Exploring the Value Proposition of Integrating Back-Up Saline Storage into Anthropogenic CO_2 Supplied EOR Operations

by

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B.S. Mechanical Engineering, B.A. Economics
Duke University, 2009

Submitted to the Engineering Systems Division and
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Abstract

Enhanced oil recovery (EOR) through carbon dioxide (CO_2) sequestration from anthropogenic sources has been gaining attention in policy circles. In particular, it is viewed as a potential way to help accelerate the deployment of carbon capture and sequestration (CCS) technologies. The interest in the EOR-CCS model stems from the economic, geologic and regulatory benefits this model offers when compared to the waste-driven CCS model that utilizes saline aquifers for CO_2 storage. However, there are still some major challenges impeding the deployment of the EOR-CCS model; chief among these challenges is the mismatch between CO_2 supplies from anthropogenic sources and CO_2 demand from EOR operations. One potential way to address this challenge is through a CO_2 stacked storage system. A CO_2 stacked storage system utilizes brine formations adjacent to EOR oilfields for the purpose of storing any additional quantities of CO_2 the EOR operation cannot handle.

The concept of a stacked storage system with focus on CO_2 supplies from coal-fired power plants was analyzed using a case study. A U.S. coal-fired power plant and a U.S. EOR oilfield were used to model a stacked storage system in order to determine the economic and technical viability of such a model. More specifically, this thesis has three main objectives. The first is to determine the overall cost of implementing the stacked storage system. The overall cost of the system came to approximately \$90 per ton of CO_2 avoided.

The second goal is to quantify the economic value of the additional revenue streams associated with the EOR operation. The purchase of the CO_2 by the EOR operator can yield significant revenues to the coal-fired power plant (CO_2 supplier)– up to $20 per ton of CO_2 avoided in this case. These revenues are maximized when there is a close match between the CO_2 supply and the EOR demand. Due to this constraint, the pursuit of partial CO_2 capture over 90% capture is recommended when the difference between the capture costs for both options is insignificant.

Finally, the third objective is to determine the type of government intervention required to help implement the CCS-EOR model. Tax revenues generated by the incremental EOR oil production are significant and should be used as tax incentives to help reduce system costs. Tax revenues for the biggest oilfields can generate in excess of $30 per ton of CO_2 stored. However, even with such tax incentives a carbon price of around $50 per ton of CO_2 is required to incentivize the deployment of the EOR-CSS model for coal-fired power plants. In the absence of a price on carbon, the EOR-CCS model can be used in CCS applications that target high purity CO_2 sources such as natural gas processing plants.

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Thesis Supervisor: Ahmed Ghoniem, Ronald C. Crane (1972) Professor of Mechanical Engineering

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Table of Contents

List of Figures

List of Tables

List of Acronyms

ACES	American Clean Energy and Security Act
API Gravity	American Petroleum Institute Gravity
ARI	Advanced Resources International
Bbls	Barrels
Bcf	Billion Cubic Feet
BOPD	Barrel of Oil Per Day
BTU	British Thermal Unit
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
CO_2-EOR	CO_2 Miscible Enhanced Oil Recovery (CO_2 flooding)
cP	Centipoise
DOE	Department of Energy
ECAR	East Central Area Reliability
EOR	Enhanced Oil Recovery
EOR-CCS	CCS operation that utilize EOR operations for CO_2 storage
ERCOT	Electricity Reliability Council of Texas
FGD	Flue-Gas Desulfurization
GOR	Gas to Oil Ratio
GW	Giga Watt
GWh	Giga Watt Hour
HHV	Higher Heating Value
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel On Climate Change
Kg	Kilo Gram
lb	Pounds
Lig	Lignite
M	Thousand
Mcf	Thousand Cubic Feet
md	Milli darcy
MEA	Monoethanolamine
MM	Million
MMP	Minimum Miscibility Pressure

MPa	Mega Pascal
MWh	Mega Watt Hour
NEMS	National Energy Modeling System
NETL	National Energy Technology Laboratory
NG	Natural gas
NGCC	Natural Gas Combined Cycle
NPV	Net Present Value
NRDC	Natural Resources Defense Council
O&M	Operating and Maintenance
OOIP	Original Oil In Place
PV	Pore Volume
R&D	Research and Development
RB	Reservoir Barrels
ROIP	Remaining Oil In Place
SCR	Selective Catalytic Converter
SECARB	South East Regional Carbon Sequestration Partnership
STB	Stock Tank Barrel
Sub	Subbituminous Coal
$	United States Dollar(s)

Chapter 1— Introduction

1.1 CO_2 Emissions from the Existing Infrastructure

Most of the recent discussions regarding supply-side climate change mitigation, as it relates to electricity generation technologies, have been focused on eliminating future carbon dioxide (CO_2) emissions through the deployment of CO_2-free generation technologies such as wind turbines, photovoltaic cells, nuclear power plants and new build Carbon Capture and Storage (CCS) plants (both coal and natural gas based plants). However, as discussed by the MIT Future of Natural Gas Study[1], one of the cheapest ways to mitigate climate change can be done by tackling CO_2 emissions from the existing infrastructure.

CO_2 emissions from the existing infrastructure may be mainly associated with one of five sectors: i) electricity generation, ii) transportation, iii) industrial production, iv) residential (non-electricity based consumption of energy) and, v) commercial (non-electricity based consumption of energy). There is similarity in terms of the CO_2 sources (ex: coal plants, private vehicles, etc…) across the major CO_2-emitting countries (ex: the United States, China, India, etc…). Therefore, solutions that can mitigate CO_2 emissions in one country are likely to be replicable across other major CO_2-emitting countries. The electricity generation sector often accounts for the largest proportion of CO_2 emissions in a given country. It accounted for 40% of annual CO_2 emissions in the United States (U.S.) in 2009. As for other sectors, the transportation sector accounted for 33% of the emissions, the industrial sector accounted for 16%, and non-electricity based (ex: oil and natural gas based heating) commercial and residential sector emissions accounted for the remaining 11%.

Examining the CO_2 emissions associated with the U.S. electricity generation sector in more detail reveals that coal-fired power plants account for more than 80% of the sector's CO_2 emissions, with natural gas-fired power plants accounting for the majority of the remaining emissions in the sector. As such, CO_2 emissions from coal-fired power plants account for about a third of all U.S. emissions.[2] In numbers, as of 2009, there were 572 coal-fired power plants in the U.S. with a cumulative nameplate capacity of around 337GW.[3] In terms of installed capacity, natural gas-fired power plant capacity exceeded that of coal-fired power plants; however, coal-fired power plants currently operate at a higher capacity factor and hence provide around 50% of the power

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1 MIT, "The Future of Natural Gas Study", Cambridge, MA. (2011).
2 EIA, "Emissions of Greenhouse Gases in the United States 2009," (2011).
3 EIA, " EIA-860 Annual Electric Generator Report," (2009).

generated in the U.S.[4] The total CO_2 emissions associated with the coal fleet were equal to 1,742 million metric tons of CO_2 in 2009.[5] This translates to approximately an average CO_2 emission rate of 922 kg/MWh (2187 lb/MWh).[6] Based on these data, it becomes evident that a suitable method to addressing the high CO_2 emissions in the power generation sector may be through the reduction of CO_2 emissions from existing coal-fired power plants. The options that have garnered the most attention in this field include[7]:

i. **Increasing the efficiency of existing plants;**
ii. **Co-firing existing plants with biomass;**
iii. **Retrofitting existing plants with post-combustion CO_2 capture technologies; and**
iv. **Retiring existing plants and replacing them with new/existing low carbon generation technologies.**

As discussed by the MIT Future of Natural Gas Study[8], the cheapest option to reduce the current CO_2 emissions of the U.S. electricity generation sector is through the retirement and replacement of the oldest coal plants with the existing spare natural gas combined cycle capacity. According to this study, up to 20% of the existing coal plants can be retired and replaced at a modest cost. However, to avoid the most severe impacts of global warming, CO_2 emissions from the existing electricity sector must be reduced beyond this 20%. The most scalable option as discussed by the MIT Symposium on the Retrofit of Coal-fired Power Plants[9] is retrofitting plants with post-combustion CCS technologies. Although this option is the most technically scalable, this option is prohibitively expensive due to the high CO_2 capture costs.

One of the potential ways to help drive down CO_2 capture costs and accelerate the deployment of CCS technologies is through the utilization of CO_2-Enhanced Oil Recovery (CO_2-EOR) operations for CO_2 storage. The integration of CO_2-EOR and CCS operations could help drive down costs by leveraging the revenue streams associated with the incremental EOR oil production.

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[4] Ibid.
[5] EIA, "Emissions of Greenhouse Gases in the United States 2009."
[6] EIA, "Net Generation by Energy Source: Total (All Sectors)," ed. EIA (2011).;EIA, "Emissions of Greenhouse Gases in the United States 2009."
[7] See Appendix A for a more extensive discussion of the U.S. coal fleet and the available CO_2 mitigation options.
[8] MIT Energy Initiative, "The Future of Natural Gas Study" (Cambridge, MA 2011).
[9] MIT Energy Initiative, "MIT Energy Initiative Symposium Report on the Retrofitting of Coal-Fired Power Plants for CO2 Emissions Reductions" (Cambridge, MA, 2009).

1.2 The Case for the CCS-EOR Model

The CCS model often discussed in the energy field is the waste driven CCS model that relies on saline aquifers for CO_2 disposal. One of the ideas gaining traction (as highlighted by the MIT Energy Initiative and the Bureau of Economic Geology at the University of Texas at Austin Symposium on the Role of CO_2-EOR in Accelerating the Deployment of CCS[10]) is the possibility of integrating CO_2-EOR operations with CCS systems to improve the economics of CO_2 capture and disposal. The general idea centers on the concept of employing a value added model, where CO_2-EOR operations are employed to store the CO_2, rather than the typical CCS waste driven model that employs saline aquifers. Through the sale of the incremental oil produced, the CO_2-EOR model offers a major source of revenue that can be shared with the coal power plants to help offset some of their CO_2 capture costs. From the EOR operator's perspective, CO_2-EOR operations are CO_2 supply constrained, that is, EOR operators will eventually run out of natural sources of CO_2 before realizing the entire U.S. EOR potential. As a result, the EOR operator has an economic interest in developing and capturing anthropogenic supplies of CO_2. The value proposition of the CO_2-EOR model is discussed in more detail in the following sections.

1.2.1 Value Proposition of CO_2-EOR as a Means to Sequestering CO_2

The CO_2-EOR storage model for CO_2 sequestration offers three principal benefits relative to a storage model that is based on geologic sequestration in saline aquifers: economic value, reduced geologic footprint (due to greater available pore volume density) and potential for regulatory acceptance.

1.2.1.1 Economic Value

CO_2-EOR model offers different revenue streams that can accrue to several stakeholders participating in the operation; all of these revenue streams are derived from the incremental oil production:

- Direct revenue stream from the sale of the oil which can be shared among the EOR operator, CO_2 supplier and the pipeline operators,
- A revenue stream that would accrue to the local or federal governments from the royalties and taxes on the produced oil; and
- Revenue from increased employment and equipment sales in the EOR industry.

[10] Ibid.; MIT Energy Initiative and Bureau of Economic Geology at UT Austin Symposium, "Symposium on the Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Storage" (Cambridge, MA, 2010).

In addition, the presence of existing infrastructure such as injection and production wells makes existing sites more favorable than green field sites in terms of CCS costs. This is very relevant since the capital investment required for storage infrastructure (production and injection wells, other surface facilities) typically exceeds the capital costs needed for transportation and compression infrastructure.[11] Improving the economics of CCS could facilitate the accelerated deployment of CO_2 carbon capture projects.

On a macroeconomic level, using CO_2-EOR as a means to sequester carbon can improve the U.S. domestic oil production. According to an analysis done by Advanced Resources International (ARI), EOR has the potential to boost U.S. oil production by as much as 3 million barrels of oil per day by 2030 if adequate supplies of CO_2 are available and affordable. Depending on the degree of substitution between domestic oil production and imported oil, an increase in oil from CO_2-EOR would likely help reduce U.S. oil imports and improve the U.S. trade balance.

1.2.1.2 Smaller Geologic Footprint

The second advantage of the CO_2-EOR model is the superiority of the confinement properties of the EOR pore volume. For saline formations, it is conservatively estimated that only 1-4% of the pore volume is utilized for geologic sequestration capacity. In contrast, oilfields undergoing EOR have a higher storage density because oil production limits pressure build-up. Due to the structural closure of oil reservoirs and the lower pressure build-up that is a result of the oil production, up to 40-60% of pore space may be utilized for CO_2 storage. To illustrate this, the CO_2 plume from a one GW plant over 30 years would occupy an area of 518.0 km^2 (200 mi^2) of a deep saline formation (using 4% geologic efficiency, 20% porosity, and 61 meters of net pay).[12] Using EOR pore space to confine the same CO_2 plume would require 51.8 km^2 (20 mi^2) (40% of the pore volume is used), and with next generation technology the area could be closer to 25.90 km^2 (10 mi^2).

1.2.1.3 Ease of Regulatory and Public Acceptance

CO_2-EOR projects could help accelerate regulatory acceptance of geologic sequestration as well as establish a technical basis that may be extended to sequestration in deep saline formations. CO_2-EOR already employs significant monitoring practices. In CO_2-EOR, significant data

[11] Perry M. Jarell and Engineers Society of Petroleum, Practical aspects of CO_2 flooding (Richardson, Tex.: Society of Petroleum Engineers, 2002).

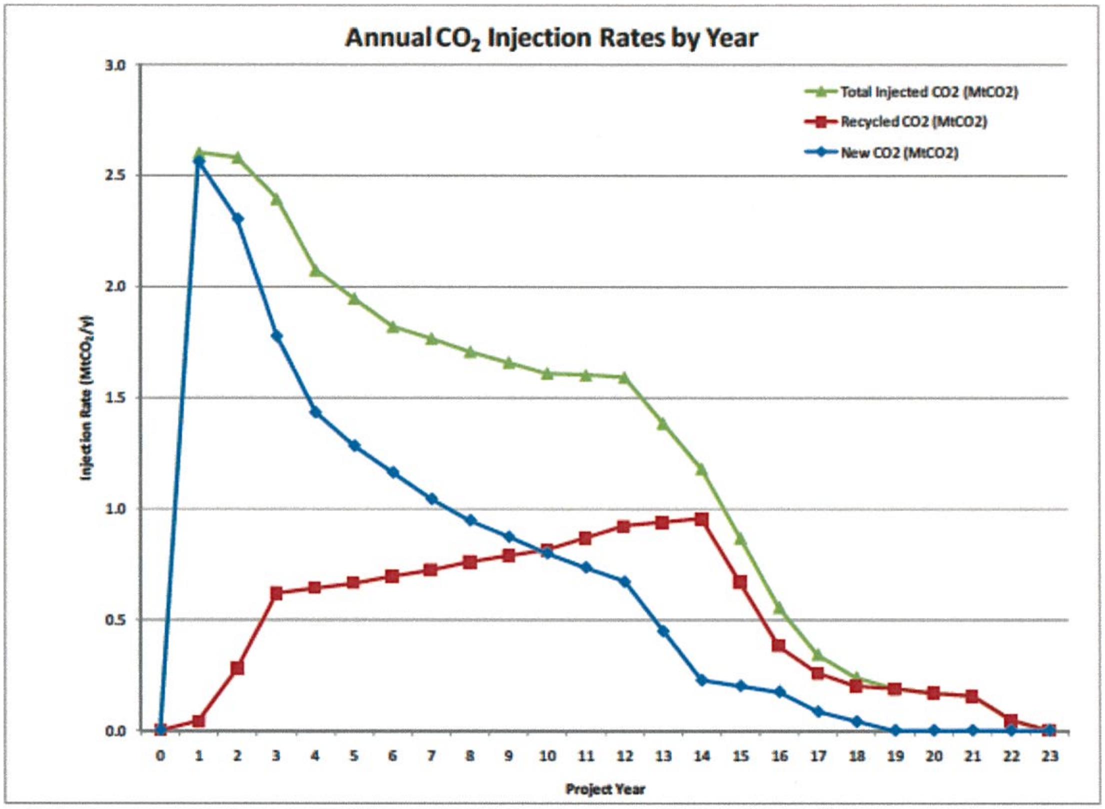
[12] Vello A. Kuuskraa, "Challenges of Implementing Large-Scale CO_2 Enhanced Oil Recovery with CO_2 Capture and Storage," in MIT Energy in MIT Energy Initiative and the Bureau of Economic Geology at the University of Texas at Austin Symposium on the Role of EOR in Accelerating the Deployment of CCS, (Cambridge, MA, 2010).

collection and monitoring of prospective CO_2 floods is done to set expectations. Once the CO_2 flooding commences, monitoring of the injected and produced fluids as well as the reservoir pressure is periodically measured. Since monitoring practices are essential to the success of a CCS program, existing EOR monitoring practices can be modified according to regulatory requirements and hence meet the legal requirements of CO_2 storage. It is likely that public acceptance of CCS will be more easily obtained in legacy areas, where local populations are accustomed to oil operations and the drilling rigs, pipelines, trucks and other similar heavy equipment that accompany these operations.

1.3 Shortcomings of the CO_2-EOR as a Model for CO_2 Sequestration

The CO_2-EOR model although promising, has several shortcomings that must be addressed. A major shortcoming is the discrepancy in terms of short term and long-term supply and demand of CO_2. CO_2 supplies from various sources will be available at rates and times that differ from the CO_2 injection patterns in EOR projects on both a short term basis (daily) and on a more long term basis (years). A coal-fired powered plant operating as a base load service will emit a very significant and almost constant amount of CO_2 year-round. By comparison, an EOR project might have a fluctuating demand for CO_2 due to operational limitations such as periodic shutdowns due to maintenance work. Furthermore, over a longer timeframe, increased amounts of CO_2 are recycled from EOR production operations. As a result, the amount of virgin CO_2 decreases as the project progresses as shown in Figure 1 below. Due to these operational mismatches, a solution must be provided if the EOR-CCS model is to succeed. One potential solution would be to implement back-up storage in deep saline formations, whereby any amount of CO_2, which cannot be handled by the CO_2-EOR operation, will be stored in an adjacent saline aquifer.

Figure 1: CO_2 Demands from a Typical West Texas CO_2-EOR Project (Assuming 20 Injection Wells per Project).[13]



Another shortcoming is that the economics of the CO_2-EOR business is driven by the price of oil rather than the price of CO_2. An analysis by (Leach et al. 2009) of CO_2-EOR economics shows that oil production from EOR projects is highly inelastic to the cost of CO_2 but highly responsive to oil prices.[14] The high uncertainty in the price of oil translates to a high uncertainty in the CO_2 storage potential of an EOR operation. Falling oil prices may lead to the shutdown of the EOR operation and in turn the halt of the CO_2 sequestration operation. It was worth noting that there are other shortcomings for the CCS-EOR model, such as the increased regulatory burden of monitoring CO_2 permanence placed on the EOR operator. However, this thesis will aim to address the challenge of matching anthropogenic supplies of CO_2 supply with CO_2 demand from EOR operations through the use of a stacked storage system.

[13] C.L. Davidson et al., "A quantitative comparison of the cost of employing EOR-coupled CCS supplemented with secondary DSF storage for two large CO_2 point sources, "*Energy Procedia Energy Procedia 4(2011). P.2362.*

[14] Andrew Leach et al., "Co-optimization of enhanced oil recovery and carbon sequestration," National Bureau of Economic Research, http://www.nber.org/papers/w15035.pdf.

1.4 Back-up Saline Storage as a Potential Pathway for the Integration of EOR and CCS Operations

The main shortcomings highlighted in the previous section can be addressed by integrating back-up CO_2 storage into the CO_2-EOR operation. By utilizing an adjacent saline formation to store any excess CO_2 supplies, the EOR operator can handle a very significant and almost constant supply of CO_2 from a coal-fired power plant. Furthermore, the back-up storage option ensures that the EOR operator will be able to handle the CO_2 supply beyond the life of the EOR operation.

In this thesis, a case study of a potential back-up CO_2 storage system often called a "stacked storage system" will be examined. The case study will investigate the technical and economic viability of a CO_2 stacked storage system. The major questions this thesis aims to address are:

I. What is the overall cost of implementing the stacked storage system?
II. What is the economic value of the additional revenue streams associated with the EOR operation?
III. What type of government intervention is required (if any) to help accelerate the adoption of the CO_2-EOR stacked storage system?

To address these questions, the CO_2 injection rates, the associated oil production and the tax revenues generated by a typical CO_2-EOR operation were estimated in Chapter 2. Chapter 3 identified a coal-fired power plant that is amenable to CO_2 capture in the vicinity of the chosen oilfield. The capture costs and the CO_2 capture rate for this plant were then estimated. The results from Chapter 3 were then used as inputs in Chapter 4 to compute the overall costs of employing the stacked storage system. Chapter 5 discussed the policy implications of the results obtained in the previous chapters. Chapter 6 concluded with some high-level findings and recommendations.

Chapter 2 — Typical EOR Operation

This chapter will establish the input and output parameters of a typical EOR operation. The modeling of a typical EOR operation will provide representative numbers for the CO_2 injection rates, CO_2 storage rates, oil production rates, tax revenues, and other relevant data required for establishing a typical EOR operation. Such numbers will then be used in later Chapters for the evaluation of the CO_2-EOR stacked storage system. To carryout the analysis, a candidate EOR oilfield must be chosen and then analyzed using a basic EOR screening model. However, to determine the candidate EOR site and analyze it, a basic understanding of EOR techniques and more specifically, the miscible EOR-CO_2 method is needed.

2.1 Oil Recovery Mechanisms

The first commercial oil well in the U.S. was drilled back in 1859 in Titusville, Pennsylvania.[15] Oil flowed out of the well due to several natural mechanisms that created a natural pressure differential between the oil trapped underground and the surface. This initial stage of oil recovery that relies on the existing reservoir pressure is called "primary recovery". [16] Over time, and as the cumulative amount of oil recovered increases, the reservoir pressure diminishes to a point where it can no longer induce the movement of hydrocarbons to the production well. To recover further quantities of oil, the reservoir pressure may be increased or augmented by the injection of water or other fluids.[17] The primary stage of oil recovery is often followed by two other stages called "secondary recovery" and "tertiary recovery". At each stage of recovery, a certain percentage of the Original Oil in Place (OOIP) is recovered; this percentage varies according to the specific reservoir properties. For instance, in the primary recovery stage, recovery factors typically range between 5-15% of OOIP. Typical recovery rates for the different oil recovery stages are summarized in Table 1 below.

Table 1: Typical Recovery Factors for the Different Oil Recovery Stages.[18]

Stage	Percentage Recovered of OOIP
Primary	5%-15%
Secondary	15%-30%
Tertiary	5%-20%
Remaining	80%-35%

For a detailed discussion of primary and secondary oil recovery mechanisms, see Appendix B.

[15] Morgan Downey, *Oil 101* ([S.l.]: Wooden Table Press, 2009). P.2.
[16] Larry W. Lake, *Enhanced oil recovery* (Englewood Cliffs, N.J.: Prentice Hall, 1989).
[17] Ibid.
[18] Ibid.

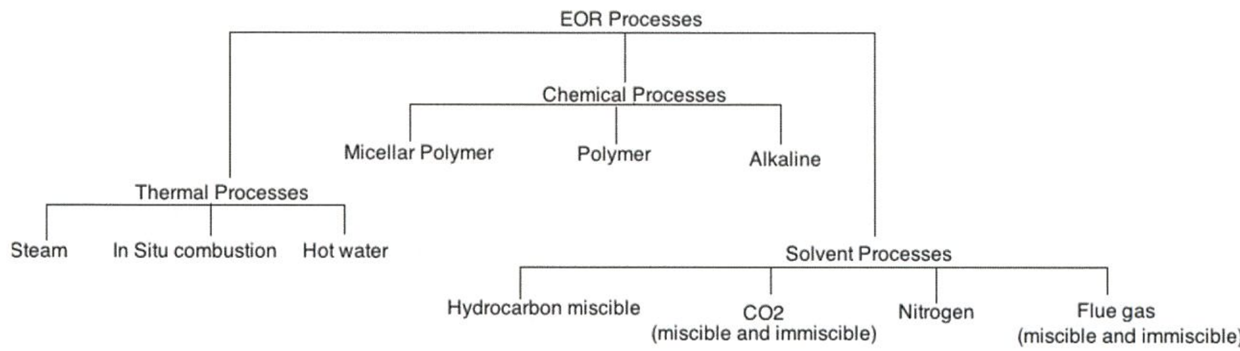
2.2 Enhanced Oil Recovery

There are several definitions for enhanced oil recovery. According to W. Lake, enhanced oil recovery "is oil recovery by the injection of materials not present in the reservoir". Jarrell defines enhanced oil recovery as "any method of economically recovering oil incremental to that produced by primary or conventional improved recovery methods".[19] Alternatively, Erle C. Donaldson[20], views the objective of enhanced oil recovery being "the increase of recovery from reservoirs depleted by secondary recovery with waterflooding or gas injection". As seen, although there is no single uniform definition for enhanced oil recovery, the differences among these definitions is minor. However, an important similarity among all three definitions is that they eliminate the common misuse of EOR as a synonym for tertiary recovery. In fact, EOR is not restricted to any stage of recovery (primary, secondary or tertiary), as many thermal EOR methods have been applied in primary and secondary processes.[21] Nonetheless, the main restriction on the definition of EOR is that it should exclude waterflooding and reservoir pressure restoration methods.[22] For the purpose of this thesis, I will use the EOR definition given by Jarrell: enhanced oil recovery is "any method of economically recovering oil incremental to that produced by primary [natural drive] or conventional improved recovery methods".[23]

Some of the earliest EOR operations can be traced back to the early 1960s, when liquefied petroleum gas was injected into oilfields.[24] Other EOR methods that date back to the 1960s include the cyclic steam method which was used for a short period of time before being replaced in the 1970s by the steamflood method due to its higher recovery potential.[25] In total, more than 13 EOR methods were commercially deployed in the U.S. at some point over the last 50 years, and many of those methods are still in use today. The majority of these different EOR methods can be lumped into three major categories: i) thermal, ii) chemical, and iii) solvent. Figure 2 below, provides a summarized breakdown of the different commercial EOR methods.

[19] Jarrell and Society of Petroleum, *Practical aspects of CO_2 flooding.*
[20] Erle C. Donaldson, George V. Chilingar, and Teh Fu Yen, *Enhanced oil recovery* (Amsterdam; New York: Elsevier, 1985).
[21] Lake, *Enhanced oil recovery.* P.1.
[22] Ibid.
[23] Jarrell and Society of Petroleum, *Practical aspects of CO_2 flooding.*
[24] Donaldson, Chilingar, and Yen, *Enhanced oil recovery.* P.234
[25] Inc. Advanced Resources International, "EPRI Enhanced Oil Recovery Scoping Study," (1999). P. 6-1.

Figure 2: Different Commercial EOR Methods Arranged According to Type[26]



2.2.1 Miscible CO_2-EOR Technique

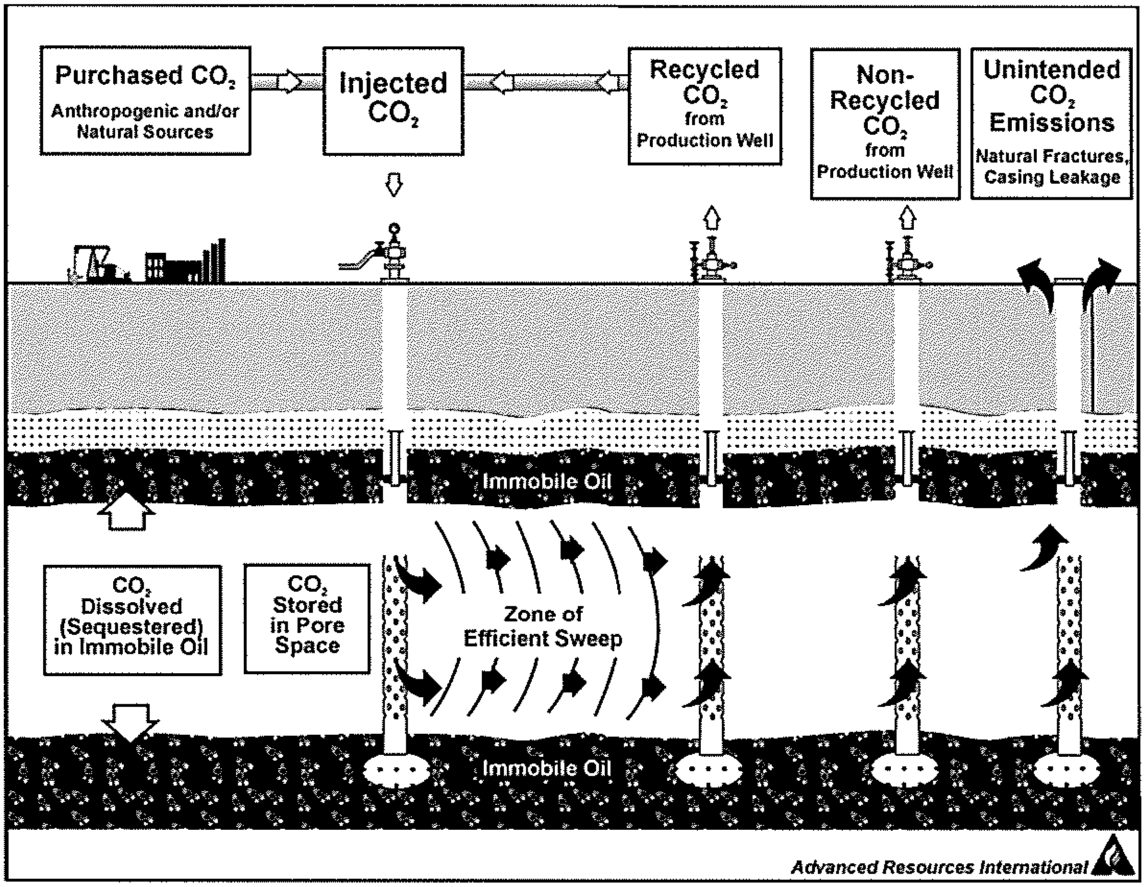
The miscible CO_2-EOR technique is the fastest growing EOR method in the U.S as demonstrated by the increase in the number of CO_2-EOR projects from one project in 1971 to more than a 109 projects in 2010. The 109 projects in 2010 produced more than 260,000 Barrels of Oil per Day (BOPD), which accounted for almost 5% of the domestic U.S. crude oil production. The CO_2-EOR method is second only to the steamflooding method (approximately 270,000 BOPD). Based on historical trends, the CO_2-EOR method should surpass the steamflooding method within two years (by 2014) and become the leading EOR method. The decline in the steamflooding method can be attributed to the diminishing number of oilfields that are amenable to steamflooding (see Appendix A for a more detailed discussion of CO_2-EOR).

2.2.2 CO_2 Sequestration in CO_2-EOR Floods

CO_2 is injected using injection wells into the ground where it becomes miscible with the oil. The miscible CO_2/oil mixture is driven towards the production well by the water and the pressure differential created by the production well. In this process, however, some of the CO_2 is incidentally stored in the reservoir: the CO_2 is trapped in immobile oil and in the pore space vacated by the displaced crude oil. This means that not all of the CO_2 injected into the reservoir can be recycled and pumped back into the ground; this necessitates the purchase of new "virgin" CO_2 to sustain the CO_2 flooding operation. This overall process is depicted in Figure 3 below.

[26] Lake, *Enhanced oil recovery*. P.13.

Figure 3: Schematic Cross-Sectional View of CO_2 Injection, Recycling and Sequestration within an EOR Field.[27]



Although CO_2-EOR operations store CO_2, today's operations are designed to optimize oil recovery rather than optimize the amount of CO_2 stored. Furthermore, in order to maximize profits, many of the EOR-CO_2 operations aim to minimize their overall CO_2 purchases by increasing CO_2 utilization factors and increasing the amount of recycled CO_2; hence the reduction in the total amount of CO_2 stored. The practice of minimizing CO_2 purchases is evidenced by the fact that the present value of CO_2 purchase costs over 10 years accounted for more than 43% of the total CO_2 flooding operation and capital costs.[28] Other estimates place the cost of CO_2 above 50% of the total capital and operating costs of the project. A valid determination based on this data is that CO_2 storage in EOR operations is purely incidental and not driven by environmental concerns.

The total amount of CO_2 stored is dependent on several factors including reservoir properties, flood injection design, oilfield history and current oilfield operation. For instance, when

[27] Advanced Resources International, "EPRI Enhanced Oil Recovery Scoping Study." 4-6.
[28] Jarrell and Society of Petroleum, *Practical aspects of CO_2 flooding.*

decommissioning an oilfield, operators typically perform a "blowing down" of the reservoir pressure to maximize oil recovery. This process also leads to the displacement of the CO_2 that was stored in the pore space vacated by the oil. The CO_2 is a valuable commodity to the operators as it can be collected and reused in future EOR operations, if there are no such plans (no economic value for the CO_2) it is then vented into the atmosphere. If long-term storage of CO_2 is a desired outcome, the state or anthropogenic producers of CO_2 can provide EOR-operators with financial incentives to forgo the blow down process and seal the wells to maintain the long-term storage of the CO_2.

