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PROJECT LINCOLN

An Assessment of CO_2-EOR Development Opportunities in the State of Illinois

FINAL REPORT

REVISED EDITION

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FOREWORD

This project began almost one year ago, and, as is true of most such undertakings, it owes much thanks to work that preceded it. So, firstly, I wish to thank Rob Finley, his staff at ISGS, and the MGSC group. Without their work and basic findings, this effort would have been much longer and time-consuming.

Though this effort is focused on CO_2-EOR opportunities in the State of Illinois, the breadth of issues covered necessarily has broadened the scope of topics reviewed. To do otherwise would have taken ″focus″ to too myopic a perspective and precluded options along the way. Given the volatile world of carbon we find ourselves, it is imprudent to build assumptions, especially ones for developing a multibillion dollar industry such as EOR, on rather ephemeral developments like carbon taxes, cap-and-trade and values therein. Someday they may exist. But for now they do not. And until they do, what-if scenarios can be run for $100/ tonne carbon to $100/ tonne carbon credits, but they do little for the emitter considering an offer from and EOR operator on which to create a commercial purchase and sale agreement.

Consequently, this project has been based on “being real” – or in other words, dealing with what’s out there. That’s not to say it’s avoided the “possible” 800 pound gorilla, but rather has tried to present an assessment that others can build on and incorporate new and evolving carbon scenarios.

I wish to thank the considerable input and written contributions from various team members, especially Robert Aaron and Al Bergunder (Praxair), Dr. Alan Brown (Schlumberger), and Dr. Syed Hassan (Gulf Interstate Engineering). I also with to thank Chris Burger (Patrick Engineering) for his practical, experienced insight into this entire effort. A special thanks goes to my colleague and the team’s reservoir engineering guide, Steve Pontious, for his considerable time and effort in review of Illinois reservoirs and options therein.

Though all partners contributed to this report and all conclusions have been broadly addressed, the final findings and summary are my own.

Project Director

Michael J. Hirl
Director, Kinder Morgan CO_2 Company, L.P.

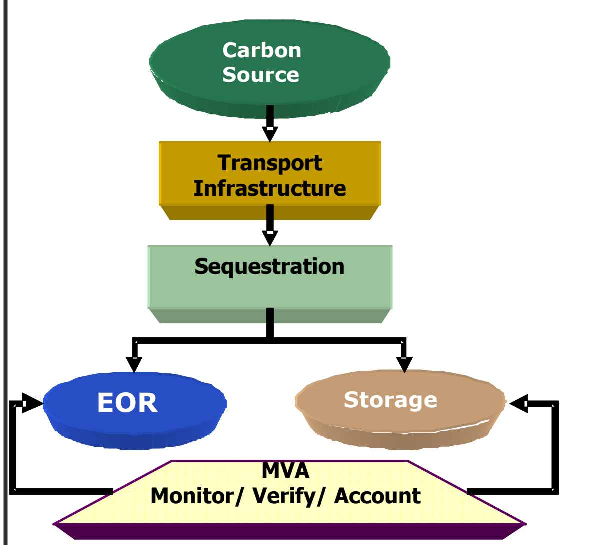
I. INTRODUCTION

Background

Greenhouse gas emissions, and more specifically carbon dioxide emissions, are one of the central environmental issues of our time. An American economy built over the last century on carbon-based energy sources now is confronted with alternative choices. How to minimize the carbon content of the U.S. energy mix and develop new technological solutions are key goals before the country. Regardless of the path ultimately chosen, one thing is certain, the carbon-based economy as we have heretofore experienced will undergo significant change. An important tool in the evolving mix of carbon mitigation approaches is the process of carbon capture and storage better known by its acronym, CCS.

As depicted in Figure I-1, CCS is a fairly straightforward proposition: **capture** carbon dioxide (CO_2) at a pointsource, **transport** it to a final geologic site, **inject** into the reservoir, and **monitor** the injection[1]. Though storage and EOR[2] both represent sequestration approaches, EOR's advantage arises from the fact that it is commercially-based wherein companies will **buy the CO_2.** Through the dynamics of the market process, the aggregation of customers creates transport demand which leads to basic infrastructure development. In turning

Figure I-1: CCS Schematic



[1] "Monitor" means utilizing approved "metering, verification, accounting" or MVA techniques if and when required for recognition of emission or tax credits – either through sequestration or EOR.

[2] EOR is also a storage process as it is a closed loop system. CO_2 is injected, produced with the oil/ gas stream, then usually stripped out and reinjected into the reservoir where it is stored. The distinction between EOR and saline formation storage is the "phased" interval over which the CO_2 is ultimately sequestered in the former versus the latter. Industry experience indicates final cumulative storage via EOR @ approximately 99.5% of injected CO_2.

what some label a "waste" product into a useful economic commodity, CO_2-EOR can underpin broader economic gains and carbon reduction objectives.

Project Defined

This study was undertaken with that goal in mind – to assess whether the necessary components upon which to build an integrated CO_2-EOR system in the State of Illinois exist. Furthermore, to evaluate the status of component elements as they now exist and may need to evolve if CO_2-EOR is to be considered economically plausible.

This project, hereinafter called **Project Lincoln,** has been funded through the State of Illinois' Department of Commerce and Economic Opportunity. It proceeds from a grant awarded to Kinder Morgan CO_2 Company (Kinder Morgan) and a subsequent Grant Agreement signed between Kinder Morgan and the State of Illinois. Based on the goal stated above and the terms of the Agreement, the following deliverables are herein presented.

1) **Review and analyze existing data** with respect to CO_2 sources and sinks in Illinois, especially with regard to potential EOR activity.
2) **Assess quantitative and qualitative characteristics** as deemed applicable to: (a) sources of CO_2, (b) sequestration sinks, and (c) EOR sites.
3) **Define CO_2 source and supply infrastructure** possibilities, preparing a design option compatible with existing and future development activity.
4) **Summarize general financial /economic data** as pertains to CO_2 sourcing, transport, and subsequent EOR/ sequestration.

In addressing these goals, Kinder Morgan created a project team consisting of industry leading companies whose expertise, experience, and energies have been directed at segments of the EOR/ CCS value chain. The team assembled for this effort consists of [3]:

- **Gulf Interstate Engineering (GIE):** overall pipeline hydraulics and infrastructure engineering;
- **Praxair, Inc.:** capture source and process engineering and economics;

[3] More details about each company are available in Appendix A

- **Schlumberger Carbon Services**: assess sequestration sites/ geology/ geomechanics/ MVA ;
- **Patrick Engineering**: provide infrastructure and engineering support for all project phases.

Project Lincoln reflects a collaborative effort by an experienced team, familiar with the various elements of CCS/ EOR and actively engaged in ongoing businesses therein. Consequently, while utilizing excellent academic and institutional studies, the approach taken has been primarily a commercially-driven one. The findings presented herein should be viewed in a pragmatic context, focused on real-world decisions required for developing a new CCS/ EOR industry in the State of Illinois given current development factors. Much can change and likely will. However, to the fullest extent possible, the Team has attempted to stay with what is real and now.

Key Objectives

Based on the project deliverables, the Team focused on answering five key questions.

1) Where are CO_2 emissions and how can a CO_2 supply system be created?
2) Where are the primary, commercially-viable EOR sites, and how close are pure sequestration sites to them?
3) How best to connect sources and sinks to both provide for an efficient supply network and ensure the system has sufficient flexibility to expand over time to accommodate higher CCS activity.
4) What obstacles and risks exist that impair financial and commercial viability?
5) What new approaches and paths might be pursued to achieve desired goals?

To answer these questions, the Team first reviewed existing literature. Of primary importance was material published by the MGSC with the Illinois State Geological Survey[4]. These reports and core data were checked for timeliness versus

[4] **Assess Carbon Dioxide Capture Options for Illinois Basin Carbon Dioxide Sources**, Topical Report issued December 31, 2006 by M. Rostam-Abadi, S.S. Chen, Y. Lu, and the Illinois State Geological Survey (Preparer contact Robert Finley w/ ISGS).

developments in the intervening 4+ years since they were written. Discussions were held with ISGS staff regarding various oil field and sequestration data. One team member (Schlumberger) is in fact currently working with ISGS on sequestration activities and was able to confirm significant related data. For the most part, all relevant data and references were confirmed.

> ***Finding:*** *Much of the reference data used in this report originates from ISGS[5] and MGSC [6] reports published within the past 4 years. To the extent practical, the timelines, rates, and related quantitative variables used herein have been consistent with those applied in the past, creating what is hoped to be a continuous framework for review and analyses. Key updates have been made where noted. The Team wishes to acknowledge the significance of their work and the solid basis it has provided for subsequent work such as this.*

With this base data, carbon emission sites were put in their analytical box, as were sequestration sites and EOR sites – each applying their respective engineering and financial framework. Lastly, once the "dots" were filtered and identified, the various infrastructure scenarios were designed, and deployment options were assessed – all directed at the Primary Question……

> ***Primary Question:*** *Can a viable, commercially-driven CO_2-EOR business be developed in the State of Illinois? One built on capturing carbon emissions from existing/ planned anthropogenic sources[7] and building a supply system sufficiently flexible to meet EOR supply needs and to accommodate the State's potential longer-term carbon sequestration needs. .*

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[5] "ISGS" or Illinois State Geological Survey
[6] "MGSC" or Midwest Geologic Sequestration Consortium
[7] Within the State of Illinois. No out-of-state sites were included.

II. CO_2 SOURCE ASSESSMENT

Source Identification

The CO_2 emission sources considered for capture included all stationary sources within the State of Illinois[8]. These sources include coal-fired power plants, natural gas combined cycle (NGCC) power plants, ethanol plants, select manufacturing plants (ammonia, glass, cement, & lime), petroleum refineries, and steel plants (electric arc furnace and blast furnace / oxygen reduction). While only accounting for 19% of total physical sites, coal-fired power plants make up over three quarters of the estimated 125 million metric tons per year (mtpy) of CO_2 emissions in the State.[9]

Figure II-1: CO2 Source Breakdown

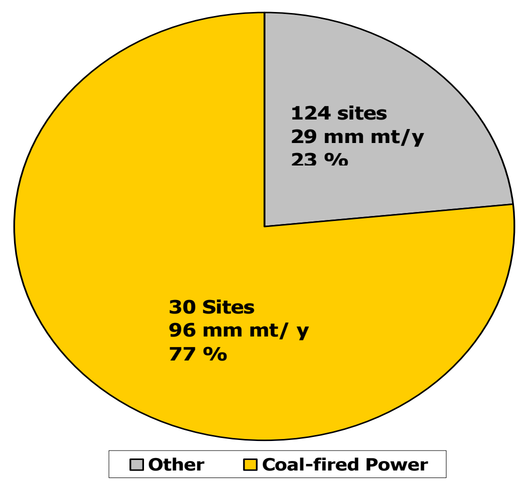
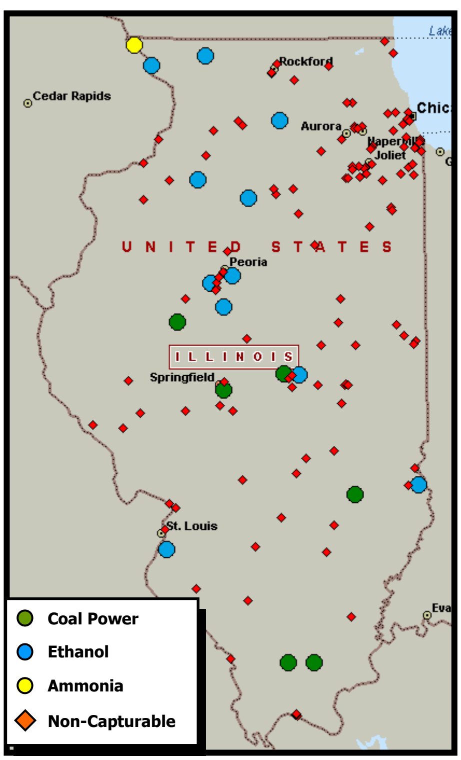


Figure II-2:Stationary CO_2 Emissions



Technological and economic factors limit the feasibility of capturing CO_2 from many potential sources. After applying project-defined screening assumptions (Appendix C), the three most feasible sources for CO_2 capture are ethanol plants, ammonia plants, and coal-fired boilers under 30 years old that emit more than 1MM mtpy of CO_2 in their flue gases. Figure II-2 shows the location of

[8] It is recognized that significant number of nearby pointsources exist in adjacent states. In a broader business plan, they could be considered. However, THIS study is focused on just Illinois.
[9] Illinois State Geological Survey, ***Inventory of Industrial Stationary CO_2 Emissions in the Illinois Basin***, August 2007

feasible CO_2 sources versus non-capturable emitters in Illinois. On a per site basis, we estimate that 12% of the stationary sources in Illinois are viable sources[10] accounting for 14% of total CO_2 emissions.

CO_2 Capture Technology

Man-made (anthropogenic) carbon dioxide (CO_2a[11]) is the by-product of combustion, chemical and biological processes that have been developed to produce practical, everyday products (i.e. steel, ethanol, glass, electricity, ammonia). In some cases, CO_2 is emitted in relatively high concentration (oxy-fuel combustion, ethanol) while in others, it is diluted with nitrogen, oxygen, particulate, water vapor and other chemical constituents.

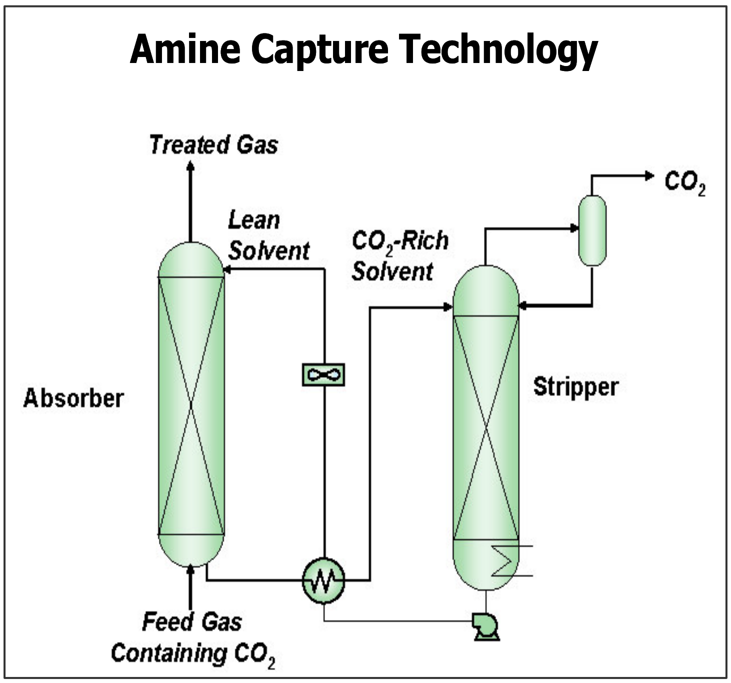
CO_2 from an ethanol process is produced in a reasonably concentrated form from the fermentation of sugars to produce ethanol. Under normal circumstances the gas is either captured for commercial use or vented to the atmosphere. For enhanced oil recovery (EOR) use, the gas is initially washed to remove any particulate being carried along, then directed through a series of compressors and dehydrators to condition to 2,000 psia, at which point, the gas will be injected into pipelines for transport to the EOR fields. The technology consumes electric energy to operate the pumps, dryers, compressors and the control system.

Dehydration & Compression System

[10] Implies that there exists a reasonable technical and economic basis for capture vis-à-vis supply for EOR.
[11] As noted in section I, a newer label distinguishes CO_2 based on its source: CO_2n for natural sources, CO_2a for anthropogenic sources. Unless otherwise specified, all references to CO_2 herein will mean CO_2a.

CO_2 from ammonia production is a high concentration by-product that has been historically vented or used for producing commercial grade liquid CO_2. For EOR use, the gas is dried and compressed to 2,000 psia for injection into a CO_2 pipeline. As is the case with ethanol sources, electric energy is required to operate dryers, compressors and the control system.

CO_2 originating from the exhaust of coal-fired combustion processes (i.e. electric generating plant) is typically diluted to concentrations of 15% of the total stream. Using a proven amine collection process, it is feasible to capture 90% or more of the CO2 molecules emitted in a highly concentrated form. The CO_2 stream is then compressed and injected into pipelines for transport to the EOR fields. The complete system requires large amounts of steam energy and electricity to operate at peak performance.



Future technologies may provide other substantial sources of CO_2. Alstom's Chilled Ammonia and PowerSpan's $ECO2_{TM}$ process are under development and may offer competitive technologies for capture from exhaust streams. Coal gasification is being developed in Illinois for the production of hydrogen, natural gas and other fuel products. If built, these plants will provide large volumes of reasonably pure CO_2, using a process design that should include purification and compression for either EOR or permanent sequestration. If built and located adjacent to future CO_2 pipelines, their scale of operation could result in a relatively secure and reliable low-cost supply source for EOR producers.

Capture Costs

CO_2 must be captured and processed before it can be transported by pipeline for EOR or sequestration. The cost of capture is driven by the source type and distance from the use point. The source types under consideration in Illinois are coal-fired boilers under 30 years old[12], ethanol plants and ammonia plants. Naturally, the market price of CO_2 will determine which sources are the most competitive for EOR. For this study, data developed and benchmarked from other projects [13] were applied to provide the fundamental economic data on capital and operating assumptions applied to each source.

Figure II-3: Capture Costs - Breakeven Basis (BE)

Ethanol	**MMcfd**	**$ / Mcf**	**$ / ton**
Aventine Renewable Energy, Inc.	**38**	**$0.90**	**$14.51**
Archer Daniels Midland Decatur	**66**	**$0.93**	**$15.00**
Archer Daniels Midland Peoria	**66**	**$0.93**	**$15.01**
Royster-Clark Nitrogen	**21**	**$1.04**	**$16.79**
Marquis Energy, LLC	**29**	**$1.06**	**$17.18**
Patriot Renewable Fuels, LLC	**29**	**$1.06**	**$17.18**
MGP Ingredients, Inc.	**19**	**$1.06**	**$17.19**
Illinois River Energy, LLC	**12**	**$1.07**	**$17.28**
Lincolnland Agri-Energy, LLC	**12**	**$1.08**	**$17.44**
Center Ethanol Company	**13**	**$1.10**	**$17.81**
Adkins Energy, LLC	**10**	**$1.13**	**$18.26**
Coal-Fired Boilers	**MMcfd**	**$ / Mcf**	**$ / ton**
Havana: Boiler 9	**147**	**$3.45**	**$55.88**
Newton: Boiler 2	**175**	**$3.46**	**$56.05**
Dallman: Boiler 33	**49**	**$3.53**	**$57.14**
Marion: Boiler 123	**48**	**$3.55**	**$57.60**
Archer Daniels Midland Decatur	**44**	**$3.65**	**$59.08**
Marion: Boiler 4	**60**	**$3.69**	**$59.73**

From this point, a financial model was constructed to estimate the breakeven (BE) CO_2 price[14] associated with each source, assuming twenty years of operation at an 8% discount factor (see Appendix C). The results confirm what most every carbon capture study has found: that post-combustion capture off a coal-fired boiler using an amine system has a much higher

[12] An arbitrary filtering system was applied to all coal-fired power plants, with age being the primary filtering element. It was deemed impractical to consider CO_2 capture off of any plants older, mainly due to site issues and boiler efficiency. Furthermore, the expected increase in capture costs with older plants was judged to put them "over the viable edge" so to speak.

