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OFFICE OF FOSSIL ENERGY

# $CO_2$-EOR Offshore Resource Assessment

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# Disclaimer

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# Table of Contents

# List of Figures

# List of Tables

# Acronyms and Abbreviations

| | |
|---|---|
| ADNOC | Abu Dhabi National Oil Company |
| ARI | Advanced Resources International, Inc. |
| Bbls | Barrels |
| BOEM | Bureau of Ocean Energy Management |
| CENSEOR | Centre for North Sea Enhanced Oil Recovery |
| C&T | Construction & Trading |
| CFB | Central Fault Block |
| $CO_2$ | Carbon Dioxide |
| EIA | Energy Information Administration |
| EOR | Enhanced Oil Recovery |
| GE | General Electric |
| GOM | Gold of Mexico |
| HCPV | Hydrocarbon Pore Volumes |
| JOGMEC | Japan Oil, Gas and Metals National Corporation |
| MMB/D | Million barrels a day |
| MMmt | Million Metric Ton |
| MMP | Minimum miscibility pressure |
| MMS | Mineral Management Survey |
| N/A | Not applicable |
| OCS | Federal Offshore |
| OOIP | Original oil in-place |
| R&D | Research and Development |
| ROIP | Remaining Oil in Place |
| ROR | Rate on Return |
| $/mt | $/metric ton |
| UERR | Undiscovered Economically Recoverable Resources |
| U.S. | United States |
| UTRR | Undiscovered Technically Recoverable Oil Resource |
| WAG | Water-alternating-gas |
| WFB | Western Fault Block |
| WTI | West Texas Intermediate |
| °C | Degrees Celsius |
| °F | Degrees Fahrenheit |

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# Executive Summary

The Gulf of Mexico (GOM) Federal Offshore (OCS), an important domestic petroleum province, accounts for about 20 percent of total domestic crude oil production. Since reaching a peak of 1.54 million barrels a day (MMB/D) in 2003, Gulf of Mexico's OCS oil production has declined to 1.23 MMB/D, as of mid-2013. While there is optimism that new discoveries in the deep and ultra-deep waters of the GOM OCS will reverse this decline, another option seems to offer even more promise -- the application of $CO_2$ enhanced oil recovery ($CO_2$-EOR).

***Offshore $CO_2$-EOR Offers Significant Benefits***. The use of $CO_2$-EOR in the GOM OCS would provide numerous benefits, including:

- Increasing the volumes of economically viable domestic oil reserves and production, including adding significant Federal royalty and tax revenues;
- Providing a market for $CO_2$ emissions from Gulf Coast electric power and industrial plants, helping "buy-down" the costs of $CO_2$ capture; and
- Providing secure locations for storing $CO_2$

The U.S. DOE already recognizes that offshore storage of $CO_2$ provides several key advantages (Litynski, 2011)[1]:

- Locating sequestration sites away from heavily populated, onshore areas avoids storing material beneath a populated area and reduces the difficulty of establishing surface and mineral rights for storage sites;
- Offshore storage reduces risks to underground sources of drinking water; and
- Offshore $CO_2$ pipelines could utilize already existing corridors and oil and gas infrastructure, thus reducing up-front capital costs.

***The Gulf of Mexico OCS Prize.*** Three distinct resource targets exist in the GOM OCS for $CO_2$-EOR: (1) mature, shallow water oil fields; (2) more recently discovered, deep water oil fields; and (3) undiscovered oil fields, primarily in deep and ultra-deep waters. Figure ES-1 provides the location of the large deep water and "anchor" oil fields located in the Gulf of Mexico.

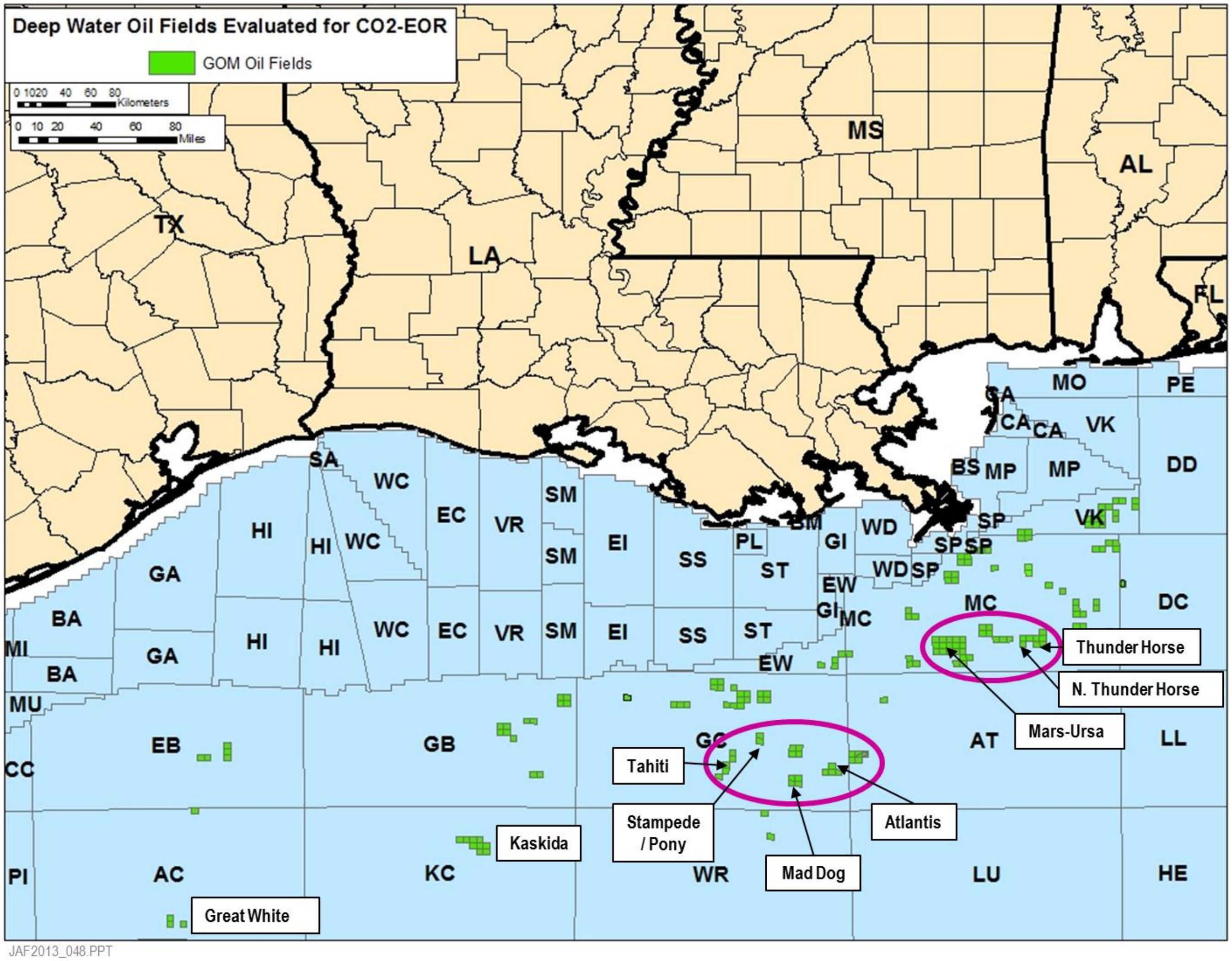
With "Next Generation" $CO_2$-EOR Technology, the offshore GOM offers a substantial prize - - nearly 15 billion barrels of additional oil recovery and storage for 3.9 Gt of $CO_2$ (equal to 40 years of $CO_2$ capture from 20 GW size coal-fired power plants), Table ES-1.

**Table ES-1 Economically viable oil recovery and $CO_2$ demand**

| | Current $CO_2$-EOR Technology | "Next Generation" $CO_2$-EOR Technology |
|---|---|---|
| **Oil Recovery** | **(MMB)** | **(MMB)** |
| Shallow Water | 390 | 3,260 |
| Deep Water | 80 | 2,100 |
| Undiscovered | 340 | 9,560 |
| **Total** | **810** | **14,920** |
| **$CO_2$ Demand** | **(MMmt)** | **(MMmt)** |
| Shallow Water | 150 | 720 |
| Deep Water | 30 | 580 |
| Undiscovered | 130 | 2,610 |
| **Total** | **310** | **3,910** |

The estimates of oil recovery and $CO_2$ demand from applying $CO_2$-EOR to discovered shallow and deepwater GOM oil fields are based on detailed reservoir-by-reservoir analyses. The estimates of oil recovery and $CO_2$ demand from applying $CO_2$-EOR to undiscovered GOM oilfields are based on extrapolation of results from existing deep water oil fields to BOEM's assessment of undiscovered GOM OCS oil resources[2].

**Figure ES-1 GOM OCS deep water oil fields with circled first order "anchor fields"**



***Significant Efforts on Offshore $CO_2$ Enhanced Oil Recovery Are Underway Outside of the U.S.*** While a number of near-shore offshore $CO_2$-EOR pilot projects were undertaken in the early 1980s, there is not yet a commercial-scale $CO_2$ flood in the offshore of the U.S. In contrast, a number of significant offshore $CO_2$-EOR efforts are underway overseas:

- The $CO_2$-EOR project in the Lula Field, a super-giant deep water oil field in offshore Brazil, serves as a most valuable case study of using early application of advanced offshore $CO_2$-EOR technology.
- The Abu Dhabi National Oil Company (ADNOC) is planning a $CO_2$-flood in the Lower Zakum oil field in the offshore of Abu Dhabi using $CO_2$ captured from a steel plant in Mussafah, UAE.
- Vietnam and Malaysia have recently conducted offshore $CO_2$-EOR pilots in preparation for larger-scale use of this technology to increase oil recovery efficiency and provide storage for $CO_2$.

Finally, while the North Sea has over a dozen hydrocarbon miscible and immiscible offshore EOR projects underway, today the interest is substituting $CO_2$ for natural gas as the injectant. In preparation for expanded use of offshore $CO_2$-EOR, the UK recently established the Center for North Sea Enhanced Oil Recovery with $CO_2$ (CENSOR-$CO_2$) to help accelerate this option.

**Technology, Oil Prices and Affordable $CO_2$ Supplies Govern the Economic Viability of Offshore $CO_2$-EOR.** The $CO_2$-EOR potential in the Gulf of Mexico is governed by three key factors:

- First is the performance level of $CO_2$-EOR technology. We examine two distinct levels of $CO_2$-EOR technology - - Current and "Next Generation";
- Second is the cost of $CO_2$ delivered to the offshore oil field. We use $50 per metric ton (mt) (consisting of a $CO_2$ purchase price of $30/mt plus $20/mt for offshore $CO_2$ transportation); and
- Third is the world oil price. We examine the $CO_2$-EOR and $CO_2$ storage potential using "today's" oil price of $90 per barrel and a future, higher oil price of $135 per barrel.

***Impact of Technology and Other Factors on Oil Recovery and $CO_2$ Demand.*** Our in-depth, reservoir-by-reservoir analysis shows that the volumes of economically viable oil recovery and $CO_2$ demand vary by nearly an order of magnitude, depending on the efficiency and sophistication of available offshore $CO_2$-EOR technology.

- ***Current $CO_2$-EOR Technology.*** With today's moderate performance $CO_2$-EOR technology (Current Technology), an oil price of $90/B, and a $CO_2$ cost of $50/mt, economically viable oil recovery and $CO_2$ demand from the GOM OCS are modest:
  - 810 million barrels of incremental oil, and
  - 310 million metric tons of $CO_2$ demand.
- ***"Next Generation" $CO_2$-EOR Technology.*** Substituting higher performing "Next Generation" $CO_2$-EOR Technology (oil price of $90/B and $CO_2$ cost of $50/mt), the economically viable oil recovery and $CO_2$ demand from the GOM OCS increase by more than tenfold:

- 14,920 million barrels of incremental oil, and
- 3,910 million metric tons of $CO_2$ demand.

While "Next Generation" Technology improves oil recovery efficiency by about half, the great bulk of the impact is from the much greater number of offshore oil fields that become economically viable. The combination of more efficient use of $CO_2$ and higher recovery per well are the main reasons for the sharp increase in the number of economically viable oil fields under "Next Generation" technology.

In reviewing these results, it is useful to recognize that a major portion of the oil fields holding substantial original oil in-place (OOIP) were screened out as being too small or too lean for CO2-EOR. Specifically, for the shallower water areas, 80 percent of the oil fields holding nearly half of the OOIP were screened out; for the deep water, half of the oil fields holding about a third of the resource were screened out.

Higher oil prices of $135 per barrel (real $2012) would materially improve the oil recovery and $CO_2$ demand potential that would result from applying $CO_2$-EOR to GOM OCS oil fields. Figure ES-2 and Figure ES-3 illustrate the oil recovery and $CO_2$ storage potential from use of Current vs. "Next Generation" $CO_2$-EOR technologies at both $90 per barrel and at $135 per barrel.

EIA's AEO 2013 projections indicate an oil price of $135/B (real) would be reached by year 2030. In addition, conversion of empty offshore natural gas pipelines to $CO_2$ transportation could lower $CO_2$ costs by $10/mt or more. Most importantly, incentives for capturing and storing $CO_2$ with EOR could make large volumes of affordable, market-competitive Gulf Coast $CO_2$ supplies available for the GOM offshore EOR industry.

***Need for Prompt Action***. There is considerable urgency for implementing $CO_2$-EOR in the offshore oil fields of the Gulf of Mexico OCS.

- ***Shallow Water Oil Fields Are Nearing Abandonment.*** The great bulk of the shallow water (less than 1,000 feet of water depth) GOM oil fields are mature and near abandonment, having produced 95 percent or more of their Original Proved Reserves. Once these fields are abandoned and their platforms removed, the costs of conducting $CO_2$-EOR or storing $CO_2$ in these oil fields increases significantly.

**Figure ES-2 GOM OCS oil recovery potential: current vs "next generation" $CO_2$-EOR technology**

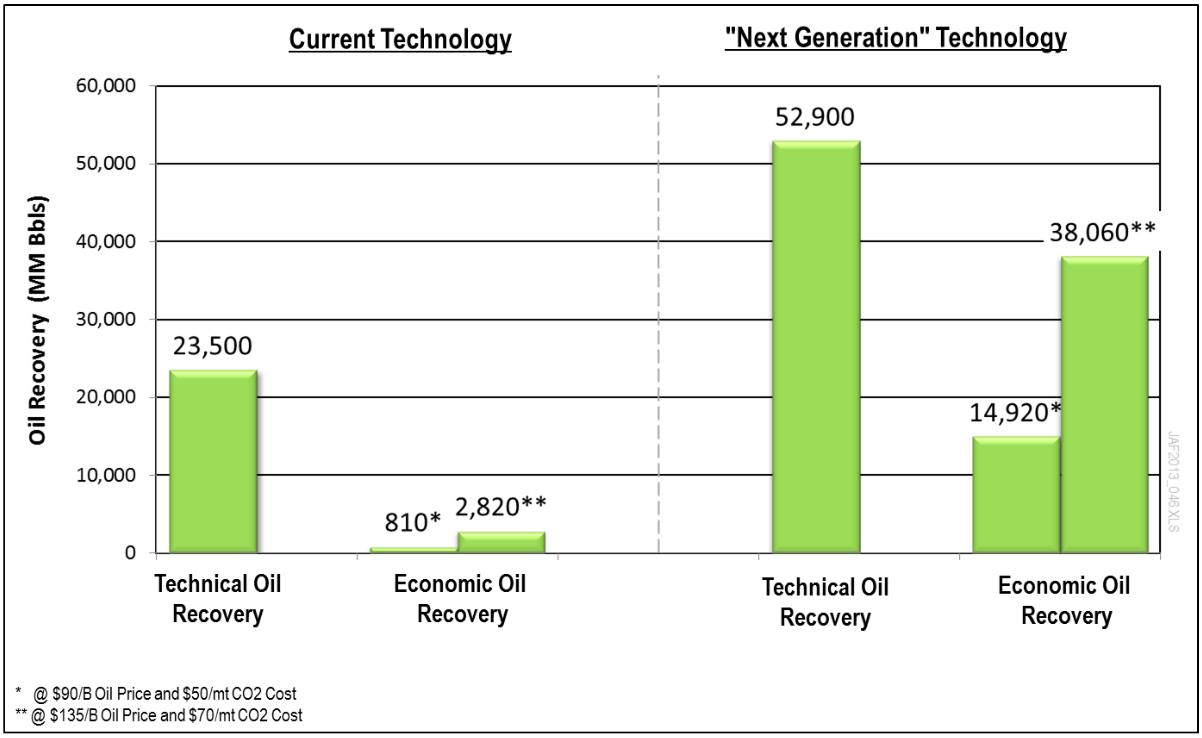



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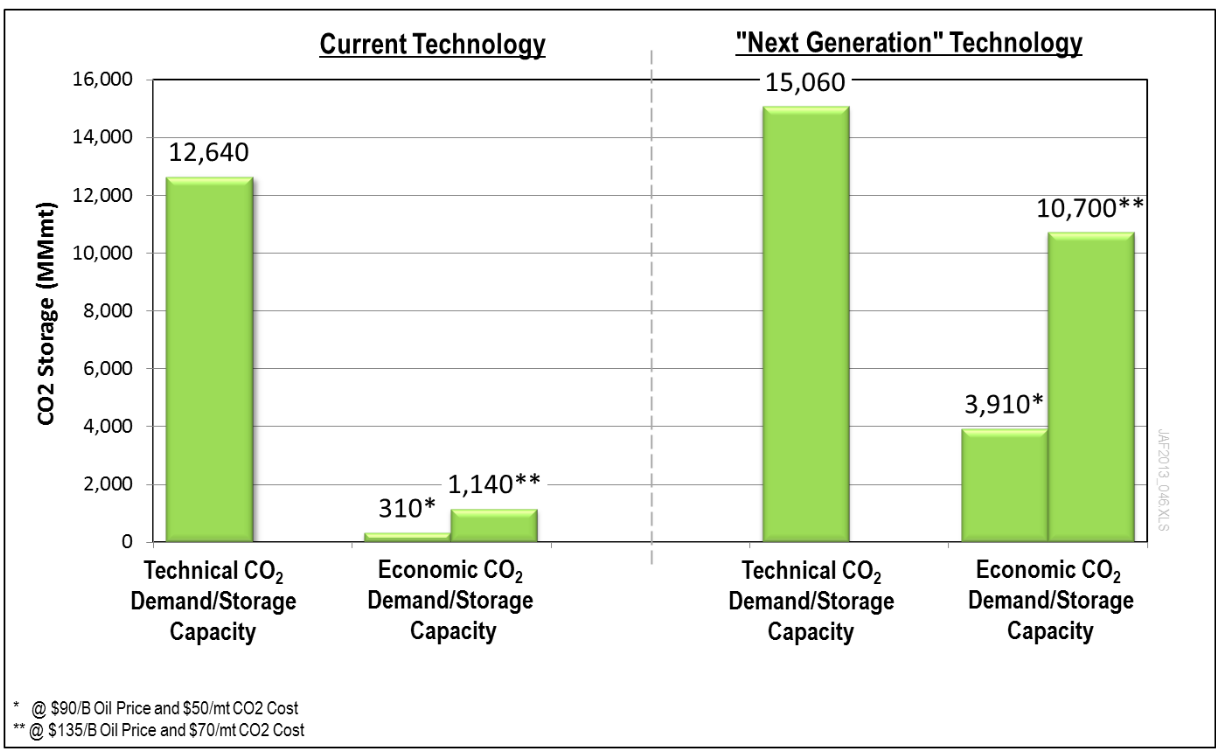
**Figure ES-3 GOM OCS $CO_2$ storage potential: current vs "next generation" $CO_2$-EOR technology**

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***Deep Water Oil Fields Would Benefit From Early $CO_2$-EOR Implementation.*** Much of the oil resource in the deep waters of the GOM is in newly discovered (or still undiscovered) oil fields. As illustrated by the case study of the super-giant Lula oil field in the ultra-deep waters of offshore Brazil, early implementation of $CO_2$-EOR at newly discovered oil fields appears to offer significant economic benefits, including higher volumes of economically viable oil recovery and accelerated opportunities for storing $CO_2$.

*****

Recently, the UK established the Centre for North Sea Enhanced Oil Recovery with $CO_2$ (CENSEOR-$CO_2$) to accelerate implementation of carbon capture and storage and unlock three billion barrels of "hard-to-reach" oil from the North Sea. The objectives of CENSEOR-$CO_2$ are to create a market for $CO_2$ captured from electric power plants and industrial plants and to increase oil recovery efficiency by up to 25 percent. The Centre, located in Edinburgh, Scotland, is funded by the Scottish Government matched by industry funding.

Similar and even larger benefits could be realized by undertaking $CO_2$-EOR in the offshore oil fields of the GOM. As the owner, overall manager and public trustee of the offshore Federal oil and gas resource, it seems reasonable that the Federal Government, through BOEM and DOE, would have similar interests as the UK for optimizing its offshore oil resources. Important next steps would be to support the development of advanced "Next Generation" $CO_2$ enhanced oil recovery technology and to provide incentives for its timely application.

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# 1 Introduction and Results of the Assessment

## 1.1 Introduction

The use of $CO_2$ enhanced oil recovery ($CO_2$-EOR) in offshore Gulf of Mexico (GOM) oil fields would provide three significant benefits: (1) increased domestic oil production and Federal revenues; (2) a market for $CO_2$ emissions captured from electric power and industrial plants along the Gulf Coast; and (3) secure, far from population center locations for storing $CO_2$.

- For the mature GOM oil fields in the shallow waters (less than 1,000 feet of water depth), there is considerable urgency for undertaking $CO_2$-EOR before these fields are abandoned and their platforms removed. A number of older deep water oil fields are also nearing maturity and face similar abandonment issues.
- For the newly discovered oil fields in the deep waters of the GOM, there is an opportunity to apply $CO_2$-EOR early in the life of these large fields, improving their economic viability and their availability for storing $CO_2$.

The economic viability of $CO_2$-EOR in the offshore GOM depends greatly on three factors - - the price of oil, the cost of $CO_2$, and the efficiency of $CO_2$-EOR technology. The study provides a variety of sensitivity analyses that examine how these three factors affect the results of the GOM $CO_2$-EOR resource assessment.

Our assessment of GOM OCS oil fields also considers - - when in the life of the oil field the $CO_2$ flood is initiated; how well developed and drilled is the oil field at the time of $CO_2$-EOR implementation; what are the water and reservoir depths; and, how much oil remains after primary/secondary oil recovery. In general, shallow water offshore oilfields have high, 40 percent to 60 percent oil recovery efficiencies. In contrast, deep water offshore oil fields, often lacking the strong bottom water drive common to shallow water offshore oil fields, have much lower recovery efficiencies and thus have considerably larger remaining oil volumes as the target for $CO_2$-EOR.

We have incorporated the considerations of oil field maturity and development status, water and reservoir depth and oil recovery efficiency into our GOM offshore oil field/reservoir database and into the calculations of expected $CO_2$-EOR performance and development costs. Figure 1-1 shows the location of the 60 deep water GOM oil fields evaluated by this $CO_2$-EOR resource assessment as well as the clusters of "anchor fields" (oil fields with more than a billion barrels of original oil in-place) that would be the destination of potential $CO_2$ pipelines.

## 1.2 Results of the GOM OCS Resource Assessment

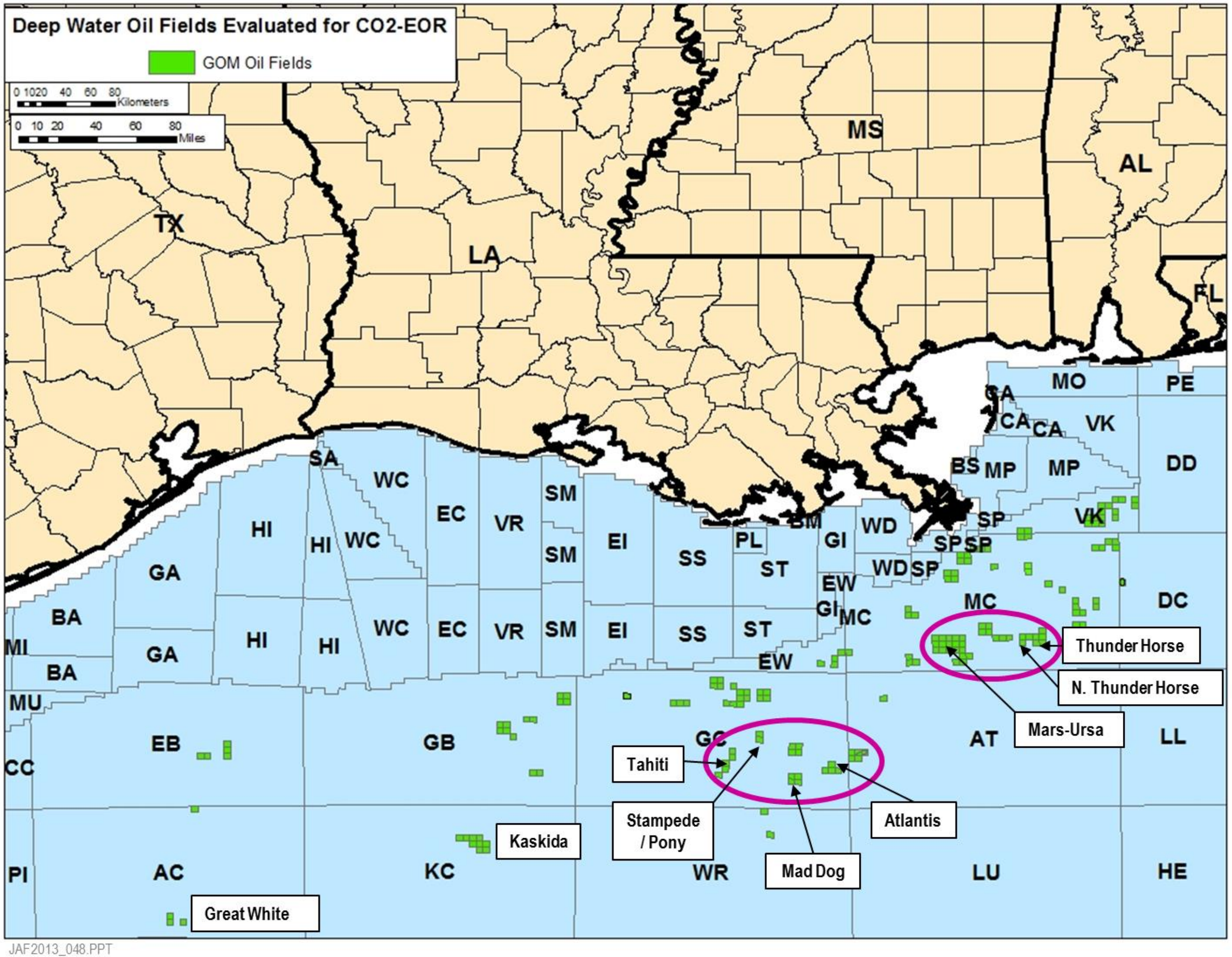
The $CO_2$-EOR assessment for the GOM OCS starts with a Base Case that assumes: (1) an oil price of $90/per barrel (B) ($2012 real, WTI); (2) $CO_2$ costs of $50 per metric ton (mt), delivered to the oil field at pressure ($CO_2$ purchase price of $30/mt (at plant gate) and $20/mt for offshore transportation); and (3) Current $CO_2$-EOR Technology. The study then examines how use of "Next Generation" $CO_2$-EOR Technology would impact the offshore GOM resource assessment.

### 1.2.1 Base Case (Current) Technology

In the Base Case, the GOM OCS offers relatively modest oil recovery and $CO_2$ storage opportunities from the application of $CO_2$-EOR - - 810 million barrels (MM barrels) of incremental oil and 310 million metric tons (MMmt) of $CO_2$ demand and storage. However, lower $CO_2$ costs and higher oil prices would significantly improve the results as discussed further below.

An important consideration when considering GOM OCS $CO_2$-EOR - - is there enough $CO_2$ available in the Gulf Coast area for large-scale implementation of $CO_2$-EOR? The available natural (geologic) $CO_2$ supplies along the Gulf Coast are limited and already committed to onshore $CO_2$-EOR projects. As such, the use of $CO_2$-EOR in the offshore GOM would need to rely on $CO_2$ captured from power and other industrial plants.