Many states (including Texas and New Mexico) do not require operators to provide detailed reports of CO_2 injections into underground reservoirs. Furthermore, with the absence of financial incentives or regulations to promote CO_2 sequestration, operators do not monitor CO_2 sequestration in reservoirs. As a result, it was somewhat challenging to find information on the CO_2 storage capacity of EOR operations. Fortunately, operators keep track of the quantities of CO_2 flowing through their operations to determine CO_2 purchase requirements. Using data supplied by operator models, a 1999 study[29] commissioned by the Electric Power Research Institute (EPRI) examined gross CO_2 injection rates, CO_2 purchases and CO_2 recycling rates at ten oilfields to determine the amount of CO_2 sequestered. The study assumed that 10% of the CO_2 purchased escapes to the atmosphere along the different steps of the process (for instance, there may be faulty well seals). Therefore, the amount of CO_2 sequestered is equivalent to 90% of the CO_2 purchased. In its calculations, the EPRI study showed that 198 million tons (3,564 Bcf) of CO_2 was stored over the life of the ten projects and the incremental oil recovery over the life of the projects was equal to 710 million barrels of oil. This implies that on average, 0.28 tons (5Mcf) of CO_2 is stored per barrel of oil produced. The detailed breakdown for the ten projects is shown in Table 2 below. The results presented in the EPRI study are consistent with the numbers provided by an Advanced Resource International (ARI) study in which the ARI estimated that 5 to 6 Mcf (0.26 – 0.32 metric tons) of purchased CO_2 is used and stored per incremental barrel of oil produced in a typical EOR operation.[30]

[29] Advanced Resources International, "EPRI Enhanced Oil Recovery Scoping Study."
[30] DOE/NET, "Storing CO_2 with Enhanced Oil Recovery". P.35.

Table 2: CO_2-EOR Ratios and Sequestration at Selected EOR Projects in the Permian Basin, U.S.A.[31][32]

Operator	Field	Estimated Ultimate EOR (MMBO)	% of OOIP	Est. Ult. Net CO_2/EOR (Mcf/BO)	Est. Ult. Net CO_2 Purchase (Bcf)	Estimated Ultimate CO_2 Sequestration (90% of Purchased)	
						(Bcf)	(Gt)
Altura	Wasson Denver	348	16.6	5.3	1,860	1,674	0.09
Pennzoil	SACROC	169	8.0	6.0	1014	913	0.05
Chevron	N. Ward Estes	47	15.0	7.1	334	300	0.02
Spirit Energy	Dollarhide	28	19.0	7.0	194	175	0.01
Phillips	Vacuum East	30	11.5	4.3	130	117	0.01
Texaco	Vacuum	33	15.6	3.7	122	110	0.01
Texaco	Mabee	24	5.5	5.0	120	108	0.01
Conoco	Ford Geraldine	13	13.1	5.0	65	59	0.00
Enron	Two Freds	8	14.1	8.0	64	58	0.00
Fasken	Hanford	10	60.9	5.7	57	51	0.00
Total/Average 10 Fields		**710**	**10.9**	**5.6**	**3,960**	**3,564**	**0.19**

2.3 Establishing the Screening Criteria for the CO_2–EOR Candidate Site

To determine the oilfield that will be used as the basis for the study of the "back-up" CO_2 storage option, several important conditions must be met. The first condition is the amenability of the oilfield to CO_2 flooding. The CO_2 flood should be at a point where CO_2-EOR would make economic sense; the field could have experienced either primary or secondary recovery. The

[31] Advanced Resources International, "EPRI Enhanced Oil Recovery Scoping Study." P.4-11. Data is accurate as of 1999.
[32] Ibid. P.4-11. Data is accurate as of 1999.

second screening condition is the availability of a suitable saline formation underneath or above the oilfield so that a stacked storage system can be implemented. The third condition relates to the site's proximity to a coal-fired power plant.

The first condition, as discussed above, is amenability of the candidate oilfield to CO_2 flooding. To determine whether or not an oilfield is amenable to CO_2-EOR, historical data from past successful CO_2-EOR floods can be used to establish basic screening criteria. Such a study was conducted by (Taber 1991); the study produced a technical screening guideline. Table 3, below, depicts the results of that study.

Table 3: Technical Screening Criteria for Miscible CO_2 Floods.[33]

	Recommended	Range of Current Projects
Crude Oil		
Gravity, °API	>22	27 to 44
Viscosity, cp	<10	0.3 to 6
Oil Composition	High percentage of intermediate hydrocarbons (especially C_5 to C_{12})	
Reservoir		
Oil Saturation, % PV	>20	15 to 70
Net Thickness	Wide range	
Type of Formation	Sandstone or carbonate and relatively thin unless dipping	
Average Permeability	Not critical if sufficient injection rates can be maintained	
Depth and Temperature	For miscible displacement, depth must be great enough to allow injection pressures greater than the MMP, which increases with temperature and heavier oil. Recommended depths for CO_2 floods of typical Permian Oil Basins follows:	
	Oil Gravity, °API	Depth must be greater than (m)
	>40	762
	32 to39.9	853
	28 to 31.9	1006
	22 to 27.9	1,219
	<22	Fails miscible

[33] J. J. Taber, F. D. Martin, and R. S. Seright, "EOR Screening Criteria Revisited - Part 2: Applications and Impact of Oil Prices," *SPE RESERVOIR ENGINEERING* 12, no. 3 (1997).

The results shown in Table 3 above do not represent absolute values, that is, the probability of success for an oilfield does not drop to zero when oil the gravity drops from an °API of 22 to 21. The numbers shown in the table are rather numbers that are based on past experiences. By examining table 3 above we see that assuming all other parameters are met, the crude oil gravity for a successful miscible CO_2 flood ranges between an °API of 27 to 44 with an average °API of 36 whereby the lighter the crude oil, the more amenable it is to miscible CO_2 flooding. Additionally, the recommended oil gravity at °API 22 is lower than the range of current CO_2 floods. This is the case because although none of the CO_2 floods surveyed had an oil gravity less than °API 27, comprehensive lab tests showed that miscible flooding can occur at 22 °API gravity crude oil. Finally, oil viscosities ranged between 0.3 and 6 with an average viscosity of 1.5cP. This indicates that the lower the viscosity the more amenable it is to CO_2 flooding. To achieve pressure that are greater than the thermodynamic MMP, a reservoir depth of at least 762 meters (2,500ft) must be supplied.

The second condition that must be met, as discussed earlier, is presence of a saline formation in the immediate vicinity (above or below) of the oilfield. This saline formation must have the ability to store the CO_2 emissions from a coal-fired power plant permanently. This requirement is necessary so that a stacked storage system can be implemented.

As for the third condition, it is tied to the presence of a coal-fired power plant that satisfies the following criterion: i) the power plant must be in close proximity of the candidate oilfield and ii) the power plant must be a good retrofit candidate for post-combustion CO_2 capture. The first criterion is based on the fact that CO_2 costs increase linearly with distance; therefore, minimizing the transportation distance improves the project's economic feasibility. According to the intergovernmental panel on climate change report on carbon capture and storage, CO_2 transportation costs can range between $1 and $8 per 250 km depending on the type of terrain and the diameter of the pipe.[34] The power plant should be from an economic perspective, a good post-combustion CO_2 capture retrofit candidate. That is, the plant must have a relatively high efficiency, adequate site space to accommodate the extra equipment (typically an additional 0.024

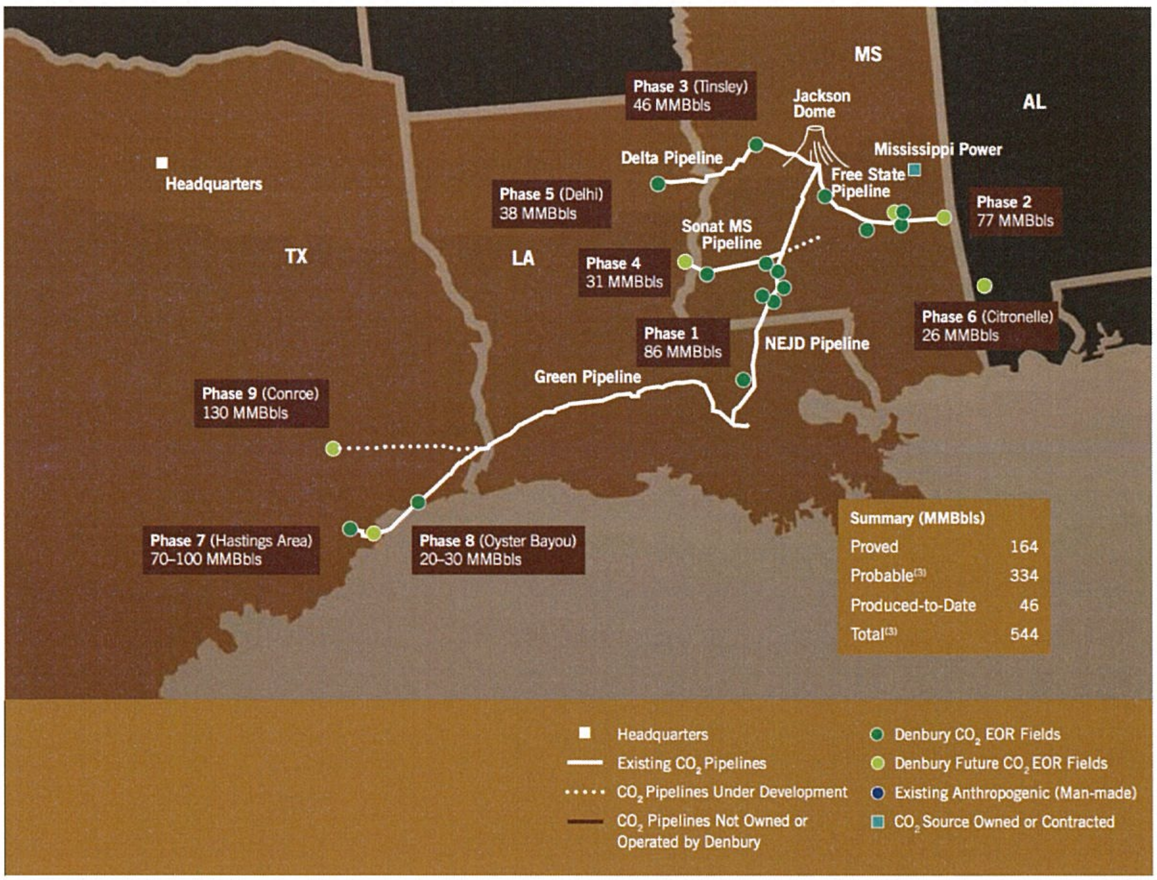
[34] Bert Metz and Group Intergovernmental Panel on Climate Change. Working, III, *IPCC special report on carbon dioxide capture and storage* (Cambridge: Cambridge University Press for the Intergovernmental Panel on Climate Change, 2005). P.191

km^2 are required for a 500MW plant), an adequate water supply and high performance NO_x and SO_x controls.[35]

2.3.1 Selection of the Candidate EOR Site

Given the availability of data, I have decided to focus my attention on Denbury Resources Inc.'s (Denbury) oilfields and other assets. Based on the screening conditions and criterion established in Section 2.3, above, the candidate EOR site must be close to a power plant to minimize total CO_2 transportation costs. However, as seen in Figure 4 below, Denbury's ownership of more than 1,920 km (1200 miles) of existing CO_2 pipeline somewhat relaxes this condition

Figure 4: Map Showing the Different Denbury Oil Fields and Pipelines.



Based on the existing CO_2 pipeline network, I surveyed the numerous CO_2-EOR fields in Alabama, Mississippi, Louisiana and the Gulf coast of Texas to identify the ideal oilfield. Applying the EOR screening criteria presented in Table 3, above, to the pool of selected oilfields provides the candidates listed in Table 4 below.

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[35] The Potential Growing Role of Post-Combustion CO2 Capture Retrofits in Early Commercial Applications of CCS to Coal-Fired Power Plants *MIT Coal Retrofit Symposium*

Table 4: Candidate EOR Oilfields in Alabama, Mississippi, Louisiana and the Gulf Coast of Texas

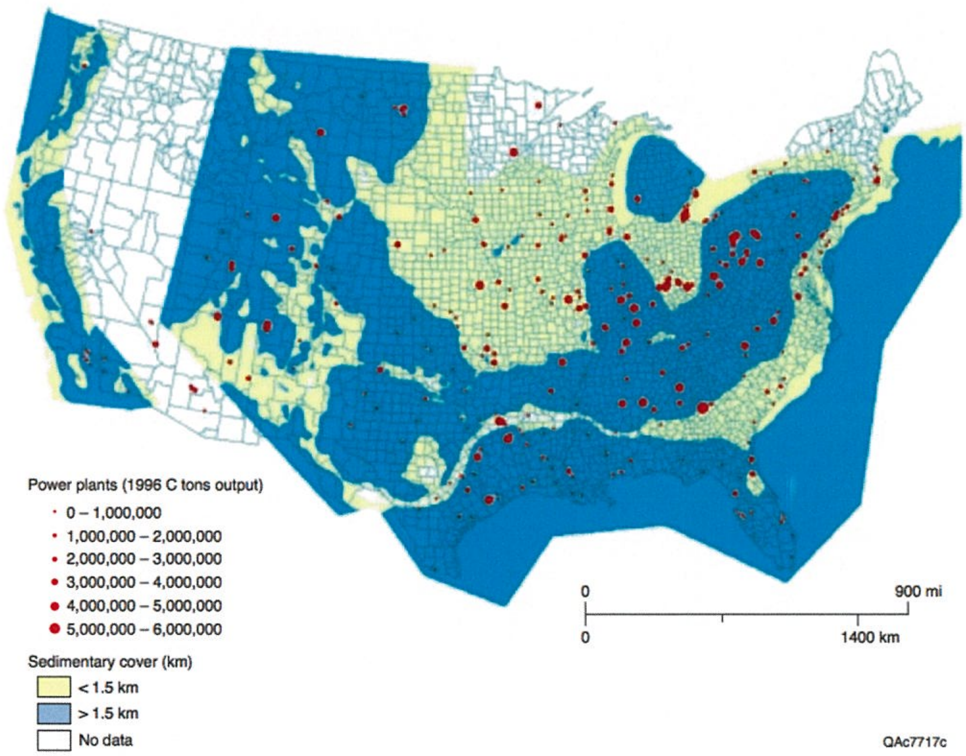
Field/State	OOIP (MMbbls)[36]	Cumulative Production (MMbbls)	ROIP (MMbbls)	Depth (meters)	Oil gravity (°API)	Active Waterflood or Gas Injection
Callilou Island (LA)	1,176	581	588	4,000	39.0	Active waterflooding
Lake Washington (LA)	556	243	311	3,800	26.0	Active waterflooding
Weeks Island (LA)	340	143	187	4,300	33.0	Past CO_2-EOR Project
West Bay (LA)	325	134	183	2,700	30.0	Active waterflooding
Tinsley (MS)	163	50	111	1,500	33	Active waterflooding
Quitman Bayou (MS)	75	21	54	1,400	39	Active waterflooding
East Heidelberg (MS)	93	36	51	1,471	25	Active waterflooding
Citronelle (AL)	537	168	362	3,379	43	Active waterflooding
Wolmack Hill (AL)	94	31	61	3,484	37	Active waterflooding
Conroe (TX)	1,596	728	863	1,524	38	Active waterflooding
Tom O'Connor (TX)	1,133	340	792	1,660	31	Active waterflooding
Seeligson	305	122	183	1,750	43	Active waterflooding

To obtain a rough estimate of the amount of incidental CO_2 stored during CO_2-EOR operations, I assumed that average recovery of the CO_2 operation is 17% of the OOIP and that the CO_2 stored per incremental barrel of oil produced is equal to approximately 0.28 tons (5Mcf) as computed in Section 2.2.4 earlier. Using these numbers, the range of CO_2 stored in the oilfield shown in Table 4 above are between a minimum of 4.4 million tons and a maximum of 75.3 million tons (79 Tcf to 1356 Tcf).

[36] OOIP = Cumulative Production + ROIP + proved primary reserves (not shown in table)

The second condition discussed in section 2.3 requires the presence of a saline formation in the proximity of the oilfield to accommodate the stacked storage concept. The U.S. has many potential saline formations that can accommodate CO_2 storage as shown in Figure 5 below.

Figure 5: Sedimentary Cover and Thickness Across U.S.[37]

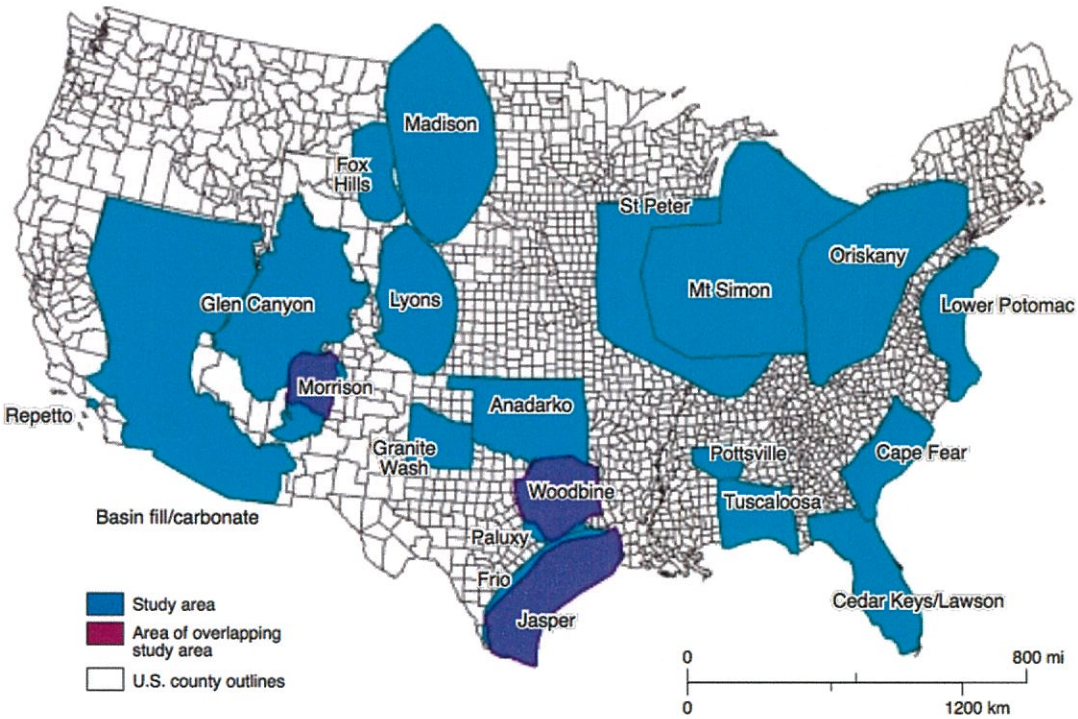


Although a large percentage of the U.S. is covered by saline aquifers, only a small percentage of the available saline aquifers in the U.S. have been evaluated closely for their CO_2 storage potential. A study published in 2000 titled "Project Evaluation: Phase II: Optimal Geological Environments for Carbon Dioxide Disposal in Brine-Bearing Formations (Aquifers) in the United States"[38] and conducted by the Department of Energy (DOE) and National Energy Technology Laboratory (NETL) examined 21 basins as shown in Figure 6 below.

[37] S. D. Hovorka, Romero, M. L., Treviño, R. H., Warne, A. G., Ambrose, W. A., Knox, P. R., and Tremblay, T. A., "Technical summary: optimal geological environments for carbon dioxide disposal in brine-bearing formations (aquifers) in the United States: The University of Texas at Austin, Bureau of Economic Geology, final report prepared for U.S. Department of Energy, National Energy Technology Laboratory," in *GCCC Digital Publication Series #00-01* (2000). P.5.

[38] Ibid. P.1.

Figure 6: Map of the 21 U.S. Basins that were Studied as Part of a DOE/NETL Report.[39]



In the states under examination (Alabama, Mississippi, Louisiana and the Gulf coast of Texas), six basins were studied: i) Tuscaloosa, ii) Pottsville, iii) Woodbine, iv) Paluxy, v) Frio and vi) Jasper basins. Table 5 below shows some representative geologic data complied by the study.

Table 5: Representative Geologic Characteristics of the Tuscaloosa Formation[40]

Formation	Lithology	Age	Facies	Seal	Seal lithology
Tuscaloosa	Sandstone	Cretaceous	Marine	Selma, middle Tuscaloosa	Chalk, shale

The third condition discussed in Section 2.3 requires the presence of a coal-fired power plant in the vicinity of the Denbury oilfields. There are 65 operating coal-fired power plants in the states of Texas, Louisiana, Alabama, and Mississippi.[41] However, it is not economically or technically feasible to retrofit many of these power plants due to their: i) age, ii) low power plant efficiency, iii) power output, iv) lack of SO_2/NO_x controls, v) water availability, and vi) area constraints.

[39] Ibid.
[40] Ibid.
[41] EIA, " EIA-860 Annual Electric Generator Report." (2009)

To select the candidate power plants, I followed a basic three-pronged screening criterion for the 38 plants in the states of Texas, Louisiana, Alabama, and Mississippi. This criterion looked at power plants that have: i) a power capacity that is higher than 500MW, ii) have been constructed after 1990, and iii) have NO_x and SO_x controls in place. The results of this screening produced the three power plants presented in table 6 below.

Table 6: Candidate Sites for Post-Combustion CO_2 Retrofit. [42]

Plant Name	State	Nameplate Capacity (GW)	Operating Year	Energy Source	Coal Delivery	NOx Controls
James H Miller Jr	AL	705.5	1991	SUB	Pulverized Coal	LN
J K Spruce	TX	566	1992	SUB	Pulverized Coal	LN
Red Hills Generating Facility	MS	513.7	2001	LIG	Fluidized Bed	Fluidized Bed Combustor

Based on the data provided in Table 6 above, there are many different combinations of oilfields, saline aquifers, and coal-fired power plants that satisfy the criteria established in Section 2.3 earlier. This is an encouraging result indicating that the CO_2 storage systems under study, if successful, can be scaled to a national level whereby they can play a significant role in achieving CO_2 reduction goals. Given that most of the oilfields and power plants examined satisfy the conditions set-out in this discussion, I had to devise a secondary level of conditions to ensure that the best possible results are obtained. First off, although saline aquifers exist in most of the area under study, more comprehensive data is available on saline aquifers in the Alabama and the Texas Gulf Coast regions. Therefore, I narrowed down my search of oilfields to those two regions. Secondly, given that the ultimate goal of this thesis is to present a scalable CO_2 storage solution, I examined oilfields that are in the medium range in terms of OOIP rather than focusing on the larger oilfields (ex: Conroe) which offer the largest CO_2 storage potential. Finally, given that the power plants listed in Table 6, above, are very similar to one another in terms of technical specifications, I decided to go with the most recently built plant, the Red Hills Generating Facility. Furthermore, the Red Hills Generating Facility offers some minor advantages over the other plants; namely, its proximity to the Denbury operations (in terms of oilfields and existing pipelines). Moreover, given that the plant is the most recently commissioned plant in the group, it is likely to be able to utilize newly installed post-combustion CO_2 capture equipment for the longest period – taking into consideration average plant lifetimes. The reasoning here is that a

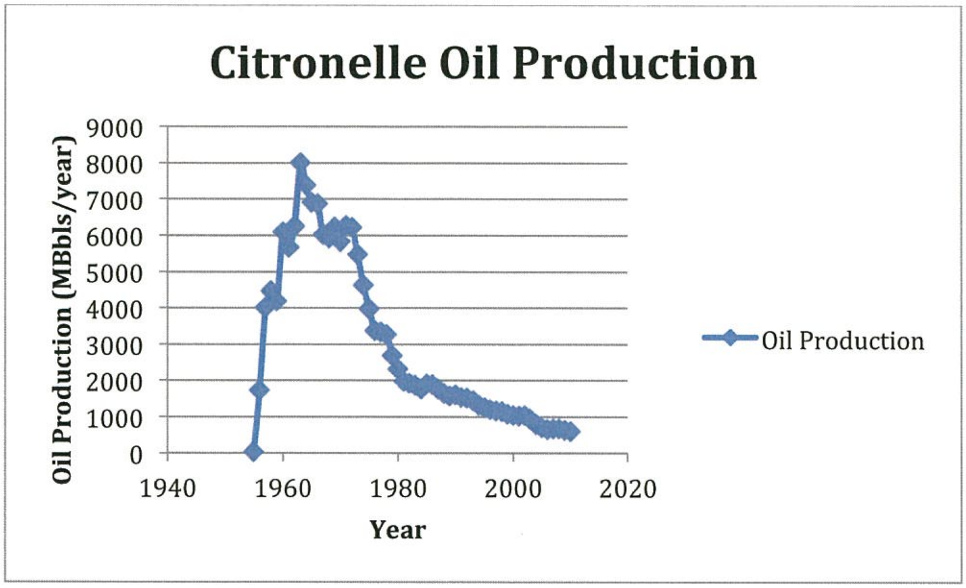
[42] Ibid.(2009)

longer remaining operating lifetime translates to a lower levelized cost for the post-combustion CO_2 capture system. Finally, the Red Hills Generating Facility is the only plant with a Fluidized Bed Combustor (FBC). The FBC helps limit NO_x and SO_x emissions: a requirement for the successful operation of amine-based CO_2 capture systems. Given the choice of power plant, the Citronelle Oilfield was chosen as the representative CO_2-EOR oilfield based on the goal of minimizing CO_2 transportation costs.

2.4 Citronelle Oilfield

The Citronelle oilfield was selected as the site of the CO_2-EOR operation, based on the conditions and criterion set-out in the previous section. The Citronelle oilfield is located 30 miles from Mobil County, Alabama and is owned and operated by Denbury. Denbury has identified the Citronelle field for CO_2-EOR during phase VI of their long-term project outline. Covering a total of 66.4km^2 (16,400 acres), the Citronelle oilfield had an OOIP estimate of 537 million barrels. Today the field has one of the largest stranded oil reserves in the southeastern U.S., with more than 362 million barrels of OOIP remaining. The field is drilled on 40 acre spacing with 524 wells drilled to date, 414 of which are listed as active or temporarily abandoned. These 414 active or temporarily abandoned wells can be employed in both EOR and CO_2 sequestration activities. Following rapid development of the field in the late 1950s and early 1960s, production rates declined exponentially as shown in Figure 7 below.

Figure 7: Citronelle Oil Production. [43]



At the end of 1973 more than 107 million barrels of oil had been produced. As of the end of 2010, cumulative oil production exceeded 169 million barrels with an annual production rate in 2010 equal to approximately 590,000 barrels of oil. If only waterflooding operations are continued, the remaining proven reserves are estimated at 7 million barrels of oil.[44] Kuuskraa et al estimated that EOR operations if implemented, would increase oil reserves by as much as 85 million barrels of oil.[45] Denbury resources places a much lower but still significant estimate of 26 million barrels of incremental oil reserves that can be achieved through EOR operations.

Given that the field has been undergoing waterflooding operations for almost 50 years, the field is well established from a reservoir engineering perspective in terms of accommodating a CO_2 flooding operation. Additionally, the field has a well-developed infrastructure that includes deep wells and lines for the distribution and gathering of fluids that can be reworked and used for the CO_2 flooding operations. From a geologic perspective, the field offers long-term CO_2 storage capabilities due to the presence of fluvial-deltaic sandstone reservoirs that lack faults and are

[43] Geological Survey of Alabama Oil and Gas Board production database. Accessed through: http://www.gsa.state.al.us/ogb/production_nav.aspx.

[44] Advanced Resources International; "Basin Oriented Strategies for CO2 Enhanced Oil Recovery: Onshore Gulf Coast", prepared for U.S. Department of Energy, Office of Fossil Energy - Office of Oil and Natural Gas, February, 2006. P. 6-2.

[45] Kuuskraa, V. A., R. Lynch, and M. Fokin, 2004, Site selection and process identification for CO2 capture and storage test centers, summary report: Geologic assessment of CO2 storage options, four proposed Southern Company power plants, prepared under Agreement E2-P79/C5887 for the Electric Power Research Institute by Advanced Resources International, Arlington, Virginia, March 26, 2004. P.183.

sealed locally by mudstone and regionally by impermeable anhydrite in a simple impermeable anhydrite structural dome.[46]

To obtain a rough estimate of the CO_2 storage capacity over the life of an EOR operation at this field, a 17% recovery rate of the OOIP, and a net incidental CO_2 storage rate of 0.25 tons (4.56 Mcf) per barrel of oil are assumed. Based on these assumptions, the CO_2 storage capacity is 16 million tons (4 years' worth of CO_2 emissions from the Red Hills Generating Facility). As a result, it is clear that even a relatively large oilfield will require some sort of backup CO_2 storage system to accommodate a long term CO_2 supply from a coal-fired power plant. Fortunately, the Citronelle Dome contains numerous saline reservoirs that are suitable for carbon sequestration (this is discussed in detail in Chapter 4 of this thesis).

2.4.1 Citronelle Reservoir Properties

To estimate the results of a CO_2 flooding operation (incremental oil production, amount of CO_2 stored, project economics, etc…), a detailed study of the reservoir properties is needed. Two of the most important reservoir properties as discussed earlier are the thermodynamic MMP and the average reservoir pressure. To induce maximum oil recovery, the reservoir pressure needs to be above the thermodynamic MMP. Unfortunately, it is difficult to determine how much of the reservoir is above the thermodynamic MMP without using a detailed reservoir simulator. Consequently, the average reservoir pressure is often used as an estimate of the pressure throughout the reservoir. As discussed in a DOE-sponsored CO_2 injection study conducted in the 1980s, provided that CO_2 miscibility occurred at 19.3 MPa (2,800 psia) and 99°C (210F).[47] Admittedly the study did not report the thermodynamic MMP; however, for the purposes of this paper, I will conservatively assume that the MMP is, based on the study, equal to 19.3 MPa (2,800 psia).

Given that the CO_2 flood in this case succeeds a waterflooding operation, the oil saturation to water must be considered. The residual oil saturation must be high enough so that the CO_2 flooding operation will produce enough oil to make the operation economically feasible. The appropriate value for the residual oil saturation will vary according to project costs, oil prices and other reservoir properties (ex: reservoir sweep). As such, a basic screening criterion that is often

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[46] R. A. Esposito, J. C. Pashin, and P. M. Walsh, "Citronelle Dome: A giant opportunity for multizone carbon storage and enhanced oil recovery in the Mississippi Interior Salt Basin of Alabama," *Environ. Geosci. Environmental Geosciences* 15, no. 2 (2008). P.3.
[47] R. E. Gilchrist, "Miscibility Study (Repeat 50% P.V. Slug) in Cores, Citronelle Unit, Mobile County, Alabama," (Houston, TX1981).

implemented in such situations will be used. Based on this screening criterion, residual oil should equal 20% of the total power volume at the commencement of a CO_2 flooding operation.[48] According to the available literature, the residual oil saturation for the Citronelle field is estimated at 40%. Table 7, below, contains a compilation of these numbers and variables as collected from a number of studies.

Table 7: Reservoir Properties for the Citronelle Oil Field.[49]

Parameter	Value
Location	Mobile County Alabama
Reservoir	Citronelle
Previous Recovery (MM Barrels)	169
Number of Patterns	414
Pattern Area in km^2 (acres)	0.16 (40)
Depth in Meters (ft)	3201 (10,500)
Initial Reservoir Pressure in MPa (psi)	37.9 (5500)
Thermodynamic MMP (psi)	19.3 (2800)
T_{res} (K), Reservoir Temperature	372
h (m), Net Pay	51.2
k_h (md), Horizontal Permeability	44
k_v/k_h, Permeability Anisotropy	0.18
f (%), Porosity	15.4
V_{DP}, Dykstra-Parsons Coefficient	0.80
S_o, Initial Oil Saturation,	0.40
g_{API} (°API)	32
m_o (cp), Oil Viscosity,	1.41
Formation Volume Factor (RB/STB)	1.19
Initial Formation Volume factor	1.162
Water Viscosity	0.4 cp
Irreducible oil saturation	0.25
Irreducible water saturation	0.21
Initial water saturation	0.6
Solution GOR at initial Pressure	150 SCF/STB

2.5 Results

To estimate the incremental oil production, the incidental CO_2 stored, and the revenue streams from initiating a CO_2 flooding operation at the Citronelle Oilfield, an existing EOR-CO_2 flooding

48 Jarrell and Society of Petroleum, *Practical aspects of CO_2 flooding.*
49 Francis Amechi Dumkwu and Engineering University of Alabama. Dept. of Chemical, "Reservoir engineering analysis : Citronelle oil field Alabama" (2009). P.67.

model was used. The CO_2-EOR flooding model used was one of three engineering-economic models developed by Dr. Sean McCoy as part of a doctoral thesis on the economics of CO_2 transport in pipelines, and CO_2 storage in saline aquifers and EOR reservoirs.[50]

The reservoir properties shown in Table 7, above, were plugged into the CO_2-EOR model. As for CO_2 costs (production and transportation), a cost of $5.4 per ton ($0.30/mcf) was assumed. This assumption is based on the approximate cost of CO_2 extraction currently under way at the Jackson dome (natural CO_2 dome). For the market price of oil, a price of $100 per barrel was assumed. The key results of the model run are summarized in Table 8 below.