[13] Reference to other internal Praxair projects dealing with various capture sources and technologies.

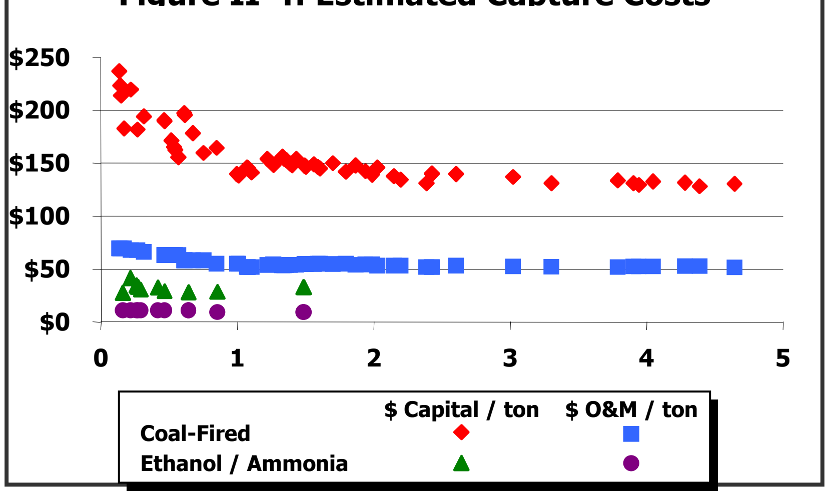
[14] "Breakeven" price refers to modeling based on a zero % return. Real world applications would include a risk-adjusted rate of return. "0%" pricing for CO_2 sourcing was applied due to variability in other related cost components (e.g. power) which would make return calculations without much more detailed information somewhat problematic. A "baseline" approach was therefore employed. This element however, is NOT applicable to pipeline operations which have a broader historical context from which to draw.

unit price than that from pre-combustion sources (e.g. gasification), ethanol and ammonia plants (see Figure II-3). This cost gap arises from the additional energy consumption and capital intensity in the former.

> ***FINDING:*** *Based on the sources listed in Figure II-3, volume weighted average costs for CO_2 from either ethanol or coal-fired boilers compare as follows:*
>
> ***Ethanol = $1.00 / mcf or ~ $20/ MT***
>
> ***Coal = $3.50 / mcf or ~ $70/ MT***

There is potential to achieve economies of scale for CO_2 capture projects. Figure 4 illustrates the differences in the estimated per ton capital and operating & maintenance (O&M) costs of CO_2 capture for coal-fired power plants and ethanol / ammonia plants. Larger volume projects require lower capital costs and operating and maintenance costs on a per unit captured basis. This feature is generally characteristic of larger CO_2 sources or like sources requiring a smaller breakeven CO_2 price. However, the possible need to run a more efficient large train in series with a less efficient small train could deteriorate the economies of scale for a given project. The graph also shows that

Figure II-4: Estimated Capture Costs



although ethanol / ammonia plants have lower costs, their volumetric potential as a CO_2 source is much more limited than a coal-fired power plant[15].

Future Sources

In researching current developments, we identified the following projects that may contribute to Illinois' need for EOR directed CO_2. These facilities will produce ethanol, electric power and synthetic natural gas. Based on public data regarding their respective technologies and operating permits, there is a possibility that the gasification-based projects will be designed to capture and compress CO_2 or as is termed "capture-ready". A brief summary of known potential future sources is profiled below.

Figure II-5: Potential Future CO2 Sources

Project	Location	Product	CO2 Out mtp/y	Online	Feedstock
Power Holdings	Mt. Vernon, IL	CTSNG	9,000	2014	Coal
Secure Energy	Decatur, IL	CTSNG	4,000	2012	Coal
Tenaska Energy	Taylorville, IL	IGCC-Elec	4,000	2011	Coal
Prairie State	Washington City, IL	PC-Elec	9,000	2011	Coal
Springfield	Springfield, IL	PC-Elec	1,300	2010	Coal
Abengoa	Madison, IL	Ethanol	420	2010	Corn

CO_2 Sourcing Basis

Locating sources of CO_2 emissions is **not** an issue. With coal plants throughout the southern area of the State and in relative close proximity to most prospective EOR reservoirs**, "potential" CO_2 supply far exceeds base case EOR demand**. However, the cost of supply IS an issue.

[15] At this time, many analysts expect capture at coal-fired plants to be required only to the extent their carbon footprint is equivalent to a similarly sized natural gas combined cycle power plant. If so, while the overall absolute value of the $ expended will decline, the per unit $ cost will likely stay as projected.

Therein lays the conundrum for Illinois CO_2 supply: ***more than enough CO_2 in aggregate, but significant issues with the characteristics of that supply base. That which is likely more reliable is far too expensive (coal-fired), while that which is less expensive is probably much less reliable (ethanol).***

> ***FINDING:*** *Illinois' stationary CO_2 sources mainly consist of ethanol plants and coal plants. Though coal plants might be considered more reliable due to their maturity and operating longevity, this "reliability" is substantially offset by their high capture cost.*
>
> *A key issue in assessing CO_2-EOR viability is **reliability AND price of CO_2 supply -** something coal-fired power plants are poorly positioned for in a market-driven EOR environment. With the probable exception **of gasification,** it is unlikely that more than a few newer coal-fired plants would even consider carbon capture. Nevertheless, three coal plants have been included as possible sources - not so much based on economics but rather non-financial considerations such as closeness to demand and possible incentives.*
>
> *On the other side, while supply from ethanol plants is cheaper, the fragile nature of the ethanol industry and the lack of any long-term commitments make ethanol supply highly problematic in serving as a baseload supply source.*
>
> *That exception aside, the assessment of CO_2 sources for EOR supply proceeds upon an assumption that predominantly only **"market viable"** CO_2 sources will be considered[16].*

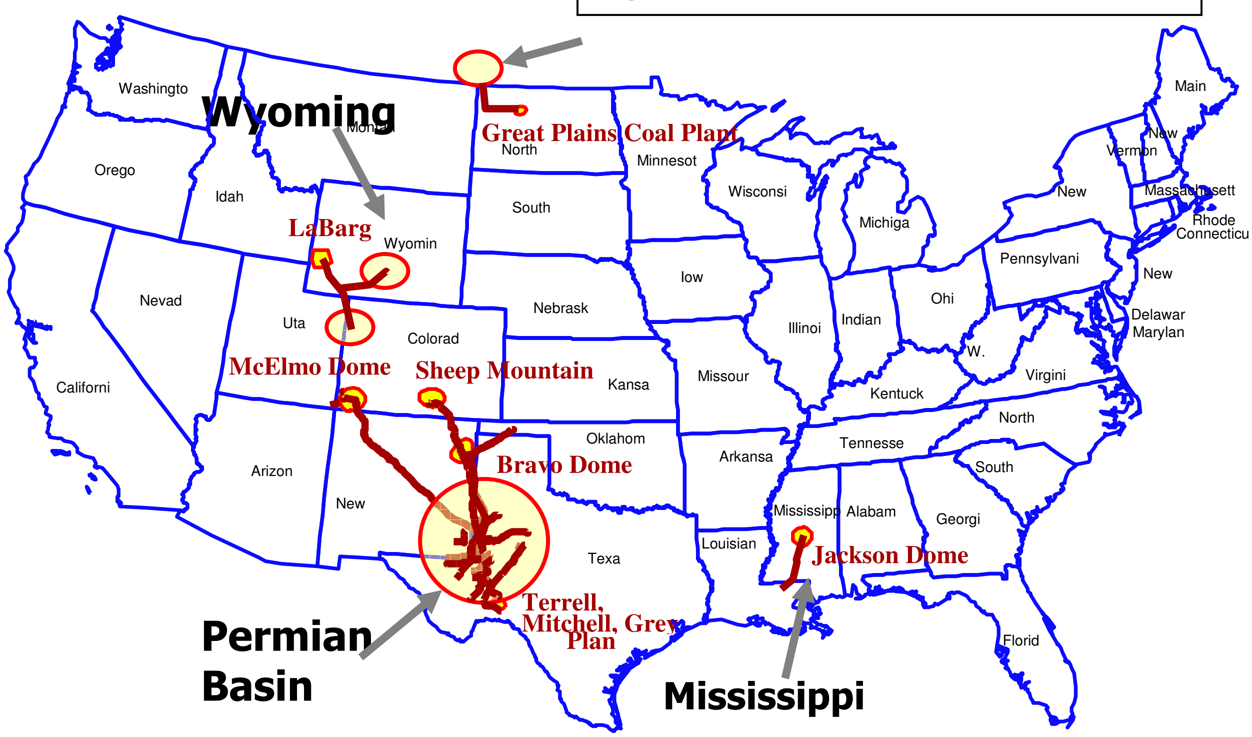
[16] It must be noted that while "market viable" pointsources are the predominant universe of "EOR directed supply", this is based on a rather strict EOR-based market price. From a longer-term infrastructure context, a much broader "carbon" context was applied. Hence, while EOR can only be driven by price sensitive sources, the infrastructure can be designed for possible climate-based carbon initiatives and the much larger resulting CO_2 volumes therein.

III. ENHANCED OIL RECOVERY (CO_2-EOR)

CO_2 - EOR Markets

The vast majority of North American CO_2 flood activity exists in four (4) locations as shown in Figure III-1. While two of these markets are based on captured/ processed CO_2 (e.g. CO_2a), the greatest volume is supplied from naturally occurring deposits in southwestern Colorado, Mississippi, and eastern New Mexico. The Permian Basin[17] represents an area where upwards of 70% of all CO_2 flood[18] activity occurs. With over 30 years of CO_2 production, transport, injection, and operational experience in the region, the CO_2-EOR industry has established a long, proven track record of success and safety. And though not as old, CO_2-EOR markets in Wyoming and Saskatchewan, Canada underscore the potential success of anthropogenic-based EOR markets given certain supply characteristics.

Figure III-1: North America CO_2-EOR



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[17] Defined based on geology, consisting of eastern New Mexico and West Texas.
[18] An oil reservoir undergoing tertiary CO_2 injection is said to be undergoing a "flood".

Essential to the development of the markets depicted in Figure III-1 was the availability of reliable, inexpensive CO_2 as well as the alignment of commercial interests. Initially, this alignment was often facilitated by the same company(s) owning the CO_2 source as well as the oil reservoir. It was from this common or shared perspective that a stable, ongoing business was created. While different in some aspects, all of these markets have three common traits.

1. **Good "rock":** As the geologists say, without good "rock" you have nothing. So to it is with respect to CO_2 flooding. If the "rock" does not have the right geological and reservoir characteristics, everything is riskier.
2. **Good CO_2 Supply**: Exactly how good is dependent on supply reliability, price, consistency, and commerciality or how the "alignment" of commercial interests proceeds.
3. **Human resources:** The people who take the risk, manage it, know how to execute a plan, and can achieve positive results. No small matter – especially in as integrated and demanding a market as CO_2-EOR. Without the right people, money and assets are simply stranded things.

Illinois' oil and gas industry has a rich history, but today can best be characterized as moderately active and relatively small. Comparatively speaking, it does not have as deep or broad a supporting infrastructure or resource base as other major oil producing areas in the country. However, there is a good case for supporting a claim to "good rock" and CO_2 sources that are relatively close to most reservoir / sequestration sites.

> ***Finding:*** *Some of the basic elements underpinning historical CO_2-EOR developments in North America **are present in Illinois**. This is **NOT** to imply that Illinois has everything required for such a development. Rather merely that **some** of the key constituent components are present and CO_2-EOR – in some shape or form – might be viable.*

EOR Development Characteristics

Though the three factors noted previously have historically been essential for any CO_2-EOR project, they should be viewed as only the very basic prerequisites. For an overall development profile to become clearer and a "project" to come forth, a few other important factors must be considered.

CO_2 floods can and usually do run inverted economics[19] for the first 1 to 2 years. As a result, prospective EOR firms must have financial strength and take a longer-term view before even considering such activity. Add to this the various operational and geologic risks as well as evolving risks posed by both financial and climate change developments/ legislation, and only certain types of operators are willing to undertake such projects. Often, such characteristics are not compatible with many companies' financial strategies, operating capabilities, and risk profile. This amalgam of issues is especially problematic in today's low-no risk capital markets and volatile energy markets. Couple these facts with a developing carbon and sequestration legal structure and it becomes clear that significant issues must be addressed beyond the purely technical and commercial for CO_2-EOR to find a conducive environment in which to develop a robust, sustainable CO_2-EOR business.

That said, based on the macro features noted earlier being present, the next development level requires the following commercial elements to both attract parties to a supply relationship and focus the operator on assumption of risk.

1. **Reliable sourcing**: the supply is not necessarily required 24/7 for 365. BUT – it needs to be not very far off.

2. The ***right*** $\mathbf{CO_2}$: Different sources will produce differing CO_2a gas mix, varying by the volume of constituent components such as sulfur, H_2S, and nitrogen. Only certain CO_2 mixes are optimal for either EOR or sequestration.

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[19] Meaning the project runs negative cash flows for an extended period until such time that there is break-through and the "CO_2 barrel" is produced. This can range from 6 to 24 months, depending on geology.

3. **Price:** the right level, flexibility, and terms.
4. **Commercial terms and conditions:** over what term, at what variability in offtake, cancellation features, and much more.

CO_2 Sourcing: A Buyer's Perspective

As noted in section II, the State of Illinois' CO_2 emissions far exceed quantities projected for potential EOR demand. The issue is not "conceptual" quantity, but rather practical, commerically-viable quantity. And that is where there ARE issues.

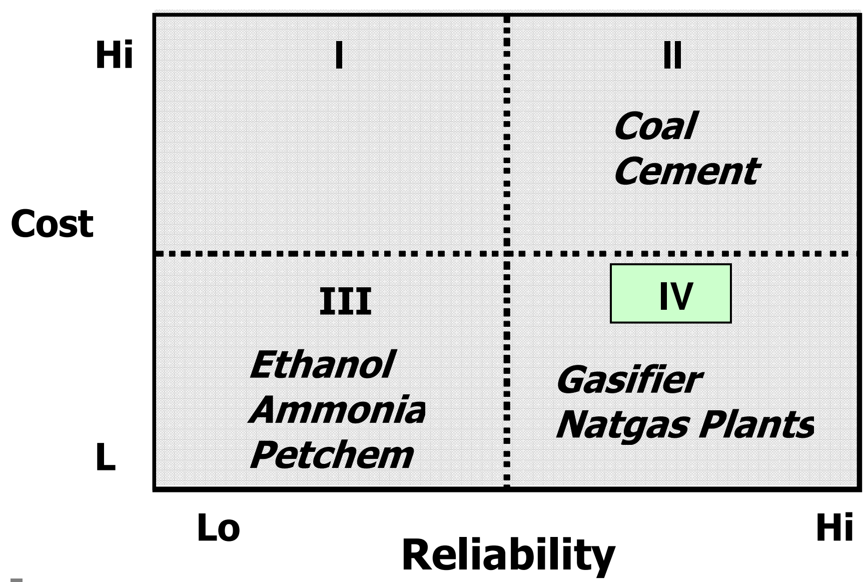
Most of the world's CO_2-EOR activity is undertaken with CO_2n – a highly reliable and low cost source. While some floods are conducted using CO_2a, there are unique economics usually accompanying them, making their cost structure more comparable to CO_2n than most CO_2a sources. More specifically, consider natural gas processing. While the capture technologies applied in stripping CO_2 from produced methane gas are costly, it ***is the methane production over which the cost is usually amortized, NOT the CO_2. Hence, the CO_2 bears only the compression and other relatively small clean-up costs***. Where parasitic cost share is NOT applied, full cost economics result in much higher unit CO_2 production costs. This latter case is true for all coal-based CO_2 sources other than post-combustion sources such as that from a gasifier.

CO_2-EOR requires various component elements to be aligned for the risk/ reward profile of a flood to be worthwhile. Along with inverted economics[20], CO_2 supply, crude oil prices, and resources are some of the key factors required for financial success – and that assumes favorable geology and reservoir dynamics.
Of these, CO_2 supply is essential. Without it obviously, there IS NO flood. Figure III-2 categorizes various CO_2a sources based on their respective reliability and cost characteristics. Those preferred by buyers would exist in quadrant IV where there is

[20] "inverted" in the context of negative cash flows during the "start-up" phase – a term which could be 6 months or up to two years – depending on the reservoir and flood dynamics.

the lower relative price (cost) at the greater relative reliability. [Note: Gasifier is placed in quadrant IV, but based on current activity/ operations probably should be on the line between III and IV.

Figure III-2: CO_2 Preference Matrix



> ***FINDING:*** *Consistent, reliable, CO_2 supply with a sound commercial and logistical framework underpinning it, is both a necessary and essential component for any CO_2-EOR development effort – be it for a single flood or a state-wide development initiative.*

Financial Considerations

CO_2 market prices are predominantly viewed in relationship to crude oil prices be it NYMEX WTI or some posted price. This price linkage, while not exclusive, serves as a general starting point with variations on indexing, escalation, and other mechanical features. In the most generic sense, CO_2 prices can be bracketed as a percentage of oil prices. Historical assessments of CO_2 prices indicate a general relationship, though by no means an absolute one, in the 1.5% to 2.5% of crude price range. A summary of this price relationship is shown below in Figure III-3.

As shown in Figure III-3, CO_2 pricing would have varied from perhaps as low as \$0.75/ mcf to upwards of \$2.00 - \$2.50/ mcf if not higher based on crude prices over the past 3 years. This pricing reflects delivery of CO_2 from its source to the delivery location or nearby hub[21].

