IPRO 302

CO_2 Mitigation: A Techno-Economic Assessment

Final Report

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Sponsor: Sargent & Lundy

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0.1 Introduction

As member of the steam team she was responsible for the research and the background section of the midterm report. After joining the compressor gang, she was helping with the research about the compressors and involved in preparation the presentation about different kinds of solution for CO2 compression.

0.2 Background

0.3 Purpose

The objective of this IPRO is to perform an in-depth analysis of all aspects of implementing the selected CO_2 mitigation technology from the sponsor by researching methods of sequestration and designing CO_2 removal equipment with the assistance of MATLAB models of the power plant and Hysys models of the CO_2 removal equipment. We also intend to provide a thorough economic analysis in order to assess the impact on power generation cost. This will include determination of capital costs for the operation and construction of CO_2 removal and sequestering equipment to the existing power plant. Our goals are based on the progress made last semester in this IPRO. They did research on this topic and we are now acting on the information they compiled.

0.4 Research Methodology

Steam Team

MATLAB

Don Chmielewski matlab code written for a flue and steam analysis was the initial basis for our project. In order to adapt the code to our specific needs some aspects needed to be changed. The addition of a SO_2 scrubber was necessary, as was the order in order which the flue gas was analyzed. Similarly, the initial data of the code was to be updated to reflect a supercritical steam power plant, rather than a sub critical steam plant. This was accomplished through use of steam schematics, provided by Charles Guilfoyle. These diagrams provided the steam temperatures and pressures at the various points throughout the steam power plant. The next major step was to introduce a dry SO_2 scrubber near the end of the code, to account for the effects of removing SO_X from the flue stream. Using basic principles of thermodynamics, a mass balance and energy balance were utilized in order to calculate the flow rate of water into the scrubber, and the temperature at which the flue stream exits the dry scrubber. Although these were the larger challenges faced in the steam and flue analysis, similar smaller problems arose. In order to calculate, the amount of coal that was to be burned, a reverse analysis was to be performed, such that we worked backwards from the gross output of the plant in order to calculate the necessary flow rate of coal being fed into the boiler. In a similar manner, the flow rate of steam was calculated using the turbine and generator efficiencies. At this point, the simulation works by analyzing the flue gas at each step in the power plant. Using the enthalpy of each element in the flue stream and an energy balance, the corresponding temperatures of the flue stream are calculated at each section of the power plant. In addition to finding the temperatures, we have also adapted the code to tabulate the composition of the flue stream. At each point in the plant, the mass percent of each element in the stream is known.

The last objective was to make certain assumptions and assure their validity. The coal used for the Council Bluffs, Iowa project was determined to be pulverized river basin coal, and therefore had a composition as follows:

C:	0.480
H:	0.034
O:	0.11
S:	0.0048
ASH:	0.064
H_2O:	0.3
N:	0.006

This was the basis for our percent composition along the flue path in the power plant. The generator efficiency was assumed to be 98.5%

Upon successful running of the simulation, various quantities were derived:
The temperature of the flue gas, as the flue crew would receive is 180 °F, the flow rate of steam is 691.4 kg/s, the total flow of flue is 730.14 kg/s, the flow rate of coal approximately 76 kg/s, and 152.1 kg/s of CO_2 exiting the bag-house.

STEAM REMOVAL

In order to properly allow equipment to function the flue crew required a certain amount of energy via steam. In order to supply them with steam, careful examination was required as to where steam loss effects would least effect the gross output of the power plant, however still supply a sufficient amount of energy to the flue crew. It was determined that the steam should be removed after the intermediate turbine. An approximate flow rate of 43 kg/s of this quality of steam was required to supply the energy needed by the flue crew. Removal of this steam did indeed alter the output of the turbine. Approximately 30 MW less would be produced after this amount of steam was removed from the flue stream.

COOLER

The CO_2 removal processes require the flue stream to be at either 35 °F or 100 °F, depending on the chosen method. As the flue stream is exiting the bag-house at 180 °F, it is necessary to cool it either one of these temperatures. As a great deal of energy is required to cool and condense the water in the flue stream, it was decided that the water could be removed from the flue stream using the water sprayers, similar to the idea a wet SO_X scrubber. The flue enters the device, in which large amounts of ambient temperature water are being sprayed. The cooler spray water immediately cools the hot flue gases, and theoretically the water within the flue stream is sufficiently cooled to the point of condensation. The water in the flue stream is therefore changed to the liquid phase and drops out of the flue stream. Therefore, only nitrogen and carbon dioxide remain in the flue stream, and the energy required to cool these two substances is much less than that of water.

As very little data is available for the large-scale refrigeration/coolers necessary to chill such large volumes of gas, a simple enthalpy analysis was performed to approximate the energy required to cool the N_2/CO_2 gas mixture to either 100 or 35 °F. These calculations showed that approximately 30 MW and 55 MW of energy would be required corresponding to the 100 and 35 °F temperatures. Although this is not the most accurate method for determining losses, it was the best possible, with the scarce amount of information available on the subject.

0.5 Assignments

Project Management

George Vrana – Team Leader

As team leader for this IPRO, George Vrana was responsible for appropriate planning and organization of all team meetings in order to assure that the project plan and scheduling was on track. Furthermore, he monitored the progress of the project and distributed tasks among all team members to ensure a balanced workload while encouraging feedback and collaboration among all members. Rarely, he may have provided moral support and encouragement to any team members that may have been lacking motivation. Finally, George was also a member of the ethics and reports deliverable sub-teams and contributed to the final poster design.

Jeff Bart – Steam Team Leader

As a member of the steam team, the majority of Jeff's work concerned both steam cycle and flue gas analysis at various points throughout the power plant. He edited and further adapted Don Chmielewski's Matlab code to serve our needs. This involved making small changes such that the simulation applied to the specific plant in Council Bluffs, Iowa and adding code to further analyze the flue gas and steam as was necessary. In addition, he also worked on the ethics portion of the deliverables. Jeff adapted the Code of Ethics from last semester to apply to our project and further edited the code as was necessary with the help of other team members. His last major contribution was the Midterm Presentation. Jeff worked to help create and pull together the steam team portion of the midterm presentation, and eventually presented the work of the steam team for midterm reviews. Other small contributions include investigations into the losses of implicating the specified CO_2 mitigation technology and similar calculations.

Daniel Gonzalez

As a member of the Steam Team, Daniel's work was more inclined towards the study and analysis of the steam cycle and flue gas of the power plant. He worked on, and revised equations that dealt with the implementation of the anti-pollution contraptions in Matlab program, as well as the effect steam removal will have on the overall performance of the power plant. He also researched for a T-S diagram of a supercritical coal fired power plant and for chillers that would lower the temperature of the flue gas after it has gone through all the pollution control. As part of the ethics and reports sub teams, he contributed towards the completion of the ethics and midterm reports and designed slides for the midterm presentation.

Timothy Baldwin

Timothy was responsible for matlab verification through hand calculations. He was also responsible for work on the exhibits and ethics deliverables.

\Joshua Marheine

Joshua was responsible for a large portion of the matlab code. He helped edit and create the code. Joshua was also responsible for work pertaining to the presentation team, specifically the final presentation.

Courtney McWethy

A member of the steam team, Courtney was also charged with taking half the minutes over the course of the semester, choosing to alternate meetings with another team member and covering when the other member was unable to do so. She reviewed calculations made during the coding process to provide a second opinion on the probability of a set of numbers being accurate. As part of the reports team, she collaborated on large portions of the project plan, midterm report, and the final report. The exhibits for IPRO Day include posters and a brochure, all of which she worked. (this could definitely use some fixing but you get the idea)

Flue Crew

Frank Costanzo

Presentation, ethics, and economic analysis within the flue crew. Frank was responsible for a large portion of the work on the flue crew side of the project. He performed much of the analysis necessary, including an economic study of the cost associated with adapting a coal fired power plant.