Table 8: Key Results of the Model Run.

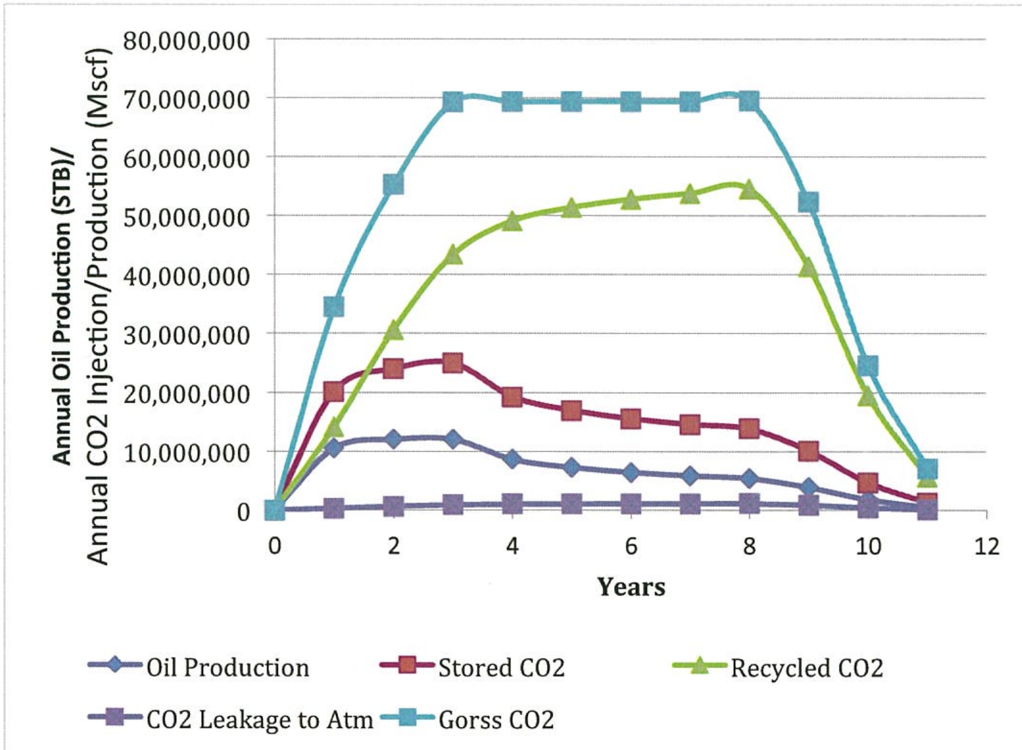
Variable	Value
Oil Recovery (million barrels)	74
Net CO_2 storage (tons)	9.2
CO_2 Leakage to the atmosphere (tons)	0.4
CO_2 Purchase (tons)	9.6
Gross CO_2 injection (tons)	33.2
Net CO_2 utilization rate (ton/bbl)	0.13
Total CO_2 utilization rate (ton/bbl)	0.45
Net Present Value ($ million)	200

According to the different reservoir characteristics and to the different economic assumptions made, around 74 million barrels of oil (13% of the OOIP) will be recovered over a period of 11 years. The total net CO_2 storage rate was equal to 9.2 million tons of CO_2, the total CO_2 purchased was equal to 9.6 million tons of CO_2 and the gross CO_2 injected into the operation was equal to 33.2 million tons of CO_2. This translates to a net CO_2 storage rate of 0.13 tons (2.34Mcf) per barrel of oil produced. This number is almost equal to half the net CO_2 storage rate of 0.28 tons (5Mcf) per barrel of oil produced discussed earlier. The discrepancy in the net CO_2 storage rate arises due to the assumptions made regarding the operation of the EOR project. The high CO_2 injection rates in the initial years translate to high oil recovery rates in the early years and hence to high CO_2 recycling rates. This is evidenced by the fact that ratio of the purchased CO_2 to

[50] Sean T. McCoy, "The economic of CO_2 transport by pipeline and storage in saline aquifers and oil reservoirs" (University Microfilms International, 2008).

the gross CO_2 injection rate is equal to 0.29:1 in this case. On the other hand, looking at the CO_2 injection rates for the West Texas CO_2-EOR project shown in Figure 1 earlier, one can compute that the ratio of the purchased CO_2 to the gross CO_2 injected to be around 0.55:1. The difference in these ratios can be attributed to the manner in which an EOR operation is managed. An EOR project is operated to maximize the value of the oil resource in place (maximize the net present value). If it is projected that the future price of oil is going to be considerably higher than today's price, then the owner might decide to delay some of the oil production to a later stage. The owner can delay the production of oil by injecting smaller quantities of CO_2 in the early stages of the EOR project. Injecting smaller quantities of CO_2 leads to lower oil flow rates towards the production well; the relatively low oil flow rate allows greater quantities of CO_2 to get trapped in immobile oil. Therefore, the different injection rates that are based on maximizing the value of the resource in the ground, dictate the net CO_2 storage rate. In this case, as shown in Figure 8 below, the greatest amount of oil was extracted in the early years of the project. By doing so, an aggressive CO_2 injection schedule was adopted which led to a lower CO_2 storage rate.

Figure 8: Model Results for the Oil Production, CO_2 Stored, Total CO_2 Injected, CO_2 Recycled and the CO_2 Leaked to the Atmosphere.



In terms of project economics, total oil revenue was equal to approximately \$4.6 billion. Total capital costs were equal to approximately \$2.1 billion dollars; these capital costs included production well workovers, injection well workovers, and the CO_2 recycling and separation facilities. Operation and maintenance (O&M) costs were equal to approximately \$800 million and these included CO_2 purchase costs and CO_2 processing O&M costs. The field also generated more than \$800 million in tax revenues and royalties. The project had a net present value (NPV) of \$200 million using a 12% discount rate. The stacked storage system that will be studied in Chapter 4 of this thesis will be evaluated against this base case in terms of financial performance.

The maximum price an EOR operator is willing to pay for the CO_2 is an important benchmark for anthropogenic suppliers of CO_2. A CO_2 breakeven price for this EOR operation at different oil prices was computed and is shown in Table 9 below. As seen in the Table 9 below, at price of \$100 per barrel and a CO_2 price of \$151.9 per ton of CO_2, the EOR operation still has a positive NPV. As the price of oil drops, the breakeven price of CO_2 drops rapidly. At an oil price of \$95, the CO_2 breakeven price drops to \$120.8 per ton of CO_2. The CO_2 breakeven price keeps dropping with the oil prices, until eventually it becomes no longer economically feasible to operate the EOR operation even if the CO2 is supplied for free. At an oil price of \$75, the operator needs to pay a negative price of CO_2 for the operation to have a positive net present value (NPV), this implies that the operation is no longer economically viable at an oil price of \$75 per ton of CO_2.

Table 9: CO_2 Breakeven Price for the Citronelle Oilfield EOR Operation.

Oil Price (\$/bbl)	CO_2 Breakeven Price (\$/mcf)	CO_2 Breakeven Price (\$/ton)
100.0	8.44	151.92
95.0	6.71	120.78
90.0	4.97	88.92
85.0	3.24	58.32
80.0	1.50	27.00
75.0	-0.24	-4.32

Table 9 provided some valuable insight that confirms Leach's[51] conclusions discussed briefly in Chapter 1. First off, EOR oil production is inelastic to CO_2 prices. This means that even if CO_2 prices increase significantly, the economics of the operation will not change significantly. This is an encouraging sign if you're an anthropogenic supplier of CO_2. In the absence of cheap natural sources of CO_2, EOR operations can still be economically viable with high CO_2 prices as long as the oil prices are relatively high. The other takeaways is that the price of oil is a much more important determinant to the success of an EOR operation. That is, the profitability of an EOR operation drops quickly as oil prices drop.

2.6 Key Takeaways from Chapter 2

This Chapter's goal was to obtain the input and output parameters for a typical EOR operation. The Chapter began by establishing criteria upon which a representative EOR candidate was chosen. The criteria included the amenability of the oilfield to the CO_2-EOR method, availability of saline aquifers to the site and, the proximity of the site to a coal-fired power plant. Based on the established criteria, the Citronelle Oilfield was chosen for the purpose of this thesis. Reservoir characteristics for the Citronelle Oilfield were then presented and then used in an EOR screening model. Based on the model runs, it was determined that the total CO_2 stored in such an operation is equal to 9.2 million tons of CO_2. Furthermore, 76 million barrels of oil were produced over an 11-year period. This translated to a net CO_2 storage rate of around 0.13 tons of CO_2 per barrel of

[51] Leach et al., "Co-optimization of enhanced oil recovery and carbon sequestration".

oil produced. A key takeaway from this chapter is that, CO_2-EOR operations are supply inelastic to CO_2 prices. This implies that as long as oil prices remain high, CO_2-EOR operations can be sustained even at CO_2 prices in excess of \$100 per ton of CO_2. Such a result implies that in the absence of cheap natural sources of CO_2, more expensive anthropogenic sources of CO_2 can help maintain oil production through CO_2-EOR operations. It is worth noting that the majority of the results presented in this section are specific to the Citronelle Dome and it should not be assumed that other oilfields would behave in the same manner.

Chapter 3 – Analysis of a Post-Combustion CCS System for the Red Hills Generating Facility

The rising threat of global warming has countries around the world researching and developing carbon-free generation technologies to help control rising CO_2 emissions. As mentioned earlier, coal-fired power plants are a major contributor to global CO_2 emissions. For example, in 2009, coal-fired power plants accounted for more than 20%[52] of global CO_2 emissions in 2009 and approximately a third of all U.S. emissions.[53] Furthermore, CO_2 emissions associated with coal-fired power plants will increase in the short-term as countries around the world attempt to fuel their economic growth with the abundant and cheap coal resources. Clean coal technologies such as Integrated Gasification Combined Cycle (IGCC) systems with CO_2 capture offer a promising CO_2-free electricity generation option; however, these technologies have yet to penetrate the commercial market due to the high costs mainly associated with CO_2 capture. Research is ongoing to help drive down CO_2 capture costs and one of the keys in helping lower these costs will be early demonstration projects. As discussed in Chapters 1 and 2, CCS projects that utilize EOR for CO_2 sequestration are promising candidates for early demonstration projects due to the more favorable economics of such projects.

From the EOR operator's perspective, natural sources of CO_2 account for approximately 81% (approximately 45 million metric tons) of the CO_2 currently injected into EOR projects.[54] The remaining 19% or (approximately 10 million metric tons) are supplied by anthropogenic sources such as the gas processing plants in West Texas and Wyoming and the coal gasification plant in North Dakota. According to EOR industry experts, natural supplies of CO_2 are declining; if the EOR potential is to be fully realized, anthropogenic sources of CO_2 for CCS are needed.[55] As demonstrated in Figure 9, below, Sheep Mountain and Bravo natural domes are witnessing production declines; others are relatively flat.

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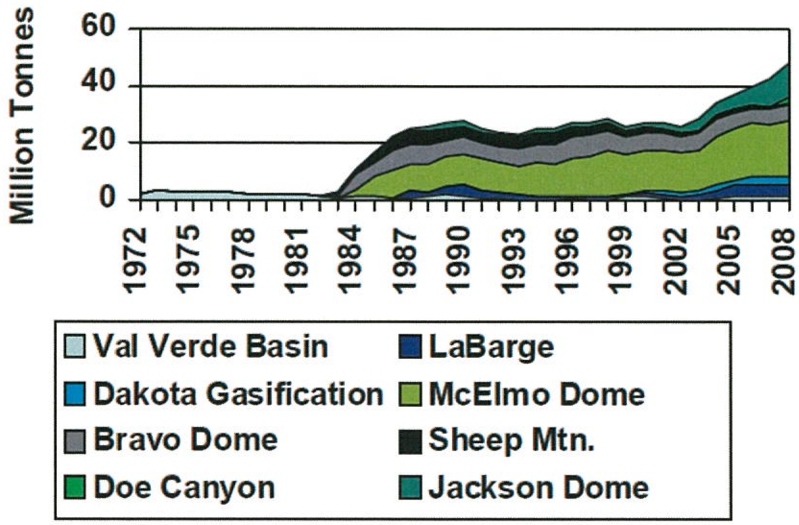
[52] Initiative, "MIT Energy Initiative Symposium Report on the Retrofitting of Coal-Fired Power Plants for CO2 Emissions Reductions." P.15.
[53] EIA, " EIA-860 Annual Electric Generator Report." (2009)
[54] Vello A. Kuuskraa. CO_2 Challenges of Implementing Large-Scale CO_2 Enhanced Oil Recovery with CO_2 Capture and Storage Provided to MITEI and UTBEG Symposium on the Role of Enhanced Oil Recovery in Accelerating the Deployment of CCS , July 23, 2010.
[55] MIT Energy Initiative, "Symposium on the Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Storage", Cambridge, 2009.

Figure 9: Anthropogenic and Natural CO_2 Sources Used in EOR Activities.[56]



To sustain current CO_2-EOR production levels, anthropogenic supplies of CO_2 must be used. This should not be an issue given that the potential supply of CO_2 from anthropogenic sources would far exceed the CO_2 demand from potential CO_2-EOR production.

To evaluate the proposition of utilizing anthropogenic sources of CO_2 in EOR operations, the CO_2 capture costs for coal-fired power plants will be examined in this Chapter. Furthermore, given the emphasis on reducing emissions from the existing fleet, this Chapter will aim to examine the cost of retrofitting existing plants with CO_2 capture systems.

3.1 Post-Combustion Capture

The goal of CCS technologies is to enable the exploitation of cheap fossil fuels (mainly coal in the short term) and at the same time avoid the CO_2 emissions associated with the combustion of these fossil fuels. The first step in the process of CCS involves the capture of a certain percentage of the CO_2 associated with the direct combustion of the fossil fuels in power plants. The capturing of the CO_2 can occur at different stages of the power generation cycle. The three main capture systems currently under study are: 1) post-combustion carbon capture systems, 2) pre-combustion capture systems, and 3) Oxy-fuel combustion capture systems. Most technology discussions surrounding the retrofit of existing plants with CCS technologies have been focused around post-combustion capture technologies. Post-combustion capture involves the separation of the CO_2

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56 U.S. EPA, "General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide: Proposed Rule for Mandatory Reporting of Greenhouse Gases," (2010). P.8.

from the exit flue gas stream. Typically, a chemical process is used to separate the CO_2 from the air and other gases present in the flue gas stream.

Although post-combustion systems are often associated with retrofit applications, oxy-fuel combustion capture systems for retrofit applications are also a technically feasible option, this technology has been gaining more attention in recent scientific discussions. However, given that partial CO_2 capture will be considered later in this thesis, post-combustion capture technologies will only be considered given the inability of oxy-fuel combustion systems to divert part of the CO_2 stream for partial capture. What follows is a brief discussion of post-combustion capture systems.

3.1.1 Post Combustion Capture Systems

There are several post-combustion capture systems that rely on chemical or physical processes to separate the CO_2. However, according to a study on capture technologies carried out by the IPCC, chemical processes are the preferred technology in the short-term horizon. Chemical processes use less energy, offer high capture efficiencies and selectivity and have relatively low costs when compared to other technologies.[57] The technology that has been most widely deployed within chemical processes is the absorption process. Absorption processes have been already deployed commercially although not on the scale required for coal-fired power plants or with the low CO_2 partial pressures found in the exit flue gas stream of coal-fired power plants. Post-combustion absorption processes rely on the chemical reversibility of the reaction between the aqueous alkaline solvent and the CO_2. The solvent is chosen such that CO_2 has a high affinity to solvent; typically, an amine (organic compound) is used as a solvent. For further information on the post combustion absorption process see Appendix D of this thesis.

3.2 Analysis of Red Hills Generating Facility Plant Parameters

Under a carbon constrained regime, operators of some of the existing coal power plants will opt to retrofit their plants with CO_2 capture technologies while other operators might be forced to shut down. As discussed in Chapter 2 of this thesis, the Red Hills Generating Facility was chosen as the candidate retrofit power plant. The decision was made based on several factors including: the size of the plant (larger than 500MWe), the plant efficiency (relatively high plant efficiency), presence of flue-gas desulfurization (FGD) and Selective Catalytic Converter (SCR) capabilities, and proximity of the desired power plant to an oilfield that is amenable to CO_2 EOR flooding.

[57] Metz and Intergovernmental Panel on Climate Change. Working, *IPCC special report on carbon dioxide capture and storage*.

3.2.1 Red Hills Generating Facility Plant Parameters

The plant currently emits CO_2 at an average annual rate of 1.15 kg/kWh (2.53 lb/kWh). This translates to more than four million tons of emitted CO_2 per year. I examined the option of retrofitting a post capture CO_2 system in the Red Hills Generating Facility with 90% emission CO_2 capture capability. Specifically, I assumed that the operator would opt for an amine based carbon capture system with monoethanolamine (MEA) as the sorbent. To compute the CO_2 capture costs, I used the plant parameters given in the NETL 2005 coal-fired power plant database and the Integrated Environmental Control Model (IECM) developed by NETL and Carnegie Mellon University.[58]

The Red Hills Generating Facility is located in Choctaw County in Mississippi and was commissioned in April of 2001. The plant has a nameplate capacity of 513.7MW and is operated by Tractebel Power Inc. The plant relies on two Alstom boilers with fluidized bed firing. The plant burns lignite coal, with the majority of this coal coming from Minnesota, Table 10, below, details the plant's technical details.

Table 10: Red Hills Generating Facility Plant Parameters.[59]

Plant Parameter	Value
Fuel Consumption (1000 tons)	3,598.00
Average Annual Heat Content of Fuel (HHV, MJ/kg)	11.84
Total Annual Boiler Heat Input (GWh)	107,50.0
Average Annual Ash Content (%)	15.60%
Average Annual Sulfur Content (%)	0.46%
CO_2 Emissions (tons)	4,115,742.00
Boiler Efficiency (%)	82.40
Boiler Design Coal Firing Rate (tons/h)	209.50
Boiler Max Continuous Steam Flow at 100% load (1000 kg/h)	1435.00
Net Annual Electrical Generation (GWh)	1,622.50
Net Plant Heat rate (BTU/kWh)	11,300.00
NO_x Emission Standard (kg/MWh)	0.31
Annual Controlled NO_x Emission Rate (kg/MWh)	0.19
Annual NO_x Emissions (tons)	2,206.00
SO_2 Emissions Standard (kg/MWh)	0.39
Annual SO_2 Emissions (tons)	1,918.00
Annual SO_2 Emissions (kg/MWh)	0.17
Particulate Emission Standard	0.02
Actual Annual Particulate Removal Efficiency (%)	99.00
Total Ash Generated (1000 Tons)	561.00

[58] NETL, "NETL's 2007 Coal Power Plant DataBase," (2007).
[59] Ibid.

Total Fly Ash Generated (1000 tons)	571.50
Total Bottom Ash Generated (1000 tons)	100.80
Design Particulate emission rate (kg/h)	16.80
Design FGP Collector Exit Gas Temperature (°C)	154.44
Design Fuel Spec for Coal Ash (%)	29.30
Design Fuel Spec for Coal Sulfur (%)	0.80
Total Ash Collection and Disposal O&M Costs ($1000)	3,803.00
FGP Collector Installed Cost ($1000)	6421.00 per bolier

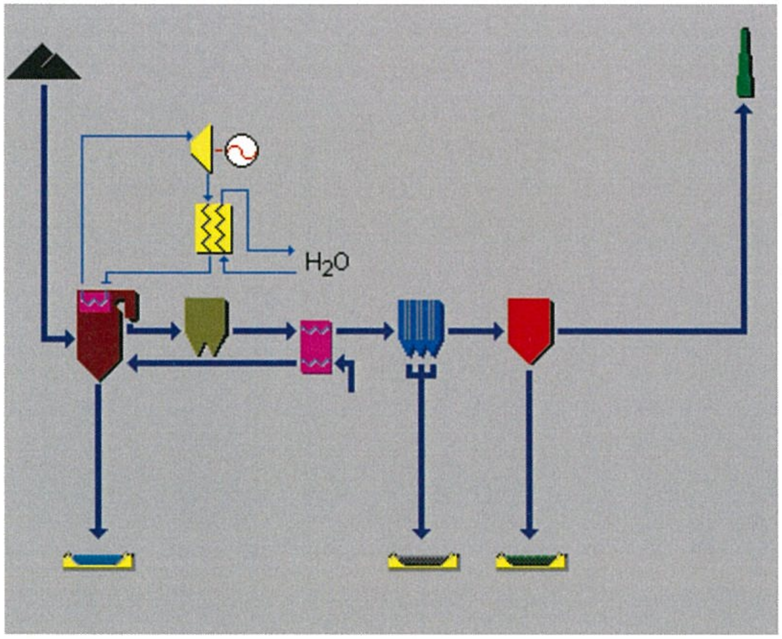
3.3 Modeling the Current Plant Configuration

The plant operates on a sub-critical steam cycle. The power plant relies on two coal boilers that have efficiencies of 82.4%. The flue gas leaving the boiler enters into a hot-side selective catalytic converter (SCR). The NO_x emission rate in the model was set to the actual plant emission legal limit of 0.17 kg/MWh. After the flue gas leaves the SCR, the gas enters into an air preheater where some of the flue gas energy is transferred to the air. The flue gas then proceeds into the particulate fabric filter. Since over 90.0% of the fabric filters used in the U.S. are reverse gas fabric filters, this technology was assumed for this plant configuration. The reverse gas fabric filter uses an off-line bag cleaning technique in which an auxiliary fan forces a relatively gentle flow of filtered flue gas backwards through the bags causing them to partially collapse and dislodge the dust cake.[60] The next flu gas treatment system present in this plant configuration is the wet FGD unit. The flue enters the wet FGD after leaving the fabric filter, for the wet FGD systems, the choice of reagent affects nearly all of the performance and economic parameters of the FGD. Limestone with forced oxidation was assumed, whereby limestone slurry is used in an open spray tower with in-situ oxidation to remove SO_2 and form gypsum sludge. This results in, in contrast to conventional systems, easier dewatering, more economical disposal of scrubber products, and decreased scaling on tower walls.

After the flue gas passes through these different flue gas pre-treatment systems, the flue gas is emitted through the stack. Figure 10, below, provides a schematic for this proposed power plant.

[60] Edward S. Rubin (P.I.), Michael B. Berkenpas, Constance J. Zaremsky, "Development and Application of Optimal Design Capability for Coal Gasification Systems", 2007. P.12.

Figure 10:Power Plant Schematic Produced Using the IECM Model



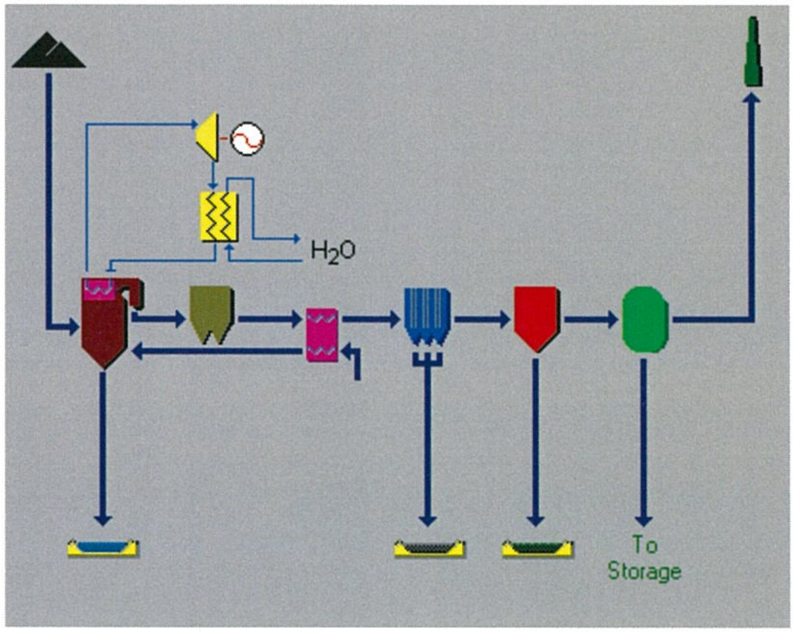
Modeling the plant according to the different system components mentioned above and the parameters shown in Table 10 above, the levelized cost of electricity assuming a new build plant comes out to 0.0608 $/kWh. Where 0.0341$/kWh or 56.7% of the total levelized cost of electricity can be attributed to capital costs and the remainder is attributed to O&M costs. The CO_2 emissions came out to 1.00 kg/kWh (2.21 lb/kWh), which is lower than the actual plant value of 1.15 kg/kWh (2.53 lb/kWh). This difference can be attributed to the different coal properties used as well some of the simplifying assumptions made.

The Red Hills Generating Facility has been in operation for over ten years and the assumption is that the amine system is installed over the next 5-10 year period. I also assumed that the capital costs for the existing plant (the base plant, scrubbers, fabric filter, etc...) will be fully amortized by the time the post-combustion system comes online. In that case, only the O&M costs contribute to the levelized cost of electricity. Assuming that the capital costs of the plant have been fully amortized, the levelized cost of electricity comes out to be 0.0267 $/kWh.

3.3.1 Configuring the Post-Combustion CO_2 Capture System Installed at the Red Hills Generating Facility

As mentioned earlier, under a carbon-constrained regime, some coal-fired power plant operators might find it economical to retrofit some of their existing coal-fired power plants with CO_2 capture technologies. Initial screening criteria showed that the Red Hills Generating Facility is a promising retrofit candidate. What follows, is a more detailed evaluation of a retrofitted CO_2 post capture amine system at the Red Hills Generating Facility. The amine system will be placed after the FGD system as shown by the green block in Figure 11 below.[61]

Figure 11: Schematic of the Power Plant with Amine System Installed Generated Using the IECM Model.



3.3.2 Model Results

Adding the amine system described above and running the model gives a CO_2 avoided cost of around $87 per ton of CO_2 captured, transported and stored, the cost breakdown is provided later in this section. Examining the post-combustion capture system, one sees that there is a significant energy penalty associated with the stripping of the CO_2 from the amine solution. Low-pressure steam must be withdrawn from the power plant steam cycle and diverted to the sorbent regenerator. There is also a significant energy penalty in the compression of the CO_2 to 13.79MPa (2000 psig). The energy consumed for the CO_2 compression use comes out to be 73.2MW. Additional energy requirements include the flue gas fan and the sorbent pump. The total energy penalty associated with these three components comes out to be 93.9MW. Other indirect energy penalties associated with the capture of the CO_2 include the higher energy requirement associated with the SO_2, NO_x and ash removal. This increase in the energy required occurs due to the larger consumption of coal. The different energy requirements are summarized in Table 11 below. Although, the nameplate plant capacity is around 514.0 MWe, the reference plant uses

[61] For more detailed information on the amine capture system see Appendix D.

approximately 45MW are used to treat the flue-gas. As for the net electrical plant output for the retrofitted plant, it is approximately 110MW less due to the energy requirements mentioned above.

Table 11: The Different Power Outputs for the Different Plants.

Power Output	Value (MWe)
Gross Plant Power Output	514.0
Reference Plant Net Electrical Output	467.9
Retrofitted Plant Net Electrical Output	352.3

As stated earlier, assuming that the capital costs of the plant have been fully amortized, the levelized cost of electricity comes out to 0.02673 $/kWh. Installing the amine system raises the total levelized cost of electricity to 0.1003 $/kWh. The incremental cost of the amine system (both capital and O&M costs) is equal to 0.05635 $/kWh. The remainder of the incremental cost is associated with the increased O&M costs that are a result of the increased quantity of treated flue gas (ex: more fuel burned, upgrades in NO_x and SO_x treatment units, etc…).

Due to upgrade in the boiler and the greater amount of energy consumed (burnt coal), the total CO_2 emissions are expected to increase by more than 40%. Therefore, to achieve the goal of avoiding 90% of the CO_2 emitted from the reference plant (the equivalent, to 10% of the emissions of the reference plant are released into the atmosphere), the amount of CO_2 captured is going to be greater than the amount of CO_2 avoided. This is depicted in Figure 12 while Table 12 provides detailed CO_2 emission data. Both are shown below.

Figure 12: Avoided CO_2 Emissions from a CO_2 Capture Plant.[62]

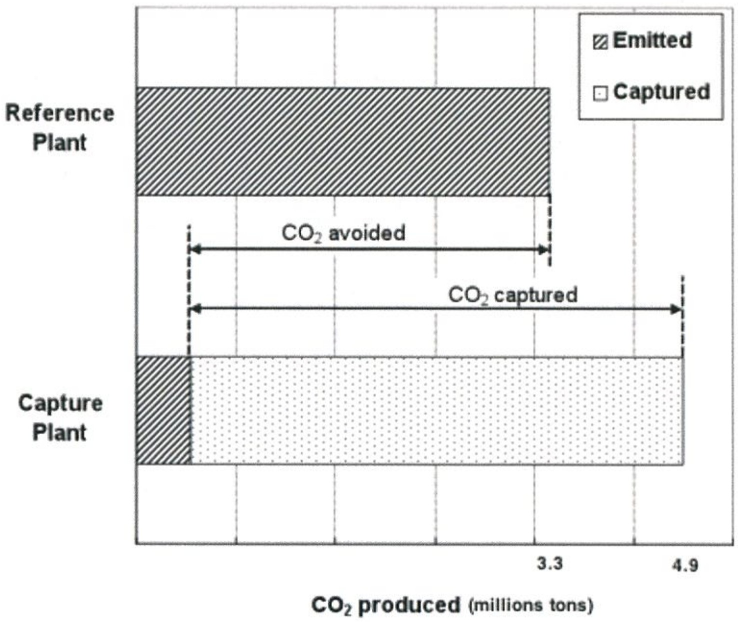


Table 12: Selected Plant Parameters Generated from the Different IECM Model Runs.

Parameter	Value
Reference Plant CO_2 emitted (tons/hr)	522.0
Reference Plant, Total CO_2 emitted (tons/ year)	3,340,278.0
CO_2 gas entering amine system (tons/hr)	760.0
CO_2 gas leaving amine system (tons/hr)	76.0
CO_2 removed (tons/hr)	684.2
CO_2 removed (tons/ year)	4,378,067
Average daily CO_2 captured (ton)	11,995.0
CO_2 avoided (tons/hr)	446.0
CO_2 avoided (tons/ year)	2,853,826.0
CO_2 emitted (tons/ year)	486,451.0
CO_2 Emissions (kg/kWh)	0.20

3.3.3 Economics of the Post-Combustion Capture System

Total incremental capital costs associated with the post-combustion capture system were equal to \$510 million, which translates to approximately 60% of the total CO_2 capture system expenditures. A breakdown of the amine system capital costs is shown in Table 13 below. Additionally, total incremental capital costs for this system totaled \$330 million. The biggest

[62] Initiative, "MIT Energy Initiative Symposium Report on the Retrofitting of Coal-Fired Power Plants for CO2 Emissions Reductions." P.20.

contributor to this cost was the CO_2 absorber vessel, the drying and recompression unit and the sorbent regenerator, which accounted for more than 73% of the capital expenditures.

Table 13: The Different Capital Costs Associated with the CO_2 Capture System.

