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ECONOMIC ANALYSIS OF AN INTEGRATED ANTHROPOGENIC CARBON DIOXIDE NETWORK FOR CAPTURE AND ENHANCED OIL RECOVERY ALONG THE TEXAS GULF COAST

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ABSTRACT

This paper explains the system economics of an example integrated network that uses anthropogenic CO_2 from Texas Gulf Coast fossil power plants for enhanced oil recovery (EOR). These CO_2 sources and sinks are connected via a pipeline network. A discounted cash flow model indicates that for all candidate oil fields that require less than an estimated \$10/BBL in EOR capital expenditure, all three entities (CO_2 capture, pipelines, and EOR operators) can have 20% internal rate of return at \$55 per tonne of CO_2 and \$56 per barrel of oil. These results include no existing or future tax incentives, and there are some costs not yet included. However, a Monte Carlo analysis shows insight by indicating that the total system rate of return is most sensitive to oil production parameters. Oil price and estimated amount of recoverable oil are the most positively influential factors while the EOR capital cost is the most negatively sensitive factor. The capital costs of capture and CO_2 price are less sensitive, both negatively affecting rate of return.

Keywords: carbon dioxide, capture, sequestration, enhanced oil recovery, economics

1. INTRODUCTION

Texas has played a pivotal role in the history of the energy industry and will continue to play a major role into the future. This future will likely include a price on emissions of greenhouse gases of which carbon dioxide (CO_2) is a major component. By planning ahead for this future "carbon constrained world", Texas can not only mitigate the negative economic impact to Texas industries, but may actually profit relative to other states and countries. The reason for this is that Texas can use CO_2 in enhanced oil recovery (EOR) operations. The revenue from the resulting oil sales can help pay for infrastructure utilized to capture and sequester CO_2 after the recoverable oil has been removed. The use of anthropogenic CO_2 for Texas EOR can act as a springboard for Texas companies and workers to gain further expertise in EOR and geologic sequestration techniques such that Texas can export this knowledge to the rest of the world. This paper explains an example scenario network that can use anthropogenic CO_2 for EOR using a subset of the Texas Gulf Coast resources.

In 2008 Texas was the number one producer of both oil and natural gas in the United States. Part of this success is due to the capability of the oil and gas industry to use newer exploration and production techniques to obtain resources from previously unobtainable locations such as shale. In particular, what is now common in Texas is the use of carbon dioxide (CO_2) in enhanced oil recovery (EOR) tertiary recovery operations in the Permian Basin. The overwhelming majority of CO_2 used for this EOR production obtained from natural sources in New Mexico and Colorado.

There are many additional oil reservoirs in the state that could economically produce oil using EOR techniques, but the CO_2 is generally unavailable. The Texas Legislature has previously recognized this potential by passing tax incentives in HB 3732 (2007) for the use of anthropogenic CO_2 in EOR and subsequent sequestration. Additionally, the Energy Independence and Security Act of 2007 created monetary incentives for using anthropogenic CO_2 for EOR. No entity is currently taking advantage of these incentives as there is no readily available source of anthropogenic CO_2 in Texas. Some companies now have plans to use anthropogenic CO_2 for EOR in Texas.

Along the Texas Gulf Coast region there are many point sources of CO_2 as well as oil reservoirs in decline that could benefit from available CO_2. This report discusses a scenario that matches some of these CO_2 sources and oil reservoirs. By facilitating such a scenario, the state of Texas can play a technical and environmental leadership role for both energy and environment concerns while at the same time create economic and employment benefits for the state that help Texas transition to a new energy future.

This paper first explains the scale of CO_2 emissions in Texas, the U.S. and the world. Then, in describing the Gulf Coast region of Texas, seven existing candidate anthropogenic CO_2 sources are matched with twenty-two major oil fields. The multiple input sources and multiple consumers are connected via an integrated pipeline network that provides operational flexibility at both ends of the pipe. The conceptual project scenario presented in this report is only a very high level view of the basic constituents and costs. There are many other important ideas and details that will have to be determined before an integrated CO_2 system can become a reality.

2. ANALYSIS BACKGROUND AND ASSUMPTIONS

In 2005, Texas emitted 625 million metric tons of CO_2 - over 2% of the world's CO_2 and 10.4% of the U.S. total [1, 2]. Texas emits more CO_2 than any state in the country. This emission rate is not without justification as Texas refines much of the nation's oil and produces a disproportionate share of chemicals and other industrial goods. Thus, Texas does much of the nation's 'dirty work', and as consumers continue to purchase goods from Texas industries, Texas economy as a whole need not disproportionately suffer under greenhouse gas regulation and policy.

In fact, Texas can benefit from matching producers of CO_2 to consumers of CO_2. Primarily, these producers can be large electricity generation plants ranging in installed capacity from a few hundred MW to over 2,000 MW. The consumers are reservoir owners that control mineral rights to the oil in place. Over the past 35 years, a long distance CO_2 pipeline network has been constructed and used for EOR in West Texas. This CO_2 is obtained from natural CO_2 reservoirs. Not until climate concerns have become paramount had there been much reason to connect anthropogenic sources of CO_2 to geologic sinks for either pure permanent sequestration or EOR purposes.

A large share of Texas' CO_2 emissions exists along the Gulf Coast and southern central and east Texas. Within 100 miles of the Texas coast, there is over 8,000 MW of installed coal power plant capacity. There is also over 4,600 MW of natural gas generation capacity with generation units above 400 MW. Additionally, many oil reservoirs in decline exist along the Texas coast from Brownsville to Beaumont. No pipeline currently exists to connect fossil power plants as CO_2 generators (sources) to EOR reservoirs as consumers (sinks).

