Southwestern Regional Partnership on Carbon Sequestration (Phase 2)

Validation and Comparison of Carbon Sequestration Project Cost Models with Project Cost Data Obtained from the Southwest Partnership

Topical Report

April 1, 2006 – December 31, 2010

October 2010

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Abstract

Obtaining formal quotes and engineering conceptual designs for carbon dioxide (CO_2) sequestration sites and facilities is costly and time-consuming. Frequently, when looking at potential locations, managers, engineers and scientists are confronted with multiple options, but do not have the expertise or the information required to quickly obtain a general estimate of what the costs will be without employing an engineering firm. Several models for carbon compression, transport and/or injection have been published that are designed to aid in determining the cost of sequestration projects. A number of these models are used in this study, including models by J. Ogden, MIT's Carbon Capture and Sequestration Technologies Program Model, the Environmental Protection Agency and others. This report uses the information and data available from several projects either completed, in progress, or conceptualized by the Southwest Regional Carbon Sequestration Partnership on Carbon Sequestration (SWP) to determine the best approach to estimate a project's cost. The data presented highlights calculated versus actual costs. This data is compared to the results obtained by applying several models for each of the individual projects with actual cost. It also offers methods to systematically apply the models to future projects of a similar scale. Last, the cost risks associated with a project of this scope are discussed, along with ways that have been and could be used to mitigate these risks. This work was funded by the Department of Energy (DOE) through the National Energy Technology Laboratory (NETL) and the State of New Mexico. It was submitted in partial fulfillment of the requirement for the degree of Masters of Engineering Management to the New Mexico Institute of Mining and Technology, October 2010.

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1   Executive Summary

Capturing and storing CO_2 deep within the earth is still in its infancy. Relatively few sites have been selected compared to the many sites that will need to be selected in order to capture enough CO_2 to have a significant reduction in the annual release of CO_2 into the atmosphere. To make a decision about a site many complex issues must be weighed in the balance. One of the main issues is that of the initial capital cost required to develop a site. Estimating the cost for a site can be very difficult and time consuming for those who do not have the experience or resources necessary. Hiring engineering firms to calculate estimates is very expensive, especially when the site in question is tentative.

This report, using several models presented by leading engineers and scientists, outlines a specific procedure which will enable a scientist, manager or engineer to determine a range of initial capital costs for a project in just a few hours using the fewest parameters possible. The procedures given in this report are designed to be completely self contained. All conversions have already been done making the equations and all variables internally consistent. Aside from the required parameters and some assumptions about the field in consideration all other data is contained within this report. The end result of following the procedure in this report will be a set of ranges for each of the main components of Carbon Capture and Storage (CCS). These ranges will give a good approximation of what the initial capital cost of a future project might be.

This report is designed to be a streamlined process, which will allow a manager, scientist or engineer to quickly calculate the cost of installing a CCS site. It therefore does not specifically analyze or interpret the individual models and their derivation process so as to reduce the amount of reading necessary to get to the meat of the project. This information can be found at the original sources of the models given in the references.   Also this report does not give any specific weight to any of the models. The method here assumes that in taking the average across each of the methods that the strengths in one will counteract the weaknesses in another and vice versa. This assumption is made in the interest in keeping with the main purpose of the project, which is to keep things as simple as possible and to reduce the time necessary to calculate the initial capital costs. All of the needed standard or constant numbers for each equation along with any needed charts are available at the location in the report where they are needed.

The report begins with an introduction describing the need for carbon sequestration as part of a larger portfolio of 'green' technologies to help reduce CO_2 emissions. The seven partnerships and in particular the Southwest Partnership for Carbon Sequestration commissioned by the Department of Energy are also introduced with their program structure. Next the methodology or procedure to calculate the initial capital cost ranges are given along with a short description of where each of the models or methods came from and how they are used in this report. The last part of the introduction is a description of how this report is relevant to engineering management principles.

Section three is the heart of this report in which all of the methods for calculating the initial capital costs are given and briefly described. The three main components addressed in this report are the compression of the CO_2 once it leaves the source, building the transporting pipeline system and drilling the injection well. Two other smaller costs that will be addressed is a line heater and dehydration

system. Each subsection begins with a nomenclature table describing each of the variables unique to that subsection as well as listing each of the standard values necessary for the calculations.

Section four describes several of the dominant risks that have been recognized by the Southwest Partnership during its field tests. To quantify these risks and to recognize their potential to increase the cost of the projects a contingency fund or 'fudge factor' is added to the overall cost of the projects.

In section five by way of example and better clarification all of the equations and methods from section 3 are used to calculate initial capital cost of a case study in which a hypothetical situation is setup. The resulting cost range and its implications are then explored.

Finally in section six three projects are considered. The first project is one that has actually been completed and the final costs have been accounted for. Two other projects have been conceptualized and cost estimates for the initial capital costs have been calculated by an engineering firm. The cost estimates by line item are given in the appendix. All of the methods in the report have been applied to each of the three projects giving a range of costs and an average. The estimates from the conceptualized projects as well as the final cost of the completed project are then compared to the results. In each case the estimated or actual cost falls within the range of the models' cost estimates.

After using the method given in this report and applying it to one actual project, two conceptualized projects and one case study several conclusions can be drawn. First, even though most of the models are well recognized and used they still produce a fairly wide cost range. This cost range is about +/-10-15% from the mean value. Second all of the actual or estimated data fit within the calculated cost ranges. Third the cost range can be reduced by having more accurate data and precise designs.

2   Introduction

2.1   Carbon Sequestration

2.1.1   Greenhouse Effect
Both the earth and the moon receive the same amount of solar radiation, yet the surface temperature of the earth is 34°C warmer with an average temperature of 15°C. This warmer temperature is made possible because of the atmosphere, which traps energy from the solar radiation. Two gases, CO_2 and water vapor, are primarily responsible for storing the solar radiation as heat. As the solar radiation is reflected from the earth's surface, CO_2 and water vapor absorb some of the solar radiation before it is either reflected back to earth or continues on back to space. In order for the earth to sustain its current average temperature, the equilibrium between the amount of solar energy that is absorbed and reflected needs to be maintained. As the concentration of greenhouse gases increases in the atmosphere, more solar radiation will be absorbed, causing the temperature of the earth to increase. (1)

The greenhouse effect is influenced by several gases. The main greenhouse gases are water vapor, carbon dioxide, methane, ozone and nitrous oxide. (2) While all of these gases effect the warming of the planet, carbon dioxide concentrations are most influenced by anthropogenic, or manmade sources.

2.1.2 Carbon Dioxide

CO_2 is a colorless, odorless gas at standard temperature and pressure that occurs naturally in the atmosphere and deep in underground reservoirs. It is produced during respiration by plants and animals as well as by the combustion of carbon fuels (fossil fuels, wood, grass, cow chips, etc). CO_2 is also required as part of photosynthesis, thus a necessary part of the cycle of life on earth. Other common uses for CO_2 include dry ice, carbonated beverages, enhanced oil recovery and fire extinguishers. The annual average CO_2 concentration in the atmosphere was 387.35 ppm for 2009 based on data collected at Mauna Loa, Hawaii. (3)

Figure 1: Law Dome and Mauna Loa CO_2 Data
(4) (3)
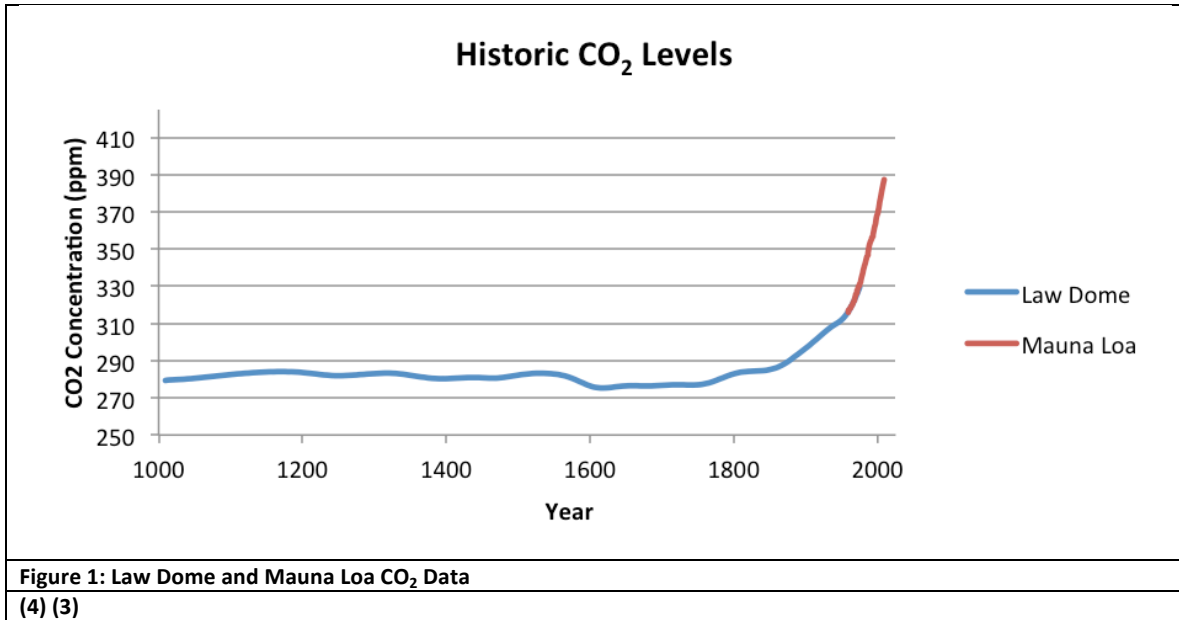
Atmospheric carbon dioxide levels have increased exponentially for nearly two hundred years, beginning with the Industrial Revolution being fueled by an increasing demand for energy. Due to climate changes that have been linked to the increase in CO_2, there has been increased interest worldwide in controlling CO_2 production. There are many proposed methods to reduce, reuse or store CO_2. As part of this growing portfolio of CO_2 mitigating options, carbon capture and storage is important because it provides a potentially viable means to reduce the amount of CO_2 released into the atmosphere while alternative energy methods are being developed.

2.2 Southwest Regional Partnership on Carbon Sequestration (SWP)

In 2003 under the direction of the Department of Energy, the National Energy Technology Laboratory (NETL) formed seven partnerships that "include 350+ state agencies, universities, and private companies, spanning 43 states, three Native American Organizations, and four Canadian provinces." (5) The SWP is a partnership of over 40 industrial companies, universities, and national laboratories, which are "composed of a diverse group of experts in geology, engineering, economics, public policy, and outreach." (6) The SWP includes all or parts of Arizona, Colorado, Kansas, Nevada, New Mexico, Oklahoma and Texas.

NETL has established three different phases for each of these partnerships. The first phase was the Characterization Phase where the SWP was required to "evaluate and demonstrate the means for achieving an 18% reduction in carbon intensity by 2012." (6) Phase I lasted two years (2003-2005). Phase II, the Validation Phase, is where the promising opportunities in carbon sequestration are tested and proven. This phase was scheduled to last four years (2005-2009), but in the case of SWP has been extended for one year. Phase III, the Deployment Phase, will demonstrate large-scale, or commercial-scale CO_2 capture, transport and storage. This phase is scheduled to last about 10 years. The SWP partnership has worked directly on three different geological sites during Phase II. These are the Aneth field in southeast Utah, Pump Canyon in the San Juan Basin in northwest New Mexico, and the SACROC field in west Texas.

Figure 2: Boundaries of the SWP
(7)

2.3   How to Use This Report

Aside from the capturing process, the three dominant capital costs included in a Carbon, Capture and Sequestration (CCS) project are compression, the pipeline system and the injection well. Two significant but smaller costs are for line heaters and dehydration units. This report describes three methods for calculating each of the dominant costs and one method each for heating and dehydration.

This report is designed in a way that all of the methods are used to determine a range of projected costs. There are three methods in the compression section, which are used to calculate the cost of compression. The first two methods require the power required to run the compressors. To calculate the power two different methods are given, they are titled Compression Power Calculation Method 1 and Compression Power Calculation Method 2. Either of these methods can be used. They both use the same basic equation for calculation, the first method is done by hand while the second one is automated and can match the actual power usage to compressors in the field making it a little more accurate. Once the power is calculated the three different methods for calculating the compression can then be used. Once they are calculated an average can be taken as well as the minimum and maximum of the three values. These will form the boundary of the range as well as the center. There are three different methods that are used to calculate the cost of the pipeline system. Each of these methods should be used to calculate the cost. Then once the cost is calculated the minimum, maximum and average should be calculated to form the range of projected costs. Likewise, to calculate the cost of injection all three methods should be used and then the minimum, maximum and average should be calculated. Because of the lower cost of the dehydrator and line heater only one method is provided. Once all of the costs have been calculated the maximum costs for compression, the pipeline system, and the injection well as well as the single cost for the line heater and dehydration unit can be added together for an overall maximum project cost. Similarly the cost for the minimum project cost can be calculated. Then using the maximum and minimum project costs an average can be calculated.

All of the equations and costs in this report have been adjusted into 2009 U.S. dollars. Cost index values for refinery and process costs from 1996 to 2009 are included as well as methods to calculate current costs and future costs. Once the minimum, maximum and average values have been calculated the cost adjustment can be applied to them as described below to adjust it to the year in interest.

Included in the appendix are several quotes that the SWP received from the Nicholas Consulting Group when preparing for the projects they have worked on. This information is primarily provided for two reasons: to give the user a better understanding of the components involved in a CCS project and to show the user approximate costs that have been quoted for the different components of the project. These quotes were used for the purpose of establishing a budget for the project.

To use the tools provided by this report, only a few basic parameters will be needed, as noted in Table 1, as well as some basic assumptions and "guesstimates" as indicated throughout the process. Most of the values for these parameters should be available from surface measurements and well logs.

Table 1 Basic Parameters for Establishing a Project Budget

Input Parameters	Output Results
Permeability	Capital Cost of the Pipeline
Thickness of Reservoir	Capital Cost of the Heating System
Depth to Reservoir	Capital Cost of Compression
Distance from Source to Sink	Capital Cost of the Dehydrator
Input Pressure to Pipeline	Capital Cost of the Injection Well
Surface Temperature	Overall Cost
Mass Flow Rate	
Reservoir Pressure	

2.4 Limitations of Study

This study is strictly designed to give a rough estimate of what to expect the initial capital costs of compression, the pipeline system and the injection well. Because of this 'roughness' of the estimate, which is due in large part to the broad assumptions, it allows and to the very basic input parameters caution must be used in ascribing specific weights to the individual methods. Also any risk analysis that is done at this stage should be very generic. Any risk analysis beyond this would qualify for its own paper and much more time than the few hours the method in this report is designed to use.

This study does not address the very large costs of the capture process in which the carbon dioxide is separated from other process gasses and liquids. For better estimates many more variables would need to be considered and more specific designs would have to be submitted for review

2.5 Brief Description of the Cost Estimation Methods

Carbon capture and sequestration (CCS) has been an increasingly hot topic for the last ten to fifteen years. There have been two modes of study: one more on a micro level and the other more on a macro or nationwide level. The macro-scaled studies are typically interested in the effects of many CO_2 sources and sinks, along with their interconnecting pipeline infrastructures. The micro-scaled models are generally concerned with individual sinks and sources and their connecting pipelines. In this report the focus is on the individual source and sink and does not considering the equally or in many cases even more significantly higher cost associated with carbon capture and separation. This report only considers the cost and risk after CO_2 is secured.

Each of the methods is briefly described below. There are three separate methods each for compression, pipeline transportation and injection and one each for the heating and dehydration systems. For each of the three main systems a summary table will be included for reference.

2.5.1 Compression Cost Calculation Methods

Compression capital costs include the cost of the compressor, valves, concrete, foundation, materials, installation, engineering fees, related facilities and other miscellaneous items. Capital costs for compression are typically found by first calculating the required power for the compression and then multiplying that by a cost factor. Two methods are considered for calculating the cost based on the

power required. A third, rougher method is used based on multiplying the cost of the compressor by a factor.