**Figure 1-1 GOM OCS deep water oil fields with circled first order "anchor fields"**



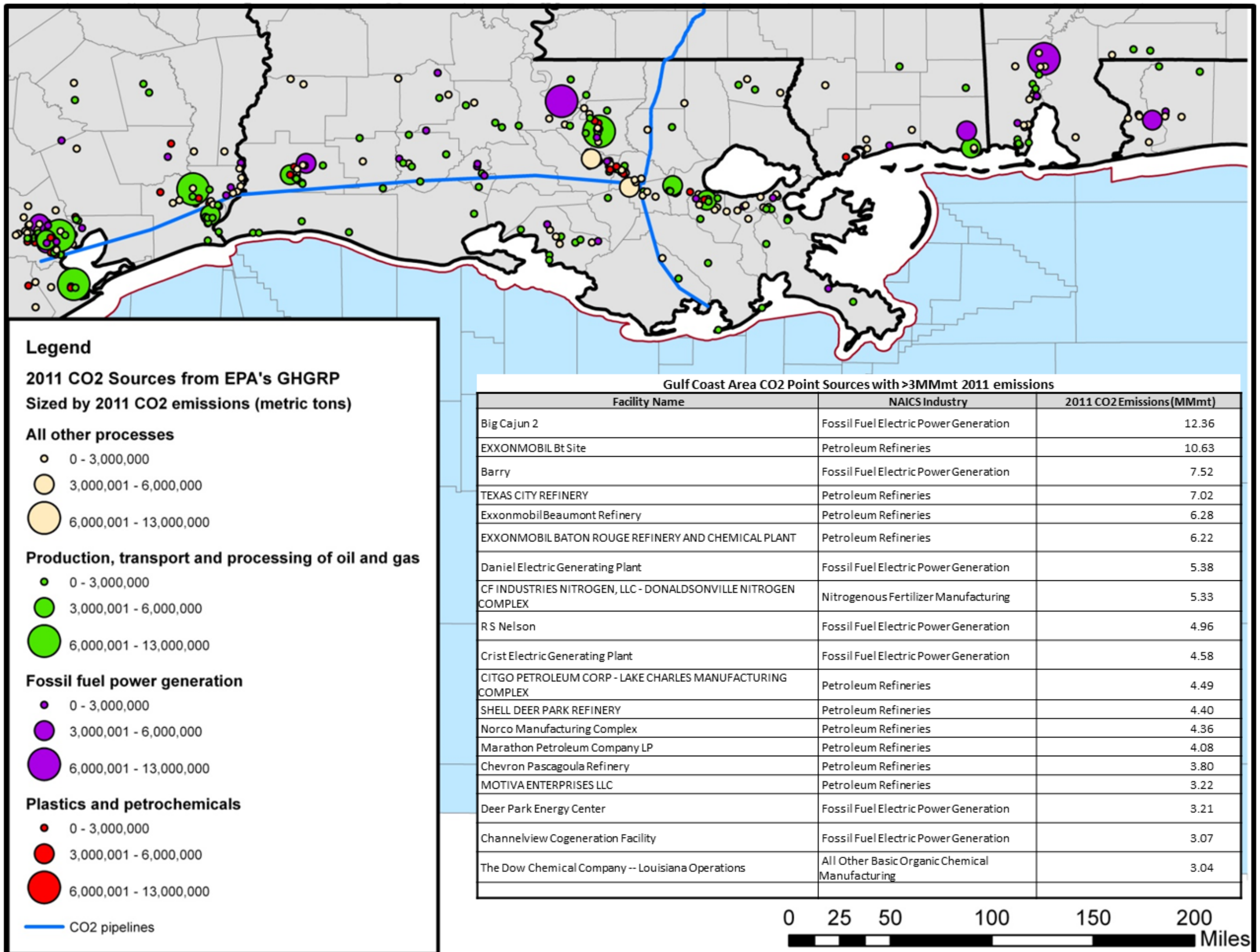
Analysis by the U.S. DOE/National Energy Technology Laboratory shows that 94 MMmt per year of $CO_2$ is currently vented from large (>3 MMmt per year) power and industrial plants along the Gulf Coast. With an EOR demand (under Current $CO_2$-EOR Technology) for $CO_2$ of 310 MMmt over a 30 year time period, about 10 MMmt per year (0.5 Bcfd) would be required, representing only a fraction of the annual $CO_2$ emissions from large point sources in the Gulf Coast area - - petroleum refineries (45 MMmt/yr), fossil fuel power plants (41 MMmt/yr) and other industrial facilities (8 MMmt/year), Figure 1-2.

***Sensitivity of Results to $CO_2$ Costs.*** The volumes of economically viable incremental oil recovery and $CO_2$ demand from the GOM OCS, using Current $CO_2$-EOR Technology, are highly sensitive to the availability and cost of $CO_2$ delivered to offshore oil fields:

- We note that a key priority is to continue the research and development (R&D) for lowering the cost of $CO_2$ capture because $CO_2$ costs above $60/mt would make the use of Current Technology $CO_2$-EOR in the GOM OCS uneconomic.
- Conversely, with lower cost $CO_2$ of $40/mt (possible with advanced $CO_2$ capture technology and the use of empty offshore natural gas pipelines for $CO_2$ transportation), the oil recovery and $CO_2$ storage potentials would more than double.

Table 1-1 and Table 1-2 show the impact of $CO_2$ costs (sales price plus transportation) on incremental oil recovery and $CO_2$ demand from offshore GOM $CO_2$-EOR.

**Figure 1-2 $CO_2$ point sources in the gulf coast area**




Gulf Coast Area CO2 Point Sources with >3MMmt 2011 emissions

| Facility Name | NAICS Industry | 2011 CO2 Emissions (MMmt) |
|---|---|---|
| Big Cajun 2 | Fossil Fuel Electric Power Generation | 12.36 |
| EXXONMOBIL Bt Site | Petroleum Refineries | 10.63 |
| Barry | Fossil Fuel Electric Power Generation | 7.52 |
| TEXAS CITY REFINERY | Petroleum Refineries | 7.02 |
| Exxonmobil Beaumont Refinery | Petroleum Refineries | 6.28 |
| EXXONMOBIL BATON ROUGE REFINERY AND CHEMICAL PLANT | Petroleum Refineries | 6.22 |
| Daniel Electric Generating Plant | Fossil Fuel Electric Power Generation | 5.38 |
| CF INDUSTRIES NITROGEN, LLC - DONALDSONVILLE NITROGEN COMPLEX | Nitrogenous Fertilizer Manufacturing | 5.33 |
| R S Nelson | Fossil Fuel Electric Power Generation | 4.96 |
| Crist Electric Generating Plant | Fossil Fuel Electric Power Generation | 4.58 |
| CITGO PETROLEUM CORP - LAKE CHARLES MANUFACTURING COMPLEX | Petroleum Refineries | 4.49 |
| SHELL DEER PARK REFINERY | Petroleum Refineries | 4.40 |
| Norco Manufacturing Complex | Petroleum Refineries | 4.36 |
| Marathon Petroleum Company LP | Petroleum Refineries | 4.08 |
| Chevron Pascagoula Refinery | Petroleum Refineries | 3.80 |
| MOTIVA ENTERPRISES LLC | Petroleum Refineries | 3.22 |
| Deer Park Energy Center | Fossil Fuel Electric Power Generation | 3.21 |
| Channelview Cogeneration Facility | Fossil Fuel Electric Power Generation | 3.07 |
| The Dow Chemical Company -- Louisiana Operations | All Other Basic Organic Chemical Manufacturing | 3.04 |

Notes and sources: Point source data from EPA's Greenhouse Gas Reporting Program (www.epa.gov/ghgreporting), base map layers from Ventyx's Energy Velocity

**Table 1-1 Sensitivity of oil recovery to $CO_2$ cost (MM barrels)**

($90/B Oil Price; Current $CO_2$-EOR Technology)

| $CO_2$-Sale Price plus Transportation ($/mt) | | | | | | |
|---|---|---|---|---|---|---|
| | **$20** | **$30** | **$40** | **$50** | **$60** | **$70** |
| Shallow Water | 1,080 | 860 | 700 | 390 | 290 | 40 |
| Deep Water | 260 | 220 | 220 | 80 | 50 | 20 |
| Undiscovered | 1,180 | 1,000 | 1,000 | 340 | 230 | 90 |
| **Total** | **2,520** | **2,080** | **1,920** | **810** | **570** | **150** |

**Table 1-2 Sensitivity of $CO_2$ demand/storage to $CO_2$ cost (MMmt)**

($90/B Oil Price; Current $CO_2$-EOR Technology)

| $CO_2$-Sale Price plus Transportation ($/mt) | | | | | | |
|---|---|---|---|---|---|---|
| | **$20** | **$30** | **$40** | **$50** | **$60** | **$70** |
| Shallow Water | 420 | 340 | 280 | 150 | 110 | 20 |
| Deep Water | 110 | 90 | 90 | 30 | 20 | 10 |
| Undiscovered | 500 | 410 | 410 | 130 | 90 | 50 |
| **Total** | **1,030** | **840** | **780** | **310** | **220** | **80** |

***Sensitivity of Results to Oil Price.*** Because Current $CO_2$-EOR Technology provides only modest volumes of additional oil, a higher oil price is generally required for economic viability. At an oil price of $135/B (anticipated to be reached by year 2030 in EIA's AEO 2013 report) and a $70/mt $CO_2$ price (the $CO_2$ price is linked to the oil price), the oil recovery and $CO_2$ storage volumes from the GOM OCS become significant - - 2,820 MM barrels of incremental oil and 1,140 MMmt of $CO_2$ demand (storage), Table 1-3.

**Table 1-3 Sensitivity of oil recovery and $CO_2$ demand (storage) to oil price**

($CO_2$ Price Linked to Oil Price; Current $CO_2$-EOR Technology)

| $CO_2$-Sale Price plus Transportation ($/mt) | | | | | | |
|---|---|---|---|---|---|---|
| | **$20** | **$30** | **$40** | **$50** | **$60** | **$70** |
| Shallow Water | 420 | 340 | 280 | 150 | 110 | 20 |
| Deep Water | 110 | 90 | 90 | 30 | 20 | 10 |
| Undiscovered | 500 | 410 | 410 | 130 | 90 | 50 |
| **Total** | **1,030** | **840** | **780** | **310** | **220** | **80** |

### 1.2.2 "Next Generation" Technology

"Next Generation" Technology with its higher oil recovery efficiencies will be an essential feature of offshore $CO_2$ enhanced oil recovery and storage.

- Shallow water oil fields, with their strong natural water driver, already achieve relatively high (40 percent to 60 percent) recovery of original oil in-place, leaving a much smaller target for $CO_2$-EOR. "Next Generation" $CO_2$-EOR Technology, with its higher reservoir sweep and oil displacement efficiencies, is needed to economically target these reduced volumes of residual oil.
- Deep water oil fields, with their high cost wells and facilities, will also need higher oil recoveries than offered by Current $CO_2$-EOR Technology to become economically viable for $CO_2$-EOR. However, in contrast with shallow water oil fields, the primary/secondary oil recovery efficiencies in deep water oil fields are considerably lower, providing a larger residual oil target.

Substituting "Next Generation" $CO_2$-EOR Technology for Current $CO_2$-EOR Technology, while keeping oil price ($90/B) and $CO_2$ price ($50/mt) the same as in the Base Case, leads to a more than tenfold increase in oil recovery and $CO_2$ demand (storage) for GOM offshore oil fields.

- Economically viable incremental oil recovery from the GOM OCS becomes 14,920 million barrels with "Next Generation" $CO_2$-EOR Technology compared to 810 million barrels with Current Technology.
- Economic demand (storage) for $CO_2$ by the offshore $CO_2$-EOR industry is 3,910 million metric tons with "Next Generation" $CO_2$-EOR Technology, compared to 310 million metric tons with Current Technology.

The higher volumes of economically viable oil recovery from the GOM OCS from using "Next Generation" $CO_2$-EOR Technology are due to: (1) more oil recovered per dollar of invested capital (i.e., spending more to implement "Next Generation" Technology provides more oil recovery and higher overall financial returns); and (2) the more favorable $CO_2$ to oil ratio of 0.24

mt of $CO_2$ per barrel of recovered oil, compared to 0.38 mt of $CO_2$ per barrel of recovered oil with Current $CO_2$-EOR Technology, lowers the cost per barrel.

Use of "Next Generation" $CO_2$-EOR leads to much higher $CO_2$ supply requirements, 3,910 MMmt over a 50 year time period (taking into consideration the time lapse for finding and developing undiscovered oil fields). This is about 80 MMmt of $CO_2$ per year, equal to about 4 Bcfd. With annual Gulf Coast $CO_2$ emissions from large point sources of 94 MMmt/year (see Figure 1-2), sufficient $CO_2$ supplies are available but would need to be captured and then transported to the offshore.

As important, the analysis shows that the GOM OCS oil fields provide sufficient long-term $CO_2$ storage capacity for all of the $CO_2$ emissions generated from large point sources along the Gulf Coast.

***Sensitivity of Results to $CO_2$ Costs.*** Lower delivered costs of $CO_2$ enable more of the offshore oil resource to become economic under "Next Generation" $CO_2$-EOR. Table 1-4 and Table 1-5 provide the analysis of incremental oil recovery and $CO_2$ demand (storage) to changes in $CO_2$ costs.

**Table 1-4 Sensitivity of incremental oil recovery to $CO_2$ cost (MM barrels)**

($90/B Oil Price; "Next Generation" $CO_2$-EOR Technology)

| | $CO_2$-Sale Price plus Transportation ($/mt) | | | | | |
|---|---|---|---|---|---|---|
| | **$20** | **$30** | **$40** | **$50** | **$60** | **$70** |
| Shallow Water | 3,600 | 3,480 | 3,440 | 3,260 | 3,050 | 2,260 |
| Deep Water | 3,250 | 2,680 | 2,380 | 2,100 | 1,640 | 1,260 |
| Undiscovered | 14,790 | 12,190 | 10,830 | 9,560 | 7,460 | 5,730 |
| **Total** | **21,640** | **18,350** | **16,650** | **14,920** | **12,150** | **9,250** |

**Table 1-5 Sensitivity of $CO_2$ demand/storage to $CO_2$ cost (MMmt)**

($90/B Oil Price; "Next Generation" $CO_2$-EOR Technology)

| $CO_2$-Sale Price plus Transportation ($/mt) | | | | | | |
|---|---|---|---|---|---|---|
| | **$20** | **$30** | **$40** | **$50** | **$60** | **$70** |
| Shallow Water | 810 | 780 | 770 | 720 | 680 | 490 |
| Deep Water | 920 | 750 | 650 | 580 | 440 | 320 |
| Undiscovered | 4,190 | 3,410 | 4,380 | 3,910 | 2,000 | 1,460 |
| **Total** | **5,920** | **4,940** | **4,380** | **3,910** | **3,120** | **2,270** |

***Sensitivity of Results to Oil Prices.*** Even though "Next Generation" $CO_2$-EOR Technology provides higher volumes of oil recovery, offshore $CO_2$-EOR is still a high cost option that would benefit from higher oil prices, Table 1-6.

- At an oil price of $135/B ($CO_2$ costs of $70/mt), the incremental oil recovery more than doubles to 38,060 MM barrels compared to 14,920 MM barrels under a $90/B oil price.
- Similarly, with an oil price of $135/B ($CO_2$ cost of $70/mt), the demand (storage) for $CO_2$ more than doubles to 10,700 MMmt compared to 3,910 MMmt under a $90/B oil price.

**Table 1-6 Sensitivity of oil recovery and $CO_2$ demand (storage) to oil price**

($CO_2$ Price Linked to Oil Price; "Next Generation" $CO_2$-EOR Technology)

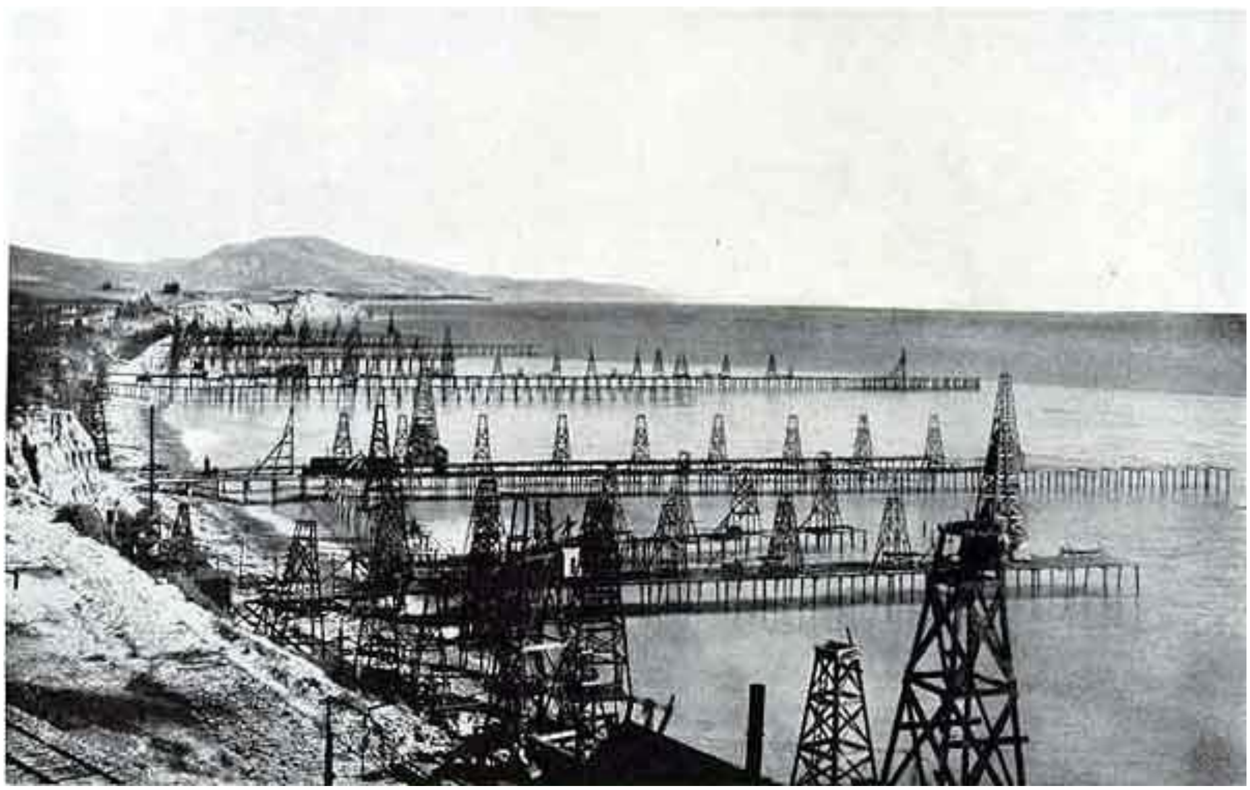
| | Oil Recovery (MM Barrels) | | CO2 Demand/Storage (MMmt) | |
|---|---|---|---|---|
| **Oil Recovery** | **@$90/B** | **@$135/B** | **@$90/B** | **@$135/B** |
| Shallow Water | 3,260 | 4,410 | 720 | 990 |
| Deep Water | 2,100 | 6,060 | 580 | 1,750 |
| Undiscovered | 9,560 | 27,590 | 2,610 | 7,960 |
| **Total** | **14,920** | **38,060** | **3,910** | **10,700** |

# 2 Overview of United States (U.S.) and International Offshore EOR

## 2.1 History of Offshore Exploration

The U.S. offshore petroleum industry started at the end of the 19th century. An enterprising California oilman, Henry L. Williams, built a 300-foot pier into the Pacific Ocean, mounted a cable tool rig on this pier, and drilled the first offshore well. The well was successful and confirmed that the prolific Summerland oil field extended offshore. Within five years, twenty-two companies had copied Williams's approach, constructing 14 piers and drilling 400 wells in the Summerland oil field, Figure 2-1, enabling this first onshore/offshore oil field to produce for 25 years.

**Figure 2-1 Development of offshore portion of Summerland oil field, California**

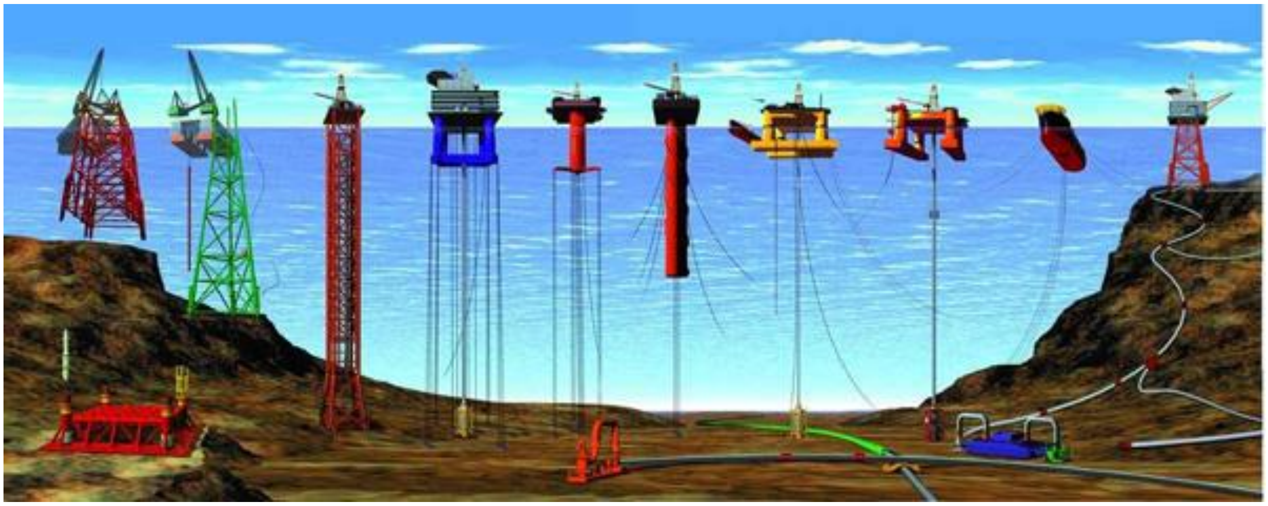


*Used with permission from American Oil and Gas Historical Society*[3]

Next, starting in 1911, Gulf Refining Co. used a fleet of tug boats, barges and floating piles to drill wells in the lakes, marshes and bayous of Louisiana. As industry's drilling expertise improved, the first productive offshore oil well was drilled in 1938, in 14 feet of water about a mile offshore from Cameron Parish, LA. Nine years later, Kerr McGee drilled the first GOM well out of sight of land.

The same march of technological progress continues in the Gulf of Mexico today as operators seek to unlock oil and gas resources farther from shore and in increasingly deeper waters. A host of technological advances have enabled this transition to deeper and now ultra-deep waters (greater than 5,000 ft of water depth), including new production system and sub-sea completion technology, Figure 2-2.

**Figure 2-2 Offshore oil and gas production structures***



*Source: National Oceanic and Atmospheric Administration[4]*

*Offshore oil and gas structures, shallow water to deeper water, from left to right: (1 and 2) Conventional fixed platforms; (3) Compliant tower; (4 and 5) Vertically moored tension leg and mini-tension leg platform; (6) Spar; (7 and 8) Semi-submersibles; (9) Floating production, storage, and offloading facility; and (10) Sub-sea completion and tie-back to host facility.

## 2.2 $CO_2$-EOR Projects in the Offshore Shallow Waters of the Gulf of Mexico

The success of using $CO_2$-EOR in onshore oil fields has inspired operators to consider using $CO_2$-EOR in offshore oil fields. While this interest has led to a variety of feasibility studies and a handful of pilot projects, there is not yet a commercial scale $CO_2$-EOR flood offshore U.S. The barriers to offshore $CO_2$-EOR - - limited $CO_2$ supplies and high well drilling costs - - are considerable but the promise of additional oil recovery and secure storage of $CO_2$ is a large potential prize.

Five $CO_2$-EOR pilot projects have been undertaken in the Gulf of Mexico's coastal waters and bays of Louisiana. These pilot projects, all conducted in the 1980s, provide valuable insights for planning and operating a $CO_2$ flood in the GOM region. Importantly, the pilot projects were generally deemed successful.

### 2.2.1 Quarantine Bay

The Quarantine Bay oil field is located about 50 miles southeast of New Orleans in Louisiana's shallow coastal waters. Gulf Oil E & P Co. (now Chevron USA Inc.) initiated a miscible $CO_2$-WAG pilot in one small watered-out oil reservoir in this large oil field. The pilot project consisted of one injection well, five production wells and two monitor wells.[5] Before conducting the pilot, the company conducted extensive reservoir characterization and used a three-dimensional compositional simulation to estimate the project's oil recovery and $CO_2$ utilization.

$CO_2$ injection commenced in October 1981 and was completed in February 1983. $CO_2$ was delivered to the field by barges and injected at an average rate of 87 tons (1.7 MMcfd) per day. The amount of $CO_2$ injected per water-alternating-gas (WAG) cycle was 2,000 tons and the last $CO_2$ cycle was followed by continuous water injection. Gulf Oil reported the project recovered 16.9 percent of OOIP with a $CO_2$ utilization rate of 2.6 Mcf of $CO_2$ per barrel of oil. The company considered the project a success.

### 2.2.2 Timbalier Bay

The Timbalier Bay oil field is located 60 miles south of New Orleans in Louisiana's coastal waters. This gravity-stable, miscible $CO_2$ flood operated by Gulf Oil (now Chevron USA) employed one injection well, three production wells, and two monitor wells.[6] Reservoir characterization and slim-tube miscibility tests were performed prior to the $CO_2$ flood. During the 15 months of the $CO_2$-EOR project, Gulf Oil injected a 30 percent HCPV slug of $CO_2$ followed by injection of field gas to recover oil from 60 feet of watered-out reservoir pay.

### 2.2.3 Bay St. Elaine Field

In 1981, Texaco (now Chevron) initiated a gravity-stable, miscible $CO_2$ flood in the Bay St. Elaine oil field in the coastal marshes of southern Louisiana.[7] Prior to initiating the $CO_2$ flood, the company performed reservoir characterization, slim-tube miscibility tests, and laboratory PVT studies. The company injected a $CO_2$ solvent slug composed of 84 mole% $CO_2$, 11 mole% methane, and 5 mole% n–butane. $CO_2$ was injected at an average rate of 85 tons per day. Following $CO_2$ injection, nitrogen was injected to drive the $CO_2$ solvent slug to production wells. The tertiary recovery pilot produced significant amounts of oil and was considered a success by Texaco.

### 2.2.4 Weeks Island Field

Starting in 1978, Shell conducted a gravity-stable $CO_2$ flood in the high permeability, steeply dipping Weeks Island reservoir located in southern Louisiana.[8] Prior to conducting the flood, the company performed detailed reservoir simulation studies and reservoir characterization. Shell reported that it recovered over 260,000 barrels of oil from injecting a 24 percent HCPV slug of $CO_2$ mixed with about 6 mole% of natural gas. The gross $CO_2$ utilization rate was 7.9 Mcf per barrel of oil including gas recycling and a net $CO_2$ utilization rate of 3.3 Mcf per barrel of oil, counting only purchased $CO_2$.

### 2.2.5 Paradis Field

Texaco (now Chevron) began a gravity-stable $CO_2$ flood in the Paradis oil field in St. Charles Parish, Louisiana in 1982, after completing 30 months of planning and construction.[9] The company injected $CO_2$ (obtained from industrial plants in the region) mixed with 10 percent nitrogen. No further information has been provided on the results of the pilot Paradis $CO_2$ flood.

## 2.3 International Offshore $CO_2$-EOR

### 2.3.1 Introduction

In contrast with the lack of current $CO_2$-EOR projects in the Gulf of Mexico's oil fields, the international pursuit of offshore EOR is much more active, as illustrated by five active or planned international $CO_2$-EOR projects:

1. Offshore Brazil, Lula Oil Field
2. North Sea, Draugen/Heidrun Oil Fields and Don Valley Project
3. Offshore Abu Dhabi, Persian Gulf Oil Fields
4. Offshore Vietnam, Rang Dong Oil Field
5. Offshore Malaysia, Dulang Oil Field

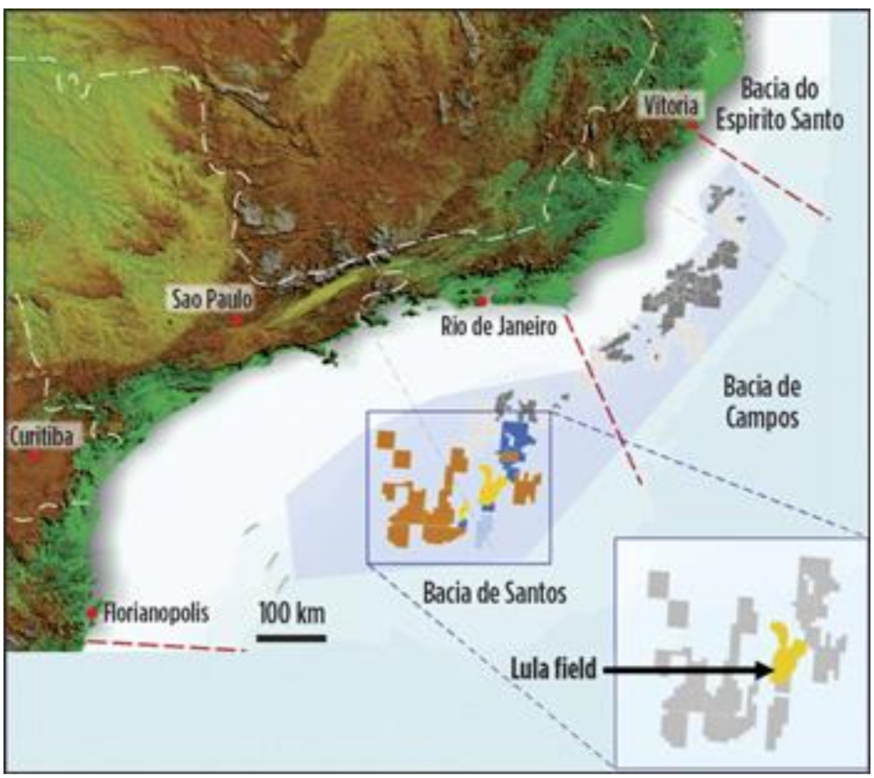
### 2.3.2 Offshore Brazil Lula Oil Field

***A Case Study in Innovation.*** Brazil's Lula oil field is currently the international pioneer in pursuing deep water offshore $CO_2$-EOR. The Lula Field (Tupi area) is a super-giant deep water oil field located in the Santos Basin of Brazil, Figure 2-3.

Given the innovative strategies being pursued by Petrobras, the Lula Field serves as a most valuable case study of using early application of advanced $CO_2$-EOR technology to optimize the development of a major offshore oil field. Significant preparation steps taken at Lula, as discussed further in this section of the report, include: intensive reservoir characterization, testing of alternative enhanced oil recovery options, and rigorous monitoring of pilot flood performance.