This section describes an example scenario for combing specific power plants to specific EOR candidate oil reservoirs via an integrated multi-input multi-output (MIMO) pipeline network. The advantage of this MIMO approach is that there is flexibility for any given power plant to temporarily halt power generation and CO_2 supply due to unforeseen or planned maintenance without unduly affecting EOR operations at a particular field. On the other side of the pipeline, any given oil field is able to halt intake of CO_2 for any operational reasons without unduly affecting operations at any one given power plant. This advantage of the MIMO approach mimics that of the electricity transmission system where there are multiple generators (power plants), multiple consumers (homes, businesses, and industry), and an open-access transmission network (power lines) connecting generators to consumers.

2.1 Candidate EOR Fields

Previous work performed at the Gulf Coast Carbon Center (GCCC) of the Bureau of Economic Geology (BEG) categorized and identified oil reservoirs that would be candidates for CO_2-based EOR [3]. Throughout Texas over 1,700 oil reservoirs were identified that can be flooded with CO_2 to produce extra oil through EOR [3]. The estimated total EOR production from each reservoir varies from tens of thousands to hundreds of millions of barrels (BBL).

Instead of considering all oil fields in Texas, the GCCC created selection criteria to find a subset of oil fields in the Gulf Coast region where EOR is a possibility. Reservoirs that are candidates for CO_2 EOR are those that are at an advanced stage of waterflooding or aquifer encroachment [3]. One of these criteria was a future EOR minimum lifetime field production of 13 million BBL when assuming a 15% recovery of original oil in place via EOR. Additional feasibility criteria considered the geology of the reservoirs to only include those reservoirs that can use the miscible CO_2 EOR method [3]. No reservoirs were included as candidates for CO_2 EOR unless the reservoir minimum miscibility pressure (MMP) was less than the initial reservoir pressure. This excludes reservoirs for which miscible CO_2-based EOR is not effective.

Table 1. Upper and lower bounds are given for the important operational parameters that govern the candidate oil fields analyzed in this document.

EOR Operational Parameters	units	Lower Bound	Upper Bound
CO_2 requirements			
Gross CO_2 injected during EOR #	Mscf/BBL*	5	15
Gross CO_2 injected during EOR	tonne/BBL	0.26	0.79
Recycled CO_2 injected during EOR #	Mscf/BBL*	2	9
Recycled CO_2 injected during EOR	tonne/BBL	0.11	0.47
Net CO_2 sequestered during EOR #	Mscf/BBL*	3	6
Net CO_2 sequestered during EOR	tonne/BBL	0.16	0.32
Oil Production			
Cumulative production of all candidate reservoirs^	BBL	5,500 million	5,500 million
Original Oil in Place (OOIP) in candidate reservoirs^	BBL	Twice cumulative production	Twice cumulative production
Production of OOIP achievable by CO_2 - EOR #	%	7	20

[4]; ^ [3]; * Mscf/BBL is 1,000 standard cubic feet of CO_2 per barrel of oil from EOR. 19 Mscf CO_2 ~ 1 metric tonne CO_2.

Out of the complete list of Texas EOR-candidate oil fields there were 26 major fields, composed of 115 reservoirs.

There are known and unknown parameters that make the predetermination of the ultimate quantity of oil produced via EOR an inherently uncertain quantity. However, a few major oil field parameters are needed to determine the size and scope of the integrated CO_2 network that is required to deliver the needed CO_2 for EOR. Table 1 displays the major EOR and reservoir operational parameter ranges that were used to predict the quantity of oil that is recoverable from the candidate reservoirs. These parameters ultimately project the number of power plants required to supply the CO_2 to the oil fields.

The recoverable oil via CO_2-based EOR can range from 7% - 20% of the estimated original oil in place (OOIP) [4]. By using the upper and lower bounds of CO_2 required per BBL of oil from CO_2-flooding, the amount of CO_2 required is estimated. The amount of CO_2 injected (i.e. gross CO_2 injected) in traditional CO_2 -flooding is greater than the actual amount of CO_2 stored (i.e. net CO_2 purchased and injected) because CO_2 produced with oil is recycled and re-injected [4].

The estimated recoverable oil from the 26 candidate major oil fields is 780 – 2,240 million BBL. In order to extract this oil using existing practices, a net of 120 – 710 million metric tonnes of CO_2 ($MtCO_2$), will be required.

Figure 1 shows the general profile of the expected oil production from the candidate oil reservoirs. This production profile is chosen to fit within a 20-year schedule and represents an abstraction of typical profiles from EOR production that reach peak production in 4-5 years followed by a steady decline until no oil is produced.

The required net CO_2 injected is assumed to follow a similar profile as the oil production except peaking 1-2 years earlier (Figure 1). An annual average over 20 years of 6 - 35 $MtCO_2$/yr would be required to be delivered to the EOR field, for 120-710 $MtCO_2$ total, respectively. This annual CO_2 rate represents a situation where CO_2 is captured and injected at a constant rate over the 20-yr time span assumed for the EOR fields. Additionally, there can be CO_2 captured at the power plants that cannot be used for EOR, but can be injected into the depleted reservoirs that are no longer producing oil. This CO_2 is represented by the green region of Figure 1.

2.2 Candidate Power Plants

The assumption of this report is that there are available point sources of CO_2 emissions in the Gulf Coast region that can supply the required CO_2 for the candidate oil fields. Thus, this report only discusses the retrofitting of existing power plants based upon pulverized coal or petroleum coke burning technology. This assumption necessarily neglects the analysis of building any new power plants specifically designed from the ground up to capture CO_2. Therefore, the construction of new integrated gasification combined cycle power plants, such as the designs considered for the former Department of Energy FutureGen program, is not considered.