Comparison of Cost Calculation Methods for Compression		
Method 1	Method 2	Method 3
☐ Calculate Power Required ☐ Determine flow rate through compressor ☐ Calculate compression cost based on regression analysis of past compression data	☐ Calculate power required ☐ Multiply required power by cost factor	☐ Costs for a range of flow rates were gathered and plotted along with a range for the required pressure increase ☐ Use the included graph to determine approximate cost based on needed flow rate and pressure increase ☐ Multiply this cost by a cost factor for the final cost

To calculate the cost for compression requires suction and discharge pressures as well as the flow rate. Two ways to calculate the power requirements are presented. Compression Power Calculation Method I is a method of calculating the compression power manually. The basic equation for compression as presented in the *Engineering Data Book* published by the Gas Processors Suppliers Association (GPSA) is explained along with a procedure to calculate the power required for each stage of compression. Compression Power Calculation Method II uses the Ariel software that is available free online and is used by the industry to calculate the power requirements and configure compressors. The basis for the calculations for this software is a similar equation used to that was presented in Method I. Instructions are included in this report for simply calculating the needed power requirements using this software.

Once the power has been calculated by the above methods, there are two methods to calculate the cost. Compressor Cost Calculation Method I is an equation that varies with the power requirements, making the lower flow rates somewhat more expensive due to initial setup costs having a smaller range

of flow rates to be averaged. Compressor Cost Calculation Method II uses a simple cost factor multiplied by the required power.

Compressor Cost Calculation Method III provides a range of compressor costs over a range of flow rates at specific suction and discharge pressures. From this compressor cost range and an industrial cost factor, a compressor cost can be obtained. This method, though rough, is included mainly as a means of quickly getting an idea of the general scale of a compression project.

2.5.2   Pipeline Cost Calculation Methods

Comparison of Cost Methods for the Pipeline System		
Method 1	Method 2	Method 3
☐ Determine pipeline diameter based on needed flow rate ☐ Use equations to calculated the cost for materials, miscellaneous and the right of way ☐ Add the three costs together to get the final cost	☐ Two equations form an upper and lower bound for pipeline costs based on length and flow rate ☐ Calculate the upper and lower costs, average them, and then adjust the expected cost based on complexity	☐ One equation calculates the cost of the pipeline based on the pipe diameter and length ☐ Diameter can be determined based on the flow rate by a table given in the text

Pipeline Cost Calculation Method I takes the vast amount of available data from natural gas pipeline installations and correlates them to laying pipelines for transporting different gases and liquids. This data is used to create a series of equations that model the costs of labor, materials, right of way leasing and remediation, and other miscellaneous costs. Even though the model derived from this data was for natural gas pipelines, the costs to install CO_2 pipelines should be similar, especially for the cost of the right of way, labor and miscellaneous costs. The cost of materials could be higher because CO_2 is an acid gas and can be corrosive to the pipelines, requiring corrosion-resistant coatings on the inside of the pipeline. Also, CO_2 pipelines are usually operated at higher pressures. A significant benefit to this study is the availability of data from a large collection of short pipelines. Other models may become unrealistic when short pipeline lengths are considered, due to the regression analysis performed.

Pipeline Cost Calculation Method II takes seven of the original models calculating CO_2 pipeline transport costs and compares them. These models considered were significantly different in the way they approached the cost calculations; for example, one model first calculated the diameter and then the cost of the pipe based on that measurement, while another model did not calculate pipe diameter at all, making the cost directly a function of the mass flow rate. For this study a set of criteria for a pipe system is designated and then seven different models are used to calculate the costs in order to get an "apples to apples" comparison. All of the highest cost results are then taken from the models and fit to a curve resulting in a function depending on length and mass flow rate. This same type of curve was created for the lowest cost cases in each of the models. The end result is a good approximation of two boundaries between which the expected cost of the pipeline should reasonably be expected to fall. This model is especially good for pipeline systems longer than 50–100 km. Since the model is a power function as the length of the pipeline approaches zero, the total cost approaches $0.

Pipeline Cost Calculation Method III is used as an industrial standard and is based on data reported to FERC, reported annually in the *Oil and Gas Journal*. This method uses a cost factor multiplied by the inch-miles of a pipeline to calculate the cost.

2.5.3 Injection Well Cost Calculation Methods

Comparison of Cost Calculations for the Injection Well		
Method 1	Method 2	Method 3
☐ Final cost is estimated by adding the cost of the site, equipment, and drilling ☐ Equations for each of these costs are dependent on the number of wells needed and the depth of the well drilled	☐ A table with a detailed list of everything required to install an injection well is included along with its associated costs ☐ All of the costs should be determined and are based on the depth of the well and the size of the surface area affected	☐ Simple equation based on regression analysis of well installation costs ☐ Calculate the cost based on depth of the well in linear equation

Two different methods of calculating the cost of injection wells are considered. Injection Cost Calculation Method I depends on fitting regression curves to data from both the Joint Association Survey (JAS) on Drilling Costs' report and the Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations' report produced by the United States Energy Information Administration. This

model depends only on well depth and the mass flow rate. Injection Well Cost Calculation Method II is somewhat more complex giving the user a greater flexibility in well design. This method allows the user to have a better understanding of the costs that go into drilling and completing a well. Injection Well Cost Calculation Method III combines all of the capital costs into one equation and is a function of well depth alone.

2.5.4 Dehydration and Heating Cost Calculation Method

For both the dehydrator and heater, a simple or rough estimate was acquired for both a high-end and a low-end flow rate. From this range a linear correlation was established dependent on the flow rate.

2.6 Applications to Engineering Management Principles

2.6.1 Risks

When a new project is undertaken, there are considerable risks that can easily cause the costs of the project to escalate. Understanding what these risks are can help reduce the difficult decisions that must be made in the face of potential financial disaster. For the SWP projects, many of the risks were initially known and understood based on other injection wells and pipelines that have been completed in the past by entities within the partnership. In the following sections, some of the main risks are discussed as well as ways they have been mitigated. Some risks are unavoidable but must be factored into schedules and cost.

2.6.2 Decision Making

Decision making is an iterative process in which Fact A must be known in order to determine something about Fact B, but Fact A may change based on decisions made related to Fact B, thus changing Fact B. Putting together a large project such as a carbon capture, transport and storage effort is by nature very iterative. Frequently when making decisions, a little understanding about Fact B will be sufficient for the decision maker to make a comfortable guess about what Fact A is without drastically altering Fact B, thus reducing the number of iterations necessary to come to a full understanding of what Fact A and B ultimately are. When these large projects are planned, it has been found necessary to evaluate several different sites, each having their own complexities. This tool or report is designed to give just enough information about the capital costs (Fact B) for a carbon sequestration project to enable decision makers to choose between sites (Fact A) and equipment when costs are an important consideration. For example, there should be sufficient resolution in the models to differentiate between sites or projects that have a 20% or more cost difference.

Frequently in order to make these decisions, personnel would be required to develop their full specifications for their projects or hire an engineering firm to provide a budgetary estimate for the cost of the project. Using this report, project managers should be able to obtain in a few hours a reasonable estimate that could help in determining which projects to send for detailed engineering and budgetary estimates. These tools should also reduce the number of times the design has to pass back and forth between the managers and engineers for changes to the process.

2.6.3 Cost Analysis

This report consists of cost analyses in actual, projected and modeled approaches. The results presented in this report are the end result of categorizing all of the costs by account. It is then possible to compare the expected costs, modeled costs and actual costs in an "apples-to-apples" approach. This will be able to confirm that the system recommended in this report will indeed give the estimated cost within the range of costs given by the models.

3 Methods for Calculating the Initial Capital Costs of a Carbon Sequestration Project

As mentioned above, this is the heart of the paper. Each section below is has several parts including one nomenclature table that will define the variables and constants unique to that subsection as well as the equations and processes necessary for each of the methods. The sections are not in any particular order and the calculations are independent of all others.

3.1 Compression

Typically, when CO_2 leaves its source it is at an insufficient pressure to traverse through the pipelines and be injected subsurface. In order to increase the pressure, either a compressor or pump is required. Compressors are used for compressing and increasing the pressure of gases and pumps are used for increasing the pressure of liquids.

Since most CO_2 introduced to the system will be in the gaseous phase, methods for calculating the power and cost for compression must be considered. It is important to note that if CO_2 can be obtained in a dense enough form to be pumped, it will be less expensive to operate due to the lower power required. (8)

Gas compression is typically done in several stages. A gas can be compressed, for example, with a compression ratio of three. Therefore, if the gas enters the compressor at 10 psi then it will exit the first stage at 30 psi, the second stage at 90 psi, the third stage at 270 psi and the fourth at 810 psi. This can be seen on the specification sheet for the compressors in Appendix C. Due to the higher specific gravity of CO_2 in relation to natural gas, it is best to maintain the compression ratio at around 2.5 or lower in order to reduce the heat output.

3.1.1 Nomenclature

Table 2 Nomenclature for Compression

Variable	Units	Standard Value	Description
T_a	K		Ambient temperature
T_s	K		Suction Temperature
Q_t	$\dfrac{tonnes}{day}$		Mass flow rate of CO_2
Q_f	$\dfrac{MMscf}{day}$		Volumetric flow rate of CO_2
M_{CO2}	$\dfrac{kg}{mol}$	.044	Molar mass of CO_2
P_a	psi		Atmospheric/reference pressure
C	$\dfrac{ft^3 psi}{Kmol}$	4.259×10^{-5}	Conversion factor
P_s	MPa		Inlet pressure to compressor
P_d	MPa		Outlet pressure from compressor
C_r			Compression ratio
W_{stage}	HP		Compressor stage power requirement
W_{comp}	HP		Compressor power requirement
N			Number of compressor stages
η	%	75	Efficiency of compressor
Z_{avg}			Compressibility average
γ			Ratio of specific heats
C_{comp}	$		Compressor cost
η_t			Number of compressor trains
q_t	$\dfrac{kg}{s}$		Flow rate through compressor trains

3.1.2 Mass Flow Rate and Standard Flow Calculation

When CO_2 operations are under consideration, two different flow rates are usually required. One is the mass flow rate, Q_t that takes into account the mass of the CO_2 and is independent of temperature and pressure. The second, Q_f is volume flow rate that depends on the pressure and temperature. In most cases this is converted to standard temperature and pressure. The following equation can be used to calculate the standard flow rate from the mass flow rate at various temperatures and pressures.

$$Q_t = \frac{Q_f M_{CO2} P_a}{TC} \tag{3.1}$$

To calculate the compressor cost, two of the methods are dependent on the power taken to run the compressors. In the next two sections two methods for calculating power are given and then this can be used in Compressor Cost Calculation Method I and Method II.

3.1.3 Compressor Power Calculation Method I

This method is more tedious than Compressor Power Calculation Method II, presented next, but gives a good understanding of how the different stages are configured. This method also provides a better way

to understand how the variables interact. For a faster, automated approach Method II is more appropriate.

As CO_2 density increases, its compressibility decreases, as does its heat capacity. Because of these changes, it is necessary to calculate the power requirements of the compressor stepwise. The compressor will compress the gas from P_s to P_d. The basic steps and equations are outlined below.

- Determine the number of stages for the compressor, N, and the C_r. (Note: N must be rounded up to nearest integer.) As mentioned previously, C_r should be about 2.5 for CO_2.

$$N = \left\lceil \frac{\ln\left(\frac{P_d}{P_s}\right)}{\ln(C_r)} \right\rceil \tag{3.2}$$

- Calculate C_r with the integer N.

$$C_r = \left(\frac{P_d}{P_s}\right)^{\frac{1}{N}} \tag{3.3}$$

- Calculate the beginning and ending pressure for each stage. For example, if $C_r = 2$, $N = 2$, and $P_s = 10$, the first stage would be bound by 10 and 20 and the second stage by 20 and 40.
- Find the compressibility factor at both the suction and discharge pressures for each stage. Z_{avg} is the averaged value of the suction and discharge compressibility factors for each stage. To find the compressibility factors either use the provided chart in Figure 3 or for exact values of Z_{avg} download and install Uconeer, an engineering unit conversion software that calculates Z_{avg}, available at www.katmarsoftware.com/uconeer.htm. To use it, once installed and started, select the fan icon and enter the temperature and pressure for the compression factor.
- Find the ratio of specific heats, γ. This can be found using Figure 4. Because the compression ratio will be under 2.5 for each stage and assuming inter-stage cooling is used, "the 150°F curve will be adequate." (9) For exact values for γ use the CO_2 Calculator located at http://www.carbon-dioxide-properties.com/ where $\gamma = \frac{cp}{cv}$.
- Based on the configuration for CO_2 compressors where the compression ratio is below 2.5 and there is interstage cooling the suction temperature for stages 2 through i can be assumed to be 120°F and the discharge temperature about 235°F.
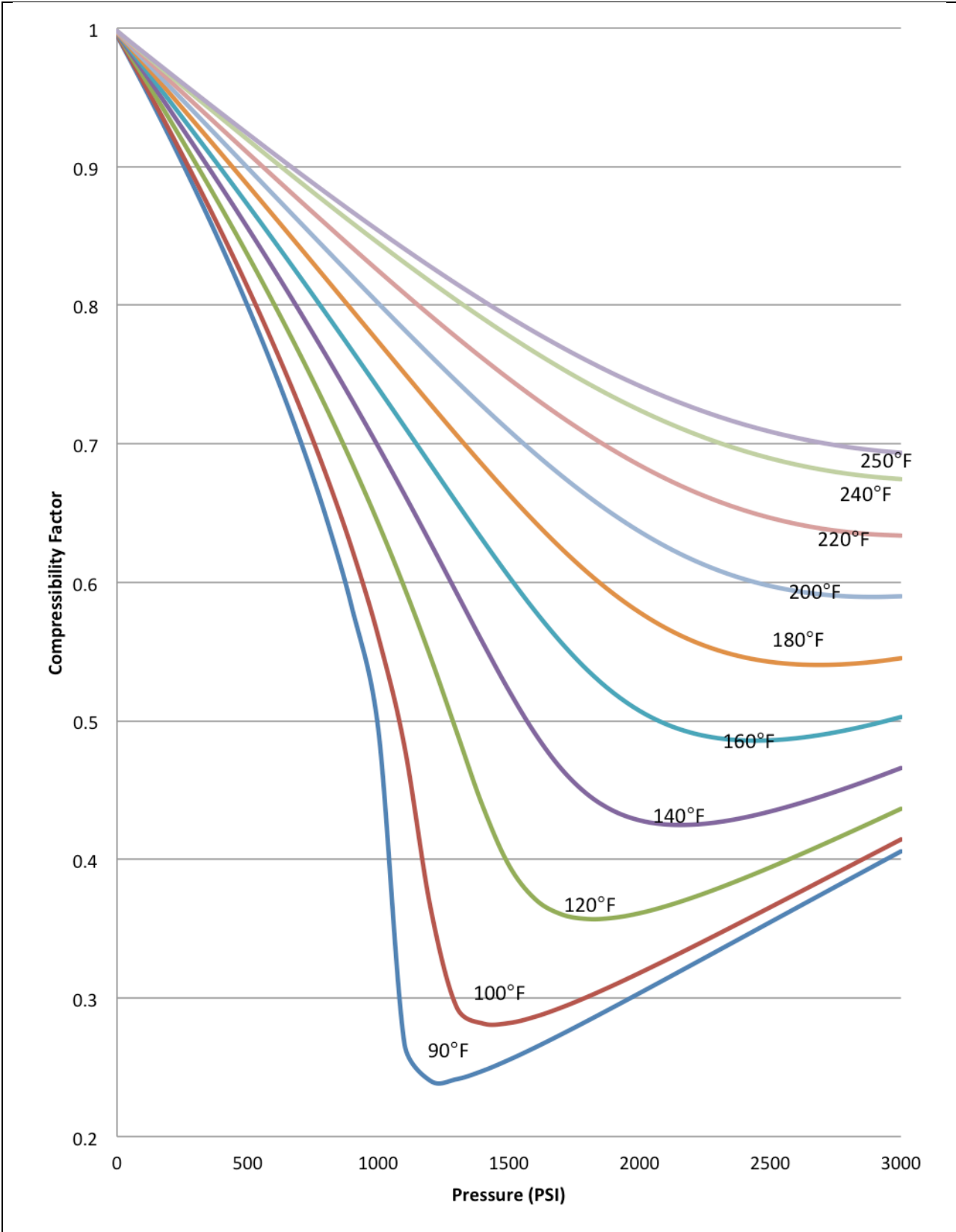
Figure 3. Compressibility factor of CO_2.
This chart was created using the Uconeer Software. (10)
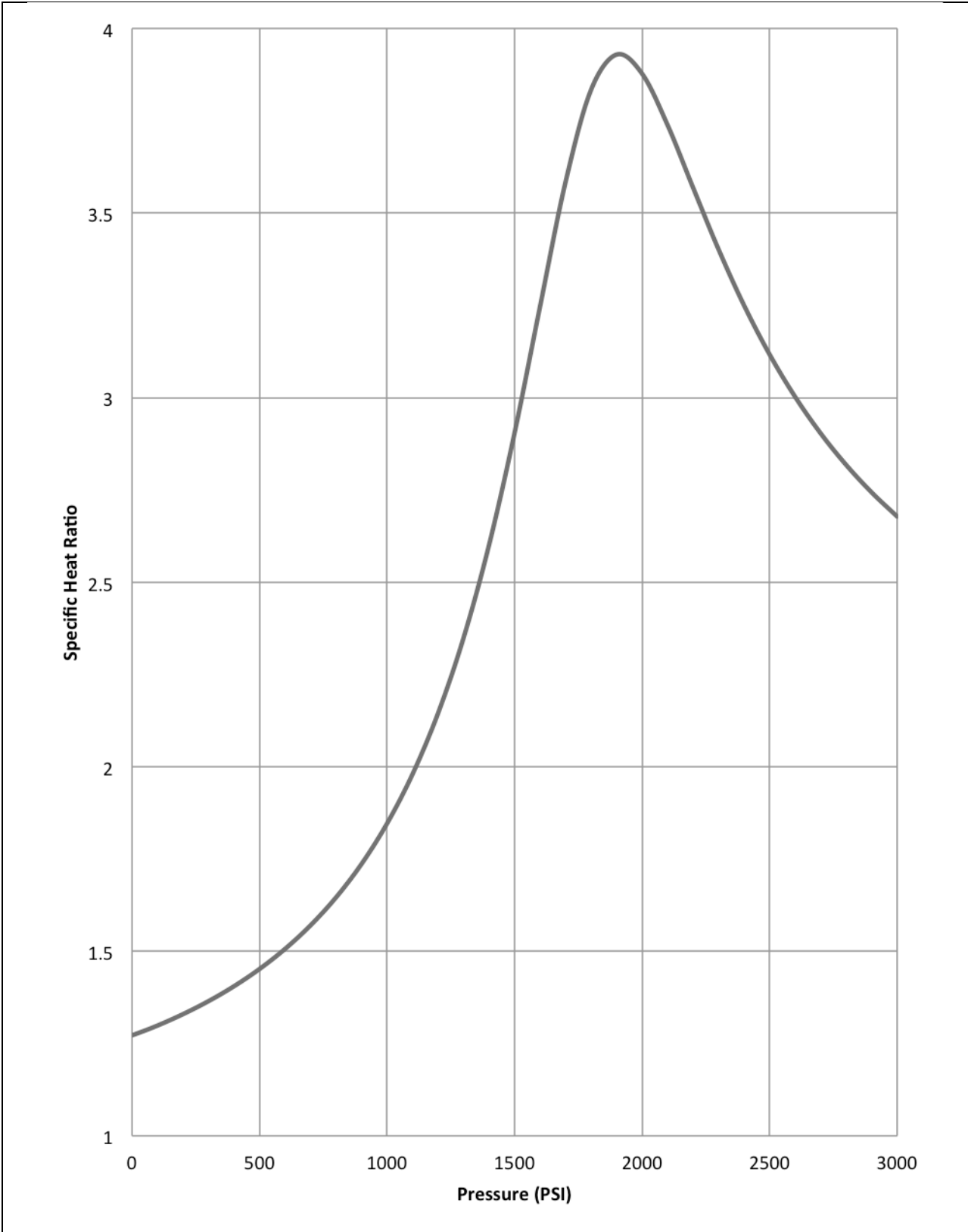
Figure 4. Specific heat ratio of CO_2 at 150°F
This curve was created using the data calculated on the CO_2 Properties Online website. (11)