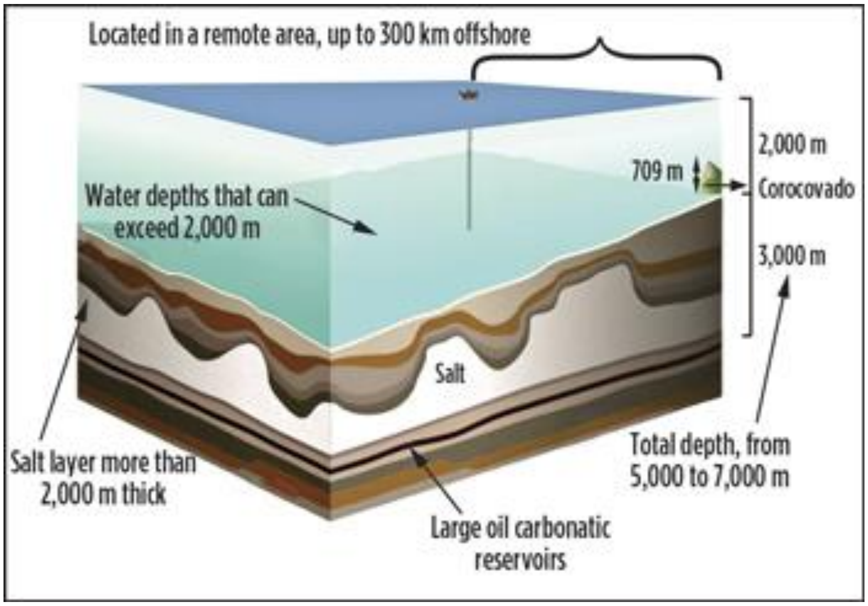
Lula was discovered by Petrobras in 2006 in ultra-deep waters, between 5,400 and 7,200 feet, approximately 180 miles south-east of Rio de Janeiro. Lula's carbonate reservoir is overlain by a thick 6,000 ft salt column and holds moderately light, 28-30 °API oil with a high solution GOR, Figure 2-4. The solution gas in the reservoir contains 8 percent to 15 percent $CO_2$.

**Figure 2-3 Brazil's Lula Field and Santos Basin**




*Used with permission from the Society of Petroleum Engineers[10]*

**Figure 2-4 Santos Basin pre-salt environment**




*Used with permission from the Society of Petroleum Engineers*[11]

***Early Implementation of $CO_2$-EOR.*** Petrobras is implementing a series of short-term EOR pilots at Lula with the intention of developing the entire field using $CO_2$-EOR, if the $CO_2$ pilot is successful. According to Petrobras, early implementation of $CO_2$-EOR would improve capital efficiency as it frees the operator from having to subsequently retrofit production systems and find platform space for $CO_2$ recycling. Early implementation of $CO_2$-EOR also precludes halting operations and shutting-in oil production when undertaking $CO_2$-EOR later in the oil field's life.

***Deepwater $CO_2$-EOR Technology***. The technology deployed by Petrobras for Lula mirrors the methodology and design used in ARI's deep water $CO_2$-EOR resource assessment modeling. Similar to Petrobras, ARI uses a hub and spoke model to service multiple fields with subsea completions. Both Lula and ARI's "Next Generation" offshore $CO_2$-EOR design utilize intelligent well completions, dynamic down hole monitoring, tracer injections and extensive $CO_2$ recycling.

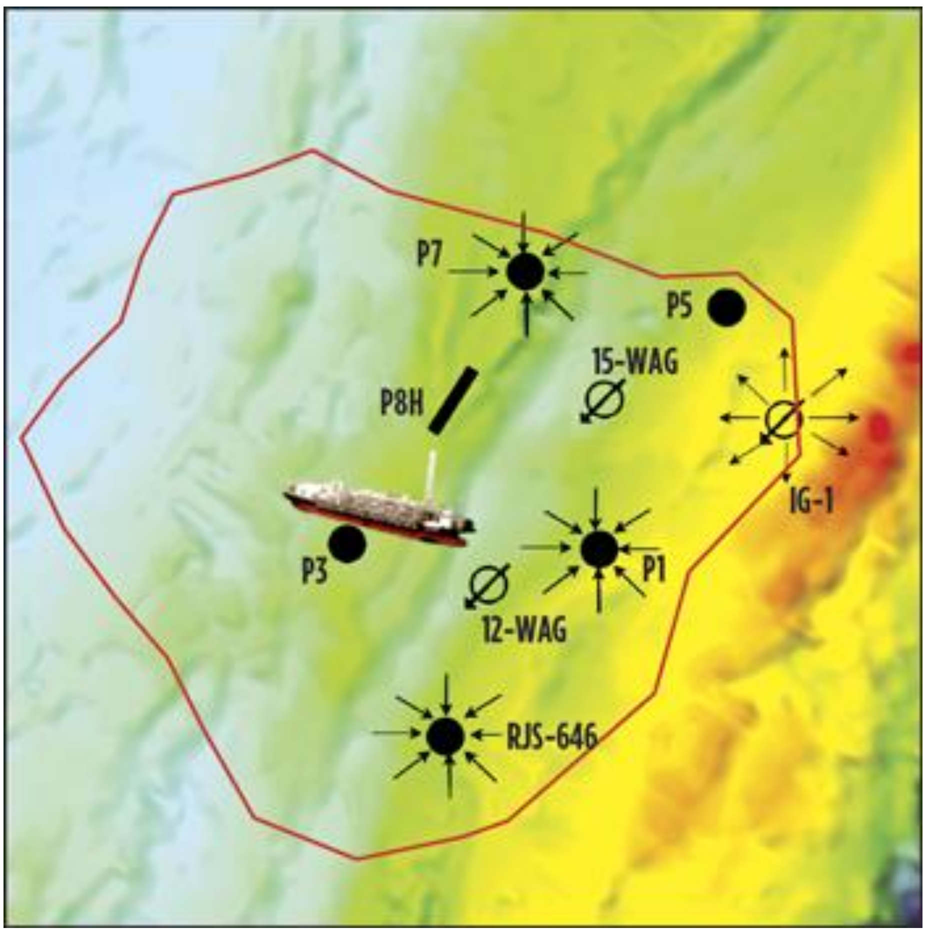
***Reservoir Characterization and Phased Development***. Petrobras is following a phased development of the Lula Field, allowing for its field development and EOR strategy to evolve as reservoir characterization and performance data improve. Importantly, the company is using Extended Well Tests (EWTs) to define reservoir connectivity and other key characteristics, and a phased development program to formulate their EOR strategy without waiting for results from the operation of a waterflood.

***Choosing a Recovery Method***. Petrobras decided early in its field development cycle not to vent the $CO_2$ produced at Lula, but to use this gas for miscible $CO_2$-EOR. In addition, the high $CO_2$ content present in the solution gas dictated that corrosion resistant alloys be used in all production wells enabling a $CO_2$-EOR flood to use existing wells and infrastructure without major refurbishment.

***First Development Phase.*** The first Lula EOR pilot consisted of one injection and one production well. In April 2011, Petrobras began injecting produced reservoir gas into the oil field at a rate of 35 MMcfd. After six months of gas re-injection, the hydrocarbon gas was separated from the $CO_2$ in the FPSO's membrane processing system and transported onshore for sale. The separated $CO_2$ was then re-injected into the reservoir at a rate of 12.3 MMcfd. A horizontal well was drilled in Q1 2012 and WAG injection, utilizing water and the high $CO_2$ concentration gas, commenced in the second half of 2012. Ultimately, the Lula EOR pilot will include one gas injector, two WAG injectors, and multiple producers, Figure 2-5.

The major takeaway from the Lula field case study is that early implementation of $CO_2$-EOR should be considered for giant, newly-discovered deep water offshore fields. As demonstrated by Petrobras, phased development, reservoir simulation and dynamic data acquisition, instead of waiting on the field's water flood performance, can be used to define how oil recovery will respond to $CO_2$-EOR.

**Figure 2-5 Planned well pattern for Lula's EOR pilot**




*Used with permission from the Society of Petroleum Engineers*[12]

### 2.3.3 North Sea Enhanced Oil Recovery History

***Past EOR Experience.*** Enhanced oil recovery using gas injection is not a new concept for North Sea oil fields. Eighteen such projects have been conducted to date, including EOR projects in major oil fields such as Brent, Ekofisk and Stratfjord, Table 2-1. However, these EOR projects have used hydrocarbon gas as the miscible agent instead of $CO_2$.

**Table 2-1 Hydrocarbon miscible EOR projects in North Sea oil fields**[13]

| Field | Operator | County | Type |
|---|---|---|---|
| Beryl | Exxon-Mobil | UK | HC Miscible |
| Brent | Shell | UK | HC Miscible |
| Alwyn North | Total | UK | HC Miscible |
| South Brae | Marathon | UK | HC WAG Miscible |
| Magnus | BP | UK | HC WAG Miscible |
| Ekofisk | Conoco-Phillips | NO | HC Miscible |
| Stratfjord | Statoil | NO | HC Miscible |
| Smorbukk South | Statoil | NO | HC Miscible |
| Snorre | Statoil | NO | HC WAG Miscible |
| Thistle | Lundin Oil | NO | HC WAG Immiscible |
| Gullfaks | Statoil | NO | HC WAG Immiscible |
| Brage | Norsk Hydro | NO | HC WAG Immiscible |
| Ekofisk | Conoco-Phillips | NO | HC WAG Immiscible |
| Stratfjord | Statoil | NO | HC WAG Immiscible |
| Oseberg | Norsk Hydro | NO | HC WAG Immiscible |
| Snorre A (CFB) | Norsk Hydro | NO | HC FAWAG |
| Snorre A (WFB) | Norsk Hydro | NO | HC FAWAG |
| Siri | Statoil | DK | HC SWAG |

Today, North Sea oil field operators are interested in substituting $CO_2$ for natural gas as the injectant for enhanced oil recovery. A number of factors, including opportunities to sell the hydrocarbon gas and interest in capturing and storing $CO_2$ from power plants, currently provide impetus for renewed consideration for combining $CO_2$-EOR and $CO_2$ storage in the oil fields of the North Sea.

***$CO_2$-EOR Projects for North Sea Oil Recovery and $CO_2$ Storage.*** A number of $CO_2$-based enhanced oil recovery projects have been considered for North Sea oil fields, including:

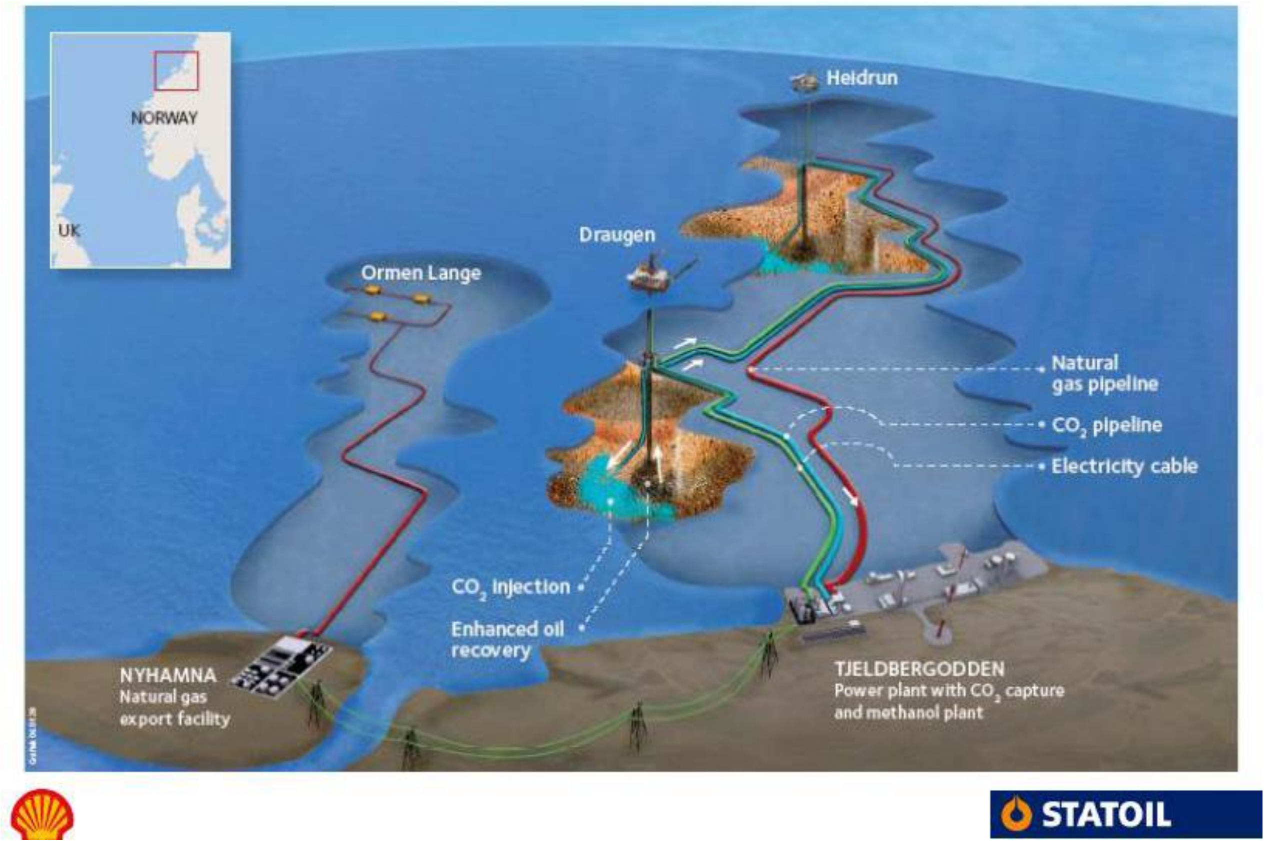
- **Draugen and Heidrun Oil Fields**. In 2006, Shell and Statoil announced plans for capture of $CO_2$ from onshore power generation with transport and injection of the $CO_2$ into two Norwegian sector offshore oil fields.

- **Don Valley Project.** The recently formed company, 2Co Energy, proposed an innovative $CO_2$-EOR project involving capturing $CO_2$ from the Don Valley IGCC power plant and transporting the $CO_2$ 300 km offshore to improve oil recovery and store $CO_2$ in two mature oil fields in the Central North Sea.
- **Miller Oil Field**. BP had defined a program to capture $CO_2$ from the Petershead gas-fired power station, storing the $CO_2$ with $CO_2$-EOR in the Miller offshore oil field. The project failed to receive government support and the Miller oil field is now abandoned.
- **Danish Oil Fields**. Maersk Oil submitted a plan to the EU for capturing of $CO_2$ from an oil refinery and transporting the $CO_2$, by ship, to oil fields in the Danish sector of the North Sea. This project is currently also on hold.
- **Tees Valley**. Progressive Energy also submitted a proposal to the EU involving the construction of a new IGCC power station with pipeline transportation of the captured $CO_2$ to Central North Sea oil fields for $CO_2$-EOR. This project is currently also on hold.

In the materials below, we further discuss two of the North Sea offshore EOR projects - - Draugen and Heidrun oil fields and the Don Valley Project.

***Using $CO_2$-EOR at Draugen and Heidrun Oil Fields.*** In 2006, Shell and Statoil announced the intent to utilize $CO_2$ for offshore EOR in the Norwegian sector of the North Sea. The Shell/Statoil JV project planned to capture $CO_2$ from onshore power generation and transport it offshore for injection, first in Shell's Draugen oil field and later in Statoil's Heidrun oil field, Figure 2-6. Both companies had good technical and management pedigrees for implementing the project. Shell pioneered using $CO_2$ for EOR in the 1970s and Statoil was the first to store $CO_2$ offshore at the Sleipner field in the 1990s. At the time, the project would have been the world's largest offshore $CO_2$-EOR operation.

**Figure 2-6 Proposed Draugen/Heidrun $CO_2$-EOR project**




*Used with permission from PennWell Corporation*[14]

After completing a technical study, the operator estimated that $CO_2$ flooding at Draugen would provide only modest volumes of additional oil recovery and, without incentives or financial support for $CO_2$ capture, the modest additional oil would not justify the cost of storing $CO_2$ with $CO_2$-EOR. The $CO_2$-EOR project required retrofitting production wells, drilling six new subsea wells to target the flanks of the oil field, and building a $CO_2$ pipeline. In addition, the platform (and thus oil production) needed to be shut down for a year, further increasing the financial impact of the project.

Although the Draugen Project was deemed to not be commercially viable, Shell and Statoil did determine that it was technically feasible. In today's environment, with higher oil prices, improved $CO_2$-EOR technology, and incentives to capture $CO_2$, future $CO_2$-EOR projects in North Sea oil fields may become economically viable.

***The Don Valley Project.*** The Don Valley Project is currently the most ambitious project for storing $CO_2$ with $CO_2$-EOR in the North Sea. The Project proposes to capture $CO_2$ from a 650 MW net (920 MW gross) coal gasification plant in the Yorkshire/Humber region of England and transport it 300 km offshore for injection into two aging Central North Sea oil fields.

The project is headed by 2Co Energy, with Shell, BOC/Linde, GE and Samsung C&T contributing in auxiliary roles. 2Co states that its CCS plant will capture and store up to 5 million metric tons (MMmt) of $CO_2$ a year.

Initially, the Don Valley Project was named by NER300, a €4.4 billion fund created by the EC to finance low carbon technologies, as a top prospect. However, the UK government did not pledge financial support for the project, making the project ineligible for NER300 funding. The UK government cited the Don Valley Project's £5 billion price tag including (£1 billion for offshore facilities, £3 billion for the power plant with $CO_2$ capture) as a main reason for their decision. 2Co is currently studying the economic feasibility of moving forward without governmental funding.

### 2.3.4 $CO_2$-EOR Offshore Abu Dhabi

The Marine Operating Unit of Abu Dhabi National Oil Company (ADNOC) has begun to examine the viability of injecting $CO_2$ into its offshore fields to improve oil recovery. Currently about 5 Bcfd of natural gas is injected to enhance oil recovery from the Abu Dhabi oil fields and ADNOC is looking to replace the hydrocarbon gas injection with $CO_2$.

In 2010, ADNOC initiated a feasibility study to determine the commercial viability of $CO_2$ flooding in the low permeability Lower Zakum field off the coast of Abu Dhabi. Talks are underway between ADNOC and Masdar, an Abu Dhabi renewable energy technology company, to capture 800,000 metric tons of $CO_2$ per year from a steel plant in Mussafah, UAE and use this $CO_2$ for enhanced oil recovery. ADNOC recently completed a successful two year $CO_2$-EOR pilot in the onshore Rumaitha field (injecting 1.2 MMcf/d) and is planning a further four to five onshore pilot $CO_2$-EOR projects for 2013 and 2014. The company plans to build upon its onshore EOR experience to implement $CO_2$-EOR in its offshore Persian Gulf oil fields to help achieve its goal of increasing oil production to 3.5 MMB/D from its current level of 2.8 MMB/D.

### 2.3.5 $CO_2$-EOR Offshore Vietnam

In 2007, Vietnam Oil and Gas Group (PETROVIETNAM), Japan Vietnam Petroleum Co., Ltd. (JVPC), and Japan Oil, Gas and Metals National Corporation (JOGMEC) completed a feasibility study that indicated that $CO_2$ injection into the oil fields in the South China Sea would increase oil recovery efficiency and provide storage for $CO_2$. To confirm the feasibility study's findings, the companies conducted a small scale $CO_2$ injection pilot test in June 2011. The pilot test consisted of a $CO_2$-EOR "Huff 'n' Puff" operation in the Rang Dong oil field, located 135 miles south-east of Vung Tau in Block 15-2 of the Cuu Long Basin. The pilot project was operated by JVPC with support from PETROVIETNAM and funding from JOGMEC.

In 2012, the companies declared the pilot test had successfully confirmed the main objectives of the pilot – adequate $CO_2$ injectivity and increased oil production.

### 2.3.6 Offshore Malaysia $CO_2$-EOR

Petronas has publically announced that two-thirds of the country's original oil in-place of 17 billion barrels is at risk of being stranded (after completion of primary/secondary recovery) without implementation of advanced EOR, Figure 2-7.

Based on this, starting in November of 2002, Petronas initiated a four year $CO_2$-EOR pilot in the Dulang oil field. The oil field is located 130 km offshore from Terengganu, eastern Malaysia, in

250 feet of water. The offshore oil field is one of Malaysia's largest with 1.1 billion barrels of OOIP and an estimated primary/secondary recovery of 328 million barrels, including the use of water injection to combat falling reservoir pressure. The field's produced gas contains a high concentration of $CO_2$ (>50 percent).

**Figure 2-7 Offshore oil fields, Malaysia**


*Source: U.S. Department of State*[15]

Petronas determined that Dulang's initial reservoir pressure was nearly 1,000 psig below minimum miscibility pressure (MMP), ruling out miscible or near-miscible gas injection. As such, the company decided to conduct a pilot immiscible water-alternating-gas (IWAG) flood that would re-inject the $CO_2$-rich produced gas back into the reservoir. The EOR pilot consisted of 3 producers and 3 injectors in the S3 Block of the Dulang Field. Petronas injected 4 MMcf/d of $CO_2$ and 3.5 MB/D of water in cycles lasting 3 months each.

After four years of operation, the IWAG EOR Pilot was terminated in 2006 and deemed a success by Petronas. The operator concluded that the offshore IWAG EOR Pilot was operationally manageable, significantly increased oil production, and reduced the water cut. Field wide application of an IWAG flood was recommended, but has yet to be implemented.

More recently, Petronas signed two new production sharing contracts (PSCs) in 2011 with Shell Malaysia for evaluating thirteen EOR projects offshore Sarawak and Sabah, looking to increase average oil recovery in the fields from 36 percent of OOIP to 50 percent of OOIP, according to Shell.

# 3 GOM OCS Hydrocarbon Resource Base

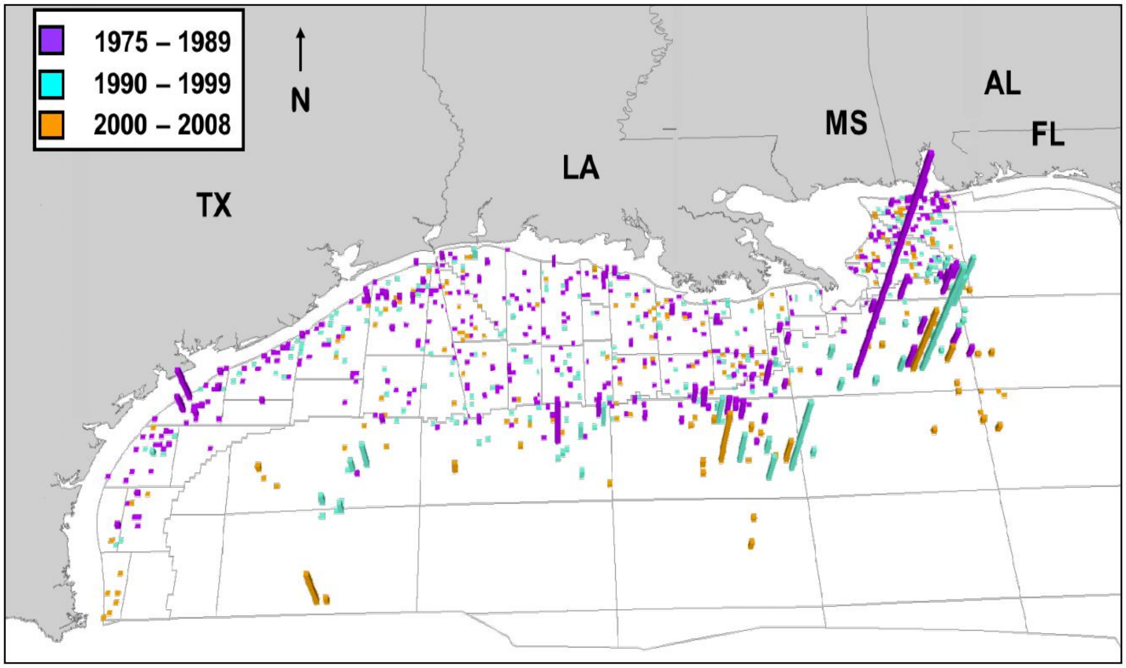
## 3.1 GOM OCS Discovered Field and Proved Reserves

The Federal Offshore (OCS) Gulf of Mexico (GOM) holds a major portion of the domestic crude oil resource base - - in mature, shallow water oil fields as well as in newly discovered and undiscovered oil fields in deep, far from shore waters. The latest U.S. Department of Interior Bureau of Ocean Energy Management (BOEM) (formerly the Mineral Management Survey [MMS]) reserves report provides information on the resource size and development status of Gulf of Mexico OCS oil fields.[16]

- The GOM OCS contains 1,278 discovered and proved oil and gas fields. Of these 1,278 proved oil and gas fields, 891 are active and 387 are now depleted and abandoned.
- These 1,278 oil and gas fields, consisting of 238 oil fields and 1,040 natural gas fields, contained Original Proved Reserves of 21.2 billion barrels of oil and 190.2 Tcf of natural gas, equal to a combined 54 billion BOE. Through the end of 2009, these fields have produced 16.5 billion barrels of oil and 176.8 Tcf of natural gas, leaving 4.7 billion barrels of oil and 13.4 Tcf of natural gas as Remaining Proved Reserves, equal to a combined 7.0 billion BOE.
- The 238 GOM OCS oil fields contain 8,228 reservoirs with each oil field holding one to several dozen reservoirs. (The BOEM often uses the term sands for reservoirs.) Our analysis of $CO_2$-EOR in the GOM offshore is performed at the individual reservoir (sand) level and then aggregated to the field level.
- The GOM OCS also contains 0.3 billion barrels of oil and 1.1 Tcf of natural gas categorized as Reserves Justified for Development plus 6.3 billion barrels of oil and 16.3 Tcf of natural gas categorized as Contingent Reserves. These two resource categories are not included in the above Proved Reserves data. According to the BOEM, "As additional drilling and development occur, additional hydrocarbon volumes will become reportable, and BOEM anticipates future proved reserves . . . to increase."

Figure 3-1 shows the location of the proved fields (oil and natural gas) discovered in the GOM since 1975, noting the steady progression of discoveries toward deeper waters containing large oil fields. To date, nearly 50,000 wells have been drilled in these fields, with 14,400 of these completions still active.

**Figure 3-1 Location and discovery sequence for proved discovered oil and gas fields, GOM OCS**




*Source: Bureau of Ocean Energy Management*[17]

## 3.2 GOM OCS Undiscovered Reserves

In addition to Proved, Justified for Development and Contingent Reserves, the GOM OCS has significant volumes of oil remain to be discovered. Based on the latest Bureau of Energy Management (BOEM) assessment, the GOM OCS is estimated to have 48.4 billion barrels of undiscovered, technically recoverable oil resources (UTRR), with 42.8 billion barrels economically recoverable (at an oil price of $90/Bbl).[16] As these offshore oil resources are discovered and developed, they will significantly increase the size of the GOM OCS resource amenable for $CO_2$-EOR.

## 3.3 GOM OCS Oil Production

After reaching its first peak in oil production of 1.54 million barrels per day (MMB/D) in 2003, production from the GOM OCS went into decline as the shallow waters of the GOM became progressively mature. Increases in deep water oil production (water depth of 1,000 feet and deeper) helped mitigate this decline and reach a second peak of 1.58 MMB/D followed by a second decline to 1.26 MMB/D as of mid-2013, Table 3-1.

- Shallow water GOM offshore oil production peaked in the late 1990s at nearly 800 thousand barrels per day (MB/B). Since then, oil production has declined to 321 MB/D in 2009 (last year of oil data from BOEM for shallow water).
- Deep water GOM oil production reached a peak of 1.26 million barrels per day in 2009 (last year of data from BOEM for deep water). With the moratorium on drilling and the

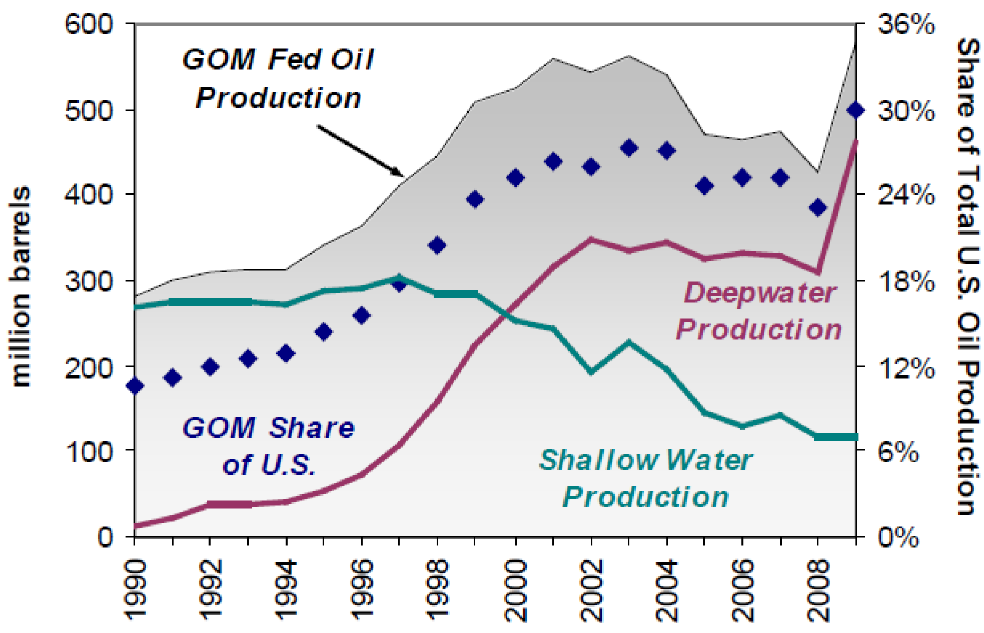
overall decline in GOM oil production, we would expect deepwater GOM oil production to also have declined.