There are three available process technologies which can in principle be used to capture CO_2 from flue gases of power plants, (many more in various levels of research and development) namely [5]:

- **Absorption** processes where the CO_2 capture is accomplished through separation with sorbents/solvents.
- **Membrane** processes where CO_2 is selectively removed from a gaseous stream using membranes made up of polymeric and metallic ceramics.
- **Liquefaction and distillation** processes where CO_2 is removed through a cycle of compression and distillation.

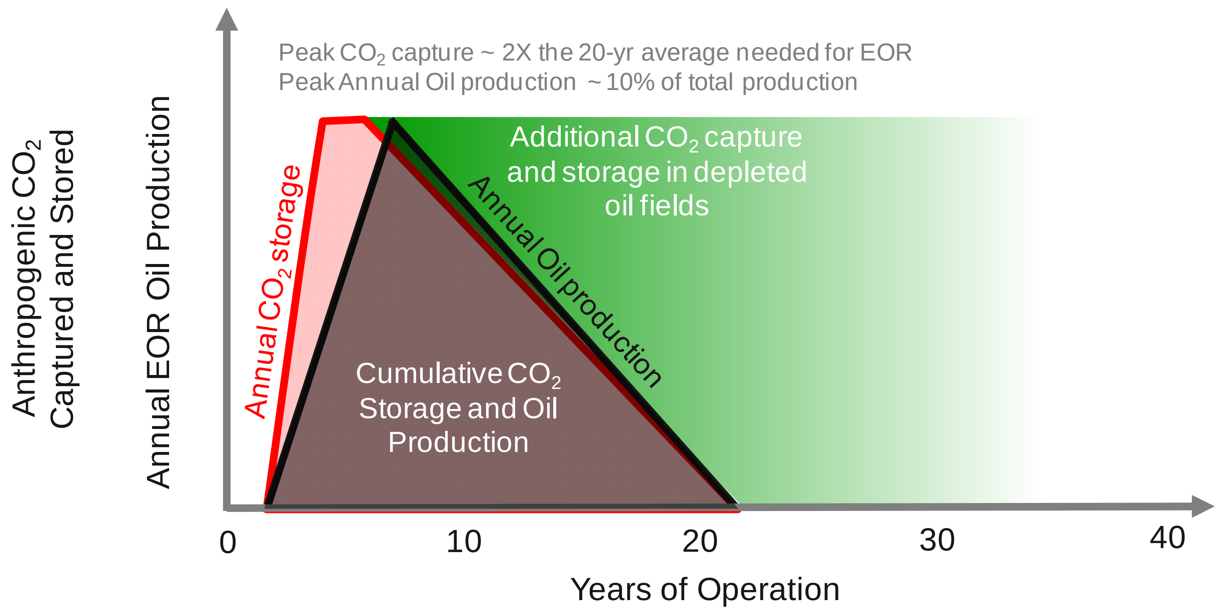

Figure 1. The analyzed scenario assumes that a maximum rate of approximately 2 times the average amount needed (6 – 35 MtCO$_2$) for the assumed 20-yr EOR project lifetime. After the locations in the EOR fields no longer viably produce oil, those same fields can potentially be used as CO_2 sequestration locations for another 10-30 years after EOR production ceases.

Of the three, absorption processes based on amines are said to currently offer high capture selectivity and have relatively well-known energy use and costs. The absorption processes is the most advanced commercial process that is currently being used worldwide. Thus, we assume an amine CO_2 absorption process will be retrofitted onto the existing power plants in Table 2.

The amine capture chemical process requires heat in the form of steam to release the captured CO_2 from the absorbing amine such that the amine is 'regenerated' and ready to capture more CO_2. This steam used the capture plant would otherwise be used to run through the plant turbines for generating electricity. For new coal plants with the same net power generation, approximately 43-48% more coal is required to generate more heat (steam) and electricity to run the amine capture process and compress the CO_2 for pipeline transmission [6]. Approximately 14%-20% of the extra needed energy goes into gross electric power generation for pumping and CO_2 compression. In retrofitting an existing power plant with a CO_2 capture plant, the plant operator has the option of constructing an additional boiler, turbine, and generator to create the additional heat, steam, and power required by the CO_2 capture process. For a retrofitted subcritical pulverized coal plant a similar estimate of 33%-42% of the gross energy of the power plant (coal input) is assumed allocated to capture process [5 – Table 3.8].

Because the amine post-combustion capture process has been practiced in industry, albeit at a smaller scale, it sets a target for newer technologies to beat. Because the auxiliary energy requirements are high and the associated added infrastructure will be on the scale of an existing coal plant, there exist ample incentives to find new CO_2 capture technology. Thus, by assuming amine post-combustion capture, we believe we are estimating near an upper cost bound.

For the calculations of this report, a value of 42% is assumed as the percentage of net equivalent power (electricity) of the power plant must be diverted as heat and auxiliary power used for CO_2 capture. For example, if a power plant before retrofit for CO_2 capture has a 500 MW net power capacity, after retrofit its net power capacity is assumed as 290 MW when using existing infrastructure to power the CO_2 capture process.

The cost range used in this report for CO_2 capture infrastructure originates from the special report by the Intergovernmental Panel on Climate Change: Carbon Dioxide Capture and Storage [5]. This report summarizes cost estimates from peer-reviewed literature discussing economics of CO_2 capture. The assumed cost of the capture plant is $600 – $1,600 per kW of the subtracted power generation and heat capacity [5]. The cost range is very large and results from the fact that all costs are estimates based upon modeling because no systems at the scale of a power plant have been constructed. The reference case economic scenario described later uses the middle value of $1,100/kW.

