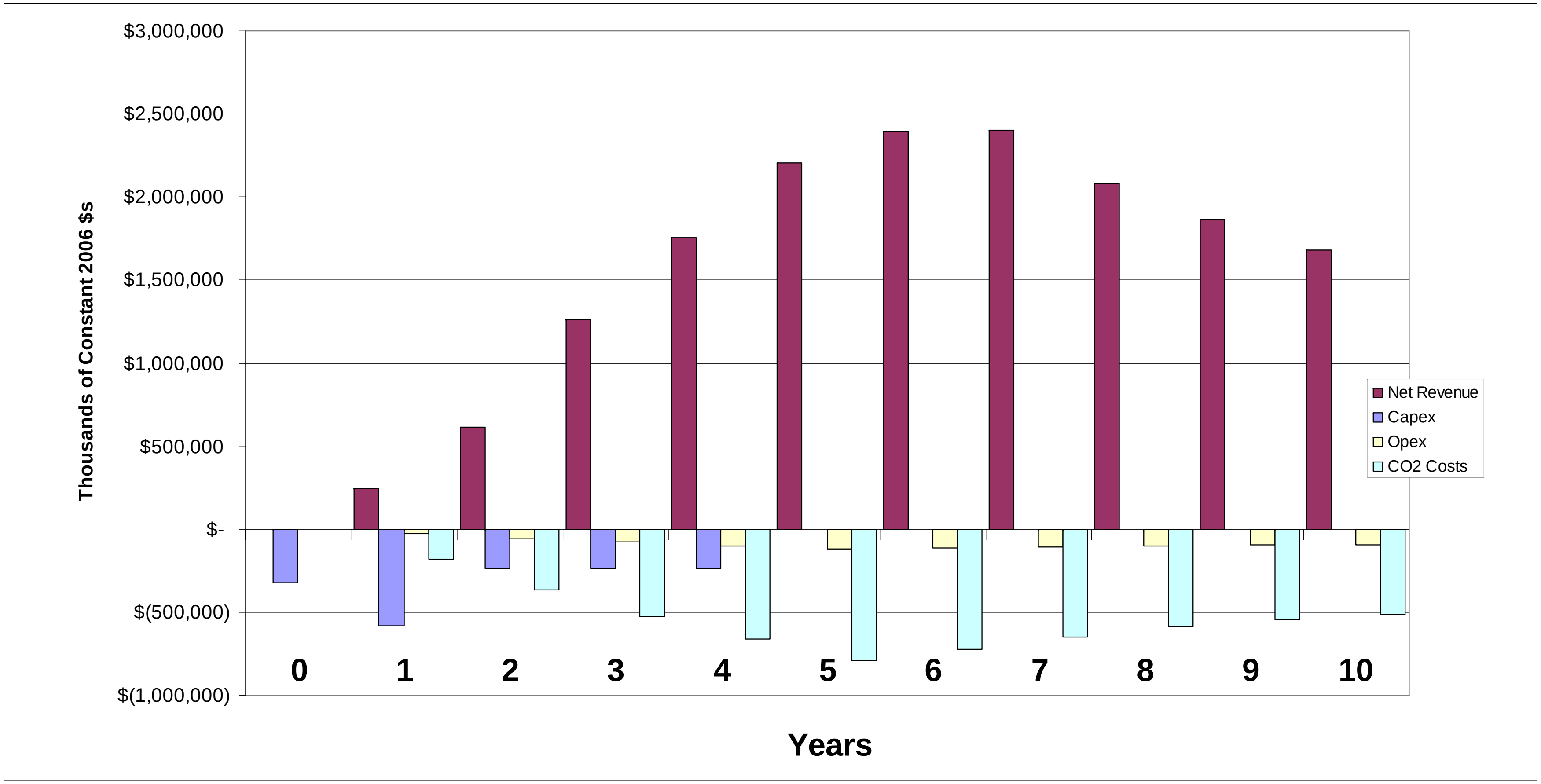

Figure 13. Abbreviated Sample CO_2-EOR Project Cashflow Chart

- **Oil Recovery.** Oil recovery from the example light oil field (with 2,365 million barrels of original oil in-place) is estimated at 665 million barrels in 43 years under "next generation" CO_2-EOR technology versus 381 million barrels in 31 years under current application of "best practices" CO_2-EOR technology.

- **Capital Investment.** Capital investment in this sample oil field under "next generation" CO_2-EOR technology is $1,614 million versus $423 million with currently used "best practices". The extra costs are due to:
  - An extra $1,094 million for drilling, completing, and equipping additional wells,
  - A larger CO_2 recycle plant, adding $17 million, and
  - An allocation of $80 million for instrumented observation wells, 4-D seismic and downhole testing to provide real-time information with which to "manage and control" the "next generation" CO_2 flood.

  However, on a dollars of capital investment per recovered barrel of oil basis, the CapEx costs of currently used "best practices" CO_2-EOR technologies and "next generation" technologies are nearly equal.

- **CO_2 Costs**. CO_2 injection and supply costs for the example oil field are higher, at $14,450 million under "next generation" CO_2-EOR technology (with its 1.5 HCPV of CO_2) versus $10,279 million under currently used "best practices". The extra costs are due to:
  - Larger volumes of purchased CO_2 under "next generation" technology versus "best practices" technology. In this example, "next generation" technology requires 3,355 bcf of purchased CO_2, compared to 2,621 bcf required under "best practices" technology. Per barrel of oil produced, "next generation" technologies purchase less CO_2 because optimized flooding techniques allow operators to minimize CO_2 usage.

  - Significantly larger volumes of recycled CO_2 are used under “next generation” technology than “best practices” technology. In this example, “next generation” technology recycles 9,234 bcf of CO_2, “best practices” technology would only recycle 5,771 bcf.

  However, on a cost of CO_2 injected per barrel of oil recovered basis, the costs for CO_2 are less with “next generation” technology (See Table 4).

- **<u>CO2 Usage.</u>** The combination of technology options discussed above allows operators to very efficiently manage the CO_2 flood, thereby minimizing the amount of purchased CO_2 needed for the project. Results from the example field show that, in this instance, oil recovery can be increased by 75% over the “best practices” scenario by purchasing only 28% more CO_2. Therefore, the example field requires less purchased CO_2 per barrel of oil produced under “next generation” technologies (0.27 mt/Bbl) than under “best practices” technologies (0.36 mt/Bbl).