Taeho Hwang

A member of Flue crew, Taeho worked on setting up the equations and calculations needed for the Matlab code of the absorber and the stripper and designed a feasible overall process. He also designed a heat integration process between two towers by using

HYSYS. As a member of the presentation team, he made the power point slides for the team presentation and contributed to the midterm presentation.

Da Hye Lee

Da Hye was responsible for the minutes, exhibits, and report sections of the deliverables. She also performed much of the mitigation analysis associated with the flue crew.

Alan Babjak

Alan created the matlab code associated with the sequestration process. He too, helped with mitigation analysis

296 Students

James Cheever

James worked to help edit the Code of Ethics. He also aided in the steam team analysis and the creation of the website.

Michael Clark

Michael was a member of the Jedi Masters under George. At the beginning of the semester he did some research into the EPA and local regulations. His main project was the design, creation and technical maintenance of the website, which was designed to act as an alternative to iGROUPS along with providing a lasting record of the group’s achievements.

Jen Guilfoyle

Near the beginning of the semester, Jen was made an administrator for this IPRO's igroups website. During the semester, she maintained igroups according to the group's specifications. She also helped the steam team program a model of the steam cycle in Matlab.

Sanghyuk Im

Sanghyuk Im was a member of flue crew. Near the beginning of the semester, he did some research about the ethics of the project. He mainly assisted for research on the component properties for the process. He also helped the abstract design by finding background samples.

Sithambara Kuhan

Kuhan worked primarily on the sequestration team. His tasks included researching the various methods of sequestration, and he focused on enhanced coal-bed methane recovery in the latter part of the project. He researched the current technologies of the process, and also the potential coal mines with relevance to the geographical location of the power plant. Furthermore, he also performed an economic analysis to compare with other methods of sequestration. Kuhan was also a member of the reports team, and often performed proof-reading and editing of the project deliverables such as the project plan, mid-term report and code of ethics.

Riju Konwar

Riju did much of the work on the compressor design. He also worked to help with the analysis necessary of the steam team.

Katie Lazicki

Originally a member of the steam team, Katie later joined the sequestration team in their effort to determine the best method of sequestration for the power plant in Iowa. Her responsibilities included researching the less viable sequestration methods and finalizing the sequestration team's portion of the presentation slides and final paper.

Kenneth Ogata

As a member of the sequestration team, Kenneth worked on an economic analysis of sequestration, thereby being able to compare the different methods of sequestration. Throughout the project, he focused primarily on enhanced oil recovery. He performed an economic analysis to determine if enhanced oil recovery is a feasible option for this particular power plant.

Wai-Kit Ong

Wai Kit worked primarily on the sequestration team. He researched the various methods of sequestration, and was later in charge of specifically the saline formation method of sequestration. He did an extensive research on the technology, identifying potential sequestration sites and evaluating the economic feasibility of sequestering carbon dioxide in saline aquifers. As part of the exhibits team, Wai Kit also helped to put the sequestration team's abstract and poster together. Besides that, he also helped with some proofreading and editing work at the beginning of the semester.

Mark Pyciak

Mark was part of the compressor team. He also helped with the presentations and general steam analysis.

Mike Schillaci

Mike worked on much of the HYSYS analysis and further performed work for the flue crew.

Farouk Yaker

Farouk worked on the compressor analysis. He researched much of the information for the compressors. In addition, he also worked on the steam team, helping with the matlba code.

Urszula Zajkowska

Ursula worked on the compressor team and also on the steam team. She also contributed to the presentation deliverable section.

Team Advisors
Don Chmielewski
Paula Moon

0.6 Obstacles

The Steam Team encountered quite a few obstacles over the past 13 weeks. Some of these problems were minor setbacks requiring a shift in organization while others were much more crippling and working around them would be failing at the assigned project. The largest task assigned to the Steam Team was creating a model of a supercritical pulverized coal fire power plant. Basing our work on a pre-existing code provided by our advisor, this looked to be quite simple. In practice, this was a lot more difficult and time-consuming than was initially assumed. Another problem facing the team was transitioning the code for a sub-critical steam cycle to a more efficient supercritical one. While a detailed sub-critical T-S (temperature versus entropy) diagram was readily available to the team from an old textbook, a supercritical T-S diagram could only be found without any numbers indicating pressures and temperatures. During the final weeks of the project, a diagram did become available to us, provided by Charles Guilfoyle. This was a huge breakthrough in making the project accurate for the supercritical power plant the project is based on. It also added a large amount of work to an already tight schedule. Along with the difficulties in information acquisition and translation, this semester was plagued with the usual outbreak of flu. Several team members were infected and missed meetings. It also impeded the work accomplished outside of meetings.

The sequestration team also was faced with some obstacles during the completion of this project. A geographical evaluation of sequestration options showed that the possible sequestration sites are located across state lines. The transportation of CO_2 over state lines must follow state and federal regulations. However, no regulations concerning CO_2 transportation currently exist. The Environmental Protection Agency (EPA) is in the process of writing these regulations, and will release them in July of 2008. Due to this lack of information, the calculations in the economic analysis do not incorporate any limitations of CO_2 transportation potentially required by regulations. Once the EPA release the regulations, future research on this project can consider them in the sequestration efficiency and the economic analysis. The sequestration team also lacked the exact locations of the power plant and the injection sites, which affected the costs of the pipelines. An approximation of the distance made an estimation of calculated pipeline costs possible.

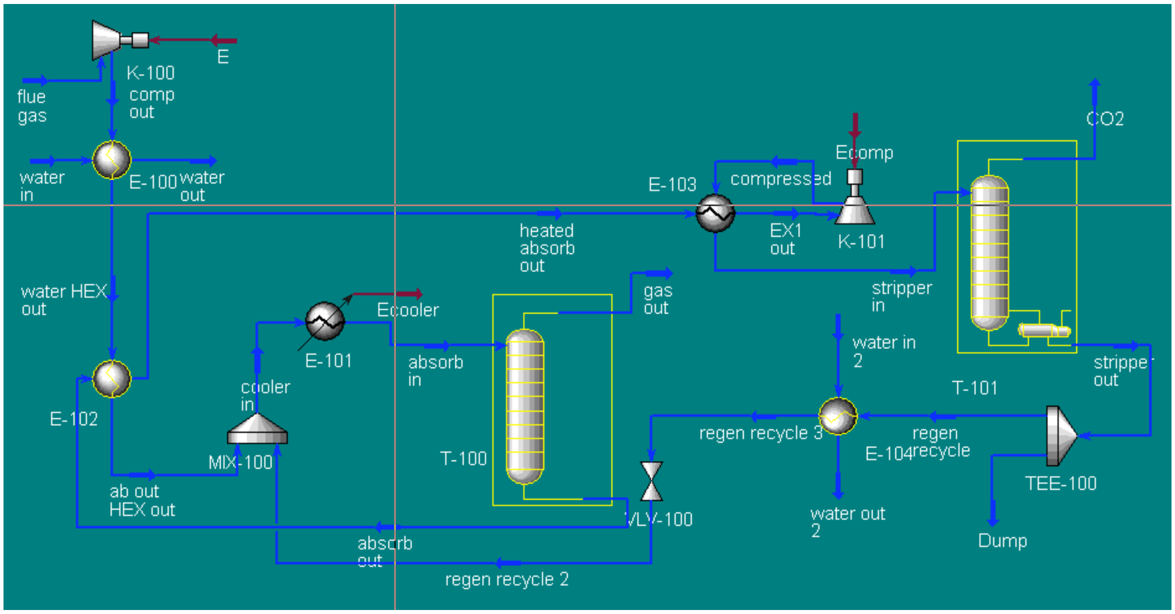
0.7 Results

The results obtained from work done by the steam team consisted of mass flow rates, temperatures, and pressures, and the composition of the flue gas. Once the conditions of the gas exiting the flue prior to the addition of further pollution control devices were known, it was necessary to begin work on a refrigeration cycle to cool the gas to 35 °F and 100 °F so that it would be ideal for entering the CO_2 removal unit. The information concerning normal exiting conditions was shared with the other sub teams for a variety of uses. The flue crew used these numbers as initial conditions for their unit. The compressor team needed these numbers to make their final recommendations. The sequestration team used the steam team's data when evaluating sequestration options.