The capital investment for retrofitting power plants assumes (1) a chemical amine plant that absorbs CO_2 from the plant flue gas, (2) dehydration and compression equipment that increases the pressure of CO_2 to levels required for pipeline transmission, and (3) the capital plant design where existing steam and plant power generation is used to operate the CO_2 capture processes, thus *reducing the net power capacity of the plant during CO_2 capture* (Table 2).

Table 2. Candidate power plants and their parameters for retrofitting with post-combustion CO_2 capture and compression infrastructure for capturing 90% of CO_2 emissions. Capturing CO_2 from only a subset of the listed plants and boiler units is sufficient to supply the candidate EOR fields. SUB = subbituminous coal, LIG = lignite, PC = petroleum coke.

Candidate Plant Names	Installed Capacity (MW)	Potential CO_2 capture ($MtCO_2$/yr)°	Subtracted Plant Capacity* (MW)
Coleto Creek (SUB)	570	3.9	239
San Miguel (LIG)	410	2.8	172
J.K. Spruce (SUB)	546	3.8	229
J.T. Deely (SUB)	892	6.2	375
AES Deepwater (PC)	184	1.3	77
W.A. Parish (SUB)	2,700	20.0	1,135
Fayette Project (SUB)	1,690	11.7	710
TOTAL	**8,260**	**50**	**2,937**

° Power plants are assumed to operate at 85% capacity factor, 90% of CO_2 emissions captured. The CO_2 emissions are approximately 0.15 tCO_2/MWh of net generation during 90% capture.
** The Subtracted Plant Capacity is the existing plant power and heat that is assumed used to operate the CO_2 capture processes.*

It is important to note that the summer peak power capacity of the power plants with CO_2 capture can be the same as without CO_2 capture by turning off the CO_2 capture process during the peak demand times [7-9]. Turning the CO_2 capture off during summer peak demand (hours, days, or months) is an option that is likely feasible for avoiding the higher capital investment costs associated with constructing more power plant capacity. Each power plant is assumed to operate at 85% capacity factor over the course of each year while capturing 90% of total CO_2 emissions. The average CO_2 emissions rate of the existing Texas coal power plant fleet is approximately 1.03 metric tonnes[1] (tCO_2) per net megawatt-hour (MWh) exported to the electric grid [10]. After capturing 90% of emissions from a coal plant, the emissions rate of net generation is estimated at 0.15 tCO_2/MWh.

From looking at the candidate power plant list in Table 2, not all of the power plants will require CO_2 capture systems to supply the CO_2 for the EOR fields. For the 20-year EOR field lifetime assumed in this report, an average of 6 – 35 $MtCO_2$/yr is required. Thus, for the low end of the range of CO_2 requirements, only 2-3 power plants (1,000 MW of existing net power capacity) would be required for retrofit. However, for the upper end of the CO_2 requirements, 4-6 of the power plants (up to 5,250 MW of net capacity) would require CO_2 capture installation on some or all of their generation units.

2.3 Pipeline Network

Capturing and compressing CO_2 for transport via pipelines is not a new engineering feat, but filling a pipeline with anthropogenic carbon dioxide from multiple sources to multiple locations will be new. However, some private industry companies operating in Texas are currently planning on being part of the value chain from capturing CO_2 from fossil power plants to injecting it into the ground for EOR and sequestration [11]. A few other initial plans exist for supplying anthropogenic CO_2 to both the Permian Basin and specific East Texas oil fields.

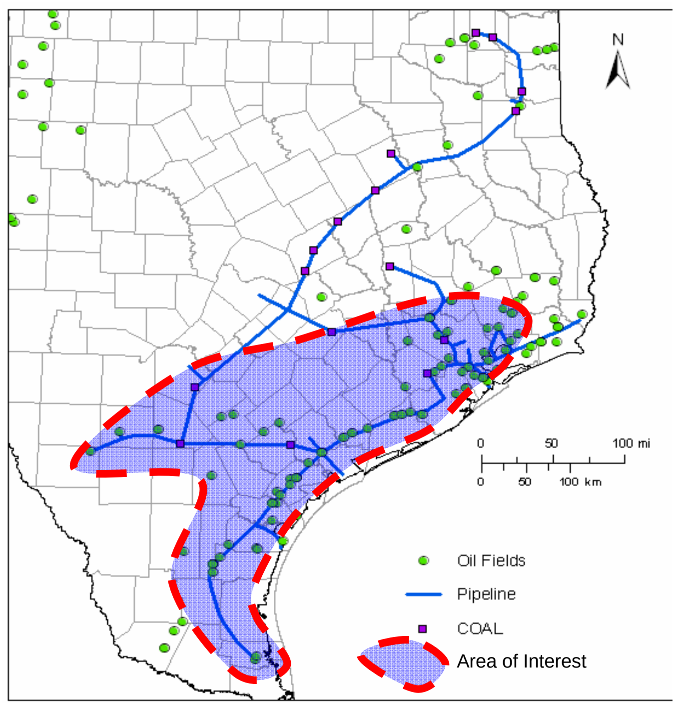

Figure 2. The area of interest analyzed in this report is mostly the area within 100 miles of the Gulf Coast from Houston almost to Harlingen and could include coal power plants as inland as Bexar and Fayette Counties.