CO2 Capture Process Area Costs	Capital Cost (M$)
Flue Gas Blower	7.47
CO2 Absorber Vessel	105.6
Heat Exchangers	7.685
Circulation Pumps	15.83
Sorbent Regenerator	57.99
Reboiler	34.49
Steam Extractor	3.297
Sorbent Reclaimer	9.489
Sorbent Processing	10.38
Drying and Compression Unit	80.72
Auxiliary Natural Gas Boiler	0
Auxiliary Steam Turbine	0
Total Capital Costs	**332.9**

3.3.4 Computing the CO_2 Capture Cost

The total capital cost expenditure directly associated with amine system is equal to $508.6 million and the annual O&M costs (variable and fixed) are equal to $67.9 million per year. Assuming a fixed charge factor equal to 0.1128, the total annual costs are equal to:

$$\$508.6 \times 0.1128 + \$69.64 = \$127.01 \; million \; per \; year$$

The quantity of CO_2 removed per year is equal to 4,378,067 tons per year. Therefore, the CO_2 capture costs can be computed as follows:

$$\frac{127.01 \times 10^6}{4{,}378{,}067} = \$29.01 \; per \; ton \; of \; CO_2 \; captured$$

A more relevant metric often found in the literature is the cost of CO_2 avoided, which is defined as follows:

$$Cost \; of \; CO_2 \; Avoided \left(\frac{\$}{ton}\right) = \frac{(\$/kWh)_{capture} - (\$/kWh)_{reference}}{(ton \; CO_2/kWh)_{reference} - (ton \; CO_2/kWh)_{capture}}$$

Entering the values compiled and discussed in this section, the calculation is as follows:

$$Cost\ of\ CO_2\ Avoided\ \left(\frac{\$}{ton}\right) = \frac{0.1003 - 0.02673}{\frac{\left(2.210\frac{lb}{kWh} - 0.4316\frac{lb}{kWh}\right)}{2000\frac{lb}{ton}}}$$

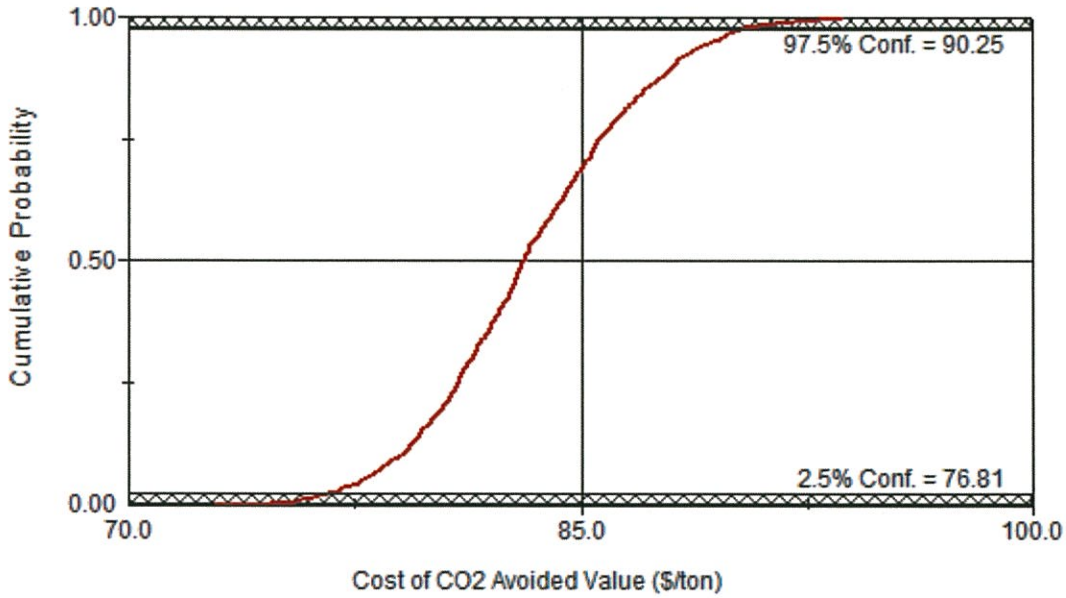
$$= \$82.77\ per\ ton\ of\ CO_2\ avoided$$

As such, the cost of CO_2 avoided comes out to be \$82.77 per ton of CO_2 avoided.

3.3.5 Uncertainty Analysis

The numbers above assume that we know the different system costs to a high degree of certainty. There is uncertainty in terms of the amine system costs since they have yet to be deployed in a commercial setting for a coal-fired power plant. Furthermore, there is uncertainty in other external variables such as electricity demand and fuel prices. To account for some of this uncertainty in the system, I resorted to probabilistic analysis. I used a normal distribution to model some of the cost parameters and overall plant parameters (eg: annual capacity factor). The mean values for the distribution are given by the values shown in the different tables provided in this Chapter. I also assumed a standard deviation that was equal to 5% of the mean value. After assigning the different probability distribution values to different cost variables, I proceeded to run a Monte Carlo simulation. According to the cumulative probability distribution curve shown in Figure 13 below, the cost of CO_2 avoided is less than \$90.25 per ton with 97.5% confidence. As such, based on the analysis carried out in this section, the CO_2 capture costs according to the assumptions made are less than or equal to \$90.25 per ton, with 97.5% confidence

Figure 13: Cumulative Probability Distribution Curve for the CO_2 Capture Costs.



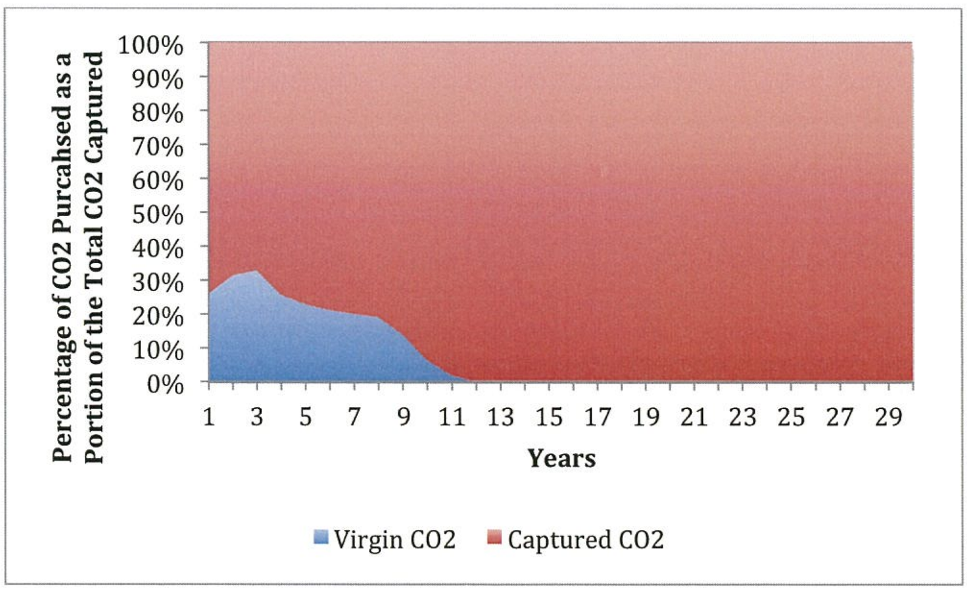
3.4 Key Takeaways from Chapter 3

To model the EOR Stacked Storage System, the anthropogenic source of CO_2 had to be modeled first. This Chapter began by establishing the plant configuration and equipment for the Red Hills Generating Facility. The CO_2 emissions and the electricity costs were then computed for the Red Hills Generating Facility in the absence of a CCS system. A second model run was then carried out in the presence of a retrofitted post-combustion CO_2 capture system in place. The net CO_2 capture rate and the new electricity prices were computed. The analysis showed that the annual amount of CO_2 captured from this plant was equal to around 4.3 million metric tons of CO_2 per year. Furthermore, the analysis showed that the cost of CO_2 avoided was equal to around $82.8 per ton of CO_2. These two key results, in addition to the results obtained in Chapter 2 were used in Chapter 4 to establish the system costs for the EOR stacked storage system.

Chapter 4 – EOR Stacked Storage System

The cumulative amount of CO_2 purchased (stored + leaked CO_2) over the eleven-year lifespan of the EOR project was equal to 9.65 million metric tons of CO_2. The maximum annual amount of CO_2 purchased over the life of the EOR project was equal to around 1.40 million metric tons of CO_2. Furthermore, the average daily amount of CO_2 purchased was equal to 2400 tons, with a maximum of 3900 metric tons in year 3 and a minimum of 218 tons towards the end of the project when most of the injected CO_2 is recycled CO_2. The total and daily quantities of the CO_2 purchased for the EOR operation are much smaller than the captured CO_2 quantities (both cumulative and daily). The average amount of captured CO_2 is equal to approximately 12 thousand tons per day and the annual average CO_2 captured from the plant is equal to approximately 3.8 million tons. As shown in Figure 14 below, the maximum amount of CO_2 purchased at any given point in the operation is equal to 33% of the average daily CO_2 captured.

Figure 14: EOR CO_2 Consumption Patterns.



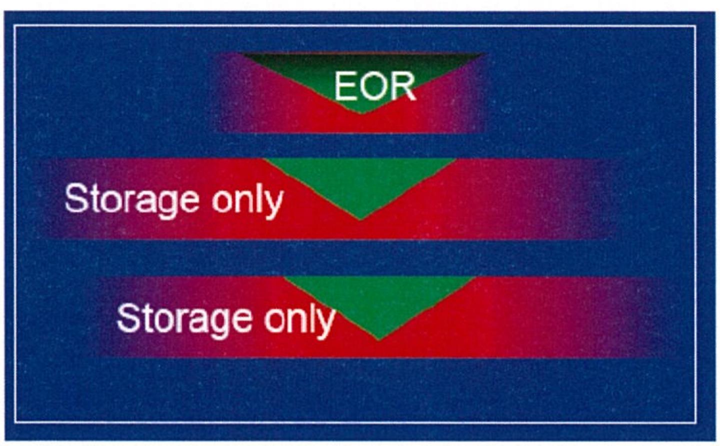
If CO_2-EOR is to become a potential pathway for CO_2 mitigation, then the short-term and long-term mismatch between supply and demand must be addressed. One of the potential options to do so is a stacked EOR storage system, which would employ saline aquifers to help regulate the discrepancies between supply and demand. The South East Regional Carbon Sequestration

Partnership (SECARB) is currently studying this concept of implementing a stacked storage system in the Citronelle Oilfield.[63]

4.1 Overview of the Stacked Storage Concept

Brine formations[64] are usually found in the vicinity of oilfields. These formations can be present above, beneath, or on the sides (water leg of the reservoir) of oilfields.[65] In a case such as this, where the EOR operator has incentive to store additional quantities of CO_2 (rather than minimize the total quantity of CO_2 used), this brine-filled pore space can be utilized to store additional quantities of CO_2. Additional quantities of CO_2 can be stored in the laterally adjacent brine-filled pore space. This can be achieved through the same injection well, whereby additional quantities of CO_2 are injected such that the CO_2 begins moving away from the production pattern. Alternatively, additional quantities of CO_2 can be stored in brine formations that are beneath or above the oilfield. These brine formations are usually stratigraphically isolated and therefore, new wells must be drilled or existing wells must be reworked to reach these non-producing strata. A schematic showing a potential stacked storage system where the brine formations are found underneath the oil producing strata is shown in Figure 15 below.

Figure 15: Large Volumes of Nonproductive Brine Formations Lie Below Many CO_2 EOR Targets. [66]



[63] Southeast Regional Carbon Sequestration Partnership (SECARB) Gulf Coast Stacked Storage Project, Cranfield Oilfield, Mississippi

[64] "Brine formations" are used interchangeably with "saline aquifers" throughout this chapter.

[65] Susan D. Hovorka, "EOR as Sequestration—Geoscience Perspective," in *MIT Energy initative and the Bureau of Economic Geology at The University of Texas at Austin Symposium on the Role of EOR in Accelerating the Deployment of CCS* (Cambridge, MA2010). P.18.

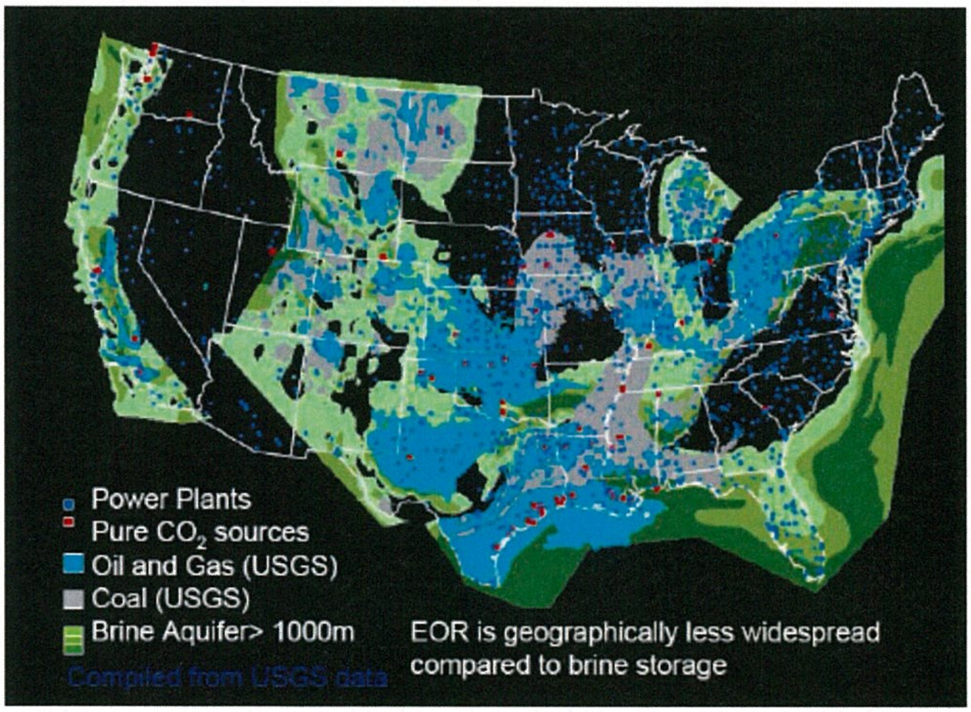
[66] Ibid. P.18.

The presence of the brine formation allows for the accommodation of additional amounts of CO_2, enabling the management of both short term and long-term disparities between the CO_2 supplied and demanded.

4.1.1 Overlap Between Saline Aquifers and Oilfields

In contrast to oilfields, brine formations are unique in their storage ability in that they do not have a localized geologic trap.[67] As a result, many brine formations across the US can be used for CO_2 storage purposes. Given the abundance of saline formations across the U.S., the concept of a stacked storage system is highly scalable. Many of the existing oil fields overlap with different brine-filled formations across the U.S. as illustrated in Figure 16 below.

Figure 16: Coincidence of Sedimentary Formations of Suitable Depth for Brine Sequestration with Hydrocarbon Basins and Stationary CO_2 Sources[68].



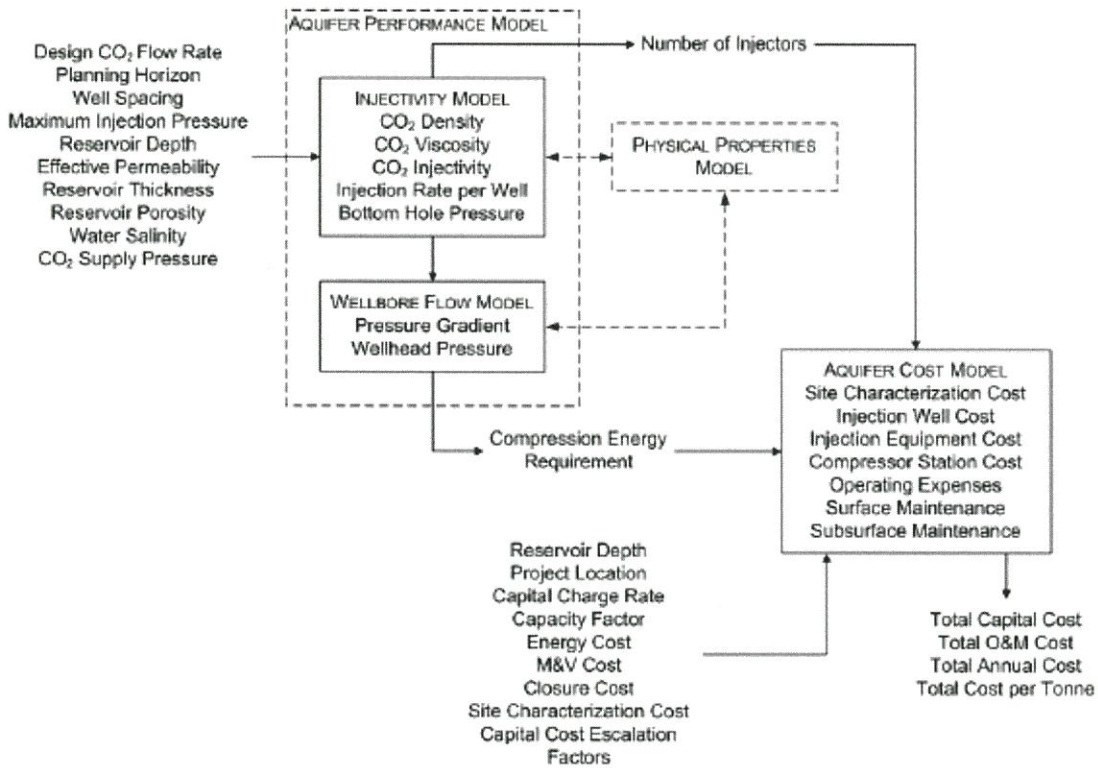
4.2 Modeling CO_2 Storage in Saline Aquifers

To estimate the CO_2 storage costs in saline aquifers, the model developed by Dr. Sean McCoy for his doctoral thesis was used. [69] The model used in this analysis is an engineering-economic model that can be separated into two parts: i) a performance model, and ii) a cost model. The

[67] Initiative, Report on the "Symposium on the Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Storage", Cambridge, 2009. P.36.
[68] Hovorka, "EOR as Sequestration—Geoscience Perspective." P.19.
[69] McCoy, "The economic of CO_2 transport by pipeline and storage in saline aquifers and oil reservoirs."

performance model, takes different input parameters that describe the reservoir and its properties. From those input parameters, the performance model estimates the number of wells required to achieve a certain injection rate over a given period of time, the wellhead pressure needed and the additional energy required (if necessary) for recompression. For the injection rate, the model develops an approximate solution for the injectivity of a doublet well system. This model of injectivity takes into account the interaction of the different injection plumes created by the different injection wells. An injectivity limit of one million metric tons per well is imposed in the model.[70] Figure 17 below is a schematic of how the different parameters in the performance model and the cost model interact.

Figure 17: Schematic of the Aquifer Storage Engineering-Economic Model Parameters Shown in the McCoy thesis.[71]



4.2.1 Cost of CO_2 Storage in Saline Aquifers

Although, some analogs to CO_2 storage such as natural gas storage and disposal of wastewater already exist, our understanding of CO_2 storage is still lacking in key aspects such as the cost of

[70] For a comprehensive discussion of the performance model and the underlying equations used in the model please see Chapter 4 of McCoy's thesis. Ibid.
[71] Ibid. P.139.

storage and the true potential of saline aquifer CO_2 storage capacity.[72] The analytical model used estimates the cost of CO_2 storage for a given range of geologic parameters and CO_2 injection rates. There are four main cost components that are incorporated in the CO_2 storage cost model: i) site characterization costs, ii) project capital costs, iii) operating and maintenance costs, and iv) monitoring verification and closure costs (for a detailed discussion of these costs please refer to Appendix C of this thesis).

4.3 Characterization of the Citronelle Dome

In order for the stacked storage system to be implemented, an evaluation of existing saline aquifers in the vicinity of the Citronelle oilfield must be carried out. Fortunately, the geology of the Citronelle oilfield, and in general, the subsurface geology of the Gulf of Mexico in Southwest Alabama has been extensively documented. The documentation of this area was mainly driven by water supply and oil and gas exploration activities.[73] Based on these oil and gas exploration activities, the Smackover, Jurassic, Norphlet and Rodessa formations were extensively studied.[74]

In terms of the Citronelle Oilfield, it is located at the tip of the Citronelle Dome. The Citronelle Dome is a "giant, salt-cored anticline" that is located in the Eastern Mississippi Interior Salt Basin.[75] The dome configuration offers a four-way elliptical structural closure that has enabled oil accumulation and offers potential CO_2 storage.[76] More than 600 wells have been drilled in this dome, penetrating different formations such as the shallow Upper Tuscaloosa Group at 1829 meters (6000ft) and as deep as the Smackover and Norphlet formations at more than 6096 meters (20,000ft) deep.[77] Most of the wells drilled reach the Lower Tuscaloosa sands were most of the oil is found. This is illustrated in figure 18 below.

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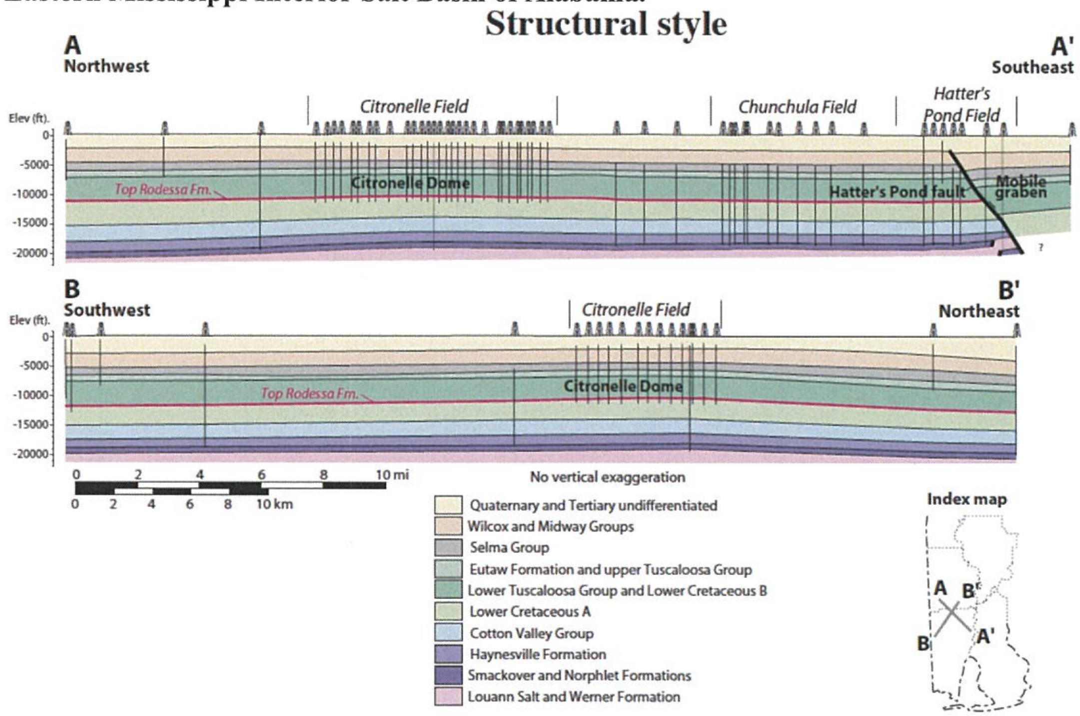
[72] Ibid. P.135.
[73] Esposito, Pashin, and Walsh, "Citronelle Dome: A giant opportunity for multizone carbon storage and enhanced oil recovery in the Mississippi Interior Salt Basin of Alabama." P.3.
[74] Ibid. P.3.
[75] Ibid. P.3.
[76] Ibid. P.8.
[77] Ibid. P.3.

Figure 18: Structural Cross Sections of the Citronelle Dome and Nearby Structures in the Eastern Mississippi Interior Salt Basin of Alabama.[78]



There are several intervals within the Citronelle Dome that can be used for CO_2 storage; these intervals include the Wilcox and Midway Group, the Upper and Lower Tuscaloosa Group, and the Eutaw Formation.[79] High porosity, high permeability, and a good reservoir seal characterize these formations. The remainder of this Chapter 4 will give a brief overview of these brine formations (for a detailed discussion of the different formations, please refer to Appendix C).

4.3.4 Storage Potential

Storage capacity is one of the main determinants when making a decision as to the geologic formation that will be used in the stacked storage system. If all other geologic factors (ex: depth, formation permeability, robustness of reservoir seal, etc…) are held constant, then the larger the storage capacity, the more desirable a certain formation is. The storage capacity of the different formations has been evaluated as part of an ongoing DOE study that is examining CO_2 storage potential in the Citronelle Dome. These storage numbers were used as a screening criterion to pick the saline aquifer that will be used as part of the stacked storage system. The storage capacity estimates is a volumetric estimate that does not take into account the partitioning of the CO_2 into gas, liquid and solid phases. The storage capacity was calculated using the reservoir properties including formation area, thickness, porosity, CO_2 density, temperature and pressure.

[78] Ibid. P.6.
[79] Ibid. P.3.

Furthermore, an efficiency factor limit of 0.4 and 0.1 were assumed and permeable fraction efficiency factors of 0.9 and 0.6 were used for the Tuscaloosa-Eutaw groups and the Rodessa formation respectively. The results of the CO_2 storage potential are shown in Table 14 below. The total storage capacity of the intervals examined was equal to 1875 million metric tons of CO_2, which is equivalent to the 436 years of CO_2 emissions from the Red Hills generating facility. The largest storage interval was the lower Tuscaloosa sand at 737 million metric tons of CO_2 followed by the Upper Tuscaloosa-Eutaw interval at 604 million metric tons.

Table 14: CO_2 Storage Potential of the Different Formations in the Citronelle Dome.[80]

Interval	**Capacity (MM ton)**
Upper Tuscaloosa/Eutaw	604
Lower Tuscaloosa (Pilot Sand)	147
Lower Tuscaloosa (Massive Sand)	736
Rodessa (Middle Donovan Sand)	105
Rodessa (Donovan Oil Sands)	283
Total CO_2 Storage Capacity	**1875**

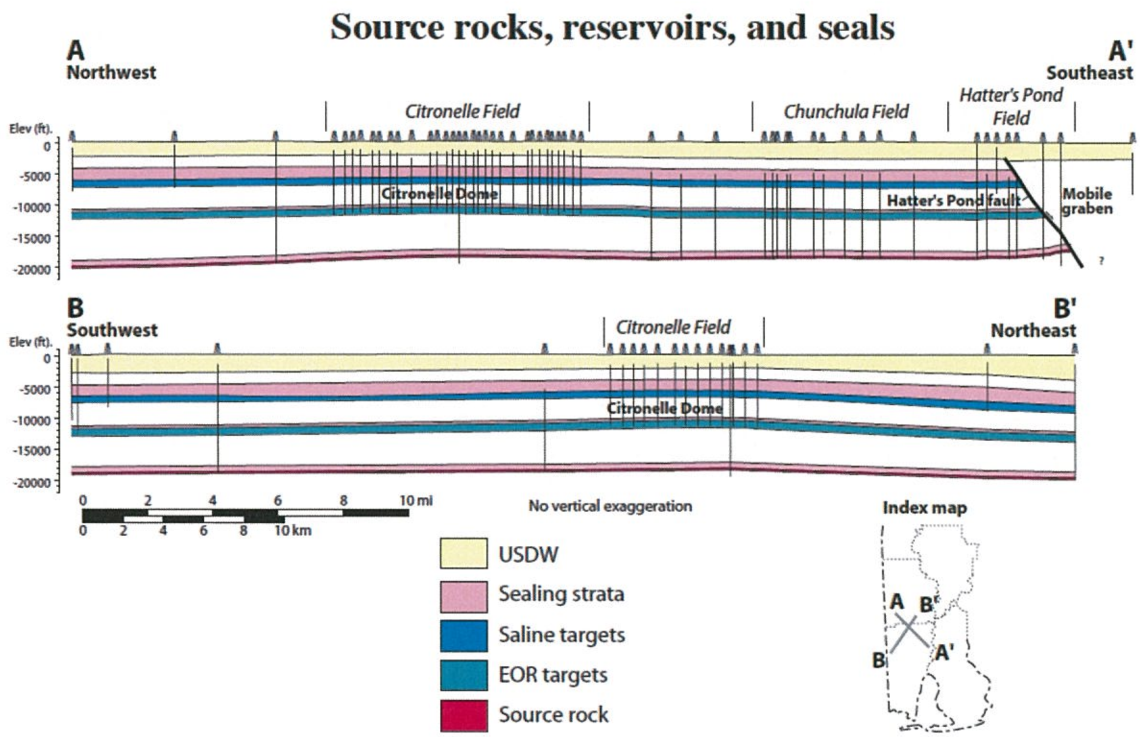
4.3.5 Deciding on a Saline Aquifer

As discussed above, there are several sandstone units within the Citronelle Dome that offer CO_2 storage potential. These sandstone units include: i) the lower Tuscaloosa Group, ii) the upper Tuscaloosa Group, iii) the Eutaw Formation, iv) Middle Donovan Sand, and v) Lower Donovan Sand. All of these units are characterized by high porosity, high permeability and low heterogeneity as discussed earlier. Moreover, these formations are considered viable geologic sinks due to the presence of proven reservoir seals, as more than 610 meters (2000ft) of chalk and marine shale overlay the Tuscaloosa-Eutaw section. In terms of CO_2 storage capacity, the Upper Tuscaloosa-Eutaw and Lower Tuscaloosa (Massive Sand) had the largest CO_2 storage potential, with the Lower Tuscaloosa (Massive Sand) offering 21% more CO_2 storage. Due to the similarity of these two intervals (Upper Tuscaloosa-Eutaw and Lower Tuscaloosa-Massive Sand) in terms of their CO_2 storage potential and other reservoir properties, the choice between these two CO_2 storage sites was based on economic considerations. As discussed in Appendix C, one of the main determinants in terms of CO_2 sequestration costs is the depth of the well drilled; costs almost increase linearly with depth. Although the groups are very close in depth, the Upper

[80] Ibid. P.9.

Tuscaloosa/Eutaw interval at a depth range of 1500m to 2000m was chosen as the site for CO_2 storage. The different reservoir layers and seals are illustrated in Figure 19 below:

Figure 19: Citronelle Dome Source Rocks, Reservoirs, and Seals. [81]



A summary of the different geologic parameters for the lower Tuscaloosa group is given in Table 15 below where the numbers are derived from the saline aquifer database complied by the Bureau of Economic Geology at the University of Texas at Austin.

Table 15: The Different Geologic Parameters for the Lower Tuscaloosa Group.

Geologic Parameter	Value
Depth (meters)	1500-2000
Permeability (md)	50-3000
Formation Thickness (meters)	0-50
Net Sand Thickness (meters)	0-10
Temperature (°C)	20-50
Pressure (MPa)	6.9-13.8
Salinity (mg/L)	10,000-151,000
Porosity	20%

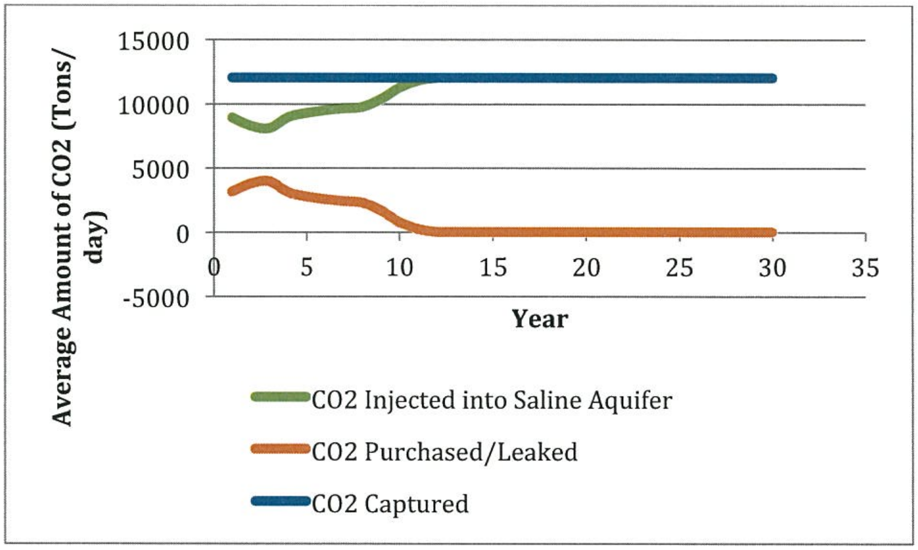
81 Ibid.

4.4 Estimating the Cost of CO_2 Storage in the Upper Tuscaloosa Group

4.4.1 Model Inputs

The first input of the model is the annual amount of CO_2 injected into the saline aquifer. This amount is going to be equal to the annual amount of CO_2 captured from the Red Hills Generating Facility less the amount of virgin (purchased) CO_2 used by the EOR operation. The amount of CO_2 injected in this case is not constant and is dependent on the CO_2 injection patterns for the EOR operation. Figure 20 below, shows the annual amount of CO_2 injected into the saline aquifer.

Figure 20: CO_2 Injection Rates in the Stacked Storage System.



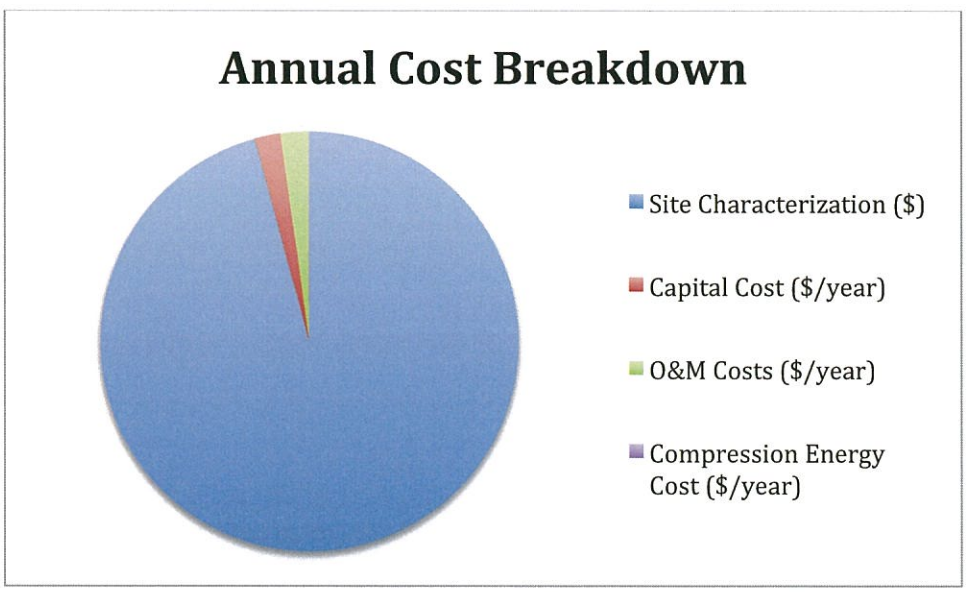
Given that the model does not allow for annual variations in CO_2 injection rates (the model assumes a constant CO_2 injection rate over the life of the project), I used the average annual amount of CO_2 injected over the lifetime of the project, which is equal to 3.5 million tons of CO_2 per year. The average amount of CO_2 injected into the saline aquifer over the lifetime of the project is 0.8 million tons less than the maximum amount of CO_2 injected into the saline aquifer at any given time. Therefore, a model run for this maximum amount of CO_2 must be carried out to determine whether significant costs are incurred to accommodate the peak CO_2 injection rate (for years 12-30).