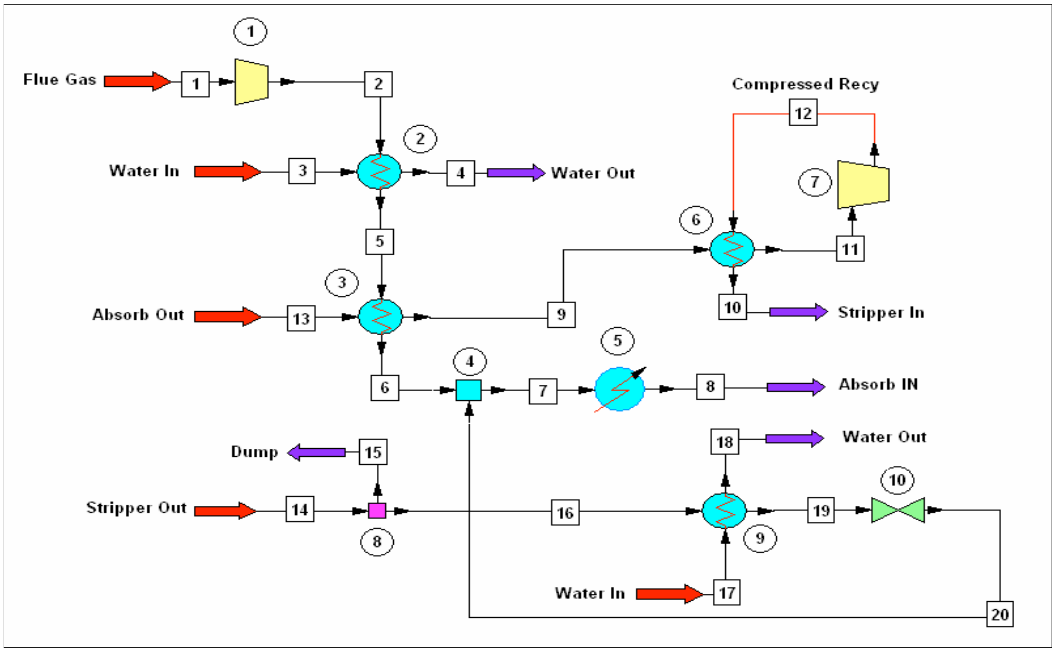
CO2 Absorption and Regeneration Process (Flue Crew)

- Absorber and Stripper
- Heat Integration

HYSYS simulation



ChemCad Simulation



Economical Analysis

Total Plant Cost	1.07E+09
Cost to Manufacture	2.88E+08

Summary of Equipment Costs

Unit ID	Unit Type	Equipment Cost
1	Compressors	18,032,566
2	Heat Exchangers	776,112
3	Heat Exchangers	458,395
5	Heat Exchangers	2,285
6	Heat Exchangers	282,816,320
7	Compressors	21,194,734
9	Heat Exchangers	99,103

Cost and Sizing Summary for Compressors

UnitOp ID	1	7
Fob. Cost	1.80E+07	2.12E+07
Utility Cost	0	0
Actual Power	4.68E+08	3.89E+08
Discharge Pressure	6.18E+01	3.00E+02
Polytropic Head	0	0
efficiency	0.75	0.75

theoretical power	3.51E+08	2.92E+08
Compressor type	2	0
Driver type	1	0
motor type	0	0
	#N/A	#N/A

Heat exchanger Cost Summary					
Unit ID	2	3	5	6	9
Fob. Cost	776112	458395	2285	282816320	99103
Utility Cost, /hr	0	0	0	0	0
Exchanger type	Shell & Tube				
	Fixed Head				
Material	Carbon steel				
Heat Duty	694526592	95557872	749195.6875	64718094336	100807344
Area	200	200	200	200	200
U	47403.09375	31191.39258	30	2162363.25	8133.01416

CO_2 Compression

The compressor selected as the most feasible for this process is a Type RG multistage integrally geared centrifugal compressor manufactured by Man Turbo. The compressor consists of a gear unit with a central bull gear that drives two to eight radial flow impellers with interstage cooling. The suction volumetric flow rate ranges from 2,000m^3/h up to 500,000m^3/h and the maximum discharge pressure of 225 bars. The number of stages depends on the outlet pressure. According to Man Turbo the Type RG compressor has an excellent performance rating under partial load conditions. It is therefore economically feasible to operate this compressor at various degrees of sequestration. The total capital cost is estimated at $55 million. This, however, is a rough estimate as each compressor is tailored to suit a specific application.

Sequestration Methods

The sequestration team's results encompass the economic analysis of the three possible sequestration methods. These results were based on the mass flow rate of CO_2 produced at the power plant, costs for installation and maintenance of pipelines, drilling new wells or refitting old ones, and profits made from recovered material in enhanced oil recovery and coalbed methane sequestration.

Saline formations:

Saline formations are composed of porous and permeable rock saturated with brine and capped by one or more regionally extensive impermeable rock formations enabling trapping of injected carbon dioxide (CO_2). Saline water is basically water that contains high levels of dissolved solids and is considered unsuitable for human consumption or for agricultural and industrial uses. Saline water can be defined as having more than 1000 parts per million (ppm) of dissolved solids while brine is saline water having more than 50000 ppm (1). The porosity (percentage of open pore spaces) and permeability (connectivity of open pore spaces) of the rocks are an important aspect to be taken into account when choosing a sequestration site as it could greatly affect how much CO_2 can be stored and at what rate. The other important factor is the depth at which the saline reservoir is at. Ideally, the reservoir should be at a depth of about 6000ft (1828m) so that CO_2 can remain in the supercritical phase. The supercritical phase is the best phase for the CO_2 to be at because it behaves like a gas where it can flow through the pore spaces easily yet behaves like a liquid where it does not take up as much volume compared to its gas counterpart. Therefore, we can store much more CO_2 easily.

Next, we shall discuss the major steps involved in storing CO_2 in deep saline reservoirs, namely receiving CO_2 from source, recompress if necessary, followed by injection to target site, and trapping. Research showed that the transport of CO_2 from CO_2 sources such as power plants is most efficient when transported via pipelines at supercritical phase. CO2 is at its supercritical phase when it is above its supercritical pressure of 7.4 MPa and critical temperature of 31 °C. Also, transport pressure within the pipelines should be maintained between 8.4 MPa and 15.2 Mpa (2). Generally, CO_2

received can be injected at pipeline pressure of about 10.3 Mpa (2), however, if this is not the case, it should be recompressed or decompressed to match a pressure of about 10.3 MPa to maintain an optimal injection pressure.