An integrated pipeline network was designed to connect the candidate EOR reservoirs with all seven of the selected power plants[2]. Figure 2 indicates the area of interest in the

[1] 1 metric tonne = 1.102 short tons

[2] All seven power plants were selected as to estimate a reference *pipeline* path to serve EOR fields in the upper range total pipeline length needed for oil production and CO_2 requirements.

shaded region and shows the relative position of the major pipeline sections. Note that there are many other viable pipeline paths that can connect the selected power plants to candidate oil reservoirs. The total pipeline path is approximately 1,000 miles long composed of pipes varying in diameter from several inches to a few feet. The preliminary pipeline paths were chosen to avoid sensitive environmental areas, state and national parks, and other restricted lands. Figure 2 shows other future pipelines that can be built to connect existing coal plants to create an even more robust integrated CO_2 network.

2.4 Costs: EOR

There are many assumptions often made in order to predict the economic costs for oil field capital equipment and operation and maintenance (O&M) related to EOR. In calculating the capital and O&M costs for EOR operations one can involve many assumptions about what and how many facilities and wells already exist at the field in addition to how many new wells are to be drilled. The major assumptions are described in this section.

For production wells, no new production wells are assumed needed to be drilled. However, significant "workover" is required on the existing production wells to prepare them for the CO_2 and oil solution flowing through them. Thus, the capital investment required for the wells is less than that required for drilling a new well. For the 26 candidate fields there are an estimated required 9,600 production wells, all assumed in existence. The capital cost for preparing each existing well is assumed as the sum of 50% of the cost of production equipment for a new well and 48% of new drilling and completion costs [4]. The costs for production equipment and drilling and completion costs is taken from both McCoy (2008) and Advanced Resources International (2006) to compare slightly different sources and methodologies.

We assume one injection well is needed for each production well, for a 1:1 ratio. As a conservative economic approach that will not underestimate the costs, all 9,600 injection wells are assumed new. In reality, there may be a significant number, if not all, of the injection wells that were formerly used for water flooding injection during secondary oil recovery. These former water-flooding injection wells could only require minor modifications, such as new wellheads for CO_2 injection [4]. However, past industry experience indicates that converting old water injection wells for CO_2 injection usually creates too many difficulties. The EOR capital costs for injection wells include lease equipment, injection equipment, and the drilling costs for the new well.

Capital costs for CO_2 processing equipment are based upon the peak quantity of CO_2 that needs to be processed. That is to say, the largest flow rate of CO_2 that is recycled (dehydrated and compressed) when brought up from a production well dictates the required capacity size of the processing capital equipment. For the capital cost calculation, we estimate the peak recycle flow rate as the average CO_2 recycle rate over the 20-year assumed field operation. The capital cost value of 700,000 \$/avg million scf CO_2 processed is used for CO_2 processing equipment [12].

The EOR O&M costs are assumed as in ARI (2006) as 0.50 \$/Mscf of processed (recycled) CO_2 plus 0.25 \$/barrel of total fluid (oil, CO_2, and water) lifted from the well. The value of 0.60 \$/BBL of oil (assuming over the life of the well that 42% of fluid lifted is oil) is used as in McCoy (2008). These amount to a final O&M assumed cost of \$5.6/BBL.

2.5 EOR Field Optimization for Reference Case

After the initial screening process for choosing oil fields for EOR, we ranked them in order of increasing capital investment cost ration of \$/BBL. We also assumed a reference recovery factor of 12% of the original oil in place. This choice establishes a reference case for the cash flow analysis results of Section 3.

The squares of Figure 3 show the expected cumulative oil production from the various EOR fields after ranking them from low to high capital investment ratio. The significant feature of the plot that there is a sharp change in slope at approximately \$10/BBL and 1.2 billion BBL cumulative oil production.

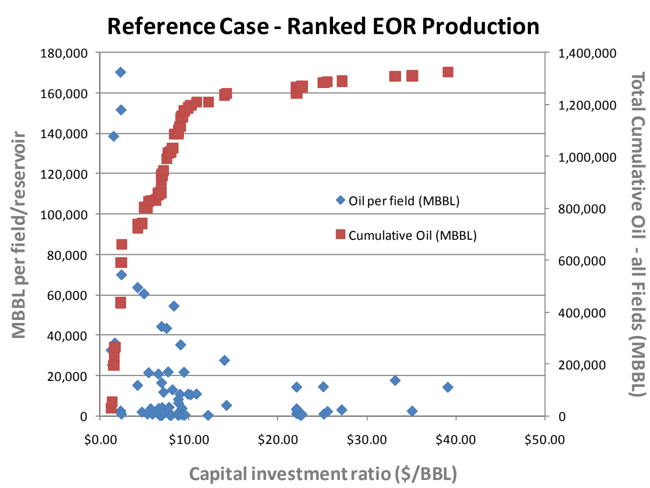

Figure 3. The difference in economic quality of the various EOR candidate fields is evident when ordering them from lowest to highest capital investment ratio (\$/BBL).

In order to see the cost implications, Figure 4 presents the same cumulative oil production alongside the cumulative capital investment. Approximately \$5.6 billion in capital investment is required for the first 1.2 billion BBL. Then another \$3.3 billion is estimated to be needed for the next 0.1 billion BBL of oil. Therefore, we choose as our reference case such that we eliminate any fields that are estimated to have a capital investment ratio of more than \$10/BBL. The reference case is \$5.6 Billion in capital investment for 1.2 billion BBL from 22 major oil fields. Figures 3 and 4 show more data than the 26 major candidate fields as many are composed of smaller subsidiary reservoirs that we were estimating Because we chose the fields with lowest capital investment ratio, only 6,150 production and injection wells are now estimated for the reference case.