- Calculate the power required, W_{cm}, for each stage of compression.

$$W_{stage} = 3.03 Z_{avg} \left(\frac{Q_t T_s}{\eta}\right) \left(\frac{P_a}{T_a}\right) \left(\frac{\gamma}{\gamma - 1}\right) \left(C_r^{\frac{\gamma-1}{\gamma}} - 1\right) \quad (3.4)$$

- Add the W_{stage} for each stage to find W_{comp}.

3.1.4 Compressor Power Calculation Method II

Ariel Corporation is a manufacturer of gas compression equipment. They have developed a freely available software package that is used to calculate the power required by compressors as well as configure the compressors for different applications. This software is used by industry for finding the power requirements, and thereby to determine the cost for compression.

- Install Ariel Software
    - Ariel Performance Software can be found at the following link or by searching for "Ariel Performance Software".
      http://www.arielcorp.com/products/selection_guides/performance_program.aspx
    - Download and install the full version.
- Open Ariel Performance from the Start menu and select the "Create a New Run" radio button and then "OK".
- Under the "General Data" tab, select the units preferred for capacity temperature and pressure. For calculation purposes, BHP (brake horsepower) needs to be selected for the "Power" unit.
- Select the "Service/Stage Data" tab. Check the checkbox next to "Gas Analysis?" and enter the approximate percentages of the expected gas output. Since this is for CO_2 injection probably about 99.9% should be entered for CO_2 with the balance made up of the other gases. This will calculate the specific gravity of the gas.
- Enter the "Required Flow", "Suction Line Press," and "Disch Line Press."
- Increase or decrease the number of stages using the spin box next to "Number of Stages" until the "Press Ratio" in the table is approximately 2.5 or less.
- The estimated horsepower, W_{comp}, will be displayed in the "Estimated" textbox, followed by "BHP."

3.1.5 Compressor Cost Calculation Method I

McCollum adapted methods from both C. Hendriks (12) and a report by the IEA Greenhouse Gas R&D Programme (13) for calculating the capital cost of the compressor and pump. Each compressor train can be sized up to about $40,000\ kW$. If the power requirements exceed this then several compressor trains can operate parallel to each other, each taking an equal load. (8)

This method can be used on either of the above Compressor Power Calculation Methods.

- Find the number of compressor trains, η_t required.

$$n_t = \left\lceil \frac{W_{comp}}{40,000} \right\rceil \tag{3.5}$$

- Find the flow rate through each compressor train.

$$m_t = \frac{1000Q_t}{24 \times 3600 n_t} \tag{3.6}$$

- Calculate the cost of compression.

$$C_{comp} = m_t n_t \left[(.155 \times 10^6) m_t^{-0.71} + (1.671 \times 10^6) \ln\left(\frac{P_d}{P_s}\right) m_t^{-0.6} \right] \tag{3.7}$$

3.1.6 Compressor Cost Calculation Method II

This method has two distinct advantages. First, it is easier to compute and second, it is used by engineers in calculating the cost for compressors for budgetary estimates. (Personal communication with representative from Nicholas Consulting Group, Inc.) The cost is found by multiplying the total power required by the compressor by a power factor as follows:

$$C_{comp} = 1100 W_{comp} \tag{3.8}$$

3.1.7 Compressor Cost Calculation Method III

To estimate how much a compressor will cost, the manufacturer's suggested retail prices were obtained from a representative of Compressor Systems, Inc. for a range of compressors from the lowest flow rate expected to an upper flow rate. The specifications for this compressor are $P_s = 15psi$, $P_d = 2000psi$, and flow rate ranging from 1 MMscf to 15 Mmscf. The ranges of costs are depicted in Figure 5. To calculate the cost for compression, find the flow rate needed on the chart in Figure 5 and then find the cost of the compressor. Another way to find this cost is to call a compressor sales associate and provide the basic specifications such as the suction and discharge pressures and the flow rate. With this limited information the sales associate will be able to provide a general cost estimate. A representative from Babcock Eagleton, Inc. gas has stated, as a rule of thumb, that the complete installed cost includes engineering fees, miscellaneous parts, foundation, concrete, valves, installation, and delivery; all of which are approximately twice as much as the cost of the compressor (personal communication). Thus to calculate the cost of compression the following cost factor can be applied.

Figure 5. Compressor Cost Range.
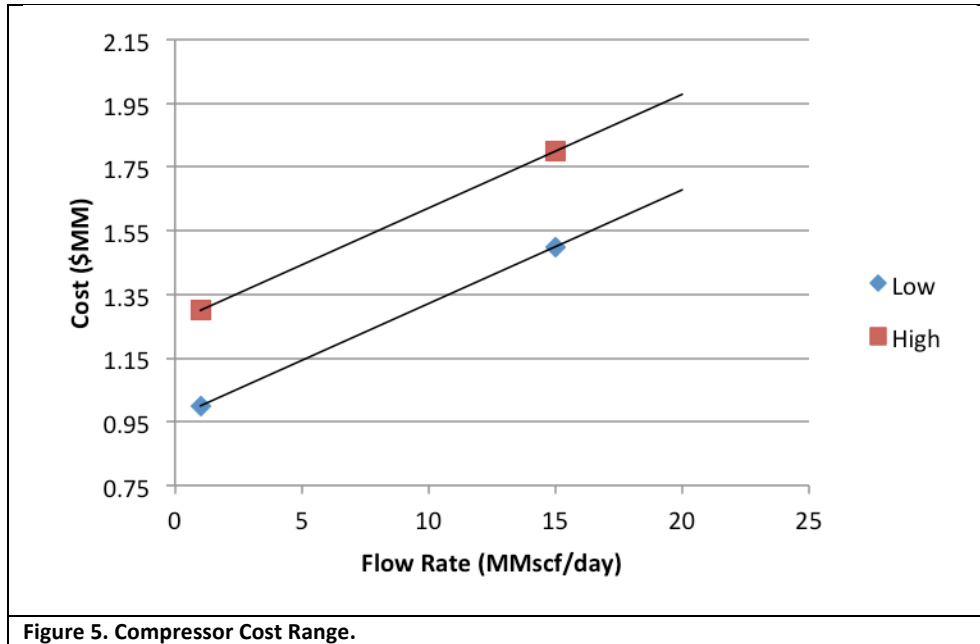
$$C_{comp} = 3 \times cost\ of\ compressor \qquad\qquad (3.9)$$

As mentioned previously, this is a rough estimate, especially if the cost of the compressor is taken from the chart.

In industry the complete cost to install a compressor is about twice the cost of the compressor alone. The "roughness" of the estimate comes from the fact that it is difficult to properly price a compressor without having the full specifications including the composition of the gas, the elevation, valves needed, and location. Once all the specifications are obtained, a quote can be generated based on the required compressor configuration.

When the chart in Figure 5 is used, it is important to note that the cost is extremely sensitive to the suction pressure. Decreasing the suction pressure from 15 psig to 5 psig or less can have an enormous effect on the cost of the compressor and the amount of gas that can be compressed. For suction pressures higher than 15 psig this chart will be relatively useful.

3.2 Pipeline

Pipelines are one of the most efficient ways to transport CO_2. Pipeline systems can be designed to transport CO_2 from multiple sources into large trunk pipelines and then to divide the liquid back into smaller pipelines to transport to separate sinks. As the fluid flows through the pipeline there is a loss of energy and hence of pressure and temperature due to frictional losses. Because of this loss of pressure it is necessary to install booster stations at about every 125 miles of pipeline (assuming relatively flat terrain) to maintain the pressure and the flow rate. (8) When a pipeline system is designed, it is important to avoid fluid flow uphill as much as possible because this increases the amount of compression needed to keep the CO_2 properly flowing. Also, when a system is designed, it is best to keep to the shortest possible length of the pipeline while avoiding obstructions such as rivers and

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roadways. There are several computer algorithms that calculate the least expensive route for a pipeline using layered GIS maps. (14)

Since the purpose of an estimate is to give a general idea of the cost of a project, a simple outline of a piping system will be all that is needed. When the system is drawn out, there will be a few things that must be avoided or that must be kept in mind that have the potential to significantly change the route of the pipelines. These obstructions are presented in Table 3. Here "[t]he relative weights are calculated as the ratios of the additional construction costs to cross those obstacles and the base case construction cost for an 8 inch pipeline." (14) Another factor to consider a pipeline system is being laid out is reducing the length of the pipelines for both economical and environmental reasons. It might be better, for example, to use one long trunk line going through the length of the field and then to connect the different sources and sinks to that main line. At some point the smaller lines will need to feed into a larger line for compression and dehydration.

Table 3 Construction Conditions and Their Cost Factors (14)

Construction Condition		Cost Factor
Base Case		1
Slope	10-20%	0.1
	20-30%	0.4
	>30%	0.8
Protected Area	Populated Area	15
	Wetland	15
	National Park	30
	State Park	15
Crossing	Waterway Crossing	10
	Railway Crossing	3
	Highway Crossing	3

Once the pipeline system has been laid out and the lengths of both the flow lines and trunk lines are calculated, the models in the following sections can be used. The Pipeline Cost Calculation Method I can be used to get a better estimate of the costs broken down by materials, labor, right of way, and miscellaneous costs. It is a little more labor- intensive, but will give a better understanding of where the costs are allocated. The Pipeline Cost Calculation Method II is faster to compute and has a built-in range of cost for the pipeline.

3.2.1 Nomenclature

Table 4 Nomenclature for the Pipeline System

Variable	Units	Standard Value	Description
D	$inch$		Pipeline diameter
L	$mile$		Pipeline length
m	$\dfrac{tonnes}{day}$		CO_2 mass flow rate
C_{Misc}	$\$$		Cost of miscellaneous supplies
C_{RoW}	$\$$		Cost of right of way
C_{Labor}	$\$$		Cost of labor to build pipeline and bury it
C_{Mat}	$\$$		Cost of pipeline materials
C_{pipe}	$\$$		Total cost
C_{low}	$\dfrac{\$}{mile}$		Pipeline capital low cost
C_{high}	$\dfrac{\$}{mile}$		Pipeline capital high cost

3.2.2 Pipeline Cost Calculation Method I

This model has two distinct advantages. The first is that each of the main costs is represented, making it possible to have a better idea of where the costs are allocated. This is important because if, for example, a right of way already exists, the cost for the right of way can be partially or fully omitted, reducing the overall cost.

To use this model (15) the length of the pipeline must be known as well as the diameter. The diameter of the pipe can be determined using Table 5.

Note: if several different pipes are required such as a trunk line and flow lines having different diameters the pipes will need to be calculated separately. Also equations 3.10-3.13 are in year 2000 dollars. Equation 3.14 has been adjusted to 2009 dollars.

Table 5 Determination of Pipe Diameter (14)

Pipeline Diameter (inch)	CO_2 Flow Rate (Mt/year)	
	Lower Bound	Upper Bound
4		.19
6	.19	.54
8	.54	1.13
12	1.13	3.25
16	3.25	6.86
20	6.86	12.26
24	12.26	19.69
30	19.69	35.16
36	35.16	56.46

$$C_{Labor} = (343D^2 + 2074D + 170013)L + 185000 \qquad (3.10)$$

$$C_{Mat} = (330.5D^2 + 687D + 26960)L + 35000 \tag{3.11}$$

$$C_{Misc} = (8417D + 7324)L + 95000 \tag{3.12}$$

$$C_{RoW} = (577D + 29788)L + 40000 \tag{3.13}$$

$$C_{pipe} = 1.44736[C_{Labor} + C_{Mat} + C_{Misc} + C_{RoW}] \tag{3.14}$$

3.2.3 Pipeline Cost Calculation Method II

This model was created by taking seven different models' high and low values as boundaries for high and low costs. Once the high and low boundaries were created, a regression curve was fit to provide a range of probable costs for each mass flow rate and length. (8) These equations have been modified slightly to accommodate an input for miles instead of kilometers. In Figure 6 the low cost and high cost as well as their average is plotted for $8000 \frac{tonnes}{day}$.

Figure 6. Pipeline cost.

$$C_{low} = [(15979.1m^{.35})(1.609L)^{.06}]L \tag{3.15}$$

$$C_{high} = [(7707.56m^{0.5})(1.609L)^{.13}]L \tag{3.16}$$

For very short pipelines it might be necessary to adjust the cost per mile up somewhat because of the nature of the power regression.

