Engineering and Economic Assessment of Carbon Dioxide Sequestration in Saline Formations

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ABSTRACT

Concern over the potential effects of greenhouse gases such as carbon dioxide (CO_2) on global climate has triggered research about ways to mitigate the release of these gases to the atmosphere. A project to study the engineering feasibility and costs of sequestering CO_2 in deep, saline reservoirs was completed as part of a U.S. Department of Energy (DOE) program supporting research on novel technologies to mitigate greenhouse gas emissions. Study activities included a review of the status of existing technologies that could be used for CO_2 sequestration, development of a preliminary engineering concept for accomplishing the required operations, and estimation of costs for sequestration systems. The primary components of the CO_2 sequestration system considered are:

- Capture of the CO_2 from the flue gas
- Preparation of the CO_2 for transportation (compression and drying)
- Transportation of the CO_2 through a pipeline
- Injection of the CO_2 into a suitable aquifer.

Costs are estimated for sequestration of CO_2 from two types of power plants: pulverized coal with flue gas desulphurization (PC/FGD) and integrated coal gasification combined cycle (IGCC). The sensitivity of cost to a variety of transportation and injection scenarios was also studied. The results show that the engineering aspects of the major components of CO_2 capture and geologic storage are well understood through experience in related industries such as CO_2 production, pipeline transport, and subsurface injection of liquids and gases for gas storage, waste disposal, and enhanced oil recovery. Capital costs for capture and compression and the operational cost for compression are the largest cost components.

INTRODUCTION

The U.S. Department of Energy (DOE) is supporting research on fast-breaking technologies to mitigate greenhouse gas emissions. Concern over the potential effects of greenhouse gases such as carbon dioxide (CO_2) on global climate has triggered extensive studies of ways to reduce emissions of these gases. One method to help control greenhouse gas emissions is to capture and sequester CO_2 in the flue gas from coal fired power plants. Battelle was funded by DOE to study sequestration of CO_2 in deep saline reservoirs. This project included a task to perform an engineering and economic (EEA) which resulted in the research reported in this paper.

Related DOE-funded work on geologic storage of CO_2 in saline formations conducted at Battelle includes compositional reservoir simulations (Gupta et al., 2001), evaluation of geochemical aspects through modeling and experiments (Sass et al., 2001a and Sass et al., 2001b), and assessment of seismic aspects (Sminchak el al., 2001).

OBJECTIVE

The objective of the EEA was to review the status of existing technologies for handling CO_2, develop a preliminary engineering concept for accomplishing the required operations, and estimate capital and operating costs for sequestration systems under various design conditions. The primary components of the CO_2 sequestration system studied in the EEA are as follows (see Figure 1):

- Capture of the CO_2 from the flue gas
- Preparation of the CO_2 for transmission as a supercritical liquid (compression and dehydration)
- Transmission of the CO_2 through a pipeline
- Injection of the CO_2 into a suitable aquifer.

Electrical generating plants using existing technologies or plants that could be brought into service in the near future were considered as possible CO_2 sources for this study. The CO_2 source was assumed to be located in the eastern United States with CO_2 injection occurring close to the source using a regionally extensive formation such as the Mt. Simon Sandstone. Conceptual piping and instrument diagrams were developed for compression, pipeline transmission, and injection systems. These diagrams served as the basis for a preliminary budget estimate of capital and operating costs (+50% to –30% accuracy).

APPROACH

Costs are estimated for sequestration of CO_2 from the following two types of power plants:

- Pulverized Coal with Flue Gas Desulphurization (PC/FGD)
- Intergrated Coal Gasification Combined Cycle (IGCC).