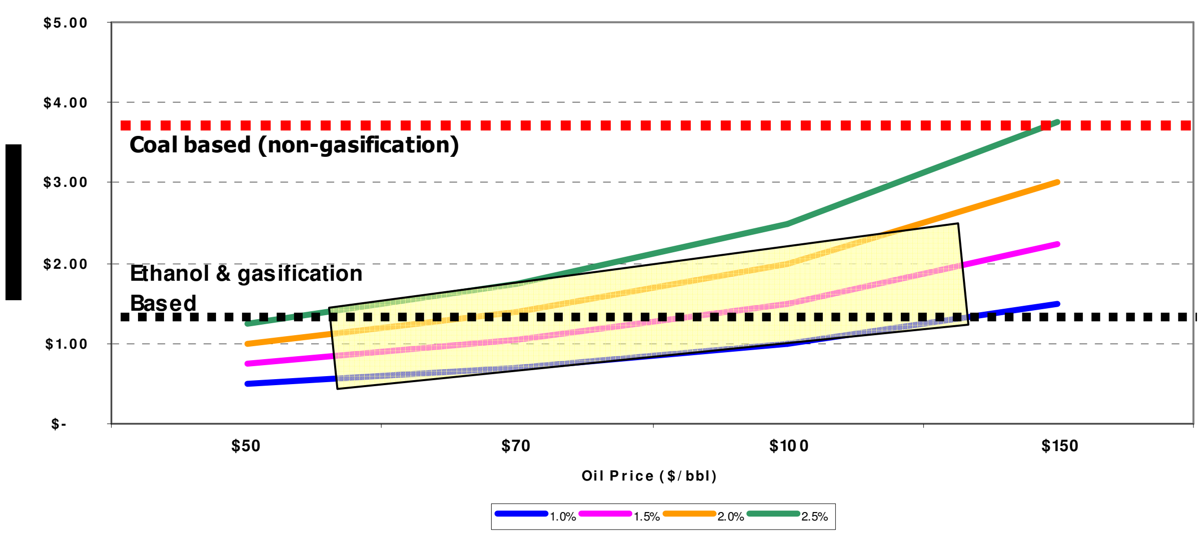
Figure III-3: CO2 Price as % Oil Price

	$/ bbl NYMEX WTI			
	$ 50	**$ 70**	**$ 100**	**$ 150**
% of Oil	**CO2 Price ***			
1.0%	$ 0.50	$ 0.70	$ 1.00	$ 1.50
	$ 9.65	***$ 13.51***	***$ 19.30***	***$ 28.95***
1.5%	$ 0.75	**$ 1.05**	**$ 1.50**	$ 2.25
	$ 14.48	***$ 20.27***	***$ 28.95***	***$ 43.43***
2.0%	$ 1.00	**$ 1.40**	**$ 2.00**	$ 3.00
	$ 19.30	***$ 27.02***	***$ 38.60***	***$ 57.90***
2.5%	$ 1.25	$ 1.75	$ 2.50	$ 3.75
	$ 24.13	***$ 33.78***	***$ 48.25***	***$ 72.38***
3.0%	$ 1.50	$ 2.10	$ 3.00	$ 4.50
	$ 28.95	***$ 40.53***	***$ 57.90***	***$ 86.85***

* Price shown in $/ mcf (black) and $/ m tonne (blue)
Conversion mcf/ tonne === **19.3**

The comparison of CO_2 prices in various markets generally supplied with CO_2n or its near cost equivalent versus likely CO_2 sources in Illinois is depicted in Figure III-4a. The graph shows CO_2 market prices at various oil prices as compared to the cost-based economics of major prospective sources in Illinois.

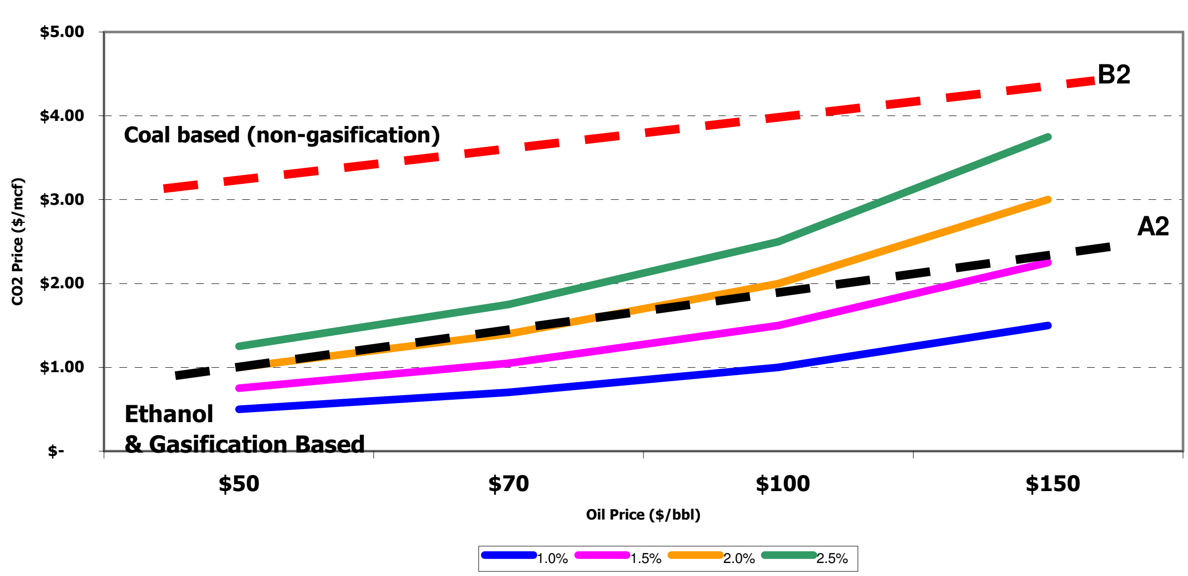
Figure III-4a : Comparative CO2 Pricing Profile



[21] In the case of Permian Basin, prices would be indicative of CO_2 delivered at Denver City, Texas.

As is evident, "ethanol-based" CO_2 sources can be priced in the general range of standard oil indexed CO_2 pricing. However, in the case of coal-based CO_2 sources, the cost far exceeds the equivalent CO_2 oil indexed price even in higher oil price conditions.

Figure III-4b: Comparative CO2 Pricing Profile



In fact, it is unlikely that the ethanol-based and coal-based price lines would in fact stay flat as shown. Rather, it is more probable that their cost function would be positively sloped, with a moderate pricing correlation to oil prices and, therefore, trend upward as well (see Figure III-4b).

This price assessment is not meant to delve too much into the arcane and unique elements of CO_2 pricing. Rather it is intended to demonstrate the financial issues accompanying CO_2 pricing arising from anthropogenic sources relative to existing markets and sources. It further proves the point that CO_2a will be on a higher relative cost curve at most points in time at most energy price levels – *ceterus paribus*[22].

[22] Meaning "all things being equal". An economics term to denote a constant external environment in which various things are measured against one another or some standard. Herein, it assumes neutrality with respect to carbon taxes and credit emissions.

And though differing markets and sourcing characteristics can justify *some* price differential, the fact is that crude oil is a fungible commodity, deliverable anywhere by transport or trade. A particular barrel's economics and netback must regularly compete against other crudes – regardless of their origin or means of production.

Consequently, while the "CO_2 barrel" is unique, the market does not distinguish it from the non-CO_2 barrel – be it produced in the U.S. or overseas, on land or offshore.

> ***FINDING:*** *For EOR development to be plausible, either CO_2 must be captured and supplied from low cost sources or significant subsidies / financial offsets will be needed for higher cost sources. With today's technology and respective energy markets, CO_2 from coal-fired power generation sources (non-gasification based) is beyond reasonable oil field economics. Based on existing knowledge, coal gasification does seem to offer a potential source of low-cost CO2, although quality and other issues remain.*
>
> *That said, while the use of CO_2 from anthropogenic sources in EOR markets can have desirable outcomes, it can NOT be expected to occur outside the industry's basic economic thresholds.*

EOR Field Analysis

Significant data on the major oil fields and carbon sinks in Illinois (and throughout the Illinois Basin) is available through work by the ISGS and MGSC. Based on that data and some reassessment of it, an analysis was conducted of the top 20 oil fields in Illinois[23].

[23] The MGSC report noted earlier identifies the "top 24" oilfields in the Illinois Basin. As this study's focus was Illinois, those fields not in Illinois proper were excluded from consideration. In the fullness of time, they might fit into an expanded Illinois CO2 supply network and come into their own at that time.

Though cumulative oil distributions are favorable geographically (most are in the southern, less densely populated areas), there are issues detracting from the overall size calculated therein. Based on MGSC data, the top 24 oilfields contain approximately 7 billion bbls OOIP[24]. However, analysis of available field data indicates that only 1 billion of this is miscible[25], and therefore likely recoverable today using existing benchmarks. The remaining reservoirs, based on existing data, are classified as immiscible or near-miscible. Of the remaining 6.0 billion bbls of reserves, approximately 40% are considered possible immiscible flood candidates, worthy of further field work/ analysis.

The "top 24 oilfields & sinks" was compared to the "top 30" as listed in published MGSC reports. Though a particularly large field (Clay City) was broken up into 3 fields for EOR consideration, the lists are basically identical. From that list, a few were excluded on purely the basis of political geography[26].

An engineering analysis was undertaken of the remaining reservoirs for all remaining fields, examining all published available field data and certain basic data including:

1. **Size:** Though smaller fields can be flooded, they are not the ones that will underpin a new industry or regional development effort. Very cheap CO_2 right "next door" may open up possibilities for the smaller fields, but generally speaking, the size of the field matters. Here, the screening criteria stopped at fields with original oil in place (OOIP) greater than 100 mm bbls. Anything less was not considered viable[27].

2. **Miscibility**: As noted previously, this is a key reservoir characteristic which weighs very heavily in assessment of CO_2 viability and economics. Reservoirs identified as miscible were ranked higher than those deemed "immiscible".

---

[24] Acronym for "original oil in place".
[25] Miscibility is based on density/ pressure. If a field is "miscible", then the oil and CO2 go to single phase, whereby the CO_2 makes the oil swell and flow through the reservoir.
[26] In these cases, the fields were in the "Illinois Basin" but not the "State of Illinois". Though regional initiatives may be beneficial, this study's focus is solely on sources and sinks within the State of Illinois.
[27] Viability has both a time and financial component. Smaller fields may not be viable today as an "anchor" field. But, if 3 or 4 other fields around it ARE developed, then it may become economic.

3. **Reservoir Characteristics:** Of the data available, those reservoirs with thin pay zones were excluded for further consideration as were reservoirs that were very shallow or noted as being highly fractured. While the crude might be there, if it's spread over a 2 – 3 mile area in a 6 foot thick payzone, it's extremely difficult to flood it and produce it.

The resulting fields are summarized in Figure III-5. As shown therein and as serves as the base EOR potential assessed for the State of Illinois, the total OOIP under initial consideration was just over 7.0 billion bbls.

Figure III-5: Primary Possible EOR Sites

Units ==>	*1,000,000*	bbls			
OOIP_RANK	FIELD_NAME	FIELD_ID	CUM_PROD	MISCIBILIT	OOIP_BBL
1	MAIN CONS.	171361	264	Immiscible	**1,403**
2	CLAY CITY CONS.	171119	375	Miscible	**1,249**
3	LAWRENCE	171336	428	Immiscible	**1,046**
4	LOUDEN	171354	399	Immiscible	**785**
5	NEW HARMONY CONS.	171415	162	Near-Miscible	**643**
6	SALEM CONS.	171533	398	Near-Miscible	**512**
7	DALE CONS.	171151	106	Miscible	**329**
8	SAILOR SPRS. CONS.	171530	71	Near-Miscible	**274**
9	ROLAND CONS.	171516	65	Near-Miscible	**202**
10	WESTFIELD	171640	40	Immiscible	**180**
11	ALLENDALE	171015	28	Immiscible	**161**
12	ALBION CONS.	171010	36	Near-Miscible	**144**
13	PHILLIPSTOWN CONS.	171474	41	Near-Miscible	**118**
		Sub-Total flds > 100 mm =			**7,046**
14	CENTRALIA	171111	59	Near-Miscible	**92**
15	HERALD CONS.	171250	22	Near-Miscible	**92**
16	GOLDEN GATE CONS.	171230	22	Miscible	**89**
17	JOHNSONVILLE CONS.	171299	58	Miscible	**79**
18	SIGGINS	171558	14	Immiscible	**79**
19	STORMS CONS.	171584	25	Near-Miscible	**78**
20	MATTOON	171377	23	Immiscible	**74**
21	BENTON	171050	42	Near-Miscible	**69**
22	BELLAIR	171041	11	Immiscible	**67**
		Sub-Total flds < 100 mm =			**719**
		TOTAL All Fields =			**7,765**

Of these 7.0 billion bbls, a reservoir by reservoir general assessment based on all of the above listed criteria resulted in the following net projections of recoverable potential in the fields summarized. As shown in Figure III-5, the net OOIP bbls were separated into miscible and immiscible categories[28]. The "immiscible" group was then further analyzed using more detailed reservoir data provided by the ISGS. Based on this data, reservoirs were either deemed "possible" and identified for further review or were deemed "unlikely" and discounted from further consideration.

> ***FINDING:*** *After field screening, net OOIP bbls under consideration for CO_2 flooding were assessed at just over 7.0 billion bbls with only 1.0 billion bbls in the more probable category of being "miscible". Nevertheless, those categorized as "immiscible" do present opportunity, albeit requiring more field assessment to fully evaluate.*[29]

From there, each group had basic "reservoir math" applied:

- Take OOIP bbls. Assume potential base-case recovery for miscible in the 6% - 10% range/ for immiscible in the 8% – 12% range.
- Assume these "recovered" bbls are done so over 20-year term with a smoothed average production level.
- Assume utilization ratio[30] in the 6 : 1 range, depending on whether miscible or not. Also, note, this is over life of the field and will include "recycled" CO_2 at some point, thereby reducing "new purchases".

Results

Based on available field data, **there appears to be potential for moderate EOR development.** This general assessment is based on available data and does not include detailed field tests and seismic data. Nor does this assessment factor in certain non-technical data, all of which are sufficient to halt commercial development.

[28] Some fields were labeled as "nearly miscible". These were categorized as "immiscible" to sustain reasonable application of basic criteria. Further field work, especially through slim-tube tests might lead to alternative findings.
[29] In some cases, a simple "slim-tube" test can be performed to more definitively establish whether a field is or is not miscible.
[30] Meaning mcf CO_2 injected per bbl of oil produced.

Chief among these are:

- Owership interests – are the fields unitized or is unitization possible and do any existing owners care to undertake a flood?
- Financing – current markets present new and pressing issues which borrowers must overcome.
- Commercial development – who and how would "first-mover" efforts be led
- Systemic risk – the commercial and execution risk to the system, a system consisting of disparate entities (e.g. CO_2 suppliers, infrastructure providers, and EOR producers).
- Technical challenges - further technical findings regarding respective field geologies
- Legal / regulatory challenges

Figure III-6 below summarizes possible CO_2 demand and oil production based on field and source analysis. Though not final, the summary does provide a good basis for quantifying the "size of the prize" as some would say. It further provides a sense of how big and dynamic the supply system would need to be to accommodate EOR demand. Salient features indicate:

- A phased source and EOR development path, focusing on miscible fields first, then immiscible.
- On average, just over 80 mmcf/d of CO_2 supply would be required initially, growing to nearly 350 mmcf/d to meet demand from immiscible fields.
- Expected daily oil production would be in the 30 to 50 mbd range (thousand bbls per day).

Figure III - 6: CO2 Flood Projections

	OOIP bbls	Recovery Rate	Oil Recovered bbls (1)	Annual Prod'n bbls (2)	CO2 Demand (3) Tonnes/ Yr (4)	CO2 Demand (3) mmcf/ day
Total OOIP	**7,000,000,000**					
Miscible	**1,000,000,000**	**8%**	80,000,000	4,000,000	1,263,158	66
		12%	120,000,000	6,000,000	1,894,737	99
Immiscible	6,000,000,000				***AVG =***	***82***
Possible	**2,580,000,000**	**6%**	154,800,000	7,740,000	3,258,947	170
43%		**10%**	258,000,000	12,900,000	5,431,579	283
					AVG =	***226***
Unlikely	3,420,000,000	**0%**	-	-	-	-
57%						
Recoverable Bbls	**3,580,000,000**		**234,800,000**	**11,740,000**	**4,522,105**	**235**
			378,000,000	**18,900,000**	**7,326,316**	**381**
		Average :	***306,400,000***	***15,320,000***	***5,924,211***	***308***
Implies avg. annual production range =				**32,164**	**51,781**	**bbls/ day**

(1) Assume recovery production over term = **20** years
(2) Figures based on a mathematical "smoothing" of probable returns over 20-yr term.. Actual figures will vary.
(3) Assumes utilization ratio (e.g. mcf/ bbl recovered) of 6:1). Will vary by field, field life, crude, geology.
Ratio = **6** :1 for miscible
8 :1 for immiscible
(4) Assumes conversion ratio mcf/ ton = **19** :1

FINDING: *Based on the criteria and elements previously described, Illinois has sufficient positive characteristics in its market and EOR potential to merit further pursuit. However, as with most market-driven developments, step 1 must be achieved. In THIS case, that requires finding a company(s) willing to invest in supplying CO_2 to a company(s) willing to undertake the investment and risk of a CO_2 flood. OR MORE SIMPLY PUT – FIND A WILLING BUYER AND SELLER!*

This will NOT be an easy task. Without more detailed discussions and perhaps confidential assessments of firms' ability and desire to carry forward, it is plausible that the context is there, but no one with whom to add substance.

IV. Sequestration – Storage

Defined

As defined by the Phase I DOE source-sink reconnaissance projects, the MGSC defined oil reservoirs as "miscible or immiscible, as a means to determine their importance for EOR during CO_2 injection and subsequence CO_2 sequestration. The use of miscible describes CO_2 and crude oil that become a single mixture under certain temperature and pressure conditions via the mass transfer of intermediate hydrocarbons (C5 – C12) from the crude oil to the CO_2 phase. Immiscible describes CO_2 and crude oil under conditions where there is a distinct and identifiable separation of the two fluids. Mass transfer exists in immiscible CO_2 flooding of the oil reservoir, however, there is a CO_2 rich phase and a crude oil rich phase."