3.2.4 Pipeline Cost Calculation Method III

This method uses data gathered by the JAS and reported in the *Oil and Gas Journal* to estimate the cost of a pipeline. (16) It is also used in industry as an estimation method as confirmed by Justin Hollums, a representative of the Nicholas Consulting Group, Inc., in a personal communication. To calculate the

cost of the pipeline, the cost factor of $\frac{\$60,000}{inch \cdot mile}$ is multiplied by the length of the pipe and then the diameter. Based on the flow rate, the diameter of the pipeline can be found in Table 5.

$$C_{pipe} = \frac{\$60,000}{inch \cdot mile} \times D \times L \qquad (3.17)$$

3.3 Injection

Each reservoir will accept CO_2 at a rate determined by its thickness, porosity, permeability, pressure and areal extent. Calculating the injection rate requires computer simulations and actual measurements in order to have a clear idea of what occurs when CO_2 is injected into the well. This complexity is a result of CO_2's natural ability to compress and decompress at varying temperatures and pressures. As CO_2 is injected it descends downhole and the fluid temperature increases due to tubular friction, hydrostatic compression (pressure increases), and increasing temperature with depth. The density of CO_2 decreases with increasing temperature and decreases with increasing pressure. Therefore fluid density and viscosity downhole are difficult to determine because of the counteracting forces.

3.3.1 Nomenclature

Table 6 Nomenclature for Injection

Variable	Units	Standard Value	Description
N			Number of injection wells required
D	ft		Depth of the injection well
C_{Equip}	$\$$		Capital cost for flow lines and connections
C_{drill}	$\$$		Capital cost to drill the well
C_{Site}	$\$$		Capital cost to screen and evaluate the site
C_{well}	$\$$		Total capital cost of injection well

3.3.2 Number of Required Injection Wells

Because one injection well may not be capable of accepting all of the CO_2 being transferred to it, the number of wells may need to be increased. Calculating how much CO_2 a well can accept is beyond the scope of this paper, but an excellent and well-presented method of calculating the flow rate has been written by McCollum and Ogden. (8) They describe an iterative process at which the initial downhole pressure is guessed and then, after several iterations, the correct pressure is found. Using the downhole pressure as well as the reservoir permeability, porosity, and thickness, the CO_2 injectivity can be calculated. For a simplified assumption for estimating the number of wells Ogden, referencing Hendriks, 1994, stated the following (17):

The injection rate of CO_2 into an underground reservoir depends on the permeability and thickness of the reservoir, the injection pressure, the reservoir pressure, the well depth, and the viscosity of CO_2 at the injection pressure. A practical upper limit on the injection rate per well is taken to be 2500 tonnes per day, limited by pressure drop due to friction in the well at higher flow rates, assuming practical well diameters (18). Using a standard equation for flow into an injection well (18), this upper limit implies that for a layer thickness above 50 m and

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permeabilities about 40 milliDarcy, the flow rate is limited not by the reservoir characteristics, but by the pipe friction flow constraints. (18)

3.3.3 Injection Cost Calculation Method I

The cost of drilling the well, the surface equipment and the site screening and selection can be calculated by the following equations.

- The cost for the site includes the preliminary site screening and evaluation. (19)

$$C_{site} = 2170550N \tag{3.18}$$

- The equipment includes the flow lines and connections such as the valves and fittings. (20)

$$C_{Eqip} = 65836\sqrt{\frac{7389}{280N}} \tag{3.19}$$

- The equation for the well cost was developed by finding the equation for a curve that corresponded to the 1998 Joint Association Survey on Drilling Costs' report. (20) The data and regression equation is represented in Figure 7.

$$C_{drill} = .129Ne^{.000244D} \tag{3.20}$$

Figure 7. Well drilling cost as a function of depth. (20)

3.3.4   Injection Cost Calculation Method II

This method was developed by the EPA and presented in June 2008. (16) The costs in this method have been left as they were presented in 2008 because they are rounded off to general numbers and because the latest cost index presented here covers only through 2009. This EPA document is important because it provides a detailed look at what is involved in drilling a well and doing the site preparation prior to drilling. C_{well} is found by adding each of following relevant costs.

Table 7 Injection Cost Calculation Method (16)

Cost Item	Cost Algorithm	Data Source
Conduct front-end engineering and design (general and injection wells)	$200,000/site + $40,000 per injection well	ICF estimate
Obtain rights-of-way for surface users. (equipment, injection wells)	$20,000 per injection (pipeline right of ways included in pipeline costs) Half of cost is legal fees for developer, other half is bonus to land owner	ICF estimate. Cost of land rights are highly variable
Lease rights for subsurface (pore space) use.	Upfront payment of $500/acre	ICF estimate. Cost of land rights are highly variable
Land use, air emissions, water emissions permits	$100,000/site+$20,000/sq mile	ICF estimate
UIC permit filing	$10,000/site+5,000/injection well	ICF estimate
Standard injection well cost	$/foot=210-280 typically down to 9000ft	Drilling cost is estimated from drilling cost equations developed from JAS and PSAC data
Corrosion resistant tubing	Additional $1.10/foot length-inch diameter for glass reinforced epoxy (GRE) lining	Based on SPE article on economics of GRE tubing
Corrosion resistant casing	Additional $1.75/foot length-inch diameter for corrosion resistant casing	PSAC and Preston Pipe Report
Cement entire length of well	$1.15/foot length –inch diameter	Cementing cost based on 2008 PSAC Well Cost Study
Use CO_2-resistant cement	Adds 25% to total cementing costs	
Set packer no more than 100 ft above highest perforation	Affects tubing length	Assumed to be in standard cost.
Set packer no more than 300ft above highest perforation	Affects tubing length	Reduces feet of tubing used. Standard tubing cost based on 2008 PSAC Well Cost Study.
Injection pressure limited to 90% of fracture pressure of injection	Affects maximum flow of well, number of wells needed	Due to uncertainty of injectibility the pressure impact is ignored
Wellhead and Control Equipment	Cost per well is $500*(maximum tons per day injected per well)^.5	Based on 2008 PSAC Well Cost Study.

3.3.5   Injection Cost Calculation Method III

This method is an equation created by Hendriks (18) that is used to calculate the capital cost of injection. This equation has been modified to accept feet instead of kilometers and also to adjust it to 2009 dollars.

$$C_{well} = 637.3D + 1675410$$ (3.21)

This equation shows that it costs approximately $637.3 per foot of depth drilled and that the base cost for a well is $1,675,410.

3.4   Line Heater

Line heaters are relatively inexpensive when compared to the project as a whole, but the cost is significant compared to the other items that would fit under a contingency fund.

> *Line heaters (also known as indirect heaters) heat the natural gas and liquids flowing in a pipeline indirectly through a heat medium such as ethylene glycol/water mix. If a pressure drop is required, a line heater is installed to offset the temperature drop created by the reduction in pressure. If the temperature drop is too large, hydrates (similar to ice) will collect in any convenient restriction or obstruction in a pipeline (valves, drips, return bends, elbows) and eventually form a large enough mass to block the gas flow. Line heaters are generally used at wellheads, in flow lines, tank batteries and refineries. (21)*

3.4.1   Nomenclature

Table 8 Nomenclature for Heating Cost Calculation

Variable	Units	Description
$C_{heatunit}$	$	Cost of Heater
Q_f	$\dfrac{MMscf}{day}$	Flow Rate
C_{heat}	$	Total cost to purchase, transport and install heater

3.4.2   Heater Cost Calculation Method

To calculate the cost of the heater the following equation is provided. The equation was developed by acquiring a cost range of heaters from Exterran over a range of standard flow rates. The costs for heaters that are designed for flow rates between the high and low flow rates are approximated by applying a simple linear regression.   In reality the slope of the line would best be approximated by a stepwise function, but to keep it simple and also because of the significance of this cost as compared to the larger costs, a linear regression will produce a sufficient resolution. The representative from Exterran also mentioned that the cost for the installation and shipping charges are approximately equal to the cost of the heater (personal communication). Also if the heater is going to be used for less than five years, renting the heater might be a more realistic option. After approximately five years the cost to rent is equivalent to the cost to purchase the heater.

Figure 8. Cost of line heaters.

$$C_{heater} = .3535Q_t + 39.646 \tag{3.22}$$

$$C_{heat} \cong 2 \times C_{heatunit} \tag{3.23}$$

3.5 Dehydration

Dehydration units are relatively inexpensive when compared to the project as a whole, but the cost is significant compared to the other items that should fit under a contingency fund.

> *A glycol dehydrator is a liquid desiccant system used to prevent hydrate formation and reduce corrosion in gas pipelines. Gas is required to meet a pipeline spec for water content, most commonly a maximum of 4 lb of water/mmscf of gas. Gas comes out of the well usually richer than the required spec.*
>
> *Rich gas enters the dehydrator and goes through a separator, which separates out any liquid or condensate in the gas stream. The gas proceeds upward to the contactor where it is mixed with Triethylene Glycol (TEG). TEG absorbs water, is non-corrosive, and chemical losses are generally quite low. Glycol is circulated through the gas in a contactor vessel, drying the gas, and then to the glycol regenerator (reboiler) where it is heated so the water boils off. The water vapor is released to the atmosphere or to an incinerator. The lean glycol is pumped back into the gas/glycol contactor. (22)*

3.5.1 Nomenclature

Table 9 Nomenclature for Dehydration Costs

Variable	Units	Description
$C_{dehyunit}$	$	Cost of Dehydrator Unit
Q_f	$\dfrac{MMscf}{day}$	Flow Rate
C_{dehy}	$	Cost to purchase, install and deliver dehy unit

3.5.2 Dehydrator Cost Calculation Method

The cost estimate is obtained the same way as for the heater along with the same assumptions.

Figure 9. Cost of dehydrators.

$$C_{dehyunit} = 10.101m + 39.899 \qquad\qquad (3.24)$$

$$C_{dehy} \cong 2 \times C_{dehyunit} \qquad\qquad (3.25)$$

3.6 Cost Indexing

Figure 10. Nelson-Farrar Cost Indexes from the Oil and Gas Journal

Costs change constantly; thus they are among the greatest risks for new projects. Projects of the scope this paper addresses usually take a year or longer to complete, during which the costs can increase by almost 20%, as shown in Figure 10. These costs typically increase more in the range of 4-10%. Some cost can even drop during economic down turns. When current costs are obtained from earlier reports, the current dollar value must be calculated. Also, when estimating future costs it is helpful to look at past trends. Methods for both finding current costs and estimating future costs are presented below. The Nelson-Farrar cost indexes are published in the first publication of each quarter in the *Oil and Gas Journal*. The Gross Domestic Product is published regularly by the U.S. Bureau of Economic Analysis at bea.gov.

Table 10 Nelson-Farrar Cost Indexes, 1997–2009

	Nelson-Farrar Cost Indexes					GDP (in Billions)
Year	Compressors	Material	Heat Exchanger	Instruments	Labor	
1997	1383.90	923.90	773.60	956.90	1799.50	9854.3
1998	1406.70	917.50	841.10	981.30	1851.00	10283.5
1999	1433.50	883.50	715.80	1006.00	1906.30	10779.8
2000	1456.40	896.10	662.20	1025.30	1979.70	11226.0
2001	1487.00	877.70	726.90	1042.90	2047.70	11347.2
2002	1522.00	899.70	732.70	1061.40	2137.20	11553.0
2003	1540.20	933.80	732.70	1076.80	2228.10	11840.7
2004	1581.50	1112.70	863.80	1087.60	2314.20	12263.8
2005	1685.50	1179.80	1072.30	1108.00	2411.60	12638.4
2006	1758.20	1273.00	1162.70	1166.00	2497.80	12976.2
2007	1844.40	1364.00	1342.20	1267.90	2601.40	13254.1
2008	1949.80	1230.60	1354.60	1342.10	2704.30	13312.2
2009	2011.40	1239.70	1253.80	1394.80	2813.00	12987.4

Oil and Gas Journal **and U.S. Bureau of Economic Analysis**

3.6.1 Finding Current Costs

When older reports are used for cost estimates, it is necessary to find the current costs or rather the cost of the item based on the present value of the dollar. To do this the category that best matches the cost should be determined; the cost can then be calculated by

$current\ cost = \frac{present\ year\ index}{index\ of\ year\ cost\ was\ incurred} \times cost$. For reference, the Nelson-Ferrar cost indexes and

the Gross Domestic Product for the past several years have both been included in Table 10. The Nelson-Ferrar cost index is published in the first *Oil and Gas Journal* each quarter and is a principal index in determining refinery construction costs.

3.6.2 Estimating Future Costs

Predicting future costs is the subject of intense study. For simple cost escalation studies it is common to look back at the relevant cost trends for the past two or three years and then make an estimate based on the average increase. (23) For example, the cost increased by 9%, 6% and 4% for the past three years respectively for the instrument class under the Nelson-Ferrar cost index. Taking the average of these percentages yields 6.3%. It would be reasonable to estimate that for a project that will span the coming year a cost escalation of about 6.3% would need to be included. Another trend noticed in these numbers as well as others in the index is that the trend is downward, justifying a lower cost escalation estimate closer to 4%.

4 Risks

"Risk is most commonly defined as the probability of an event that causes a loss and the potential magnitude of that loss. By this definition, risk is increased when either the probability of the event

increases or when the magnitude of the potential loss (the consequences of the event) increases." (24) The risks considered in this report are directly related to the potential increases to the capital cost when beginning a project. These are risks that the managers of the SWP have recognized and have worked with. Here, a number of risks are discussed and some possible solutions to mitigate or prevent the loss posed by the risks are suggested.

4.1   Environmental Risks

Environmental risks are the risks that are specific to a location and can be posed by natural conditions, legislative policies and local manmade hazards. The losses as a result of these risks can be increased labor cost due to extended construction time, missed deadlines, delayed project start times, broken equipment and supplies and harm to personnel and the local residents and their property. Each of these losses can contribute to additional costs.

Environmental risks may include weather, wildlife restrictions, unlabeled or mislabeled pipelines, poorly maintained roads and local regulations. The weather risks include flash floods, lightning, high winds, snow, ice and heat. Because of rain and snow causing the dirt roads to become very muddy the SWP found that there were regulations preventing travel to their sites because of wet conditions on the roadways. They also found that they were restricted from access to their sites during big game closures (elk mating season, in this case). Because of the regulations regarding the depth of rut formations in the road and the elk mating season, the project was delayed by four to five months. Lightning and the threat of flash floods delayed or interrupted work. Other risks they learned about were the potential of having mismarked or unmarked pipelines, which could be hit during excavation for new pipelines, or other buried equipment. There are also archeology sites that are protected and cannot be disturbed. Due to these factors, pipelines may have to be rerouted and injection sites changed.

Ways to address and work with environmental risks include asking specific questions about the wildlife, weather and any restrictions that they pose or that might be imposed by local agencies because of the wildlife and weather. The questions need to include changes due to different seasons in the behavior patterns of wildlife or regulations. When digging and constructing the pipeline and well close attention needs to be paid to plans and contingencies, and emergency plans need to be in place in case a loss or emergency does occur.

4.2   Permitting Risks

The greatest risk posed by the permitting process is not filing for the permit early enough to allow enough time for approval. The SWP filed for all of the necessary permits except for one section of a permit that it was unaware of. Parts of the work had to be postponed, which caused some scheduling conflicts.

The best way to mitigate this risk is to be aware of all the necessary permits. This can be done by finding the permits that were required for similar projects. In addition to this, it is also important to know of any laws or regulations that have changed since the similar project was performed, creating a need for additional permits.

4.3 Contract Risks

Contracts are an essential binding agent that makes it possible for companies and individuals to work with each other. Contracts that are formed without proper preparation can have serious consequences.

The problems of this risk can be avoided. Time and effort for an adequate contract must be taken to ensure that requirements of the company as well as what they offer coincide with what is required by the DOE and the SWP. Additionally, clear specifications must be in the contract so issues can be worked out.

4.4 Equipment and Facilities Risks

The risks associated with the equipment and facilities are damage caused by accident, vandalism and adverse weather and also the failure of the materials forming the equipment and facilities. The best ways to mitigate these risks is to have policies in place that will ensure that safe practices are followed when working on the equipment and within the facilities. Policies should also be in place that ensure that the equipment and facilities are regularly inspected to identify early signs of failure.