The PC/FGD plant is used as the base case because it is the most common type of coal fired power generation system. Costs are estimated for the IGCC plant to provide information about possible economies provide by an innovative technology that has been developed and tested at the commercial scale. The PC/FGD plant is assumed to use a high performance SO_2 removal system such that the flue gas is compatible with a conventional CO_2 capture system such as amine absorption. Sulfur removal at the IGCC is assumed to be accomplished using wet oxidation to remove H_2S with CO_2 capture at elevated pressure using physical absorption. Cost results are presented on an annual basis with the capital costs being converted to yearly costs using a capital recovery factor calculated using an effective interest rate of 4.1% for a useful life of 25 years. The input data for the cost calculations are summarized in Table 1.

The sensitivity of cost to pipeline length, terrain, and injection depth was studied. The minimum pipeline length was assumed to be 15 km (9.3 mi). Increasing pipeline length in the cost estimation model allows examination of the cost increases that would occur if a suitable injection zone cannot be located near the power plant. The maximum transmission distance was assumed to be 400 km (249 mi) based on the assumption that the wide extent of the Mt. Simon formation would allow location of a suitable injection site within a reasonable distance. Analysis of scenarios involving pipeline construction in difficult (i.e., hilly and rocky) terrain or an urban area was done to quantify the cost sensitivity of the transmission system. The depth of the Mt. Simon formation ranges from about 1,000 to 3,000 m (3,281 to 9,843 ft) in the area of interest, so the cost effect of this range of injection depths was evaluated.