  - The analysis performed for this report assumes there are no economic incentives for sequestering CO_2. In this situation, operators utilize only a fraction of the available CO_2 storage capacity in the oil reservoirs. Without the marginal revenue from produced oil, profit-maximizing operators will not continue to purchase and inject CO_2 outside of the project’s productive horizon.
  - However, significant CO_2 storage potential exists in the large depleted oil reservoirs analyzed in this study. If operators could earn additional revenue at the end of a CO_2-EOR project by sequestering CO_2, they would have the incentive to use their existing infrastructure to continue to inject and store large volumes of CO_2. In this instance, more CO_2 could be injected into candidate oil fields than contained in the incremental oil produced, resulting in “Green Oil.” A case study of such an operation is provided in Appendix C.

- **<u>Operating and Maintenance Costs (O&M)</u>**. O&M costs in the sample oil field are almost two and a half times higher, at $3,833 million (for 43 years) under "next generation" CO_2-EOR technology versus $1,561 million for (31 years) under "best practices". The extra costs are due to:
  - An extra $1,127 million for operating a larger number of wells for 12 additional years and lifting additional volumes of oil and water,
  - An extra $1,080 million for purchase and injection of viscosity enhancing materials and mobility control aspects, and
  - An additional allocation of $65 million for supporting the integrated project management for helping "manage and control" the "next generation" CO_2 flood.

5.0 Technically Recoverable Resources from “Next Generation” CO_2-EOR Operations

Our reservoir-by-reservoir assessment of the 1,111 large oil reservoirs amenable to CO_2-EOR shows that a significant volume, 87.2 billion barrels, of domestic oil may be recoverable with the application of “next generation” CO_2-EOR technologies. This is a significantly larger volume of oil than the 67 billion barrels of oil recoverable with current “best practices” technologies, as discussed in the previous report, Table 9. Extrapolating the ARI data base results to the national-level indicates that 121.0 billion barrels of domestic oil may become recoverable by applying “next generation” CO_2-EOR, compared to 87 billion barrels in the “best practices” case, Table 10.

Subtracting the 2.3 billion barrels of oil that has already been produced and proven by CO_2-EOR (as of 2006), the application of “next generation” CO_2-EOR would add 118.7 billion barrels of technically recoverable oil to domestic supplies. This is 33 billion barrels greater than the amount of oil found to be technically recoverable from “best practices” CO_2-EOR in the previous “*Storing CO_2 with Enhanced Oil Recovery*” report, Figure 14. For perspective, the current domestic proved crude oil reserves are 21 billion barrels, as of the end of 2006.

Not surprisingly, the Permian Basin of West Texas and New Mexico, with its world class size, favorable geology and carbonate reservoirs, offers the largest volume of technically recoverable oil resource from CO_2-EOR. In addition, significant volumes of oil resource potential exist in East and Central Texas, the Mid-Continent, the Gulf Coast and California.

Reservoirs with large volumes of residual oil (due to low primary and secondary recovery sweep efficiencies) will be most benefitted by “next generation” technologies. For example, the West Texas/Permian Basin oil reservoirs that are geologically complex will have less efficient oil recovery using “best practices” CO_2-EOR. As Table 9 shows, by more effectively contacting the residual oil, “next generation” technologies are able to increase the amount of technically recoverable oil resource in this basin by 64% over “best practices.”

Table 9. Technically Recoverable Resources from Applying "Next Generation" CO_2-EOR: Totals from Oil Reservoirs in Advanced Resources' Database

Basin/Area	OOIP (Billion Barrels)*	OOIP Favorable for CO_2-EOR (Billion Barrels)	Technically Recoverable (Billion Barrels)		
			"Best Practices" Technology	"Next Generation" Technology	% Increase
1. Alaska	65.4	64.5	12.0	12.0	0%
2. California	75.2	31.6	5.7	9.0	58%
3. Gulf Coast (AL, FL, MS, LA)	26.4	20.2	4.2	4.4	5%
4. Mid-Continent (OK, AR, KS, NE)	53.1	28.0	6.4	10.1	58%
5. Illinois/Michigan	12.0	4.6	0.8	2.1	63%
6. Permian (W TX, NM)	72.4	63.1	13.5	22.7	68%
7. Rockies (CO,UT,WY)	23.7	18.0	2.9	5.2	79%
8. Texas, East/Central	67.4	52.4	10.9	12.4	14%
9. Williston (MT, ND, SD)	9.4	7.2	1.8	2.8	56%
10. Louisiana Offshore	22.2	22.1	4.6	4.6	0%
11. Appalachia (WV, OH, KY, PA)	10.6	7.4	1.2	1.9	58%
Total	437.8	319.1	64.0	87.2	36%

*Source: Advanced Resources International, 2008.

Table 10. Technically Recoverable Resources from Applying "Next Generation" CO_2-EOR: Totals from Extrapolating Advanced Resources' Database to National Level

Basin/Area	OOIP (Billion Barrels)	OOIP Favorable for CO_2-EOR (Billion Barrels)	Technically Recoverable (Billion Barrels)	
			"Best Practices" Technology	"Next Generation" Technology
1. Alaska	67.3	64.5	12.4	12.4
2. California	83.3	31.6	6.3	10.0
3. Gulf Coast (AL, FL, MS, LA)	44.4	20.2	7.0	7.4
4. Mid-Continent (OK, AR, KS, NE)	89.6	28	10.7	17.1
5. Illinois/Michigan	17.8	4.6	1.2	3.2
6. Permian (W TX, NM)	95.4	63.1	17.8	29.9
7. Rockies (CO,UT,WY)	33.6	18.0	4.2	7.4
8. Texas, East/Central	109.0	52.4	17.6	20.0
9. Williston (MT, ND, SD)	13.2	7.2	2.5	5.2
10. Louisiana Offshore	28.1	22.1	5.8	5.8
11. Appalachia (WV, OH, KY, PA)	14.0	7.4	1.6	2.6
Total	595.7	319.1	87.1	121.0