4.5 Cost Escalation Risks

Costs can rapidly escalate due to two main causes. The first is the natural changes in the economy. The second is cost escalations due to unexpected losses resulting from the other risks. To mitigate these risks it is especially important to recognize that unexpected risks or losses can occur as a result of not being prepared for the outcome. With proper planning and preparation most risks can be identified and can be prepared for. The risks must be estimated so that contingency can be built into the project.

4.6 Scheduling Risks

When creating a schedule the main risk that should be considered is scheduling conflicts that can then create other conflicts in a snowball effect. The best way to mitigate these conflicts is to be realistic and somewhat conservative when estimating the amount of time each step will require.

4.7 Risk Summary

The best way to mitigate the risks is to be informed and aware of them. The SWP found and worked closely with personnel that lived and worked in the project areas. Because of their advice, the SWP was able to avoid many of the adverse effects of the present risks. Another way to deal with the risks is to recognize that some things will happen or some loss will occur and to prepare for it. This preparation comes by ensuring that there is a contingency fund as well as allowing extra time for greater flexibility. Studying the losses and problems that occurred in similar projects can lead to a better understanding of what can be expected.

Risks are extremely difficult to specifically quantify. Some risks can be catastrophic in nature and can completely shut down entire project and the areas they are located in such as major earthquakes. Risks such as these must be evaluated based on their probability of occurrence. Here the probably very low, but the cost can be extreme. Other risks such as delayed construction crews have a high probability of happening, but have manageable costs. In the estimates given to the SWP by Nicholas Consulting Group a contingency of 15% of the total cost is used to mitigate the effects of the more likely risks. This is

shown in the data given the appendices below. The models that are used in this report are based on actual construction projects that have been completed in the past. Because of this the risk costs have already been factored in to the models. So for this report it is assumed that the additional costs for reasonable risks are included within each of the models and no additional cost should be added. If the project under consideration has a high probability that a more extreme risk might develop such as in hurricane prone areas additional contingency funds may be necessary.

5   The Case Study: Example Site

In order to better explain them, a full demonstration of all the methods will be presented using a hypothetical site named Example Site. Each equation and calculation here relates directly to the equations in the corresponding methods above. At the conclusion of the presentation a summary will be provided that will aid in understanding how each of the methods compare with each other.

5.1   The Case Study Description

This project is a carbon sequestration project that will accept CO_2 from a source, compress it and then transport it to two different injection wells. It is assumed that the injectibility is sufficient so that at the specified flow rate only two injection wells will be needed.

Table 11 Project Parameters

Input Parameters	Value	Units
Permeability	50	mD
Thickness of Reservoir	50	m
Depth to Reservoir	5000	ft
Distance from Source to Sink	3	$miles$
Distance from Well 1 to Trunk Line	.5	$miles$
Distance from Well 2 to Trunk Line	2	$miles$
Input Pressure to Pipeline	200	psi
Surface Temperature	40	C
Mass Flow Rate	4000	$\frac{tonnes}{day}$
Reservoir Pressure	2000	psi
CO_2 Temperature in Compressor	356	K

5.2   Compression

5.2.1   Compressor Power Calculation Method I

The first step to calculate the compression cost is to determine the power requirements necessary to compress the gas. Table 12 gives the results of calculating each of the variables for a three-stage compression.

Table 12 Case Study Compression Calculations

			Stage 1	Stage 2	Stage 3
Q_f	75.5				
η	0.75	Z_{low}	0.929	0.856	0.667
P_a	14.7	Z_{high}	0.926	0.848	0.705
T_a	293	Z_{avg}	0.928	0.852	0.686
		T_s	313	322	322
P_s	200	T_d	385	385	385
P_d	2000	γ	1.371	1.557	2.790
N	3	P_s	200	431	928
C_r	2.154	P_d	431	928	2000
		P_{avg}	315	680	1464
P_s	200				
P_1	431	W_{stage}	3790	3709	3352
P_2	928				
P_d	2000	W_{comp}	**10851**	HP	

For the parameters given it will take a three-stage compressor that will use a total of 10,851 horsepower to run.

5.2.2 Compression Power Calculation Method II

Using the Ariel software and entering the same parameters as in Compression Power Calculation Method I above the following screenshot is obtained.

Figure 11. Screenshot of Ariel Software showing parameter input on Service/Stage Data tab.

Note here that the estimated required power needed is 11523.53 horsepower. In order to specify what the specific gravity for the gas composition the following two screenshots provide a look at what the software will require. As noted in the second one below it is assumed that there will be 100% CO_2. In reality it will be slightly less than that with some other gasses such as oxygen and nitrogen.

Figure 12. Screenshot of Ariel Software showing the pressure ratios for each stage.

Figure 13. Screenshot of Ariel Software showing the composition of compressed gas.

5.2.3 Compression Cost Calculation Using Method I

5.2.3.1 Power Calculation Methods I and II

Because there are two different methods for calculating the power required for compression both will be addressed here. Because both of the power requirements are less than 40,000 horsepower and because of the ceiling function in the first two equations below we see that using either power calculation from above will yield a one, therefore both calculations for the cost will be the same.

$$n_{t1} = \left\lceil \frac{W_{comp}}{40,000} \right\rceil = \left\lceil \frac{10851}{40,000} \right\rceil = 1$$

$$n_{t2} = \left\lceil \frac{W_{comp}}{40,000} \right\rceil = \left\lceil \frac{11524}{40,000} \right\rceil = 1$$

$$m_t = \frac{1000m}{24 \times 3600 n_t} = \frac{1000 \times 4000}{24 \times 3600 \times 1} = 42.2963$$

$$C_{comp} = m_t n_t \left[(.155 \times 10^6) m_t^{-0.71} + (1.671 \times 10^6) \ln\left(\frac{P_d}{P_s}\right) m_t^{-0.6} \right] = \$18{,}309{,}170$$

The total cost of compression using this method is \$18,309,170.

5.2.4 Compression Cost Calculation Using Method II

Using the two different power values calculated above and the Compression Cost Calculation Method Ii the following values are calculated.

5.2.4.1 Power Calculation Method I
$$C_{comp} = 10851 \times \$1100 = \$11.9361 \; Million$$

5.2.4.2 Power Calculation Method II
$$C_{comp} = 11524 \times \$1100 = \$12.6764 \; Million$$

Because of the lower power requirements calculated using Power Calculation Method I there is a lower cost associated with the compression with the cost at \$11.9361 million. The Power Calculation Method II has a higher power requirement and thus has a higher cost requirement at \$12.6764 million.

5.2.5 Compression Cost Calculation Using Method III

Using Figure 5 and extrapolating to about $25\frac{MMscf}{day}$ the cost for one the compressor is about \$1.85 $Million$ and three compressors will be \$5.55 $Million$.

$$C_{comp} = \$5.55 \; Million \times 3 = \$16{,}065{,}000$$

The total cost for compression using Compression Cost Calculation Method III is \$16.065 million.

5.3 Pipeline

5.3.1 First Method

5.3.1.1 Lateral Lines
Since there is a flow rate of $4000\frac{tonnes}{day}$, under the assumption that each well will accept $2500\frac{tonnes}{day}$ based on Hendriks' practical limit, two wells will be needed each with a flow rate of $2000\frac{tonnes}{day}$. Also it is assumed that each well will accept an equal amount of CO_2 therefore each lateral line will transport $2000\frac{tonnes}{day} \times 365\frac{days}{year} = .73\frac{Mtonnes}{year}$. Using Figure the required pipe size is 8". For $L = 2.5 \; miles$ and $D = 8 \; inches$ C_{tot} is calculated as follows:

$$C_{Labor} = (343D^2 + 2074D + 170013)L + 185000 = \$706{,}392$$

$$C_{Mat} = (330.5D^2 + 687D + 26960)L + 35000 = \$169{,}020$$

$$C_{Misc} = (8417D + 7324)L + 95000 = \$281,650$$

$$C_{RoW} = (577D + 29788)L + 40000 = \$126,010$$

$$C_{Tot} = 1.44736(C_{Labor} + C_{Mat} + C_{Misc} + C_{RoW}) = \$1,716,867$$

5.3.1.2 Trunk Line

The main trunk line will have the cumulative flow from each of the lateral lines, thus $4000\frac{tonnes}{day} \times 365\frac{days}{year} = 1.46\frac{Mtonnes}{year}$. Using FIGURE the trunk line will need to be 12". For $L = 3.0$ and $D = 12\ inches$, C_{tot} for the trunk line is calculated as follows:

$$C_{Labor} = (343D^2 + 2074D + 170013)L + 185000 = \$917,879$$

$$C_{Mat} = (330.5D^2 + 687D + 26960)L + 35000 = \$283,388$$

$$C_{Misc} = (8417D + 7324)L + 95000 = \$419.984$$

$$C_{RoW} = (577D + 29788)L + 40000 = \$150,136$$

$$C_{Tot} = 1.44736(C_{Labor} + C_{Mat} + C_{Misc} + C_{RoW}) = \$2,370,405$$

5.3.1.3 Total Pipeline Cost
The total cost for the pipeline is $\$1,716,867 + \$2,370,405 = \$4,087,272$.

5.3.2 Second Method

5.3.2.1 Lateral Lines
Based on the same assumptions above the average cost for the upper and lower bounds for the cost of the pipeline is calculated as follows where $Q_t = 4000\frac{tonnes}{day}$ and L=2.5 miles:

$$C_{low} = \left[(15979.1Q_t{}^{.35})(1.609L)^{.06}\right]L = \$999,260$$

$$C_{high} = \left(7707.56Q_t{}^{0.5}\right)(1.609L)^{.13} = \$1,661,546$$

$$C_{average} = \$1,330,403$$

5.3.2.2 Trunk Line
$$C_{low} = \left[(8500Q_t{}^{.35})(1.609L)^{.06}\right]L = \$1,545,152$$

$$C_{high} = \left(4100Q_t{}^{0.5}\right)(1.609L)^{.13} = \$2,887,369$$

$$C_{average} = \$2,216,260$$

5.3.2.3 Total Pipeline Cost
The total cost for the pipeline is $\$1,330,403 + 2,216,260 = \$3,546,664$.

5.3.3 Third Method

5.3.3.1 Lateral Lines

$$C_{lat} = \frac{\$60,000}{inch \cdot mile} \times D \times L = \frac{\$60,000}{inch \cdot mile} \times 8\ inches \times 2.5\ miles = \$1,200,000$$

5.3.3.2 Trunk Lines

$$C_{trunk} = \frac{\$60,000}{inch \cdot mile} \times D \times L = \frac{\$60,000}{inch \cdot mile} \times 12\ inches \times 3\ miles = \$2,160,000$$

5.3.3.3 Total Pipeline Cost

$$C_{tot} = \$1,200,00 + \$2,160,000 = \$3,360,000$$

5.4 Heater

A heater just before the injection well is used to keep the temperatures elevated enough so that when or if the pressure must be dropped before the CO_2 is injected into the well it will not freeze the lines. A better-engineered analysis would be able to determine the certainty of need for a heater.

$$C_{heater} = 2.8286m - 112.14 = \$101\ thousand$$

$$C_{tot} \cong 2 \times C_{heater} = \$202\ thousand$$

5.5 Dehydrator

Because most CO_2 comes with water moisture in it a dehydration unit should be used. If there is too much moisture present in the CO_2 stream it will combine with the CO_2 to make carbonic acid at sufficiently high levels to corrode the pipeline. For this reason the cost for a dehydration unit is included.

$$C_{dehy} = 10.101m + 39.899 = \$762,000$$

$$C_{tot} \cong 2 \times C_{dehy} = \$1,525,000$$

5.6 Injection Well

5.6.1 Cost Calculation for Injection Well Method I

The total cost for the well is found by calculating the overall cost for the site, equipment and drilling and then totaling these costs as follows:

$$C_{site} = 2170550N = \$4,341,100$$

$$C_{Eqip} = 65836N \sqrt{\frac{7389}{280N}} = \$239,146$$

$$C_{drill} = 129,000Ne^{.000244D} = \$873,894$$

$$C_{well} = C_{site} + C_{Equip} + C_{drill} = \$5,454,140$$

5.6.2 Cost Calculation for Injection Well Method II

Values for each of the line items are included in the table below. This method requires some assumptions as to the length of the tubing, but these can be assumed to be approximately the same as the depth of the well unless otherwise indication. Also it is assumed that the used pore space will be about one square mile per injection well. Each square mile has 640 acres.

Table 13. Parameters for Calculation with Method II

Cost Item	Cost Algorithm	Item Totals
Conduct front-end engineering and design (general and injection wells)	$200,000/site + $40,000 per injection well	280,000
Obtain rights-of-way for surface users. (equipment, injection wells)	$20,000 per injection (pipeline right of ways included in pipeline costs) Half of cost is legal fees for developer, other half is bonus to land owner	40,000
Lease rights for subsurface (pore space) use.	Upfront payment of $500/acre	640*500*2= 640000
Land use, air emissions, water emissions permits	$100,000/site+$20,000/sq mile	140000
UIC permit filing	$10,000/site+5,000/injection well	20000
Standard injection well cost	$/foot=210-280 typically down to 9000ft	250*5000*2= 2500000
Corrosion resistant tubing	Additional $1.10/foot length-inch diameter for glass reinforced epoxy (GRE) lining	1.1*8*5000*2= 88000
Corrosion resistant casing	Additional $1.75/foot length-inch diameter for corrosion resistant casing	1.75*8*5000*2= 140000
Cement entire length of well	$1.15/foot length –inch diameter	1.15*8*5000*2= 92000
Use CO_2-resistant cement	Adds 25% to total cementing costs	92000*.25*2= 46000
Wellhead and Control Equipment	Cost per well is $500*(maximum tons per day injected per well)^.5	500*4000^.5*2= 63246
	Total	$4,049,246
	Adjusted Total (2008 to 2009)	$4,111,201

5.6.3 Method III

This method is straight forward as it only depends on depth and assumes that everything else is constant.

$C_{well} = \$637.3D + \$1,675,410 = \$4,864,946$

5.7 Summary Total

Table 14 Case Study Calculation Summary

Component	Method I	Method II	Method III	Average	St. Dev.	% Dev.	Minimum	Maximum
Compression	18,311,995	12,676,400	16,065,000	15,684,465	2,837,003	18%	12,676,400	18,311,995
Pipeline	5,915,754	3,546,664	3,360,000	4,274,139	1,424,740	33%	3,360,000	5,915,754
Injection	5,454,140	4,111,201	4,864,946	4,810,096	673,148	14%	4,111,201	5,454,140
Heater	202,000			202,000			202,000	202,000
Dehy	762,000			762,000			762,000	762,000
			Total	$25,732,700			$21,111,601	$30,645,889

A project like that defined above can reasonably be expected to cost between $21 and $31 million dollars; most likely, about $25.7 million dollars. The largest variance comes from the first method for compression. This model has higher compression rates for smaller flow rates. As the flow rates approach 10,000 $\frac{tonnes}{day}$ or greater, the cost per HP approaches $1100 per HP, which is the rate at which the other costs are figured.