The next step is trapping of CO_2. Trapping mechanisms of CO_2 can be either physical, where injected CO_2 remains as a separate phase in the reservoir, or chemical, where CO_2 dissolves into the formation water and may react with minerals present in the formation, becoming immobilized over thousands of years (3). It is important to note here that the rate at which CO_2 can be injected into the reservoir is not affected by what type of trapping mechanism is available, however, the storage capability with respect to leakage will be affected by it. Therefore, no matter which mechanism is available, it is always better to inject CO_2 in deep formations as mentioned earlier, with a thick layer of shale formation to serve as a trapping cap. There are two main methods in which CO_2 can be trapped physically underground; they are the stratigraphic trapping and structural trapping. In stratigraphic trapping, CO_2 is trapped by an overlaying layer of caprock coupled with impermeable rock within a narrowing of the storage formation. On the other hand, structural trapping can further be split into two types, where CO_2 could either be trapped by a fold or by a shift of the impermeable layer. A pictorial description of the above-mentioned trapping mechanisms can be found in *Figure 1* below (4).

Now that the whole storage process has been explained, we shall move on to discuss some of the major advantages and disadvantages of this form of sequestration. There are several other forms of sequestration such as the enhanced oil recovery (EOR) method, the enhanced coalbed methane (ECBM)
method, oceanic sequestration, and even terrestrial sequestration. The greatest advantage of saline sequestration is its capacity. According to the a survey conducted by the Department of Energy (DOE), saline formations all over the United States hold a potential of 919 to 3378 billion metric tons of CO_2, compared to about 82 billion metric tons of CO_2 storage in oil and gas reservoirs, and about 190 billion metric tons of CO_2 in unminable coal seams (5). Besides having great capacity potential, saline formations are readily found all over the United States. Then, CO_2 produced by power plants or other sources could be easily sequestered in a nearby saline formation without much piping. However, one of its disadvantages when compared to EOR or ECBM is that it does not

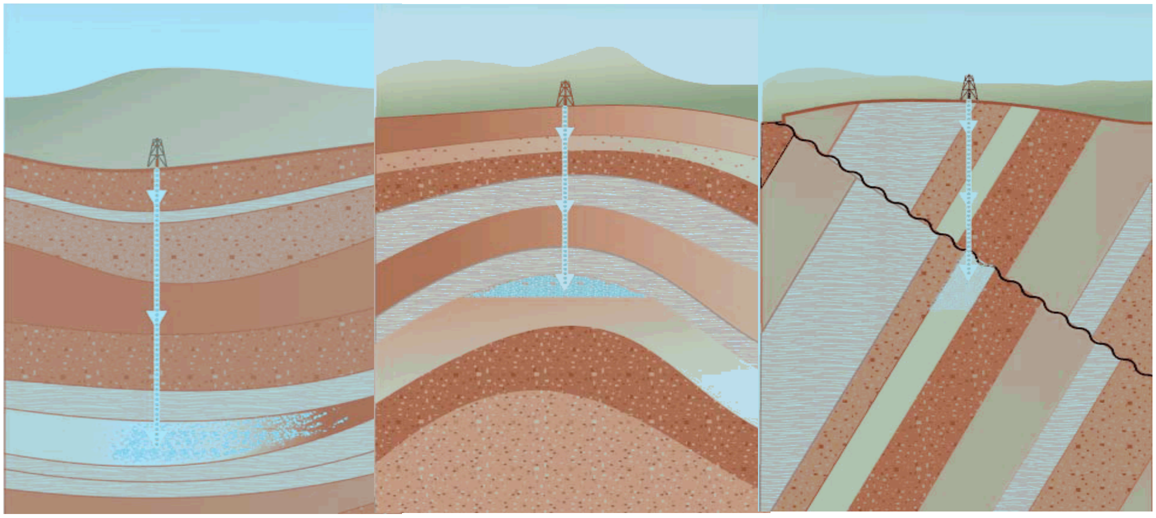


Figure 1 **–** These figures displays the different ways CO_2 can be trapped by stratigraphic trapping (left), structural trapping by a fold (middle), or structural trapping by a shift (right)

provide any value-added product. Therefore, the overall levelized cost of sequestering CO_2 in saline formations is generally higher than that of EOR and ECBM.

For this study, two major saline reservoirs nearest to our power plant in Council Bluffs have been located: Illinois Basin and part of Southwest Regional Partnership. The two specific sites within the Illinois Basin studied are Mount Simon Sandstone and St Peter Sandstone. Together, these two sites are estimated to be able to hold up to 40 billion metric tons of CO_2. On the other hand, Arbuckle Group in Kansas has been identified as the potential saline reservoir within the Southwest Regional Partnership, and is expected to hold up to 60 billion metric tons of CO_2. These sites satisfy the criteria of a good saline reservoir. The sandstones in Illinois Basin are have thickness of about 50 to 100 m and are about 1000 m deep while the reservoirs at Arbuckle, Kansas are about 600 m thick and 2400 m deep. These parameters are important and will be used to do the cost analysis in the next section. Since the Arbuckle Group has more potential, greater capacity, and is nearer to our power plant, the cost analysis done in the next section will focus on potential sequestration sites around that area. *Figure 2* that follows shows the location of the potential sequestration sites in Illinois Basin and the Arbuckle Group.

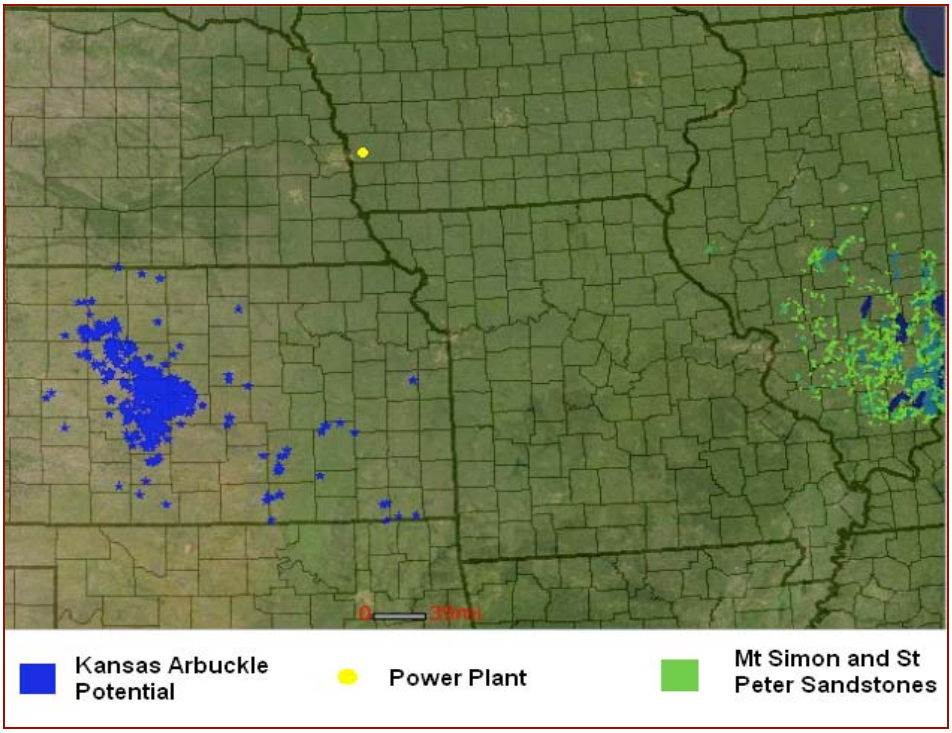


Figure 2 – Saline Sequestration sites at Mt Simon and St Peter Sandstones, and by the Arbuckle Group

Source: NATCARB-alpha Interactive Atlas

Enhanced Oil Recovery:

The first Enhanced Oil Recovery (EOR) projects began in the late 1970's. Since then, the number of these projects in the U.S. has increased to 80 in 2006, producing about 250,000 barrels of oil per day. There are two types of EOR, one involves miscible CO_2 flooding and the other type immiscible. Production from miscible flooding is more efficient than immiscible flooding. Production from miscible flooding accounts for slightly more than a third of the total domestic U.S. oil production from EOR methods (7).