The geologic input parameters to the model were summarized in Table 15 earlier. The cost parameters discussed above, were intended to be used to model a greenfield site where there is no existing infrastructure. In this case, an extensive infrastructure is already in place due to previous primary and secondary oil recovery operations. According to the State Oil and Gas Board of Alabama, more than 524 wells have been drilled to date with 414 of those wells listed as currently active or temporally abandoned in the Citronelle oilfield. Some of these existing wells include water injection wells used during secondary operations; these wells can be reworked and used for the purpose of CO_2 storage. To assess whether or not a well should be reworked, the levelized cost of reworking an existing well versus drilling a new one should be evaluated. For the purpose of this study, it was assumed that new injection wells were drilled for CO_2 storage.

4.4.2 Model Results

First off, the number of wells necessary to achieve a certain injectivity was determined using the performance model. Given that the amount of CO_2 injected varies from year to year, I assumed, as discussed in the previous section, an average amount of CO_2 injected into the saline aquifer equal to 3.5 million tons of CO_2 per year. According to the performance model, 4 injection wells are needed to achieve this injection rate. The relatively low number of injection wells can be attributed to the high horizontal permeability of the formation, which enables the CO_2 to flow with minimal resistance through the formation. According to the different input parameters, the total annual cost of the CO_2 storage operation in the saline aquifer is equal to \$15.2 million per year. Figure 21, below, shows the predicted cost breakdown for any given year:

Figure 21: Annual Cost Breakdown for the CO_2 storage Operation in the Saline Aquifer.



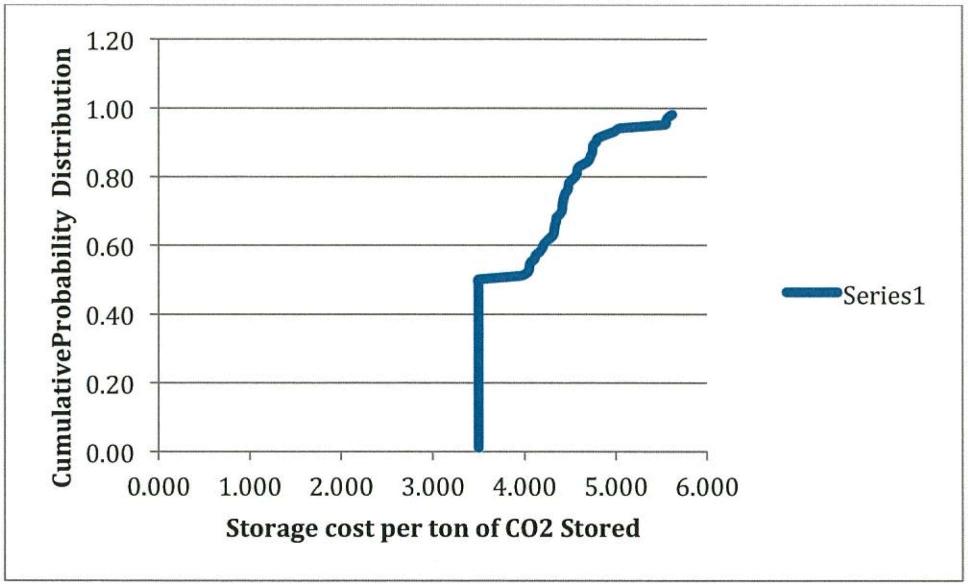
The cost of the CO_2 storage operation is mainly attributed to the site characterization cost. The site characterization cost is dependent on the size of the area under review, which is a function of the aerial extent of the CO_2 plume. According to the performance equation, the maximum radius of such a plume is equal to 16.4 km; therefore the aerial extent of this particular plume is equal to approximately 1700 km^2. Given that a well is needed every 65 km^2, and assuming that it costs \$3 million to drill and log a well, then 26 wells are needed at a cost of approximately \$78 million. The total site characterization costs came out to be equal to \$97 million. Given that only four CO_2 injection wells have to be drilled, the total capital costs are equal to \$2.3 million. O&M costs are a relatively small portion of the total costs at around 0.4 million per year. Using a capital charge factor of 15%, the total annual costs equate to \$15.2 million per year. Dividing the annual costs by the average amount of CO_2 injected in a given year (approximately 3.5 million tons of CO_2) translates to a levelized storage cost of \$4.35 per ton of CO_2 stored.

Running the model for the peak CO_2 injectivity at 4.3 million tons (years 12-30), it is found that only one additional well needs to be drilled to accommodate this difference. Given that site characterization costs dominate the overall project economics, one can assume that using an average CO_2 injectivity of 3.5 million tons provides an accurate representation of the project costs.

4.4.3 Sensitivity Analysis

As shown in Table 15 earlier, the given geologic parameters lie in a wide range of values. Therefore, to determine the robustness of the levelized storage cost calculation shown above, a sensitivity analysis was run to determine the distribution of the storage costs. By rerunning the model using the parameter distribution used in the above discussion, the resulting data, shown in Figure 22 below, is obtained.

Figure 22: Cumulative Probability Distribution of Storage Cost per Ton of CO_2 Stored.



It can be seen from the results in the Figure 22, above that the storage cost are unlikely to be less than \$3.5 per ton. Furthermore, it can be said with 90% confidence that the storage cost per ton of CO_2 is less than \$5.

4.5 Evaluation of Total System Costs

The individual system costs were evaluated in Chapters 2 and 3 of this thesis. As mentioned earlier, the total mean CO_2 capture and compression cost is equal to \$82.77 per ton of CO_2 captured. The total mean cost of saline storage has been found to be equal to \$4.35 per ton of CO_2 stored. As for CO_2 transportation costs, they were ignored in this analysis due to the presence of a CO_2 pipeline for the majority of the distance between the Red Hills Generating Facility and the Citronelle oilfield. Therefore, the mean total system costs were calculated at \$87.12 per ton of CO_2 stored. This number indicates the CO_2 price needed to incentivize the Red Hills Generating Facility to capture and store its CO_2 emissions is going to be significant. A breakdown of the EOR-CSS stacked storage system costs is shown in Table 16 below.

Table 16: Breakdown of the EOR-CCS Stacked Storage System Costs.

Variable	Value (\$/ton)
CO_2 Capture Cost	82.77
Saline Storage Cost	4.35
CO_2 Transportation Costs	0 (assumed given the presence of an existing CO_2 pipeline)
Total EOR-CCS Stacked Storage System Cost	87.12

4.6 Key Takeaways from Chapter 4

Given that the maximum amount of CO_2 purchased at any given point in the operation is equal to 33% of the average daily CO_2 captured, backup saline storage is a necessity for the success of the EOR-CCS model. Based on the past statement, Chapter 4 began by identifying a suitable saline formation that can be used for backup CO_2 storage. Based on CO_2 storage capacity considerations and on cost minimization goals, the Upper Tuscaloosa/Eutaw interval at a depth range of 1500m to 2000m was chosen as the site for CO_2 storage. After deciding upon the Upper Tuscaloosa/Eutaw interval, some key geologic data pertaining to these formations was complied and presented. A CO_2 storage model for saline aquifers was then run to establish the CO_2 saline aquifer storage costs. The saline aquifer storage costs came out to be equal to $4.35 per ton of CO_2 stored in the saline aquifer. Given that the CO_2 capture costs were equal to $82.77 per ton of CO_2, this brought the total cost of the EOR-CCS stacked storage system up to $87.12 per ton of CO_2.

Chapter – 5 Policy Implications

The mean price of \$87.12 for the capture, transport and sequestration of CO_2 using the stacked storage concept is within the range of the CO_2 abatement costs found in the literature. However, this value does not take into account the additional revenue streams that might be derived from the EOR operation. The next section looks into possible private/public funding mechanisms that could help make this an economically feasible option.

5.1 Possible Revenue Sharing Mechanisms

The first question that arises is whether or not a stacked storage system can be an economically feasible option in the absence of a price on CO_2. To address this question, the price paid for the CO_2 (an important determinant to the success of such an operation) by the EOR operator must be quantified. As mentioned earlier, natural sources of CO_2 are expected to be insufficient to meet the entire EOR potential; therefore, anthropogenic sources of CO_2 will become necessary. In such a scenario, coal-fired power plants will be competing with alternative sources of anthropogenic CO_2 (rather than natural sources of CO_2). Such a scenario resembles the current situation for some EOR operators that do not have access to natural sources of CO_2 and must purchase their CO_2 from a different company (ex: Kinder Morgan). Therefore, to estimate the revenue streams that would accrue to the coal-fired power plant, one can look at the CO_2 contracts between independent CO_2 suppliers and EOR operators.

CO_2 contracts are not traded on futures markets like other commodities such as oil as they are long-term contracts between the supplier and purchaser. Typically, CO_2 prices in such long-term contracts are either set at a fixed price, or are partially tied to the price of oil (scaling-up with the price of oil). One such long-term contract is between Kinder Morgan and Resolute Energy Corporation. According to the financial statements submitted by Resolute Energy Corporation, it can be estimated that their CO_2 purchase price is equal to approximately \$1.1 per Mcf, which equates to approximately \$20 per ton of CO_2. Therefore, assuming that the \$20 per ton of CO_2 is a representative price, then the levelized amount paid for the entire CO_2 captured approximately equates \$1.5 per ton of CO_2. This implies that the levelized cost of capturing the CO_2 over the entire quantity of CO_2 stored is still around \$81.3. Therefore it is obvious that additional government incentives must be provided to bring the capture costs further down.

It was mentioned earlier that EOR-CCS operations result in several additional revenue streams, one of which is the incremental tax income generated due to domestic oil production. Given that CO_2-EOR operations are CO_2 supply constrained in the long run, it is safe to assume that the full CO_2-EOR potential will not be fully achieved without the anthropogenic supplies of CO_2. Consequently, we can assume that the tax revenues associated with the incremental EOR oil production would not have been generated in the absence of anthropogenic supplies of CO_2. Therefore, a potential way to help bring capture costs down is to share all the additional tax revenues (severance + ad valorem taxes) associated with the incremental oil production. This can be seen as a tax incentive for early adopters of CCS projects. One could further justify this tax incentive by assuming that in a world where natural supplies of CO_2 supplies are limited, these additional tax revenues would not have been generated.

The total present value (at 12% discount rate) of the severance taxes and ad valorem taxes paid by the EOR operator in this case are equal to \$281.0 million over the life of the project. The total tax payment is equivalent to a tax incentive of \$16.5 million per year over the entire life of the operation. Given that the average annual CO_2 emissions injected into the operation are equal to approximately 4.4 million tons of CO_2, the tax incentive translates to a payment of \$3.75 per ton of CO_2 stored. This brings the total revenue to the coal-fired power plant up to approximately \$5.3 per ton of CO_2, which is well below the \$82.8 dollars incurred due to the capture of the CO_2 as the uncovered capture cost is equal to \$77.5 per ton of CO_2 captured and stored. Moreover, these costs do not account for the transportation and storage costs. Therefore, if such a system is to be implemented, further government intervention will be needed.

Government intervention needs to address the remaining costs incurred by the operators (uncovered capture, transportation and storage cost of around approximately \$77.5 per ton of CO_2 captured and stored). This can be done, for example by subsidizing the remaining costs through some sort of government incentive/credit. Subsidizing such an operation is clearly a huge expense on the government (around approximately \$330 million dollars per year for this one 500MW plant). To make this concept economically feasible, one of two things must occur, either the revenues associated with the operation must be increased, or the costs of CO_2 capture must decrease. A potential way to increase revenues is through increasing the taxes generated by the CCS-EOR operations. One way to do so is by targeting the largest EOR fields.

5.2 Targeting Large EOR fields

Although the Citronelle oilfield examined in this thesis is quite large in terms of ROIP, it only consumes at its peak around 33% of the CO_2 captured by the plant. Furthermore, only 8% of the total captured CO_2 was used over the lifetime of the EOR operation. The majority of the CO_2 was injected into the saline aquifer without any added benefit. To utilize a greater percentage of the captured CO_2 (at a given carbon price), one could use a single source of CO_2 to supply multiple EOR fields over the life of the power plant. Alternatively, a greater utilization of the captured CO_2 may be achieved through targeting larger oilfields (fields with larger remaining oil reserves). Both options should achieve the same results, however, the former option is logistically more difficult to implement. Therefore, given the current availability of large oilfields, I will examine the latter option in more detail. To do this, I have compiled a list of the biggest oilfields that are amenable to EOR operations. This list is provided in Table 17 below.

Table 17: Some of the Biggest U.S. Oil Fields that are Amenable to EOR Methods.[82]

Large Fields/ Reservoirs	Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)	State
Slaughter (San Andres)	3600	1150	99	2351	West Texas
McElroy (Grayburg-San Andres)	2544	562	70	1912	West Texas
Eunice Monument (Grayburg-San Andres)	2000	392	22	1586	New Mexico
Panhandle (Hutchinson)	1955	384	6	1565	Central Texas
Denver Wasson (San Andres)	2372	1042	57	1273	West Texas
Earlsboro (Earlsboro)	1395	208	1	1185	Oklahoma

To compute the tax incentives generated by each operation, one would have to rerun the analysis performed for the Citronelle oilfield for all the oilfields shown above. In order to do so, detailed reservoir data for each oilfield is required. Collection of such data would require extensive time and resources. Therefore, rather than rerunning the model using the detailed geographic data, I

[82] Inc. Advanced Resources International, "Basin Oriented Strategies for CO2 Enhanced Oil Recovery; prepared for U.S. Department of Energy, Office of Fossil Energy - Office of Oil and Natural Gas," in *Basin Oriented Strategies for CO2 Enhanced Oil Recovery* (2005).

will rely on rules of thumb based on the Citronelle run. As such, the following assumptions are made: the CO_2 is equal to 4.36 million tons, the recovery of the OOIP using EOR operations equals to 10%, CO_2 utilization rates equal 0.16 ton of CO_2 per barrel of oil produced and, the combined tax rate on the oil revenues is equal to 7%. Based on these assumptions, Table 18 was generated to reflect the tax incentives created for the different operations.

Table 18: Value of Tax Incentive for the Different Oil Fields.

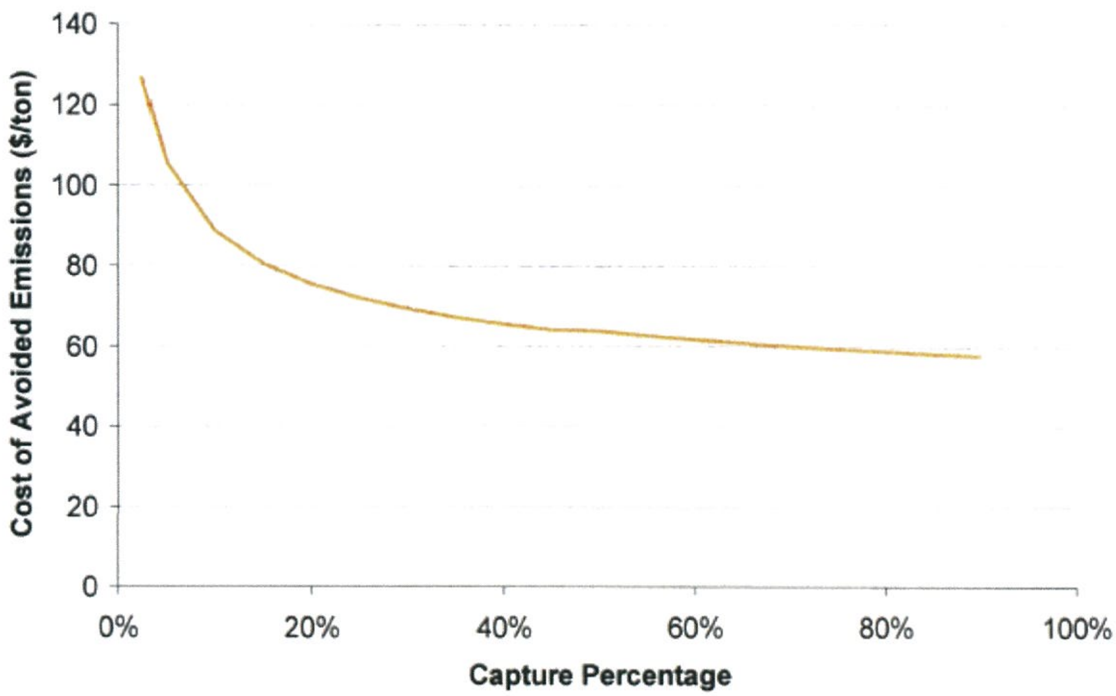
Large Fields/Reservoirs	Tax Incentive ($/ton)
Slaughter (San Andres)	33.7
McElroy (Grayburg-San Andres)	23.8
Eunice Monument (Grayburg-San Andres)	18.7
Panhandle (Hutchinson)	18.3
Denver Wasson (San Andres)	22.2
Earlsboro (Earlsboro)	13.1

The highest tax incentive came at round \$33.7 per ton of CO_2 captured and stored. This means that the total revenues to the operation are around \$35.0, which means that about \$52.8 out of the \$87.8 incurred costs is still uncovered. In other words, the entire CCS operation would be feasible at a CO_2 price of around \$53. Therefore, it can be seen that these giant oilfields offer significant economic benefits for the early adopters of CCS technologies. The deployment of these early systems will help incentivize multifold reduction in CCS costs (mainly capture costs) through "learning by doing". Given the large tax revenues that could be generated from such oil fields, the retrofit of plants in the proximity of these oilfields should be pursued for early CCS projects.

5.3 Partial CO_2 Capture

As discussed in Section 5.2 earlier, under normal EOR operations, the Citronelle Oilfield would require 9.6 million metric tons of CO_2 to produce around 73 million barrels of oil. On the other hand however, the CO_2 captured from the coal-fired power plant over the entire power plant lifetime is estimated to be equal to around 121 million metric tons of CO_2. Therefore, in this case, the power plant operator receives payment for only 8% of the captured CO_2 (9.6 tons/121 tons). The majority of the CO_2 in this case is stored in the saline aquifer without creating any value. One possible way to increase the utilization factor of the captured CO_2 as discussed in the earlier section is to extract more oil. If such opportunities are not available, then one might consider decreasing the amount of CO_2 captured so that it can match the EOR needs more closely. One can lower the amount of CO_2 captured by decreasing the CO_2 capture rate. Rather than capturing 90% of the CO_2 in the entire flue gas, one can divert a fraction of the flue gas for capture and emit the rest. For instance, one could divert 10% of the flue gas exiting the boiler and then capture 90% of the CO_2 in that stream. The overall result of such an operation would be to avoid CO_2 emissions of around 8% (the percentage of CO_2 avoided would depend on the energy penalty). In such a case, the CO_2 captured would more closely match the CO_2 demand from the EOR operation. However, due to economies of scale, as the capture percentages decrease, the cost of a ton of CO_2 avoided increases as shown in Figure 23 below.

Figure 23: Sensitivity of the Cost of CO_2 Avoided to the CO_2 Capture Percentage.[83]



Assuming that a single carbon dioxide removal (CDR) train can handle 90% capture, it can be seen in Figure 23 above that capture costs double when one decreases the CO_2 capture percentage from 90% to 10%. Assuming that this relationship holds for the Red Hills Generating Facility, then the cost of a ton of CO_2 avoided for around 10% capture would be equal to approximately $164 per ton of CO_2 avoided. The cumulative amount of CO_2 avoided would be equal to approximately 334 thousand tons of CO_2 and the total CO_2 capture would be equal to

[83] Ashleigh Nicole Hildebrand, Strategies for demonstration and early deployment of carbon capture and storage: a technical and economic assessment of capture percentage. P.88.

approximately 510 thousand tons of CO_2. This means that during the life of the CCS system (30 years), around 15 million tons of CO_2 will be captured. Rerunning the calculation done in Section 5.1 for a CO_2 purchase price of \$20 per ton of CO_2, one sees that the levelized revenue from the coal-fired power plant is now much higher at \$12.8 per ton of CO_2 captured versus the \$1.5 per CO_2 captured for the 90% capture case. The \$11.3 increase in revenues is obviously over shadowed by the fact that I assumed capture costs would increase dramatically. If the cost of capturing 10% of the CO_2 in the exit flue gas stream is not much more costly than capturing 90% of the CO_2, then the partial capture of CO_2 should be pursued in early EOR-CCS projects. The alternative to increasing CO_2 utilization rates through partial capture as discussed earlier would be to utilize the captured CO_2 across several oilfields for EOR operations. This would entail the careful synchronization of the different EOR operations; a more manageable task if the same operator owns the different oilfields.

5.4 Scalability of the EOR-CCS Model

The analysis above has shown that pursuing CCS projects with EOR storage can have substantial economic benefits. The question that arises then is how scalable is this option? To determine the scalability of the EOR-CCS model, one must first examine the EOR-CO_2 storage capacity.

5.4.1 EOR CO_2 Storage Capacity

A recent assessment of the storage capacity in the Main Pay Zones (MPZs) by Advanced Resources International (ARI)[84] estimated that the *technically* recoverable oil potential would be equal to 81 billion barrels using today's state of the art technology[85] and 126 billion barrels using next generation technology.[86] The *economically* recoverable oil, which was calculated using an oil price of \$70.0/bbl, CO_2 cost of \$45.0/mt and a 15% rate of return, was equal to 38 billion using today's state of the art technology and 58 billion barrels under next generation technology. A similar calculation for the CO_2 storage capacity was made by estimating the number of one-GW coal power plants[87] which could provide the estimated CO_2 required for EOR operations, assuming a 30-year operating life. Table 19, below, summarizes these results.

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[84] Kuuskraa, "Challenges of Implementing Large-Scale CO_2 Enhanced Oil Recovery with CO_2 Capture and Storage". P.8.

[85] Next Generation technologies include: i) increasing CO_2 injection rate to 1.5 HCPV, ii) optimization of well design and placement would enable more of the residual oil in a reservoir to be contacted, iii) improving the mobility ratio, iv) extending the miscibility, and iv) Integrating Application of "Next Generation" Technology Options.
As seen in Storing CO2 and Producing Domestic Crude Oil with Next Generation CO2-EOR Technology: An Update , April, 2010 DOE/NETL

[86] Kuuskraa, "Challenges of Implementing Large-Scale CO_2 Enhanced Oil Recovery with CO_2 Capture and Storage". P.7.

[87] Assuming 6.2 MMmt/yr of CO_2 emissions and 90% capture.

Table 19: Technically and Economically Recoverable CO_2-EOR Resource.[88]

	State of the Art	Next Generation
Technically Recoverable (Billion barrels of oil)	81	126
Economically Recoverable (Billion Barrels of oil)	38	58
Technically Recoverable (# of 1GW Size Coal Fired Power Plants)	94	156
Economically Recoverable (# of 1GW Size Coal Fired Power Plants)	56	67
Technically Recoverable (CO_2 Emissions in gigatonnes)	15.7	26.1
Economically Recoverable (CO_2 Emissions in gigatonnes)	9.3	11.2

To put this in perspective, it is estimated that a maximum of 59% (184GW) of the generation capacity of the existing U.S. coal fired power plant fleet is candidate for CCS retrofits. Furthermore, taking into account potential plant-specific and location constraints and limitations the potential is reduced to about 20% of the fleet, or around 61 GW of coal fired generation technically and economically suitable for retrofitting.[89] This number implies that the EOR storage capacity is large enough to accommodate the majority of the captured CO_2 emissions from coal-fired power plants. Although, there is ample storage capacity, the distribution of this storage capacity is equally important. If the majority of the EOR storage capacity is concentrated in areas without coal-fired power plants, than transporting the CO_2 to those areas might make this model economically unfeasible.

5.4.2 Matching Anthropogenic CO_2 Sources with Large EOR Opportunities

As the distance increases, so does the capital cost for laying more pipeline and the operating cost for compressing and transporting the CO_2 across larger distances. The Intergovernmental Panel on Climate Change (IPCC) report on Carbon Capture and Storage estimated the cost of transporting one ton of CO_2 over a distance of 250 km to be in the range of \$1 to \$8 depending on the type of terrain and the diameter of the pipeline.[90] It is thought that high purity sources within a reasonable radius (100 miles) of an oil field will be the first choice for CO_2-EOR. The IEA

[88] Kuuskraa, "Challenges of Implementing Large-Scale CO_2 Enhanced Oil Recovery with CO_2 Capture and Storage." P.8.
[89] Initiative, "MIT Energy Initiative Symposium Report on the Retrofitting of Coal-Fired Power Plants for CO2 Emissions Reductions."
[90] Metz and Intergovernmental Panel on Climate Change. Working, *IPCC special report on carbon dioxide capture and storage.*

Greenhouse Gas R&D Programme surveyed high purity sources of CO_2 (sources $\geq$ 40% CO_2 concentration in the exit flue gas) within a 100 mile radius of an EOR potential site and found 62 candidates that matched the criteria.[91] Some sources were within range of more than one oil field, creating a total of 329 options for high purity sources matched to EOR candidate fields.

Figure 24: U.S. Map Showing the Overlap Between Existing Oilfields and Saline Aquifers.[92]

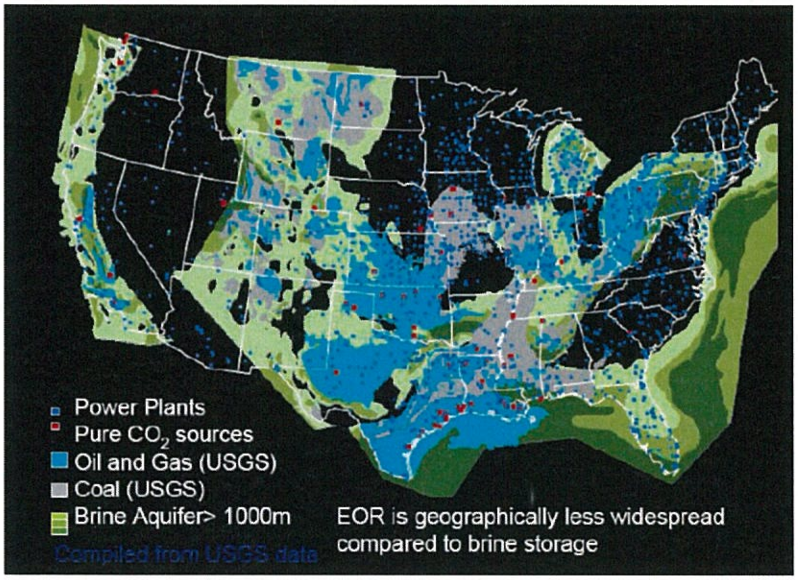

Figure 24, above, depicts existing oil fields, large pure sources of CO_2 and power plants in the U.S. The Electricity Reliability Council of Texas (ERCOT) has large oil fields that are amenable to CO_2-EOR as well as a large CO_2 supply (approximately 100 million metric tons of CO_2 per year). By comparison, areas in the Ohio River Valley represented by the East Central Area Reliability (ECAR) Coordination Agreement release more than 500 million metric tons of CO_2 per year but have limited EOR potential.

A detailed breakdown of the potential CO_2 sources and CO_2-EOR potential up to year 2030 is shown in Table 20 below. The CO_2 supply is based on the modeling analysis conducted by ARI for the Natural Resources Defense Council (NRDC) using the Energy Information Administration (EIA) National Energy Modeling System (NEMS) electricity market model. The analysis shows CCS deployment in thirteen U.S. regions based on the implementation of the provisions of the American Clean Energy and Security Act (ACES) passed by the House of Representatives in 2009.

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[91] IEA Green House R&D Programme, "Opportunities for Early Application of CO2 Sequestration Technology."
[92] Hovorka, "EOR as Sequestration—Geoscience Perspective." P.19.

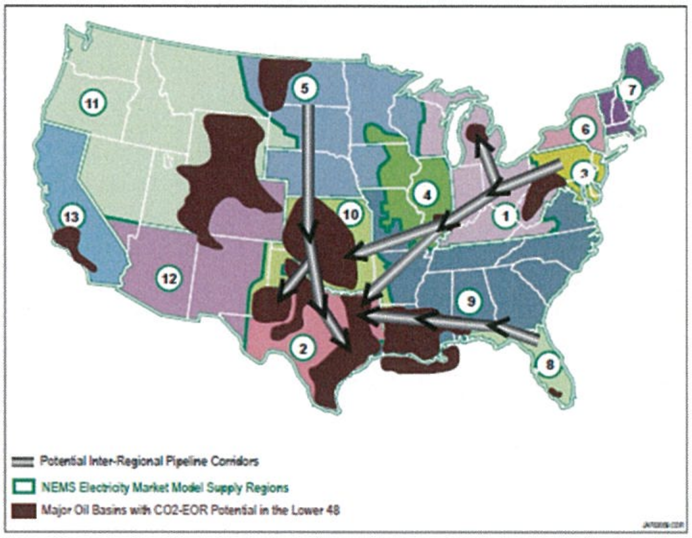
Table 20: Comparison of Estimates of Anthropogenic CO_2 Capture Under Proposed Cap-and-Trade Legislation with Potential EOR Uses[93]

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

Using the estimates from the NEMS modeling analysis, ARI examined the possible flow of the captured CO_2 to the oil basins. For instance, the East/Central Texas market for CO_2-EOR is estimated at 1,940 million tons of CO_2 up to 2030; however, the CO_2 supply from that region (ERCOT) over the same time period represented is only equal to 110 million metric tons of CO_2. Conversely, the CO_2 supply in the ECAR region is equal to 670 million metric tons of CO_2 and far exceeds the market for CO_2 in that region which is equal to 130 million metric tons. If the CO_2 supplied by the ECAR region was integrated into an EOR project, an interstate pipeline would be needed to connect the ECAR region to the more abundant oilfields in the midcontinental U.S. If the remainder of the CO_2 is to be moved into oil regions as proposed by the ARI study, then a more extensive CO_2 pipeline network would be required as shown in Figure 25.

[93] Advanced Resource International, "U.S. Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage," (2010). P.38.

Figure 25: A Proposal for a U.S. CO_2 pipeline.[94]



Additionally, the ARI study analyzes the technical potential for CCS deployment based on the provisions contained in the House-passed ACES legislation. These estimates would need to be refined to reflect the fact that a significant percentage of the existing U.S. coal-fired power generation fleet is not amenable to retrofitting for capture of CO_2.

5.5 Alternative Anthropogenic CO_2 Sources

While the potential supply of anthropogenic CO_2 from coal-fired power plants is large (even with conservative CCS assumptions), the cost of CCS for coal-fired power plants is at the upper end of the potential anthropogenic CO_2 supply cost curve. High purity sources of CO_2 such as gas processing plants and ammonia plants represent lower cost CO_2 supplies when compared to coal-fired power plants. CCS costs for high purity sources can range from as low as \$4.0 per ton of CO_2 to as high as \$47.0 per ton of CO_2. Table 21, below, provides a summary of CCS costs for industrial operations.

[94] Ibid. P.37.