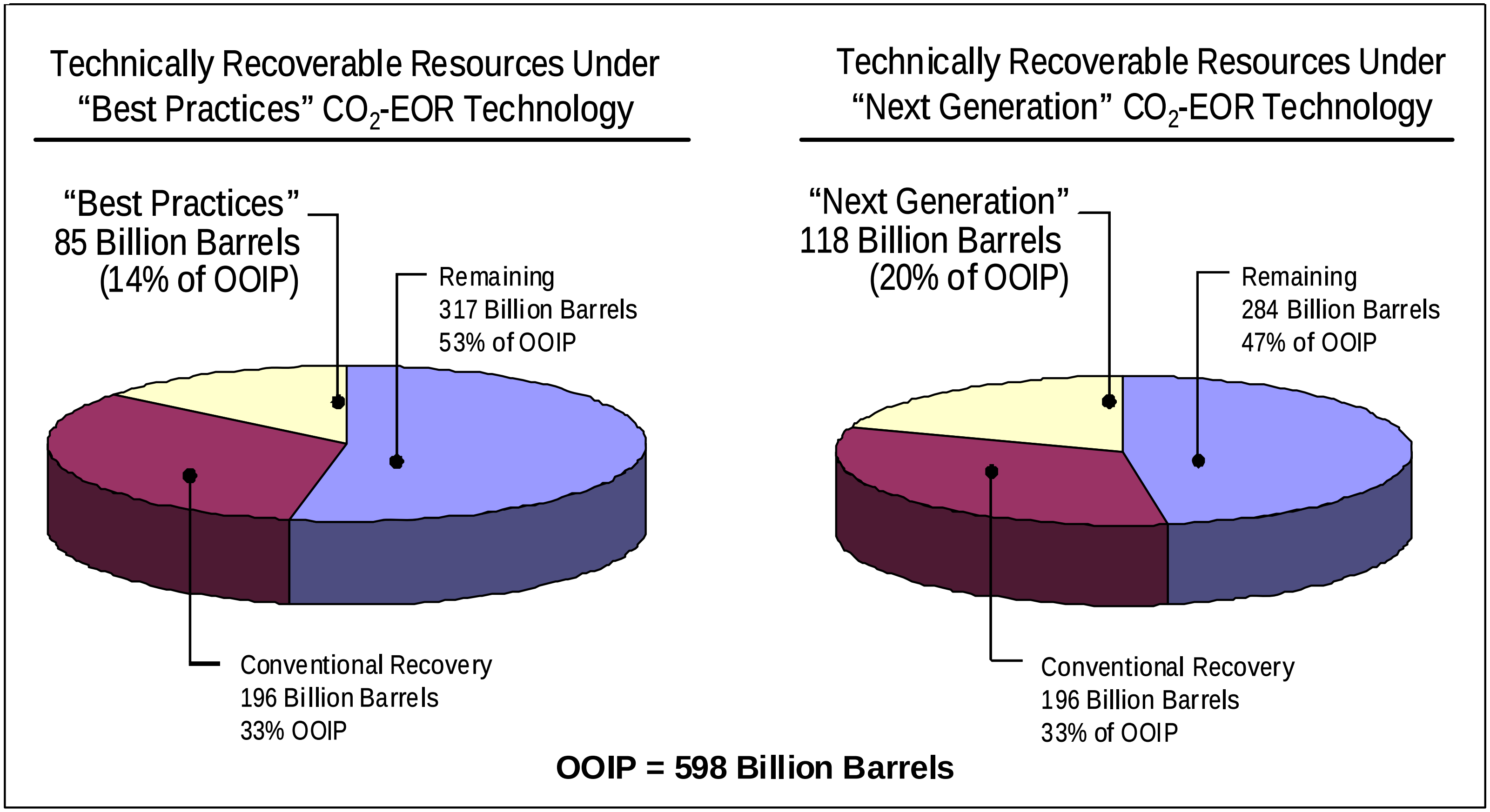

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Figure 14. Comparison of Technically Recoverable Resource between State of the Art and Next Generation CO_2-EOR Technologies.

On the other hand, the more homogeneous sandstone reservoirs in the Gulf Coast Basin lend themselves to high oil recovery efficiencies using current practices. As such, they contain much smaller volumes of residual oil. In these reservoirs, “next generation” technologies provide only about 5% additional oil recovery over “best practices”.

Additionally, a number of reservoirs are located at depths too shallow for current miscible EOR in the “best practices” case. The addition of miscibility enhancers in the “next generation” case allows these reservoirs, previously developed as immiscible CO2-EOR, to be developed with much more efficient miscible CO2-EOR. The large oil recovery improvement from California basin, shown in Table 9, is in part due to this effect.

6.0 Economically Recoverable Resources

6.1 Perspective on CO_2-EOR Economics

Conducting a CO_2-EOR project is capital intensive and costly, entailing the drilling and/or reworking of wells, installing a CO_2 recycle plant, and constructing CO_2 gathering and transportation pipelines. However, in general, the single largest cost of the project is the purchase of CO_2. As such, operators strive to optimize and reduce its purchase and injection, where possible.

The recent increases in domestic oil prices have significantly improved the economics outlook for conducting CO_2-EOR. However, oil field costs have also increased sharply, reducing the economic margin essential for justifying this still emerging (and to many operators, novel and risky) oil recovery option.

Given the significant front-end investment in wells, recycle equipment and purchase of CO_2 and the time delay in reaching peak oil production, significant economic margins will be required to achieve economically favorable rates of return. Oil reservoirs with higher capital cost requirements and less favorable CO_2 to oil ratios would not achieve sufficient return on investment, requiring credits for storing CO_2 to make an integrated CO_2-EOR and CO_2 storage project economic.

6.2 Economically Recoverable Resources: Base Case

The Base Case evaluates the “next generation” CO_2-EOR potential using an oil price of $70 per barrel (constant, real) and a CO_2 cost of $45 per metric ton ($2.38 per Mcf) (constant and real, delivered at pressure to the field). In the Base Case, 64.4 billion barrels of incremental oil become economically recoverable from applying “next generation” CO_2-EOR technology, after subtracting the 2.3 billion barrels of oil already produced through existing CO_2-EOR operations.

Table 11 presents the basin-by-basin tabulation of economically recoverable domestic oil resources should “next generation” CO_2-EOR technology be successfully developed and aggressively applied.