The conditions that are optimal for miscible CO_2 injection are "critical pressure (1073 psia) and temperature (87.8 deg. F.) of CO_2 are important to determining miscible and immiscible potential of oil reservoirs. For miscibility to occur CO_2 must exist as a critical fluid (i.e. dense phase, liquid-like, supercritical CO_2); this is only possible for reservoir temperature exceeding the critical temperature of CO_2 and reservoir minimum miscibility pressure (MMP; which increases with temperature and is at least equal to the critical pressure of CO_2)."

> ***Finding:*** *If EOR development utilizing CO_2 transported from multiple source points in the **Illinois Basin** can be done economically, then the infrastructure utilized therein could be used to store additional CO_2 not only in the oil intervals but in coal and brine intervals associated with the same oil trapping structures.*

CO_2 Storage-Beyond EOR

The MGSC has identified that the potential for CO_2 storage in brine reservoirs has a capacity that goes far beyond the identified capacities of the Phase I studies that focused on structural closure over oil producing structures as the controlling storage factor. This study supports this conclusion and would suggest that any possible EOR infrastructure development can support any future consideration for CO_2 storage at those sites.

It is recognized that brine reservoirs extend outside the structural closures allowing for the potential of storing large additional volumes of CO_2. This suggests that the infrastructure that could be built around moving CO_2 to EOR sites could be used long after the EOR benefits are realized. The recognition of regional brine reservoir storage capacity is being tested at the Phase III Decatur ADM project at a site that does not utilize a structural closure associated with an oil trap. The success of this project would demonstrate that CO_2 could be stored in areas not necessarily needing a defined structural trap. This would also suggest that there is a need for a basin wide testing of CO_2 storage capacity beneath all large CO_2 point sources. Such an effort would enable the development of the most optimal pattern for both CO_2 for EOR and CO_2 that is simply captured and stored in the subsurface. An example would be the full development of a capture and transportation infrastructure targeted for EOR but used to move CO_2 to any optimal storage location. If each major pointsource location could be tested by drilling an evaluation well to test the storage potential at that site, the business entity could decide whether it is more economical to move the CO_2 to an EOR operation or not.

Depending on the method of determining CO_2 value, various alternatives are available for consideration. These include: (1) use onsite for EOR, (2) use of beneficial geology at owned site for public sequestration, or (3) integration into a larger CO2 infrastructure for EOR/ sequestration at other geographic locations.

> ***FINDING:*** *If regional brine storage of CO_2 proves to be feasible across the Illinois Basin, then the infrastructure utilized for EOR could be used to move additional CO_2 to already established CO_2 storage sites or to point source locations that have established at their specific locations that they could store CO_2 on site and possible take CO_2 from other locations that do not have these optimal storage intervals.*

Looking ever further afield, while CO_2-EOR may or may not ever develop in the State, a future carbon-constrained world might provide the State of Illinois with an alternative, new industry to develop – SEQUESTRATION. It could be that with that infrastructure and development in place, EOR might then be more readily implemented.

> ***FINDING:*** *For any CO_2a based EOR system to function,* ***it is necessary to have an accompanying sequestration site(s)****. This essential development need is based on likely offtake and scheduling disconnects between the supply (emitters) and demand (EOR firms).*
>
> *Only a combination of sequestration (storage) AND EOR can provide the level of consistent performance an emitter would expect in assuring continuous carbon abatement. Consequently, pure sequestration or storage serves the dual role of being a "safety-valve" in a dual EOR/ sequestration environment.*

V. INFRASTRUCTURE

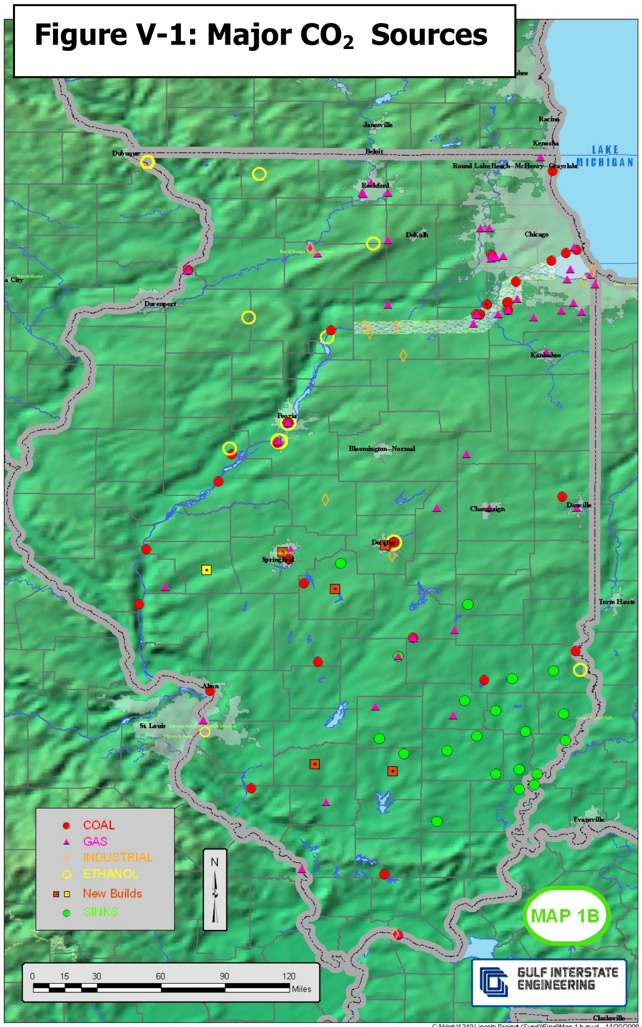
While the ingredients for a CO_2-EOR development are there, one last thing remains – there are sources, there are potential EOR fields, there is sequestration (storage) capacity, both within the EOR sites but in adjacent formations as well. The last major ingredient is the infrastructure to tie it all together.

In examining the possible infrastructure designs, the primary motivation was to keep it simple and direct, staying focused on the commercial BUT – to keep an eye on the longer term sequestration needs not only of the State of Illinois, but perhaps as significantly, the entire Illinois Basin region.

Consequently, the infrastructure design proceeded upon the following basic principles:

1) **Stay simple, stay direct** with minimal environmental/ landowner impact
2) **Design flexibly** for EOR now and larger sequestration/ carbon abatement in the future.
3) **Maximize bolt-on approach** for other sources not incorporated herein for EOR supply (e.g. spread a broad net with standardized platforms).
4) **Stay R-E-A-L** by designing for Today, but planning for the Future. Focus on existing and near term sources for baseload supply. Incorporate longer-term potential sources in routing design.
5) **Stick to creating a commercially viable system that is structured to drive EOR development** but sufficiently flexible to accommodate increased carbon abatement through geological storage.

Figure V-1: Major CO_2 Sources



Map depicted in Figure V-1 highlights major sources and sinks from which a CO_2 supply infrastructure was considered.

In the first phase a projected quantity of approximately 200 Mmscfd (9 MMmtpy) of CO_2 will be collected from mid state sources. In phase 2 five additional sources from northern part of the state with approximately 350 Mmscfd (2MMmtpy) CO_2 will be added to the system. Most of these sources are Ethanol based for reason of economy of capture as explained earlier.

For the most part, the proposed pipelines follow existing pipeline corridors where available. In the absence of existing pipeline corridors, utility corridors were used. This is a reasonable approach at this stage of the study as it would preclude any major environmental issues associated with permitting a CO_2 pipeline.

The pipeline route passes though a fairly flat country with less than 600 feet elevation difference over a total run length of more than 350 miles. The slope is gentle and generally from north to south (sources to sinks).

CO_2 gas displays special properties. At a pressure of 1073 psig and 87.8 ^oF it goes into a supercritical dense phase and acts as a compressible fluid. In this state it can be pumped just like a liquid and has potential for saving in capital cost of expensive compression equipment as well as in lower operating cost in horsepower requirement. For this reason, most cross country CO2 pipelines are designed for operation in the dense phase, with source pressure generally ranging from 2000 psig to 2700 psig (within the limit of 900# system). Intermediate pumping is added as required to ensure that the line pressure remains well above the critical pressure and CO_2 stays in dense phase.

CO_2 in dense state is a high energy gas and when released, it can cool the pipe to extreme low temperatures. The pipeline material requires special testing during manufacture to ensure high ductile strength at low temperatures.

Based on the economics of capture costs for Lincoln project, a source pressure of 2000 psig was selected at each plant location. A preliminary hydraulics analysis was performed for the pipeline system to determine required pipeline sizes for each of the segment with the system. The system with pipe sizes and pipe lengths is shown in Figure V-2.

The proposed pipeline system with Line 1 and 2 contains line pipes in the size range of 6" minimum to 30" maximum with associated pumping stations and an overall pipe length of approximately 540 miles. A budgetary cost estimate was developed for this system using best available current market pricing for pipe and associated equipment. Overall cost estimate for the full complete system is approximately $1.4 billion, with a basic infrastructure built on planned gasification facilities and some of the lower ethanol and coal-fired sources in the $850 million range[31].

> ***Finding:*** *Alternative infrastructure deployment options are needed to accommodate an uncertain development path and carbon environment. Varying financing options can be further examined wherein current needs are met, yet contingencies are built in for future sequestration need.*

[31] The tables and additional data in Appendix H summarize in detail all cost details. Due to the complexity of matching to various demand scenarios, more details are left for further discussion elsewhere.

Figure V-3: Proposed 2-Phase Pipeline System (Option A)

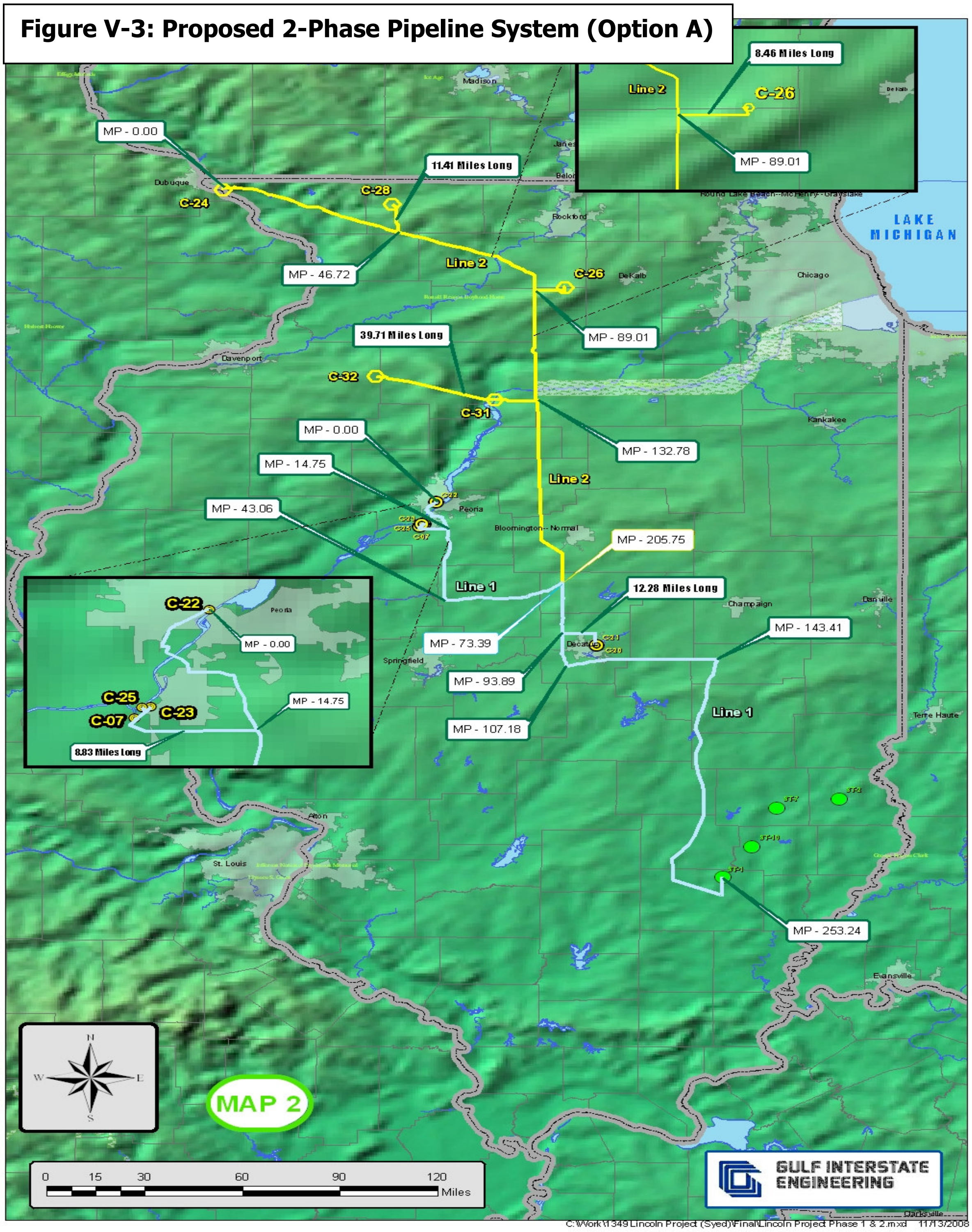


Table V-4: Project Lincoln Pipeline Infrastructure

Line 1 (Ethanol C-22, 23, 25, 21 & Coal C-07, 20)

SN	Description	Flow mmscfd	Line Size inches size	Line Size inches OD	WT inches	Unit Weight lbs/ft	Length miles	Weight tons
1	C-22 to C-23/25/07 junction	66	12	12.750	0.375	49.56	14.75	1,930
2	C-23 to C-25 junction	38	8	8.625	0.322	28.55	0.44	33
3	C-25 to C-23 junction	19	8	8.625	0.322	28.55	0.38	29
4	C-23/25 to C-07 junction	57	8	8.625	0.322	28.55	0.84	63
5	C-07 to C-23/25 junction	216	12	12.750	0.375	49.56	0.17	22
6	C-23/25/07 to C-22 junction	273	20	20.000	0.406	84.96	7.55	1,693
7	C-22/23/25/07 to Line 2 junction	339	20	20.000	0.406	84.96	58.64	13,153
8	C-20/21 to Line 1 & 2 junction	110	12	12.750	0.375	49.56	12.28	1,607
					Sub-total Line 1:		**95**	**18,531**
	Line 1 (with expanded Line 2 flow added in)							
9	Line 1 & 2 to C-21/20 junction	440	20	20	0.406	84.96	20.5	4,598
10	Line 1 & 2 to sink ST-1	550	24	24	0.476	119.59	159.35	50,310
				Sub-total Line 1 expanded:			**180**	**54,908**
				Sub-total Entire Line 1			**275**	**73,439**

Line 2 (Ethanol C-28, 26, 31, 32 & Ammonia C-24)

SN	Description	Flow mmscfd	Line Size inches size	Line Size inches OD	WT inches	Unit Weight lbs/ft	Length miles	Weight tons
11	C-24 to C-28 junction	21	10	10.750	0.365	40.48	46.72	4,993
12	C-28 to C-24 junction	10	8	8.625	0.322	28.55	11.41	860
13	C-24/28 to C-26 junction	31	10	10.750	0.365	40.48	42.29	4,520
14	C-26 to C-24/28 junction	12	8	8.625	0.322	28.55	8.46	638
15	C-24/28/26 to C-31/32 junction	43	12	12.750	0.375	49.56	43.77	5,727
16	C-32 to C-31	29	12	12.750	0.375	49.56	29.87	3,908
17	C-31/C-32 to Line 2	58	12	12.750	0.375	49.56	9.84	1,288
18	C-24/28/26/31/32 to Line 1 jcn	101	16	16.000	0.375	62.58	72.97	12,055
				Sub-total Line 2			**265**	**33,989**

Grand Total Pipelines M	**540**	**$ 107,428**
Total Project Capital Cost - MM $	**$**	**890**
Capital Cost per mile - MM$/mile		**1.65**

Based on BA simulation

This "base infrastructure system" consists of a two-phase development with construction of a Line 1 and Line 2 pipeline for an estimated total cost of approximately $1.1 billion. What the system shown enables is the following:

- **Focus:** Line 1 is the first phase of the development. It is based on nearby (or relatively so) CO2a sources and is directed at supplying EOR demands with one or two sequestration sites includes in the overall system.
- **Flexibility**: If more demand is needed, and IF only real/ existing sources are considered, then line 1 is sized so as to accommodate an expansion via Line 2 to other ethanol plants and an ammonia plant further north. However, it must be noted that this expansion is NOT the most desirable or advantageous due both to distance and cost. A more desirable alternative is through the expansion of Line 1, called 1a, wherein possible future gasification-based supply is linked in.

The cost summary profiled in Figure V-5 highlights this approach wherein planned / expected gasification sources are added into the system. With three different infrastructure deployment alternatives, a flexible plan exists to accommodate a strong-carbon constraint or a moderate to a non-existent/ EOR only one. All options are summarized in the table below[32].

Option	Name	Description	Cost
1	Base Case	Includes excess capacity to meet all EOR demand from ethanol and some coal sources	**$ 1.1 billion**
1a	Expanded Base	Includes future gasification projects	**$1.4 billion**
2	EOR focused	Includes only sources in option 1 with the exception of any coal plants but includes gasification sources.	**$0.9 billion**

[32] No specific tariffs have been included in the report due to the extreme uncertainty in sourcing. Generally, given the capex and opex associated with the 3 options presented, it is expected that a pipeline tariff in the $0.25 to $1.00 or $5 to $20/ tonne range would exist. This does not factor in excess capacity for growth as noted elsewhere.

Given the uncertainties of "planned" gasification projects, the risk of ethanol-only sources, and the costs of coal-based sources – the designed infrastructure can move toward any source that is commercially viable.