Table 21: CCS Costs for High Purity Sources.[95]

Source	Cost estimate (USD/tCO_2)	Comments	References
LNG plant	9	Retrofit to existing LNG plant; compressed gas injected into a depleted gas field.	IEA GHG (2008a) all capital costs based on 2012 prices and discounted at 12.5% over 21 years; cost of transport and storage assumed to be paid as gate fee by the capture plant operator. This reflects average costs across a range of developing country gas fields and pipeline transport distances including *in situ* injection
Offshore NGP (deep water)	31	Retrofit to existing deep water NGP facility; compressed gas injected into a depleted gas field.	
Offshore NGP (shallow water)	18-21	Range indicates difference in capital cost between retrofit (higher cost) and new-build (lower cost) NG plant; compressed gas injected into a depleted gas field.	
Onshore NGP	16-19	Range indicates difference in capital cost between retrofit (higher cost) and new-build (lower cost) NG plant; compressed gas injected into a depleted gas field.	
Ammonia	4-47	Different figures indicate capture from pure CO_2 stream (lower cost) and flue gas (8% CO_2 content, higher cost); data exclude cost of compression, which would add c. USD 10-15/tCO_2	Hendriks, C. *et al* (2004) capital costs discounted at 10% over 25 years; EUR/tCO_2 figures converted to USD/tCO_2 on basis of 1 EUR: 1.3 USD
Hydrogen	15	Capture costs only	IPCC, (2005)
Ethylene oxide	-	No known cost studies	-
Coal-to-Liquids	‹ 25	Cost analysis covering liquid-only and poly-generation CtL production using Selexol™ and MEA capture indicates CCS is cost effective with a carbon tax of USD 25/tCO_2 at oil price of USD 100 per barrel (bbl)	Matripraganda. and Rubin (2009)

Furthermore, not only are the CCS costs of these higher purity sources lower than the CCS costs of coal-fired power plants, these higher purity sources are large and can be found across the U.S. According to the EPA Green House Gases Database (ghgdata), there are more than 1,462 industrial facilities in the U.S. emitting around 565 million tons of CO_2 per year. Moreover, the EPA database shows that out of the 1,462 industrial facilities, 213 of those facilities emit more

[95] United Nations Industrial Development Organization, "Carbon Capture and Storage in Industrial Applications: Technology Synthesis Report", Working Paper, (November 2010). P.17.

than one million tons of CO_2 per year with a cumulative CO_2 emission rate of 346 million tons of CO_2 per year for the 213 facilities. It is likely that many of these facilities are superior in terms of capture costs when compared to coal-fired power plants due to the relatively high CO_2 concentrations in the exit flue gas stream. However, even if one assumes that only 30% of these facilities are superior to coal-fired power plants in terms of capture costs, CO_2 supplies from these industrial sources would translate to 103.8 million tons of CO_2. These numbers are well above the current EOR demand of around 81 million metric tons of CO_2 per year. Therefore, these numbers clearly indicate that abundant industrial sources of CO_2 will be more cost competitive than the CO_2 supplied by coal-fired power plants in the near terms. Based on the results presented above, it is most likely that CCS of high purity sources will be pursued in the short-term before CCS of coal-fired power plants is attempted. However, if the CO_2 challenge is to be met, then CCS from the U.S. coal-fired power plant fleet will be necessary; if CCS is not an option then the retirement of these plants becomes inevitable.

Chapter 6 – Conclusion

6.1 Findings

- A large amount of CO_2 emissions is locked in the existing infrastructure. U.S. coal-fired power plants today account for approximately a third of all U.S. emissions and are projected to contribute a significant amount of CO_2 emissions in the near future. Furthermore, projected CO_2 emissions from the existing Chinese coal fleet far exceed those of the U.S; China's coal fleet at around 500GW, is much larger than that of the U.S. and is younger at an average age of 12 years versus 36 years for the U.S.
- The most economically viable solution to reducing the CO_2 emissions from the existing U.S. coal fleet is to retire the oldest power plants. Annual emissions from the existing coal fleet can be reduced by 17% if plants that are older than 50 years today are retired.
- The best option to achieving further CO_2 reduction is through the retrofit of existing coal-fired power plants with CCS technologies. However, for CCS technologies to be deployed on a large scale, capture costs of CCS systems must be brought down significantly. Moreover, given China's large projected consumption of coal, there is great value in developing retrofit CCS technologies in the hopes of transferring such technologies to China.
- Incremental oil production from EOR operations is s inelastic to CO_2 prices. This implies that an EOR operation can still be profitable even with large increases in CO_2 prices. On the other hand however, EOR operations are supply elastic to oil prices. This implies that a sharp drop in oil prices leads to a rapid drop in the profitability of the EOR operation.
- Although the EOR-CCS model still requires a carbon price for it to be implemented, the EOR-CCS model offers potential revenue streams that can be leveraged to help bring down total CCS costs. The two main revenue streams studied here were the purchase price of the CO_2 and the incremental tax revenues generated by the EOR operations. Both can provide substantial revenues, covering up to 37% of the total CCS costs.
- Given the high utilization of CO_2 in large oilfields, taxes associated with each ton of captured CO_2 can be as high as \$33.
- The inadequacy of the additional EOR revenues to cover the CCS costs implies that a price on carbon of at least \$50 per ton of CO_2 captured and stored is still needed for the EOR-CCS model to be implemented. To put this into perspective, many economic models require CO_2 prices that reach \$100 per ton within a couple of decades if appreciable CO_2 emissions reductions are to occur in response to the CO_2 price. Therefore, \$50 per ton of CO_2 is a promising number that implies that in presence of a

price on carbon, the EOR-CCS model will eventually be able to compete with other CO_2-free generation technologies.

- Nevertheless, the current absence of a price on carbon, coupled with the availability of natural sources of CO_2 supplies means that it is unlikely that the EOR-CCS model will witness wide scale deployment in the short-term.
- Given that EOR operations are supply inelastic to CO_2 prices. Opportunities for the EOR-CSS model lie in regions that lack natural sources of CO_2. In such instances, the EOR operator would be willing to purchase CO_2 at a higher price if oil prices are relatively high. In this case, anthropogenic supplies of CO_2 become attractive. Therefore, short-term opportunities for the EOR-CCS model lie in areas that have large EOR opportunities but lack any natural supplies of CO_2 (i.e. transporting natural supplies of CO_2 to those areas would make the EOR operation economically unfeasible).
- Partial capture of CO_2 offers incremental revenues due to the higher utilization of the captured CO_2. However, due to diseconomies of scale, it seems that these additional benefits are negated by the incremental capture costs. If partial capture costs are brought down to costs comparable to 90% capture, then partial capture of CO_2 for EOR operations becomes an economically attractive option.
- For the EOR-CCS model to be implemented in the near term, significant government intervention will be required in the form of significant tax incentives in addition to a high carbon price (above $50).

6.2 Recommendations

- To help incentivize the EOR-CCS model, the large tax revenues generated through EOR operations should be redistributed to EOR operators and power plant operators. These tax revenues should be split between the two parties according to the relative costs incurred by each party. For instance, if the capture costs constitute 70% of the overall CCS costs and transportation and sequestration costs account for 30%, then tax revenues should be split accordingly (70% to 30%).
- The largest oilfields that are amenable to EOR should be pursued in early government funded CCS demonstration projects to help mitigate project costs.
- Given that China and other developing countries have even greater projected CO_2 emissions from coal-fired plants, a collaborative R&D program between developing and developed countries should be pursued. The program should focus on developing and

demonstrating CCS technologies that are optimized for existing plants (rather than new build plants).

- As discussed in the MIT Future of Natural Gas Study, the federal government should retire the oldest coal plants (plants that are older than 50 years) and replace them with the underutilized capacity in the existing NGCC fleet. Old U.S. coal plants can be replaced by the underutilized capacity in the existing NGCC fleet at a modest cost of approximately \$20 per ton of CO_2. To better determine the scalability of replacing coal plants with the existing NGCC fleet, a local study of the coincidence of underutilized NGCC capacity and coal plants needs to be carried out. Furthermore, the flexibility in the natural gas supply delivery system (NG pipelines) and the availability of excess capacity in the electric transmission lines should be evaluated at a local level.

6.3 Future work

- A U.S. CO_2 supply curve for EOR operations is unavailable in the literature. A CO_2 supply curve showing the CO_2 supply curve for natural sources of CO_2 and anthropogenic sources (industrial and power sector) would help establish the cost at which anthropogenic sources can start competing without government intervention.
- Detailed data were compiled for the Citronelle Dome. Similar data should be gathered for the other large oilfields identified in this thesis. The data should then be used with basic screening models for oilfield and saline aquifers to arrive at more accurate estimates of the incremental oil recovery and the CO_2 storage potential for these large oilfields. The results of such a study would help identify the top oilfields that should be targeted for early CCS projects.
- This thesis did not consider the future value of the oil left in place, after the CO_2 is stored and the wells are sealed. As is the case with secondary and tertiary recovery, further improvements in oil drilling and stimulation technologies might enable the extraction of further quantities of oil. Due to the possibility of such an occurrence, the oilfield owner might be more interested in leaving the oilfield idle (rather than using it for CO_2 storage) until further technological improvements or market conditions occur. Therefore, future studies should take into account the opportunity cost of leaving the oil in the ground (i.e. the future value of the oil left in place). If it is determined that the future value of the oil is large, the EOR operator then might not be willing to use his oilfield for CO_2 sequestration purposes.

- The potential of new CO_2-EOR techniques that use greater CO_2 pore volume should be studied. These new technologies might offer more favorable project economics.
- To determine regions in the U.S. where the EOR-CCS model can be implemented in the absence of a price on CO_2, a study examining stranded oil fields should be carried out. The study should identify stranded (in terms of natural supplies of CO_2) oilfields across the U.S. and determine the breakeven CO_2 prices for such an operation. When the breakeven price of CO_2 for these operations are comparable to anthropogenic prices of CO_2, the CCS-EOR model is economically feasible.

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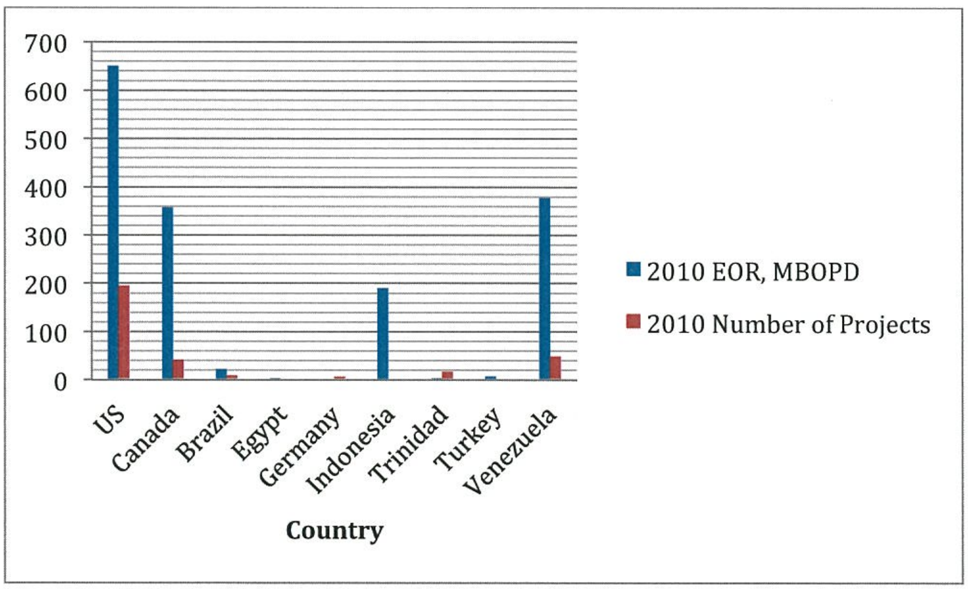
Appendix A– Background Information on EOR

A.1 EOR Activity

A.1.1 Global EOR Activity

As of mid 2010, there were nine countries around the world that were implementing EOR. These countries are the U.S., Canada, Brazil, Egypt, Germany, Indonesia, Trinidad, Turkey and Venezuela.[96] The total production from these operations amounted to approximately 1.6 million BOPD, which was equal to approximately 1.8% of the global oil supply. More than 60% of the oil recovered through EOR operations is recovered in North America (the U.S. and Canada). Furthermore, four countries (the U.S., Canada, Venezuela and Indonesia) accounted for more than 97% of the oil produced through EOR methods. Current global EOR operations are summarized in Figure 26 below. The EOR method that is most widely deployed globally (in terms of oil produced) is the steamflooding method with the CO_2 miscible method coming in second.[97]

Figure 26: Number of EOR Projects and the Corresponding EOR Oil Production in 2010.[98]



A.1.2 Overview of U.S. EOR Activity

It has been argued that the world is approaching "peak oil", a stage in global oil production whereby global oil production begins to decrease steadily. The eventual decline of the oil supply coupled with the lack of a short-term alternative for oil as a fuel (mainly as a transportation fuel) has led to unprecedented oil prices; oil prices peaked in the summer of 2008 at more than $140

[96] Leena Koottungal, "Special Report: 2010 worldwide EOR survey," *The oil and gas journal.* 108, no. 14 (2010).
[97] Ibid.
[98] Ibid.

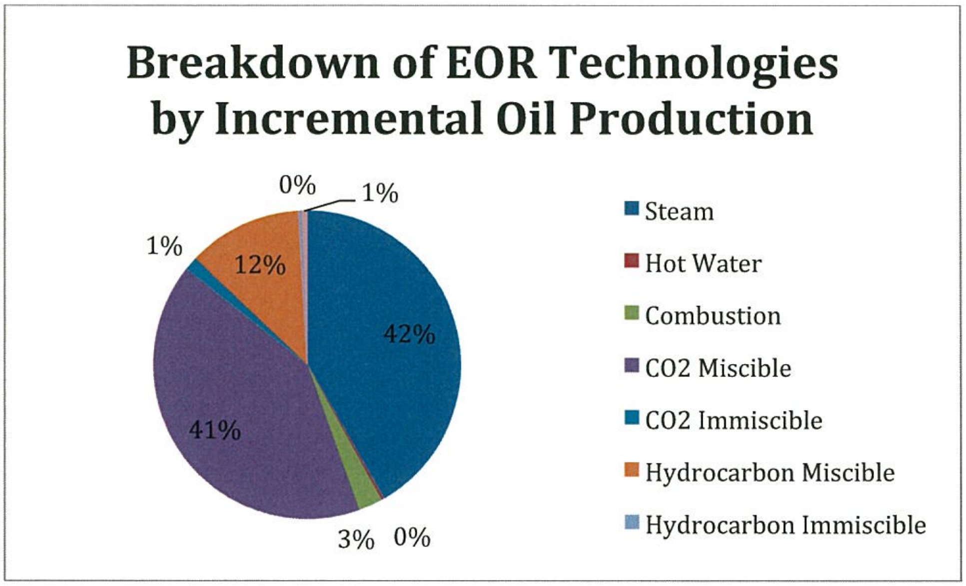
per barrel of oil. The limited supply of oil is further exacerbated by the concentration of this resource in relatively unstable regions in the world. This was evident by the recent fluctuations in oil prices due to the recent political turmoil in Egypt and Libya. Realizing the diminishing supply of oil and the lack of short-term alternatives to this versatile fuel, many countries around the world have attempted to maximize the extraction of oil from their domestic resources by utilizing enhanced oil recovery techniques. The U.S. has an estimated cumulative oil resource of 1,132 billion barrels, of which 230 billion barrels have been recovered through different recovery stages (mainly through primary and secondary stage processes). This means that the remaining oil in place is equal to 902 billion barrels. A sizeable portion of the ROIP can be recovered using EOR techniques.

As mentioned earlier, the first global EOR operation was implemented in the U.S. back in the 1960s. Early U.S. policy of aggressively exploiting domestic oil supplies has led to the quicker maturation of U.S. oilfields. As a result, the majority of the global EOR operations today, are located in the U.S.

US daily EOR oil production in early 2010 was equal to 650 thousand BOPD. This was equal to approximately 0.75% of the daily global crude oil production and 12% of the daily domestic U.S. crude oil production.[99] The EOR method that produced the largest amount of oil was steamflooding at around 275 thousand BOPD with CO_2 miscible a very close second at around 260 thousand BOPD. These two methods combined, accounted for more than 80% of the oil produced through EOR operations.[100] The U.S. currently deploys ten different EOR operations for commercial purposes. These methods and their respective share of oil produced through EOR is shown in Figure 27 below.

[99] Ibid.
[100] Ibid.

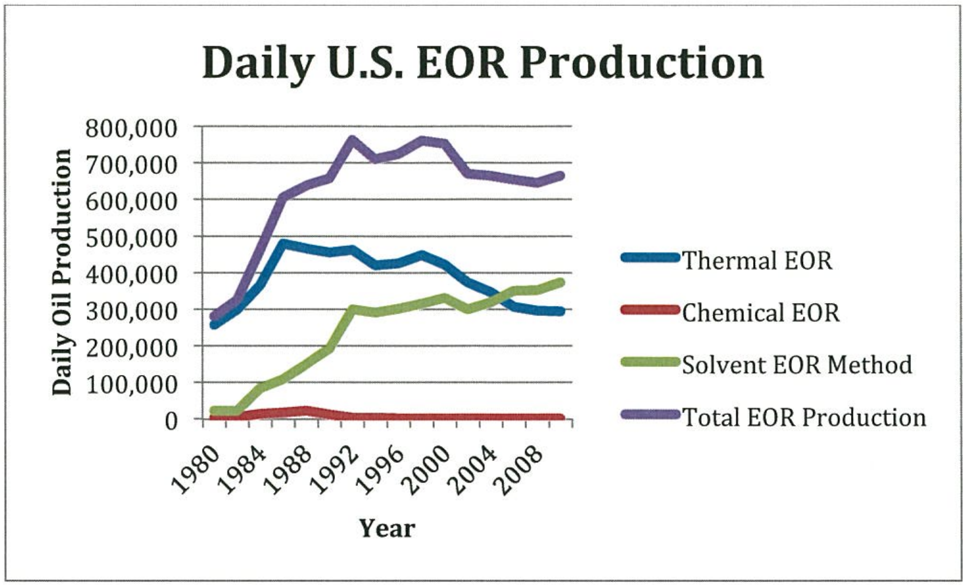
Figure 27: Breakdown of EOR Technologies by Incremental Oil Production in 2010.[101]



From a historical perspective, EOR production is on a decline. EOR production peaked in 1992 and achieved similar production levels in 1998. The decline in total EOR production can be attributed to the diminishing number of oilfields that are amenable to steamflooding. Steamflooding as discussed later on, is the most productive EOR method, the least energy intensive EOR method and carries the least financial risk (based on 100% success rate of past U.S. projects). The historic EOR production levels for the past thirty years is shown in Figure 28 below.

[101] Ibid.

Figure 28: Daily U.S. EOR Production.[102]



A.2 Overview of Oil Recovery Stages

A.2.1 Overview of Primary Oil Recovery

The existing natural pressure in the reservoir is the main determinant behind oil displacement efficiency in the primary oil recovery stage.[103] As mentioned earlier, this initial stage of oil recovery relies on natural mechanisms to create a pressure differential between the oil trapped underground and the surface (production well). These natural mechanisms/forces consist of the following:

1) Expanding force of natural gas: is an extremely effective force in displacing oil into the production wells.

2) Gravitational force: this force by itself is not sufficient to cause significant oil production, however, when combined with other forces it can help move large quantities of oil by facilitating oil drainage. This force is most effective in steeply inclined reservoirs.

3) Buoyancy force of encroaching water: encroaching water either through the side or the bottom of the reservoir is an effective oil displacing force. The ability of the water to displace oil is based on reservoir permeability as well as pressure distribution in the reservoir.

4) Finally, an expulsive force due to the compaction of poorly consolidated reservoir rocks is induced when fluids are withdrawn from the reservoir. This force leads to the movement of oil into production wells.

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[102] Company PennWell Publishing, *Historical enhanced oil recovery surveys - Worldwide* ([Tulsa, Ok.]: PennWell Corp., 2011).
[103] Donaldson, Chilingar, and Yen, *Enhanced oil recovery*. P.2.

These forces can either act concurrently or sequentially depending on the specific reservoir properties.

A.2.2 Overview of Secondary Oil Recovery

The pressure differential between the oil in the reservoir and the surface (production well) slowly diminishes with the production of oil. The pressure in the reservoir keeps on decreasing until the quantities of oil produced make the operation uneconomical. At this point, depending on the economics of the operation (how much oil is remaining, reservoir properties, current oil price, further capital expenditures, etc…), an oil field operator may choose to augment the current field operation to extract a larger quantity of the OOIP. This secondary process of extracting additional oil is what is called secondary oil recovery. To extract additional quantities of oil, one or a combination of the following can be done: i) raise the reservoir pressure, ii) improve the mobility of the oil by lowering the oil viscosity and iii) lower the interfacial tension between the oil and the displacing fluids.[104] Secondary recovery processes mainly deal with the augmentation of the reservoir pressure and typical recovery ratios for this recovery stage range between 15%-30% of the OOIP.

The production mechanisms in secondary oil recovery are very similar to those in primary oil recovery; the pressure differential between the reservoir and the production well lead to the displacement of oil. The differences between primary and secondary recovery processes is that i) more wellbores are used in the secondary recovery stage and ii) the pressure differential between the production wells and reservoir is created artificially. To artificially raise the pressure one of the following can be done: i) injection of fluids (mainly water and gases) and, ii) the application of a vacuum to the well.[105]

After the pressure is depleted in the reservoir, one of the most common ways to restore the reservoir pressure is through the injection of water or what is called "waterflooding". Water is injected into the reservoir using injection wells; the water injected moves the oil through the reservoir rocks towards the production wells. The most common injection pattern is the five-spot injection pattern in which one injection well is surrounded by four producing wells as shown in Figure 29 below. Often times, chemicals are added to the water to improve the efficiency of the water flooding process. These chemicals work on improving the mobility of oil and reducing the viscosity of the oil. For a full discussion on waterflooding see (Lake 1989).

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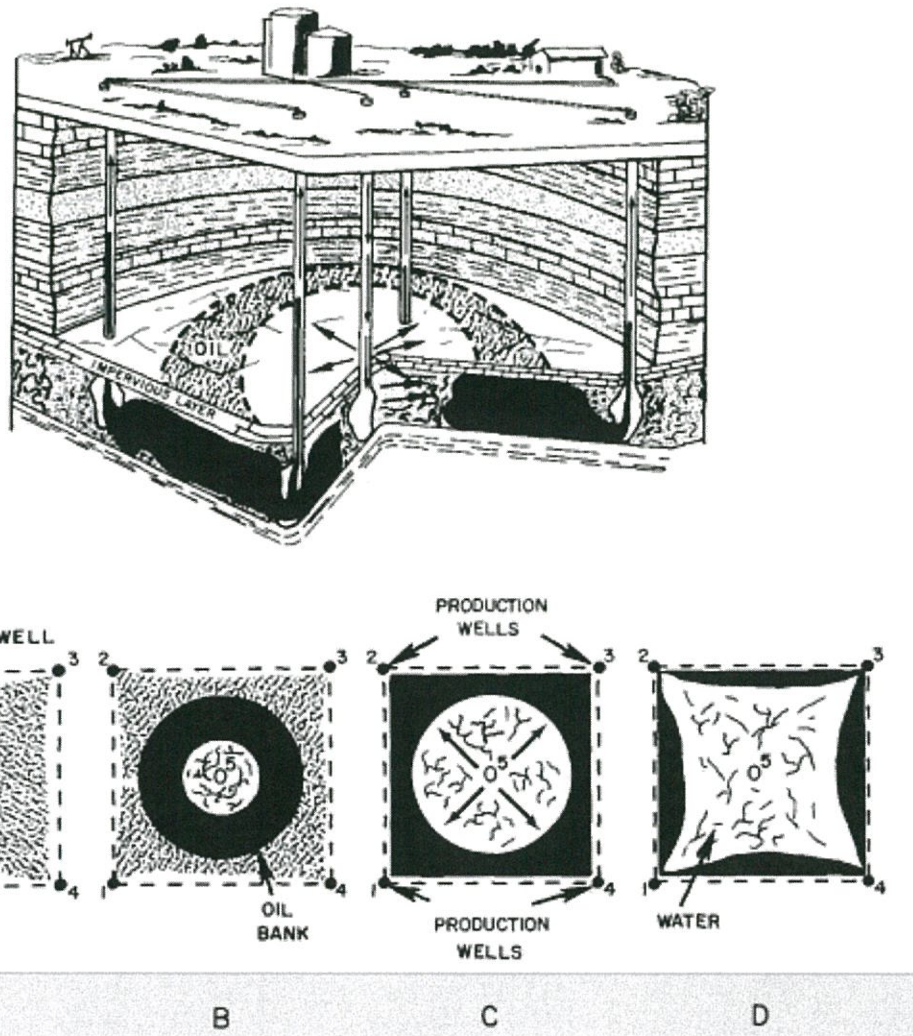
104 Ibid. P.3

105 Ibid. P.3.

Figure 29: Displacement of Oil Through Reservoir Rocks by Water Flooding (Five Spot Injection Pattern).[106]



Other popular secondary methods include the injection of gases; depending on how you inject the gas, you can achieve one of the following three operations: i) pressure restoration, ii) pressure maintenance and, iii) gas drive. For instance, gas drive entails the continuous injection of pressurized gas through the injection well; the gas drives the oil in a film like form to the production well. [107]

A.2.3 Overview of Tertiary & Quaternary Oil Recovery

If any of the enhanced oil recovery processes mentioned earlier (Section 2.2) are used after the primary and secondary recovery stages to recovery more oil, then the process is defined as tertiary recovery. As mentioned earlier, secondary oil recovery operations typically aim to

[106] Donaldson, Chilingar, and Yen, *Enhanced oil recovery*. P.4.
[107] Ibid. P.4

recover more oil by increasing the reservoir pressure; tertiary recovery operations on the other hand, primarily use methods that aim to increase the mobility of the oil. As seen in Table 1 earlier, typical tertiary oil recovery values range between 5-20% of the OIIP. Cumulative oil production in the primary recovery, secondary recovery and tertiary recovery stages are estimated to be equal 125, 325 and 200 billion barrels of oil respectively.[108]

More speculative oil recovery opportunities/methods are often referred to as quaternary oil recovery. For instance, oil extraction from Residual Oil Zones (ROZs), which are believed to be very significant in terms of resource estimates; is considered a quaternary recovery opportunity.[109]

A.3 Overview of Enhanced Oil Recovery Technologies

A.3.1 Thermal Enhanced Oil Recovery

From a historical perspective, the thermal enhanced oil recovery (TEOR) method has accounted for the largest incremental oil production output. TEOR accounted for more than 80% of the incremental oil produced in the late 1980s, this number has been steadily declining over the years as TEOR methods have becomes less widely used and as the CO_2-EOR method has become more widely deployed. Today, more than 290,000 BOPD are produced using TEOR methods; this is a significant decrease from the peak production figure of almost 480,000 BOPD back in 1986. Nevertheless, TEOR methods today still account for the second largest share of incremental oil produced through EOR methods at around 45%.

As shown in Figure 2 earlier, there are three basic TEOR methods: 1) steam, 2) in situ combustion, and 3) hot water. The steam method is by far the most used method accounting for more than 90% of the incremental oil produced using TEOR methods. TEOR method is one of the most effective EOR methods as it has one of the lowest power intensities at around 373 W (0.5hp) per barrel of oil produced, that is almost 7 times less than the energy intensity of gas injection EOR processes.[110]

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[108] Ming and Melzer, "CO2 EOR: A Model for Significant Carbon Reductions," in *MIT Energy initative and the Bureau of Economic Geology at The University of Texas at Austin Symposium on the Role of EOR in Accelerating the Deployment of CCS* (2010). P.12.
[109] Ibid.
[110] Advanced Resources International, "EPRI Enhanced Oil Recovery Scoping Study." P. 6-1.

EOR methods as mentioned earlier, attempt to recover more oil by attempting to do one or a combination of the following: 1) raise reservoir pressure, 2) improve mobility of oil, 3) lower the interfacial tension between oil and the reservoir rock. TEOR methods mainly employ the third mechanism to displace oil. Reduction in the viscosity of the oil is achieved by raising the oil temperature. Significant reductions in viscosity can be achieved by raising the temperature by around a 100K. It is worth noting that the effects of temperature on viscosity reduction are more pronounced for the heavier oils (10-20 API).[111]

TEOR methods such as steam flooding are highly effective in recovering oil; oil recovery ratios can go as high as 35%. This is evident by the relatively small number of TEOR projects when compared to their oil production. For instance, in 2010, there were 46 steamflooding projects producing around than 274,000 BOPD versus more than 109 EOR-CO_2 projects producing around 263,000 BOPD. For a more thorough discussion of thermal enhanced oil recovery see (White and Moss, 1983).

A.3.2 Solvent Enhanced Oil Recovery Methods

Solvent enhanced oil recovery methods can be divided into four main groups as seen in Figure 2 earlier, these include: i) hydrocarbon miscible injection, ii) CO_2 miscible injection, iii) CO_2 immiscible injection, iv) flue gas (both miscible and immiscible) injection. The first solvent enhanced oil recovery operations date to the early 1960s and included the injection of small slugs of liquefied petroleum gas (LPG). As the price of the LPG increased, the solvent method became less economical. Resurgence in the solvent method was witnessed in the 1970s due to increasing oil prices; the new preferred solvent at that time was CO_2.[112] This was evident by the increase in miscible CO_2 operations from 1 in 1971 to 52 by 1990.

EOR production from the solvent method presented a small fraction of the total EOR production, solvent EOR methods accounted for less than 10% of the EOR production back in 1971. Today, the solvent methods accounts for the largest portion of incremental EOR oil production at 55%, with the miscible CO_2 method accounting for 74% of that total and the hydrocarbon miscible method accounting for 22% of that total.

[111] Lake, *Enhanced oil recovery*. P.450.
[112] Ibid. P.234

A.4 Science Behind CO_2-EOR

CO_2-EOR operations fall under two main categories: i) miscible CO_2 flooding and ii) immiscible CO_2 flooding. The term miscible here is defined as "two fluids that mix together in all proportions within a single phase."[113] Miscible CO_2 flooding is used to recover light to medium crudes (greater than 22 API), while immiscible floods are more effective with heavier crudes (lower than 22 API gravity crudes) and in gravity drainage reservoirs.[114] Based on this distinction, miscible CO_2 flooding offers greater potential in recovering more valuable grades of crude oil. This is evidenced by the fact that as of 2010, there were only 5 immiscible CO_2 floods in the U.S. and 109 miscible EOR floods. Therefore, given the widespread deployment of the misicbile CO_2 method versus immiscible CO_2 method, this thesis only considered the miscible CO_2-EOR method.

CO_2 is an effective injectant in EOR operations due to its very attractive properties when in the supercritical fluid state (when subjected to high pressure); as a supercritical fluid, CO_2 has liquid like density and gas like diffusivity and viscosity. Furthermore, under the right conditions (mainly high pressure), CO_2 becomes miscible with oil. Under these conditions CO_2 densities range between 0.7 - 0.8 g/mL which are very close to crude oil densities; crude oil 32° to 48°API have densities that range between 0.862 g/mL and 0.79 g/mL.[115] Furthermore, viscosities of CO_2 under miscible conditions range between 0.05 to 0.08 cP, which are much lower than that of oil, 1 to 3 cp.[116] The high densities and low viscosities facilitate the displacement of the CO_2-Oil mixture into the production wells.

Miscibility as defined earlier, is when two fluids mix together to form a single phase where one phase can fully displace the other phase. Miscibility generally occurs according to one of these two mechanisms: first contact miscibility or multiple-contact miscibility. First contact miscibility as the name suggests, is when two fluids mix upon contact, for instance, when ethanol and water are mixed together, they become miscible with no observable separation. Another example of first contact miscibility is butane and crude oil, if it were not for the high cost of butane; it would have been an ideal solvent for EOR.[117] On the other hand, as is the case with oil and CO_2, other fluids are not miscible upon first contact and require multiple contacts and a minimum pressure before they become miscible. Multiple contacts in which the components of the oil and CO_2

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[113] Ibid. P.234.
[114] Jarrell and Society of Petroleum, *Practical aspects of CO_2 flooding.* P.4.
[115] Ibid. P.13.
[116] Ibid. P.13.
[117] Ibid. P.13

mixtures are transferred back and forth before miscibility is achieved; this process of component transfer was named condensing/vaporing mechanism by Zick.[118] In this process, some of the CO_2 condenses into the oil making it lighter, at the same time; some of the crude vaporizes into the CO_2 rich mixture. The process of condensation and vaporization keeps on happening until "equilibrium" is reached and the fluid properties of both mixtures become indistinguishable from one another, at that point, the mixtures are said to have become miscible.[119]

The development of miscibility between two fluids is a function of pressure and temperature. However, in an isothermal reservoir, miscibility is mainly a function of the pressure. As the pressure is increased, it becomes easier for the CO_2 to vaporize more oil and similarly, it becomes easier for the oil to dissolve more CO_2. At a certain pressure, the two fluids become in immediate contact of one another and no reservoir mixing is required to induce miscibility. The pressure at which miscibility occurs without reservoir mixing is called the thermodynamic minimum miscibility pressure (thermodynamic MMP).[120] Initially, increasing the CO_2 pressure leads to an increase in oil recovery. This relationship is maintained until the CO_2 pressure reaches the thermodynamic MMP, at this point, any further increases in the CO_2 pressure (beyond the thermodynamic MMP) will not yield any improvements in the oil recovery. Therefore, it is desirable to operate a CO_2 flood just above the thermodynamic MMP.