Figure 14 Case Study Project Costs

	Compression	Pipeline	Injection	Heater	Dehydration
Method 1	18,311,995	5,915,754	5,454,140	202,000	762,000
Method 2	12,676,400	3,546,664	4,111,201		
Method 3	16,065,000	3,360,000	4,864,946		
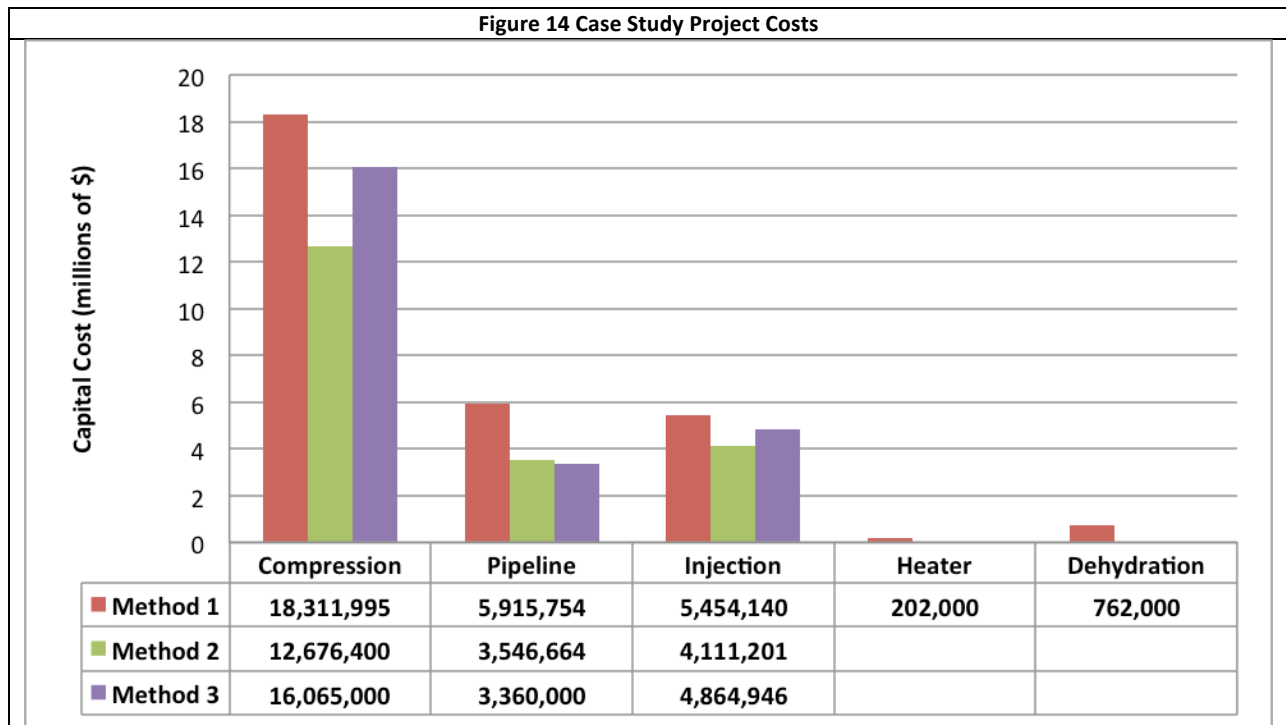
As can be noted above the heater and dehydration costs, while still relatively expensive, are low compared to the higher costs of compression, the pipeline system and the injection well.

Figure 15 Case Study Data Comparison

	Compression	Pipeline	Injection	Heater	Dehydration
Maximum	18,311,995	5,915,754	5,454,140	202,000	762,000
Average	15,684,465	4,274,139	4,810,096		
Minimum	12,676,400	3,360,000	4,111,201		
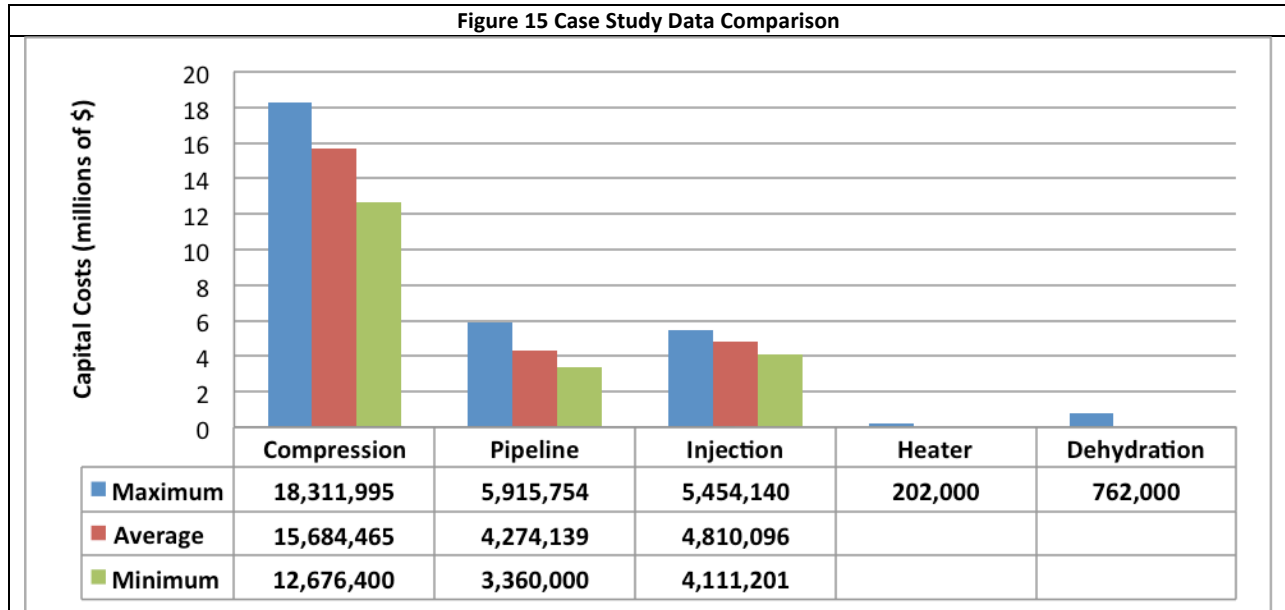
When considering other projects with little or no overlap in the range of the capital costs it should be reasonable to expect the project costs to differ enough to choose between the projects. If they significantly overlap in their capital cost ranges then more information will be needed for better resolution in the capital cost estimation.

6 Actual and Conceptualized Projects

6.1 San Juan Basin

Table 15 San Juan Basin Calculation Summary

	Expected	Calculated						Actual
		Method I	Method II	Method III	Average	Minimum	Maximum	
Compression	0	0	0	0	0	0	0	0
Pipeline	767,354	1,166,692	1,066,142	729,000	987,278	729,000	1,166,692	1,020,477
Injection	1,392,130	2,811,777	1,725,861	3,905,988	2,814,542	1,725,861	3,905,988	1,143,176
Dehy	0	0	0	0	0	0	0	0
Heater	0	79,646			79,646	79,646	79,646	50,464
Other	413,125							101,109
Total	2,572,609				3,881,465	2,534,507	5,152,326	2,315,226
Adjusted Total	**$2,852,612**				**$3,881,465**	**$2,534,507**	**$5,152,326**	**$2,567,215**
Data obtained from invoices gathered from the main contractor and subcontractors.								

Applying these methods to past projects is somewhat difficult because the many costs that accrue during the course of the project do not fit completely within one category or another. For example, the company that works on both the injection well and the pipeline for welding may only send one invoice without specifying where their time was charged. Also it is possible that not all of the invoices were

submitted by the main contract company because the limits of the SWP funding had been reached, thus making it impossible to obtain an accurate count of exactly how much the project cost.

Figure 16 San Juan Basin Project Costs

	Pipeline	Injection	Heater	Other
Actual	1,020,477	1,143,176	50,464	101,109
Expected	767,354	1,392,130		413,145
Method 1	1,166,692	2,811,777	79,646	
Method 2	1,600,142	1,725,861		
Method 3	729,000	3,905,988		
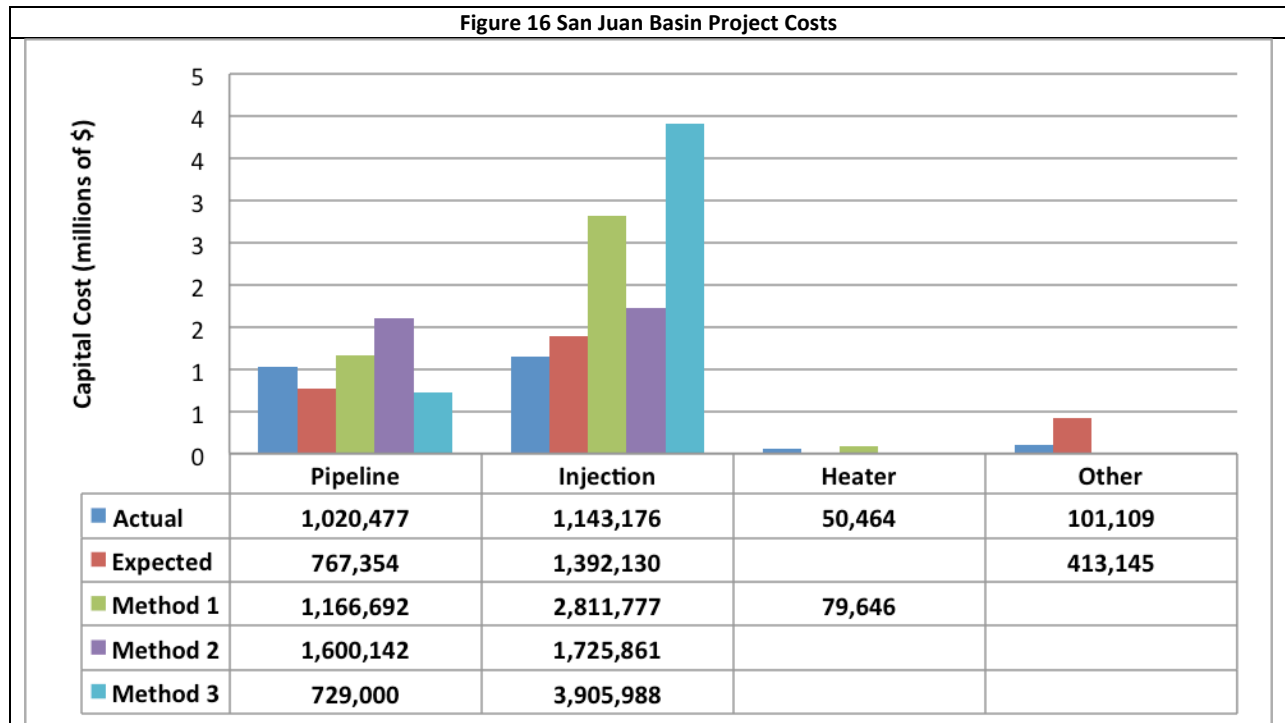
The injection costs as seen above are high compared to the actual cost. This could be partly due to the main contracting company having to absorb some of the cost because it was higher than was contracted. The costs for the pipeline system were more tightly grouped showing that the pipeline equations were more consistent for the short line that was buried. The miscellaneous (Other) category was higher than expected, but again this is likely due to inaccuracies in reading the returned invoices.

Figure 17 San Juan Basin Project Costs Compared

	Pipeline	Injection	Heater	Other
Maximum	1,166,692	3,905,988	79,646	
Expected	767,354	1,392,130	79,646	413,125
Average	987,278	2,814,542	79,646	
Actual	1,020,477	1,143,176	50,464	101,109
Minimum	729,000	1,725,861	79,646	
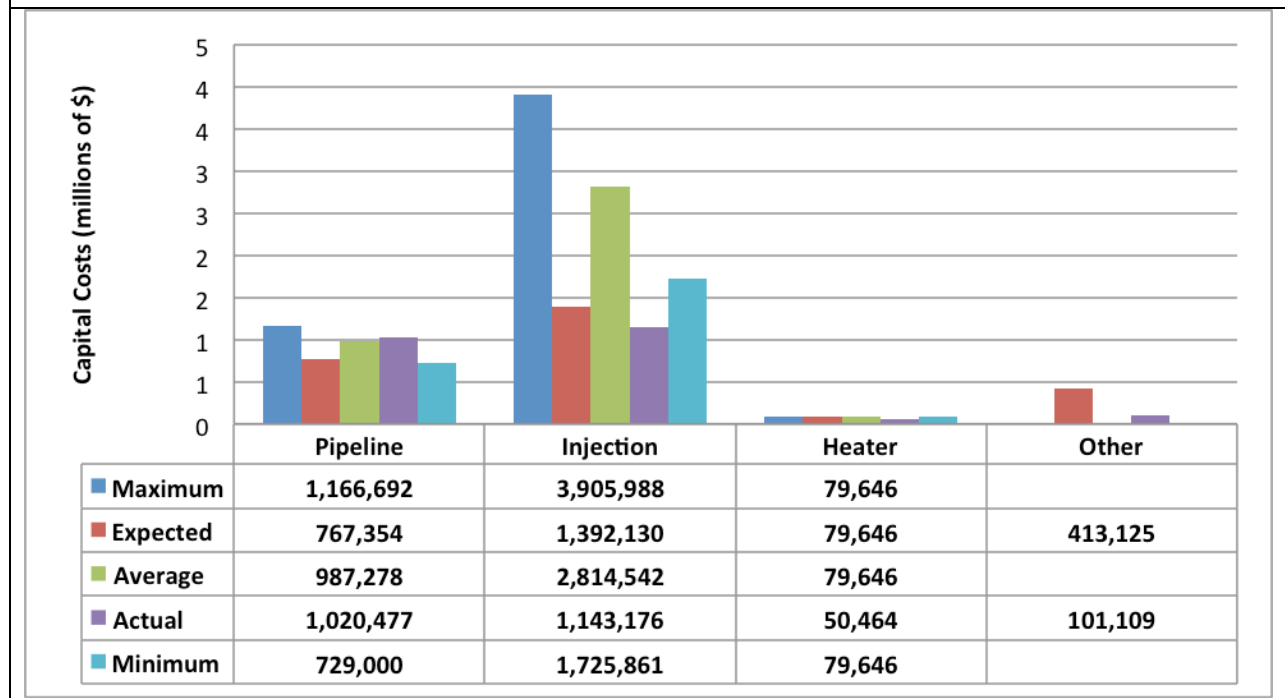
The actual cost seen above for the injection is significantly below the estimated costs and well below the average. In order to understand more fully how these models compare to actual injection costs more data will need to be obtained to compare the results to. The actual pipeline cost is only about 3% higher than the average projected cost, showing that the three models together gave a good estimate. The actual cost for the heater was very difficult to distinguish from the cost of the injection site because many of the costs were combined. But, compared to the overall cost of the project, the costs for the heater were close.

6.2 Site 1

Table 16 Site A Project Calculation Summary

	Expected	Calculated						Actual
		Method I	Method II	Method III	Average	Minimum	Maximum	
Compression	7,660,000	11,803,847	7,530,600	11,250,000	10,194,816	7,530,600	11,803,847	0
Pipeline	1,572,820	3,878,777	1,941,302	1,928,636	2,582,905	1,928,636	3,878,777	0
Injection	0	0	0	0	0	0	0	0
Dehy	1,200,000	1,100,000			1,100,000	1,100,000	1,100,000	0
Heater	312,000	246,000			246,000	246,000	246,000	0
Other	621,200							0
Total	11,366,020				14,123,721	10,805,236	17,028,624	0
Adjusted Total	$11,539,931				$14,123,721	$10,805,236	$17,028,624	$0

The project at Site 1 was not started, although much of the characterization phase was carried out. The expected costs were calculated by an engineering firm and were more in-depth than what the methods here allow. Some of the costs included in the other category are shipping charges, engineering fees and power facilities (sufficient power was not available onsite).

Figure 18 Site 1 Project Costs

	Compression	Pipeline	Heater	Other
Expected	7,360,000	1,572,820	312,000	921,200
Method 1	11,803,849	3,878,777	246,000	
Method 2	7,530,600	1,941,302		
Method 3	11,250,000	1,928,636		
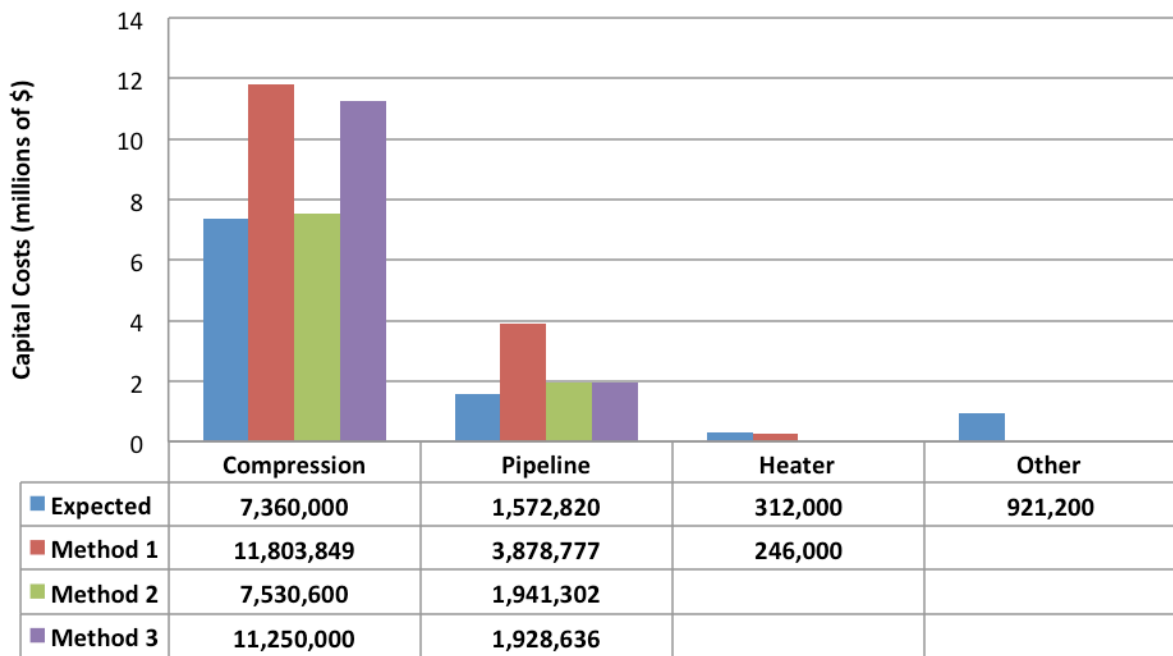
Data for expected values from Nicholas Consulting Group and included in appendix.