Table V-5: Alternative Infrastructure Development

(Based on Gasifier Projects Included *)

Line 1 (Ethanol C-22, 23, 25, 21; Coal C-07, 20 & Tenaska, Secure) 12/10/2008

SN	Description	Flow mmscfd	Line Size inches size	Line Size inches OD	WT inches	Unit Weight lbs/ft	Length miles	Weight tons	Total Price MM$
1	C-22 to C-23/25/07 junction	66	12	12.750	0.375	49.56	14.75	1,930	4.82
2	C-23 to C-25 junction	38	8	8.625	0.322	28.55	0.44	33	0.08
3	C-25 to C-23 junction	19	8	8.625	0.322	28.55	0.38	29	0.07
4	C-23/25 to C-07 junction	57	8	8.625	0.322	28.55	0.84	63	0.16
5	C-07 to C-23/25 junction	216	12	12.750	0.375	49.56	0.17	22	0.06
6	C-23/25/07 to C-22 junction	273	20	20.000	0.406	84.96	7.55	1,693	4.23
7	C-22/23/25/07 to Line 2 junction	339	20	20.000	0.406	84.96	58.64	13,153	32.88
8	C-20/21 to Line 1 & 2 junction	110	12	12.750	0.375	49.56	12.28	1,607	4.02
				Sub-total Line 1			**95.05**	**18,531**	**$ 46**
	Line 1 (with Line 2 flow)								
9	Line 1 & 2 to C-21/20 junction	440	20	20	0.406	84.96	20.5	4,598	11.50
10	Line 1& 2 to Secure junction	550	24	24	0.476	119.59	6.01	1,897	4.74
11	Secure to Line 1 & 2	200	16	16	0.375	62.58	4.88	806	2.02
12	Line 1 & 2 to Tenaska junction	750	30	30	0.595	186.86	7.28	3,591	8.98
13	Tenaska to Line 1/2 (MP-107.28)	200	16	16	0.375	62.58	21.26	3,512	8.78
14	Line 1/2 MP-107.28 to ST-1	950	36	36	0.714	269.08	146.06	103,756	259.39
				Sub-total Line 1& 2			**205.99**	**118,162**	**$ 295**
				Sub-total Entire Line 1			**301.0**	**136,693**	**$ 342**
	Line 2 (Ethanol C-28, 26, 31, 32 & Ammonia C-24)								
15	C-24 to C-28 junction	21	10	10.750	0.365	40.48	46.72	4,993	12.48
16	C-28 to C-24 junction	10	8	8.625	0.322	28.55	11.41	860	2.15
17	C-24/28 to C-26 junction	31	10	10.750	0.365	40.48	42.29	4,520	11.30
18	C-26 to C-24/28 junction	12	8	8.625	0.322	28.55	8.46	638	1.59
19	C-24/28/26 to C-31/32 junction	43	12	12.750	0.375	49.56	43.77	5,727	14.32
20	C-32 to C-31	29	12	12.750	0.375	49.56	29.87	3,908	9.77
21	C-31/C-32 to Line 2	58	12	12.750	0.375	49.56	9.84	1,288	3.22
22	C-24/28/26/31/32 to Line 1 jcn	101	16	16.000	0.375	62.58	72.97	12,055	30.14
				Sub-total Line 2			**265.3**	**33,989**	**$ 85**
			Grand Total Pipelines				**566**	**170,682**	**$ 427**

Pipeline Materials (at $2500/ton)	**(MM$)**	**$ 427**
Pump Stations (2), Line Valves etc.	**(MM$)**	**$ 25**
Sub-total material	**(MM$)**	**$ 452**
Sub-total E&C, ROW, Permits, & all other	**(MM$)**	**$ 917**
Total Project Capital Cost - MM $		**$ 1,369**
Capital Cost per mile - MM$/mile		***$ 2.42***

Based on BA simulation
** Includes prospective IGCC and SNG projects announced by Tenaska and Secure.*

VI. Summary Comments

In today's carbon-focused world, attempts to leverage carbon-mitigation with ongoing industrial and economic activity is both prudent and challenging. For CO_2, that linkage exists with EOR developments. However, such developments can not happen in a vacuum, does not happen accidentally, and can not serve as a silver bullet for either carbon issues or larger economic concerns. It is merely a start.

Based on assessment of key components required to develop a CO_2-EOR market, the State of Illinois has the ingredients required of such an undertaking. Specific assessment summaries of the major constituent components are highlighted below.

Findings

1. **CO_2 Supply**

   As noted, the State of Illinois has more than enough CO_2 to meet any expected EOR demand. The issues are of pricing, reliability, and availability.

   - CO_2 emissions from existing coal-fired power plants are more than sufficient supply to meet expected EOR demand. But capture costs put it beyond what is reasonable for EOR markets. Without massive State or Federal assistance, it is unlikely that much carbon will be captured off of current operating coal-fired power plants.

   - Ethanol plants, though dispersed around the state, are the only existing source with adequate capture economics to support an EOR-centric supply system. However, the ethanol industry is volatile at best. Its future – beyond 3 to 5 years – is uncertain and nobody within the industry would consider a CO_2 supply agreement for a long enough term to satisfy the certainty required of an EOR producer. Nevertheless, as sources go – it is there and it is relatively cheap.

   - A primary CO_2 supply system, with a few exceptions, can only arise AT THIS TIME from the ethanol industry with perhaps a few coal plants added in by early-movers. It is the only low-cost, readily available CO_2

source in the region. For it to become commercially viable, it is likely the State will need to intervene to provide some type of guarantees or other similar assistance to facilitate commercial development.

- Supply will evolve in the State over time. The most beneficial development for supply to EOR sites would be some gasification-based plants (IGCC/ SNG) in areas relatively close to the EOR region. Such a development would satisfy both price and reliability, the latter especially so if augmented with regional ethanol supply.

- State-centric supply will likely narrow the supply choices. This study is focused on the State of Illinois. However, there are gasification projects in nearby Indiana and western Kentucky which might serve as a quicker source of CO2 if in fact the State's nascent EOR market needed it. Alternatively, the State of Illinois might be a preferred sequestration site for these non-state regional carbon sources. The issue of State versus regional carbon use needs to be further explored and considered in both a legal and economic context.

- Commercial time frame conflicts: The EOR producer needs long term supply commitments of 10 years of more. The ethanol industry does not work in such time frames. More importantly, supply, demand, sequestration, infrastructure MUST all be coordinated in a manner which precludes any single participant from being over exposed to completion risk. As noted earlier in this report, the "alignment of all commercial interests" was a key condition of a CO2-EOR market development. Such "alignment" amongst such divergent parties in the State is significant challenge.

2. CO_2-EOR / Sequestration

- EOR opportunities are there, but limited miscible flood potential evident at this time. Substantial possibilities if further assessment of immiscible fields yields favorable results.

- Nothing can proceed without a buyer - an operator who has the resources (financial and human) and desire to conduct a flood and the patience to put it together. **This single item likely represents the single greatest obstacle to EOR development within the State of Illinois.**

- There is an inherent inconsistency in overall CO_2-EOR development based on CO_2a supply. This issue arises from what could be termed the EOR/ Sequestration Conundrum as defined earlier in this report. It is no small matter. And though State efforts – either regulatory or legislative – can impact it, they likely are not enough to counter what most likely will be a federally induced issue and constraint.

- Sufficient immediate and near term storage capacity exists to balance EOR demand and serve as a system "safety-valve" while enabling the system to fully accommodate the CCS needs of all emitters. However, based on MGSC's own work, longer term storage questions do exist – predominantly based on the quantified capacity and term such storage could handle. More work by the State of Illinois and the MGSC is needed, especially in addressing the dynamics of non-contained saline reservoir storage. Without better knowledge, the State's sequestrable capacity may be sufficient only as a back-up for EOR and not as a separate ongoing undertaking.

3. Infrastructure

- Dual purpose development directed at supply requirements for a CO_2-EOR industry, but designed to accommodate future growth needs through sequestration/ storage.

- A two-phase engineering and construction plan, focused on the most likely initial EOR activity (miscible fields), then evolving with other supply to integrate with expansion potential with immiscible floods.

- A flexible path plan for growth. The plan being characterized by a "baseload" ethanol supply, then augmented either through (a) more ethanol with some coal or (b) output from planned gasification projects in the southern part of the State.

- Sufficient flexibility to accommodate "local" Illinois needs, but capable of dealing with broader carbon sequestration needs throughout the Midwest region.

- Three infrastructure development paths are offered, none exclusive of the others, each dependent on the real-world commercial developments that might be expected.

Combining these elements and integrating them into a conceptual supply / demand schedule yields the table in Figure VI-1. Key salient features therein are:

- A two-phase supply and infrastructure development with initial CO_2 supply of 189 mmcf/d, directed at phase I miscible EOR development requiring 66 mmcf/d.
- An immediate sequestration need to accommodate supply overage for this initial period.
- Phase II supply development offering two alternatives. The first based on existing supply, albeit with 2 key coal plants also included. An alternative supply path displaces all pointsources shown in II-A with prospective new sources at proposed gasification facilities.
- Aggregate CO_2 supply of up to 550 mmcf/d satisfying demand at approximately 350 mmcf/d. Excess balances sequestered in nearby aquifers. The storage of excess is depicted graphically in Figure VI-2.
- Though oversupplied based on the "numbers" only, market experience indicates that almost every CO2 flood starts conservatively, then with some confirmation of breakthrough, demand continues to increase beyond the "simple template calculations" applied herein. Consequently, supply exceeds theoretical demand – the balance of which can be sequestered. However, sufficient volume initial exists to meet large, unexpected increases in demand.
- Varying total project costs from around $800 million to $1.4 billion depending on the breadth and depth of sources. The most likely infrastructure path will be one focused on both EOR and the broader, longer term sequestration requirements should the latter need arise.

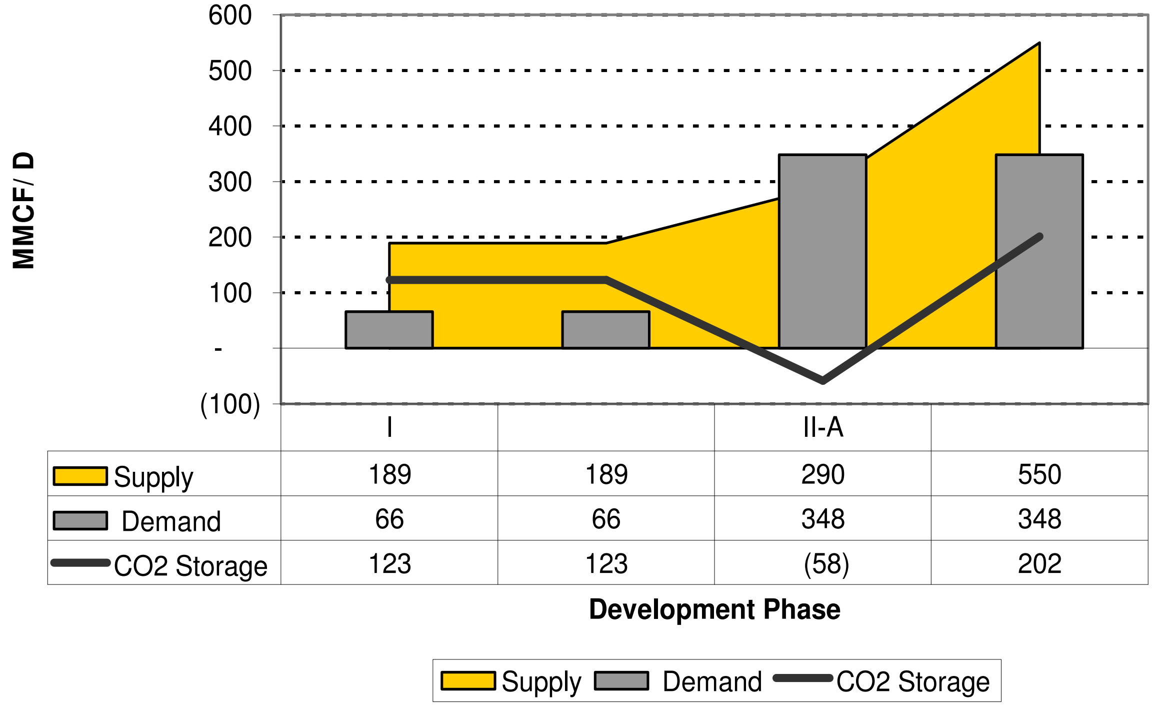
Figure VI - 1: Supply/ Demand Profile

Development Phase	Supply				Demand *		
	Description	Code	Volume		Description	Volume	
			mmcf/ d	MT/ yr		mmcf/ d	MT/ yr
I	**Ethanol ONLY**				Miscible floods	82	570,000
	ADM Peoria	C22	66	457,710	ST 1, 2, 7, 10		
	Aventine Renewable	C23	38	263,530			
	MGP Ingredients	C25	19	131,765			
	ADM Decatur	C21	66	457,710			
	Total Phase I =		**189**	**1,310,715**		**82**	**570,000**
II	**N. IL Ethanol plants**				Viable Immisicible	226	1,568,640
	Royster-Clark Nitrogen	C24	21	145,635	ST 3, 4, 5, 8, 11, 13,16, 17		
	Illinois River Energy	C26	12	83,220			
	Marquis Energy	C31	29	201,115			
	Patriot Renewable Fuels	C32	29	201,115			
	Adkins Energy	C28	10	69,350			
	Subtotal =		**101**	**700,435**			
	Central IL Coal (1st mover)						
	ADM Decatur Coal	C20	44	305,140			
	Powerton #1	C7-A	108	748,980			
	Powerton #2	C7-B	108	748,980			
	Subtotal =		**260**	**1,803,100**			
	Total Phase II =		**361**	**2,503,535**		**226**	**1,568,640**
			Supply			**Demand**	
			mmcf/ d	*tons/ yr*		*mmcf/ d*	*tons/ yr*
	Grand Total ===>		**550**	**3,814,250**		**308**	**2,138,640**

(1) Conversions @ **19** mcf/ ton   * Demand based on mean of values shown in Figure III-6

The supply / demand balances reflected in IV-1 highlight the role sequestration (e.g. storage only) serves in a CO_2a based supply system. Graphically, the variance in sequestration vis-à-vis overall CO2 supply is depicted graphically in Figure VI-2. As shown therein, the magnitude of sequestration will vary over the development term, but at all times be available to emitters as a carbon-mitigation tool. Such 24/7 carbon management will be an important element in any carbon-constrained regime that might develop.

Figure VI - 2: Supply Demand Balances



	I		II-A	
Supply	189	189	290	550
Demand	66	66	348	348
CO2 Storage	123	123	(58)	202

With the basic ingredients present and viable, there is an opportunity for the State of Illinois to seek development of CO_2-EOR with a small, but potentially even larger sequestration industry. The task is significant however. There are no easy, silver bullets to get it done. In the best of circumstances, it will likely take 2 – 3 years to initiate and 5 – 10 years to develop.

Challenges

To pursue any opportunities, it is important to first take stock of the assets at hand. Toward this end, the State of Illinois has strong assets with which to proceed.

1. **Political will** to examine it.
2. **Coal reserves** with which to provide, subject to the various permitting/ CCS provisions, a means to fuel this activity.

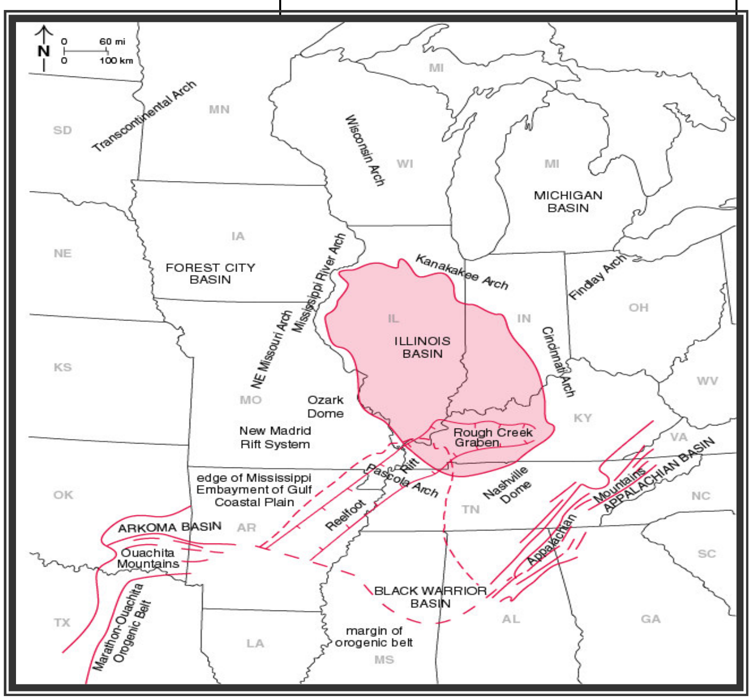
3. **Technology / institutional support**
   The State has excellent educational institutions and a State Geologic Survey that's one of the nation's best. Its efforts both within the MGSC and overall oil and gas development within the State speak well of both its director (Dr. Rob Finley) and his excellent staff.

4. **Location**
   Middle of the Midwestern U.S. – the middle of the primary coal-fired power generating region in the U.S. (hence large possible CO2 sources) and atop of one of the largest saline reservoirs in North America (storage potential). With moderate, yet real, EOR-capable oil reservoirs.

5. **Moderately favorable CO_2 flood candidates**. As previously noted, there are sufficient oil reserves that at least satisfy initial screening to suggest commercial opportunities exist. More subsurface work is required to fully characterize the magnitude of recoverable oil. This work will include some additional seismic and slim tube[33] tests.

6. **New Sequestration industry**
   Could examine serving as a larger sequestration center, using strengths of geology overlying geography plus skill sets in the ISGS, a small but existing oil industry, familiar legal structure (basis FutureGen effort.)

Figure VI-3: Illinois Basin



[33] A physical test of a reservoir to determine its miscibility. Costs usually in the $5000 - $10,000 range.

Closing Comments

In this day of carbon concerns, there is heightened awareness of the benefits CO_2-EOR can realize. Though significant oil reserves exist in many different areas throughout the U.S., only a handful have sufficient resources, infrastructure, and desire to attempt any development program. Even fewer have the requisite ingredients with which to attempt creating a carbon-mitigation based industry based CO2a -EOR business and a linked sequestration business. The State of Illinois is one of them.

The task to achieve it will NOT be easy. There are challenges in every segment of the effort. Yet the opportunity does exist. While the ingredients are there, it is the final roadmap or recipe which ultimately will determine what is created and how it functions. The State of Illinois will need to play a vital and active role in development of any such activity. This role applies to every phase of the undertaking – capture, EOR, infrastructure (for excess capacity), and sequestration.

Though every effort has been made to build the models and economics on a purely market-driven development, it is likely that some State or Federal support of some sort will be required – especially from a sourcing perspective.

With climate change legislation and various carbon fiscal regimes being considered nationally and in various statehouses, it is logical to assume some such motivation or driver develops through which CO2-EOR development is accelerated. This review, while cognizant of such developments, does NOT accept that such developments are essential to some of the basic efforts defined herein.

Appendix A – Project Lincoln Team

Project Lead: Kinder Morgan CO_2 Company, L.P.