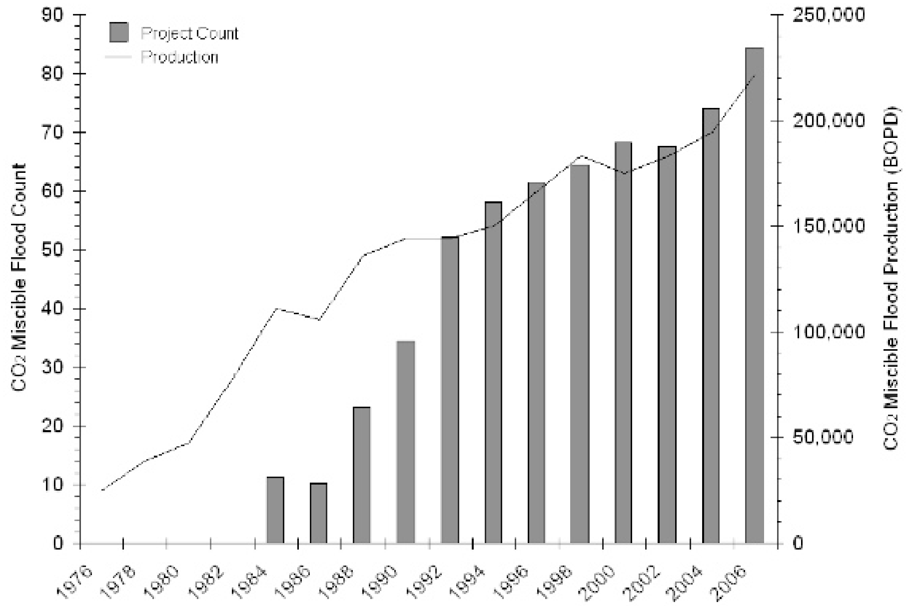


Figure 1 Counts of domestic U.S. miscible CO_2 flood EOR projects and production in barrels of oil per day (7).

This shows the increased interest in EOR. A number of studies have examined the potential for production from miscible Flooding by using semi-analytical screening models relating oil production rates to CO_2 injection rates, geological properties, and assumptions on the development of an oil field. More recently, there have been several studies that have attempted to evaluate the economics of carbon storage through miscible flooding.

In the U.S. there is currently no commercial-scale EOR project that utilizes CO_2 from a power plant. The main obstacle to the utilization of CO_2 from power plants is the significant cost of CO_2 capture. Most of the EOR projects, particularly those located in the Permian basin, are dependent upon naturally occurring CO_2, which is obtained from high-pressure, high-purity underground deposits. The most important of these natural CO_2 deposits, are the McElmo Dome, the Bravo Dome and the Sheep Mountain Field (8).

Most flooding is achieved through miscible displacement. Miscible displacement involves the injected CO_2 mixing thoroughly with the oil in the reservoir whereas, in the case of immiscible displacement, the CO_2 remains physically distinct from the oil. The type of displacement that occurs is dependent on the reservoir pressure and crude oil composition. With a reservoir depth greater than 1,200 m and an oil density less than 22 API typically lead to miscible conditions (8). Miscible displacement leads to an ultimate recovery of about 7 to 15 percent of the original oil in place. Immiscible displacement yields lower recoveries compared to miscible conditions, but can still achieve a high recovery rate due to oil swelling and viscosity reduction. It is expected that the number of immiscible flooding will increase as the use of CO_2-EOR becomes increasingly widespread.

In CO_2 flooding it is most common for the CO_2 not to be injected as a continuous fluid stream, but for CO_2 to be alternated with water injection in a water-alternating-gas process. This process is applied to help overcome the problem of high CO_2 mobility that greatly reduces the effectiveness of CO_2 flooding. This high CO_2 mobility problem, caused by the CO_2 having a lower density and viscosity than the reservoir oil. Taking advantage of the fact that water is less mobile than Co_2, the water-alternating-gas process is able to significantly improve the sweep efficiency through reducing CO_2 mobility. This, in turn, results in improved oil recovery while preventing early CO_2 breakthrough in producing wells.

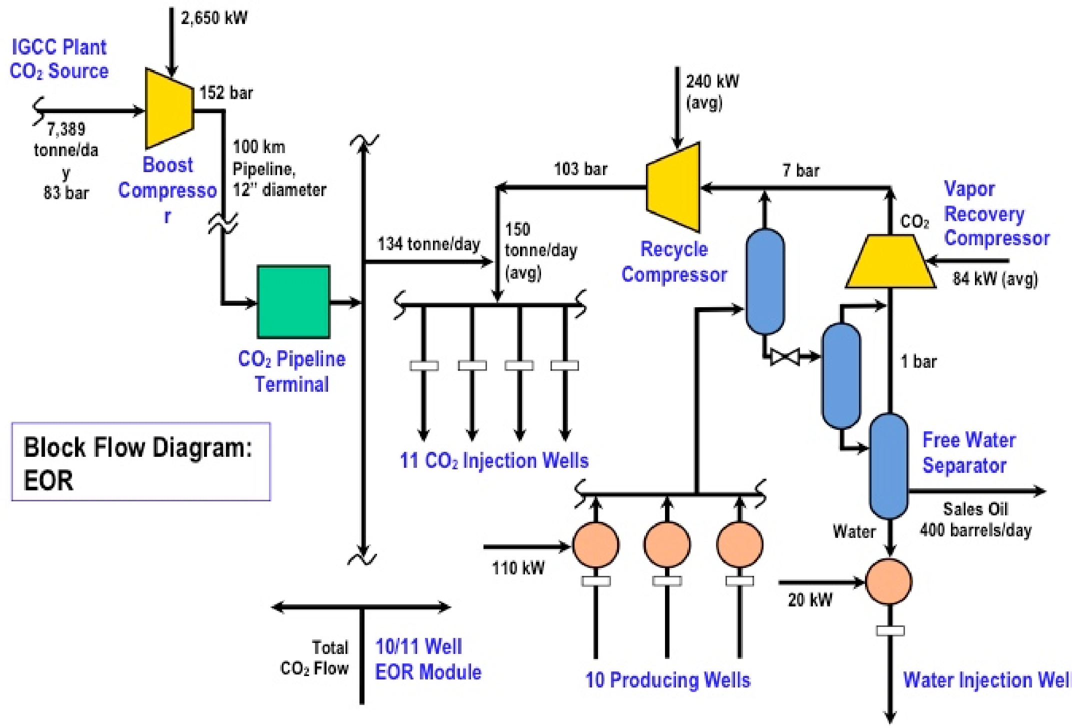


Figure 2 Block Flow Diagram of EOR process (8).

The major advantage in EOR is the fact that storage results in a value-added product. This helps to offset the initial capital cost and the O&M costs. The values used to estimate the cost of the project and the profit made from the oil are based on the system outlined in figure 2. A module includes 11 injection wells, 10 producing wells and one disposal well. The average amount of enhanced oil produced per day per well over the 20-year life of the field is taken to be 40 bbl. There is no evidence to suggest that the amount of enhanced oil produced per day per well is dependent on the basin in which the CO_2 flood is located. The number of production wells depends on the required well spacing that is set by the state's gas and oil commission, and can vary significantly. In one state it might be one well per 0.08 km^2 (20 acres), while in another it might be one well per 1.30 km^2 (320 acres). The typical well is shown in figure 3.