There was to be several injection wells drilled at this site, but prior to canceling this project no estimate was formally done on the site, therefore there were no calculations done for the injection wells. The first and third methods were high for the compression cost calculation whereas the second one was very close to the expected cost given by the Nicholas Consulting Group. The first method was higher for the pipeline system calculation while the second and third calculations were fairly close. Some of the items categorized under the Other category could be classified under the Compression or Pipeline categories, which would narrow the gap between the engineering estimate and the computed costs. Many of the items classified under Other may relate to either Compression, Pipeline or both, but because of the difficulty in separating them, they were separated and put in the Other category.

Figure 19 Site 1 Costs Compared

	Compression	Pipeline	Heater	Dehydrator	Other
Maximum	11,803,847	3878777	246,000	1,200,000	921,200
Expected	7,360,000	1,572,820	312,000	1,100,000	
Average	10,194,816	2,582,905	246,000	1,100,000	
Minimum	7,530,600	1,928,636	246,000	1,100,000	

Data for expected values from Nicholas Consulting Group and included in appendix.
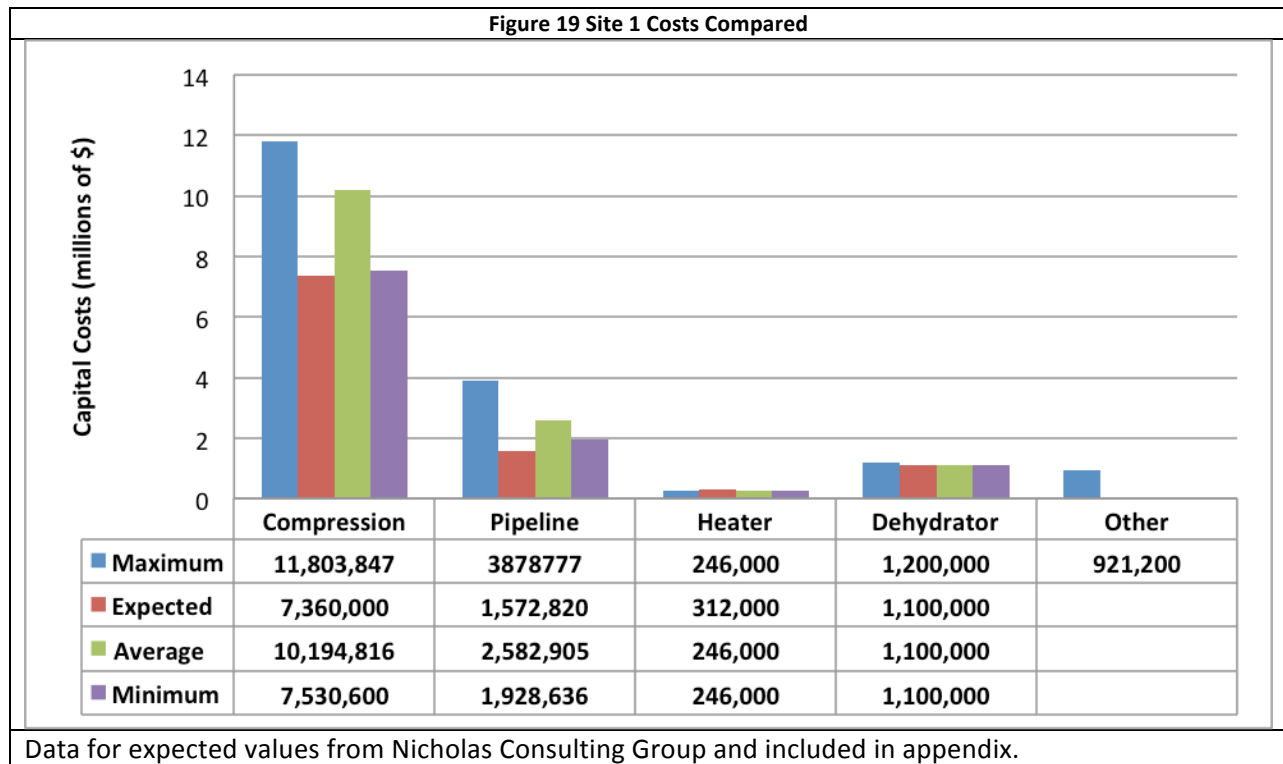
6.3 Site 2

Table 17 Site 2 Project Calculation Summary

	Expected	Calculated						Actual
		Method I	Method II	Method III	Average	Minimum	Maximum	
Compression	6,945,160	10,269,653	5,494,500	9,000,000	8,254,718	5,494,500	10,269,653	0
Pipeline	2,361,360	3,278,096	1,722,512	1,299,090	2,099,899	1,299,090	3,278,096	0
Injection	0	0	0	0	0	0	0	0
Dehy	2,400,000	1,200,000	0	0	1,200,000	0	1,200,000	0
Heater	255,000	228,000			228,000	228,000	228,000	0
Other	1,303,580							0
Total	13,265,100				11,782,617	7,021,590	14,975,749	0
Adjusted Total	**$14,708,873**				**$11,782,617**	**$7,021,590**	**$14,975,749**	**$0**

The SWP is currently investigating this project at Site 2 in central Utah. The expected numbers above were received recently from the Nicholas Consulting Group. The expected costs in this case are somewhat higher than those for Project A because some significant costs are not directly included in the models, but are included above in the "Other" category. The main extra expenses include some costs for new injection and production wells, a scrubber, and a coalescing filter, as well as labor that will be used partly on the injection and production wells.

Figure 20 Site 2 Project Costs

	Compression	Pipeline	Dehydration	Heater	Other
Expected	6,945,160	2,361,360	2,400,000	255,000	1,303,580
Method 1	10,269,653	3,278,096	1,200,000	228,000	
Method 2	5,494,500	1,722,512			
Method 3	9,000,000	1,299,090			
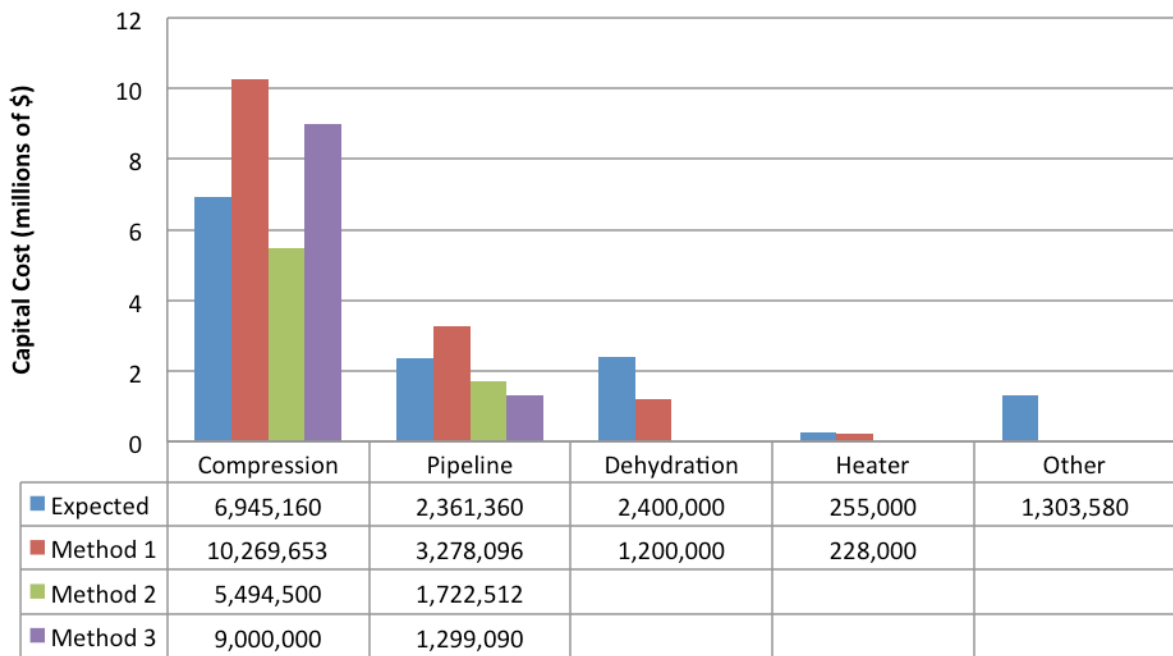
Data for expected values from Nicholas Consulting Group and included in appendix.

The difference in cost between the different calculation methods for compression is quite large which emphasizes the need to combine multiple models and not rely sole on one. But, despite the large spread the expected cost given by the Nicholas Consulting Group is fairly close to the middle. Also as with the compression the cost for the pipeline is also close to the middle of the other values.

Figure 21 Site 2 Costs Compared

	Compression	Pipeline	Dehydration	Heater	Other
Maximum	10,269,653	3,278,096	1,200,000	228,000	
Expected	6,945,160	2,361,360	2,400,000	255,000	1,303,580
Average	8,254,748	2,099,899	1,200,000	228,000	
Minimum	5,494,500	1,299,090	1,200,000	228,000	
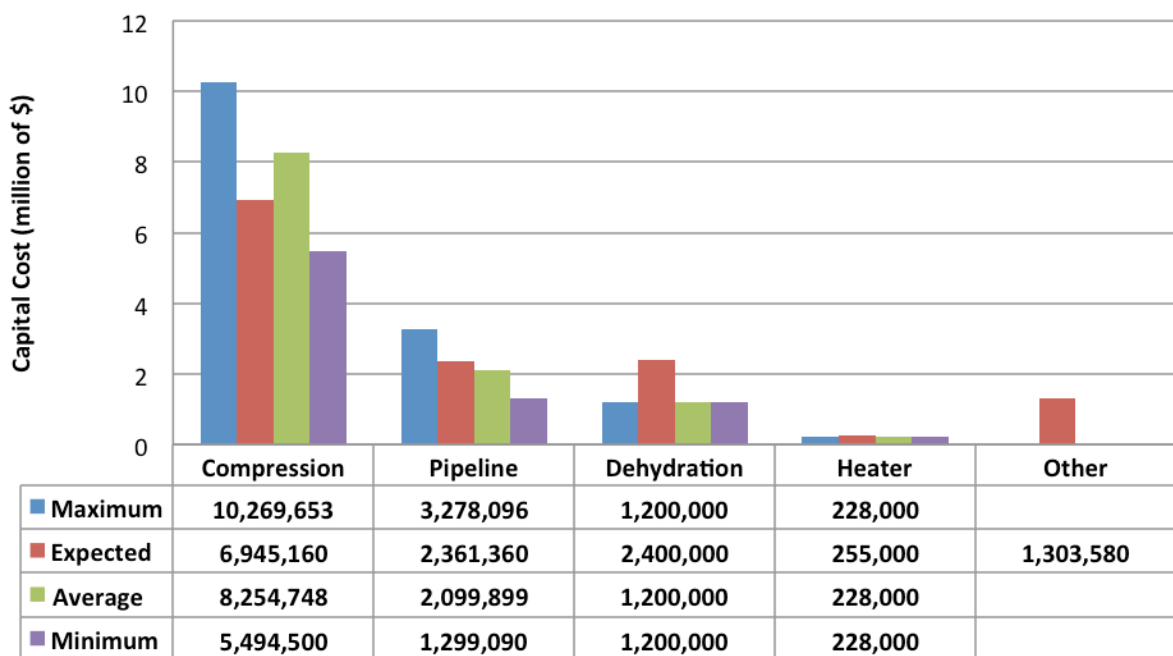
Data for expected values from Nicholas Consulting Group and included in appendix.

With the exception of the dehydration all of the different components fit well within the ranges given them. When the Other category is factored into to the cost there will still be enough room within the given ranges to accept the additional costs.

7   Conclusion

This report has taken and assimilated many different models or methods for calculating the various parts of a Carbon Capture and Sequestration project. Combining these methods it has been shown that a sufficient range of initial capital costs can be established in which to determine if a more detailed estimate should be pursued for different sites. The ranges of costs offered by this project should give good enough resolution to be able to distinguish between projects that are more than about 20% different in cost. When the costs for different project fall inside of this range further work should be done to narrow the gap. Some of this work might include getting better data and a better characterization of the field in question, selecting the larger costs, such as compression, and getting a better estimate by either consulting with a sales company or hiring an engineering firm, or looking at the sensitivities in the models to see what part of the project is most sensitive to the cost. For example, increasing the suction pressure for the compressors from 3 psi to 15 psi can have an enormous effect on the power requirements and hence the cost of the compressors.

In the following figure of the combined summary of the different projects it is easily seen that actual and estimated capital costs for each of the projects falls within the range of costs predicted by the models. There is typically about a 20 to 25% difference between the mean and the extremes of the range. Based on the extremely limited information that was provided to the methods above there is a great enough difference to choose between, for example, the San Juan Basin site versus Site 1 or 2, but not enough difference to choose between Site 1 and Site 2. In fact, because Site 2 was meant to be a replacement project for Site 1 it is appropriate that they came out fairly close.

Figure 22 Combined Summary of All Projects

	Case Study	San Juan Basin	Site 1	Site 2
■ Minimum	21,111,301	2,534,507	10,805,236	7,021,590
■ Average	25,732,700	3,881,465	14,123,721	11,782,617
■ Expected		2,572,609	11,539,931	14,708,873
■ Actual		2,567,215		
■ Maximum	30,645,889	5,152,326	17,029,624	14,975,749
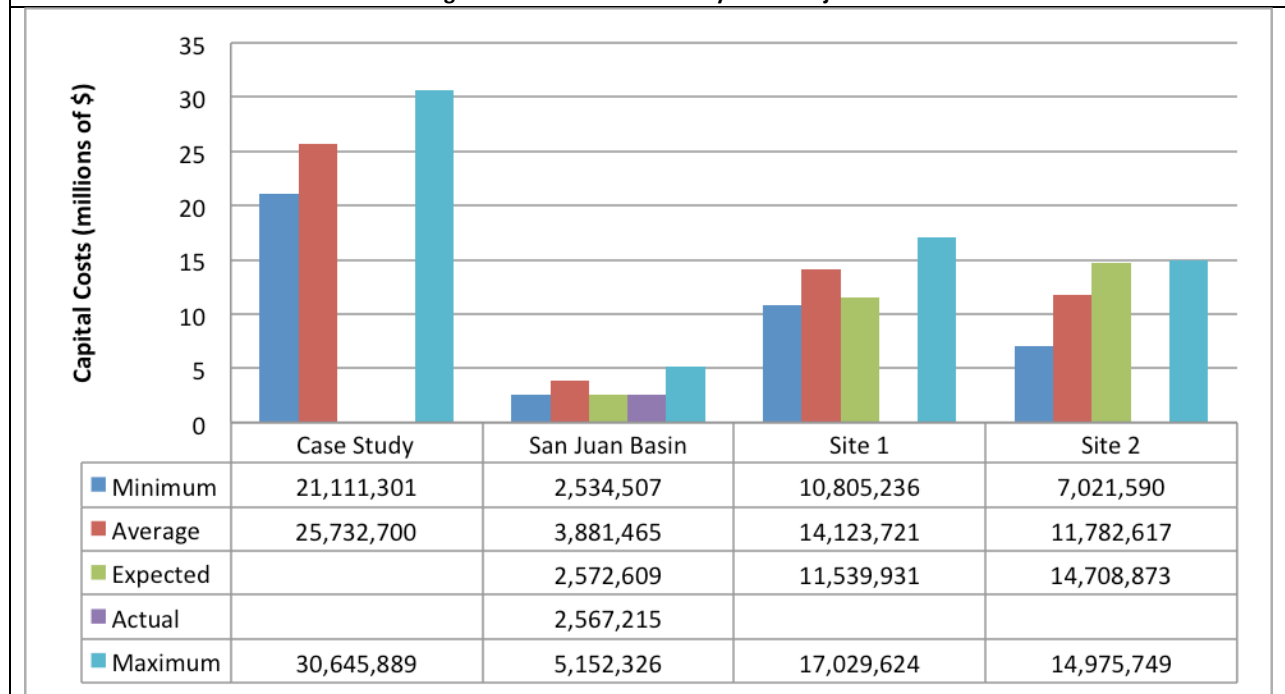
When beginning this report it was observed that despite the fact that many of the models were well recognized and used in the industry they came out with significantly different estimates for the same project. Upon investigation it was found that the assumptions of each model were different, especially in what they included within their estimate. For example one might include the right of way for a pipeline system and another one would not and it might have to be added in later. Some of the models didn't specify exactly what was included due to the lack of data or detail in the information they drew their data from. Also as was found during the SWP San Juan Basin project the accounting methods and how things are reported can vary widely. When reporting costs within such an involved and large project there will always be some overlap in costs making it difficult to distinguish, for example, whether the cost belongs to the pipeline system or the injection well. Because of this it was found that combining the models and forming a range with a mean, minimum and maximum made it possible to work around the variations in the models and obtain a reliable method for quickly estimating costs. One notable trend is that costs obtained with each method tend to stay higher or lower than other, similar costs. For example, the Compression Cost Calculation Method I is always higher than that of Method II, which is always higher than Method III. Similar trends are found for the pipeline and injection costs. A possible reason for this is all of the flow rates are relatively low, staying below about 1,000,000 tonnes per year. If the flow rates were to increase the Compression Cost Calculation Method I would likely merge with the others. This is based on the regression model originally used relying on higher flow rates making the slower flow rates less accurate.