Kinder Morgan CO_2 Company, L. P. (KM CO2) is a division of Kinder Morgan Energy Partners L.P. (KMP), one of the largest midstream energy companies in the U.S. KM CO2 is the largest marketer and transporter of CO_2 for EOR/ sequestration in the world. It is also a leader in applying advanced technologies for enhanced oil recovery (EOR) and is the second largest oil producer in the State of Texas with nearly 100% of its production associated with its tertiary (CO_2) oil operations.

KM CO_2 owns and operates over 1300 miles of CO2 pipelines and 200+ miles of crude oil pipelines. It both produces and transports over 20 million tonnes of CO2 per year. This oil production experience, coupled with extensive operational expertise in handling and transporting CO_2 underscores KM CO_2 proven ability to execute. The company's unique experience includes:

- Conducted the only large scale hydrostatic test on a CO_2 line,
- Built the last major CO_2 pipeline (100+ mile Centerline in West Texas)
- Expanding CO_2 capacity in the region at a cost of approximately $250 million.

Kinder Morgan is a major source of CO_2 supply to the oil industry and to its own EOR operations in the world's largest EOR region - the Permian Basin. Operating the largest CO_2 pipeline in the business and the largest natural source in the Americas, the McElmo Dome, KM CO2 continues to expand its carbon expertise through CCS engagement throughout North America.

Project Partners / Contractors

Gulf Interstate Engineering, Inc.

Based in Houston, Texas, Gulf Interstate Engineering Company (Gulf) has served the energy industry since 1953, providing quality project management and engineering services to the worldwide oil and gas industry. Having been in business for over 55 years, Gulf takes pride in being one of the most experienced companies in the industry. Gulf is committed to delivering on time, quality services and solutions to our customers. Our integrated project management systems, proven design applications and advanced web-based reporting tools brings value to our clients.

Gulf specializes in the management and engineering of pipeline systems, a focus that covers onshore and offshore pipelines, gathering systems, production facilities, pump and compressor stations, storage terminals and loading facilities. Gulf's experience and capabilities encompass all aspects of oil and gas production from the wellhead to the export terminal.

Gulf has extensive experience in the engineering and design of high-pressure carbon dioxide (CO_2) transmission systems. For Project Lincoln, Gulf is coordinating and designing the pipeline infrastructure to carry CO_2 from identified capture sources to potential sequestration sinks with priority to tertiary oil recovery.

Praxair, Inc.

Praxair is the largest industrial gases company in North and South America, and one of the largest worldwide, with 2007 sales of $9.4 billion. The company produces, sells and distributes atmospheric, process and specialty gases, and high-performance surface coatings. Praxair products, services and technologies bring productivity and environmental benefits to a wide variety of industries, including aerospace, chemicals, food and beverage, electronics, energy, healthcare, manufacturing, metals and others.

Praxair is working with an alliance of industrial, engineering and academic companies on a project to demonstrate technology designed to capture carbon dioxide emissions from both new and existing coal-fired electricity-generating plants. If successful, the demonstration project, involving the construction of a new, 50-megawatt circulating fluidized bed (CFB) plant in Jamestown, New York, would be the first of its kind in the United States, integrating several tested technologies for the first time.

Praxair's oxy-coal technology involves the introduction of pure oxygen instead of air into the utility boiler, creating a highly concentrated stream of carbon dioxide which is more economical to capture than emissions from existing systems. The technology is designed to capture more than 90% of the carbon dioxide generated, and also to further reduce emissions of sulfur dioxide, nitrogen oxides and mercury.

More information on Praxair is available on the Internet at www.praxair.com

Patrick Engineering, Inc.

Patrick Engineering Inc. has **over 30 years expertise in project management**, specializing in the fields of engineering, planning, technology consulting and construction management. **The Engineering News Record (ENR) has included Patrick in its ENR Top 500 for 16 consecutive years, including a rank of 238 in 2009 with revenues exceeding $500 Million**. Midwest Construction Magazine has similarly ranked Patrick's sister company, Albin Carlson and Co., as the Midwest's **9th largest transportation contractor** and the **9th largest water supply contractor.**

Patrick is headquartered **in Illinois, performs work in 36 states through 12 regional offices, and employs more than 400 professionals.** Clients include government agencies, public utilities and major corporations in a broad range of industries. **Patrick's core competencies include environmental, infrastructure, hydrogeology, heavy civil, construction, as well as energy engineering including transmission, substation and smart-grid design services.** Patrick clients recognize our commitment to excellence and that is why **Patrick has over 85% of its work coming from repeat business.**

Schlumberger Carbon Services, Inc.

Schlumberger Carbon Services provides comprehensive geological storage solutions for carbon dioxide (CO_2), consistent with care for health, safety, and the environment. Technical expertise, project management and technology are leveraged from more than 80 years of proven subsurface evaluation experience in the oil & gas industry.

For more information visit www.slb.com/carbonservices

Schlumberger

Schlumberger is the world's leading supplier of oilfield technology, integrated project management and information solutions that optimize reservoir performance. Founded in 1926, the company employs more than 80,000 people of over 140 nationalities working in approximately 80 countries. Schlumberger revenues were $23.28 billion in 2007.

For more information visit www.slb.com

Appendix B – Terminology & Units

Units

CO_2 is marketed, sold, transported, and controlled in the U.S. in units of "thousand cubic feet" or "mcf". CO_2 floods typically indicate offtake volumes in "millions of cubic feet" or "mmcf". However, most policy discussions in the U.S. and abroad, especially within a GHG or CCS context, refer to CO_2 in metric tones or "tonnes" or "MT". The conversion of one to the other therefore, is significant. Within this study, BOTH figures are cited wherever possible so that the reader does not need to convert. In general volumetric discussions, a simple rounded conversion of 20:1 is normally used.

A conversion factor of approximately 19.0 mcf : 1 metric tonne was applied throughout this report.

Terminology

A few of the special terms used throughout the report:

- **CO_2 Flood**: A "flood" is a term used to describe a tertiary CO_2 injection project. A reservoir undergoing injection is said to being "flooded".
- **CO_2n** : A term used to distinguish the sourcing of CO_2 in special situations. The "n" indicates it was derived from a "natural" or underground source.
- **CO_2a** : A term used to distinguish CO_2 sources from anthropogenic or man-made sources. Anthropogenic sources predominantly are emissions from power plant, chemical, petrochemical, and other hydrocarbon processing industries. Most carbon initiatives deal with the capture, transport, and storage of this type of CO_2.
- **Tertiary Recovery**: Oilfield term applied to an advanced recovery system normally using some type of gas – be it nitrogen, carbon dioxide, or other special chemical injectants. It usually follows a secondary recovery which is a water-flood project.
- **Offtake**: Term used to describe the volume a Buyer will "take off" from the Seller. An "offtake agreement" is a contract to obtain CO_2 volumes.

Appendix C – CO_2 Source Assumptions

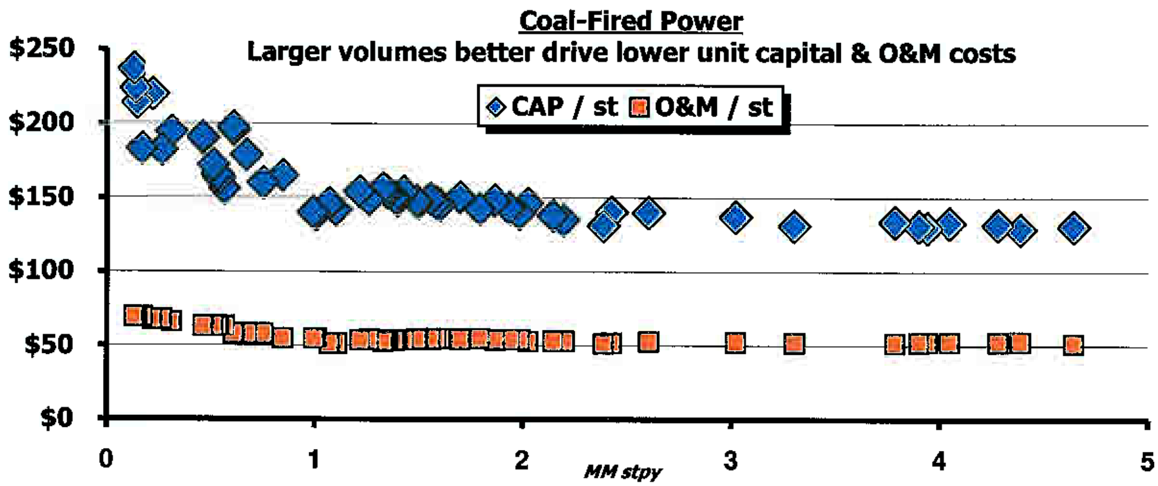
- **Capture & Compression Systems for the project**
  - **Amine capture systems** for low CO2 concentrations in flue gases
    - System includes cleaning & polishing and amine capture systems
    - CO2 source being captured must emit ≥ 1 million metric tons per year of CO2 to meet baseline economic assumptions
    - SOx level of captured flue gas must be below < 10 PPM after additional polishing & cleaning
    - Base line CO2 concentration of ≥ 10% in flue gas
    - Amine systems run steam and electricity
      - Steam is taken from coal-fired plants and causes a parasitic loss to the coal plant
        - The capital cost for the retrofit and monthly parasitic power costs are included in our capital & O&M model
      - The amine system is connected to the local power grid and get all electricity needs from there; electricity costs are included in our O&M model ($0.07 / KWh)
    - Amine systems will capture 90% of CO2 in flue gas
    - Coal fired power source must be ≤ 30 years old
      - Higher likelihood of successful installation of retrofit system to younger plants
  - **Dehydration & compression systems**
    - System dehydration, compression, cooling, & metering systems
    - Gas entering system must contain low to no particulate matter
    - Dehydration & compression systems run on electricity from the local grid and are non-parasitic to targeted power sources ($0.07 / KWh)

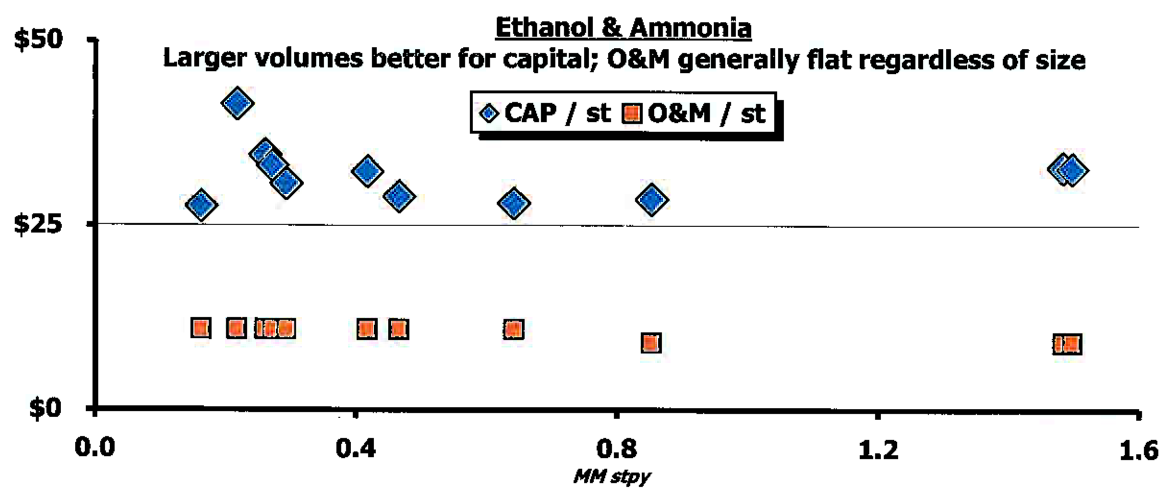
- CO2 exits compression system (with cooling system) at the following specifications

  2,000 psig / 100°F / dew point -50°F / H_2S < 5 PPM

- Owner of capture system meters amount of CO2 entering pipeline

- **Capital & Operating Costs Model**
  - Praxair utilized internal R&D and CO2 business assets to develop a model to estimate operating and capital costs for capture and compression systems.
    - Maximum train size for both system types is 3,000 tons per day of CO2
    - Trains can be linked in series to increase capacities
    - Economies of scale- Larger trains are cheaper to purchase & operate on a per unit captured and compressed basis
    - Un-utilized train capacity must be paid for in capital cost but is not counted in operating expense
    - Systems are assumed to take three years from conception to start up, follow a 20-year MACRS depreciation schedule, and are 100% debt financed
    - The **breakeven price of CO2** is the price estimated to achieve a net present value of $0 over a 20-year project life at an 8% discount rate based on the volume of CO2 captured and sold versus the capital and operating costs.
    - Amine system capital & operating costs include cleaning & polishing system, amine system, retrofit to coal plant, steam costs, electricity costs, amine costs, labor, and other costs
    - Dehydration / compression system capital & operating costs include electricity costs
    - Power prices: $7 per MMbtu price for natural gas, $0.07 / KWh





- **MGSC data sources**
  - Assume source emission data presented by the MGSC in "Inventory of Industrial Stationary CO2 Emissions in the Illinois Basin (August 2007)" is accurate for point sources in Illinois for total sites However, data for coal-fired power plants is presented at a "total site" level and not the more granular "boiler" level. We applied screening criteria and analyzed sources at the "boiler" level as opposed to the total plant

- While we assume their data is accurate at the site level we do not assume it to be complete and have added sources that are new since the publication of the data
- Flue Gas characteristics by source type from "Carbon Dioxide Capture & Transportation Options in the Illinois Basin" by the ISGS, September 2004

Emission Source	CO2 % of Flue Gas
Coal Fired Power	**14%**
NGCC Power Plant	**4%**
Iron & Steel	**20 to 27%**
Refineries	**8 to 15%**
Cement & Glass	**14 to 33%**
Lime	**14 to 33%**
Ammonia	**> 95%**
Ethanol	**95%**

- **Coal-Fired Power Plants**
  - Flue gases from separate boilers cannot be combined via manifold into one stream
  - Each boiler will require its own Amine capture system
  - Flue Gas Cleaning & Polishing
    - Based on MGSC data, all coal-fired boilers exhaust require further cleaning & polishing even after flue gas de-sulphurization (FGD) since their flue gases have SOx concentrations above the acceptable limit for amine capture systems (< 10 ppm)
    - Assume additional cleaning & polishing will bring flue gases within the required specification

	Illinois Coal (high sulphur) Without FGD	Illinois Coal (high sulphur) With FGD	PRB Coal (low sulphur)
SOx, PPM	1,774	80	257
Additional C&P Needed	Yes	Yes	Yes

- **Natural Gas Combined Cycle Power Plants**
  - Flue gases from separate boilers cannot be combined via manifold into one stream
  - Each boiler will require its own Amine capture system
- **Glass Plants**- Praxair's field experience shows the high levels of particulate matter in the flue gases of these plants renders the CO2 unusable
- **Lime Plants**- Praxair's field experience shows the high levels of particulate matter in the flue gases of these plants renders the CO2 unusable
- **Cement Plants**- Praxair's field experience shows the high levels of particulate matter in the flue gases of these plants renders the CO2 unusable
- **Ethanol Plants-** Flue gases from these sources are readily gathered in a manifold and processed in the dehydration and compression systems
- **Ammonia Plants-** Flue gases from these sources are readily gathered in a manifold and processed in the dehydration and compression systems
- **Refineries-** CO2 is emitted from multiple points at different locations throughout a refinery; according to Praxair internal sources, it would be extremely difficult to combine the emissions via a manifold for capture. As such we consider refinery flue gases from refineries are un-capturable at this point in time
- **Iron & Steel Plants-** CO2 is emitted from multiple points at different locations throughout a blast furnace steel plant; according to Praxair internal

sources, it would be extremely difficult to combine the emissions via a manifold for capture. As such we consider steel plant flue gases from refineries are un-capturable at this point in time

- **Based on the above assumptions**
  - **The following sources are assumed to be Not Capturable**

Plant Type	Reason Not Capturable
Coal Fired Boiler < 1MM mtpy CO_2 emissions	**Not economically feasible to retrofit Amine system**
Coal Fired Boiler > 30 years old	**Not economically feasible to retrofit Amine system**
NGCC	**Low CO_2 concentration in flue gas**
Cement, Glass, & Lime	**High particulate matter in flue gas**
Refinery	**Not possible to manifold multiple emissions sources at site**
Steel Plant	**Not possible to manifold multiple emissions sources at site**

  - **The following sources are assumed to be Capturable**

Plant Type	Age Requirement	Annual CO_2 Emissions	Capture Equipment
Coal Fired Boiler	**≤ 30 years**	**≥ 1MM mtpy**	**C&P, Amine, Dehydration, Compression**
Ethanol Plant	**Any**	**Any**	**Dehydration, Compression**
Ammonia Plant	**Any**	**Any**	**Dehydration, Compression**

Appendix D – Top EOR Prospects

The table below summarizes prospective oil fields as defined through ISGS and MGSC. For analytical purposes, the list was decreased those shaded as they were not in the State of Illinois. The remaining 19 were then expanded to 21 by expanding Clay City field into 3 separate reservoir sites due to its large aerial size.

Table 3: Capacities and locations of the top 24 potential sinks in the Illinois Basin.*

Rank (ST*)	Field Name	Field ID	State	Summary CO2 (MMT) Oil	Coal	Saline	Total CO2 (MMT)	Longitude (DD-N83_XY)	Lattitude (DD-N83_X)
1	Clay City (MGSC SW)	17119	IL	39	70	710	820	-88.33	38.56
2	Main Cons.	171361	IL	39	17	533	589	-87.81	39.00
3	Lawrence	171336	IL	29	14	290	333	-87.74	38.71
4	Sailor Sprs. Cons	171530	IL	9	29	251	290	-88.41	38.80
5	New Harmony Cons.	171415	IL	22	21	222	265	-87.92	38.30
6	Dale Cons.	171151	IL	16	10	211	237	-88.6	37.98
7	Clay City (MGSC N)	171119	IL	11	27	197	235	-88.09	38.95
8	Louden	171354	IL	22	8	195	226	-88.86	39.10
9	Union	181996	IN	9	1	199	210	-87.44	38.46
10	Clay City (MGSC NE)	171119	IL	10	20	172	202	-88.2	38.73
11	Salem Cons	171533	IL	17	4	110	131	-88.99	38.54
12	Golden Gate Cons.	171230	IL	4	9	110	123	-88.2	38.30
13	Albion Cons.	171010	IL	5	8	92	104	-88.04	38.33
14	Johnsonville Cons.	171299	IL	4	8	89	101	-88.53	38.46
15	Parkersburg Cons.	171462	IL	3	8	89	99	-88	38.59
16	Allendale	171015	IL	4	5	88	97	-87.73	38.53
17	Phillipstown Cons.	171474	KY	4	8	78	90	-88.04	38.20
18	Fordsville Cons.	2112962	IN	2	-	82	84	-86.72	37.62
19	Griffin Consol.	181787	IL	12	6	62	80	-87.94	38.23
20	Divide Consol	171160	IL	2	3	72	78	-88.82	38.44
21	Easton Cons	2.1E+07	KY	0	-	77	77	-86.69	37.70
22	Mattoon	171377	IL	2	5	63	70	-88.39	39.45
23	Mt. Auburn Cons.	171399	IL	2	1	67	69	-89.25	39.73
24	Aetnaville Cons.	214643	KY	1	-	62	62	-86.8	37.67

** As extracted from "Assess Carbon Dioxide Capture Options for Illinois Basin Carbon Dioxide Sources" (pg 14) by the Midwest Geological Sequestration Consortium Dated December 31, 2005*

*** "ST" indicates "strorage ID assigned site in Project Lincoln*
Note: Highlighted fields are NOT in the State of Illinois.