Table 11. Economically Recoverable Resources from Applying "Next Generation" CO_2-EOR: National Totals at Base Case Economics*

Basin/Area	Technically Recoverable (Billion Barrels)	CO_2-EOR Currently Underway (Billion Barrels)	Incremental Technically Recoverable (Billion Barrels)	Incremental Economically Recoverable** (Billion Barrels)
1. Alaska	12.4		12.4	9.5
2. California	10.0		10.0	8.1
3. Gulf Coast (AL, FL, MS, LA)	7.4		7.4	2.7
4. Mid-Continent (OK, AR, KS, NE)	17.1	-0.1	17.0	8.8
5. Illinois/Michigan	3.2		3.2	1.7
6. Permian (W TX, NM)	29.9	-1.9	28.0	13.2
7. Rockies (CO,UT,WY)	7.4	-0.3	7.1	3.8
8. Texas, East/Central	20.0		20.0	11.8
9. Williston (MT, ND, SD)	5.2		5.2	0.6
10. Louisiana Offshore	5.8		5.8	3.9
11. Appalachia (WV, OH, KY, PA)	2.6		2.6	0.1
Total	121.0	-2.3	118.7	64.4

*Incremental technically recoverable resources after subtracting 2.3 billion barrels already produced or proven with CO_2-EOR.
**Base Case Economics use an oil price of $70 per barrel (constant, real) and a CO_2 cost of $45 per metric ton ($2.38/Mcf), delivered at pressure to the field. Economically recoverable resources form the database of large oil reservoirs are not further extrapolated to national totals. We assume that all the reservoirs with economic potential are already included in this database.

6.3 Economically Recoverable Resources: Sensitivity Cases

To gain insights as to how changes in oil prices would affect “next generation” CO_2-EOR projects, the report examined one lower and two higher oil price cases (and their associated CO_2 costs).

Table 12 presents the 64.4 billion barrels of domestic oil recovery potentially available from CO_2-EOR at the Base Case oil price and CO_2 cost by basin. The economically recoverable resource increases to 68.9 to 69.6 billion barrels at higher ($90 to $100/Bbl) oil prices and drops to 54.3 billion barrels at a lower ($50/Bbl) oil price.

The estimates of economically recoverable domestic oil from applying CO_2-EOR have been calculated using a minimum financial hurdle rate of 15% (real, before tax). Higher financial hurdle requirements, appropriate for rapidly installing “next generation” CO_2-EOR technology in new basins and geologic settings, would reduce the volumes of economically recoverable oil.

Table 12. Economically Recoverable Resource from "Next Generation" CO_2-EOR : National Totals at Alternative Economic Cases

Basin/Area	Base Case	Lower Oil Price Case*	Higher Oil Price Cases**	
	($70/Bbl) (billion barrels)	($50/Bbl) (billion barrels)	($90/Bbl) (billion barrels)	($100/Bbl) (billion barrels)
1. Alaska	9.5	7.9	9.9	10.0
2. California	8.1	7.5	8.5	8.6
3. Gulf Coast (AL, FL, MS, LA)	2.7	1.8	2.9	2.9
4. Mid-Continent (OK, AR, KS, NE)	8.8	8.3	8.9	8.9
5. Illinois/Michigan	1.7	1.0	2.0	2.1
6. Permian (W TX, NM)	13.2	10.3	14.1	14.5
7. Rockies (CO,UT,WY)	3.8	3.2	4.0	4.0
8. Texas, East/Central	11.8	11.2	13.3	13.3
9. Williston (MT, ND, SD)	0.6	0.4	0.6	0.7
10. Louisiana Offshore	3.9	2.7	4.5	4.5
11. Appalachia (WV, OH, KY, PA)	0.1	0.1	0.2	0.2
Total Demand	64.4	54.3	69.0	69.7

7.0 The Market for Storing CO_2 with EOR

The previous chapter established that 54 to 70 billion barrels of economic, incremental domestic oil could be produced by timely application of "next generation" CO_2-EOR technology. This chapter draws on this oil recovery assessment to estimate how much CO_2 would be required to produce this volume of economically recoverable oil, helping establish the market for captured CO_2 emissions.

7.1 The CO_2 Injection and Storage Process

The analysis shows that significant volumes of captured CO_2 emissions (ranging from 9 to 13 billion metric tons, depending on oil price) could be injected and subsequently stored with "next generation" CO_2 EOR. The sequence for doing so is as follows:

- Initially, purchased or captured CO_2 emissions would be injected into the oil field along with water for mobility control.

- As oil with CO_2 begins to be produced, the CO_2 is separated from the oil and reinjected. As the produced volumes of CO_2 increase, these larger volumes of CO_2 are reinjected, continuing the life of the CO_2-EOR project.

- Near the end of the CO_2-EOR project, the operator may choose to close the field at pressure, storing essentially all of the injected CO_2, or may inject a large (1 to 2 HCPV) slug of water to recover any remaining mobile oil and CO_2. This CO_2 may then be used in another portion of the reservoir or sold to another oil field. Both "best practices" and "next generation" cases assume that all the CO_2 purchased for a CO_2-EOR project remains sequestered in the reservoir at the end of the project.

On average, consuming a barrel of oil will release about .40 metric tons of CO_2.[*] Under the base case scenario analyzed in this report, the 64.4 billion barrels of

[*] This figure varies depending on the composition and uses of the crude oil. We use .40 tons/barrel as a conservative average of available estimates.

incremental oil produced using "next generation" technologies will release 26 billion metric tons of CO_2. However, 13.8 billion tons of CO_2 were purchased and injected to recover this incremental oil (see Table 13, below), reducing its net CO_2 footprint by 53%. Stated differently, relative to imported oil, oil produced from next generation CO_2-EOR is 53% "carbon free".

With incentives for storing CO_2 emissions and "Second Generation" CO_2 storage technology, significant additional volumes of CO_2 could be stored, resulting in over 100% "carbon free" oil. For additional discussion of this technology, see Appendix C.

7.2 The Market for CO_2

Table 13 provides a basin-by-basin tabulation of the volumes of CO_2 that would be required by "next generation" CO_2-EOR projects under Base Case assumptions ($70 per barrel oil price and $45 per metric ton CO_2 cost, delivered at pressure), excluding CO_2 demand from projects already underway.