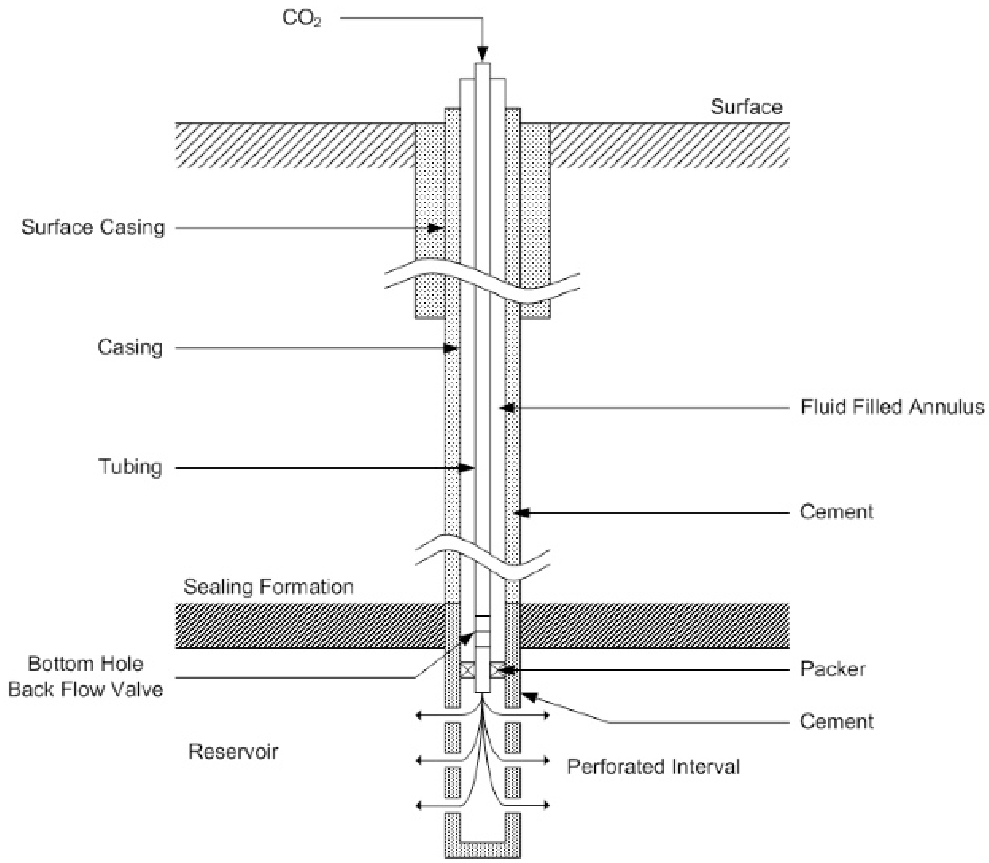


Figure 3 A typical well, with components (7).

The total capital cost is comprised of the injection and production equipment costs, and the costs of refurbishing the existing wells. The O&M costs include normal daily expenses, and surface and subsurface maintenance costs. Figure 4 shows the capital and O&M cost estimation factors.

Parameter	Unit	Value
CAPITAL COSTS		
Injection Equipment:		
Recycle & Vapor Compressors	$/module	1,773,000
Plant	$/module	113,600
Distribution Lines	$/module	77,200
Header	$/module	61,100
Electrical Service	$/module	97,400
Producing Equipment:		
Tubing Replacement	$/module	90,800
Rods & Pumps	$/module	41,000
Equipment	$/module	405,000
Makeover of Existing Wells	$/module	605,000
O&M COSTS		
Normal Daily Expenses:		
Supervision & Overhead	$/module	53,100
Labor	$/module	62,600
Consumables	$/module	7,500
Operative Supplies	$/module	7,700
Pumping & Field Power	$/kW-hr	0.044
Recycle Compressor Power	$/kW-hr	0.044
Surface Maintenance (Repair & Services):		
Labor (roustabout)	$/module	32,200
Supplies & Services	$/module	44,300
Equipment Usage	$/module	16,300
Other	$/module	2,300
Subsurface Maintenance (Repair & Services):		
Workover Rig Services	$/module	46,400
Remedial Services	$/module	15,100
Equipment Repair	$/module	11,200
Other	$/module	9,900

Figure 4 Capital and O&M cost estimation factors

	25%	50%	90%
New CO2 [kg/day]	3590297.5	7180595	12925071
Amount of Co2 sequestered[kg/module/day]	135790	135790	135790
Oil Production[bbl/well]	40	40	40
Cost of oil/bbl	15	15	15
Number of Modules	26.44007291	52.88014581	95.18426246

Capital [$/module]	3264285.714	3264285.714	3264285.714
O&M[$/module/year]	482142.8571	482142.8571	482142.8571
Capital [$]	86307952.27	172615904.5	310708628.2
O&M[$/year]	12747892.29	25495784.59	45892412.26
Oil[$/day]	158640.4374	317280.8749	571105.5748
Oil[$/year]	57903759.67	115807519.3	208453534.8

Figure 5 Cost Calculation

Using the base case of 56 modules, the total capital cost comes out to be $182,800,000, and the O&M costs come out to $27,000,000 per year. It is assumed that the amount of new CO_2 per day per module is 68,000 scm. With this amount of information it is possible to get a rough estimate of the cost of CO_2 flooding. Figure 5 shows the cost of sequestering the CO_2 based on different percentages of CO_2 captured at the power plant. It can be seen that the number of modules to handle the power plant is fairly large. The levelized cost for the base case comes out to be -$12.21 per ton of CO_2. However, assuming that the power plant does not own the oil fields, the profit will be a fraction of this. Either way it can be seen that EOR is a very useful and profitable process.

Enhanced Coalbed Methane Recovery

Coalbed methane is a type of natural gas extracted from unmineable coal seams, which are generally richly adsorbed with methane. Currently, it accounts for over 7% of the United States' annual natural gas production (9). The process involves drilling a steel-encased hole into the ground up to 1000-1500 meters deep and pumping out methane gas through it. The produced gas in often termed as 'sweet gas' for it's low content of contaminants such as hydrogen sulfide (10). The figure below depicts the most common process utilized in coalbed methane extraction today.

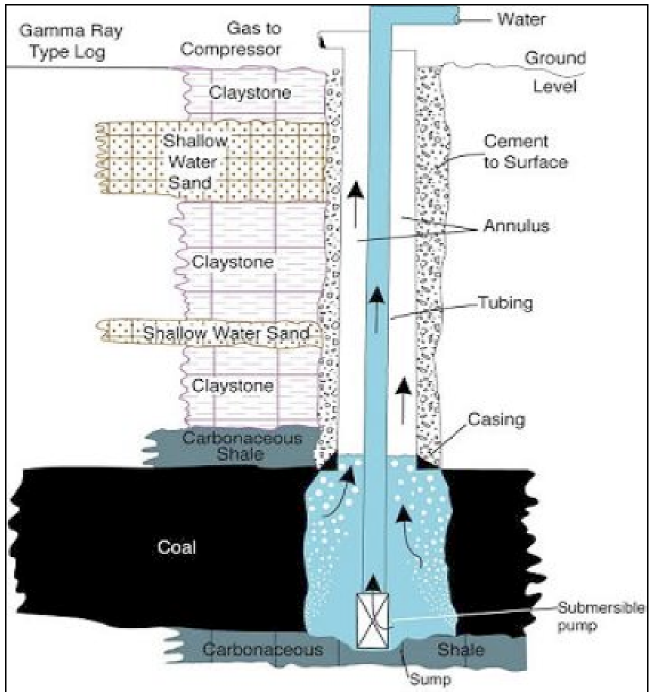


Figure adapted from Wyoming Geographical Survey website.[7]

Enhanced coalbed methane recovery is a modification of the current process, which involves the displacement rather than the desorption of coalbed methane using carbon dioxide, and thus effectively sequestering carbon dioxide (9). Current methods recover only 20-60 percent of the original methane in place, whereas the ECBM method recovers about 90 percent (9). The efficiency ratio of this process is approximately 2, as coal adsorbs around twice the volume of carbon dioxide in comparison to methane. In this method, CO_2 is pumped into the coal seams through multiple injection wells, and production wells are used to collect the recovered methane. The methane is then dewatered, pressurized and sent to a gas line for sales (9).