A.4.1 CO_2 Injection Design

Depending on the previous oilfield recovery operations, reservoir properties (ex: heterogeneity), and other economic factors such as CO_2 availability, a certain injection design might be chosen over another. As discussed in (Jarrell Et.al) there are five basic CO_2 injection designs: i) continuous CO_2 injection, ii) continuous CO_2 chased with water, iii) conventional alternating CO_2 and water, iv) tapered alternating CO_2 and water (sometimes chased with water), v) alternating CO_2 and water chased with gas.[121] In all five processes, the miscible mixture of CO_2 and crude oil reaches the production well, the mixture is separated into its different components, for instance, for the conventional alternating CO_2 and water process, the different components are spilt into an oil stream, a water stream and CO_2 stream that usually is mixed with other hydrocarbon gases (the hydrocarbon gases can be separated if there is an off-take contract or if they can adversely affect the oil recovery process). The CO_2 is then recycled and re-injected to minimize CO_2

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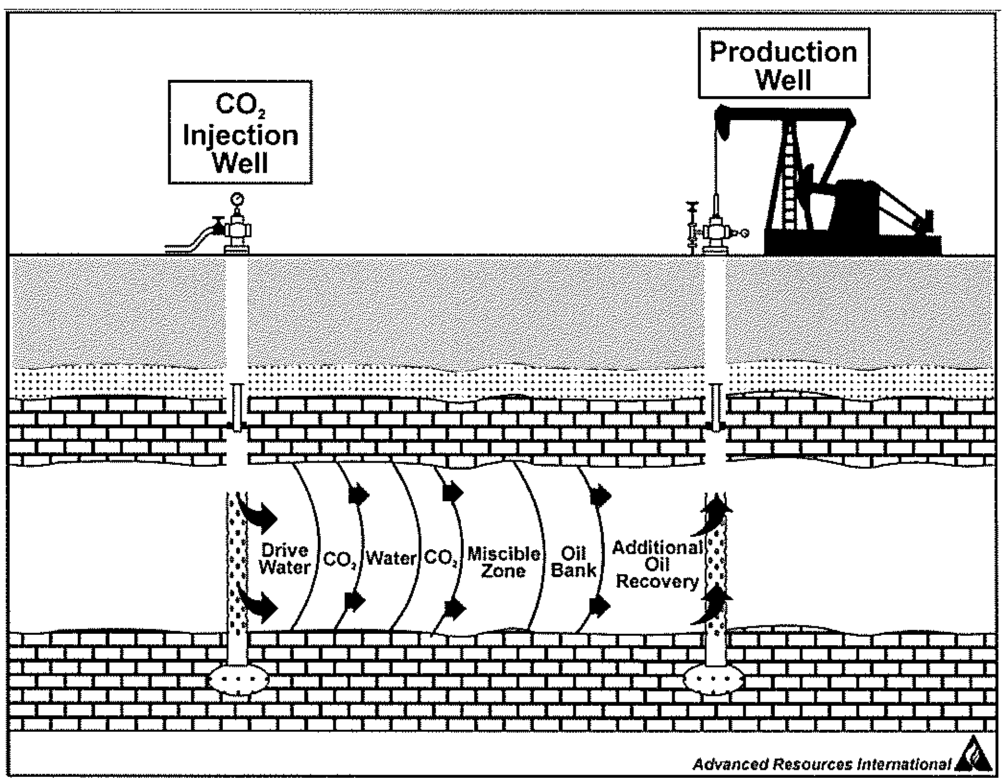
[118] Ibid. P.13.
[119] Ibid. P.13.
[120] Ibid. P.13.
[121] Ibid.

purchase costs. What follows is a brief discussion highlighting some of the unique characteristics of some of these five basic methods.

Conventional Alternating CO_2 and Water Chased with Water: this method involves the injection of a predetermined slug of CO_2 in alternating cycles with water; this is what is often called water-alternating gas (WAG). A fixed volume of CO_2 to water (WAG ratio) is held throughout the process. When the entire slug of CO_2 is injected, water as a chase fluid is injected to help drive the miscible fluid towards the production wells. This type of design is most effective in highly stratified heterogeneous reservoirs as it helps improve areal and vertical sweep efficiencies.

Figure 30: Cross-Sectional View of a CO_2 Flooding Operation[122]



Tapered Alternating CO_2 and Water (sometimes chased with water): this method also involves the injection of a predetermined slug of CO_2 in alternating cycles with water. However, unlike the conventional WAG process, the WAG ratio in this process is not held constant. The volume of injected water in each cycle is tapered with the completion of an individual injection cycle. This process continues until the entire slug of CO_2 has been injected. Often times, water is injected as

122 Advanced Resources International, "EPRI Enhanced Oil Recovery Scoping Study." 2-3

chase fluid after the completion of the operation. The aim of this design is to reduce the amount of the CO_2 injected per barrel of oil recovered (utilization factor) by adjusting the WAG ratio. Adjusting the WAG ratio reduces both CO_2 purchases and CO_2 recycling, hence improving the profitability of the project. In the near term, this process sacrifices some revenues due to the diminished quantity of CO_2 injected. However, in the long run, the oil recovery rates improve due to the gains in areal efficiencies; that is because the CO_2 does not go through the oil bearing layers as fast, it does a better job of recovering more oil.

Continuous CO_2 Injection: this design as the name suggests, involves the injection of a continuous slug of CO_2 with no other injectant or chase fluid. This type of design is typically employed after the primary recovery stage in gravity drainage reservoirs and non-waterfloodable reservoirs.

The other two operations that employ a chase fluid are slight variations to the other operations discussed above. The chase fluid is used mainly for economic considerations (to minimize the amount of CO_2 purchased); a relatively cheap gas (ex: air, N_2) is typically injected after the total CO_2 slug has been injected. The chase fluid helps drive the supercritical fluid towards the production wells.

A.5 Life Cycle Analysis of CO_2 Storage in the CO_2-EOR Flood

As demonstrated above, CO_2-EOR operations sequester significant amounts of CO_2 incidentally. However, if CO_2-EOR is to be considered as a potential pathway to mitigating CO_2 emissions, then a life-cycle analysis of the entire CO_2-EOR operation must be carried out. CO_2-EOR operations are one of the most power intensive EOR operations, as they require around 3.68kW (5hp) per barrel of oil moved as opposed to only 0.75 kW (1hp) for thermal operations.[123] The energy requirements for CO_2-EOR operations comprise of the following:

i) energy to power pumps that lift and drive the oil and water out of the reservoir and to the processing and distribution centers;

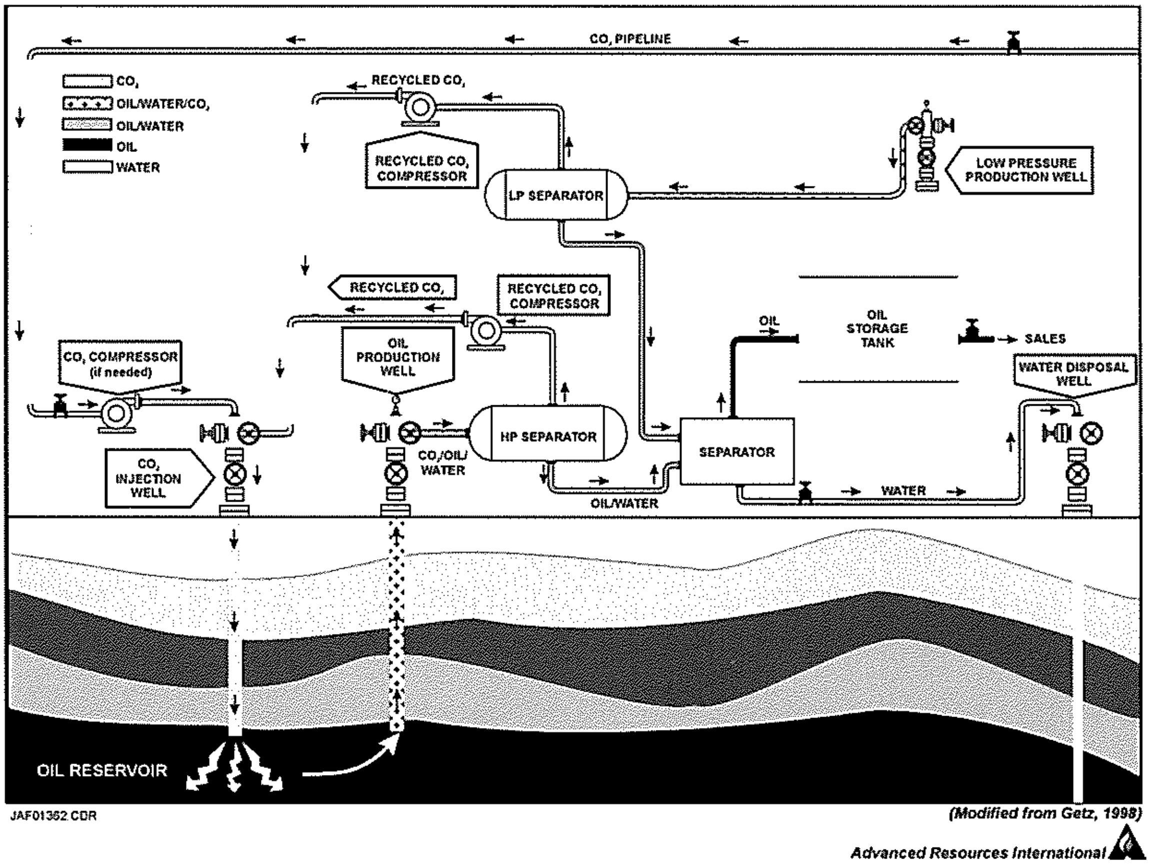
ii) recompression energy requirements: power is needed to recompress the CO_2 before it is re-injected. Furthermore, if the hydrocarbon gases (ex: CH_4) are sold then they must be compressed as well before they are transported using pipeline; and

iii) again, if the hydrocarbon gases are to be sold then there are certain pipeline requirements on the concentrations of certain containments (ex: water and CO_2). To

[123] Ibid.

remove these containments energy is needed to separate the CO_2 (ex: using Ryan-Holmes process). Furthermore, energy is needed to dehydrate the water present in the hydrocarbon gas stream.

Figure 31: Schematic of a Typical CO_2 Flooding Operation.[124]



The exact emissions associated from these energy intensive activities will vary slightly from an CO_2-EOR operation to another depending on the choices made by the operators regarding the type of equipment employed. For instance, to drive the compressor, the operator has the choice between an electric motor and a natural gas powered engine. To estimate the life-cycle CO_2 emissions of an EOR operator, Aycaguer[125] conducted an assessment of a reservoir in the Permian basin. The study concluded that approximately 0.36kg of CO_2 per kg of oil (0.94Mcf per barrel of oil[126]) produced are emitted due to emissions associated with power needed for auxiliary

[124] Ibid. P.2-4.
[125] Aycaguer, A.; Lev-On, M.; Winer, A. M. Reducing carbon dioxide emissions with enhanced oil recovery projects: A life cycle assessment approach. Energy. Fuels. 2001, 15, 303-308.
[126] Assuming crude oil density of 873 kg/m^3.

equipment, flaring of hydrocarbon gases and fugitive emissions. Taking the net utilization rate of 0.13 ton (2.34 Mcf) of CO_2 per barrel of oil from Chapter 2 and subtracting the 0.05 ton (0.94 Mcf) of CO_2 emitted per barrel of oil produced, gives a new net utilization rate equal to 0.08 ton (1.40 Mcf). That is, for every barrel of oil produced, 0.08 ton (1.40 Mcf) of CO_2 is stored in the reservoir. This calculation takes into account the CO_2 emissions associated with powering auxiliary field equipment, flaring of unsold hydrocarbon gases and fugitive emissions. To put the CO_2 storage into perspective, a barrel of crude oil typically produces around 20 gallons of gasoline.[127] Combustion of the 20 gallons of gasoline produces around 176.48 kg of CO_2. Therefore, the CO_2 stored during the EOR operation can offset around 45% of CO_2 emissions associated with the combustion of gasoline. However, for this to be truly net negative process in terms of CO_2 emissions, the CO_2 source has to be anthropogenic. If the operation relies on a natural source of CO_2, then the process would not yield any benefits in terms of CO_2 benefits as one would be basically moving the CO_2 from one reservoir to another.

[127] This number depends on several factors such as the oil refinery configuration and quality of crude oil being processed.

Appendix B– Evaluating the Four CO_2 Mitigation Options

B.1 U.S. Coal Fleet

As mentioned earlier, coal fired power plants accounted for approximately a third of all U.S. CO_2 emissions in 2009. As of 2009, there were 572 coal-fired power plants in the U.S. with a cumulative nameplate capacity of around 337GW.[128] In terms of installed capacity, natural gas plant capacity exceeds that of coal plants, however, coal plants operate at a higher capacity factor and hence provide around 50% of the electricity generated in the U.S.[129] The total CO_2 emissions associated with the coal fleet were equal to 1742 million metric tons of CO_2 in 2009.[130] This translates to approximately an average CO_2 emission rate of 992 kg/MWh (2187 lb/MWh).[131]

The U.S. coal fleet is relatively old when compared to other developing countries such as China. The capacity-weighted average age of the U.S. coal fleet in 2009 was approximately equal to 36 years.[132] Very few coal plants have been built over the last 20 years due to the increasing regulatory burden of new environmental legislation on new build plants and due to the growing attractiveness of natural gas combined cycle plants. Noting that historically, U.S. coal-fired power plants on average operate for 50.1 years before being retired and assuming that current plants would on average be retired around this age, it becomes evident that significant future CO_2 emissions are already locked into the existing infrastructure. The age distribution of the existing coal fleet is shown in Figure 32 below.

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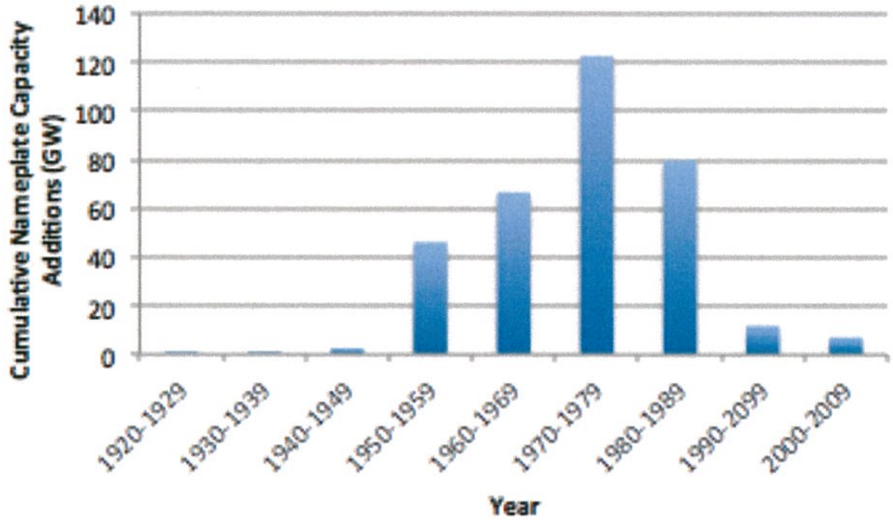
[128] EIA, " EIA-860 Annual Electric Generator Report."
[129] Ibid.
[130] EIA, "Emissions of Greenhouse Gases in the United States 2009."
[131] EIA, "Net Generation by Energy Source: Total (All Sectors).";EIA, "Emissions of Greenhouse Gases in the United States 2009."
[132] EIA, " EIA-860 Annual Electric Generator Report."(2009)

Figure 32: Cumulative Capacity Additions in the U.S. in Each of the Last Nine Decades[133]



According to Figure 32 above, only ~99GW or only 29% of the existing fleet has been built over the last thirty years. In comparison, the age of China's coal fleet is much lower at an average age of 12.5 years.[134] Therefore, assuming that on average, current operating coal plants will be retired at the U.S. historical operational average age of 50.1 years, it becomes evident that the problem in China and other developing countries is even more acute given the relatively young age of the coal fleet in those countries. This fact is further exacerbated by rapid expansion of China's coal fleet; it is expected that China will add another 690GW of coal-fired power plants by 2020.[135]

B.2 Overview of the Different CO_2 Mitigation Pathways

Given the significant CO_2 emissions that are associated with the current global coal fleet, what follows is an overview of four different CO_2 mitigation pathways. The current mitigation options are compared to one another in terms of their cost and scalability/adaptability (i.e. CO_2 mitigation potential).

B.2.1 Increasing the energy efficiency of the existing fleet

It was argued in J. McNerney[136] that the average efficiency of the current fleet is currently at an optimal value and it will be difficult to increase these plant efficiencies further. This optimal value arises due to the tradeoff between fuel costs and capital expenidtures required to raise the

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[133] Ibid.
[134] S. J. Davis, K. Caldeira, and H. D. Matthews, "Future CO₂ emissions and climate change from existing energy infrastructure," *Science Science* 329, no. 5997 (2010).
[135] Initiative, "MIT Energy Initiative Symposium Report on the Retrofitting of Coal-Fired Power Plants for CO2 Emissions Reductions." P.15.
[136] J. McNerney, J. Doyne Farmer, and J. E. Trancik, "Historical costs of coal-fired electricity and implications for the future," *Energy Policy* 39, no. 6 (2011). P.5.

plant efficiency. That is, if fuel costs are high, this might justify investing in plant effieicny inmprovements where the gains in effieicny lead to reduced fuel costs that are greater than the new capital expenditires. Altough this argument holds for a large number of plants, many of the exisiting plants have been operating for long periods of time and as a result, the reported (design) heating values are lower than the actual heating values of the plants today. These efficiency losses as highlighted in a Sargent & Lundy[137] study can be due to a variety of reseaons such as:

i) Turbine losses (ex: blade erosion);
ii) losses in the condensor (ex: fouling of the condensor pipes);
iii) detroriation of motors and drivers moving the conveyor belt;
iv) deterioration of boiler feed pumps over time;
v) the installtion of NO_x and SO_x controls at later stages of the plant life, in this case; and,
vi) these NO_x and SO_x controls are retorfitted and therefore, are not optimized to the orginal plant design.

Some of these efficiency improvements such as overhauling the turbine require major capital expenditures. Other efficiency improvements such as the replacement of the conveyor motors require more modest investments. A full list of the potential improvements is given later on. An improvement in the energy efficiency of the system reduce the amount of coal consumed per unit of electricity produced and consequently, reduces CO_2 emissions per unit of energy produced. In some cases, the fuel costs savings might be larger than the required capital investment, in other cases, the fuel savings will not be enough to offset the additional capital expenditures and O&M costs.

B.2.2 Co-firing with biomass

The concept of co-firing coal plants with biomass calls for replacing some of the combusted coal (i.e. the regular fuel) with biomass to lower CO_2 emissions per unit of electricity produced. Examining the existing literature (ex: Basu[138] and Froese[139]) reveals that most of the studies on biomass co-firing were done for individual plants or for select regions in the U.S. I however, did not come across any study that evaluated the overall biomass co-firing potential for the entire U.S. coal fleet. The consensus among the existing studies was that direct co-firing is technically

[137] Sargent & Lundy LLC, "Coal-Fired Power Plant Heat Reduction," (2009).
[138] P. Basu, J. Butler, and M. A. Leon, "Biomass co-firing options on the emission reduction and electricity generation costs in coal-fired power plants," *Renewable Energy* 36, no. 1 (2011).
[139] Robert E. Froese, et al. (2010). An evaluation of greenhouse gas mitigation options for coal-fired power plants in the US Great Lakes States, Biomass and BioEnergy, 34

feasible and requires little modifications to the plant. Other than direct co-firing, there are three other ways in which co-firing can occur:

i. Direct co-firing in the same boiler;
ii. indirect co-firing, using a separate boiler; and,
iii. gasification and co-firing.

Typical direct biomass co-firing on an energy input basis ranges from 5%-15% depending on the type of boiler technology in place.[140] For the co-firing option to make sense, the Life Cycle (LC) CO_2 emissions associated with the biomass on a unit energy basis must be less than that of coal. If for instance, the biomass used was carbon neutral (i.e. the biomass absorbs as much CO_2 as it releases when it is combusted, harvested, transported, etc.) then, for every 1% of coal replaced by biomass (on an energy input basis) CO_2 emissions drop by 1%.

B.2.3 Retrofitting with post combustion CO_2 capture technologies

This option as the title suggests, involves the installation of CO_2 capture systems into an existing coal plant. The MIT Energy Initiative Symposium on the Retrofit of Coal-Fired Power plants[141] and Chung[142] discussed this option in detail. The MIT symposium discussed the different available technologies and the scalability of the option while Chung's thesis assessed the technical and economic feasibility of the different CCS technologies. Given that the plant is already operating, post combustion capture systems (versus pre-combustion and oxy-fuel combustion systems) are the most technically feasible. Post combustion capture systems such as amine-based systems are already deployed in several facilities around the world.

B.2.4 Retiring the plant

If any of the last three options is prohibitively expensive to implement and if carbon prices are high enough, then retiring the existing coal plant and replacing it with a low carbon technology is the best option. This option was discussed by the MIT Future of Natural Gas study that examined the potential of retiring a percentage of the existing coal fleet and utilizing the existing spare capacity in the electricity generation fleet to replace the retired capacity.

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[140] Basu, Butler, and Leon, "Biomass co-firing options on the emission reduction and electricity generation costs in coal-fired power plants."
[141] Initiative, "MIT Energy Initiative Symposium Report on the Retrofitting of Coal-Fired Power Plants for CO2 Emissions Reductions."
[142] Timothy S. Chung. (2009). Expert Assessments of Retrofitting Coal-fired Power Plants with Carbon Dioxide Capture Technologies

B.3 Methodology

To determine which (or a combination) of the different CO_2 mitigation pathways offers the most viable option to reducing CO_2 emissions from the existing coal fleet, two key questions were addressed: i) what is cost of CO_2 mitigation option (i.e. price of each ton of CO_2 avoided) and, ii) what is the adoptability/scalability of each of the CO_2 mitigation options. To answer these two questions and, the following approach was taken for each option.

The following methodology was adopted to determine the cost of each ton of CO_2 avoided by increasing the efficiency of a coal fired power plant. A comprehensive literature review of potential improvements to existing plants was carried out. The heat reduction achieved (increase in efficiency) for each improvement along with the associated capital costs, fixed O&M costs and variable O&M costs were complied and are shown in Table 22 below.

Table 22: Potential Efficiency Improvements to the Existing Coal Fleet and the Corresponding Capital Costs, Fixed O&M Costs and Variable O&M Costs Associated with Each Improvement.[143]

Improvements	Heat Reduction (BTU/kWh)	Capital Costs ($ Millions)	Fixed O&M Costs ($/yr)	Variable O&M Costs ($/yr)
Boiler Island				
Boiler Operation	50-100	4-8	100,000-150,000	0
Neutral Network	0-100	0.75	50,000	0
Intelligent Soot Blowers	30-90	0.5	50,000	0
Limit Air Heater Leakage	10-40	0.6-1.2	75,000-100,000	0
Lower Air Heater Outlet Temp.	50-120	2.5-18	75,000-100,000	425,000-1,500,000
Turbine Island				
Turbine Overhaul	100-300	4-25	0	0
Condenser	30-70	0	80,000-60,000	0
Boiler Feed Pumps	25-50	0.5-0.8	0	0
Flue Gas System				
ID Fans	10-50	9-16	85,000-130,000	0
Variable Frequency Drives	20-100	3-6	30,000-50,000	0
Emission Control Technologies				
FGD System	0-50	0-5	0-150,000	0
Particulate Control System	0-5	0-0.8	0-25,000	0

[143] LLC, "Coal-Fired Power Plant Heat Reduction."
Note: The range of numbers is given for power output range of 500MW to 900MW.

SCR System	0-10	0-2	0-100,000	60,000-100,000
Water Treatment System				
Advanced Cooling Tower Packing	0-70	5-3	0-175,000	0

Determining the applicability of each specific efficiency improvement to each of the 572 existing plants is a very onerous task that is beyond the scope of this project. To get a general idea of the scalability of such an option, I assumed that only plants with a lifetime of 30 years or more would be willing to invest in efficiency improvements, otherwise, the plants will opt to keep their current configuration. This assumption implies that only ~100GW of the existing fleet would opt for efficiency improvements. The next challenge is to determine if any of the efficiency improvements listed in Table 22 above can result in a low (ideally negative) incremental CO_2 abatement costs. I constructed a model that randomly chooses efficiency improvements and randomly selects a cost profile associated with a given power output. The model then applies the given efficiency improvements and cost profile to the entire fleet. This process is repeated 10,000 times using a Monte Carlo simulation to get a mean estimate of the CO_2 abatement costs.

A similar approach was adopted for analyzing the option co-firing the plant with biomass. Although three potential co-firing options were listed earlier, only the option of direct co-firing was studied here. As discussed earlier, fluidized bed boilers have fewer restrictions in terms of the percentage energy content of biomass burnt when compared to pulverized coal boilers. According to Basu, fluidized beds can accommodate 15% co-firing of biomass, while pulverized coal boilers can accommodate less than 10% (I assumed 7.5% for the purpose of this study).[144] It was assumed for the purpose of this study, that if an X% (on heat input basis) of coal is replaced with biomass, then an X% reduction in CO_2 emissions achieved. This assumption basically implies that the biomass is CO_2 neutral. I then proceeded to construct a financial model that evaluated the co-firing option for plants that relied on either fluidized bed boilers or pulverized coal boilers. In terms of cost inputs, I assumed that no further capital expenditures are required. Therefore, the only required costs are the biomass fuel costs; those costs were acquired from Basu.

To evaluate the option of retrofitting the coal plants with post combustion capture technology, I first began by evaluating the coal-fired plants that are eligible for retrofit. According to the MIT

[144] Basu, Butler, and Leon, "Biomass co-firing options on the emission reduction and electricity generation costs in coal-fired power plants."

Energy Initiative report on the retrofit of existing plants, only 59% of the existing fleet is technically eligible for retrofit and out of this 59%, only a third have certain requirements (land availability, water availability, etc.) needed to run a successful post combustion capture operation. Therefore, the total percentage of coal plants eligible for retrofit is close to ~20% of the total fleet.[145] However, it is difficult to pin point which plants specifically have the land availability and water availability restrictions. Therefore, I randomly selected an equivalent of 20% of the total fleet from only a pool of new plants (less than 30 years old), since these plants would have the greatest capital recovery factors for the new installed capture equipment. To determine the capture, transport and sequestration costs for this option, I relied on the Integrated Environmental Control Model (IECM Model). I ran the model for one of the plants given in the sample (see Chapter 3 for details); I then introduced an uncertainty bound to the different cost parameters and ran a Monte Carlo simulation to determine the distribution of the CCS costs.

When none of the last three options is economically feasible, then the plant should be retired. In the case of replacing the plant with new builds, the cost of retiring a plant is the decommissioning cost and the cost of the new generation technology. The cost of the new generation technology is going to depend on the specific region, the prevailing market and political scene and the investor's constraints (financing, risk, etc.) Therefore, there is great uncertainty in terms of the CO_2 abatement cost for this option. When replacing retired plants with existing capacity, the cost of retiring the plant is the cost of decommissioning and the difference between the fuel and O&M costs for the retired and underutilized plant.

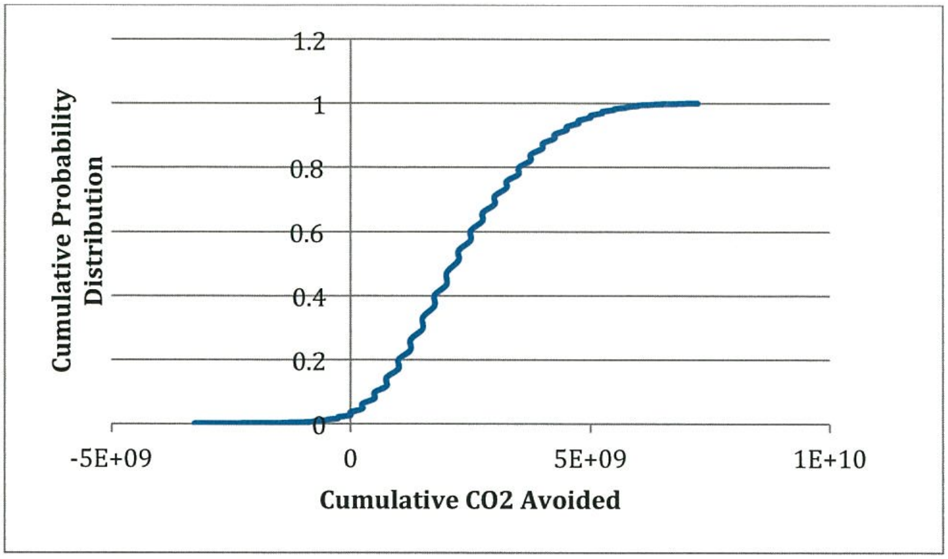
B.4 Analysis and Results

B.4.1 Increasing Power Plant Efficiency

Running the model using the given input parameters shown in Table 33 earlier shows that around 0.48 gigatonnes of CO_2 can be avoided if the average plant lives on for 24 years after the improvements have been made. This cumulative amount of CO_2 avoided is equivalent to around 2% of the projected CO_2 emissions from the existing coal fleet (i.e. 24 gigatonnes). The cumulative distribution showing the uncertainty around this number is shown in Figure 36 below.

145 Initiative, "MIT Energy Initiative Symposium Report on the Retrofitting of Coal-Fired Power Plants for CO2 Emissions Reductions."

Figure 33: Uncertainty in the Cumulative CO_2 Emissions Avoided.



The average cost of achieving this energy reduction is equal to \$3.3 per ton of CO_2 avoided. This implies that a modest cost is paid to abate CO_2 emissions. Furthermore, the analysis suggests that there are some opportunities where CO_2 abatement costs are negative. This implies that levelized fuel costs savings will be larger than the new capital expenditures and O&M costs. Some might suggest that negative abatement costs are unrealistic because it is safe to assume that if there any costs savings, the plant operator would have already captured those savings. However, given that many of the coal plants are operated by utilities that receive a fixed rate of return, these utilities have no incentive to improve their plants as they are guaranteed a certain rate of return. Such a pricing policy allows the utilities to pass potential fuel price increases onto the ratepayers.

B.4.2 Co-firing with Biomass

The first step of the analysis showed that approximately ~300GW or 90% of the existing fleet utilizes a pulverized coal boiler, while only ~5GW of ~1.5% of the existing fleet utilizes fluidized bed boilers. This implies that the majority of the plants will only be able to co-fire biomass at a heat input percentage of 7.5% biomass to 92.5% coal. Running the model for the given cost parameters, assuming a discount rate of 7% and a remaining plant lifetime of 17 years on average, shows that the average cost of avoiding a ton of CO_2 is equal \$31. Furthermore, the analysis shows that implementing the switch to biomass results in a maximum CO_2 reduction of 4 gigatonnes of CO_2. This CO_2 reduction is equivalent 17% of the total CO_2 emissions projected from the existing fleet.

B.4.3 Retiring Existing Plants

The plants that are not amenable to any of the last three CO_2 mitigation options are the plants that should be retired. These plants are typically the older plants where the capital costs have been fully amortized. The cost of retiring and replacing these plants is going to be mainly a function of the technology that replaces the coal generation. Taking the levelized costs of new generation provided by the EIA[146] and dividing it by the net CO_2 savings (average CO_2 emissions per coal plant of 2249 lb/MWh minus that of the other generation technology) gives the CO_2 abatement costs:

Table 23: Levelized Cost of Electricity, Life Cycle (LC) CO_2 Emissions , and the Abatement Cost for the Different Electricity Generation Options.

Generation Technology	Levelized Cost (\$/MWh)[147]	CO2 emissions (gCO2eq/kWh)[148]	Abatement Cost (\$/ton)
Old Coal	109.4	1080	(Infinite)
CCS	136.2	120	141.9
Conventional Natural Gas Combined Cycle (NGCC)	66.1	520	118.0
Existing NGCC	38.1	520	21.2
Advanced Nuclear	113.9	10	106.4
Wind	97	12	90.8
Solar PV	210.7	56	205.8
Hydro	86.4	8	80.6

According to table 23 above, the cheapest retirement option is replacing the retired coal plant with the existing underutilized NGCC fleet. This is because, assuming sufficient flexibility in the delivery systems as well (electricity transmission lines and natural gas pipeline) no additional capital expenditures are required. The additional costs incurred are going to be the difference in fuel costs for both plants.

B.5 Comparison of CO_2 Mitigations Options for the Existing Coal Fleet

The CO_2 abatement costs for the different CO_2 mitigation options are summarized in Figure 34 below. A detailed description of the data and models used to construct this figure are given in the following section.