In our previous study, "*Storing CO_2 with Enhanced Oil Recovery",* we estimated overall demand for CO_2 in the base case of 11.8 billion metric tons. Under next generation technology, overall demand for CO_2 increases to 13.8 billion tons. A portion of this CO_2 demand, equal to 2.5 billion metric tons, can be met by natural and industrial emissions of CO_2 already being captured.

Table 14 provides the aggregate tabulation of the market for CO_2 for EOR as a function of oil price and CO_2 cost for four alternative oil prices (using the relationships between oil prices and CO_2 costs established in the economic model). Additionally, this table subtracts out CO_2 from natural and anthropogenic sources and the CO_2 demand in Alaska to provide a net demand for CO_2 in the lower 48 states. The resultant "net demand" for CO_2 represents the potential market for captured CO_2 emissions from power plants in the lower 48 states[*]. In the Base Case, net CO_2 demand is approximately 9.4 gigatons, roughly equal to the amount of CO_2 that could be captured from 65 GWs of coal fired power plant capacity over 30 years[*]. This represents an

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[*] No significant additions of coal fired power plant capacity are expected in Alaska.
[*] Assuming 85% capacity factor and 34% efficiency. A 1GW powerplant with these specifications would generate 223 billion kWh of electricity in

increase over our previous analysis of “best practice” CO_2-EOR technologies, where the unmet CO_2 demand was 7.4 gigatons, equal to the emissions from 40 GWs of coal fired capacity.

thirty years (1GW * 85% * 8.76 (conversion between GW and billion kWh/year) * 30 years). With a CO_2 intensity of .94 million tons CO_2/kWh (thermodynamic equivalency based on efficiency of power plant and emissions profile of coal) and 90% capture, this power plant could supply 188 million tons of CO_2 in 30 years.

Table 13. Economically Feasible Market for CO_2 for "Next Generation" CO_2-EOR: Base Case* (Eleven Basins/Areas)

Basin/Area	Gross Market for CO_2 (million metric tons)		CO_2 Already or Scheduled to be Injected (million metric tons)	Net New Market for CO_2 (million metric tons)	
	"Best Practices"	"Next Generation"		"Best Practices"	"Next Generation"
1. Alaska	2,094	2,094	-	2,094	2,094
2. California	1,375	1,556	-	1,375	1,556
3. Gulf Coast (AL, FL, MS, LA)	652	691	-	652	691
4. Mid-Continent (OK, AR, KS, NE)	1,443	1,845	20	1,423	1,825
5. Illinois/Michigan	127	329	-	127	329
6. Permian (W TX, NM)	2,712	3,598	570	2,142	3,028
7. Rockies (CO,UT,WY)	574	759	74	500	683
8. Texas, East/Central	1,940	2,099	-	1,940	2,099
9. Williston (MT, ND, SD)	130	122	-	130	122
10. Louisiana Offshore	1,368	1,368	-	1,368	1,368
11. Appalachia (WV, OH, KY, PA)	36	18	-	36	18
Total	12,451	14,477	664	11,787	13,813

*Base Case: Oil price of $70 per barrel; CO_2 cost of $45 per metric ton.

Table 14. Economically Feasible Market Demand for CO_2 by CO_2-EOR: Alternative Cases (Eleven Basins/Areas)

Basin/Area	Base Case	Lower Oil Price Case*	Higher Oil Price Cases**	
	($70/Bbl) (million metric tons)	($50/Bbl) (million metric tons)	($90/Bbl) (million metric tons)	($100/Bbl) (million metric tons)
1. Alaska	2,094	1,740	2,214	2,235
2. California	1,556	1,385	1,669	1,698
3. Gulf Coast (AL, FL, MS, LA)	691	492	745	745
4. Mid-Continent (OK, AR, KS, NE)	1,825	1,698	1,850	1,850
5. Illinois/Michigan	329	219	407	421
6. Permian (W TX, NM)	3,028	2,306	3,266	3,379
7. Rockies (CO,UT,WY)	683	536	733	733
8. Texas, East/Central	2,099	1,940	2,491	2,491
9. Williston (MT, ND, SD)	122	74	122	127
10. Louisiana Offshore	1,368	904	1,599	1,599
11. Appalachia (WV, OH, KY, PA)	18	15	25	39
Total Demand	13,813	11,309	15,121	15,317
Less: Natural CO2 Sources	2,275	2,275	2,275	2,275
Less: Industrial Sources	222	222	222	222
Total US	11,315	8,812	12,624	12,820
Total Lower 48***	9,486	7,337	10,674	10,849

*Lower Oil Price Case: Oil price of $50 per barrel; CO2 cost of $35 per metric ton.

**Higher Oil Price Cases: Oil price of $90 and $100 per barrel; CO2 costs of $55 and $60 per metric ton.

*** 264 MMmt of Natural CO2 Supplies were from Alaska.

In the future, large volumes of CO_2 could be available from coal-fired power plants that invest in CO_2 capture facilities. As discussed in our previous report "*Storing CO_2 with Enhanced Oil Recovery*," the demand for CO_2 from the EOR market can be an important source of revenue for those plants.

Table 15 tabulates the volumes of natural and anthropogenic CO_2 currently being used for CO_2-EOR, with the coal gasification plant in North Dakota serving as the "poster child" for linking capture of industrial CO_2 emissions with CO_2-EOR.

Table 15. Existing CO_2 Supplies

(Volumes of CO_2 Injected for EOR*)

State/ Province (storage location)	Source Type (location)	CO_2 Supply MMcfd**	
		Natural	Anthropogenic
Texas-Utah-New Mexico-Oklahoma	Geologic (Colorado-New Mexico) Gas Processing (Texas)	1,700	110
Colorado-Wyoming	Gas Processing (Wyoming)	-	240
Mississippi	Geologic (Mississippi)	400	-
Michigan	Ammonia Plant (Michigan)	-	15
Oklahoma	Fertilizer Plant (Oklahoma)	-	35
Saskatchewan	Coal Gasification (North Dakota)	-	145
TOTAL		2,100	545

* Source: 12th Annual CO_2 Flooding Conference, Dec. 2007

** 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 * 10^3 (Mcf per metric ton).

Appendix A

Study Methodology

A. STUDY METHODOLOGY

A.1 OVERVIEW. A six part methodology was used to assess the CO_2 storage and EOR potential of domestic oil reservoirs. The six steps were: (1) assembling the Major Oil Reservoirs Data Base; (2) calculating the minimum miscibility pressure; (3) screening reservoirs for CO_2-EOR; (4) calculating oil recovery; (5) assembling the cost and economic model; and, (6) performing economic and sensitivity analyses.