**Table 3-1 GOM OCS oil production, by water depth***

| Year | Shallow Water (MB/D) | Deep Water (MB/D) | Total (MB/D) |
|---|---|---|---|
| 2003 | 622 | 920 | 1,542 |
| 2004 | 540 | 940 | 1,480 |
| 2005 | 397 | 893 | 1,290 |
| 2006 | 356 | 915 | 1,271 |
| 2007 | 389 | 904 | 1,293 |
| 2008 | 318 | 838 | 1,156 |
| 2009 | 321 | 1,260 | 1,581 |
| 2010 | | | 1,551 |
| 2011 | | | 1,317 |
| 2012 | | | 1,267 |
| 2013 (est.) | | | 1,260 |

Figure 3-2 provides a longer-term overview of shallow water, deep water and total GOM OCS oil production.

**Figure 3-2 GOM federal offshore oil production**




*Source: U.S. Energy Information Administration*[18]

Looking forward, oil production from the GOM OCS is expected to rebound to 1.39 MMB/D in 2014, according to EIA's Short Term Energy Outlook[19]. This oil production increase would result from eight large deep water oil fields due to come on-line, including the large Jack-St. Malo joint field, peak production of 100,000 B/D, plus Lucius, Big Foot, Tubular Bells, Atlantis Phase 2 and others with a combined peak production of over 200,000 B/D, **Table 3-2**.

**Table 3-2 New GOM OCS oil fields expected on-line**[20]

| Oil Field | Start Date | Peak Date (Date) | Production (M Bbls/D) |
|---|---|---|---|
| Jack- St. Malo | Jan-14 | Aug-14 | 100 |
| Entrada | Mar-14 | Oct-14 | 3 |
| Dalmatian | Mar-14 | Oct-14 | 7 |
| Big Foot | Jun-14 | Jan-15 | 50 |
| Tubular Bells | Jun-14 | Jan-15 | 40 |
| Lucius | Sep-14 | Apr-15 | 70 |
| Atlantis Phase 2 | Sep-14 | Apr-15 | 50 |
| Hadrian South | Sep-14 | Apr-15 | 5 |

## 3.4 Key Features of GOM OCS Oil Fields

Four features provide perspective on the potential for using $CO_2$-EOR in the Gulf of Mexico OCS:

- ***Large Anchor Oil Fields***. First, much of the oil resource is held in large fields. Offshore $CO_2$-EOR efforts would initially target these large fields that subsequently would support expansion of $CO_2$-EOR to the numerous smaller, surrounding oil fields.
- ***Mature Shallow Water Oil Fields***. Second, essentially all of the large GOM shallow water oilfields are mature, with only modest volumes of remaining proved reserves. As such, there is critical need for acceleration of shallow water $CO_2$-EOR preparation and development before this large remaining domestic resource is abandoned. (Once the offshore production platform is removed, the use of $CO_2$-EOR for storing $CO_2$ becomes much more challenging.)
- ***Maturing Deep Water Oil Fields***. Third, a significant number of the GOM deep water oil fields, having also produced 90 percent or more of their original proved reserves, are also approaching abandonment. There is need for accelerated $CO_2$-EOR development in selected deep water GOM oil fields as well.

- ***$CO_2$-EOR for Newly Discovered Ultra-Deep Water Oil Fields***. Fourth, new discoveries in the deep and ultra-deep waters of the GOM OCS continue, with a large number of these expected to be placed on production in the next several years. Early integration of $CO_2$-EOR into the facility design and field development and production strategies for these newly discovered oil fields could provide improved oil recovery with more favorable economics, as illustrated for the giant Lula (Tupa Area) oil field offshore of Brazil.

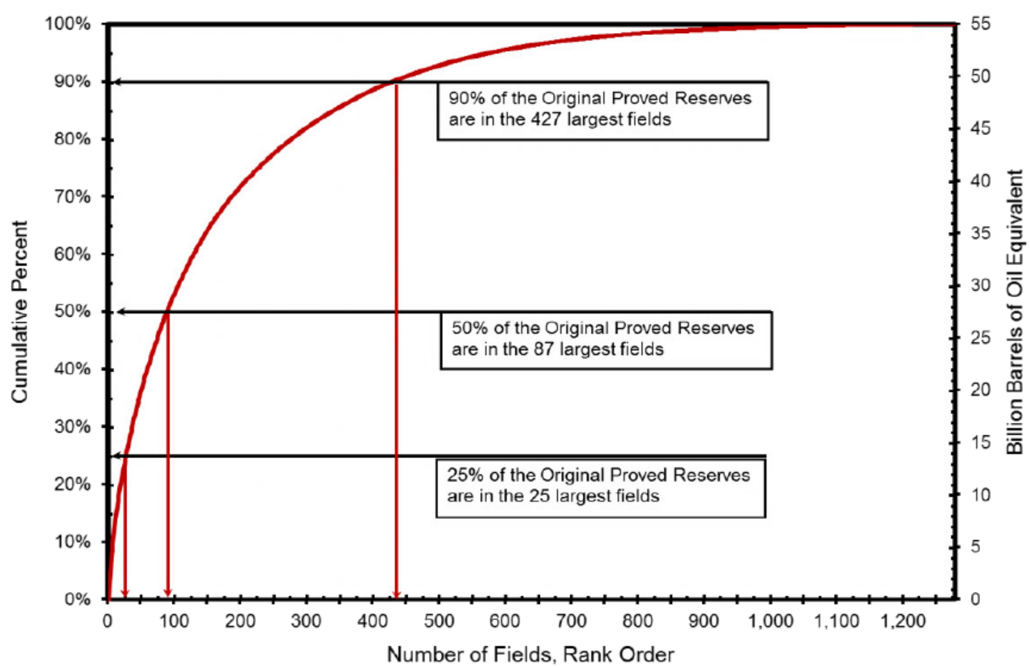
### 3.4.1 Field Size Distribution for GOM OCS Oil Fields and Reserves.

As is common for natural resources, the great bulk of the GOM OCS oil and natural gas resource is held by large fields, as illustrated in Figure 3-3 that tracks cumulative proved reserves versus number of oil fields for the GOM OCS:

- Twenty-five percent of the original proved hydrocarbon reserves of 54 billion BOE are contained in just 25 giant offshore GOM OCS fields.
- Half of the original proved hydrocarbon reserves are in 87 large offshore fields.
- Ninety percent of the original proved hydrocarbon reserves are contained in the 427 largest fields, with the remaining 851 fields holding only 10 percent of the original proved reserves in the GOM OCS.

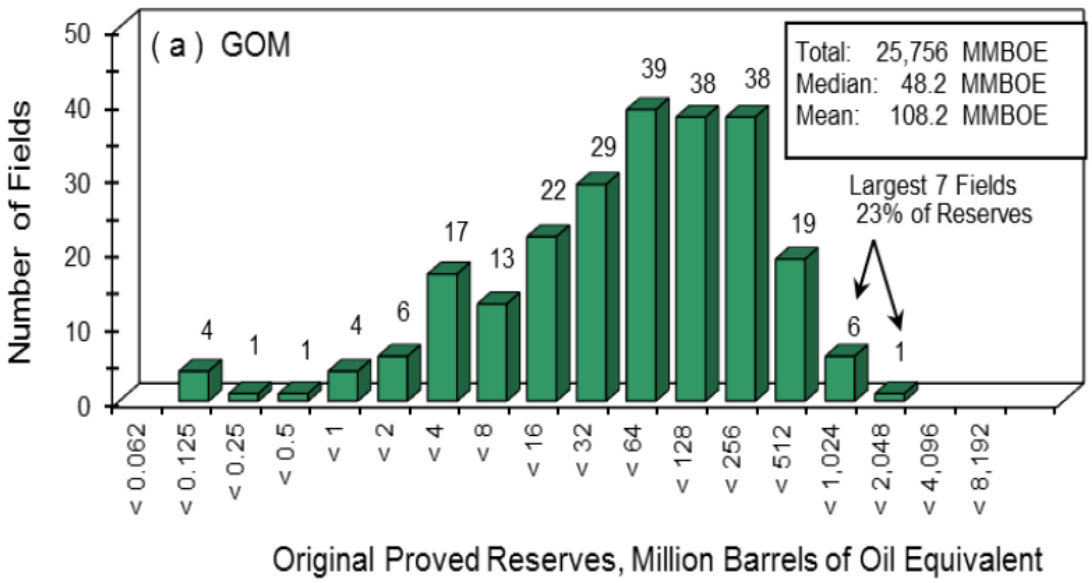
The field-size distribution data for the 238 oil fields shows that seven of the largest oil fields hold nearly a quarter of the original proved reserves, Figure 3-4.

**Figure 3-3 Cumulative reserves versus field size for 1,278 proved fields (GOM OCS)**




*Source: Bureau of Ocean Energy Management*[21]

**Figure 3-4 Field-size distribution for 238 GOM proved oil fields**

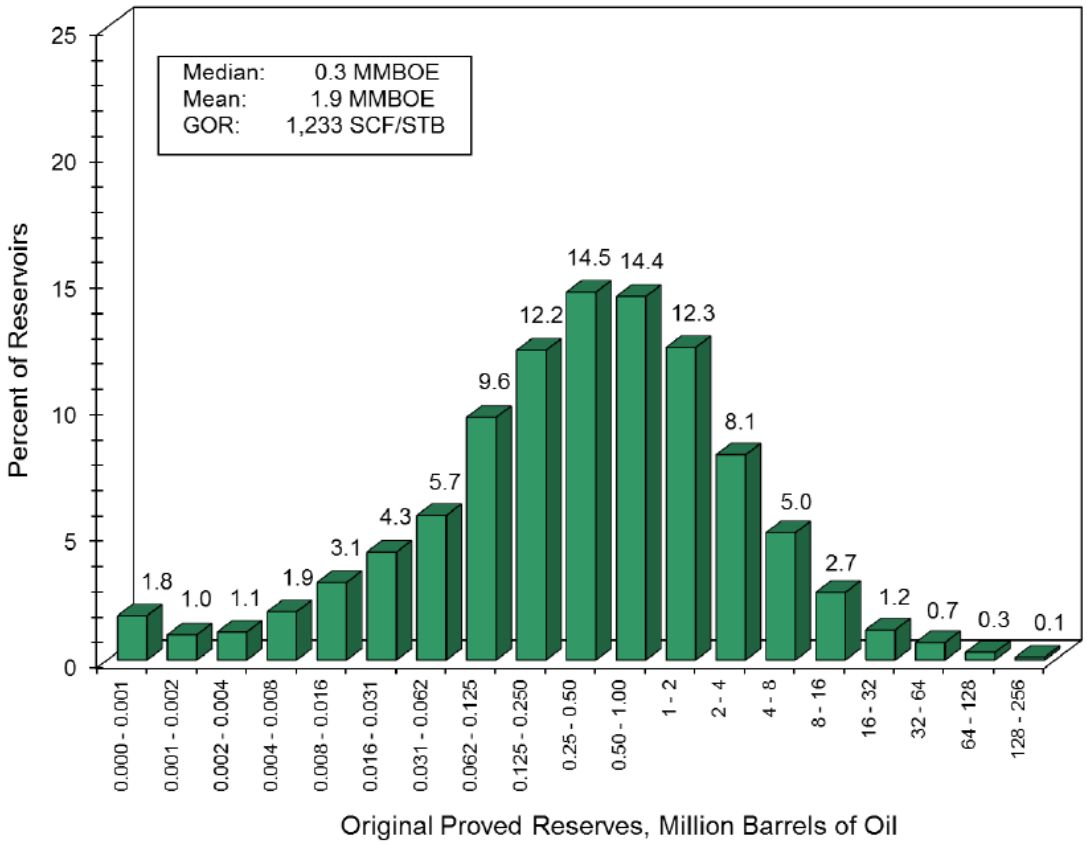



*Source: Bureau of Ocean Energy Management*[22]

A similar size distribution, shown for oil fields, exists for the oil reservoirs (sands) in the GOM OCS. The 8,228 oil reservoirs contained in the 238 proved oil fields range from very small to large, Figure 3-5.

- About 18 percent of the reservoirs (1,500) are large, with each reservoir holding more than 2 million barrels of Original Proved Oil Reserves (with a handful of these holding 100 million barrels or more).
- About 28 percent of reservoirs (2,900) are very small with each reservoir holding less than 125,000 of Original Proved Oil Reserves
- The bulk of the reservoirs (about 54 percent or 4,400) are modest in size, with each reservoir holding from 125,000 to 2 million barrels of Original Proved Oil Reserves.

**Figure 3-5 Reservoir-size distribution for 8,228 GOM proved oil reservoirs**




*Source: Bureau of Ocean Energy Management*[23]

### 3.4.2 Status of the Large GOM OCS Oil Fields.

Because so much of the GOM OCS resource is contained in big oil fields, it is useful to take a closer look at this set of fields. The ten largest proved oil fields (as of end of 2009) contain 5.6 billion barrels of the 21.2 billion barrels of Original Proved Oil Reserves in the GOM OCS, Table 3-3.

**Table 3-3 Ten largest GOM OCS proved oil fields[24]**

| Field Name | Original Proved Oil Reserves | Remaining Proved Oil Reserves | Water Depth |
|---|---|---|---|
| | (MMB) | (MMB) | (feet) |
| MC807—Mars-Ursa | 1,326 | 387 | 3,335 |
| MC778—Thunder Horse | 733 | 684 | 6,078 |
| WD 030 | 641 | 70 | 48 |
| BM 002 | 536 | 7 | 50 |
| EI 330 | 434 | 6 | 247 |
| GC 640—Tahiti | 414 | 391 | 4,312 |
| GC 743-Atlantis | 397 | 328 | 6,297 |
| GI 043 | 384 | 16 | 140 |
| MC 776 –N. Thunder Horse | 383 | 347 | 5,665 |
| GI 016 | 304 | 3 | 54 |

- The five large, shallow water oil fields (WD030, BM002, EI330, GI043 and GI016), that together hold 2.3 billion barrels of Original Proved Oil Reserves, are highly mature having produced over 95 percent of their original endowment and are nearing abandonment, with only 100 million barrels of combined remaining reserves.
- Four of the large, deep water oil fields (MC778 (Thunder Horse), GC743 (Atlantis), MC776 (N. Thunder Horse), and GC640 (Tahiti)) are just starting to be developed. Early consideration of $CO_2$-EOR would, in our view, be a prudent design strategy for these new deep water oilfields.
- The fifth and largest deep water oil field, MC807 (Mars-Ursa), with over 1.3 billion barrels of Original Proved Oil Reserves, is steadily nearing maturity with over 70 percent of its original oil endowment already produced. The technical literature reports that initial efforts are underway for starting a secondary recovery waterflood in this giant oil field. With access to affordable $CO_2$, it may be prudent to complement this secondary recovery waterflood with a $CO_2$ miscible flood.

## 3.5 Gulf of Mexico Shallow Water vs. Deep Water Fields.

A review of the 1,278 fields shows that the great bulk of the discovered oil and gas fields and resources have, through 2009, been in the shallow waters. However, the great bulk of the

Remaining Proved Reserves are in the smaller number of deep water (1,000 feet of water depth or greater) fields discovered more recently, Table 3-4.

**Table 3-4 GOM proved fields and proved reserves by water depth**

| Water Depth (feet) | Number of Proven Fields | Original Proved Reserves (MMBoe) | Remaining Proved Reserves (MMBoe) |
|---|---|---|---|
| <1,000 | 1,129 | 44,949 | 1,859 |
| ≥1,000 | 149 | 12,083 | 5,184 |
| **Total** | **1,278** | **57,032** | **7,043** |

### 3.5.1 Mature Shallow Water Oil Fields

As illustrated by the status of the five giant shallow water GOM OCS oil fields (Table 3-3) and the data in Table 3-4, the shallow water oil fields in the GOM are near depletion, with less than 5 percent of their Original Proved Reserves remaining to be produced. As such, there is urgent need to consider using $CO_2$-EOR to extend the life of these fields, particularly for providing options for storing $CO_2$ captured from power plants and other industrial facilities along the Gulf Coast.

### 3.5.2 Mature Deep Water Oil Fields

While many of the large deep water oil fields, such as Atlantis and Thunder Horse, have only recently come on-line, a number of the previously discovered large, deep water oil fields are also reaching maturity. These older deep water oil fields could also benefit from application $CO_2$-EOR before being abandoned and having their platforms removed.

Set forth below (in Table 3-5) are five large (each with Original Proved Reserves of over 100 MM Bbls), deep water oil fields that have produced 90 percent or more of their oil endowment. This list includes notable fields such as Auger and Bullwinkle that overcame the deep water barrier with use of tension-leg and other leading platform technology and deep water production practices.

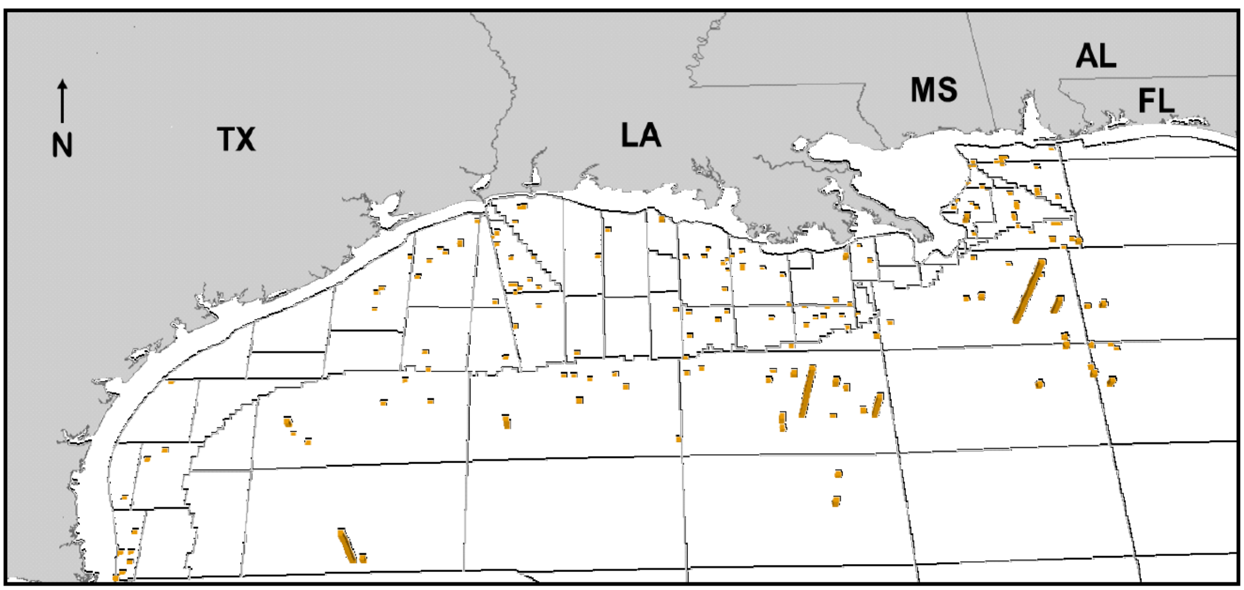
**Table 3-5 Large, mature GOM deep water oil fields**

| Field Name | Original Proved Reserves | Cumulative Production | Remaining Reserves |
|---|---|---|---|
| | (MMB) | (MMB) | (MMB) |
| GB 426 Auger | 244 | 224 | 20 |
| GC 244 Troika | 193 | 163 | 30 |
| MC 194 Cognac | 182 | 178 | 4 |
| GC 065 Bullwinkle | 103 | 98 | 5 |
| GC 205 Genesis | 105 | 95 | 10 |

### 3.5.3 Progression towards Deeper Waters and Deeper Reservoirs

As the shallower water areas (less than 1,000 feet of water depth) of the GOM have become developed, exploration has progressively moved toward deeper waters. Figure 3-6 illustrates this progression, noting the location and relative size of the recently discovered (2000 to 2008) oil and gas oil fields.

**Figure 3-6 Location of proved fields discovered between 2000-2008**




*Source: Bureau of Ocean Energy Management*[25]

This progression towards deeper waters is important for offshore $CO_2$-EOR because, while the shallower waters of the GOM tended to be gas prone, the deeper waters of the GOM are oil prone with lower overall oil recovery efficiencies. In addition, an increasing number of the new discovered deep water oil fields are at great reservoir depth (more than 20,000 feet), with high well drilling and completion costs. Early consideration of $CO_2$-EOR in the well placement and construction strategy for these deep water, deep reservoir oil fields could help reduce the future costs of conducting $CO_2$-EOR in these costly to drill fields.

# 4 The Gulf of Mexico OCS Oil Field and Reservoir Database

The Bureau of Ocean Energy Management (BOEM) has assembled reservoir-level information on each of the proved oil fields and reservoirs (sands) in the GOM OCS. We have relied extensively on this database to individually model (using the PROPHET2 stream-tube finite difference reservoir simulator) each of the large, prospective oil reservoirs in this database and aggregated the results into our GOM OCS $CO_2$-EOR resource assessment.

In addition, the BOEM publishes information on estimates of undiscovered GOM OCS oil and gas resources. While the BOEM databases provided the important starting point, we undertook a series of additional steps to screen and consolidate the data for use in the resource assessment.

## 4.1 Incorporating the GOM OCS Database into the $CO_2$-EOR Resource Assessment

Our methodology for converting the BOEM database into the ARI Offshore GOM Big Oil Fields Database and Analytic System (GOM BODS) is as follows:

- First, we obtained from the Bureau of Ocean Energy Management (BOEM) the latest information on offshore Gulf of Mexico reservoirs (referred to as "sands" by the BOEM) including rock characteristics, oil fluid properties, original oil in-place (OOIP), cumulative oil production, and remaining reserves. This database was released in 2012, for estimating GOM OCS oil and gas reserves as of 2008.
- Next, we added a variety of special features to the BOEM database so that it could be used in our GOM OCS $CO_2$-EOR Analytic System. These additions included:
    - Calculations to estimate each reservoir's minimum miscibility pressure (MMP),
    - Volumetric calculations to estimate and verify each reservoir's original oil in-place (OOIP),
    - Calculations to estimate each reservoir's sweep efficiency and use of this data to estimate reservoir heterogeneity,
    - Estimations of the residual oil saturation in each reservoir's swept zone,
    - Calculations to estimate the oil and water viscosity for each reservoir, and
    - Calculations of the $CO_2$ and water injectivity for each reservoir.
- Finally, we formatted the GOM OCS data so that the information for each reservoir could be efficiently placed into our $CO_2$-PROPHET2 reservoir simulator and into our GOM Offshore Economic Model to estimate economically feasible oil recovery and $CO_2$ storage. Figure 4-1 illustrates the reservoir data inputs assembled for each offshore GOM oil field and reservoir used in the $CO_2$-EOR resource assessment.

## 4.2 Screening the BOEM GOM OCS Discovered Oil Fields Database

A significant effort was devoted to screening the large BOEM Gulf of Mexico OCS database for the final set of discovered oil fields and reservoirs to be placed into ARI's GOM BODS. This screening process involved applying oil field and reservoir size limits and using our $CO_2$-PROPHET2 reservoir and economic models to exclude economically non-viable reservoirs.

## Figure 4-1 GOM OCS reservoir data input sheet for GOM BOD

| | | | |
|---|---|---|---|
| **Basin Name** | | **Area:** | |
| **State** | | | To change Basin, click on cell above |
| **Field Name** | | **Reservoir Number** | |
| | | **Manual** | |
| **Reservoir** | | **Total Reservoirs** | |

**Reservoir Parameters:**

| | |
|---|---|
| Area (A) | |
| Net Pay (ft) | |
| Depth (ft) | |
| Lithology | |
| Dip (°) | |
| Gas/Oil Ratio (Mcf/Bbl) | |
| Salinity (ppm) | |
| Gas specific Gravity | |
| Historical Well Spacing (Acres) | |
| Current Pattern Acreage (Acres) | |
| Permiability (mD) | |
| Porosity (%) | |
| Reservoir Temp (deg F) | |
| Initial Pressure (psi) | |
| Pressure (psi) | |
| $B_{oi}$ | |
| $B_o$ @ $S_o$, swept | |
| $S_{oi}$ | |
| $S_{or}$ | |
| $S_{wi}$ | |
| $S_w$ | |
| API Gravity | |
| Viscosity (cp) | |
| Dykstra-Parsons | |

**Miscibility:**

| | |
|---|---|
| C5+ Oil Composition | |
| Min Required Miscibility Press(psig) | |
| Depth > 3000 feet | |
| API Gravity >= 17.5 | |
| Pr > MMP | |
| Flood Type | |

**Oil Production**

| | |
|---|---|
| Producing Wells (active) | |
| Producing Wells (shut-in) | |
| 2010 Production (MMbbl) | |
| 2010 P/S Production (MMbbl) | |
| Cum Oil Production (MMbbl) | |
| EOY 2010 Oil Reserves (MMbbl) | |
| Water Cut | |

**Water Production**

| | |
|---|---|
| 2010 Water Production (Mbbl) | |
| Daily Water (Mbbl/d) | |

**Injection**

| | |
|---|---|
| Injection Wells (active) | |
| Injection Wells (shut-in) | |
| 2008 Water Injection (MMbbl) | |
| Daily Injection - Field (Mbbl/d) | |
| Cum Injection (MMbbl) | |
| Daily Inj per Well (Bbl/d) | |

**EOR**

| | |
|---|---|
| Type | |
| 2010 EOR Production (MMbbl) | |
| Cum EOR Production (MMbbl) | |
| EOR 2010 Reserves (MMbbl) | |
| Ultimate Recoverery (MMbbl) | |

**OGJ Data**

| | |
|---|---|
| 2010 Enhanced Production (B/d) | |
| 2010 Total Production (B/d) | |
| Project Acreage | |
| Scope | |
| # Projects | |

**Volumes**

| | |
|---|---|
| OOIP (MMbl) | |
| Cum P/S Oil (MMbl) | |
| EOY 2010 P/S Reserves (MMbl) | |
| Ultimate P/S Recovery (MMbl) | |
| Remaining (MMbbl) | |
| Ultimate P/S Recovered (%) | |
| P/S Sweep Efficiency (%) | |

**OOIP Volume Check**

| | |
|---|---|
| Reservoir Volume (AF) | |
| Bbl/AF | |
| OOIP Check (MMbl) | |

**SROIP Volume Check**

| | |
|---|---|
| Reservoir Volume (AF) | |
| Swept Zone Bbl/AF | |
| SROIP Check (MMbl) | |

**ROIP Volume Check**

| | |
|---|---|
| ROIP Check (MMbl) | |

### 4.2.1 Excluding Small and Economically Non-Viable Oil Fields and Reservoirs.

We started with a BOEM database of 531 GOM OCS oil and gas fields, containing 4,709 active oil reservoirs (sands). These fields and reservoirs hold 68.6 billion barrels (B Bbls) of original oil in-place (OOIP) and 47.6 B Bbls of expected remaining oil in-place (ROIP), Table 4-1.

**Table 4-1 Original BOEM GOM OCS oil field database**

| Oil Fields | Reservoirs (Sands) | OOIP | Cum. Prod | Remaining Proved Reserves | ROIP |
|---|---|---|---|---|---|
| (#) | (#) | (BBbls) | (BBbls) | (BBbls) | (BBbls) |
| 531 | 4,709 | 68.8 | 14.4 | 6.6 | 47.6 |

**A significant number of offshore fields designated as gas fields contain oil reservoirs.*
***The BOEM data base that we used did not include inactive, abandoned oil fields and oil reservoirs.*
****Includes 1.8 B Bbls of reserves added to as undeveloped deep water oil fields to reflect Expected P/S Recovery.*

We excluded oil fields and reservoirs holding less than 10 million barrels (MM Bbls) of OOIP. Based on our analysis, these reservoirs are deemed too small for economically viable $CO_2$-EOR. This provided a much smaller set of oil fields (294) and oil reservoirs (1,091) but retained the great majority (87 percent) of the remaining oil resource in the GOM OCS, Table 4-2.

**Table 4-2 Large GOM OCS oil reservoirs database**

| Oil Fields | Reservoirs (Sands) | OOIP | Cum. Prod | Remaining Proved Reserves | ROIP |
|---|---|---|---|---|---|
| (#) | (#) | (BBbls) | (BBbls) | (BBbls) | (BBbls) |
| 294 | 1,091 | 59.3 | 11.5 | 6.2 | 41.6 |

We further screened the remaining reservoir database for reservoirs with highly efficient primary/secondary recovery and low residual oil saturations (less than 20 percent Sor). This excluded only a small set of reservoirs and modest volumes of remaining oil.

We also examined the oil reservoir database for reservoirs that would significantly reduce the economic viability of conducting $CO_2$-EOR. These consisted of low permeability and/or largely undrilled oil reservoirs that would require extensive additional well drilling. Because the $CO_2$-EOR process in the offshore is applied at the field level, as opposed at the reservoir level in the onshore, this step is consistent with screening steps expected to be undertaken by an offshore oil field operator. This screening step excluded a modest number of low permeability, lightly drilled oil reservoirs.

Finally, after exclusion of the small, low residual oil saturation and economically unviable oil reservoirs, we re-evaluated the minimum viable size of the oil fields (with their remaining viable oil reservoirs) for offshore $CO_2$-EOR.

- For shallow water oil fields, we excluded all proved oil fields with less than 50 MM Bbls of OOIP.
- For deep water oil fields, we excluded all proved oil fields with less than 50 MM Bbls of OOIP and all unproved oil fields with less than 100 MM Bbls of OOIP.