The 22 oil fields chosen for EOR are: Big Wells (3 fields total), Borregos (10 fields total), Conroe, Fig Ridge, Giddings (2 fields total), Gillock, Goose Creek, Hastings, Hull (2 fields total), Liberty South, Orange (2 fields total), Oyster Bayou, Pearsall, Pierce Junction, Portilla, Seeligson, T-C-B, Tom O'Connor, Webster, West Ranch (8 fields total), White Point East, and Willimar.

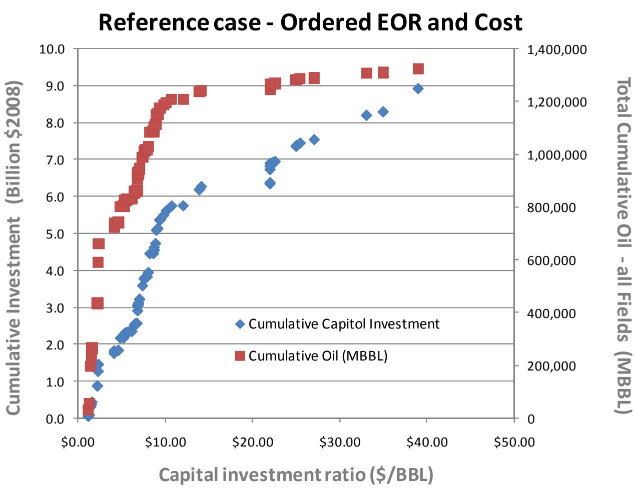

Figure 4. The trend of cumulative EOR capital cost ratio ($/BBL) increases more slowly after $10/BBL, but cumulative oil production also increases very slowly.

Over the life of the EOR field, we assume that the fields require a net of 0.24 tCO_2/BBL of oil while recycling 0.29 tCO_2/BBL. Thus, a total gross quantity of 636 $MtCO_2$ (at 0.53 tCO_2) is injected into the reservoirs while 280 $MtCO_2$ remains (net) in the reservoirs. The 1.2 billion BBL of EOR-produced oil will emit approximately 430-500 $MtCO_2$ if all burned[3], but approximately 85% of products from a BBL are eventually combusted.

2.6 Costs: Power Plant CO_2 Capture Facility

The costs for capital infrastructure and annual O&M for operating the CO_2 capture portion of the power plant varies substantially depending upon the number of power plants needed to supply CO_2. A fleet of coal power plants could use one of two, or a combination, of investment and operational strategies associated with retrofitting existing power plants for post-combustion CO_2 capture (see Table 3). The capital expenditure is higher when installing more gross generating capacity at a power plant in order to maintain the existing net generating capacity when the capture process is running at full power. However, technology advancement could enable the shutting off of the capture process during peak demand times of the year. Determining the differences in technical and economic feasibility between each of these strategies could be a major goal of the first few full scale (> 150 MW) CO_2 capture plants. The annual operation and maintenance cost is the same for either strategy based upon the quantity of gross generation.

For the reference case, there is an assumed peak CO_2 need of 25 $MtCO_2$/yr at a mid-range capital cost for the capture plant of $1,100/kW of added or subtracted plant capacity to run the capture processes. The upper and lower ranges for capital cost are $600/kW and $1,600/kW [5]. Operation and maintenance costs for running the capture plant are 19-38 $/tCO_2$.

2.7 Costs: Pipeline Network

Connecting several power plants to a couple of dozen oil field locations will require an extensive pipeline network, but not one that is unprecedented compared to existing oil and gas pipelines in Texas. A potential pipeline path and sizing solution was designed to connect the candidate oil fields with the candidate power plants. This provides an estimate of the materials, cost, and labor associated with the integrated pipeline concept. The total pipeline length is approximately 1000 miles with diameters ranging from just a six inches (for small CO_2 flow rates to small oil fields) to a 30 inches in diameter for central "backbone" portions of the pipeline that carry CO_2 from multiple power plants to multiple oil fields.

Pipeline costs are spread between labor (50%), materials (20%), right of way (10%), and other miscellaneous (20%) costs [4]. Past analyses of pipeline construction cost estimates from McCoy (2008) and MIT (2003) approximately $20,000-$30,000 per inch per km ($32,000-$50,000/in/mile). Thus, to estimate the cost of a pipeline segment one can multiply the diameter of the pipeline (in inches) and the length (in miles or km as needed). However, industry costs announcements of 2007 and 2008 indicate that pipeline costs had become significantly higher. The cost estimates of the last 2-5 years have varied over an order of magnitude, notwithstanding any possible cost reduction due to general economic downturn starting late 2008.

For the pipeline analyzed by the GCCC, the estimated installed cost for the pipeline network is $1 – $2 billion. This pipeline connects all seven potential power plants of Table 2 to the candidate oil fields. The cost per unit is approximately $50,000-$70,000 per inch diameter per mile. For Annual operation and maintenance costs are estimated at approximately 2.85 $/tCO_2$ (0.15 $/Mscf of CO_2) transported. This is consistent with O&M costs for natural gas pipelines and estimates from some of the proposed CO_2 pipeline projects.

[3] 0.42 tCO_2/BBL per http://www.eia.doe.gov/oiaf/1605/coefficients.html

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2.8 Costs: Cash Flow Input Summary

Table 3 shows all of the final cost assumptions for estimating the cash flow for the integrated CO_2 network.

Table 3. Economic Parameters used to estimate net present value of an integrated CO_2 network along the Texas Gulf Coast.