A.2 ASSEMBLING THE MAJOR OIL RESERVOIRS DATA BASE. The study started with the data base used in the previous set of “basins studies”. The study updated and augmented this data base by incorporating the internally prepared Appalachian Basin Data Base and by making other improvements to this data base.

Table A-1 illustrates the oil reservoir data recording format developed by the study. The data format readily integrates with the input data required by the CO_2-EOR screening and oil recovery models, discussed below. Overall, the Major Oil Reservoirs Data Base contains 2,012 reservoirs, accounting for 74% of the oil expected to be ultimately produced in the U.S. by primary and secondary oil recovery processes.

Table A-1. Reservoir Data Format: Major Oil Reservoirs Data Base

Basin Name	
Field Name	
Reservoir	

Print Sheets

Reservoir Parameters:	ARI
Area (A)	
Net Pay (ft)	
Depth (ft)	
Porosity	
Reservoir Temp (deg F)	
Initial Pressure (psi)	
Pressure (psi)	
B_{oi}	
B_o @ S_o, swept	
S_{oi}	
S_{or}	
Swept Zone S_o	
S_{wi}	
S_w	
API Gravity	
Viscosity (cp)	
Dykstra-Parsons	

Oil Production	ARI
Producing Wells (active)	
Producing Wells (shut-in)	
2002 Production (Mbbl)	
Daily Prod - Field (Bbl/d)	
Cum Oil Production (MMbbl)	
EOY 2002 Oil Reserves (MMbbl)	
Water Cut	
Water Production	
2002 Water Production (Mbbl)	
Daily Water (Mbbl/d)	
Injection	
Injection Wells (active)	
Injection Wells (shut-in)	
2002 Water Injection (MMbbl)	
Daily Injection - Field (Mbbl/d)	
Cum Injection (MMbbl)	
Daily Inj per Well (Bbl/d)	
EOR	
Type	
2002 EOR Production (MMbbl)	
Cum EOR Production (MMbbl)	
EOR 2002 Reserves (MMbbl)	
Ultimate Recovered (MMbbl)	

Volumes	ARI P/S
OOIP (MMbl)	
P/S Cum Oil (MMbl)	
EOY P/S 2002 Reserves (MMbl)	
P/S Ultimate Recovery (MMbl)	
Remaining (MMbbl)	
Ultimate Recovered (%)	
OOIP Volume Check	
Reservoir Volume (AF)	
Bbl/AF	
OOIP Check (MMbl)	
SROIP Volume Check	
Reservoir Volume (AF)	
Swept Zone Bbl/AF	
SROIP Check (MMbbl)	
ROIP Volume Check	
ROIP Check (MMbl)	

Considerable effort was required to construct an up-to-date, volumetrically consistent data base that contained all of the essential data, formats and interfaces to enable the study to: (1) develop an accurate estimate of the size of the original and remaining oil in-place; (2) reliably screen the reservoirs as to their amenability for miscible and immiscible CO_2-EOR; and, (3) provide the *CO_2-PROPHET* Model the essential input data for calculating CO_2 injection requirements and oil recovery.

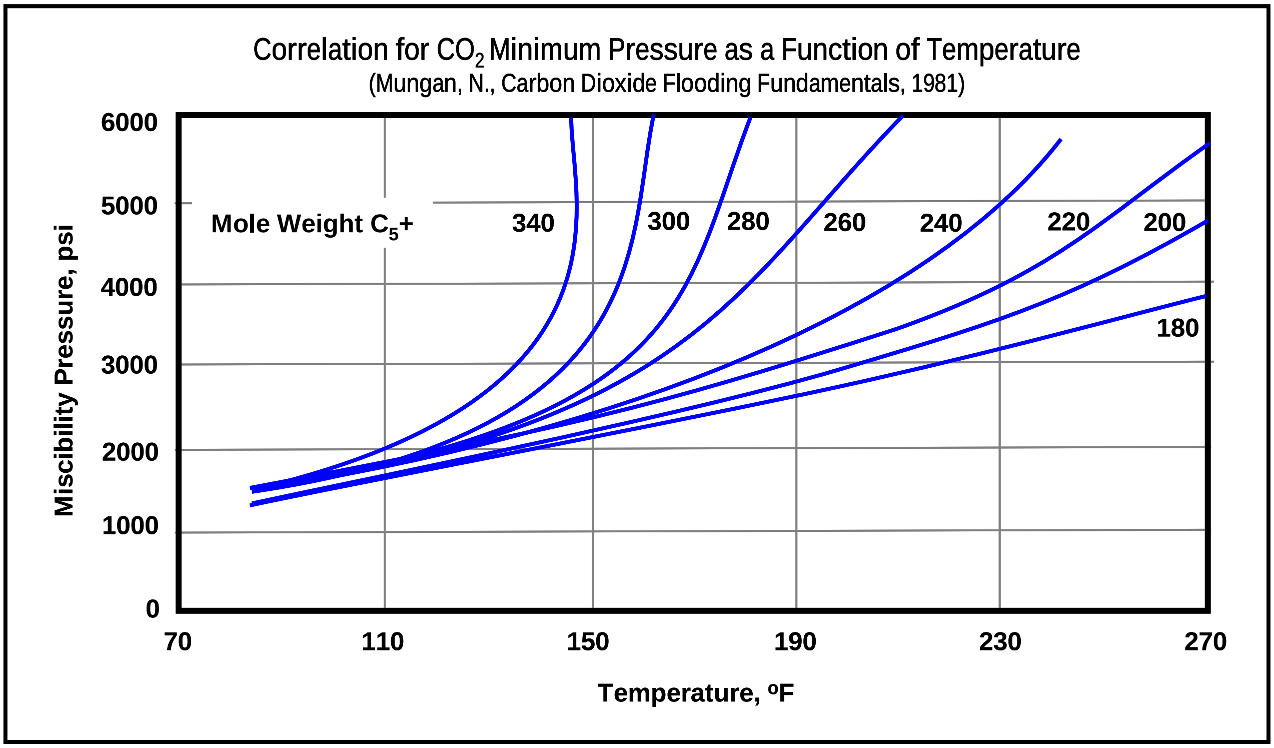
A.3 CALCULATING MINIMUM MISCIBILITY PRESSURE. The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and oil composition, was to determine whether the reservoir would hold sufficient pressure to attain miscibility. Where oil composition data was missing, a correlation was used for translating the reservoir's oil gravity to oil composition.