### 4.2.2 The Final Offshore GOM OCS Discovered Big Oil Fields Database.

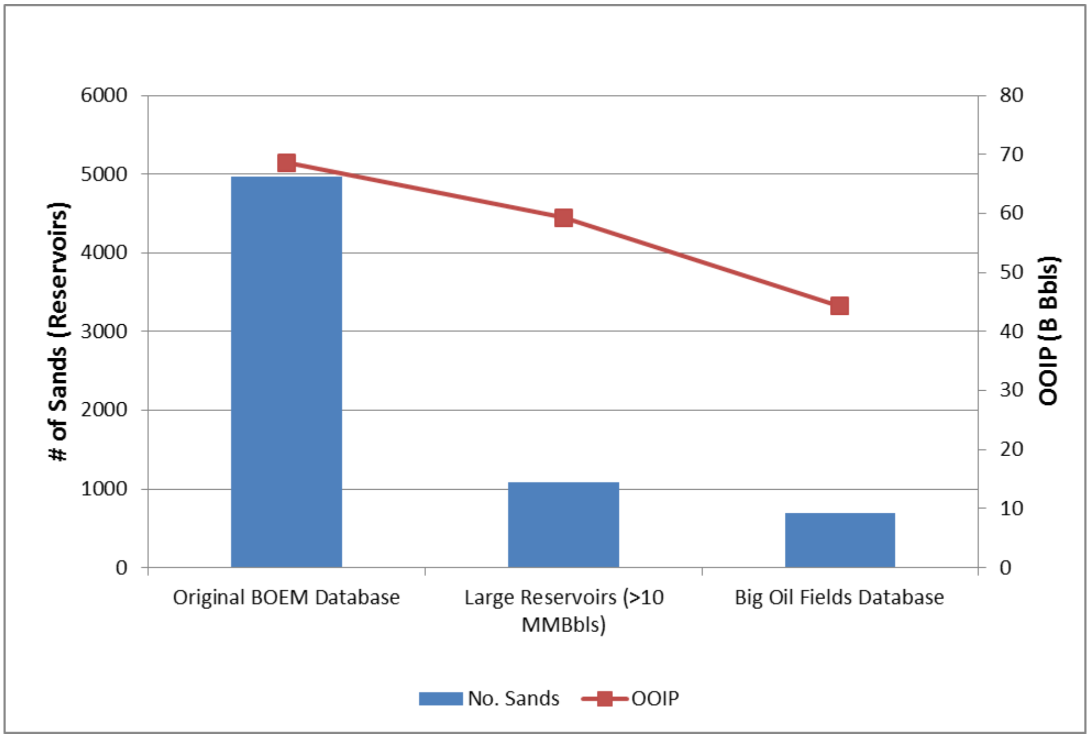
These final screening steps resulted in an Offshore Gulf of Mexico Big Oil Fields Database containing 140 large discovered oil fields with 696 significant size oil reservoirs. These oil fields hold 44.3 B Bbls of OOIP and 29.4 B Bbls of remaining oil in-place (ROIP). While the number of oil fields and reservoirs have been significantly reduced, this final database still contains nearly two-thirds (65 percent) of the discovered Original Oil Reserves and over 60 percent of the remaining oil resource in the Federal offshore waters of the Gulf of Mexico, Table 4-3 and Figure 4-2.

**Table 4-3 Oil Fields and reservoir in the offshore GOM big oil fields database**

| Oil Fields | Reservoirs (Sands) | OOIP | Cum. Prod | Proved Reserves* | ROIP |
|---|---|---|---|---|---|
| (#) | (#) | (BBbls) | (BBbls) | (BBbls) | (BBbls) |
| 140 | 696 | 44.3 | 9.3 | 5.6 | 29.4 |

**Proved reserves includes 1.8 B Bbls of reserves added to undeveloped deep water fields based upon expected average deep water P/S recovery.*

**Figure 4-2 Database screening progression: number of reservoirs vs. total OOIP**




## 4.3 Partitioning the GOM OCS Discovered Big Oil Fields Database by Water Depth.

The above screened database was then partitioned into a shallow and a deep water GOM OCS database, as further discussed below.

### 4.3.1 Shallow Water GOM Database.

The Shallow Water Offshore Gulf of Mexico Big Oil Fields Database used for this resource assessment includes 80 oil fields comprised of 512 reservoirs (sands) with OOIP of 15.8 B Bbls and ROIP of 9.2 B Bbls, Table 4-4. This final database has been screened down from the original BOEM database of 404 shallow water oil fields contains 4,044 sands (reservoirs), with OOIP of 28.7 B Bbls.

**Table 4-4 Shallow water GOM big oil fields and reservoirs database**

| | Original BOEM Database | Final ARI Database |
|---|---|---|
| No. Fields | 404 | 80 |
| No. Sands (Reservoirs) | 4,044 | 512 |
| OOIP (B Bbls) | 28.7 | 15.8 |
| Cum P/S Prod. (B Bbls) | 11.0 | 6.4 |
| Remaining Reserves (B Bbls) | 0.6 | 0.2 |
| P/S Recovery Efficiency (%) | 40% | 42% |

Table 4-5 lists the 80 large shallow water oil fields used in the GOM OCS $CO_2$-EOR resource assessment.

**Table 4-5 Shallow water GOM oil fields included in the resource assessment**

| Shallow Water Database | | | | | | |
|---|---|---|---|---|---|---|
| **Field** | **Field Name** | **# of Reservoirs** | | **Field** | **Field Name** | **# of Reservoirs** |
| BM002 | | 22 | | SM073 | | 7 |
| EB165 | Snapper | 2 | | SM115 | | 2 |
| EC271 | | 4 | | SM128 | | 10 |
| EC321 | | 5 | | SM130 | | 9 |
| EC338 | | 5 | | SM236 | Amber | 3 |
| EC359 | | 1 | | SM239 | Trinity Shoal | 2 |
| EI032 | | 3 | | SM269 | | 7 |
| EI126 | | 11 | | SP027 | East Bay | 13 |
| EI175 | | 3 | | SP049 | | 3 |
| EI188 | | 3 | | SP061 | | 20 |
| EI238 | | 4 | | SP062 | | 11 |
| EI258 | | 3 | | SP065 | | 7 |
| EI276 | | 7 | | SP078 | | 7 |
| EI330 | | 16 | | SP089 | | 7 |
| EI342 | | 3 | | SS107 | | 2 |
| EI361 | | 4 | | SS113 | | 5 |
| EW826 | | 4 | | SS154 | | 6 |
| EW873 | Lobster/Oyster | 4 | | SS169 | | 11 |
| GC019 | Boxer | 8 | | SS208 | | 8 |
| GI016 | | 15 | | SS222 | | 4 |
| GI041 | | 4 | | SS230 | | 10 |
| GI043 | | 26 | | SS274 | | 2 |
| GI047 | | 13 | | SS291 | | 2 |
| HI384A | | 4 | | SS349 | Mahogany | 2 |
| HI573A | | 6 | | ST021 | | 6 |
| MC020 | | 4 | | ST037 | | 4 |
| MC311 | Bourbon | 3 | | ST052 | | 3 |
| MP041 | | 12 | | ST054 | | 3 |
| MP061 | | 2 | | ST131 | | 4 |
| MP073 | | 3 | | ST135 | | 8 |
| MP140 | | 3 | | ST176 | | 3 |
| MP144 | | 4 | | TS000 | | 3 |
| MP151 | | 3 | | VR245 | | 5 |
| MP290 | | 6 | | VR331 | | 3 |
| MP299 | | 7 | | WC066 | | 3 |
| MP306 | | 7 | | WD030 | | 33 |
| MP310 | | 2 | | WD041 | | 5 |
| MP311 | | 5 | | WD073 | | 10 |
| PL020 | | 8 | | WD109 | | 2 |
| SM006 | | 5 | | WD117 | | 3 |

### 4.3.2 Deep Water GOM Database.

The Deep Water Offshore Gulf of Mexico Big Oil Fields Database used for this resource assessment includes 60 oil fields comprised of 184 reservoirs (sands) with 28.5 B Bbls of OOIP and 20.2 B Bbls of ROIP, Table 4-6. This final database has been screened down from the original BOEM database of 127 deep water oil fields containing 665 sands (reservoirs), with OOIP of 39.9 B Bbls.

**Table 4-6 Deep water GOM big oil fields and reservoirs database**

| | Original BOEM Database | Final ARI Database |
|---|---|---|
| No. Fields | 127 | 60 |
| No. Sands (Reservoirs) | 665 | 184 |
| OOIP (B Bbls) | 39.9 | 28.5 |
| Cum P/S Prod. (B Bbls) | 3.4 | 2.9 |
| Remaining Reserves (B Bbls)* | 6.0 | 5.6* |
| P/S Recovery Efficiency (%) | 24% | 30% |

**Includes 1.8 B Bbls of reserves added to undeveloped deep water oil fields to reflect Expected P/S Recovery.*

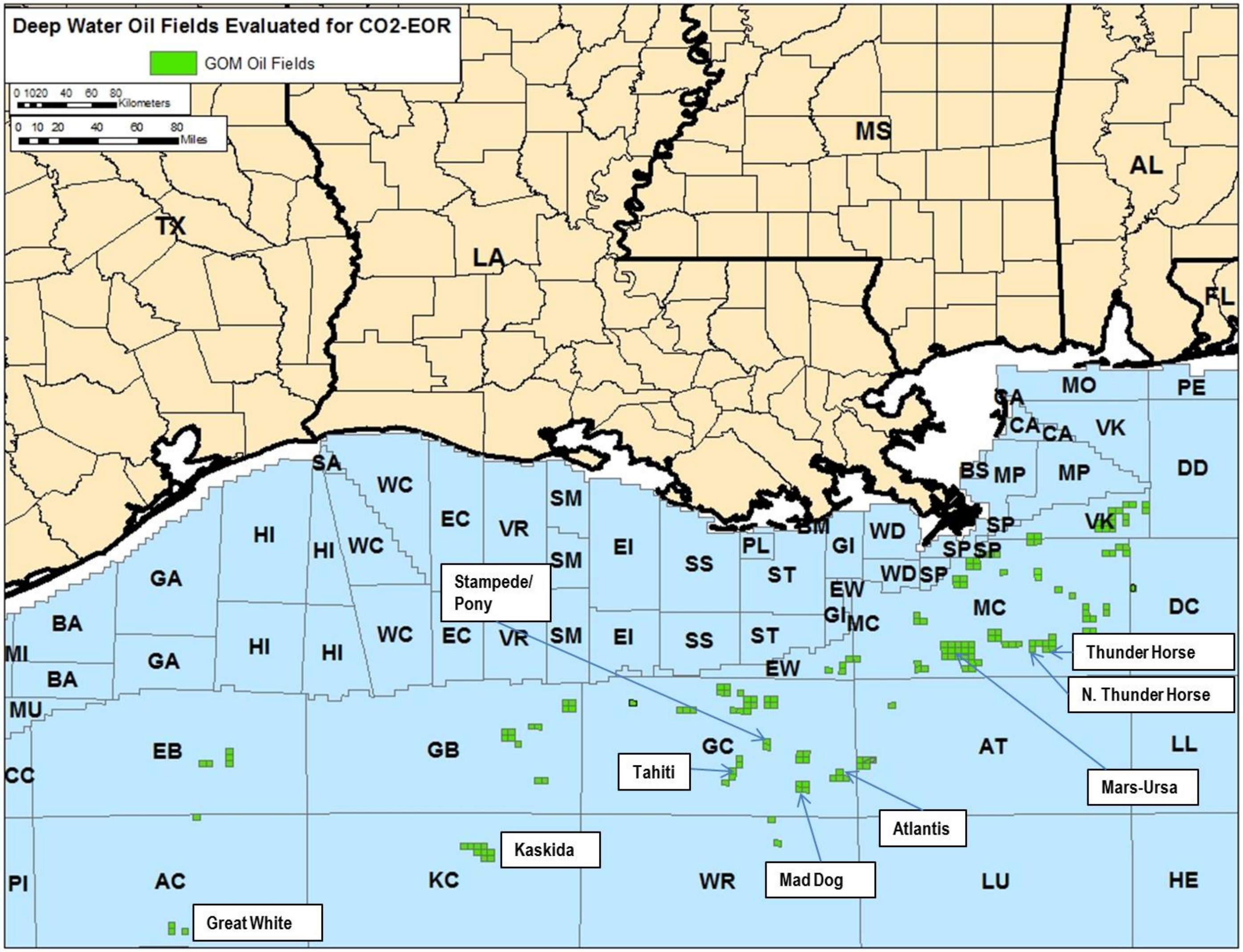
Table 4-7 lists the 40 large deep water oil fields used in the GOM OCS $CO_2$-EOR resource assessment.

Of the 60 deep water oil fields included in the GOM Big Oil Fields Database, nine have an OOIP greater than 1 billion barrels and serve as the deep water "anchor fields" for $CO_2$-EOR, Figure 4-3.

**Table 4-7 Deep water GOM oil fields included in the resource assessment**

| Deep Water Data Set | | | | | | |
|---|---|---|---|---|---|---|
| **Field** | **Field Name** | **# of Reservoirs** | | **Field** | **Field Name** | **# of Reservoirs** |
| AC025 | Hoover | 1 | | MC194 | Cognac | 3 |
| AC857 | Great White | 4 | | MC243 | Matterhorn | 3 |
| AT575 | Neptune (AT) | 6 | | MC281 | Lena | 5 |
| EB602 | Nansen | 3 | | MC292 | Gemini | 1 |
| EB643 | Boomvang North | 3 | | MC383 | Kepler | 1 |
| EW878 | | 1 | | MC429 | Ariel | 4 |
| EW921 | Morpeth | 2 | | MC522 | Fourier | 1 |
| EW963 | Arnold | 2 | | MC582 | Medusa | 4 |
| GB260 | Baldpate | 2 | | MC607 | East Anstey | 1 |
| GB387 | Llano | 2 | | MC696 | Blind Faith | 5 |
| GB426 | Auger | 4 | | MC773 | Devils Tower | 3 |
| GB516 | Serrano | 1 | | MC776 | North Thunderhorse | 6 |
| GB783 | Magnolia | 1 | | MC778 | Thunderhorse | 11 |
| GC065 | Bullwinkle | 2 | | MC807 | Mars-Ursa | 20 |
| GC112 | Angus | 1 | | MC899 | Crosby | 4 |
| GC158 | Brutus | 2 | | MC935 | Europa | 3 |
| GC184 | Jolliet | 2 | | VK783 | Tahoe/SE Tahoe | 1 |
| GC205 | Genesis | 4 | | VK786 | Petronius | 3 |
| GC236 | Phoenix | 1 | | VK825 | Neptune | 3 |
| GC243 | Aspen | 1 | | VK915 | Marlin | 3 |
| GC244 | Troika | 2 | | VK956 | Ram-Powell | 4 |
| GC562 | K2 | 3 | | VK990 | Pompano | 4 |
| GC640 | Tahiti | 4 | | AC859 | Tobago | 1 |
| GC644 | Holstein | 8 | | GC468 | Stampede | 3 |
| GC654 | Shenzi | 3 | | KC292 | Kaskida | 1 |
| GC680 | Constitution | 1 | | MC682 | Tubular Bells | 1 |
| GC743 | Atlantis | 5 | | AT182 | | 1 |
| GC826 | Mad Dog | 3 | | DC353 | | 1 |
| MC084 | Kin/Horn Mt. | 4 | | WR029 | Big Foot | 1 |
| MC109 | Amberjack | 3 | | WR206 | Cascade | 1 |

**Figure 4-3 GOM OCS deep water oil fields with labeled "anchor fields"**



## 4.4 Incorporating the Undiscovered GOM Oil Resources Base

Even after several decades of exploration, the Gulf of Mexico still holds major volumes of undiscovered oil resources, primarily in deep water oil fields, as further discussed in Appendix 3. To provide a more comprehensive look at the potential of using $CO_2$-EOR in the GOM OCS, we have included these undiscovered resources in our assessment.

The undiscovered GOM OCS database used for this resource assessment consists of deep water oil fields holding 129.8 B Bbls of OOIP, 38.7 B Bbls of economically recoverable resources, and 91.1 B Bbls of ROIP, Table 4-8. This final, “high graded” undiscovered oil resource database has been screened down from the original BOEM undiscovered oil resource database containing 181.7 B Bbls of OOIP, 42.8 B Bbls of economically recoverable resources, and 138.9 B Bbls of ROIP.

**Table 4-8 Undiscovered GOM OCS oil resource database**

| | BOEM Undiscovered Resources Database | Final ARI Undiscovered Resources Database |
|---|---|---|
| OOIP (B Bbls) | 181.7 | 129.8 |
| Economically Recoverable Resources (B Bbls) | 42.8 | 38.7 |
| Remaining Reserves (B Bbls) | 138.9 | 91.1 |
| P/S Recovery Efficiency (%) | 24% | 30% |

Notable is that since the completion and publication of the 1/1/2009 BOEM database of offshore GOM discovered oil fields and reserves (that serves as the foundation for this study), 40 major oil fields holding nearly 8 billion barrels of technically recoverable oil resources have been identified, Table 4-9. We would anticipate that the subsequent BOEM database of discovered offshore GOM oil fields will include many, if not most, of the recently announced deep water discoveries due on line by 2020.

**Table 4-9 Size and water depth of announced deep water discoveries due online by 2020**

| Field/Project Name | Block | Water Depth (feet) | Year of Discovery | Field Size Class | Field Size (MMBoe) |
|---|---|---|---|---|---|
| Anduin West | MC754 | 2,696 | 2008 | 11 | 46 |
| Bushwood | GB463 | 2,700 | 2009 | 13 | 182 |
| Caesar | GC683 | 4,457 | 2006 | 11 | 45 |
| Chinook | WR469 | 8,831 | 2003 | 14 | 372 |
| Clipper | GC299 | 3,452 | 2005 | 11 | 45 |
| Galapagos | MC519 | 6,526 | 2009 | 11 | 45 |
| Goose | MC751 | 1,624 | 2003 | 11 | 45 |
| Isabella | MC562 | 6,535 | 2007 | 11 | 45 |
| Mandy | MC199 | 2,478 | 2010 | 13 | 182 |
| MC241 | MC285 | 2,427 | 2006 | 11 | 45 |
| Ozona | GB515 | 3,000 | 2008 | 11 | 45 |
| Pyrenees | GB293 | 2,100 | 2009 | 12 | 89 |
| Silvertip | AC815 | 9,226 | 2004 | 12 | 372 |
| West Tonga | GC726 | 4,674 | 2007 | 12 | 89 |
| Wide Berth | GC490 | 3,700 | 2009 | 12 | 89 |
| Axe | DC004 | 5,831 | 2010 | 12 | 89 |
| Dalmatian | DC048 | 5,876 | 2008 | 12 | 89 |
| Knotty Head | GC512 | 3,557 | 2005 | 14 | 372 |
| Jack | WR759 | 6,963 | 2004 | 14 | 372 |
| Lucius | KC875 | 7,168 | 2009 | 13 | 182 |
| St. Malo | WR678 | 7,036 | 2003 | 14 | 372 |
| Freedom | MC948 | 6,095 | 2008 | 15 | 691 |
| Heidelberg | GC859 | 5,000 | 2009 | 13 | 182 |
| Kodiak | MC771 | 4,986 | 2008 | 13 | 182 |
| Samurai | GC432 | 3,400 | 2009 | 12 | 89 |
| Winter | GB605 | 3,400 | 2009 | 11 | 45 |
| Mission Deep | GC955 | 7,300 | 1999 | 13 | 182 |
| Stones | WR508 | 9,556 | 2005 | 12 | 89 |
| Tiber | KC102 | 4,132 | 2009 | 15 | 691 |
| Vito | MC984 | 4,038 | 2009 | 13 | 182 |
| Shenandoah | WR052 | 5,750 | 2009 | 13 | 182 |
| Buckskin | KC872 | 6,920 | 2009 | 13 | 182 |
| Diamond | LL370 | 9,975 | 2008 | 11 | 45 |
| Julia | WR627 | 7,087 | 2007 | 12 | 89 |
| Appomattox | MC392 | 7,217 | 2009 | 15 | 691 |
| Hadrian South | KC964 | 7,586 | 2009 | 13 | 182 |
| Hal | WR848 | 7,657 | 2008 | 11 | 45 |
| Vicksburg | DC353 | 7,457 | 2009 | 14 | 372 |
| Cardamom | GB427 | 2,720 | 2010 | 13 | 182 |
| Hadrian North | KC919 | 7,000 | 2010 | 14 | 372 |

# 5 Special Topics for Evaluating Offshore $CO_2$-EOR

As part of our $CO_2$-EOR resource assessment of the Offshore Gulf of Mexico, we identified three key issues that merit additional discussion:

1. Offshore $CO_2$-EOR/$CO_2$ Storage Challenges
2. Incentivizing Early Implementation of $CO_2$-EOR/$CO_2$ Storage
3. Precluding Premature Offshore GOM Oil Field Abandonment

## 5.1 Topic #1. Offshore $CO_2$-EOR/$CO_2$ Storage Challenges

$CO_2$-EOR technology has been successfully implemented onshore for over 40 years - - increasing oil production, extending the life of oil fields, and storing $CO_2$. However, applying this technology in the offshore arena requires overcoming a number of additional challenges.

***Installation of $CO_2$ Recycling Facilities.*** Offshore platforms are designed to efficiently use all available space and therefore have limited room for new $CO_2$-EOR facilities, particularly $CO_2$ recycling plants. As such, operators will need to consider innovative approaches for offshore $CO_2$ separation, compression and re-injection.

One potential solution could be to install modular subsea gas separation and compression facilities, similar to Statoil's installations at Asgard and Gullfaks North Sea oil fields. Another solution could be to install a large volume $CO_2$ recycling facility on a central platform servicing multiple oil fields. A third solution could be to use a large-volume pipeline to bring the $CO_2$/oil/water mixture onshore for separation and $CO_2$ compression, returning the $CO_2$ in the existing $CO_2$ pipeline.

***Retrofitting Production Wells and Facilities.*** For $CO_2$-EOR, the production facilities and well tubing will likely need to be retrofitted to prevent corrosion. These alterations may require a platform to be shut down, causing a loss of oil production and revenues. For the proposed $CO_2$-EOR project at the Heidrun in the North Sea, the operators estimated that the facilities and well modification process would take a year, during which time oil production would be shut in. Installation of corrosion resistant production facilities and well tubing during initial well construction could be used to address this challenge.

***Optimal Well Placement.*** In offshore oil fields, installing the required well patterns and spacing for optimal $CO_2$-EOR performance may be cost prohibitive due to the high costs of offshore well drilling. Using horizontal wells with wider well spacing could be used to help overcome this challenge.

***Reservoir Characterization to Reduce Performance Uncertainty.*** Detailed reservoir characterization is essential for accurately defining the reservoir and estimating oil production and $CO_2$ utilization for any $CO_2$-EOR project - even more so when operating in a costly, deep water environment. Procedures that facilitate sharing of reservoir characterization and flood performance data could help address this issue.

***Adequate and Affordable $CO_2$ Supplies.*** Installation of carbon capture technology on the industrial and power plants along the Gulf Coast could make large volumes of $CO_2$ supply available. Still, $CO_2$ capture technology is costly and makes the current price of $CO_2$ capture from power plants too high for many offshore $CO_2$-EOR projects. Incentives for storing $CO_2$

emissions with $CO_2$-EOR, such as lower royalty rates for offshore operators and tax credits for $CO_2$ capture and storage, would help close the current cost gap.

***Subsea Technology.*** A key technology for deep water $CO_2$-EOR will be the use of subsea systems for fluid separation, gas compression, gas/water treatment and fluid re-injection. Overseas, Petrobras' Marlim oil field in the deep offshore waters of Brazil uses subsea systems to separate heavy oil, gas, sand and water as well as treat and re-inject the separated water to boost oil production. Procedures and forums that facilitate information sharing of sub-sea technology could help accelerate the use of this technology for $CO_2$-EOR.

## 5.2 Topic #2. Incentivizing Early Implementation of $CO_2$-EOR/$CO_2$ Storage

Many of the constraints and challenges faced by operators when implementing offshore $CO_2$-EOR can be mitigated by early implementation of $CO_2$-EOR. Also, the additional volumes of incremental oil production from $CO_2$-EOR at the beginning of a project help its economic viability.

***Early $CO_2$-EOR Implementation in Deep Water Oil Fields.*** Deep water Gulf of Mexico oil fields are prime targets for early implementation of $CO_2$-EOR. Three of the major challenges of implementing $CO_2$-EOR in the offshore discussed above - - installation of $CO_2$ recycling facilities, retrofitting production wells and facilities, and optimal well placement - - become even more challenging in deep water operations. However, these constraints can be mitigated by accounting for $CO_2$-EOR in the planning phase of a deep water project, including acquiring detailed reservoir data, studying optimal well placement, and designing a platform with the flexibility to handle EOR. As such, consideration of $CO_2$-EOR is highly recommendable in the conception phase of a GOM project as it is easier and less costly to implement EOR early than to retrofit the platform later for EOR.

***The Lula Oil Field Example.*** Brazil's Lula oil field, discussed in detail in Chapter 2 of this report, is a compelling example of the benefits of early implementation of $CO_2$-EOR in a challenging deep water environment. Petrobras, the oil field's operator, has designed its production strategy for Lula with early EOR implementation in mind. The platforms, production facilities, subsea systems and well placements have all been designed to facilitate the cost-efficient, early implementation of $CO_2$-EOR.

## 5.3 Topic #3. Precluding Premature Gulf of Mexico Oil Field Abandonment

The shallow water GOM oil fields are mature and nearing abandonment with less than 5 percent of their proved oil reserves remaining, making the implementation of $CO_2$-EOR in these shallow water oil fields urgent. (A number of the deep water oil fields are also mature are rapidly approaching maturity as well.)

$CO_2$-EOR can extend the lives of these offshore oil fields, boosting oil recovery and adding value through $CO_2$ storage. Without $CO_2$-EOR, these mature oil fields will be abandoned and their platforms removed, making future $CO_2$-EOR or $CO_2$-storage in these fields cost prohibitive.

# 6 Modeling Offshore $CO_2$-EOR

## 6.1 The Reservoir Simulation Model

We use $CO_2$-PROPHET2, a finite difference stream-tube reservoir simulator to calculate oil production and $CO_2$ injection requirements for each GOM OCS oil reservoir. The simulator uses finite difference calculations to generate streamlines for flow of water, oil, gas and $CO_2$ between injection and production wells and then calculates oil displacement and fluid flow within these streamlines.

## 6.2 Model Input Requirements

To model a five spot pattern Miscible WAG $CO_2$ flood for each Gulf of Mexico reservoir, we draw on the ARI GOM Database and Analytic System for the required inputs to $CO_2$-PROPHET2, Figure 6-1. Some of the more important parameters required as model inputs are:

- Pattern Type
- Initial and Current Oil Saturation
- Viscosities of Oil and Water
- Formation Volume Factor
- Oil Gravity
- Reservoir Temperature
- Reservoir Pressure
- Minimum Miscibility Pressure
- Reservoir Heterogeneity (Dykstra-Parson's Coefficient)
- Permeability (mD)
- Reservoir Thickness (ft)
- Porosity
- Reservoir Area (square ft)
- Hydrocarbon Pore Volumes (HCPV) of $CO_2$ Injection
- Water Injection Rate (Bbls/D)
- Solvent ($CO_2$) Injection Rate (Mcf/D)

**Figure 6-1 Input data sheet for $CO_2$-PROPHET2 reservoir simulation**

```
'FED-OFFSHORE - EXAMPLE RESERVOIR '
'********** 'WELL AND PATTERN DATA ********'
'PATTERN'
'CS'
'NWELLS       NOINJ'
2,             1
'WELLS        WELLY         WELLQ'
0,            0,             1
1,            1,            -1
'NBNDPT'
 5
'BOUNDX       BOUNDY'
0,             0
0,             1
1,             1
1,             0
0,             0
'*************  PROGRAM CONTROLS  ********'
'LWGEN        OUTTIM'
'N',           1
'**** RELATIVE PERMEABILITY PARAMETERS ***'
'SORW         SORG          SORM'
0.25,         0.25,          0.1
'SGR          SSR'
0.25,          0.25
'SWC          SWIR'
0.3,           0.3
'KROCW        KWRO          KRSMAX        KRGCW'
0.8,          0.2,          0.4,           0.45
'EXPOW        EXPW          EXPS          EXPG          EXPOG'
2,            2,            2,            2,            2
'KRMSEL       W'
1,             0.999
'***************  FLUID DATA  ************'
'VISO         VISW'
1.19,          0.24
'BO           RS            API           SALN                GSG'
1.05,         400,          34,           98312.73,            0.62
'************** RESERVOIR DATA ***********'
'TRES         P             MMP'
315,          19214.277,     4052.1
'DPCOEF       PERMAV        THICK         POROS         NLAYERS       CO2SOL        VisMultiplier'
0.886,          92.3,         109.78,    0.26,         5,            0,            0
'SOINIT       SGINIT        SWINIT'
0.25,         0,             0.75
'FLAGS'
'AREA         XKVH'
6969600,       9.23
'********** INJECTION PARAMETERS *********'
'NTIMES       WAGTAG'
4,            'T'
'HCPVI        WTRRAT        SOLRAT        TMORVL'
0.25,         7917.2,       15.834,       0.25
0.35,         7917.2,       15.834,       0.35
0.4,          7917.2,       15.834,       0.4
0.2,          7917.2,       0,            1.0
```

The $CO_2$-PROPHET2 generated fluid output streams are then entered into ARI's Offshore Economics Model to determine the costa and economic viability of $CO_2$ flooding for each offshore oil reservoir and oil field in the GOM OCS.

## 6.3 $CO_2$-EOR Technology

For our GOM OCS $CO_2$-EOR resource assessment, we use two $CO_2$-EOR technology cases, Current Technology and "Next Generation" Technology:

- Current Technology consists of a tapered WAG $CO_2$ flood using 1 HCPV slug of $CO_2$.
- "Next Generation" Technology consists of four major technological improvements over Current Technology $CO_2$-EOR:
  - Improved reservoir conformance,
  - Advanced $CO_2$ flood design,
  - Enhanced mobility control and injectivity, and
  - Increased volumes of efficiently used $CO_2$.

These improvements are supported by three enabling technologies: (1) Robust reservoir characterization; (2) Enhanced fluid injectivity; and (3) Extensive monitoring, diagnostics and process control.