Economic Parameters	Reference Case
Enhanced Oil Recovery Production and Costs	
Oil production from EOR, 20 years (million BBL)	1,200
Total EOR net CO_2 need over 20 years ($MtCO_2$)	290
Total EOR net CO_2 need over 20 years (million Mscf CO_2)	5,500
Peak annual EOR CO_2 purchase need ($MtCO_2$)	25
EOR capital costs ($ million)	5,600
EOR O&M costs ($/BBL)[@]	5.6
CO_2 Pipeline Costs	
Pipeline capital cost ($ million)	2,000
Pipeline O&M Cost* ($/Mscf CO_2)	0.15
CO_2 Capture Installation and Costs	
CO_2 capture capital costs ($/kW for capture)**	1,100
CO_2 capture O&M costs ($/Mscf CO_2)	2.0
Gross equivalent power for capture (MW)	1,500
Capital Cost for CO_2 capture facilities ($ million)	1,650
Tax Rates and Royalties	
State Tax on CO_2 capture activities (%)	2
State Tax on CO_2 pipeline activities (%)	2
State Tax on EOR oil (before HB 3732 incentive)[#] (%)	8.6
Royalty Fee for landowners (%)	20

[@] *O&M = (1% oil price per BBL in $/Mscf CO_2 recycled)*(0.60 $/BBL oil). Using method from [4] Table 3.14 and [12] Appendix B plus a 10% increase to account for contingency values and inflation.*

[*] *Based on estimates by Denbury for its CO_2 pipeline from Mississippi to East Texas. This is also consistent with O&M costs for natural gas pipelines.*

[**] *Midrange from [5].*

[#] *HB 3732 (2007) approves an additional 50% severance tax decrease for EOR projects that permanently sequester the Texas-originated anthropogenic CO_2 after operations.*

2.9 Costs: Those not included – left for Future Work

There are several costs for various parts of the system that were not yet included either due to lack of data, high uncertainty, or need for an augmented methodology. These costs are left for future work. Thus, the results in Section 3 are not all inclusive.

Costs not included in the analysis are:

- Measurement, monitoring, and verification costs associated with sequestration of CO_2 in depleted oil fields after oil production has ceased, although pure sequestration costs are often quoted at < $10/tCO_2$ [5],
- Feeder CO_2 pipelines in the EOR that go from the modeled pipeline dispersed throughout the field,
- The operation costs of CO_2 recycling based upon the amount of CO_2 recycled over time as we have yet to estimate a profile for the recycled CO_2,
- The fact that there has been a historical limit on CO_2 price that oil producers are willing to pay: approximately 0.3-0.4 for the ratio ($/tCO_2$)/($/BBL), and
- Existing State of Texas or federal subsidies in place to promote CO_2 capture and sequestration, with or without EOR.

3. RESULTS AND DISCUSSION

When accounting for all of the CO_2 flows of the system over the course of the 23 years of the reference integrated scenario, 280 $MtCO_2$ are stored in the depleted oil reservoirs and 430-500 $MtCO_2$ is emitted from the recovered oil[4]. Thus, there is a net exchange of 270 $MtCO_2$ to the atmosphere. However, the existing reservoirs and infrastructure can be used to sequester additional CO_2 after all oil has been recovered such than an estimated 560 $MtCO_2$ is eventually stored and the system over the entire life cycle is carbon neutral.

3.1 Cash Flow assumptions

We developed a discounted cash flow model with financing to investigate under what conditions such an integrated capture-pipeline-EOR infrastructure could be commercially viable. The EOR operator buys the CO_2 from the power plants with capture it and then pays the pipeline company for transporting the CO_2 to the oil field.

In addition to fundamental inputs in Table 3, the financial assumptions for the base case are: 10% discount rate; 10 year loans at a rate of 12% for 60% of capital costs (40% equity) – 2.5% of the loan amount is paid as the up-front fee; 0.6% interest during construction. Capital investments in all infrastructure are made over 3 years (30% first year, 50% second year, and 20% third year).

[4] Oil is assumed to embody 0.42 tCO_2/BBL and 85-100 percent of the full volume of the barrel is assumed burned without CO_2 emissions reduction technology.

3.2 Cash Flow results

In order for all three major parties – power plant operator, pipeline operator, and EOR field operator – to achieve 20% internal rate of return (IRR), the required long-term average prices are \$55/tCO_2, \$56/BBL of oil, and 1.23 \$/mcfCO_2 charged as a pipeline transport tariff. Although EOR operators can afford to pay \$55/tCO_2 as long as oil price is at least \$56/BBL, they do not have to. This price is much higher than the prices seen in European and U.S. carbon markets. In Europe after reaching a high of about \$44/tCO_2, the price has sunk to about \$13/tCO_2 in early 2009. The results imply that CO_2 operations are not economically viable below \$50-\$60/tCO_2 such that capture might have to be supported via tax credits or otherwise. Stringent climate regulation will likely increase the CO_2 price but as of now there is huge uncertainty about future policies and their impacts, especially under current economic conditions.

At the same time, \$56/BBL may seem like a high price for oil in today's environment; but it appears to be a very reasonable average. The breakeven price for many marginal onshore producers is about \$55-60/BBL, especially in the U.S., and, more importantly, some analysts believe \$60/BBL is necessary for long-term sustainability of oil supplies.[5] The Organization of Petroleum Exporting Countries has stated that in the future after the current economic downturn, that \$70/BBL is a reasonable target price to induce investments [13]. Hence, it would not be prudent to assume prices higher than 60-70 \$/BBL for investment decisions.