Appendix E – Background: CO_2 Pipelines

Carbon dioxide (CO2) pipelines have been safely operated in North America since the middle 1970's. Over 3,000 miles of CO2 pipelines are used to safely transport over two billion cubic feet of CO2 per day to mature oil fields for Enhanced Oil Recovery. The Permian Basin in Eastern New Mexico and West Texas has the largest concentration of CO2 pipelines with over 2,300 miles in service. Pipe diameters vary from 4" OD up to the 30" OD Cortez Pipeline.

Carbon Dioxide pipelines transport the CO2 in a dense phase gas form that has the viscosity of a gas and the density of a liquid. The normal operating pressure of a CO2 pipeline is near 2000 psig. Most pipelines are designed with a Maximum Operating Pressure (MOP) of 2140 psig, but several have MOP's over 3000 psig.

Dry, high purity CO2 can be safely transported using standard industry carbon steel pipe through most areas of the country.

Regulation and Permitting

The U.S. Department of Transportation (US DOT) regulates the design, construction, operation and maintenance of CO2 pipelines in the United States under the Hazardous Liquids and Carbon Dioxide Pipeline Regulation, CFR 49 Part 195. Either the Canadian Federal Government or the individual provinces could possibly develop regulations, rules and laws governing CO2 pipelines.

The Federal Energy Regulatory Commission (FERC) does not regulate CO2 pipelines in the United States.

Individual states have regulations covering the construction of pipelines, setting forth construction and/or operating permit requirements. The State of Texas requires all pipelines to obtain an operating permit. The permit requires public notice of the intent to build and any comments are addressed prior to the permit being issued. The permit also requires a survey to determine any historical sites along the proposed pipeline alignment.

Ground disturbance of over 1 continuous acre requires a National Pollution Discharge Elimination System (NPDES) plan approved by the Environmental Protection Agency to insure water runoff does not pollute the waters of the United States.

Currently, in the U.S., CO2 is not considered a pollutant, so no air permits are required for the construction of a CO2 pipeline.

As part of Pipeline Integrity Management, the DOT requires pipeline operators to survey pipeline alignments and determine High Consequence Areas (HCA) and to consider these in the design and construction of the pipeline. The DOT does not issue an approval, but will inspect the operator's records of this HCA determination. If they disagree or disapprove, the operator could be assessed a fine for failure to adequately determine and design for the HCA locations.

A carbon dioxide pipeline requires the purchase of an easement from all landowners along the pipeline to allow for construction and installation. Most western states have laws in place that allow a CO_2 pipeline to use the right of eminent domain to obtain right of way from landowners if necessary. Many mid-West and Eastern States do not have a law that allows a CO_2 pipeline the right of eminent domain.

General Operations

Carbon dioxide is a gas at atmospheric pressure. Most operators in the United States use electric driven compression to compress CO_2 up over 2,000 psig. The CO_2 is then cooled and forms the near liquid, dense phase gas that can then be pumped.

Electric driven centrifugal pumps are used along CO_2 transmission systems to move the CO_2 over high elevations.

Where large elevation drops are encountered, reducing stations are required to reduce the flow and pressure in the CO_2 pipeline to prevent high pressure from damaging the pipeline.

Water removal is one of the most important elements in the safe transportation of CO_2. Water content should be less than 30 lbs of H_2O in One Million Standard Cubic Feet (MMSCF) of CO_2. This will prevent any free water formation in the transmission pipe. The elimination of water allows a CO_2 pipeline to be made from the same carbon steels as a natural gas or oil pipeline while substantially mitigating the risk of corrosion.

Glycol dehydration or solid desiccant can be used to dry CO_2 prior to entry into a CO2 transmission pipeline. Where water cannot be eliminated, CO2 pipelines are constructed of stainless steel or carbon steel pipe lined with polyethylene pipe (a liner) to create a barrier between the carbon steel and the water/CO_2 mix.

Carbon dioxide pipeline equipment requires special elastomers specifically designed for CO_2. Improperly designed elastomers absorb the high pressure CO_2 and then fail when the CO_2 pressure is relieved. Usually the elastomer will suffer damage when the absorbed CO_2 is released, permanently deforming and eliminating the elastic properties of the elastomer. Special elastomers have been developed that withstand exposure to CO_2. External Corrosion control is handled in the same way as on natural gas and hazardous liquids pipelines. Above ground pipe sections that can be isolated from the main pipeline should be protected with thermal relief valves to prevent an over pressure condition in the piping.

Safety

Carbon Dioxide pipelines have been safely operated for over 35 years in the United States. This **safe operation is a direct result of:**

- proper installation of the pipeline and equipment,
- remotely monitored control equipment,
- inspection and maintenance of the pipeline and pipeline equipment,
- prevention of corrosion by eliminating internal corrosion threats
- installation of standard external corrosion control equipment.

To insure the safe operation of CO_2 pipelines, pipeline operators conduct the following inspections/maintenance: (A pipeline SCADA control room is pictured below.)

1. Right of way inspections by Aerial patrol 26 times per year
2. Semi-annual valve maintenance of all critical valves
3. Emergency drills of all pipeline employees annually
4. Inspection and maintenance of cathodic protection rectifiers bi-monthly
5. An annual survey of cathodic protection levels
6. Assessment of the integrity of the pipeline in high consequence areas at least once every five years
    - Use of "smart" pigs on CO2 pipelines has had limited success. A few small diameter (12" or less) and short pipelines have been successfully inspected.

- External Corrosion Direct Assessment has been successfully performed on the 30" Cortez Pipeline.

7. Inspection and calibration of overpressure relief devices once per calendar year
8. Conducting a public awareness and damage prevention program annually
9. Membership and participation in the state one-call systems in each state of operation.
10. Respond to locate requests, properly locate pipeline, inspect the excavation, crossing, and backfill of the pipeline to insure the safety and integrity of the pipeline.

Emergency plans have been developed to guide pipeline employees during a leak or catastrophic event on the pipeline. The priority of the emergency response is to protect people and the environment by isolating the release site.

Carbon dioxide pipelines are monitored and controlled by a supervisory control and data acquisition (SCADA) system. The SCADA system is monitored 24 hours per day/ seven days a week by employees on rotating shifts. The SCADA system allows the remote monitoring and operation of compressors, pumps, mainline valves, and volume/pressure control at metering sites.

All buildings with CO2 handling equipment are equipped with CO2 monitoring with audible and visual alarms. The buildings have automatic power venting in case of high CO2 levels in the building.

Differences from Oil and Gas Pipelines

- Higher Pressure operating pressure to maintain dense phase
- Gas with liquid density
- High energy release when CO_2 goes from pipeline pressure to atmospheric pressure requiring consideration of prevention of a propagating crack failure
- Requires special pump and compressor seals

Key Issues

Carbon dioxide is a safe gas to transport in pipelines. The various contaminants that may be entrained in CO_2 from industrial sources have more toxic properties than the CO_2. Hydrogen Sulfide (H_2S) and Sulfur dioxide (SO_2) are toxic contaminates that often may be included with industrial sources of CO_2. Concentrations of these contaminates would require special metallurgy in the pipeline steel.

High oxygen content (10 ppm or higher) in the CO_2 will also aggravate any corrosive contaminants attack on the steel of the pipeline. Also, this level of CO_2 can combine with hydrogen sulfide in an oil field and create elemental sulfur which will clog well bores and process equipment. Concentrations of Nitrogen or hydrocarbon gases over 5% are detrimental the density of the CO_2.

Water is the worst contaminant and will easily form carbonic acid which attacks the pipe. Removal of water is the highest priority in transporting CO_2.

Appendix F – CO_2 Pipeline Product Specification

Specifications. The Product delivered by Seller or Seller's representative to Buyer at the Delivery Point shall meet the following specifications, which herein are collectively called "Quality Specifications":

(a) Product. Substance containing at least ninety-five mole percent (95%) of Carbon Dioxide.

(b) Water. Product shall contain no free water, and shall not contain more than thirty (30) pounds of water per mmcf in the vapor phase.

(c) Hydrogen Sulfide. Product shall not contain more than twenty (20) parts per million, by weight, of hydrogen sulfide.

(d) Total Sulfur. Product shall not contain more than thirty-five (35) parts per million, by weight, of total sulfur.

(e) Temperature. Product shall not exceed a temperature of one hundred twenty degrees Fahrenheit. (120°F).

(f) Nitrogen. Product shall not contain more than four mole percent (4%) of nitrogen.

(g) Hydrocarbons. Product shall not contain more than five mole percent (5%) of hydrocarbons and the dew point of Product (with respect to such hydrocarbons) shall not exceed minus twenty degrees Fahrenheit (-20°F).

(h) Oxygen. Product shall not contain more than ten (10) parts per million, by weight, of oxygen.

(i) Glycol. Product shall not contain more than 0.3 (three tenths) gallons of glycol per MMCF and at no time shall such glycol be present in a liquid state at the pressure and temperature conditions of the pipeline.

Appendix G – CO_2 Pipeline Engineering

Material Selection for CO_2 Pipeline System

Carbon dioxide exists as gas, liquid or solid depending on its temperature and pressure. At normal temperature and pressure CO_2 is odorless, colorless and nonflammable gas. It is 1.5 times heavier than air. When leaked it will remain close to the ground, accumulate in depressions and valleys and replace air causing potential health hazard to life form. At concentrations above 25 %, it is lethal. However, it does not cause flammable gas clouds as in the case of natural gas.

At a temperature of 87.8 °F and pressures above 1063 psi, CO_2 assumes a supercritical dense phase and behaves like a compressible fluid. As dense gas, CO_2 can be transported more economically than in gaseous state. Almost all existing long distance CO_2 pipelines are designed for dense phase flow. Illinois CO_2 pipeline system is therefore designed consistent with the industry practice. At the capture points, the CO_2 gas will be dehydrated and compressed to a dense supercritical phase at 2000 psig for transportation to designated oil fields for enhanced oil recovery (EOR). As dense gas, CO_2 is a compressible fluid and can be pumped with low power requirement. At present CO_2 transportation is regulated by CFR 195 – Transport of Hazardous Liquids. Other regulations may become applicable in future, when agencies finally agree on whether to treat CO_2 as a commodity (such as use in EOR) or pollutant as a greenhouse gas.

Dry CO_2 gas is basically inert and non corrosive provided that its dew point is maintained at a reasonably low level, at least 10 ° F below the minimum service temperature. The dehydration process at the capture point shall ensure that the gas does not contain more than 20 ppm of water before entering the pipeline system. Presence of water will result in the formation of carbonic acid which lowers pH to a level that will initiate corrosion in steel pipe. For this reason it is important that CO_2 pipeline is kept dry after initial pressure testing and during its normal operation and periodic shutdowns. With proper care, carbon steel pipe provides a good and economical solution to CO_2 transportation.

H_2S may be present in the CO_2 gas in varying concentrations. A gas containing more than 20 ppm H_2S by volume is considered sour for health safety reasons. Pipelines containing 100 ppm or greater levels of H_2S may be governed by state and federal regulations. Regulations may require gas dispersion analysis at the detailed engineering stage to ensure public safety. At the conceptual stage of route selection, it would be prudent to self-impose a buffer zone of at least 1500 feet from any private or public occupied buildings in order to comply with any future requirements. Consultations with permitting agencies will be required at appropriate time.

Meanwhile, selection of suitable material for H_2S service combined with appropriate construction and treatment procedures and H_2S monitoring will ne specified in compliance with NACE-175.

H_2S in higher concentrations attacks steel as sulfide attack resulting in gradual metal loss and as structural attack at the heat-effected zones, such as welds, resulting in more dramatic and sudden failures. Both are controllable with proper mitigation procedures. However, to counter adverse effects of presence of any amount of moisture in CO_2, the process of material selection will be properly controlled.

Another important factor affecting the selection of pipe material is its ability to withstand extreme low temperatures, which can occur with dense phase CO_2. A rapid depressurization of CO_2 in dense phase can cause temperatures as low as -110° F resulting in low ductility and brittle fracture cracking, which can propagate very rapidly in longitudinal direction and may continue indefinitely unless arrested. The fracture ductility property of selected material at low temperatures is of extreme importance.

Carbon steels in general exhibit excellent ductility at temperatures above the freezing point of water (32°F) but tend to lose ductility at lower temperatures resulting in cleavage or inter granular cracking. Carbon steel material specified for CO_2 dense phase service must be tested during manufacturing process to ensure required level of low temperature toughness in the specified range of temperatures. The objective is to select a material that has an upper shelf fracture toughness (CNV) of minimum 30 ft-lbs., so that the fracture velocity of steel is < 400 ft/second and the fracture surface presents over 98% shear face of fractured surface. It is important to ensure that fractures initiate as ductile, not brittle, fractures because brittle fractures typically initiate and propagate at lower energy inputs than ductile fractures and tend to be fast running resulting in potentially catastrophic failures. Sufficient design toughness is determined by calculating the required fracture toughness of the pipeline steel to support a critical flaw (crack) size.

High yield materials above X80 grade materials have lower ductility and have greater propensity to brittle fracture, especially in high stress conditions and where nascent hydrogen is evolved from corrosion or from the application of cathodic protection. Hence, it would be prudent to use extreme caution in selecting material with higher yield strength. It is recommended that material with higher yield strength may be avoided and grades above grade X-70 may be considered only if absolutely necessary and with additional testing. For this project grade X70 has been selected for all line pipes (and used in hydraulic analysis for pipe sizing).

The experience with all API grades of pipes from X60 to X80 have regularly shown that at minus 20 ° F the CNV impact properties have far exceeded the required values and their shear has been over 98% (and often 100% shear has been reported for both Charpy impact, CNV, and the DWTT tests). Thus the impact values required at upper shelf temperature are not beyond the normal reach of the steel material used to make API-PSL 2 level of pipes. PSL 2 is the common specified level for such critical line pipes.

For the Lincoln project X70 Double Submerged Arc Welded (DSAW) API 5L PSL–2 line pipes are recommended. ERW pipes may be considered when DSAW pipes are not possible to obtain due to size constraint.

Propagation Arrestors

Propagation (crack) arrestors are used to stop propagation of brittle fractures by diverting the crack energy in diverse directions thereby stopping crack propagation instantaneously. Cracks would generally start at the point of rapid depressurization, which may result in very low localized temperatures causing brittle fracture. Cracks propagate very rapidly and may extend indefinitely if not stopped. There is no code or specification governing placement of crack arrestors.

Many of the existing CO_2 pipelines have used crack arrestors as an added protective measure[1].Steelmaking processes have advanced significantly over the years and line pipe is reliably produced conforming to specified toughness with proper quality control measures as stated above. This may eliminate the need for crack arrestors and should be reviewed during detailed design.

Propagation arrestor spacing is also not regulated but general industry practice on existing CO_2 pipelines is at intervals of 1000 feet.

Station Piping and Equipment

The booster pump stations will receive dry inert CO_2 gas in dense phase, boost pressure to the specified level and discharge to the pipeline in dense phase. No physical change is expected in the gas except a slight rise in temperature during the pumping process.

No corrosion is expected. However, due to possibility of H_2S (hydrogen sulfide) in the gas, the welds will be radiographed and post-weld heat-treated in the same manner as the line pipe.

The lowest anticipated design temperature is minus 20 $^{\circ}$F for the selection of material for vessels and piping. The service temperature at pump discharge may rise up to 120 $^{\circ}$F which is within the service range of the selected materials.

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[1] Kinder Morgan CO_2 Company utilizes "crack propagation arrestors" on their lines at approximately 1000 ft. intervals.

To make allowance for the worst-case scenario of H_2S presence, a corrosion allowance will be provided based on a conservative corrosion rate estimate of 3.0 mils per year. This corresponds to a corrosion allowance of 3/32" for the 30 years projected life.

The given corrosion conditions do not suggest any possibility of SSC except in high yield materials. If ultimately such a material is selected, the possibility of SSC should be re- examined in the light of the correct data.

Material for Pumps

The pumps and impellers are designed for very low design temperatures (often lower than -40 °F). These materials often have much higher upper shelf transition temperatures than the anticipated design temperature range of minus 20 °F to 120 °F for the proposed pipeline system. In the given condition, the options would remain open to consider either conventional compatible grades of steels or nickel alloys or specialized CRAs. Working closely with the equipment manufacturers would be the best way to select the optimum material both from corrosion as well as from the capital cost point of view.

External Corrosion Control

A composite approach is taken to protect the pipeline from external corrosion. This includes coating the pipe and as well as application of cathodic protection. The two are briefly discussed below.

1. **Fusion Bonded Epoxy (FBE) Coating**

   The pipes shall be coated with fusion-bonded epoxy at the mill. The FBE coating shall be suitable for up to 200 °F service temperature. For the mill applied coating the final minimum cured thickness shall not be less than 16 mils. A detailed specification will be developed during the detailed design.

2. **Cathodic Protection (CP)**

   Pipelines shall be protected from external corrosion by sacrificial anode cathodic protection system during construction and while the permanent CP system using impressed current is not commissioned. The current density of $10 \mu A/m^2$ given here is for basic design calculations. The life of temporary CP system shall be designed for two years assuming that within this period the impressed current system shall be commissioned.

   After the construction is completed, the external corrosion protection to the pipeline shall be provided by impressed current cathodic protection system. The system shall be designed using following parameters. The current densities used are basic minimum and shall be revised upon review of the affecting parameters such as the following:

- Coating resistance,
- Native soil survey
- Other environmental conditions
- Proximity to foreign pipelines and structures
- Other interference areas affecting the CP system.
- AC mitigation

The CP system shall be designed for 30 years life of pipeline.
For initial calculations purpose, the following data shall be used.