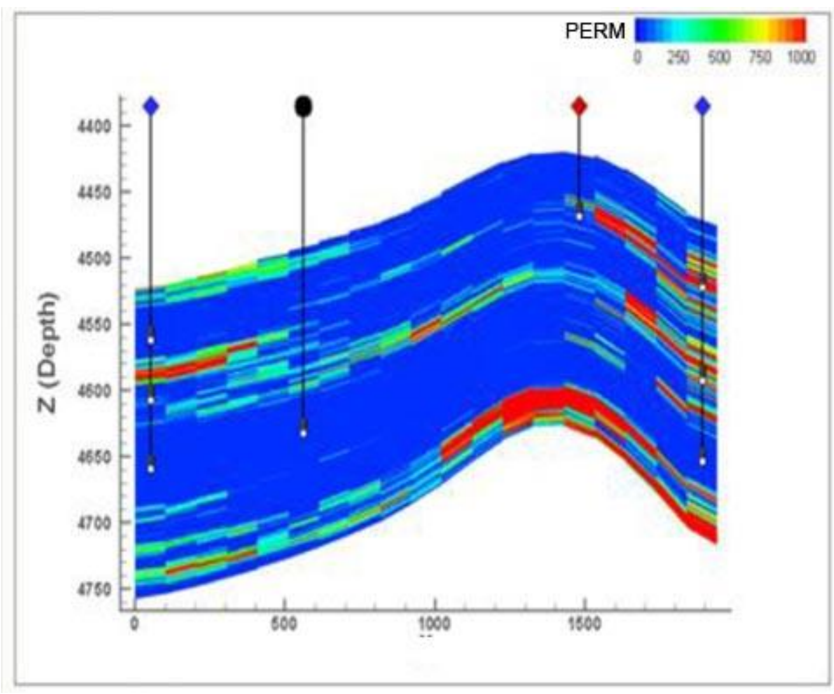
### 6.3.1 Technology #1. Improved Reservoir Conformance.

***Technology Objective***. The objective of Improved Reservoir Conformance is to reduce the unproductive channeling of $CO_2$ (and water) through high permeability reservoir flow paths. Improved Reservoir Conformance is implemented through:

1. Reservoir characterization, including advanced core and log analyses and reservoir simulation, to identify and map existing reservoir flow paths.
2. Remediation of high permeability reservoir channels using deep diversion materials (foams, polymers) and plugging actions (cement, other).
3. Reservoir monitoring, diagnostics and process control featuring annual spinner surveys, pressure measurements and fiber optic temperature surveys.
4. Improved Reservoir Conformance leads to more efficient utilization of $CO_2$ (lower $CO_2$/oil ratios) and increased oil recovery from improved reservoir sweep efficiency.

***Technology Analysis.*** A significant number of domestic oil reservoirs are highly heterogeneous with Dykstra-Parsons coefficients of over 0.75. Achieving improved reservoir conformance in these heterogeneous oil reservoirs represents a major technology challenge, as illustrated by the Reinecke carbonate reef reservoir in West Texas that has three reservoir units, each with high permeability channels, Figure 6-2.

**Figure 6-2 Permeability distribution in reservoir cross-section of Reinecke Reservoir, west TX**

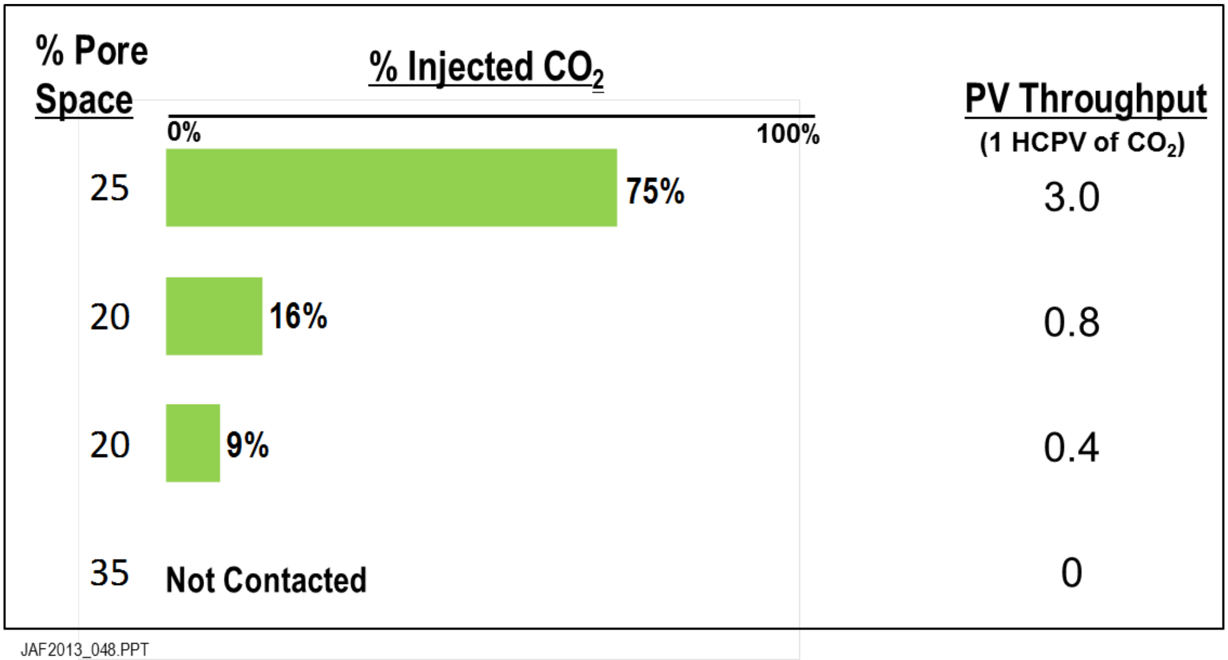



*Used with permission from SPE*[26]

In the Wasson oil field of the Permian Basin, similar high permeability streaks were discovered in the Denver Unit by Shell. Early in the life of the Wasson (Denver Unit) $CO_2$ flood, Shell installed a subsurface conformance pilot test, using coring, logging and fluid sampling, to establish the $CO_2$ flow paths in the formation.

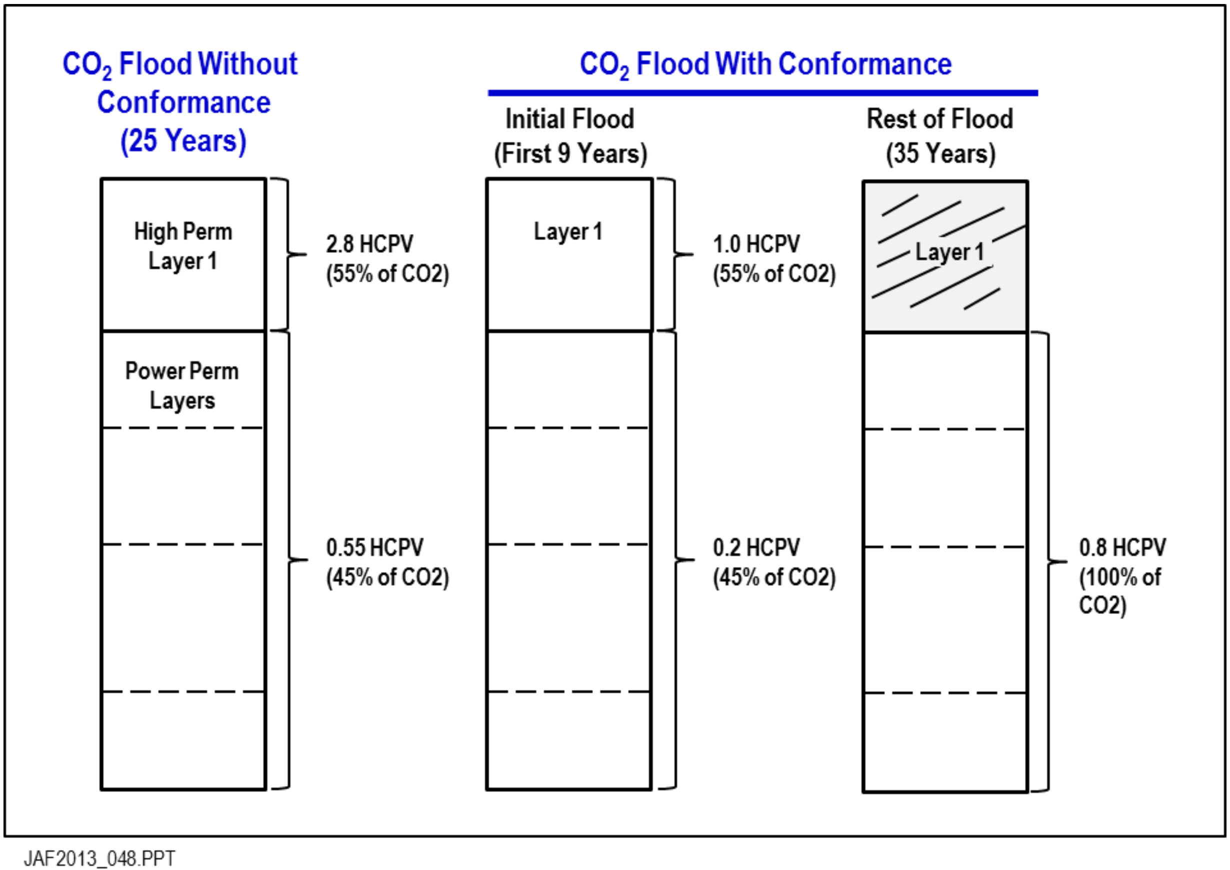
Installation of reservoir surveillance showed high $CO_2$ channeling through a small portion of the Wasson (Denver Unit) reservoir's pore space, Figure 6-3.

**Figure 6-3 Wasson Denver Unit conformance pilot observation results**




***Technology Implementation***. Improved Reservoir Conformance involves plugging-off the high permeabilities "thief zones" of the reservoir after these layers have been swept by $CO_2$ and then diverting the $CO_2$ to less efficiently swept, less permeable reservoirs zones. This process is depicted for an example oil reservoir with a coarsening upward deposition and a Dysktra-Parsons coefficient of 0.81, Figure 6-4.

**Figure 6-4 Modeling "improved reservoir conformance" with "next generation" technology**




## 6.3.2 Technology #2. Advanced $CO_2$ Flood Design.

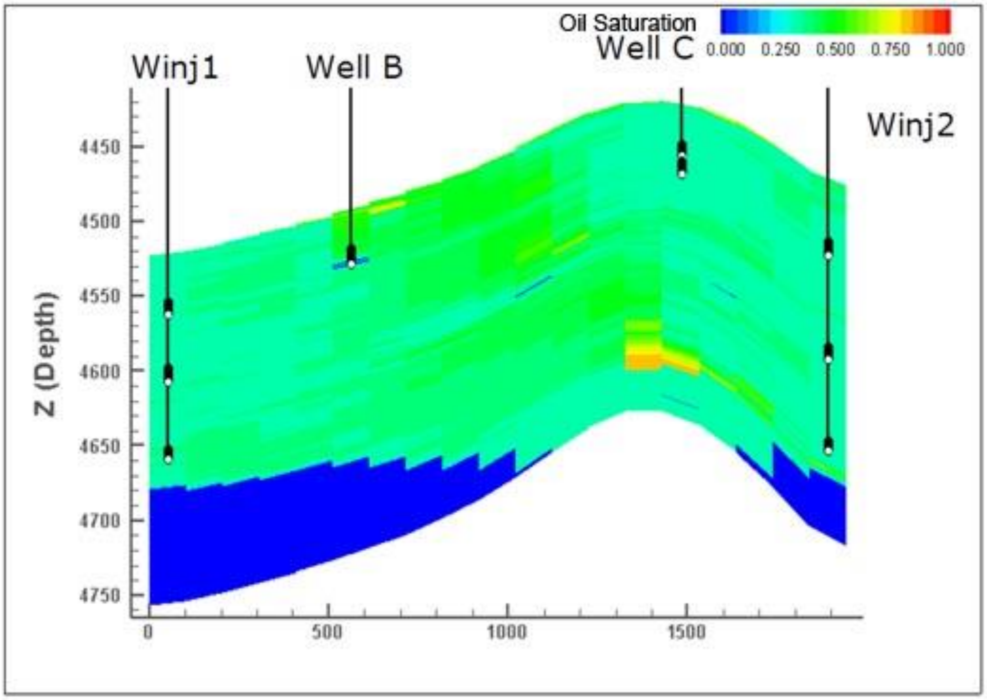
***Technology Objective***. The objective of Advanced $CO_2$ Flood Design is to target and produce the high remaining oil saturation reservoir segments bypassed or poorly swept by the waterflood. Advanced $CO_2$ Flood Design is implemented through:

1. Reservoir characterization, including advanced core and log analyses, 3D seismic survey and reservoir simulation, to identify and map higher oil saturation, poorly swept reservoir intervals.
2. Alternative $CO_2$ injection well and flood design consisting of: short lateral horizontal wells to increase reservoir contact and injectivity, pattern realignment and closer spaced wells to create new fluid flow paths, and pressure management to increase reservoir contact by $CO_2$.
3. Reservoir monitoring, diagnostics and process control, featuring 4-D seismic and annual spinner surveys.

Advanced $CO_2$ Flood Design enables recovery of by-passed mobile oil and improved reservoir sweep efficiency.

***Technology Analysis.*** Up-front reservoir characterization is essential for mapping the location and richness of the remaining oil saturation prior to the $CO_2$ flood. Remaining oil saturation can vary widely in the reservoir, as demonstrated by the Reinecke oil field of West Texas, Figure 6-5.

**Figure 6-5 Oil saturation distribution prior to $CO_2$ flood, Reinecke oil field**




*Used with permission from SPE*[27]

***Technology Implementation***. A variety of advanced $CO_2$ flood and well placement designs can be used to contact more of the oil left behind after a waterflood. ARI's modeling of Advanced $CO_2$ Flood Design involves adding a second $CO_2$ injection well to flood low permeability, high oil saturation layers, Figure 6-6, and using pattern re-alignment to improve oil contact in high permeability anisotropic settings, Figure 6-7.

**Figure 6-6 Targeting high oil saturation layer with short-lateral $CO_2$ injection well**

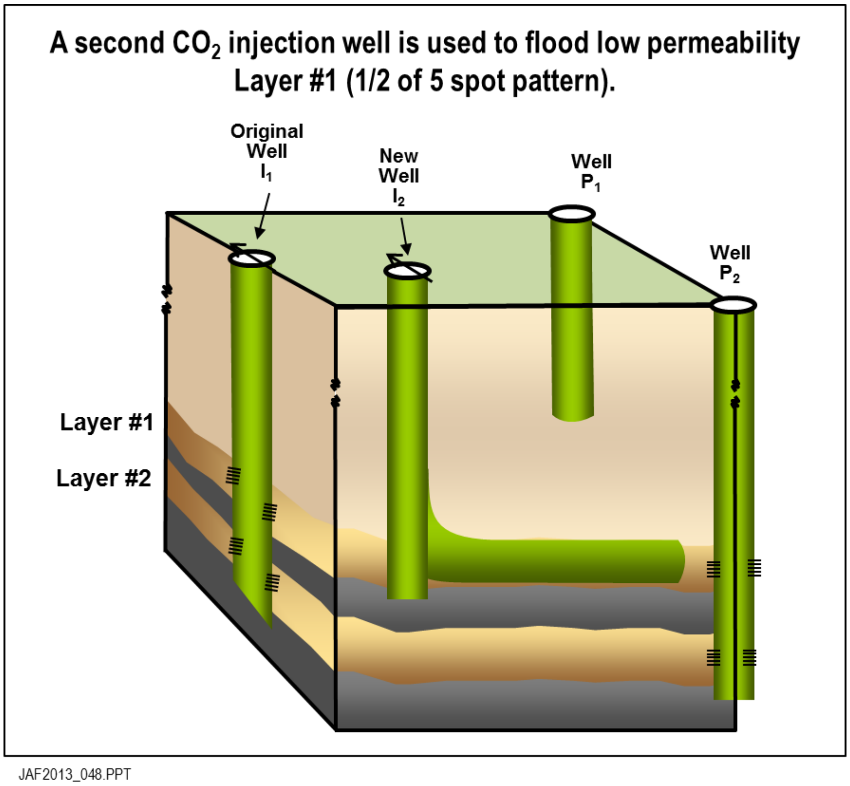
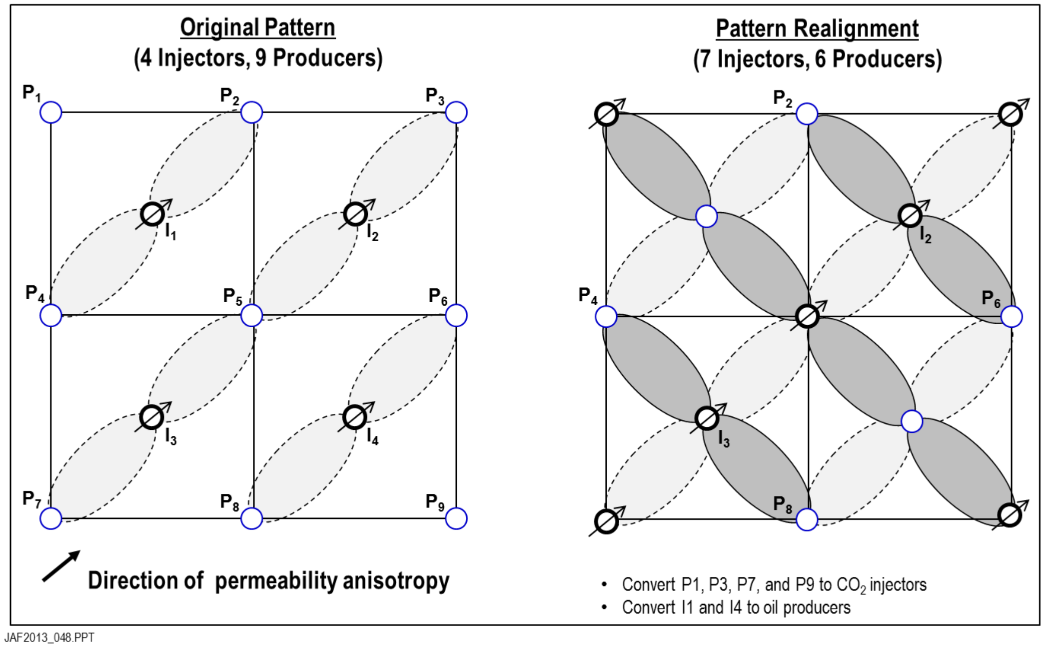



**Figure 6-7 Pattern realignment to contact additional oil in the reservoir in high permeability anisotropic settings**



### 6.3.3 Technology #3. Enhanced Mobility Control and Injectivity.

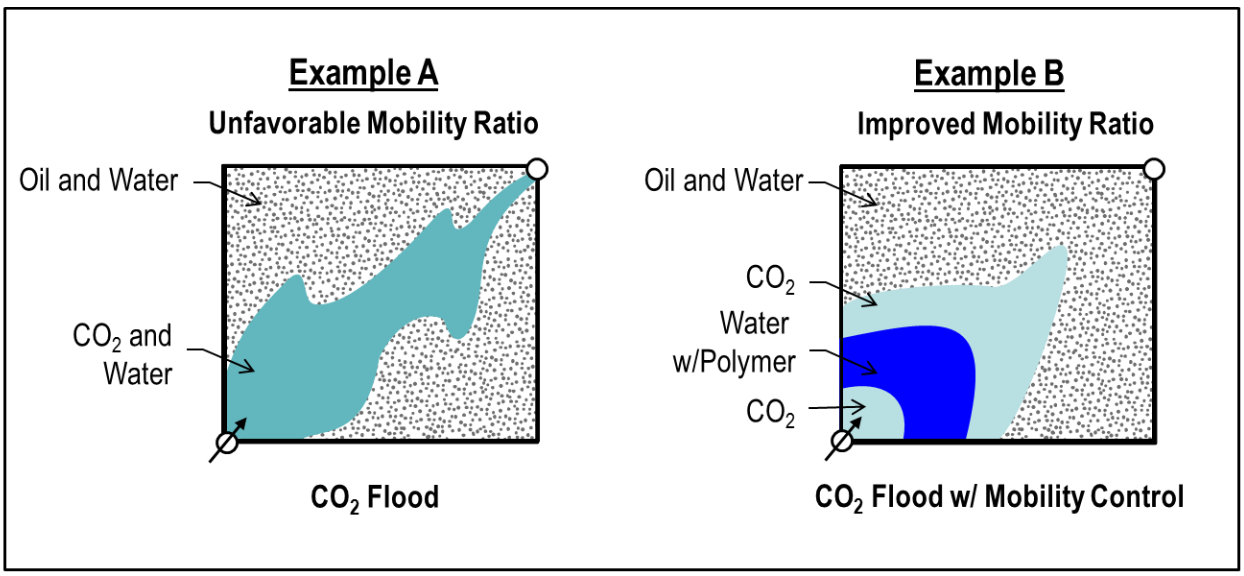
***Technology Objective.*** The objective of Enhanced Mobility Control is to improve the mobility ratio of the injected fluid(s) and the residual oil in the reservoir.

- The addition of polymers to increase the viscosity of the drive/displacement water used as part of a WAG $CO_2$ flood.
- Injectivity is maintained through the use of near-wellbore well stimulation in the form of a small volume "tip screen-out" frac, with $x_f$ of about 15 feet.

Enhanced Mobility Control and Injectivity support higher areal sweep efficiency due to reduced "viscous fingering" of the $CO_2$ through the reservoir's oil.

***Technology Analysis.*** The viscosities of the injected fluids ($CO_2$ and water) are generally lower than the viscosity of the reservoir oil, leading to viscous fingering of the $CO_2$ through the reservoir's oil and thus inefficient sweep of the reservoir, Figure 6-8.

**Figure 6-8 Example of unfavorable and favorable mobility ratio**




Source: Advanced Resources International, Inc. 2014.

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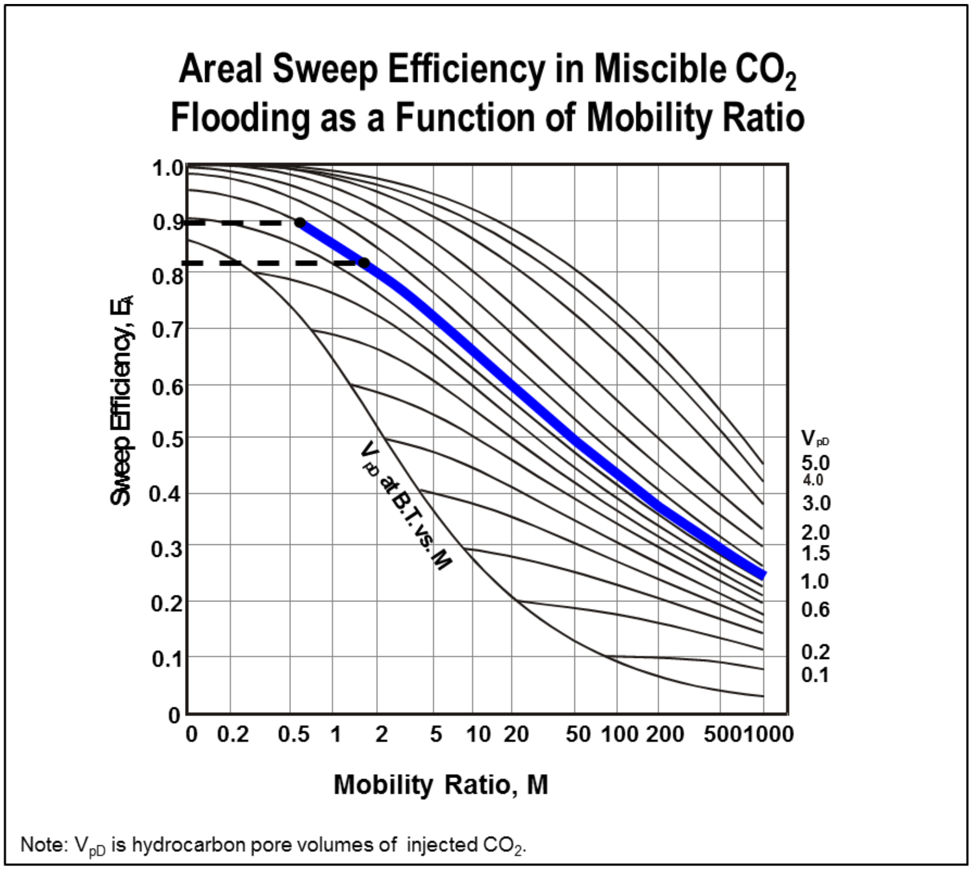
***Technology Implementation***. Enhanced Mobility Control involves raising the viscosity of the drive water (in the WAG process) to 1 cp. Depicted below is an "example" oil reservoir with an oil/water mobility ratio of 1.8, based on an oil viscosity of 0.74 cp and a water viscosity (in the reservoir) of 0.41 cp. Decreasing the oil/water mobility ratio from 1.8 to 0.7 (by increasing the viscosity of the water to 1 cp) improves the areal sweep efficiency from 82 percent to 89 percent, Figure 6-9.

**Figure 6-9 Areal sweep efficiency in miscible $CO_2$ flooding as a function of mobility ratio[28]**

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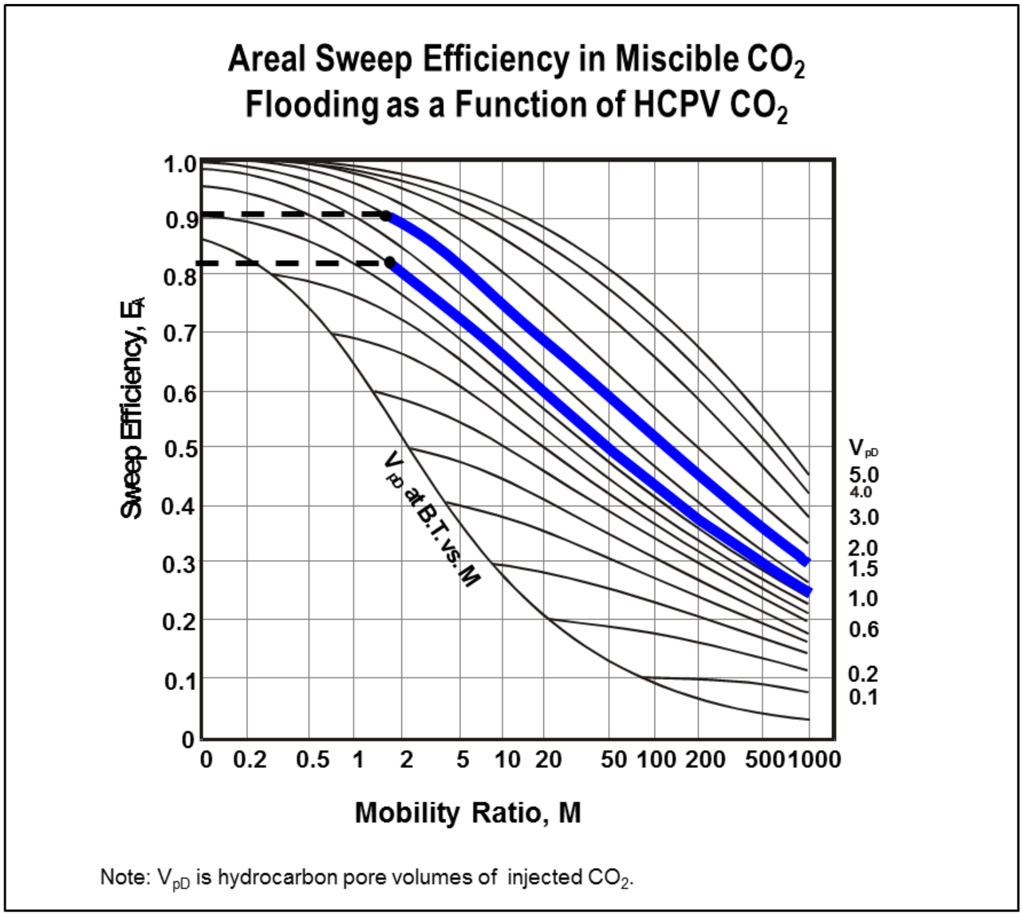
*Note: $V_{pD}$ is hydrocarbon pore volumes of injected $CO_2$.

### 6.3.4 Technology #4. Increased Volumes of Efficiently Used $CO_2$.

***Technology Objective***. The objective of Increased Volume of Efficiently Used $CO_2$ is to increase $CO_2$/reservoir contact and displacement of residual oil.

***Technology Analysis***. In the "example" oil reservoir, increasing the volume of $CO_2$ injection from 1 HCPV to 1.5 HCPV increases the areal sweep efficiency from 82 percent to 91 percent, Figure 6-10.

**Figure 6-10 Areal sweep efficiency in miscible $CO_2$ flooding as a function of HCPV $CO_2$[29]**




JAF2013_048.PPT

*Note: $V_{pD}$ is hydrocarbon pore volumes of injected $CO_2$.

***Technology Implementation***. ARI's modeling of Increased Volumes of Efficiently Used $CO_2$ involves:

- Increasing the volume of $CO_2$ injection to 1.5 HCPV
- Using near-wellbore well stimulation (small volume "tip screen-out" frac, with $x_f$ of about 15 feet) or a second $CO_2$ injection well, to maintain $CO_2$ and water injectivity.
- Using reservoir monitoring, diagnostics and process control, including 4-D seismic, annual pressure and spinner surveys, and fiber optic temperature surveys to track $CO_2$/reservoir contact.