Looking at it in a sequestration point of view, the enhanced coalbed methane recovery method has a number of advantages that we could consider. Firstly, this form as sequestration, as mentioned above, produces a value-added byproduct (coalbed methane). The revenue from the sales of methane can be used to offset the costs of sequestration, although our cost analysis (displayed later) shows that this method actually produces a large net profit in the long run. Coal mines are also conveniently located nearby power plants in general (as is the case with our power plant as well), hence one would not require much piping to transport the CO_2 to the site (14).

Enhanced coalbed methane recovery does have several pitfalls. For example, it has a lower storage potential in comparison to some other sequestration methods – namely enhanced oil recovery and saline aquifers (9). However, these findings are in stark contrast to a paper on ECBM sequestration potential in Wyoming which estimated that the sequestration potential of coalbeds that underlie the deep areas in northeastern Wyoming alone can sequester all of the current CO_2 emissions from nearby power plants for the coming 150-160 years (15). Due to the limited number of studies and the difference of the coal seams in each area in terms of area and depth, these estimations are not very reliable, and we cannot generalize the sequestration potentials for the entire nation. Another pitfall would be that the technology is also relatively new and has only been demonstrated in limited field tests. Some coal basins also have thick coal seams that make the recovery of methane impossible with the current injection and production technology (16).

For the case of our power plant, this method seems to provide us with the best sequestration option, both geography-wise and cost-wise. Our power plant in Council Bluffs, Iowa is actually located on land with underground coal seams that have future potential for enhanced coalbed methane recovery. The following is a map of our power plant, and the underground coal basins around it according to the US Geological Survey.

Our Power Plant

Area shaded yellow represents coal basins based on US Geological Survey studies. Map adapted from NATCARB Interactive Atlas (14).

However, for short-term purposes, it is important to note that there is no coalbed methane activity currently in Iowa, and the closest currently-operating coalbed methane wells we found are located in the northern counties of Kansas, which is still not very far off as transporting CO_2 from our power plant to these counties would take approximately 100-150 kilometers of piping (14).

In an effort to compare the different sequestration methods, we performed an economic analysis of each method. For enhanced coalbed methane recovery, we needed to define a number of parameters to facilitate our cost calculations. We assumed the supercritical CO_2 entering the pipes from the compressor at the power plant to be 152 bars. This is the recommended pressure for efficient transport of CO_2 across pipelines, along with a temperature of 38°C (9). In order to facilitate the pumping of CO_2 into the ground, we assumed an outlet CO_2 pressure of 103 bars. With these and the tabulated values of CO_2 properties, we found that the diameter of the pipe needed to be at least 15". Hence, we used 16" steel pipes for our calculations.

For the purpose of our analysis, we assumed a project lifeline of 20 years, which is basically the expected lifespan of an enhanced coalbed methane recovery well system (9). The costs of piping are simplified and expressed in a range of $12400-$21000 per inch per kilometer (9). We assumed the worst case scenario, and used the maximum price. With this, we were able to calculate our total costs of piping which came up to be $36,000,000. We also found maintenance costs of these pipes to be around $3100/km, which added to our costs to bring it up to $36,465,000.

Next, we calculated the initial costs of setting up an enhanced coalbed methane recovery module in place of a currently operating coalbed methane well. In order to determine the total initial costs, we had to decide on the number of wells required. We found average estimates of methane production per well to be approximately 20,000 million cubic feet (16). These With this, the efficiency ratio of 2 units volume CO_2 per unit volume methane and the rate of production of CO_2 in our power plant, we found that we would need approximately 183 wells to effectively sequester all of our daily CO_2 production. We then multiplied this number by the initial costs we found our power plant to have, and the results of these calculations are shown in the following table.

CAPITAL COSTS	**Unit**	**Value ($)**	**Final Costs ($)**
Injection Equipment			
Plant	$/well	104455	19083666.98
Distribution Lines	$/well	70182	12822075.69
Header	$/well	55545	10147932.44
Electrical Service	$/well	87818	16044128.74
Producing Equipment			
Tubing	$/well	40800	7454057.851
Rods & Pumps	$/well	39200	7161741.857
Pumping Equipment	$/well	340000	62117148.76
Gathering System			
Flowlines	$/well	42500	7764643.595
Manifold	$/well	42600	7782913.345
Gathering Compressor	$/well	105000	19183237.12
Sales gas compressor	$/well	3970000	725309060.5
Lease Equipment			
Producing Separator	$/well	12400	2265448.955
Storage Tanks	$/well	76600	13994628.22
Accessory	$/well	35800	6540570.37

Equipments			
Disposal System	$/well	96700	17666847.9
Total Costs			**935338102.4**

Source: Laboratory for Energy and Environment at the Massachusetts Institute of Technology (2003) (15).

Hence, we found the initial costs to be huge at approximately 9.35 billion dollars. However, seeing that we are assuming a project lifeline of 20 years, we can expect these costs to somewhat levelize over the timeline.

Next, we calculated the recurring costs of operating and maintaining the wells. Assuming a cost of $1446601/well and estimating operation and maintenance costs to be $7,000,000 a year (9), we were able to determine the annual costs and hence the total costs over the project lifeline. We then considered our value-added byproduct, and calculated the revenue one could get through sales of the coalbed methane produced. The price of methane in the United States market often fluctuates, but it has been steadily increasing in the long run. The following graph shows the prices of methane over the last decade up to the year 2003, and clearly illustrates the fluctuation of the prices.

Prices expressed in dollars per million cubic feet (MCF). Source: Kansas Geological Survey (12).

Based on the graph and other more recent papers (11, 15), we used a price of $5/MCF for our calculations. Next, we practically multiplied this by the production rate of methane per year to find our annual expected revenue.

We can now find the net value of the sequestration project by multiplying the annual recurring costs by the project lifeline of 20 years and adding the initial costs to these. By determining the CO_2 we would have sequestered over the 20 years, we found the levelized annual costs of sequestering one tonne of CO_2. As expected, the analysis over the long run showed that one should be making significant profit through this method of sequestration.

Parameters	**Base Case**
Cost Calculations	
CO2 Effectiveness	2
Production per well (scm/day)	20000
Gas Price ($/mcf)	5
Depth	600
Pipeline Distance	150
Total CBM Production (scm/day)	1.88E+06
CO2 Mass Flow Rate (scm/day)	7307899.854
No. of CBM wells	182.6974964
Cost per injection and production well ($)	1446601
Total Injection & Production Costs ($)	264290380.9
Operation & Maintenance (O&M) costs ($/yr)	7000000
Total Initial Costs ($)	1199628483
Project Lifeline (yrs)	20
O&M Costs ($/yr)	7000000
Total Costs at Site ($)	1339628483

Offset Calculations	
CBM Production over project lifeline (mcf)	941853095.1
Revenue from CBM sale ($)	4709265475
Final Calculations	
Total Costs for 20 yr lifeline ($)	1376093483
Net Cost for 20 yr lifeline ($)	-3333171992
Amount of CO2 Sequestered (tonnes)	104836682.4
Levelized Costs ($/tonne CO2 sequestered)	-31.79394766

Partial summary of parameters and calculation details in analyzing the costs associated with the ECBM process. Negative sign on costs indicate a profit.