To determine the minimum miscibility pressure (MMP) for any given reservoir, the study used the Cronquist correlation, Figure A-1. This formulation determines MMP based on reservoir temperature and the molecular weight (MW) of the pentanes and heavier fractions of the reservoir oil, without considering the mole percent of methane. (Most Gulf Coast oil reservoirs have produced the bulk of their methane during primary and secondary recovery.) The Cronquist correlation is set forth below:

$$MMP = 15.988 * T^{(0.744206+0.0011038*MW\ C5+)}$$

Where: T is Temperature in °F, and MW C5+ is the molecular weight of pentanes and heavier fractions in the reservoir's oil.

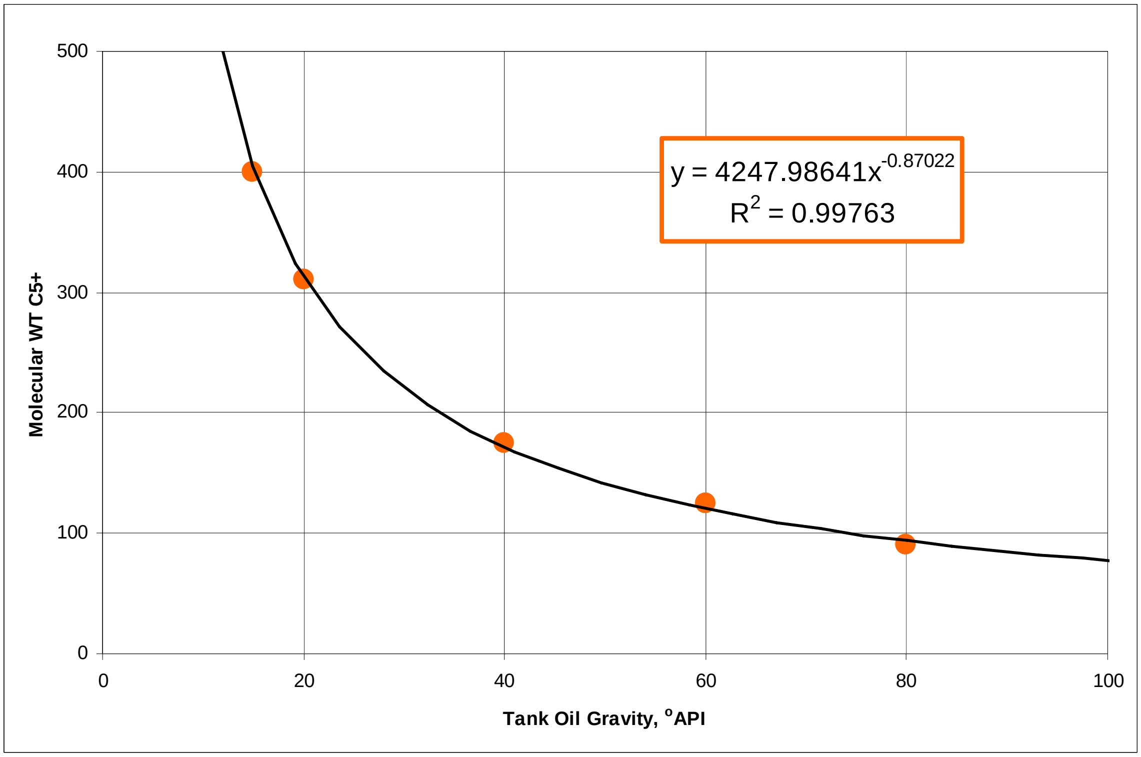
Figure A-1. Estimating CO_2 Minimum Miscibility Pressure



The temperature of the reservoir was taken from the data base or estimated from the thermal gradient in the basin. The molecular weight of the pentanes and heavier fraction of the oil was obtained from the data base or was estimated from a correlative plot of MW C5+ and oil gravity, shown in Figure A-2.

The next step was calculating the minimum miscibility pressure (MMP) for a given reservoir and comparing it to the maximum allowable pressure. The maximum pressure was determined using a pressure gradient of 0.6 psi/foot. If the minimum miscibility pressure was below the maximum injection pressure, the reservoir was classified as a miscible flood candidate. Oil reservoirs that did not screen positively for miscible CO_2-EOR were selected for consideration by immiscible CO_2-EOR.

Figure A-2. Correlation of MW C5+ to Tank Oil Gravity



A.4 SCREENING RESERVOIRS FOR CO_2-EOR. The data base was screened for reservoirs that would be applicable for CO_2-EOR. Five prominent screening criteria were used to identify favorable reservoirs. These were: reservoir depth, oil gravity, reservoir pressure, reservoir temperature, and oil composition. These values were used to establish the minimum miscibility pressure for conducting miscible CO_2-EOR and for selecting reservoirs that would be amenable to this oil recovery process. Reservoirs not meeting the miscibility pressure standard were considered for immiscible CO_2-EOR.

The preliminary screening steps involved selecting the deeper oil reservoirs that had sufficiently high oil gravity. A minimum reservoir depth of 3,000 feet, at the mid-point of the reservoir, was used to ensure the reservoir could accommodate high pressure CO_2 injection. A minimum oil gravity of 17.5 °API was used to ensure the reservoir's oil had sufficient mobility, without requiring thermal injection.

A.5 CALCULATING OIL RECOVERY. The study utilized *CO_2-PROPHET* to calculate incremental oil produced using CO_2-EOR.

- *CO_2-PROPHET* generates streamlines for fluid flow between injection and production wells, and
- The model performs oil displacement and recovery calculations along the established streamlines. (A finite difference routine is used for oil displacement calculations.)

Even with these improvements, it is important to note the CO_2-PROPHET is still primarily a "screening-type" model, and lacks some of the key features, such as gravity override and compositional changes to fluid phases, available in more sophisticated reservoir simulators.