# 7 Findings of the GOM OCS $CO_2$-EOR Resource Assessment

## 7.1 The GOM OCS Resource Base

The Gulf of Mexico's offshore oil fields offer attractive potential for increasing domestic oil production and for securely storing $CO_2$ using $CO_2$-EOR. To establish the size of this oil recovery and $CO_2$ storage potential, we evaluated: (1) a "high graded" set of 80 large, shallow water oil fields (containing 512 reservoirs); (2) a "high graded" set of 60 large, deep water oil fields (containing 184 reservoirs); and (3) the still undiscovered oil resources in the GOM offshore.

The 140 discovered oil fields (696 reservoirs) evaluated by this study hold 44.8 billion barrels of OOIP. With 15.2 billion barrels of expected ultimate primary/ secondary oil recovery, a significant volume of oil, 29.1 billion barrels, remains "stranded" in these oil fields awaiting the use of advanced oil recovery technologies, Table 7-1. The undiscovered oil fields hold 129.7 billion barrels of OOIP, with 91.0 billion barrels remaining after primary/secondary oil recovery as the target for $CO_2$-EOR.

**Table 7-1 Database used for the offshore GOM $CO_2$-EOR resource assessment**

| | "High Graded" Discovered Oil Reservoirs | | | "High Graded" Undiscovered Oil Resources |
|---|---|---|---|---|
| | **Shallow Water** | **Deep Water** | **Combined** | **Total** |
| Fields | 80 | 60 | 140 | n/a |
| Reservoirs | 512 | 184 | 696 | n/a |
| Original Oil In-Place (B Bbls) | 15.8 | 28.5 | 44.3 | 129.7 |
| Ultimate Primary / Secondary Oil Recovery (B Bbls) | 6.7 | 8.5* | 15.2 | 38.7 |
| Remaining Oil In-Place (B Bbls) | 9.1 | 20.0 | 29.1 | 91.0 |
| Primary/Secondary Oil Recovery Efficiency | 42% | 30% | 34% | 30% |

**Includes 1.8 B Bbls of additional primary/secondary oil recovery assigned by this study to unproved and recently discovered oil fields.*

## 7.2 Importance of "Next Generation" Offshore $CO_2$-EOR Technologies

Our in-depth reservoir-by-reservoir resource assessment shows that the level of efficiency and sophistication of $CO_2$-EOR technology is the single most important factor governing the oil recovery and $CO_2$ storage potential of the GOM OCS:

- With Current Technology (oil price of \$90/B and $CO_2$ costs of \$50/mt), $CO_2$-EOR provides a valuable but modest prize - - 810 MM barrels of incremental oil recovery and 310 MM metric tons of $CO_2$ storage.

- With <u>"Next Generation" Technology</u> (same oil prices and $CO_2$ costs as above), $CO_2$-EOR offers a much greater prize - - 14,920 MM barrels of incremental oil recovery and 3,910 MM metric tons of $CO_2$ storage.

A higher oil price of $135/B substantially increases the incremental oil recovery and $CO_2$ storage potential from using both Current and "Next Generation" $CO_2$-EOR Technologies.

- At a $135/B oil price ($CO_2$ cost of $70/mt) and use of Current Technology, the economically viable oil recovery and $CO_2$ storage volumes increase to 4,410 MM barrels and 1,140 MM metric tons.
- With "Next Generation" $CO_2$-EOR Technology (same oil prices and $CO_2$ costs as above), the economically viable oil recovery and $CO_2$ storage volumes increased markedly - - to 38,040 MM barrels and 10,700 MM metric tons (equal to 40 years of $CO_2$ capture from over 56 GW size coal-fired power plants.)

Figure 7-1 and Figure 7-2 illustrate the GOM OCS $CO_2$-EOR and $CO_2$ storage potential as functions of $CO_2$-EOR technology and oil prices.

**Figure 7-1 GOM OCS oil recovery potential: current vs "next generation" $CO_2$-EOR technology**

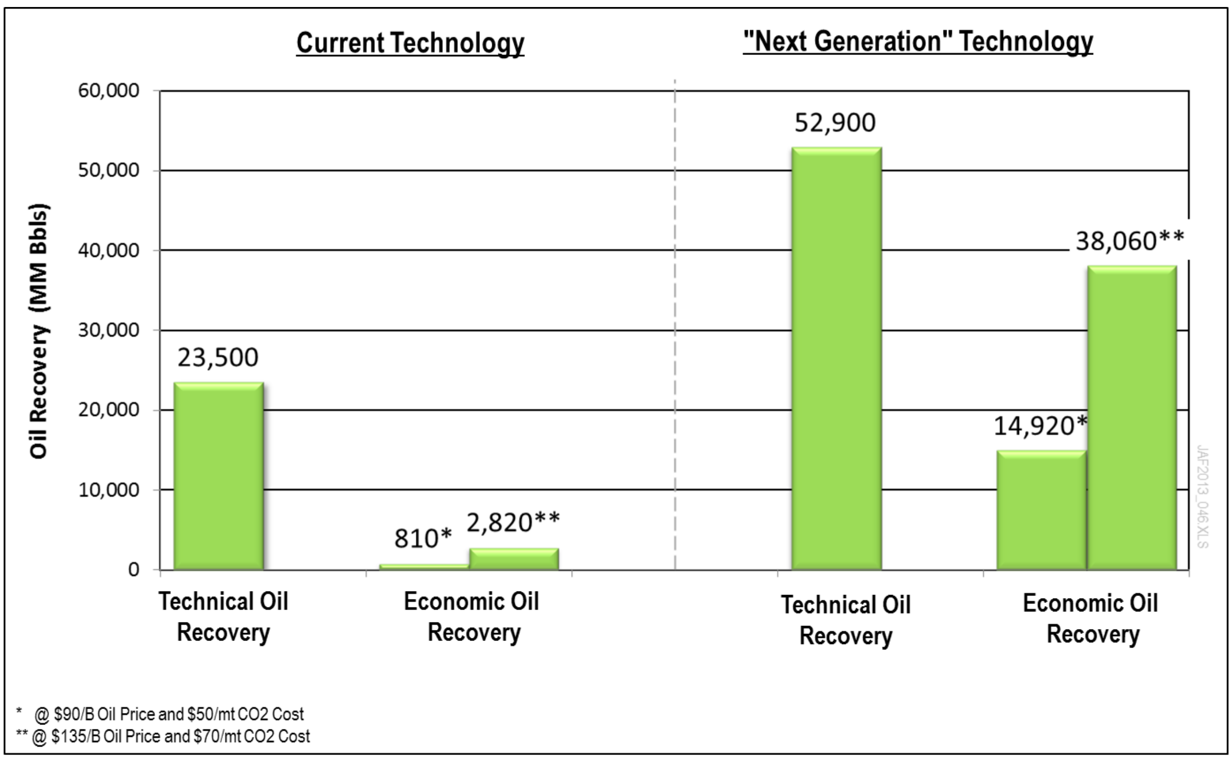



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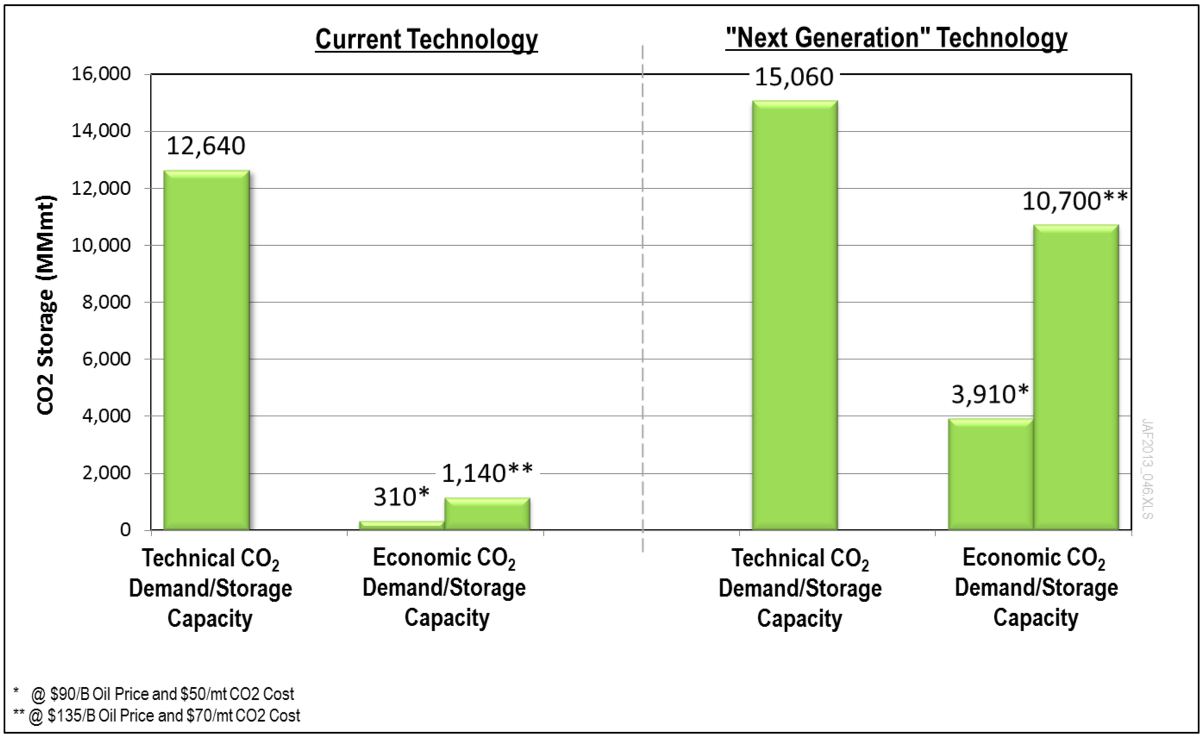
**Figure 7-2 GOM OCS CO2 storage potential: current vs "next generation" CO2-EOR technology**

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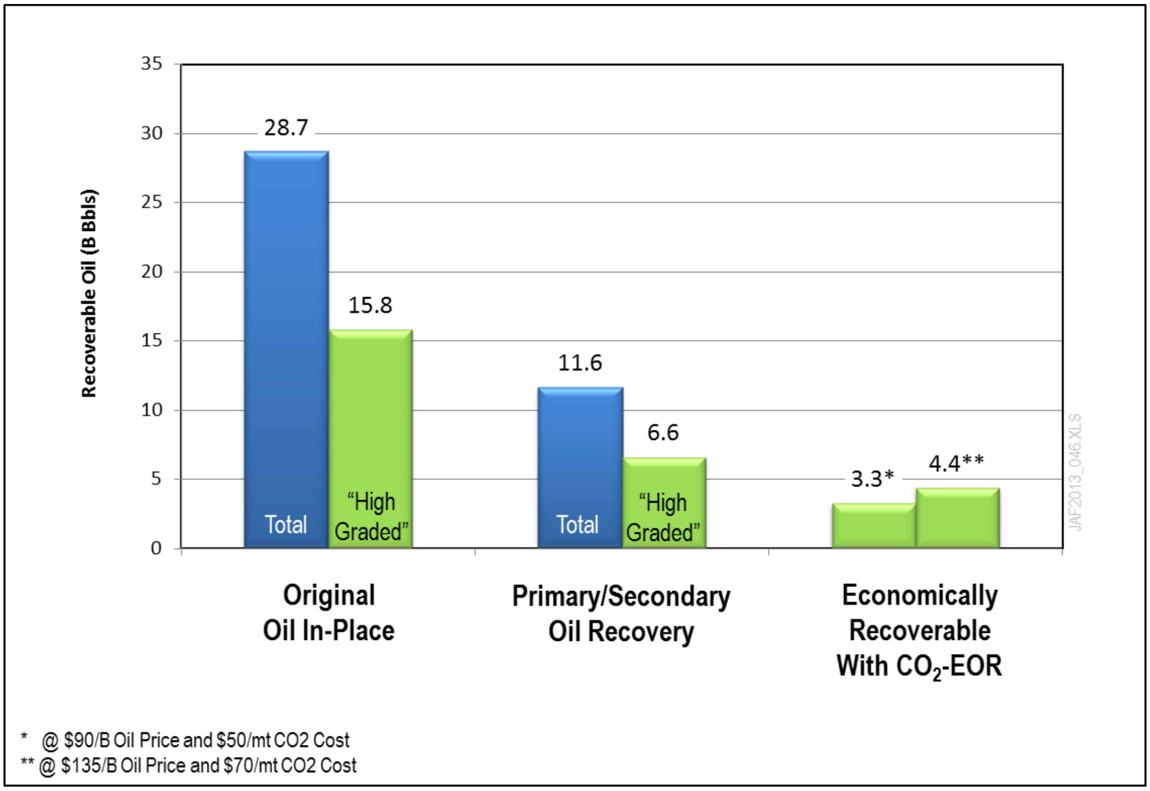
## 7.3 Shallow Water GOM OCS $CO_2$-EOR Potential

The full set of 404 oil fields in the shallow waters of the Gulf of Mexico OCS have an OOIP of 28.7 B Bbls and an estimated primary/secondary oil recovery (Original Proved Reserves) of 11.6 B Bbls. The "high-graded" 80 shallow water oil fields in the GOM OCS have an OOIP of 15.8 B Bbls with 6.6 B Bbls of estimated primary/secondary oil recovery. "Next Generation" $CO_2$-EOR could boost these economically recoverable oil volumes from this "high-graded" set of 80 shallow water oil fields by 3.3 to 4.4 B Bbls, depending on oil price and $CO_2$ costs, Figure 7-3.

**Figure 7-3 Shallow water GOM OCS $CO_2$-EOR oil resources**

(Assumes "Next Generation" $CO_2$-EOR Technology)

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The use of $CO_2$-EOR in the shallow water oil fields of the GOM OCS is highly sensitive to $CO_2$ costs. Moderate reductions in $CO_2$ costs (prices) could make major portions of the remaining oil economically recoverable using "Next Generation" $CO_2$-EOR, Table 7-2.

**Table 7-2 Shallow water GOM OCS $CO_2$-EOR sensitivity analysis**

(Assumes "Next Generation" $CO_2$-EOR Technology)

| $CO_2$ Cost | $90/Bbl Oil Price | | $135/Bbl Oil Price | |
|---|---|---|---|---|
| | Oil Recovery | $CO_2$ Demand | Oil Recovery | $CO_2$ Demand |
| ($/mt) | (MMBbls) | (MMmt) | (MMBbls) | (MMmt) |
| 20 ("Free" $CO_2$) | 3,600 | 810 | 4,530 | 1,020 |
| 30 | 3,480 | 780 | 4,450 | 1,000 |
| 40 | 3,440 | 770 | 4,440 | 1,000 |
| 50 (Base Case) | 3,260 | 720 | 4,440 | 1,000 |
| 60 | 3,050 | 680 | 4,440 | 1,000 |
| 70 | 2,260 | 490 | 4,410 | 990 |
| 80 | 2,020 | 440 | 3,900 | 870 |
| 90 | 1,560 | 330 | 3,810 | 850 |
| 100 (Today) | 1,220 | 250 | 3,800 | 850 |

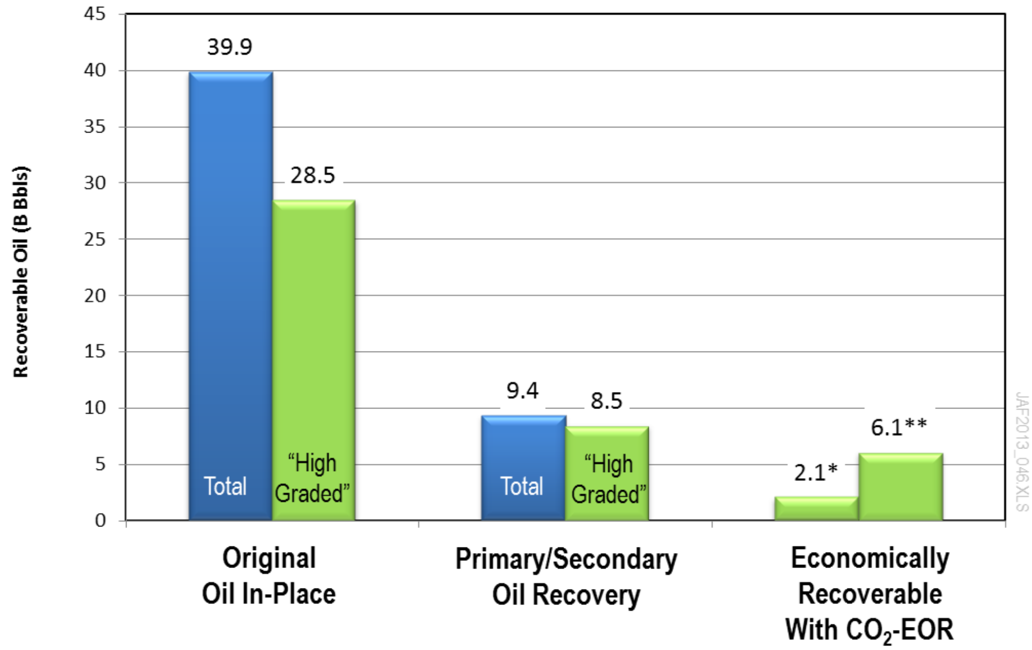
## 7.4 Deep Water GOM OCS $CO_2$-EOR Potential

The full set of 127 oil fields in the deep waters of the Gulf of Mexico OCS have an OOIP of 39.9 B Bbls and an estimated primary/secondary oil recovery (Original Proved Reserves) of 9.4 B Bbls. The "high-graded" 60 deep water oil fields in the GOM OCS have an OOIP of 28.5 B Bbls in the 8.5 B Bbls of estimated primary/secondary oil recovery. "Next Generation" $CO_2$-EOR could boost these economically viable oil volumes from this "high graded" set of 60 deep water oil fields by 2.1 to 6.1 B Bbls depending on oil price, Figure 7-4.

Similar to shallow water areas, we also analyzed the deep water offshore Gulf of Mexico's $CO_2$-EOR oil recovery and $CO_2$ storage (demand) potential under alternative $CO_2$ costs (prices), Table 7-3.

**Figure 7-4 Deep water GOM OCS $CO_2$-EOR oil resources**

(Assumes "Next Generation" $CO_2$-EOR Technology)




* @ $90/B Oil Price and $50/mt CO2 Cost

** @ $135/B Oil Price and $70/mt CO2 Cost

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**Table 7-3 Deep water GOM OCS CO2-EOR sensitivity analysis**

(Assumes "Next Generation" $CO_2$-EOR Technology)

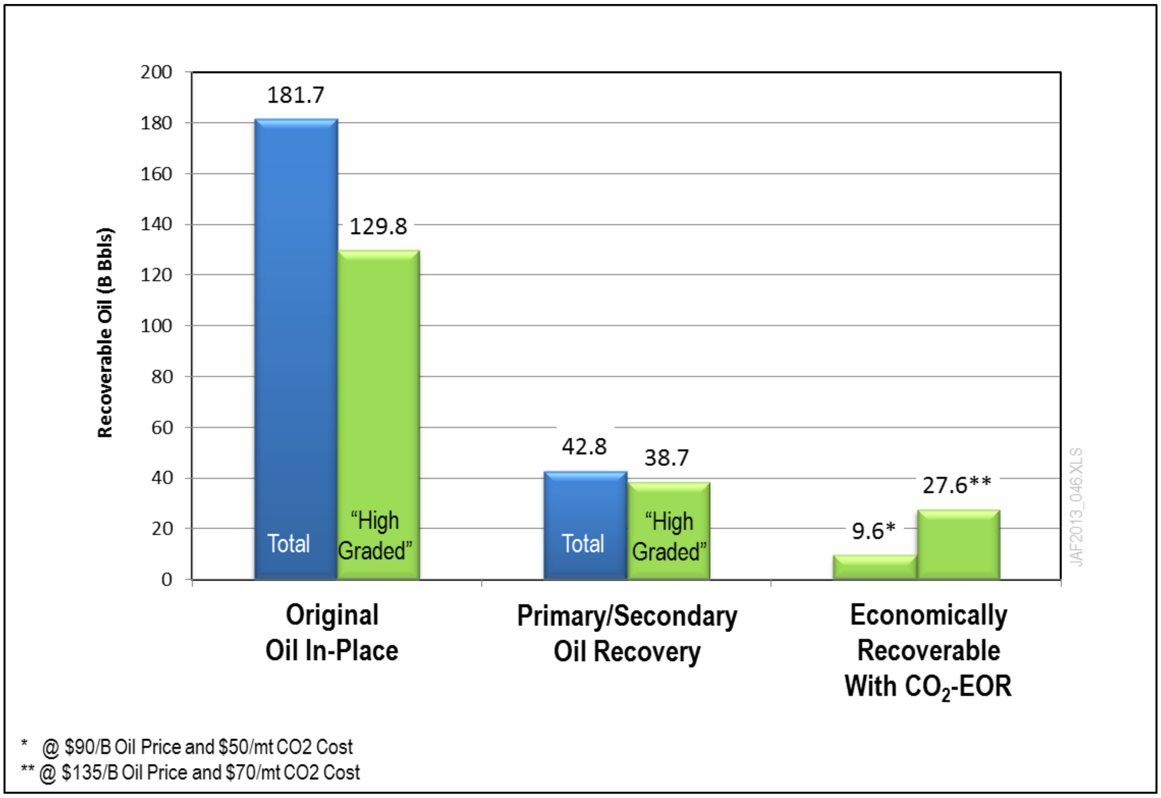
| $CO_2$ Cost | $90/Bbl Oil Price | | $135/Bbl Oil Price | |
|---|---|---|---|---|
| | Oil Recovery | $CO_2$ Demand | Oil Recovery | $CO_2$ Demand |
| ($/mt) | (MMBbls) | (MMmt) | (MMBbls) | (MMmt) |
| 20 ("Free" $CO_2$) | 3,250 | 920 | 7,240 | 2,130 |
| 30 | 2,680 | 750 | 7,190 | 2,120 |
| 40 | 2,380 | 650 | 6,700 | 1,980 |
| 50 (Base Case) | 2,100 | 580 | 6,640 | 1,960 |
| 60 | 1,640 | 440 | 6,110 | 1,760 |
| 70 | 1,260 | 320 | 6,060 | 1,750 |
| 80 | 620 | 150 | 5,520 | 1,580 |
| 90 | 540 | 130 | 5,290 | 1,510 |
| 100 (Today) | 480 | 120 | 5,170 | 1,470 |

## 7.5 Undiscovered Deep Water GOM OCS $CO_2$-EOR Potential

The full set of economically viable undiscovered oil fields of the deep waters of the Gulf of Mexico OCS have estimated OOIP of 181.7 B Bbls and an estimated primary/secondary oil recovery (Original Proved Reserves) of 42.8 B Bbls. The "high graded" portion of undiscovered resources in the GOM OCS holds 129.8 B Bbls of OOIP with 38.7 B Bbls of estimated primary/secondary oil recovery. Use of "Next Generation" $CO_2$-EOR Technology on undiscovered oil fields would boost the volumes of economically viable oil recovery by 9.6 to 27.6 B Bbls depending on oil price and $CO_2$ costs (prices), Figure 7-5.

**Figure 7-5 Undiscovered GOM OCS $CO_2$-EOR oil resources**

(Assumes "Next Generation" $CO_2$-EOR Technology)

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We also analyzed the undiscovered deep water offshore Gulf of Mexico's $CO_2$-EOR oil recovery and $CO_2$ storage (demand) potential under alternative $CO_2$ costs (prices), Table 7-4.

**Table 7-4 Undiscovered GOM OCS $CO_2$-EOR sensitivity analysis**

(Assumes "Next Generation" $CO_2$-EOR Technology)

| $CO_2$ Cost | $90/Bbl Oil Price | | $135/Bbl Oil Price | |
|---|---|---|---|---|
| | Oil Recovery | $CO_2$ Demand | Oil Recovery | $CO_2$ Demand |
| ($/mt) | (MMBbls) | (MMmt) | (MMBbls) | (MMmt) |
| 20 ("Free" $CO_2$) | 14,790 | 4,190 | 32,940 | 9,690 |
| 30 | 12,190 | 3,480 | 32,170 | 9,650 |
| 40 | 10,830 | 2,860 | 30,480 | 9,010 |
| 50 (Base Case) | 9,560 | 2,640 | 30,210 | 8,920 |
| 60 | 7,460 | 2,000 | 27,800 | 8,010 |
| 70 | 5,730 | 1,460 | 27,570 | 7,960 |
| 80 | 2,820 | 680 | 25,120 | 7,190 |
| 90 | 2,460 | 590 | 24,070 | 6,870 |
| 100 (Today) | 2,180 | 550 | 23,520 | 6,690 |

## 7.6 Comparison of Current vs. Prior GOM OCS $CO_2$-EOR Resource Assessment

The current (year 2013) Gulf of Mexico Federal Offshore (GOM OCS) $CO_2$-EOR Resource Assessment updates and greatly expands on the prior (year 2011) GOM $CO_2$-EOR study. The current study includes a much larger, more up-to-date offshore oil field database and includes an appraisal of applying $CO_2$-EOR to undiscovered GOM oil resources. The current study methodology incorporates advanced sub-sea $CO_2$-EOR field development technology and a significantly updated offshore cost model. Finally, the current study examines the impact of using both Current and "Next Generation" $CO_2$-EOR technologies; the prior study only used Current $CO_2$-EOR Technology.

As shown in Table 7-5, the volumes of economically viable $CO_2$-EOR based oil recovery and $CO_2$ storage potential are significantly higher in the current (year 2013) then in prior (year 2011) GOM Federal Offshore $CO_2$-EOR resource assessment.

**Table 7-5 Comparison of current vs prior GOM $CO_2$-EOR studies***

| $CO_2$-EOR Technology Case | Current Study (Year 2013) | | Prior Study (Year 2011) | |
|---|---|---|---|---|
| | Oil Recovery | $CO_2$ Storage | Oil Recovery | $CO_2$ Storage |
| | (B Barrels) | (MMmt) | (B Barrels) | (MMmt) |
| Current Technology | 0.8 | 310 | 0.9 | 260 |
| "Next Generation" Technology | 14.9 | 3,910 | N/A | N/A |

**Economically viable volumes at $90/B oil price and $50/mt $CO_2$ cost.*

- For the Current $CO_2$-EOR Technology Case, the volumes of economically viable additional oil recovery and $CO_2$ storage (demand) are similar for the year 2013 and year 2011 studies.
- However, the current (year 2013) study incorporates "Next Generation" $CO_2$-EOR Technology (the prior year 2011 study did not). As such, the current study shows that large volumes of $CO_2$-EOR based oil recovery (14.9 billion barrels) and $CO_2$ storage (3,910 billion metric tons) are available from the GOM OCS with advances in $CO_2$-EOR technologies.

### 7.6.1 Expanded and Updated GOM OCS Resource Base

The GOM OCS oil field database used in the current study is considerably larger than the database used in the prior study, primarily due to incorporation of newly discovered deep water oil fields and undiscovered resources, Table 7-6 and Table 7-7.

**Table 7-6 Current study (year 2013) GOM OCS oil field data base**

| | # Fields | # Sands | Original Oil in Place (B Bbls) | Original Proved Reserves (B Bbls) |
|---|---|---|---|---|
| Shallow | 80 | 512 | 15.8 | 6.6 |
| Deep | 60 | 184 | 28.5 | 8.3 |
| Undiscovered | n/a | n/a | 129.7 | 38.7 |
| Total | 140 | 696 | 174.0 | 53.6 |

**Table 7-7 Prior study (year 2011) GOM OCS oil fields data base**

| | # Fields | # Sands | Original Oil in Place (B Bbls) | Original Proved Reserves (B Bbls) |
|---|---|---|---|---|
| Shallow | 102 | 479 | 15.8 | 7.4 |
| Deep | 40 | 163 | 13.7 | 4.6 |
| Undiscovered | Not Included | | | |
| **Total** | **140** | **642** | **29.5** | **12.0** |

### 7.6.2 Advanced Offshore Field Development Technology

In addition to a larger GOM resource base, the current study also incorporates a series of advanced offshore technologies. For example, the prior study relied on platforms for $CO_2$-EOR development, limiting the use of $CO_2$-EOR in ultra-deep waters. The current study uses platforms for shallow water $CO_2$-EOR and uses sub-sea completions for deep water $CO_2$-EOR.

### 7.6.3 Updated Costs and Economic Parameters

Finally, the current offshore GOM $CO_2$-EOR resource assessment uses significantly updated costs and more current economic parameters, Table 7-8.

**Table 7-8 Comparison of current and prior study costs and economic parameters**

| | $CO_2$-EOR Resource Assessment | |
|---|---|---|
| | **Current (Year 2013) Study** | **Previous (Year 2011) Study** |
| $CO_2$ Total Cost | $50/mt | $40/mt |
| Oil Price | $90/B WTI | $85/B WTI |
| Shallow Water Royalty | 18.5% | 16.5% |
| Deep Water Royalty | 18.5% | 12.5% |
| $CO_2$ Trunkline Costs | Updated | |
| Well Costs | Updated | |
| $CO_2$ Recycling Costs | Updated | |

# 8 Next Steps

The goal of this study has been to assess the potential for recovering additional domestic oil while simultaneously storing $CO_2$ in the Gulf of Mexico Federal Waters (OCS) using $CO_2$-EOR. As part of this resource assessment, we have identified and discussed in considerable detail two key issues:

1. ***Accelerated Implementation of $CO_2$-EOR in Shallow Water Oil Fields***. Given the maturity of the shallow water GOM OCS oil resource; there is need for accelerated application of $CO_2$-EOR in these near-abandonment oil fields.
2. ***Early Implementation of $CO_2$-EOR in Deep Water Oil Fields***. Considerable priority needs to be placed on developing advanced strategies and technologies for early $CO_2$-EOR implementation, in both newly discovered and still undiscovered deep water oil fields.