These calculations indicate huge profits, but we must take into consideration the numerous assumptions we have made. We also did not take into account the costs of acquiring the currently-operating CBM wells. In terms of literature values for comparison, a 2003 paper by the U.S Department of Energy performed a more detailed and complete analysis of ECBM recovery's CO_2 sequestration potential for different basins in the United States (15). Their results are summarized in the following table.

Costs of ECBM sequestration at different basins across the United States based on a $4.50/MCF price of methane. Source: Assessment of CO_2 Sequestration and ECBM Potential of U.S Coalbeds, U.S Department of Energy.

It needs to be noted that in this study, the calculations were based on lower estimated methane price of $4.50/MCF. The study also took into account the time value of money and a 25% premium to both new injection and production wells for CO_2 –storage monitoring and verification. For our power plant, we should be primarily concerned with the Forest City basin (13), which according to the study would result in a sequestration cost of $2.11/ton CO_2 sequestered.

Based on both our calculations and the studies, it is shown that the fluctuating price of methane greatly affects the sequestration costs. These costs also vary greatly by basin, where the parameters of coal thickness, sequestration capacity, depth of coal seams and feasibility of piping come into account. Based on these results, and the proximity of the coal seams of the Forest City Basin to our power plant, we recommend enhanced coalbed methane recovery as the most economically feasible option of sequestration.

Oceanic Sequestration:

To conduct a thorough investigation of sequestration methods, some less developed and less relevant methods were researched. One of the less relevant methods was oceanic sequestration. Oceanic sequestration is based on the observations of activity between the ocean and the atmosphere. The ocean naturally absorbs approximately a third of the carbon dioxide in the atmosphere (17). Through oceanic sequestration, the process of absorption of carbon dioxide by the ocean is sped up. Though equilibrium is eventually reached again with the atmosphere and the ocean, one third the CO_2 will remain dissolved in the ocean for approximately 500 years (17). This is a more optimistic result than other sequestration methods, which temporarily prevent the eventual total release of CO_2.

Pipelines, the same type used for transportation of CO_2 to oil fields, coalbed methane wells and saline formations, carry carbon dioxide from the source to the injection site. There are a few different methods for injecting carbon dioxide into the ocean, distinguished by the depth at which they are injected. Although it depends on where and how the CO_2 is injected, generally injections at greater depths will remain in the ocean for longer periods of time. The shallowest injection depth is 200-400 meters, though the CO_2 gradually reaches greater depths as currents pull it farther from the shore along the ocean floor (18). The average depth to inject CO_2 is about 1000 meters. To inject carbon dioxide at this depth, a diffuser injects CO_2 from either a stationary platform or a ship in motion. When using a diffuser, the gas will not rise more than 100 meters from the injection point, which means gas can be injected at any depth below 1000 meters (18). As the injection depth becomes greater than 3000 meters, the formation of CO_2 hydrates helps prevent the removal of carbon dioxide from the ocean. Below 3700 meters, a film of seawater saturated with CO_2 will cover the injected CO_2 (18). This phenomenon prevents the liquid CO_2 from dissolving in the ocean (19).

One theoretical method for injection of CO_2 into the ocean uses carbon dioxide in the form of dry ice instead of as a gas or pressurized liquid. Using CO_2 in its solid form would eliminate the need for pipes or diffusers, as the blocks would simply sink into the ocean (18). Because of the costs for transportation, this is not a likely option for oceanic sequestration in the future.

While oceanic sequestration appears to be more beneficial to the environment since it is based on a natural process, in reality, it has significant consequences to the ecosystem. Adding carbon dioxide to the ocean creates environmental problems just as adding carbon dioxide to the atmosphere does. By increasing the CO_2 content of the ocean, the acidity of the ocean increases. According to current research, the surface water will experience a 0.4 pH drop by the end of the century (20). Increased acidity results in the corrosion of calcium carbonate, a major component of shells (17). Such increase in the acidity of the ocean could pose a threat to oceanic wildlife.

Though ocean sequestration can keep a third of the carbon dioxide injected dissolved in seawater for a few centuries, the resulting consequences to the ocean's ecosystem makes this a less viable form of sequestration. Because the power plant is located in Iowa, oceanic sequestration is not a feasible type of sequestration for this project and so the economic and geographic components will not be evaluated.

Terestrial Sequetration:

Terrestrial sequestration is the use of forestry to remove carbon dioxide from the atmosphere. Because trees store carbon dioxide, an increase in forestation will allow more carbon dioxide to be stored in trees, and thereby removed from the atmosphere. Even after plants die and decompose, some of the carbon stored in the organic material remains in the soil instead of returning to the atmosphere (17). Conversely, when trees are cut down and burned, the stored CO_2 is completely released into the atmosphere again. Deforestation increases of CO_2 content of the atmosphere in two ways: producing CO_2 emissions through the burning of carbon-storing material, and reducing the amount of trees that mitigate the CO_2 in the atmosphere.

The land's ability to remove CO_2 from the atmosphere can be enhanced by several methods. By planting trees that live longer, more carbon can be stored per tree, and there will be a longer period before the tree dies and releases the carbon into the atmosphere once again. The tillage of farmlands involves turning over the soil, which releases the carbon stored in the land (22). This causes an increase of CO_2 emissions in the atmosphere. By growing more crops that don't require tillage, the crops do not need to be destroyed in order to prepare the soil for another season, reducing CO_2 emissions (21).

Another way to improve an area's sequestration potential is by planting trees on land not currently used for forestry. This is split into two groups: afforestation and reforestation. Afforestation is the cultivation of land that has not previously been devoted to forestry, such as mined areas (17). Reforestation is the cultivation of land that has recently been used for forestry. Afforestation is slightly more effective in sequestering carbon, since the soil at afforestation sites have not yet become depleted in nutrients. The increase of annual sequestered CO_2 resulting from afforestation is 2.2 –9.9 tons of CO_2 per acre, for approximately 120 years, while the increase of annual CO_2 sequestered per year is only 1.1-7.7 tons of CO_2 (17).

The methods just described are the main methods for terrestrial sequestration. Some additional ways to manage a land's ability to capture and store CO_2 are to use carbon-storing wood for practical uses, such as furniture (17). This prevents the wood from rotting right away, and keep the carbon from escaping at first. Another method is to clear brush and other undergrowth from forests. Brush increases the risk and severity of forest fires, and it can better be used for renewable biomass power production (17).

Like all types of sequestration, the results are not permanent. However, the changes to land management described above would make it possible to prevent most of the carbon dioxide emissions from returning to the atmosphere. Although there are many benefits to terrestrial sequestration, it is not useful for storing captured CO_2. Therefore, the geographical and economic components of terrestrial sequestration will not be evaluated.

0.8 Recommendations

The steam team recommends that the steam for running the CO_2 removal unit be removed from its normal course before the feedwater heater and return in to the normal flow after the feedwater heater. The CO_2 removal unit requires the heat from the steam and cools it as the feedwater heater would so that the rerouted steam can be returned without undue trouble.

The sequestration team recommends the use of coalbed methane sequestration for this power plant. Considering the profits gained from the recovered methane, the costs involved in coalbed methane sequestration are less than the potential profits. This profit would slightly offset the expense of implementing a CO_2 capture system in the power plant.

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