8   Future Work

This report strictly evaluates the initial capital costs that can be expected when getting a project infrastructure installed. An equally important area of study would be what future costs might be such as

the operating and maintenance costs. Models that account for these costs are bountiful and scattered. Bringing them together in a report such as this would enable managers to further evaluate the validity of a project once it is running. Models for future costs and maintenance would have much less variability than starting a project because there is much more data available about the cost of energy and maintenance, which has more similarities with other processes and industries.

Right now there are many projects that are in the conceptual stage. If measures could be designed and taken that will allow a systematic collection of cost data for the installation of CCS project components better models could be designed to calculate the expected capital costs. These better models would be instrumental in reducing the gap between the minimum and maximum of the range of costs. Also if this more detailed data could be made available more specific models could be designed. Models such as the one above that was put together by the EPA which detailed each specific part of drilling an injection well and installing the infrastructure above to manage it would be very helpful useful by making it possible to make fewer assumptions.

Despite the fact that this report should be straight forward and systematized it will still take several hours to work through and going back through the calculations to make adjustments for 'what if' scenarios will be tedious. Automating the procedures within this report will be very useful either in a spreadsheet format or as a desktop or web application.

One of the largest costs associated with sequestering carbon dioxide is separating it from other gasses in the post-process gas streams and making available for the compression and injection. Right now many of the methods of separation are still under development and thus are not commercially available with any known costs. But, as they do become available it will be important to include their capital costs with the rest of the costs listed above.

9   Acknowledgements

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Appendix A   San Juan Basin Estimate

This appendix is included primarily as a reference to see the many costs that are included in a project. This one does not include any costs related to compression because the CO_2 was purchased at the needed pressure.

Table 18 San Juan Basin Cost Estimate

Task 3.1	Site/Reservoir characterization and model development		
subtask 3.1.1			
Logging			$62,000
Pressure transient			$27,800
Coring and Analysis (coring $23,031 and analysis $17,492)			$40,523
Total Task 3.1			**$130,323**
Task 3.2	**Implement regulatory permitting and risk mitigation**		
subtask 3.2.3			
Archeological Survey			$26,578
Total Task 3.2			**$26,578**
TASK 3.3	**Construction, safely, and site preparation, baseline MMV**		
subtask 3.3.1			
Drilling with Coring/Cost estimate is with rig time only			
<u>Account Description</u>	<u>Units</u>	<u>Unit Cost</u>	<u>Cost</u>
Location Cost (Build location & roadways)			$30,000
Move-in (H&P cost include rig rate/day, $2000 added to transport other equipment not associated w/H&P			$22,000
Rig Cost	6	days @ $12,000/day	$72,000
Mote Rig	1	pre-set surface hole	$5,500
Health & Environmental Safety			$3,079
Drilling Fluid	5	days @ $2,500/day + mud	$17,000
Fresh Water		Cost for deliver & water	$15,000
Bits		8-3/4" bit, 6-1/4" bit	$10,000
Cementing		BJ cement job	$12,000

Casing Accessories (Centralizers, External Packer, Float Collar, Shoe)			$18,800
Coring and Analysis			$0
Fuel (For rig & air compressor) (Cost included in rig day rate)		0 $/day	$0
Rentals (Light rental, trailers, down hole drillstring)			$4,000
Fishing			$0
Other Rentals			$0
Transportation (Move frac tanks, transport csg to location)			$5,000
Directional Service			$0
Inspection (Casing inspection, BOP testing services)			$4,043
Logging Services (Mudloggers)			$0
Production Testing			$0
Swabbing, Snubbing,Coiled Tubing			$0
Stimulation			$0
Consultants (Mote supervision, Drilling rig supervision)			$6,656
Technical Services			$0
Contract Labor (5th man on rig floor, csg crew)			$2,000
Miscellaneous			$1,600
Packer Rentals			$0
Health & Safety Environmental Costs (Safety Bonus for Consultant)			$2,000
Disposal Costs	4	days @ $100/day	$400
District Tools	4	days @ $400/day	$0
Overhead (ConocoPhillips personnel going to field)			$5,000
Casing			
9-5/8" 32.3# H-40	120'	ft @ $20.73/ft)	$2,487
7.0" 20.0# J-55	3085'	ft @ $12.22/ft)	$37,637
Wellhead Equipment			$12,000

Account Description	Units	Unit Cost	Cost
Wellhead & Tree Service (Labor only)			$1,200
Total Drilling Cost			**$288,202**

Recompletion of injection well upon early breakthrough			
<u>Account Description</u>	<u>Units</u>	<u>Unit Cost</u>	<u>Cost</u>
Workover rig to pull and rerun tubing prior to and following recompletion operations			$44,986
Wireline unit to run/install a wireline bridge plug and perforate the new interval			$20,000
Pump truck to perform a small, proppant-less perforation breakdown treatment			$10,000
Total recompletion			**$74,986**

Completion Costs			
<u>Account Description</u>	<u>Units</u>	<u>Unit Cost</u>	<u>Cost</u>
Location Labor			
Location Costs			$20,000
Move In, Move Out			$10,000
Accommodations & Catering			$0
Rig Cost (Rig Cost $3200/day Plus Power Swivel $800/day)	12	days @ $4,000/day	$48,000
Health & Environmental Safety (Safety	12	days @ $200/day	$2,400
Drill Fluids	7	days @ $200/day	$1,400
Air Package	12	days @ $2,500/day	$30,000
Alt/Brine/Fresh Water			$0
Fresh / Salt Water			$1,000
Bits			$3,000
Cement			$0
Cement & Mud Engineer			$0
Coring & Analysis			$0
Fuel	12	days @ $850/day	$10,200
Bops/Wellhead Rentals	12	days @ $130/day	$1,560
Rentals - Subsurface	12	days @ $600/day	$7,200
Fishing Tool Rentals			$0
Other Rentals - Surface	12	days @ $750/day	$9,000

Account Description	Units	Unit Cost	Cost
Transportation	12	days @ $150/day	$1,800
Directional Services			$0
Tubular Inspection			$2,000
Cased Hole Services (Phoenix to run gauges down hole, 2 runs)			$7,000
Production Testing			$0
Swabbing & Coil Tubing			$0
Fracturing & Stimulation			$0
Casing & Tubing Equipment (tangible)(Packers and Accessories (Nickel Plated Packer, On/Off tool, two nipples)			$15,000
Consultants	12	days @ $950/day	$11,400
Technical Contract & RA Tagging			$0
Roustabout Labor			$0
Miscellaneous			$2,450
Environmental Costs (Pit Clean Up)			$1,000
Disposal Cost (Removing produced water from pit)			$3,000
Environmental Compliance (Soil sample of reserve pit)			$1,000
Direct Labor			$0
Transportation - Air	12	days @ $350/day	$4,200
Employee Meals			$300
Casing (liner			
Plain	55	ft @ $15.00/ft)	$825
Plug Perf Liner	25	ft @ $43.00/ft)	$1,075
Tubing	3150	ft @ $9.50/ft)	$29,925
Casing/Liner equipment (liner hanger)			$2,000
Tubing Equipment			$0
Wellhead Equipment (Stainless steel tree & donut)			$25,000
Total Completion Cost			$251,735
Well Facilities Costs			
Account Description	Units	Unit Cost	Cost

Labor-Contract, Roustabout, Consultants	Labor		$0
Company Vehicles			$0
Location, Roads & Canals			$0
Damages, Property Losses			$0
Equipment Coating and Insulation			$0
Environmental			$0
Tanks and Pits			$0
Metering Equipment			$24,963
Flow Line			$15,000
Compressor			$2,415
Building			$11,500
Safety			$0
Technical Contract Services			$28,750
Miscellaneous			$0
Cathodic Equipment			$13,800
Right of Way			$0
Minor Pipelines			$58,650
Surface Pumps			$0
Electrical Accessories	Location Electrification		$22,532
Pulling Unit Cost/Valves/Fittings			$6,900
Environmental Compliance-Assessment			$0
Environmental Compliance-Remediation			$0
SPCC Compliance			$0
Direct Labor			$0
Freight/Water Transportation			$0
Tangible - Tubing			$0
Communication Systems			$31,632
Total Facilities			**$216,142**

Pipeline Costs			
Account Description	Units	Unit Cost	Cost
Low bid for the pipeline for 13,906 ft of 4.5" OD x 0.188 W.T. API 5L X52, Carbon Steel Pipeline			$403,868

Hydrotest and dewater 12 miles of Existing 4" Carbon Steel Pipeline plus the 2.7 miles of new pipeline			$91,049
Pipeline Survey			40000
As-builds on the existing portion of the pipeline			20000
As-builds on the new portion of the pipeline			10000
Pipeline Engineering			30000
Pipeline right of way			15000
Pipeline material and construction cost escalations			38000
Total Pipeline			**$647,917**

Appendix B   Site 1 Cost Estimate

Table 19 Site 1 Cost Estimate

Site 1 Material and Equipment					
Component	**Size / Description**	**Quantity**		**Cost / Unit**	**Total Expense**
Facility Compression	(3) 2 100 hP- 18,000 MCFD each: 300-1800 psig	3	ea	S 2,310,000	$6,930,000
Process Gas Dehydration	(1) unit 60,000 MCFD @ 300 psig	I	tot	$1,200,000	$1,200,000
Production Flow Lines	4" Flex Pipe, Isolation Valve, Valve Box	11,230	ft	$34	$381,820
Production Trunk Line	12" A-106 B STD Wall FBE w/ HDPE Liner	6,400	ft	$90	$576,000
Process Line Heaters	2.5MMBTU/hr Indirect Gas Fired Line Heater	3	ea	$104,000	$312,000
Typical Well Head Package	Pipe, Valves, Meters, RTU, Solar Panel, etc...	7	ea	$74,000	S 518,000
Packaged Power House	Ctrl Bldg, Equip. Room, Operators Room, etc...	1	tot	$300,000	S 300,000
CO2 Injection Line	8" API 5L X-52 STD Wall FBE	6,000	ft	$50	S 300,000
Electrical Equipment	Transformers,PLC, Master Radio, UPS, etc...	I	tot	$522,800	$522,800
Instrument Air Package	Supply air to facility instruments	I	tot	S 18,000	$18,000
H2S Detection System	4 channel H2S sensor system	1	tot	S 8,400	$8,400
CO2 Detection System	CO2 Monitors for all buildings	8	ea	$3,000	$24,000
TEG Sump Package	Tank, Pump, and Level Switches	1	tot	$18,000	$18,000
Misc. Pipe and Fittings	Pipe, Fittings, Flanges, etc.	I	tot	$65,000	$65,000
Freight Expense	Cost for delivery of Equipment & Materials	1	tot	$30,000	S 30,000
TOTAL MATERIAL AND EQUIPMENT EXPENSE					**11,204,020**

Labor				
Item Description	**Task**	**Quantity**	**Cost / Unit**	**Total Expense**
Detailed Engineering	Engineering & Project Mgmt. (6% of M&E)	1 tot	$672,241	$ 672,241
Mechanical Construction Labor	Fitting, Welding, Assembly, etc.	1 tot	S 50,000	$50,000
I&E Construction Labor	Ditching, Conduit Routing, Programming, etc.	1 tot	$230,000	$230,000
TOTAL LABOR EXPENSE				$952,241

Estimate Totals	
MATERIAL AND EQUIPMENT EXPENSE	S 11,204,020
LABOR EXPENSE	S 952,241
TAX	
SUBTOTAL	S 12,156,261
15 % CONTINGENCY	S 1,823,439
TOTAL PROJECT EXPENSE	$13,979,700

Appendix C   Site 2 Cost Estimate

Table 20 Site 2 Cost Estimate

Component	Size / Description	Quantity		Cost / Unit		Total Expense	
Production Wells	piping, valves, instrumentation; pressure cntl.	3	ea	$	40,000	$	120,000
Flowlines (installed)	transfer lines from wellhead to comp. facility	3,500	ft	$	80	$	280,000
Line Heater	produced gas line heater near the wellhead	3	ea	$	85,000	$	255,000
Fuel Gas Distribution System	fuel gas to facility and production well sites	15,840	ft	$	30	$	475,200
Inlet Gas Scrubber	2 phase vertical; ~700psi MAWP	1	ea	$	60,000	$	60,000
Dehydration	25 MMSCFD dehy to > 40lb/MMSCF of H2O	2	ea	$ 1,200,000		$	2,400,000
Coalescing Filter	sized to handle 50 MMSCFD of CO2	1	ea	$	96,000	$	96,000
Compression (skidded units)	25 MMSCFD - 2700 hp; 350psi to 1650psi	5,400	hp	$	1,000	$	5,400,000
Instrument Air	inst. air pkg; engine start air & instrumentation	1	ea	$	70,000	$	70,000
Power Upgrade (unknown)	480V power to new compression facility	1	tot	$	150,000	$	150,000
Miscellaneous Valves	CVs, SDVs, manual valves (comp. facility)	1	tot	$	78,000	$	78,000
Pipe, Fittings, Flanges, etc..	mechanical construction mtls. (comp. facility)	1	tot	$	180,000	$	180,000
Foundations & Structures	civil construction mtls. (comp. facility)	1	tot	$	320,000	$	320,000
Controls Devices	PLC, transmitters, etc… (comp. facility)	1	tot	$	84,000	$	84,000
Conduit, Cable, etc…	power & ctls. construction mtls. (comp. facility)	1	tot	$	148,000	$	148,000
CO2 Injection Line (installed)	6" SCH 80 CS; dry CO2 to injection well	7,920	ft	$	80	$	633,600
Water Injection Line (installed)	produced liquids to inj. well or existing facility	7,920	ft	$	30	$	237,600
Injection Well	valves and instrumentation; injection control	1	ea	$	40,000	$	40,000
TOTAL MATERIAL AND EQUIPMENT EXPENSE						$	11,027,400

Labor

Item Description	Task	Quantity		Cost / Unit		Total Expense	
Engineering & Design	detailed engineering and design	1	tot	$	882,192	$	882,192
Facility Construction Labor	compression facility - all phases of const.	1	tot	$ 2,205,480		$	2,205,480
TOTAL LABOR EXPENSE						$	3,087,672

Estimate Totals

MATERIAL AND EQUPIMENT EXPENSE	$	11,027,400
LABOR EXPENSE	$	3,087,672
TAX		
SUBTOTAL	$	14,115,072
CONTINGENCY		
TOTAL PROJECT EXPENSE	$	14,115,072