A.6 ASSEMBLING THE COST MODEL. A detailed, up-to-date CO_2-EOR Cost Model was developed by the study. The model includes costs for: (1) drilling new wells or reworking existing wells; (2) providing surface equipment for new wells; (3) installing the CO_2 recycle plant; (4) constructing a CO_2 spur-line from the main CO_2 trunkline to the oil field; and, (5) various miscellaneous costs.

The cost model also accounts for normal well operation and maintenance (O&M), for lifting costs of the produced fluids, and for costs of capturing, separating and reinjecting the produced CO_2. A variety of CO_2 purchase and reinjection costs options are available to the model user.

A.7 CONSTRUCTING AN ECONOMICS MODEL. The economic model used by the study is an industry standard cash flow model that can be run on either a pattern or a field-wide basis. The economic model accounts for royalties, severance and ad valorem taxes, as well as any oil gravity and market location discounts (or premiums) from the "marker" oil price. A variety of oil prices are available to the model user.

Appendix B

ECONOMICS OF "NEXT GENERATION" CO_2-EOR TECHNOLOGY

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B1. BASIC ECONOMIC MODEL. The economic model used in the analysis draws on the previously published economic models in the above mentioned "Storing CO_2 with Enhanced Oil Recovery" report. This basic economic model was modified to incorporate the additional costs associated with applying "next generation" CO_2-EOR technology in the field. The specific process and cost changes incorporated into the "next generation" CO_2-EOR version of the economic model are set forth below.

- **Oil and Water Production.** The oil production and CO_2 injection rates from applying "next generation" CO_2-EOR technology and the increase in the life of the CO_2-EOR project were estimated using *PROPHET*. This involved assembling the reservoir properties for each of the reservoirs and then placing them into the *PROPHET* stream-tube reservoir model to calculate CO_2 injection and oil and water production versus time.

- **CO_2 Injection.** The costs of injecting CO_2 were estimated using the same pricing formula assumed in the "Storing CO_2 with Enhanced Oil recovery" report:

  – Cost of Purchased CO_2 (per Mcf): 4 Cases

    – $35/mt CO_2 ($1.85/Mcf) @ $50/BBl Oil
    – $45/mt CO_2 ($2.38/Mcf) @ $70/BBl Oil
    – $55/mt CO_2 ($2.91/Mcf) @ $90/BBl Oil
    – $60/mt CO_2 ($3.17/Mcf) @ $100/BBl Oil

  – Cost of Recycled CO_2 (per Mcf): 1 percent of oil price ($/Bbl)

  The capital investment costs for the CO_2 recycle plant were scaled to reflect the higher peak recycled CO_2 volumes in the "next generation" technology cases.

- **<u>Additional Costs for Applying Advanced CO_2-EOR Technology.</u>** Four additional modifications were made to the cost and economics model to account for the higher costs of applying each of the "next generation" CO_2-EOR technologies, as set forth below:

  – *Increased Volume of CO_2 Injection.* The costs for purchasing, recycling, and injecting 1.5 HCPV of CO_2 are included in the "next generation" economic model, using the cost formulas set forth above.

  – *Innovative Flood Design and Well Placement.* The "next generation" economic model assumes that one additional new vertical or horizontal production well (depending on the settings) would be added to each pattern. In the example California reservoir discussed above, a new horizontal production well is used. This well would produce from previously bypassed or poorly contacted portions of the reservoir. (The model assumes that each pattern already has or drills one production and one injection well.)

  – *Viscosity Enhancement.* The economic model assumes that the water injection costs for the CO_2-WAG process are increased by $0.25 per barrel of injected water to account for the addition of viscosity enhancers and other mobility control agents or actions.

  – *Flood Performance Diagnostics and Control.* The economic model assumes that the "next generation" CO_2-EOR project is supported by a fully staffed technical team (geologists, reservoir engineers, and economic analysts), uses a series of observation wells and downhole sensors to monitor the progress of the flood, and conducts periodic 4-D seismic plus pressure and residual oil saturation measurements to "optimize, manage, and control" the CO_2 flood. The "next generation" economic model adds 10 percent to the initial capital investment and 10 percent to the annual operating costs of the CO_2 flood to cover these extra costs.

APPENDIX C: "Second Generation" CO2-EOR with Advanced CO2 Storage

A large Gulf Coast oil reservoir with 329 million barrels (OOIP) in the main pay zone has been selected as the “case study” for this analysis. The “Second Generation” CO_2-EOR flood design is shown in Figure C-1, below. The starting conditions of the sample Gulf Coast reservoir are as follows:

- The primary/secondary oil recovery in this oil reservoir is favorable at 148 million barrels, equal to 45% of OOIP. Even with this favorable oil recovery using conventional practices, 181 million barrels is left behind (“stranded”).

- In addition, another 100 million barrels of essentially immobile residual oil exists in the underlying 130 feet of the transition/residual oil zone (TZ/ROZ).

- Below the TZ/ROZ is an underlying saline reservoir with 195 feet of thickness, holding considerable CO_2 storage capacity.

Based on the above, the theoretical CO2 storage capacity of this oil reservoir and structural closure is 2,710 Bcf (143 million metric tons). One purpose of the “Second Generation” design is to utilize as much of the safe and secure CO2 storage capacity as possible.

Assuming there is value to storing CO_2 with “Second Generation” CO_2-EOR and sequestration technology, much more CO_2 can be stored relative to “next generation” technology and more oil becomes potentially recoverable:

- CO_2 storage increases by 3 to 4 fold to 109 million tons with 76% of the theoretical storage capacity utilized.

- Oil recovery is increased by two fold, to 180 million barrels, containing 72 million tons of CO_2 (when combusted). Importantly, 109 billion tons of CO_2 is injected and stored during the EOR flood. As such. more CO_2 is stored than contained in the produced oil, making the produced oil “green.”

Table C-1. 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	Seq.	Total
CO_2 Storage (tonnes)	32	76	33	109
Storage Capacity Utilization	22%	53%	23%	76%
Oil Recovery (barrels)	92	180	-	180
% Carbon Neutral ("Green Oil")	87%	106%	-	151%

Figure C-1. Illustration of "Second Generation" Integration of CO_2 Storage and EOR