Implementing $CO_2$-EOR in the shallow and deep water oil fields of the GOM OCS faces three key challenges:

- ***Lack of Adequate, Affordable $CO_2$ Supplies***. This constraint could be overcome by installation of $CO_2$ capture facilities on the power and other industrial plants along the Gulf Coast. Incentives for storing $CO_2$ with EOR and pursuit of advanced; lower cost $CO_2$ capture technologies could overcome the lack of $CO_2$ supplies constraint.
- ***Availability of "Next Generation" Offshore-Appropriate $CO_2$-EOR Technologies***. Our analysis shows that using "Next Generation" rather than Current $CO_2$-EOR Technology enables significantly more economically viable offshore $CO_2$-EOR projects to be launched, leading to materially higher volumes of oil recovery and $CO_2$ storage.
- ***High "First-Entry" Costs and Risk Premiums***. As for any new venture, the first-mover company faces a series of "thorny" issues (such as limited platform space, high $CO_2$ transportation costs, novel options for $CO_2$ recycling, etc.) and will need to develop customized solutions to address these issues. A series of strategies, discussed further below, could help overcome these "first-entry" cost and risk premium barriers.

Five important "next steps" could help the offshore $CO_2$-EOR industry address these three key challenges:

- ***Royalty Reductions***. Royalty reductions for storing $CO_2$ with EOR in shallow and deep water oil fields could serve as incentive for accelerated application of $CO_2$-EOR technology. The current 18.5 percent royalty places a high financial barrier to implementation of $CO_2$-EOR in offshore waters.
- ***Flagship Offshore $CO_2$-EOR Projects***. Nothing beats "learning by doing." As such, there is an urgent need for two GOM offshore $CO_2$-EOR projects - - one in a mature shallow water oil field and one as an early application of $CO_2$-EOR in a newly discovered deep water oil field. The focus would be on learning and cost reductions with the results shared with the offshore industry.
- ***Affordable $CO_2$ supplies***. The offshore $CO_2$-EOR industry would benefit greatly from investments in advanced $CO_2$ capture technologies that reduce the cost of capturing $CO_2$ emissions and expand the supply of $CO_2$.

- ***Advanced Sub-Sea Technology***. There is need for continued sponsorship of research for improving subsea technologies essential for deep water $CO_2$-EOR. Statoil's recent development of subsea gas compression is an example of technology that would be beneficial to deep water $CO_2$-EOR.
- ***Research and Field Pilots of "Next Generation" $CO_2$-EOR Technology***. There is need for field testing the four main technology components of "Next Generation" $CO_2$-EOR - - improved reservoir conformance, advanced $CO_2$ flood design, enhanced mobility control, and increased volumes of injected $CO_2$ - - in offshore oil fields.

The benefits of undertaking these next steps for offshore $CO_2$-EOR are large - - nearly 15 billion additional barrels of economically viable domestic oil and secure locations for storing nearly 4 billion metric tons of $CO_2$.

*****

Recently, the UK established the Centre for North Sea Enhanced Oil Recovery with $CO_2$ (CENSEOR-$CO_2$) to accelerate implementation of carbon capture and storage and unlock three billion barrels of "hard-to-reach" oil from the North Sea. The objective of CENSEOR-$CO_2$ is to create a market for $CO_2$ captured from power plants and industry and increase oil recovery efficiency by up to 25 percent. The Centre, located in Edinburgh, Scotland, is funded by the Scottish Government matched by industry funding.

Similar and even larger benefits could be realized by undertaking $CO_2$-EOR in the offshore oil fields of the GOM. As the owner, manager and public trustee of the offshore Federal oil and gas resource, it seems reasonable that the Federal Government, through BOEM and DOE, would have similar interests as the UK for optimizing its offshore resources. Important next steps would be to support the development of advanced "Next Generation" $CO_2$ enhanced oil recovery technology and to provide incentives for its timely application.

# Appendix 1 Designing and Implementing Offshore $CO_2$-EOR

Because shallow and deep water GOM fields are so different with respect to their platform types, production strategies, costs and technical difficulty, we used different design criteria and assumptions for implementation of $CO_2$-EOR in shallow water and in deep water oil fields.

## A1.1 Application of $CO_2$-EOR in Shallow Water GOM Oil Fields

A series of modeling strategies and assumptions were used to represent the process of using $CO_2$-EOR in the shallow water oil fields and reservoirs of the GOM OCS, as discussed below.

***Timing of the $CO_2$-EOR Flood.*** For shallow water oil fields, because they consist of mature reservoirs, the $CO_2$-EOR flood is implemented at the end of primary/secondary oil recovery, either once the natural water drive has reached its effective limit or after completion of the waterflood. We assume the production platform is present and that a portion of the existing wells can be used for the $CO_2$-EOR project.

***Available Wells for the $CO_2$-EOR Flood.*** New well drilling is the largest single capital expenditure for offshore $CO_2$-EOR operations. Active and inactive oil well counts were obtained from the BOEM and matched to each oil field and reservoir. We assume that an offshore well could be completed into and thus produce from only one reservoir.

***Pattern and Well Spacing for the $CO_2$ Flood.*** The objective is to maximize oil recovery while minimizing drilling capital expenditures. We use the combination of $CO_2$ injectivity and reservoir size to estimate a well spacing that would achieve a 20 to 25 year $CO_2$-EOR flood. The BOEM data shows that shallow water reservoirs have been drilled at 80 acre to over 1280 acre spacing, with average well spacing generally of 320 to 640 acres. Given the generally high permeability and moderate net pay, most reservoirs are $CO_2$ flooded at 320 acre spacing. Reservoirs with low permeability, poor injectivity or insufficient reservoir area are $CO_2$ flooded using smaller well spacing.

***$CO_2$ Recycling Facilities.*** The second most significant cost for undertaking $CO_2$-EOR in offshore shallow water fields is the construction of a recycling plant. In the economic model, we assume that the $CO_2$ recycling plant is built on an abandoned existing shallow water platform and can service multiple oil fields. The portion that each oil field pays towards the recycling plant is determined by the field's maximum $CO_2$ recycle rate. While operators of large offshore oil fields also have the option of building their $CO_2$ recycling plants onshore, if the construction cost savings outweighed the added $CO_2$ transport cost, we did not include this option in the economic model.

***$CO_2$ Delivery System.*** We assume that each oil field builds a 15 mile $CO_2$ delivery line, connecting the large-scale offshore $CO_2$ pipeline to the platform.

## A1.2 Application of $CO_2$-EOR in Deep Water GOM Oil Fields

The discovered deep water GOM oil fields are less mature and considerably larger than the GOM shallow water oil fields. We incorporated these conditions in designing our $CO_2$-EOR development for the deep water areas of the GOM.

***Deep Water Technology.*** In the past decade, offshore operators have achieved significant advances in subsea completion technology, high pressure/high temperature materials, below salt seismic, and multi-field production hubs to facilitate the economic development of large deep water oil fields. As such, we use sub-sea technology for implementing $CO_2$-EOR for deep water oil fields.

***Timing of the $CO_2$-EOR Project.*** As many of the deep water fields are in the early stages of development, we needed to select the appropriate time for implementing $CO_2$-EOR in our models. We had three choices: (1) begin $CO_2$-EOR at the start of the oil field's development, (2) begin $CO_2$-EOR towards the middle of primary recovery operations, or (3) begin $CO_2$-EOR after the completion of primary/secondary recovery. Despite our extensive discussion of the value of implementing $CO_2$-EOR early in a deep water oil field's life (to improve capital and other economic efficiencies), we chose to implement the $CO_2$ flood after secondary recovery/water flooding based upon current practices in the Gulf of Mexico.

***Field Development.*** We used the following assumptions about expected primary/secondary recovery, reservoir sweep efficiency, and well spacing for the deep water oil reservoirs in our database:

- We obtained active and inactive well counts from the BOEM for deep water oil fields in our database. Based on this, we established that developed deep water oil fields have been drilled on 1280 acre well spacing. For fields currently at wider well spacing, we assumed that new wells would be drilled to achieve 1280 well spacing as part of primary/secondary recovery. As part of implementing $CO_2$-EOR, we assumed that well spacing would be further reduced to 640 acres, with each 640 confined 5-spot pattern having a $CO_2$ injection well.
- Many deep water oil fields in the early stages of development currently have low recoveries and sweep efficiencies that will increase with time as more wells are drilled. To remedy this situation, we assumed that all deep water oil fields would have a minimum sweep efficiency of 50 percent at completion of primary/secondary recovery operations and adjusted the swept and un-swept zone oil saturations to reflect this minimum sweep efficiency.
- For unproven reservoirs lacking production and reserves, we estimated an ultimate P/S oil recovery based upon deep water oil field analogs. P/S recovery efficiency from reservoirs in the same field (as well as porosity, permeability, initial oil saturation, oil viscosity, Dykstra Parsons (reservoir heterogeneity), and depth) was used to find appropriate reservoir analogs.

***Analysis of Reservoir Performance.*** Similarly to the shallow water, we examined the performance of each deep water reservoir using $CO_2$-PROPHET2 and our economic model. We then individually reviewed each reservoir associated with a deep water field and deleted reservoirs with low potential oil production and high well drilling requirements that would hurt the overall economic viability of conducting $CO_2$-EOR in a deep water oil field.

***$CO_2$ Recycling Facilities and Well Drilling.*** Deep water $CO_2$-EOR infrastructure consists of subsea completed wells tied back to a central production platform, known as a "hub and spoke" arrangement. This is modeled after the Independence, Na Kika, and Canyon Express hubs currently operating in the offshore Gulf of Mexico which each hub serving multiple fields. We assume the hub will also house the necessary $CO_2$ recycling plant for $CO_2$-EOR project. Given that new deep water wells are assumed to be subsea completions, a drill ship is used to drill the required $CO_2$ injection and oil production wells.

***$CO_2$ Delivery System***. We assume that each operator builds a 15 mile $CO_2$ gathering line from the hub to their oil field.

# Appendix 2 ARI's Offshore Cost and Economic Model

## A2.1 Overview of the Cost and Economic Model

The ARI Offshore Gulf Of Mexico Cost and Economic Model (OGMEM) was significantly updated and modified for this $CO_2$-EOR resource assessment. The model includes costs for: (1) drilling new wells and 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 other costs. The cost model also accounts for well operation and maintenance (O&M), for lifting the produced fluids, and for capturing, separating and re-injecting the produced $CO_2$.

## A2.2 Capital Cost and Economic Model Inputs

The economic model used by the study is based on 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 taxes, as well as any oil gravity and market location discounts (or premiums) from the "marker" oil price. The key inputs and assumptions of the OGMEM are the following:

- For shallow water oil fields (water depth less than 1,000 feet), $CO_2$-EOR flood make use of existing platform structures and pipelines. $CO_2$ recycling plants are housed on currently existing platforms or on a central platform shared by a number of oil fields.
- For deep water oil fields (water depth greater or equal to 1,000 feet), production facilities consist of subsea systems connected to major floating or moored processing centers where $CO_2$ recycling facilities and major oil production facilities are housed. This is modeled after the Independence, Na Kika, and Canyon Express hubs in the Gulf of Mexico where multiple fields are tied back to the same platform. This deep water production facility design is also similar to Petrobras' Lula development, which includes subsea completions tied-back to an FPSO containing $CO_2$ separation and recycling facilities.
- For all oil fields, a 15-mile $CO_2$ supply line is built, connecting the field to the main $CO_2$ source. In-field $CO_2$ pipeline distribution systems are also included in the cost and economic model. The $CO_2$ supply line is scaled to handle each field's $CO_2$ requirements.
- Developmental well costs, typically the largest capital expenditure in each field, are a function of water depth and below mudline reservoir depth. Shallow water wells are assumed to be drilled using an on-platform rig. Deep water wells are assumed to be drilled using a drill ship. Well costs were derived from variety of public and industry sources. The BOEM was consulted to ensure the model's well costs were in-line with current offshore GOM well costs.

Table A2-1 provides examples of the relationship of well drilling and completion costs to water depth and reservoir depth, for the shallow water areas of the GOM. Table A2-2 provides similar information for the deep water areas of the GOM.

**Table A2-1 ARI OGMEM shallow water well costs**

| Shallow Water Well Drilling | | |
|---|---|---|
| Water Depth | Reservoir Depth (Below Mudline) | Well Cost |
| (Ft) | (Ft) | ($MM) |
| 50 | 5,000 | 11.1 |
| 50 | 10,000 | 15.6 |
| 200 | 8,000 | 13.9 |
| 200 | 12,000 | 17.6 |
| 400 | 8,000 | 14.1 |
| 400 | 12,000 | 17.7 |

**Table A2-2 ARI OGMEM deep water well costs**

| Deep Water Well Drilling | | |
|---|---|---|
| Water Depth | Reservoir Depth (Below Mudline) | Well Cost |
| (Ft) | (Ft) | ($MM) |
| 2,000 | 10,000 | 26.3 |
| 2,000 | 15,000 | 46.4 |
| 4,000 | 16,000 | 55.2 |
| 4,000 | 25,000 | 91.4 |
| 6,000 | 16,000 | 59.9 |
| 6,000 | 25,000 | 96.1 |

## A2.3 Other Cost and Economic Model Inputs

We use oil prices of $90 (WTI) per barrel for the Base Case and $135 per barrel (WTI) for the upside oil price case (real, $2012). We use a $CO_2$ cost of $50 per metric ton (delivered at pressure to the oil field), consisting of a $CO_2$ sales price (at the $CO_2$ source) of $30/mt and for offshore $CO_2$ transportation. We use a cost of $10/mt (at a $90/B oil price) for $CO_2$ recycling.

We use the standard GOM OCS royalty rate of 18.5 percent and set the financial hurdle to 20 percent ROR (before tax).

## A2.4 Special Cost and Economic Model Considerations

Based on past discussions with industry, the study incorporated the following additional features into this version of the OGMEM:

- The analysis assumes that the thinner, edge areas of the oil field, accounting for 20 percent of each reservoir's area and 10 percent of the reservoir's OOIP, are not feasible for application of $CO_2$-EOR.
- The analysis assumes that a one year period of $CO_2$ and water injection is required to raise reservoir pressure to above MMP.
- The recovery model assumes that the residual oil left in the pore space after $CO_2$ injection is 10 percent for Current Technology $CO_2$-EOR and 8 percent for "Next Generation" Technology $CO_2$-EOR.
- The quantity of $CO_2$ injected is 1 HCPV for Current Technology and up to 1.5 HCPV for "Next Generation" Technology. The tapered WAG ratios include an initial large slug of $CO_2$ plus water for mobility control.
- An economic truncation algorithm (comparing annual revenues with annual costs) halts project operation and $CO_2$ injection once the annual cash flow becomes negative.

## A2.5 $CO_2$ Pipeline Transportation Costs

### A2.5.1 The Example Onshore/Offshore $CO_2$ Pipeline

To calculate $CO_2$ transportation costs for the offshore GOM, we assume a pipeline with 1 Bcfd of $CO_2$ capacity is built from East Baton Rouge Parish, LA to an offshore $CO_2$ hub in the Mission Canyon area of the deep water Gulf of Mexico, providing $CO_2$ to the anchor oil fields of Mars-Ursa, Thunderhorse, and North Thunderhorse (combined OOIP of 8.4 B Bbls). This pipeline, travelling 100 miles onshore and 150 miles offshore, is estimated to cost $1.2 billion to construct.

We then use the following inputs to ARI's $CO_2$ Transport Model to determine the $CO_2$ transportation cost for this 250 mile onshore/offshore $CO_2$ supply line:

- $CO_2$ daily max flow rate of 1 Bcfd,
- $CO_2$ delivered to pipeline inlet at 2,000 psi,
- $CO_2$ delivered to the central offshore $CO_2$ hub at 1,800 psi,
- Pipeline operates 24 hours/day with an on-line factor of 85 percent,
- Price of electricity of $0.08/kwh, and
- Capital cost recovery factor of 15 percent.

Using the inputs above, the cost to transport $CO_2$ from onshore Louisiana to an offshore $CO_2$ hub servicing the Thunderhorse and Mars-Ursa oil fields is calculated at about $20/mt.

### A2.5.2 Estimations and Calibration of Pipeline Costs

- ***Onshore Pipelines***. To calibrate our onshore $CO_2$ pipeline costs, we used Denbury's 320 mile Green Pipeline recently constructed in southern Louisiana. The Green Pipeline, with a 24 inch ID capable of delivering 800 MMcf/d of CO2, cost roughly a billion dollars to complete. This equates to about $3 million per mile and $130,000 per inch-mile, installed. The US average cost-per-mile for onshore pipeline construction was $3.1 million per mile (12 month period ending June 30, 2012), equal to the cost-per-mile of Denbury's Green Pipeline.30
- Offshore Pipelines. The US average cost-per-mile for offshore pipeline construction was $5.37 million in 2009, the last year for which offshore U.S. pipeline construction data is available from FERC.31 Assuming a 15 percent cost inflation for 2010-2012, the 2012 US average cost-per-mile for offshore pipeline construction would be $6.2 million.
- Onshore/Offshore Pipeline. Using $3.1 million per mile for the onshore portion and $6.2 million per mile for the offshore portion of the CO2 pipeline, we arrived at a total pipeline construction cost of $1.2 billion dollars for a 250 mile onshore/offshore 1 Bcfd GOM $CO_2$ supply pipeline.

# Appendix 3 Estimating $CO_2$-EOR Oil Recovery and $CO_2$ Storage Potential from GOM Undiscovered Oil Resources

## A3.1 Introduction

Significant volumes of oil remain to be discovered in the Gulf of Mexico's Federal waters. The latest BOEM resource assessment report entitled "Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2011" estimates 48.4 billion barrels as the Undiscovered Technically Recoverable Oil Resource (UTRR), Table A3-1. Of this resource, 42.8 billion barrels is estimated as economically recoverable (UERR), assuming a $90/Bbl oil price, Table A3-2. The great bulk of the undiscovered oil resource is expected to be in the deep water portion of the Gulf of Mexico, Figure A3-1.

A portion of this undiscovered oil (not yet included in the 1/1/2009 BOEM database of offshore GOM discovered oil fields and reserves used by this study) has since been discovered and is expected to start production in the next several years. Table A3-3 tabulates 40 major oil fields holding nearly 8 billion barrels of technically recoverable oil resources (UTRR) expected to be placed on-line by 2020. As such, including undiscovered oil resources in our estimates of offshore $CO_2$-EOR potential enables us to better reflect the near- and mid-term outlook for oil recovery and $CO_2$ storage volumes offered by the Gulf of Mexico OCS.

We have combined the data from BOEM on discovered oil resources in the GOM OCS deep waters with BOEM's estimates for remaining undiscovered oil resources to estimate $CO_2$-EOR oil recovery and $CO_2$ storage for undiscovered GOM OCS resources.

- Of the 42.8 billion barrels of UERR, we estimate 38.7 billion barrels is the "high graded" portion of the undiscovered resource base.

**Table A3-1 Undiscovered technically recoverable oil and gas resources (UTRR)**

| Region | Undiscovered Technically Recoverable oil and Gas Resources (UTRR) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil (Bbo) | | | Gas (Tcfg) | | | BOE (Bbo) | | |
| Planning Area | 95% | Mean | 5% | 95% | Mean | 5% | 95% | Mean | 5% |
| Gulf of Mexico OCS | 38.86 | 48.4 | 59.18 | 193.99 | 219.46 | 245.25 | 73.38 | 87.45 | 102.82 |
| Western Gulf of Mexico | 8.58 | 12.38 | 17.15 | 57.39 | 69.45 | 81.94 | 18.79 | 24.74 | 31.73 |
| Central Gulf of Mexico | 22.54 | 30.93 | 40.69 | 111.77 | 133.9 | 156.62 | 42.43 | 54.76 | 68.55 |
| Eastern Gulf of Mexico | 3.46 | 5.07 | 6.95 | 12.34 | 16.08 | 20.68 | 5.66 | 7.93 | 10.63 |
| Straits of Florida | 0.01 | 0.02 | 0.03 | 0.01 | 0.02 | 0.03 | 0.01 | 0.02 | 0.03 |

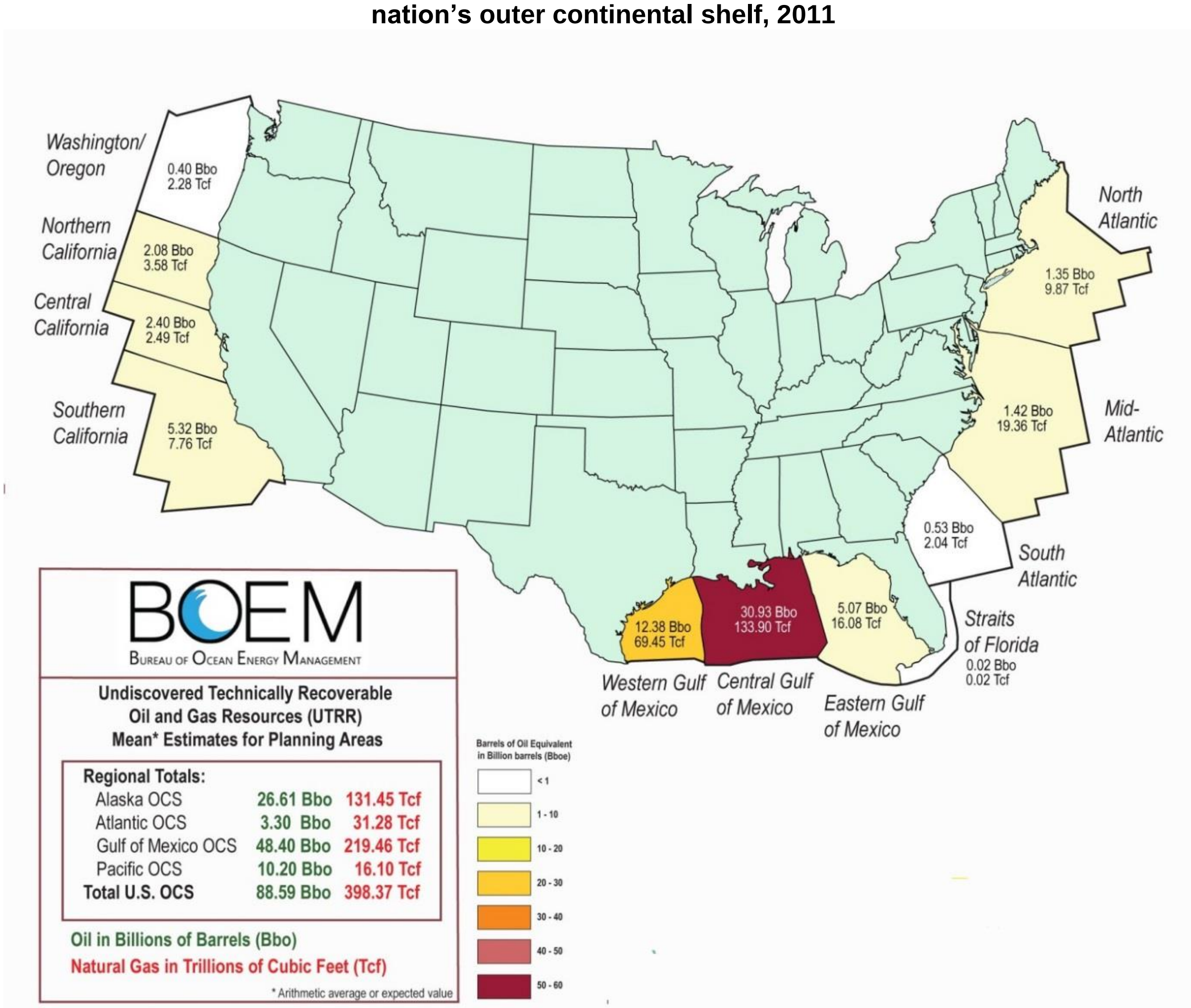
*Source: Bureau of Ocean Energy Management*

**Table A3-2 Undiscovered economically recoverable oil and gas resources (UERR)**

| Region | Undiscovered Economically Recoverable oil and Gas Resources (UERR) | | | | | |
|---|---|---|---|---|---|---|
| | $90/Bbl $6.41/Mcf | | $110/Bbl $7.83/Mcf | | $120/Bbl $8.54/Mcf | |
| Planning Area | Oil | Gas | Oil | Gas | Oil | Gas |
| Gulf of Mexico OCS | 42.8 | 185.94 | 43.64 | 190.46 | 43.97 | 192.25 |
| Western Gulf of Mexico | 10.96 | 61.46 | 11.19 | 62.71 | 11.28 | 63.2 |
| Central Gulf of Mexico | 27.52 | 112.77 | 28.04 | 115.61 | 28.25 | 116.74 |
| Eastern Gulf of Mexico | 4.31 | 11.71 | 4.4 | 12.13 | 4.43 | 12.31 |
| Straits of Florida | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |

*Source: Bureau of Ocean Energy Management*

**Figure A3-1 Assessment of undiscovered technically recoverable oil and gas resources of the nation's outer continental shelf, 2011**




*Source: Bureau of Ocean Energy Management*

**Table A3-3 Size and water depth of announced deep water discoveries due online by 2020**

| Field/Project Name | Block | Water Depth (feet) | Year of Discovery | Field Size Class | Field Size (MMBoe) |
|---|---|---|---|---|---|
| Anduin West | MC754 | 2,696 | 2008 | 11 | 46 |
| Bushwood | GB463 | 2,700 | 2009 | 13 | 182 |
| Caesar | GC683 | 4,457 | 2006 | 11 | 45 |
| Chinook | WR469 | 8,831 | 2003 | 14 | 372 |
| Clipper | GC299 | 3,452 | 2005 | 11 | 45 |
| Galapagos | MC519 | 6,526 | 2009 | 11 | 45 |
| Goose | MC751 | 1,624 | 2003 | 11 | 45 |
| Isabella | MC562 | 6,535 | 2007 | 11 | 45 |
| Mandy | MC199 | 2,478 | 2010 | 13 | 182 |
| MC241 | MC285 | 2,427 | 2006 | 11 | 45 |
| Ozona | GB515 | 3,000 | 2008 | 11 | 45 |
| Pyrenees | GB293 | 2,100 | 2009 | 12 | 89 |
| Silvertip | AC815 | 9,226 | 2004 | 12 | 372 |
| West Tonga | GC726 | 4,674 | 2007 | 12 | 89 |
| Wide Berth | GC490 | 3,700 | 2009 | 12 | 89 |
| Axe | DC004 | 5,831 | 2010 | 12 | 89 |
| Dalmatian | DC048 | 5,876 | 2008 | 12 | 89 |
| Knotty Head | GC512 | 3,557 | 2005 | 14 | 372 |
| Jack | WR759 | 6,963 | 2004 | 14 | 372 |
| Lucius | KC875 | 7,168 | 2009 | 13 | 182 |
| St. Malo | WR678 | 7,036 | 2003 | 14 | 372 |
| Freedom | MC948 | 6,095 | 2008 | 15 | 691 |
| Heidelberg | GC859 | 5,000 | 2009 | 13 | 182 |
| Kodiak | MC771 | 4,986 | 2008 | 13 | 182 |
| Samurai | GC432 | 3,400 | 2009 | 12 | 89 |
| Winter | GB605 | 3,400 | 2009 | 11 | 45 |
| Mission Deep | GC955 | 7,300 | 1999 | 13 | 182 |
| Stones | WR508 | 9,556 | 2005 | 12 | 89 |
| Tiber | KC102 | 4,132 | 2009 | 15 | 691 |
| Vito | MC984 | 4,038 | 2009 | 13 | 182 |
| Shenandoah | WR052 | 5,750 | 2009 | 13 | 182 |
| Buckskin | KC872 | 6,920 | 2009 | 13 | 182 |
| Diamond | LL370 | 9,975 | 2008 | 11 | 45 |
| Julia | WR627 | 7,087 | 2007 | 12 | 89 |
| Appomattox | MC392 | 7,217 | 2009 | 15 | 691 |
| Hadrian South | KC964 | 7,586 | 2009 | 13 | 182 |
| Hal | WR848 | 7,657 | 2008 | 11 | 45 |
| Vicksburg | DC353 | 7,457 | 2009 | 14 | 372 |
| Cardamom | GB427 | 2,720 | 2010 | 13 | 182 |
| Hadrian North | KC919 | 7,000 | 2010 | 14 | 372 |

- Using an expected oil recovery factor of 30 percent (actually 29.8 percent), we calculate an original oil in-place of 129.8 billion barrels and remaining oil in-place of 91.1 billion barrels for the "high graded" portion of the undiscovered oil resource base. These oil resources are the target for $CO_2$-EOR.
- We use the relative size of the "high graded" undiscovered oil resource (91.1 billion barrels) and for "high graded" discovered oil resources in deep waters (20.0 billion barrels) to calculate an extrapolation factor.
- We apply this extrapolation factor to the volumes of $CO_2$-EOR based oil recovery and $CO_2$ storage (demand) from discovered oil fields in the deep waters of the GOM to estimate the volumes of oil recovery and $CO_2$ storage (demand) from using $CO_2$-EOR in the undiscovered oil fields of the GOM OCS.

Table A3-4 provides the data on the discovered and undiscovered oil resources of the GOM OCS that we use in establishing the factor for estimating oil recovery and $CO_2$ storage (demand) from undiscovered GOM OCS oil resources.

**Table A3-4 Discovered and undiscovered oil reserves and resources: Gulf of Mexico OCS**

| | Discovered Oil Resources (Deep Water) | | Undiscovered Oil Resources (Total) | | |
|---|---|---|---|---|---|
| | Total | "High-Graded" | Total Technical | Total Economic | "High-Graded" |
| OOIP (BBbls) | 39.9 | 28.5 | 205.4 | 181.7 | 129.8 |
| Ult. P/S (BBbls) | 9.4 | 8.5 | 48.4 | 42.8 | 38.7 |
| Remaining Recovery (BBbls) | 30.5 | 20.0 | 157.0 | 138.9 | 91.1 |
| Recovery Efficiency | 24% | 30% | 24% | 24% | 30% |

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