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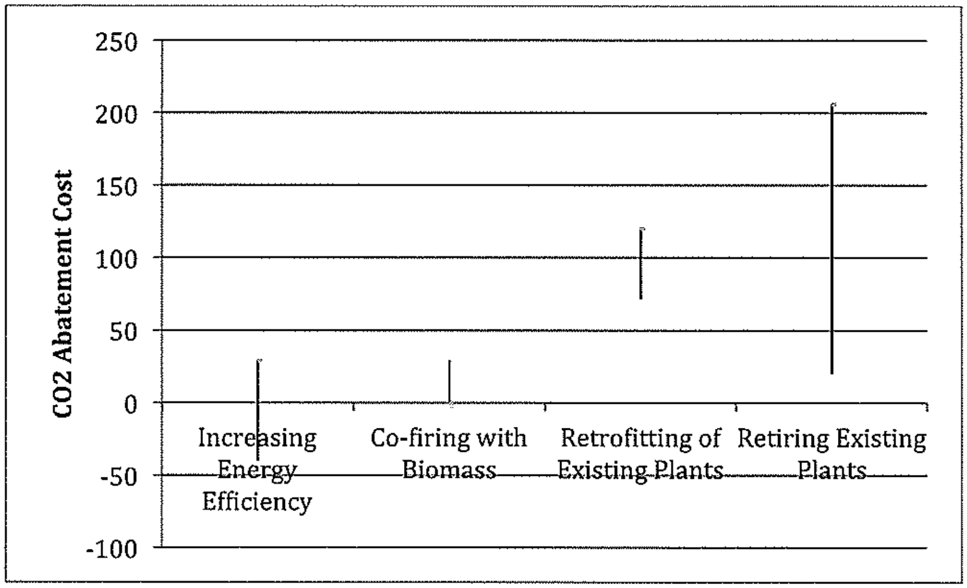
[146] EIA, Levelized Cost of New Generation Resources in the Annual Energy Outlook 2011, http://38.96.246.204/oiaf/aeo/electricity_generation.html, accessed on November 11th, 2011.
[147] Ibid.
[148] D. Weisser, "A guide to life-cycle greenhouse gas (GHG) emissions from electric supply technologies," *Energy* 32, no. 9 (2007).

Figure 34: 95% Confidence Interval for the CO_2 Abatement Costs for the Different CO_2 Mitigation Options.[149]



The cheapest CO_2 mitigation option at a modest mean abatement cost of $3 is increasing the energy efficiency of the existing plants. Although this is the most attractive option in terms of cost, this option is limited in scale as it can at best reduce the emissions of the existing fleet by 0.48 gigatones, which is equivalent to around 9% of the annual CO_2 emissions in the U.S. To get a better estimate of the CO_2 emission reductions associated with this option, a comprehensive study of each individual plant must be carried out to determine the specific plant improvement. The second most attractive option in terms of abatement costs is co-firing the plants with biomass. The majority of the existing plants from a technical perspective can adopt this option; the main obstacle to the wide deployment of such an option is the local availability of high quality, low cost biomass. Even if an infinite supply of carbon neutral biomass is assumed, analysis shows that maximum CO_2 emission reductions that can be achieved using this option is equal to 7.5% of the total (over the remaining life of the plants) projected coal-fired CO_2 emissions. Therefore, even if the upper limit is achieved, this option is limited in terms of CO_2 reductions.

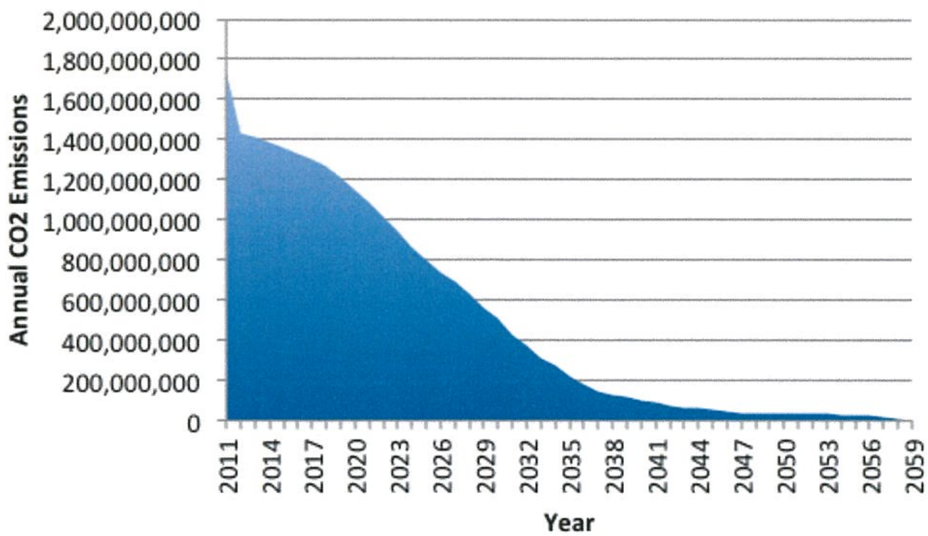
The third option of retrofitting existing plants with CCS technologies is widely applicable (~59% of the existing fleet is technically amenable for retrofit[150]) however, with current technologies,

149 Co-firing with biomass was done for one fuel (wood residue)

this option is prohibitively expensive due to the high CO_2 capture costs. R&D into new capture technologies and early demonstration projects might help drive down capture costs.

Finally, retiring existing plants and replacing them with the underutilized NGCC capacity seems to be the most attractive short-term option. According to the MIT Future of Natural Gas Study, 20% of the projected CO_2 emissions from coal-fired plants could be reduced at a modest cost of $20 per ton of CO_2 abated. Even if this final option is implemented (i.e. plants that are older than 50 years are retired), one sees that the projected CO_2 emissions from the existing fleet are still significant as shown in Figure 35 below.

Figure 35: Projected Annual CO_2 Emissions From the Existing U.S. Coal Fleet. [151]



[152]

Computing the area under Figure 35 above reveals that the projected CO_2 emissions from the existing coal fleet amount to around 24 gigatonnes. This demonstrates that CO_2 mitigation options beyond retiring plants must be explored. Given the limited scale of increasing the energy efficiency of the existing plants and co-firing with biomass by elimination, the most scalable option is then retrofitting existing coal-fired power plants with CCS technologies.

[150] Initiative, "MIT Energy Initiative Symposium Report on the Retrofitting of Coal-Fired Power Plants for CO2 Emissions Reductions."
[151] EIA, " EIA-860 Annual Electric Generator Report."
[152] It was assumed: i) plants on average retire at that the age of 50 years, ii) emissions from the existing power plants remain constant at 2009 emissions rate and iii) no further coal plants are built

For the CCS option to be deployed on a large scale in the U.S. and in other developing countries (primarily China and India), capture costs of CCS systems must be brought down significantly. In order to achieve this significant reduction in capture costs, a comprehensive R&D program focused on developing CCS technologies that are optimized for existing plants (rather than new build plants) must be developed. The other mechanism that can help drive down costs is the deployment of early CCS systems and pilot programs. These early projects are needed to help achieve multi-fold reductions in capture costs and to develop the regulatory basis for sequestration. First adopters of CCS technologies will provide invaluable real-life experience or so the called provide "learning by doing" which will help drive down costs. As discussed in this thesis, utilizing EOR reservoirs for CO_2 storage may provide the early demonstration opportunities that are required to achieve multifold reductions in capture costs.

Appendix C– Characterization of the Saline Formations in the Citronelle Dome

C.1.1 Citronelle Oil Field

As mentioned earlier, the Citronelle Oilfield is located on the tip of the Citronelle Dome as shown in Figure 18 earlier. The Citronelle oilfield has produced more than 169 million barrels of oil over its life and more than 362 million barrels of oil remain in place. The oil has been primarily produced from the Lower Cretaceous sands, which is considered to be part of the Rodessa Formation.[153]

C.1.2 Rodessa formation

The Rodessa Formation found at a depth of around 3,500 meters (11,500ft) is an interbeded shale and sandstone formation that spans more then 230 meters (800ft).[154] The formation is situated above the Silgo formation and beneath the Ferry Lake anhydrite.[155] The formation is composed primarily from the following rock types: i) variegated shale, ii) yellowish quartz and, iii) sandstone.[156] The oil found in the upper Donavan sandstone unit is said to have originated from the Smackover Formation; however, the exact path of migration is not known. After migrating from the Smackover Formation, the oil was trapped in the upper Donvan units due to the excellent reservoir seal created by the shale units. The porosity of the sandstone units found in the Rodessa Formation are equal to 13% and the average permeability of those units is equal to 13md with some places achieving permeabilities higher than 75 md.[157] Stratigraphy of the Rodessa Formation and adjacent Strata is shown in Figure 37 below.

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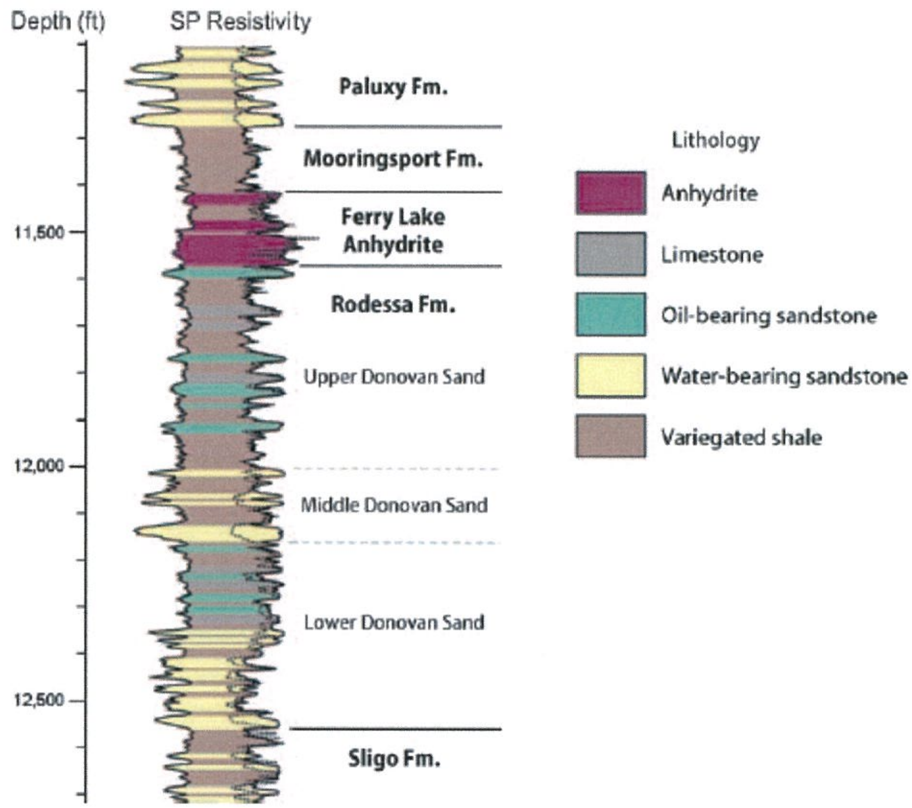
[153] Esposito, Pashin, and Walsh, "Citronelle Dome: A giant opportunity for multizone carbon storage and enhanced oil recovery in the Mississippi Interior Salt Basin of Alabama." P.55.
[154] Ibid. P.55.
[155] Ibid. P.56.
[156] Ibid. P.56.
[157] Ibid. P.58.

Figure 36 Geophysical Well Logs and Stratigraphy of the Rodessa Formation and Adjacent Strata in the Citronelle Dome[158]

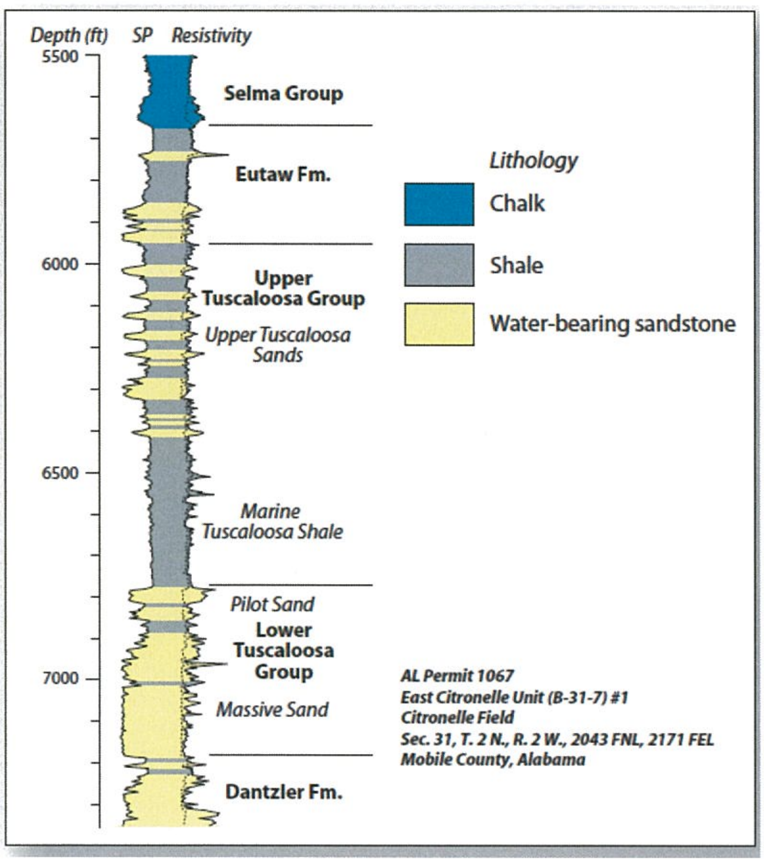


[158] Ibid. P.59.

C.1.3 Eutaw Formation

The Eutaw Formation and the Upper Tuscaloosa group are situated above the oil bearing Lower Cretaceous sands at around 1,830 meters (6,000ft) and with a thickness of 460 meters (1500ft).[159] The Eutaw Formation and the Upper Tuscaloosa group have been used to store the produced water from the Citronelle oil field operation. Storing CO_2 in the Eutaw-Tuscaloosa interval seems attractive based on the experience of storing produced water in the saline sandstone units within that geologic interval. The Eutaw-Tuscaloosa interval is sealed on the top by the Selma Group, which consists of more than 1200ft of chalk. Porosity values for the Tuscaloosa-Eutaw section are around 20% and the permeability for the section varies from 50md to above 3000md.

Figure 37: Geophysical Well Logs and Stratigraphy of the Tuscaloosa-Eutaw Interval and Adjacent Strata in the Citronelle Dome[160]



[159] Ibid. P.58.
[160] Ibid. P.60.

C.2 Saline Storage Model Costs

C.2.1 Site Characterization Costs

The first incurred expenditure when beginning CO_2 storage in a saline aquifer is the cost of the site characterization. Site characterization must be carried out prior to the injection of CO_2. The cost of the site characterization is a function of the regulatory requirements, the history of the area under study (ex: history of active oil drilling) and the size of the area under study. The area under review should be based on the expected areal extent of the CO_2 plume over a long term time period (~100s of years). Nordbotten et al. proposed a way to predict the size of the CO_2 plume and this method was used in McCoy's model.[161] Furthermore, Tomabri estimates that: i) site characterization costs to be equal on average to \$100,000 per square mile for geophysical characterization, ii) \$3,000,000 to drill and log a well where one well is required for every 25 mi^2 under review and, iii) modeling and data processing costs are an incremental 30% of first two costs.[162]

C.2.2 Capital Costs

The capital cost expenditures used in this CO_2 saline storage model can be broken down into three main categories: i) compression equipment, ii) well drilling and completion costs and, iii) injection equipment costs.

The cost of the compression equipment is highly dependent on the pressure level of the CO_2 upon its arrival to the EOR site. If the CO_2 pressure level falls significantly during the journey from the power plant to the oilfield, a recompression pump will then be needed at the EOR field. The cost of the recompression equipment in this model was based on the numbers provided by the International Energy Agency. The cost can be estimated using the following equation:

$$C = 8.35P + 0.49$$ [163]

Where C is the cost of the compressor expressed in millions of dollars and P is the power of the booster pump given in MW. This gives a cost of \$8346 per kW required.

The second major capital cost component is well drilling and completion costs. The costs include, the "cost of physically drilling the well, running casing, hanging tubing, and installing any downhole equipment (e.g., chokes and packers)".[164] Based on the average cost of drilling oil and

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[161] Jan Nordbotten, Michael Celia, and Stefan Bachu, "Injection and Storage of CO2 in Deep Saline Aquifers: Analytical Solution for CO2 Plume Evolution During Injection," *Transport in Porous Media* 58, no. 3 (2005).
[162] McCoy, "The economic of CO_2 transport by pipeline and storage in saline aquifers and oil reservoirs." P.170.
[163] Ibid. P.174.
[164] Ibid. P.174.

gas wells at different depths and across different states, Lewin and Associates developed a regression model that estimates the drilling and completion (D&C) costs. The Lewin and Associates cost model is as follows:

$$C = a_1 e^{a_2 d}$$

where C is the D&C cost per well, a_1 and a_2 are regeression coefficients that are region dependent and d is the drilling depth. The coefficients in the study were based on 2007 dollars from the EIA Oil and Gas Lease Equipment and Operating Cost index and are shown in Table 24 below:

Table 24: Updated Drilling and Completion Regressions Coefficients. [165]

Region	**States**	**Drilling and Completion Regression Coefficients**	
		a_1	**a_2**
1	West Texas	31226	8.57×10^{-5}
2	South Texas	37040	4.54×10^{-5}
3	South Louisiana	39876	3.45×10^{-5}
4	Mid-Continent Region	39876	3.45×10^{-5}
5	Rocky-Mountain Region	29611	7.92×10^{-5}
6	California	38931	6.39×10^{-5}

The final capital cost component in the saline CO_2 storage models is the injection equipment costs. The injection cost numbers used in this model were based on injection costs associated with water injection activities. The EIA annually releases water injection cost numbers for varying injection depths for the West Texas region. The data were then scaled for the other U.S. regions using EIA numbers for the cost of primary oil production equipment. The EIA numbers calculate the cost of adding 11 water injection wells to an operation with 10 existing production wells. The correlation between the injection cost (C_i), the injection depth (d) and the geographic region is given in the equation below:

$$C_i = a_1 e^{a_2 d}$$

The coefficients for the above equation are given in Table 25 below:

[165] Ibid.

Table 25: Injection Equipment Regression Coefficients. [166]

Region	States	Injection Equipment	
		a_1	a_2
1	West Texas	31226	8.57×10^{-5}
2	South Texas	37040	3.54×10^{-5}
3	South Louisiana	39876	3.45×10^{-4}
4	Mid-Continent Region	39876	3.45×10^{-4}
5	Rocky-Mountain Region	29611	7.92×10^{-5}
6	California	38931	6.39×10^{-5}

As mentioned above, the numbers assume some level of existing infrastructure. If the saline site is a greenfield site where no infrastructure exists, then the injection well costs must be scaled up. The equation used to scale the costs is based on a power-law scaling rule:

$$C_{I,n} = \begin{cases} C_I\left(\dfrac{21}{n}\right)^{0.5}, n \leq 21 \\ C_I, n > 21 \end{cases}$$

Where $C_{I,n}$ is the scaled average injection cost for n wells and C_I is the un-scaled injection costs computed earlier. The EIA model shows that economies of scale disappear after the total number of wells in place exceeds 21.

C.2.3 Operating and Maintenance Cost

The operating and maintenance costs in this saline aquifer cost model included the following expenses: i) labor, ii) chemicals and other consumables, iii) expenses related to surface equipment and subsurface equipment that include period well workovers and, iv) energy cost of operating the CO_2 compressor (if applicable). The model assumes that O&M costs are comparable to cost of water injection in secondary oil recovery operations. Similar to the equipment costs provided for water injection, the EIA provides O&M costs for water injection wells operated in secondary oil recovery operations in West Texas. These estimates are provided annually and for a variety of well depths (2000ft, 4000ft and 8000ft). The correlation again is similar to that provided earlier:

$$C_{O\&M} = a_1 e^{a_2 d}$$

The numbers were scaled from the West Texas Region to the other Regions using the EIA estimates for O&M cost of primary production for oil fields located in six regions. The values for

[166] Ibid.

the regression coefficients are shown in Table 26 below.

Table 26: Operating and Maintenance Cost Regression Coefficients.

Region	States	Operating and Maintenance Cost	
		a_1	a_2
1	West Texas	26873	8.57×10^{-4}
2	South Texas	38954	4.54×10^{-5}
3	South Louisiana	38853	3.45×10^{-4}
4	Mid-Continent Region	26790	3.45×10^{-4}
5	Rocky-Mountain Region	32893	7.92×10^{-5}
6	California	29537	1.67×10^{-4}

C.2.4 Monitoring, Verification and Closure Costs

The monitoring and verification costs are mainly dependent on the regulatory requirements imposed at the time. The model at hand bases the monitoring and verification costs on two hypothetical scenarios studied by Benson et al.[167] Both scenarios assumed that 258 million tons of CO_2 are injected over a 30 year period. Furthermore, it is assumed in both scenarios that seismic surveys are performed in year one, two, five and every fifth year thereafter for 80 years. The scenarios varied the residual gas saturation between high and low levels, leading to low and high CO_2 plume sizes respectively. The resulting levelized operational cost of monitoring and verification was equal to \$0.02 per ton of CO_2. The closure costs depend highly on how well the actual behavior of the aquifer conforms to the initial modeling. If the actual performance of the CO_2 storage site is close to the model prediction, then the responsibility of the site can be transferred to the government and in that case closure costs are equal to zero. On the other hand, if difficulties are encountered, then the operator might be forced to assume responsibility of the site for a longer period of time until the site is stabilized. In that case, the operator will incur an incremental cost associated with site closure. Although, there is no empirical evidence to support this, the model assumes that on average, closure costs (if any) will be incurred as a one time payment at the very end of the project (highly discounted) therefore, the costs are relatively insignificant. To deal with this issue, the operator can pay a one-time lump sum payment at the time of closure. Alternatively, a small fee can be collected in a fund over the life of the project (similar to the decommissioning cost collection mechanism for nuclear plants) to deal with any closure costs. Given the high uncertainty and high discount rate associated with closure costs, these costs were assumed to be zero for the purpose of this study.

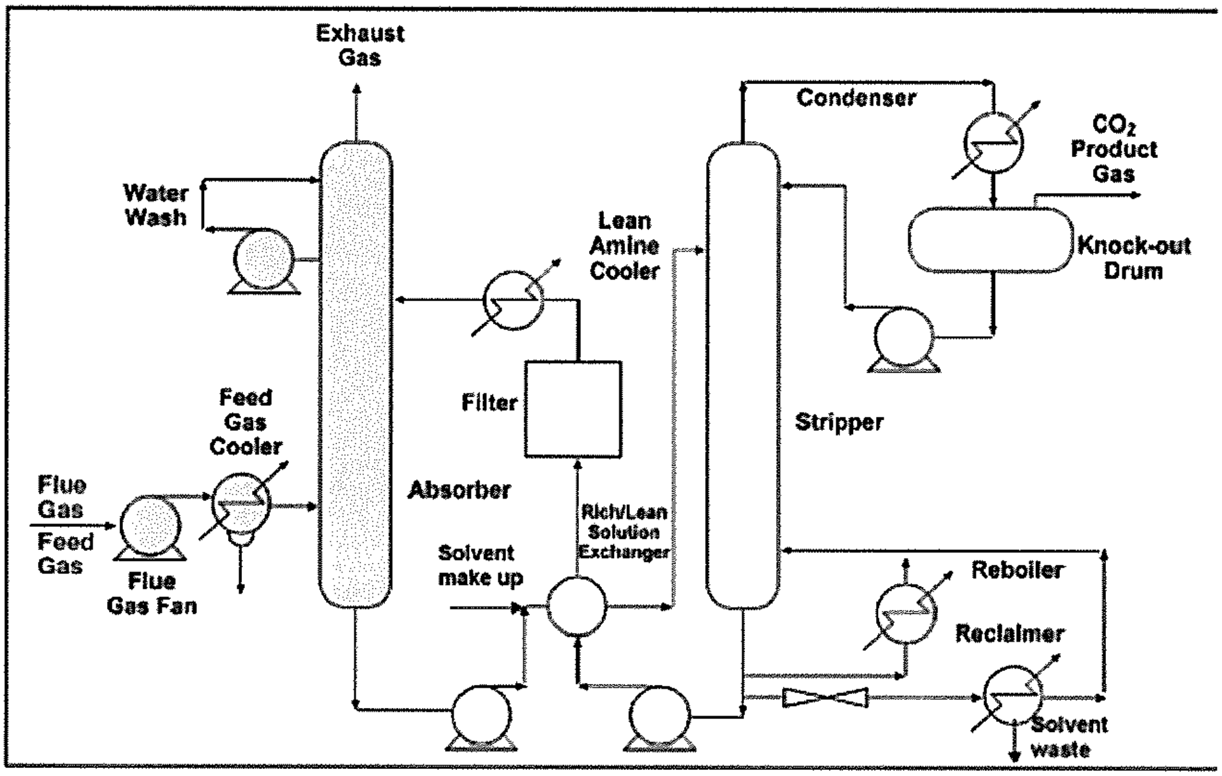
[167] Benson, S.M., et al. Monitoring Protocols and Life-Cycle Costs for Geologic Storage of Carbon Dioxide. in 7th International Conference on Greenhouse Gas Control Technologies. 2004. Vancouver, Canada: Elsevier Science.

Appendix D– Post Combustion Capture

As mentioned earlier, post combustion absorption processes rely on the chemical reversibility of the reaction between the aqueous alkaline solvent and the CO_2. The solvent is chosen such that CO_2 has a high affinity to solvent. Typically, an amine (organic compound) is used as a solvent. The process begins by cooling the flue gas to temperatures around 40-60°C to better facilitate the absorption process. After the flue gas is cooled down, it is then passed through the absorber column where it comes in contact with the solvent and forms a chemical bond. In some cases, a blower is employed to help overcome pressure drops in the absorber. High CO_2 absorption rates (low CO_2 concentrations in the exiting flue gas stream) can be achieved by lengthening the height of the absorber column. The final stage in the absorber involves a water section that is designed to balance the water in the system and remove any remaining droplets of the solvent or the solvent vapor.[168] The CO_2 rich solvent is then pumped into the regeneration vessel (stripper) via a heat exchanger. The temperature of the solvent is raised in the regenerator up to 100-140°C using a reboiler; steam is also added to help strip the CO_2 from the solvent. Due to high temperatures that exceed the solvent desorption temperatures and the presence of the steam "stripping gas", the CO_2 disassociates from the solvent. The CO_2 leaves the regenerator and the steam goes through the condenser where it is resued again to strip the CO_2. The lean solvent exits the regenerator and is passed back through the heat exchanger to pre-heat the rich solvent coming into the regenerator. The lean solvent is cooled further to bring the solvent back to the conditions necessary to absorb the CO_2. The heat added to raise the temperature of the solvent and provide the steam is where the first major energy penalty is incurred in the CCS system. Other equipment seen in Figure 38 such as filters help maintain the solution quality by preventing the formation of corrosion and the degradation of products.

[168] Metz and Intergovernmental Panel on Climate Change. Working, *IPCC special report on carbon dioxide capture and storage.*

Figure 38: Diagram of a Post Combustion CO_2 Absorption System.[169]



According to the IPCC report on capture technologies, the key parameters determining the technical and economic operation of a CO2 absorption system are:

Flue gas flow rate: determines the size of the absorber. The absorber itself represents a significant portion of the overall cost.

CO2 content in flue gas: the flue gas exiting the plant is usually at atmospheric pressure. The partial pressure of the CO_2 in the flue gas can be as low as 3-15 kPa. The most suitable separation technologies under these low CO2 partial pressure conditions are aqueous amines (chemical solvents) technologies.

CO2 removal: CO_2 recoveries can go as high as 99%. The higher the recovery rate the taller the absorption column, the higher the energy penalties and hence the larger the capital and O&M costs.

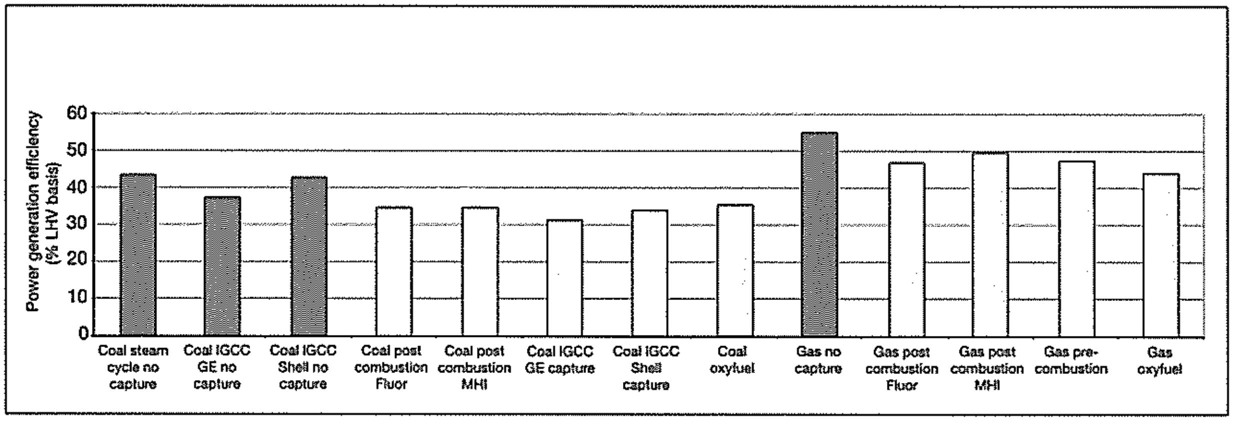
Solvent flow rate: apart from the absorber, the solvent flow rate dictates the size of the equipment

[169] Ibid. P.115.

in the system. For a specific solvent, the flow rate will be fixed by the CO_2 recovery rates and the other previously set plant parameters.

Energy requirement: energy in the form of heat is needed primarily to regenerate the solvent and in the form of steam for stripping the CO_2. Other less energy intensive requirements include electricity needed to operate the pumps, blowers, fans and CO_2 compressors. Figure 40 below shows the energy efficiency of different power generation systems with and without CO_2 capture. For instance, the energy efficiency of a coal steam cycle drops from 43% without CO_2 capture to 34% with a CO_2 capture system that employs the Flour Daniel process.

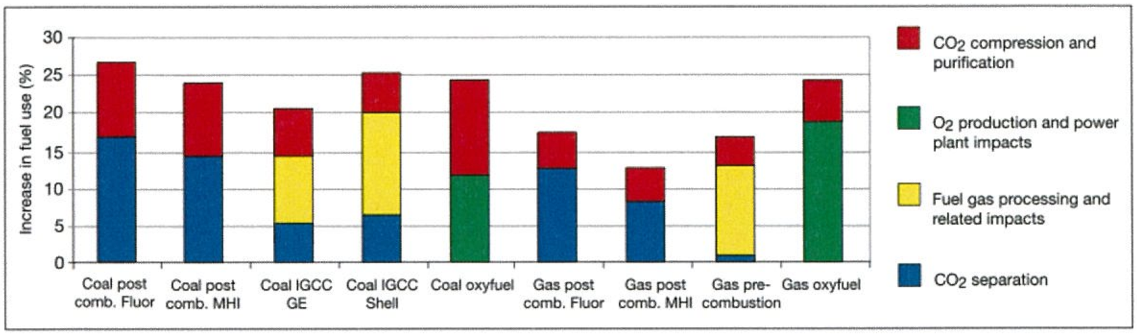
Figure 39: Power Efficiencies of Different Power Generation Systems (With and Without CO_2 Capture. [170]



Depending on the solvent process, typical heat requirements for the leading absorption technologies range between 2.7 and 3.3 GJ/ Ton of CO_2.[171] Typical values for the electricity requirement are between 0.06 and 0.11 GJ/ Ton of CO_2 for post-combustion capture in coal-fired power plants.[172] According to the IEA Green House Gas programme, compression of the CO_2 to 110 bar will require around 0.4 GJ/ton of CO_2.[173] Figure 42 below shows the percentage increase in fuel use per kWh of electricity due to CO_2 capture.

[170] Ibid. P.118.
[171] Ibid. P.117
[172] Ibid. P.117.
[173] Ibid. P.117.

Figure 40: Percentage Increase in Fuel Use per kWh of Electricity Due to CO_2 Capture, Compared to the Same Plant Without Capture. [174]



Cooling requirement: cooling is required to decrease the temperatures of the flue gas and the solvent to allow the efficient absorption of CO_2. Furthermore, the product from the stripper requires cooling in order to recover steam from the stripping process.

Choice of solvent: is one of the main factors behind an economically and technically successful CO_2 absorption process. The combustion of the coal typically occurs at atmospheric conditions and as a result, the CO_2 in the flue gas stream is diluted (CO_2 has a low partial pressure). As a result, it is very important that the solvent used has the following characteristics: i) high CO_2 loading, ii) low heat of desorption energy, iii) low byproduct formation and, iv) low decomposition rates.[175] Solvents need to be replaced on a constant basis as they are consumed due to the formation of heat stable salts and to the decomposition of products.

Flue gas pretreatment: The flue gas also contains NO_x and SO_x components from the combustion of coal, these components interact with alkaline solvent in an irreversible reaction to form heat stable salts that result in loss of the solvent. Therefore, these components must be removed to minimize overall operation costs (sorbent purchases). The SO_2 content of the stream prior to the CO_2 absorption process is a cost trade-off between CO_2-solvent consumption and SO2-removal costs.[176] Typical SO_X concentrations are around 10 ppm.

[174] Metz and Intergovernmental Panel on Climate Change. Working, *IPCC special report on carbon dioxide capture and storage*. P.119.
[175] Ibid. P.117.
[176] Ibid P.117.