Current density:	25μA/m^2
Design Safety factor	1.3
Anode utilization factor:	0.85 for solid anodes
Anode Utilization factor:	0.6 for ribbon anodes.
Pipeline natural potential:	(-) 0.50 V

Protection Criteria:

The CP system's protection criteria shall be as below:

- Pipe to soil potential shall be between –0.85 V to – 1.2 V with respect to $Cu/CuSO_4$ This shall be the minimum potential in anaerobic environment.
- A positive potential shift of 100 millivolts or more shall be considered sufficient to indicate the presence of an interference situation requiring investigation and incorporation of mitigation measures.
- Following data is to be collected for the design of the CP system and to mitigate any interference:
  - Route survey to identify the locations and types of foreign structures including the crossings, etc. that may be likely in near future.
  - Diameter, soil cover and coating type and year of commissioning of the foreign pipelines and CP system.
  - Status of casings of the foreign pipelines.
  - Details of the type of CP protection provided to the foreign pipelines.
  - High tension electric transmission lines running parallel or crossing the route of the proposed pipeline.
  - Crossing or parallel running of electric traction lines.
  - Waterways and river crossings planned.
  - Railroads crossed.

- The CP system shall include following major equipment and sub-systems.
  - Test stations
  - Sacrificial anodes and anode beds
  - CP system at cased crossings and carrier pipe protection
  - Interconnecting cables
  - Cable to pipe connections
  - Grounding of Sacrificial anode at HT line crossing. (NACE RP 0177)

Internal Corrosion Protection and mitigation Plan

Pipelines carrying dry dense phase CO_2 is not expected to have any moisture. Hence no internal corrosion is expected. However, pump station piping and equipment may be subjected to some moisture due to differential pressure and temperature which may cause internal corrosion especially in presence of high level of H_2S. Some measure of protection for internal corrosion and corrosion allowance may be considered prudent.

A typical internal corrosion monitoring system would include the combination of the following two activities.

1. Injected corrosion inhibitors to mitigate internal corrosion.
2. An internal corrosion monitoring system, including on-line corrosion monitoring.

A typical internal corrosion monitoring system consists of access fittings including plugs and covers, chemical injection quills, coupons, electric resistance probes, and sampling points. Some of the tools required for these systems are instrumentation, i.e.

- Electrical resistance data loggers
- Retrievers and service valves for the removal and insertion of the monitoring devices while the line is under pressure.

The monitoring system shall cover vessels, equipment and piping comprising the station system. The location, placement and number of injection, monitoring and sampling equipment depends upon the design, related equipment (i.e. vessels, compressors tie-ins, etc.) and the length of the pipeline. The access fitting should be installed during the pipeline fabrication and the corrosion coupons, probes and instruments can be added at the time of system commissioning. Once PFD's and P&ID's are created, the placement and numbering can be established. A specialist contractor can be engaged to assist with the design and specifications as well as the manufacture, procurement, installation, commissioning and monitoring of the internal corrosion protection package.

Proper monitoring and control system shall be specified during Detailed Engineering to mitigate incidence of corrosion.

Fabrication and Testing

Importance of welding and fabrication control cannot be over emphasized. All welding and fabrication shall be in accordance with the detailed welding procedures, which will be developed during Detailed Design.

Cleaning

Post hydro-test drying of the pipes, vessels and other equipment is very essential to avoid CO_2 corrosion. In general all drying will be done to –50 °F using hot dry air. Detailed procedures will be developed during the Detailed Design.

Appendix H – CO_2 Pipeline Cost Summary

Consolidated List of Line Pipes for Phase 1 & 2

Nominal Size	Pipe OD inches	Total Length miles	WT inches	Unit Weight lbs/ft	Total Weight tons	Percent %	Unit Price $/ton	Total Price $
8'	8.625	21.53	0.322	28.6	1,628	1.5	2,500.00	**4,057,497**
10'	10.750	89.01	0.365	40.5	9,513	8.9	2,500.00	**23,782,716**
12'	12.750	110.68	0.375	49.6	14,482	13.5	2,500.00	**36,205,083**
16'	16.000	72.97	0.375	62.6	12,055	11.2	2,500.00	**30,138,345**
18'	18.000	0.00	0.375	70.6	0	0.0	2,500.00	**0**
20'	20.000	86.69	0.406	85.0	19,445	18.1	2,500.00	**48,611,773**
24'	24.000	159.35	0.476	119.6	50,310	46.8	2,500.00	**125,774,764**
Total		540			107,428			268,570,100

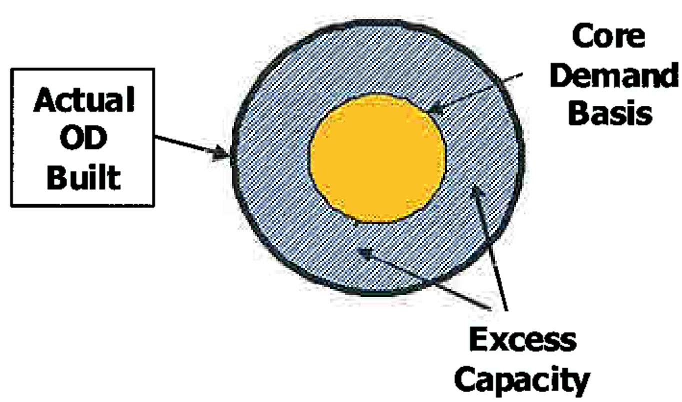
Typical Pipeline Cost Estimates		
#	**Description**	**%**
1	Right of Way / Damages	**7.0**
2	Environmental / Permitting	**1.5**
3	Materials	**33.0**
6	Construction	**53.0**
7	Construction Management (included in Owners costs)	**see below**
8	Survey / Geotech	**0.6**
9	Inspection, X-ray etc.	**0.5**
10	Engineering	**1.0**
11	Owners overheads including construction management	**2.0**
	Total Project Cost	**100%**

Appendix I – Infrastructure Expansion

There is an ever present conflict inherent in design of infrastructure systems. This conflict arises from engineering for the "task at hand" with its associated cost level while tacitly appreciating the impacts future growth will have on the system. Though working toward satisfying "today's" needs is of primary importance, given the great variance in potential future carbon capture initiatives, a more than passing appreciation of future growth needs is needed.

But how – given the tremendous costs, funding issues, credit and risk associated with each of the respective CCS components? How can a pipeline infrastructure be built for "today" yet ready to accommodate tomorrow's as yet to be defined needs?

Figure IV – 5
Concentric Financing



One possibility is through a financial structure herein referred to as "*concentric financing*". In this structure, a pipeline is built as depicted in Figure IV-5. The pipeline hydraulics are designed beyond, perhaps much beyond, than that economically justified under the current commercial considerations (e.g. those based on satisfying current "core demand"). At the time of design however, it is expected that future demand will readily use the excess capacity, but to do so it must first be readily available.

Typically, only the near term need could reasonably be expected to be satisfied, especially if future demand, while expected, was still evolving and far from "defined". The capability to reconcile long term needs with near term financial realities may rest on the use of this financing mechanism in a quasi private – public partnership.

In such a case, the private firm would undertake to design and build the entire, full size pipe. However, it would segment the capital cost components into "today" vs. "tomorrow" components[2]. The private entity would finance the former, while the public entity, be it municipality, State, or Federal, would finance the latter.

The government entity would own a portion of the pipeline infrastructure throughput capacity if and when that "excess capacity" was used or planned to be so. A variety of means could be contractually agreed between the private and public entities regarding "peak" use of the excess capacity and future use when and if demand rose to the levels required. Various options could be structured within the financial agreements as to how and when the government owned capacity could be dealt with. One such option might include public auction or sharing or fee-based operation.

Regardless of the specifics, such a financial structure provides the means through which to deal with the "now" while addressing the broader, longer term issues often needed from a policy-maker's perspective. Just such a perspective exists in today's view of future carbon or CCS developments. While "today's need" is focused on EOR as they are the ONLY existing paying customer. Tomorrow might bring a carbon constrained world wherein geologic sequestration becomes a significant public need – one requiring infrastructure though which to be implemented. Concentric financing just might provide the flexibility through which to deal with it.

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[2] This capex segmentation would neither occur in a vacuum nor only by the private party. Rather, some impartial 3rd party would be required to authenticate and validate any such figures from the very beginning.

Appendix J – Pipeline Project Schedule

Project Lincoln is designed with flexibility of implementation in a phased manner. CO2 gas from phase 1 source plants will be collected through Line 1 which may be designed, built and commissioned ahead of phase 2. Line 1 will be designed large enough to accommodate flows from Line 2 when it is placed in service.

Based on the above, three project schedules are provided, one each for the design and construction of Line 1 and Line 2 separately and the third for both lines together as one project.

Line 1 is 253 miles long from the farthest source plant to the designated EOR sink in the south. However, overall construction pipe length including the spurs is estimated as 275 miles. The line may be divided into 2 or 3 construction spreads. With three spreads, the line can be built in eight months in the field. However, schedule shown here is more conservative with two spreads to allow time for inclement weather, permitting delays and other unforeseen reasons.

Line 2 connects selected Ethanol plants in northern Illinois to Line 1 in mid state. This line is 206 miles long (265 miles including lateral spurs). Two construction spreads are assumed as above.

Overall schedule is estimated to be 30 months for each line with possible reduction of up to six months with the additional spread. The schedule is based on the following assumptions:

1. Engineering and design will be completed in six months, based on experience from past projects.
2. Environmental activities will not involve an EIS but will include activities that are typical for a project of this nature – consultations, field surveys, reports, permits etc. An overall duration of nine to twelve months is allowed for environmental activities, based on data from recent similar projects.
3. The pipeline routes mostly follow existing corridors, which may help ROW acquisition process. It is estimated that land and ROW activities will be completed in 10 months, in the same time frame as environmental permitting.
4. Durations of procurement and delivery of major equipment is based on preliminary data from recent projects.

5. Pipeline construction will progress at a rate of approximately one mile per day per crew. Production rates ranging from 5600'/day to 6800'/day for small diameter pipe and fom 4800'/day to 5600'/day for the larger diameter pipe are assumed.
6. Pump stations construction will be performed by a separate contractor, in parallel with the pipeline construction. The station construction requires much shorter duration, approximately four months, and will be scheduled appropriately with pipeline completion.
7. The critical path for this project is driven by the long-lead items including procurement of the line pipe and the large size line valves. Activities on the critical path include detail engineering, environmental permitting and procurement of the line pipe.

Appendix K – CO_2 Pipelines Hydraulic Analysis

Result Summary – Line 1

Assumptions

1) Inlet pressure, Max (Supply Points)= 2000 psig
2) Injection point pressure (Min) = 1200 psig, compressed to1500 psig
3) Inlet Temperature = 100 F
4) Ground Temp (Max) = 90 F
5) Pipe roughness (assumed) = 750 microinches
6) Line Length = 253 miles
7) Flow Rate Cases = 550 MMcfd
8) An intermediate booster is located about MP 94 from C-22.
9) An injection booster is located at MP 253.

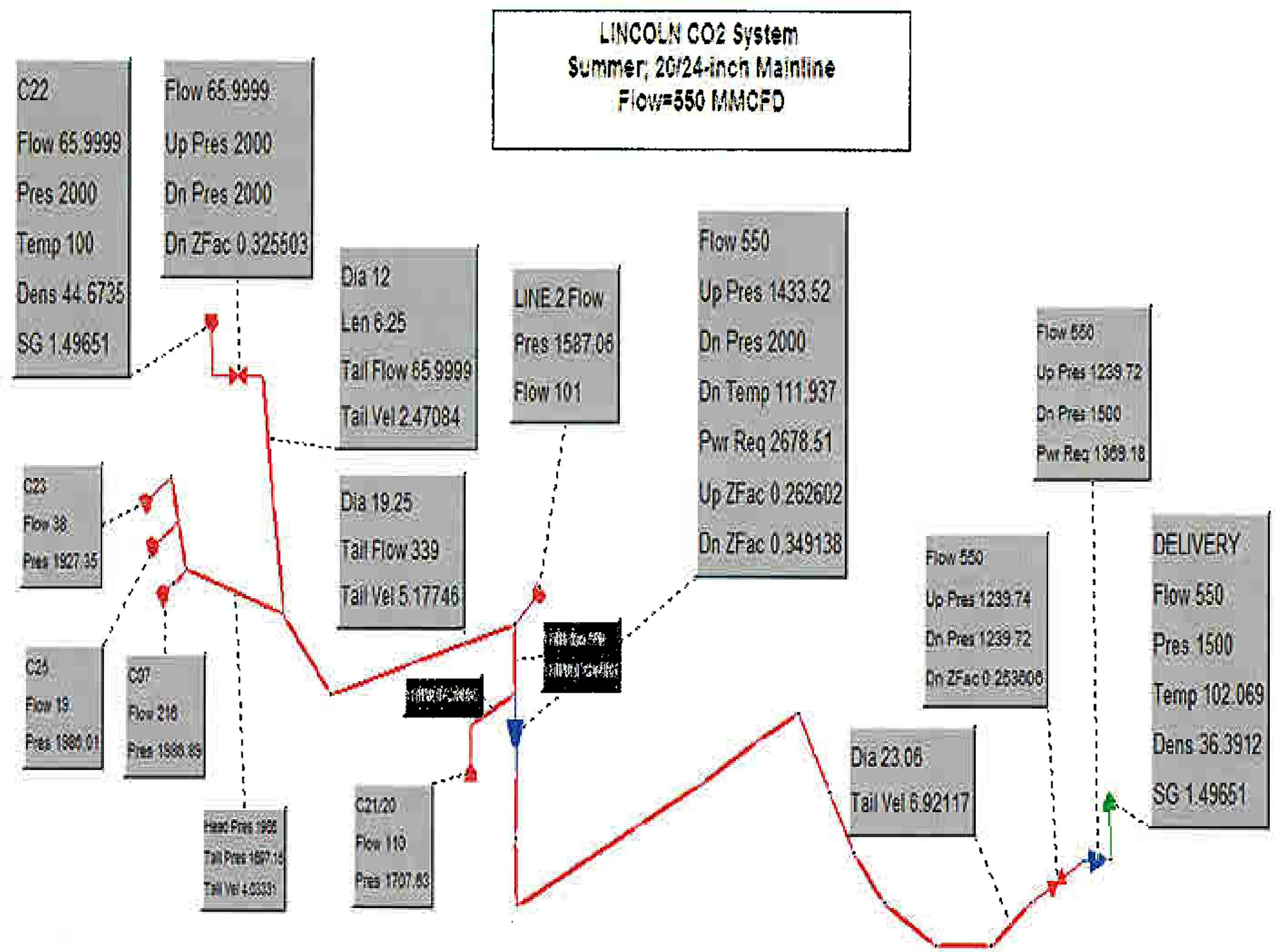
Summary

1) A **12-inch pipeline** (with a wall thickness of 0.375") will be required for the segment **MP 0 – MP 14.75**).
2) A **20-inch pipeline** (with a wall thickness of 0.406") will be required for the segment **MP14.75 –MP 93.89**. A 16-inch pipe was evaluated and found to be inadequate.
3) A **24-inch pipeline** (with a wall thickness of 0.476") will be required for the segment **downsream** of the booster(at mile post 93.89). A 20-inch pipe was evaluated and found to be inadequate.
4) A **20-inch pipeline** (with a wall thickness of 0.406") will be required for the C23/C25/C7 lateral (at mile post 14.75).
5) A **12-inch pipeline** (with a wall thickness of 0.375") will be required for the C20/C21 lateral (at mile post 93.89).
6) An injection pump will be required at MP 253.24

TABLE 1 - SUMMARY OF SIMULATION RESULTS – LINE 1

Segment	Flow, MMcfd	Diameter wt inches	Inlet Pressure, psig	Outlet Pressure, psig	Station Suction, psig	Station Discharge, psig	Comments
1 MP 0 – MP 14.75	66	**12** 0.375	2000	**1897**	-	-	14.75 miles
2 MP 14.75 – MP 93.89	339-440	**20** 0.406	1897	**1434**	-	-	79.14 miles
3 mainline d/s booster	550	**24** 0.476	2000	**1240**	-	-	159.35 miles
4 C23/C25/C7 Lateral	273	**20** 0.406	1987	1897	-	-	8.83 miles
5 C21/C20 Lateral	110	**12** 0.375	1675	1434	-	-	12.28 miles
Intermediate Booster	550	-	-	-	1430	2000	At MP 93.89
Injection Booster	550	-	-	-	1240	1500	At MP 253.24

Figure 1 Schematic of LINE 1 (550 MMcfd) – 20/24-inch Option



Result Summary – Line 2

Assumptions

1. Inlet pressure, Max (Supply Points)= 2000 psig
2. Outlet pressure (Min) = 1200 psig
3. Inlet Temperature = 100 F
4. Ground Temp (Max) = 90 F
5. Pipe roughness (assumed) = 750 microinches
6. Line Length = 205 miles
7. Flow Rate Cases = 101 MMcfd
8. An intermediate booster is located about MP 94 from C22.

Summary

1. A **10-inch pipeline** (with a wall thickness of 0.365") will be required for the segment **MP 0 – MP 89.01**).
2. A **12-inch pipeline** (with a wall thickness of 0.375") will be required for the segment **MP 89.01 –MP 132.78.**
3. A **16-inch pipeline** (with a wall thickness of 0.375") will be required for the segment **MP 132.78 –MP 205.75.**
4. A regulator will be require at the intersection of Line 1 and Line 2 to reduce the pressure of Line1 to about 1587 psig.
5. No booster is required on this line.

TABLE 2 - SUMMARY OF SIMULATION RESULTS – LINE 2

Segment	Flow, MMcfd	Diameter wt inches	Inlet Pressure, psig	Outlet Pressure, psig	Comments
1 MP 0 – MP 89.01	21 - 31	**10** 0.365	2000	**1906**	89.01 miles
2 MP 89.01 –MP 132.78	43	**12** 0.375	1906	**1921**	43.77 miles
3 MP 132.78 –MP 205.75	101	**16** 0.375	1921	**1778**	72.97miles
4 C28 Lateral	10	**8** 0.322	1925	1918	11.41 miles
5 C26 Lateral	12	**8** 0.322	1907	1906	8.46 miles
6 C31/32 Lateral	29-58	**12** 0.375	1966	1921	39.71 miles

Figure 2 Schematic of LINE 2 (101 MMcfd) – 10/12/16-inch Option