There are many uncertainties in this system: from Table 1, a range of 0.16 to 0.32 tCO_2/BBL and a range of 7% to 20% of recovery of OOIP are possible. Also, capital costs have wide ranges, especially for capture and EOR operations, and the prices of CO_2 and oil are likely to be very volatile. We use Monte Carlo (MC) analysis to help frame the possible outcomes (see Table 4).

Table 4. Monte Carlo Simulation Assumptions for variable distributions.

Variable	Distribution	Mean	St. Dev.
CO_2 purchase	Normal	0.24 tCO_2/BBL	0.02
% OOIP	Log-normal	12%	2%
EOR K-cost	Log-normal	\$5.6 billion	\$1 billion
CC K-cost	Normal	\$1.65 billion	\$247 million
Oil price	Log-normal	\$56/BBL	\$6/BBL
CO_2 price	Log-normal	30 \$/tCO_2	10 \$/tCO_2
Pipe tariff	Normal	\$1.23/mcf	\$0.25/mcf

For EOR, we assume a log-normal distribution with \$5.6 billion as the mean because it is possible for capital costs of EOR operations to be significantly larger (as there are more uncertainties associated with EOR) but it is not likely for costs to be much lower. The oil and CO_2 prices are modeled as log-normal for similar reasons. Our reference case values are taken as the mean except for the CO_2 price, which we assumed a mean of \$30 to reflect CO_2 markets more realistically as discussed earlier.

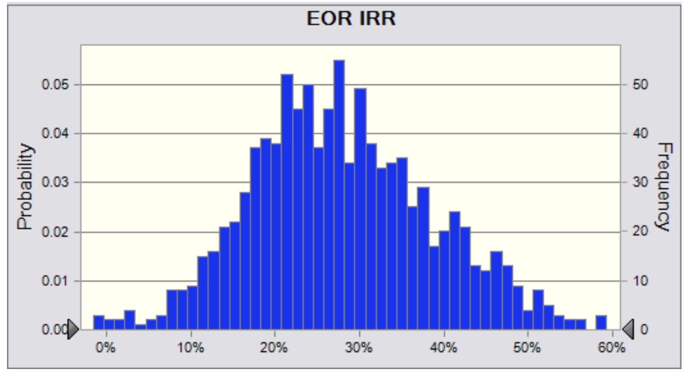

Figure 5. Monte Carlo Results: frequency distribution for EOR IRR

The cumulative impact of all these uncertainties on EOR IRR is displayed in Figure 5. There is a good chance for EOR operations to yield an IRR of 20% or greater. In Figure 6, oil price and % of OOIP recovery are the most important variables on the positive side, explaining why the distribution for EOR IRR looks so good. The uncertainty about the capital cost is a significant risk but it is overcome by the potential higher price of oil and higher yield of the oil fields after CO_2 injection. Higher CO_2 prices pose a sizeable risk despite our assumption of historical CO_2 price average of \$30/tCO_2. The need for more CO_2 per barrel and higher transportation tariffs will also negatively impact EOR returns but these risks are minimal.

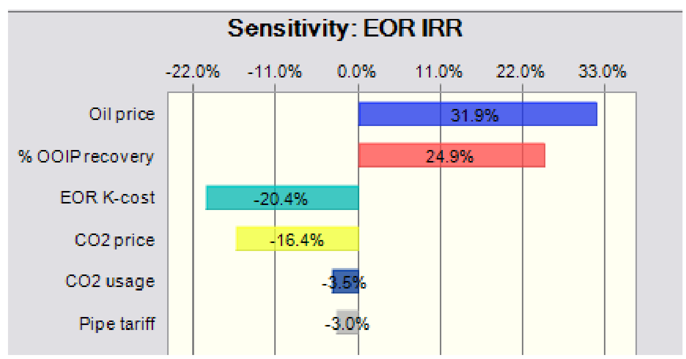

Figure 6. Sensitivity of EOR IRR to stochastic variables.

4. CONCLUSIONS

We developed a cash flow model for financing that integrates three segments of the CO_2-EOR value chain: carbon capture at coal plants, pipeline transportation of CO_2 to target oil fields and investment in EOR operations. Our reference case is for each segment to yield an IRR of 20%. This raises the challenge to the EOR operators, who have to buy CO_2 and pay for transportation. Nevertheless, an oil price of \$56/BBL

[5] For example, see *Cost of Producing Oil* by Deutsche Bank, February 24, 2009.

is sufficient for viability. However, \$55/tCO_2 that is necessary for 20% IRR in the capture segment is higher than historical prices of CO_2 in cap-and-trade markets and the prices paid by existing CO_2-EOR operators. There is great uncertainty about the capital cost of capture and EOR, especially given the large number of plants and fields we consider not to mention volatility of the oil price. We also considered two technical uncertainties: CO_2 needed for each barrel of oil and percent of OOIP that can be recovered via EOR. Monte Carlo simulations indicate that EOR operations are more likely to yield an IRR greater than 20%, mainly because we expect oil price to be higher and CO_2 price to be lower than those in our reference case. However, low CO_2 prices imply that capture operations will have to be supported by policy incentives. In the future, we will expand our research to look at the impact of various CO_2 regulation schemes and incentives on capture, EOR, and sequestration operations.

NOMENCLATURE

BEG = Bureau of Economic Geology
BBL = blue barrel of oil (42 gallons)
EOR = enhanced oil recovery (using CO_2)
GCCC = Gulf Coast Carbon Center
IRR = internal rate of return
MIMO = multi-input multi-output
MtCO_2 = million metric tons of carbon dioxide
OOIP = original oil in place
tCO_2 = metric ton of CO_2

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