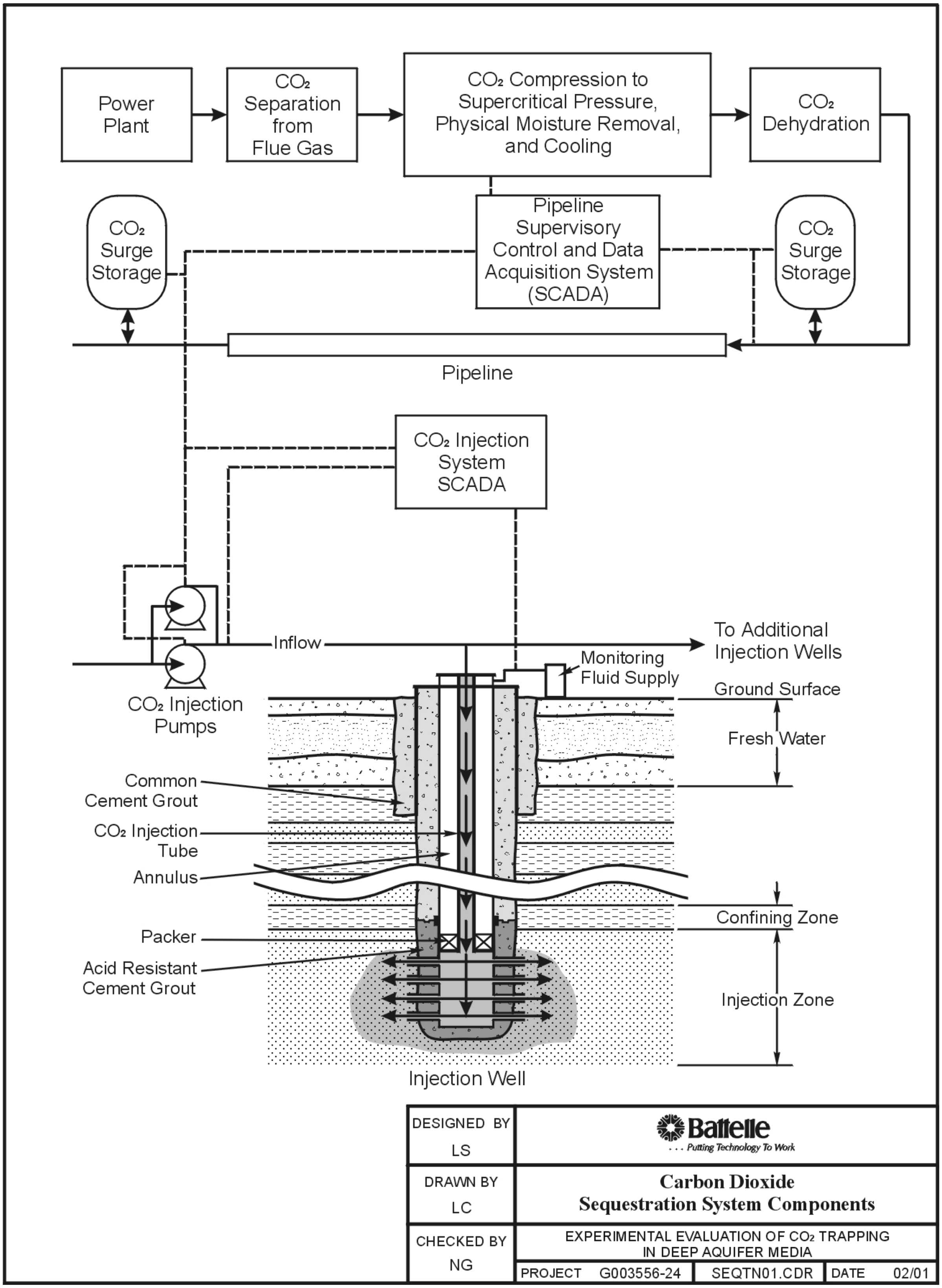

Figure 1. Carbon Dioxide Sequestration System Components

Table 1. Summary of Basis for Cost Estimation

	PC/FGD and CO_2 Capture by Amine Absorption	**IGCC and CO_2 Capture by Physical Absorption**
System Power Output		
Power without CO_2 capture (MW)	500	500
Power with CO_2 capture (MW)	362	428
System Cost		
Electricity price without capture (bus bar) ($/kWh)	4.9	5.3
Electricity price with capture (bus bar) ($/kWh)	7.4	6.3
CO_2 Capture Output		
CO_2 released without capture (kgs/kWh)	0.828	0.756
CO_2 released with capture (kgs/kWh)	0.083	0.136
CO_2 to pipeline (metric ton/yr)	3,360,000	2,800,000
CO_2 to pipeline (standard ft^3/hr)	6,860,000	5,710,000
CO_2 supply pressure	170 kPa (25 psig[a])	170 kPa (25 psig[a])
Pipeline operating pressure	10,340 kPa (1500 psig[a])	10,340 kPa (1500 psig[a])

(a) psig = pounds per square inch gauge (i.e., absolute pressure – atmospheric pressure)

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Capital cost data for compression and pipeline were taken from the annual pipeline economic issue of the Oil and Gas Journal (2000). Capital cost for dehydration equipment was estimated using data from Ormerod (1994) and Holt and Lindeberg (1993). Costs for other transmission equipment such as surge storage tanks and booster pumps were estimated using standard sources such as Richardson (1999), Peters and Timmerhaus (1991), and Page (1996). Injection well capacity of 1,500 metric tons CO_2 per day was estimated using data from Doherty and Harrison (1996), Hendriks and Blok (1993), and Van der Meer (1993) and well installation costs were derived from Ormerod (1994). All costs were adjusted to the year 2000 using Nelson-Farrar refinery cost indexes.

The estimate for the compressor capital cost is based on using 3 parallel 13.0 MW (17,400 hp) four-stage centrifugal compressors with diesel engine drives costing $18,400,000 each. Interstage cooling for the compressors is assumed to be provided using cooling water from the power plant. The capital cost for a dehydration plant is estimated as $5.1 million/metric ton of CO_2 processed per year. Dehydration of the compressed CO_2 stream is assumed to be done using adsorption in a packed particle bed.

The estimated cost for installing the pipeline was $710/m ($220/ft) based on a buried 20 in-diameter carbon steel pipe. The evaluation includes consideration of the sensitivity of the cost of pipeline installation in different types of terrain. Pipeline installation cost is estimated for hilly/rocky or urban terrain as well as for the base case of normal terrain. The pipeline installation costs for hilly/rocky terrain is assumed to be 5% higher than the cost for normal terrain over the entire length of the pipeline. The pipeline length that occurs in urban areas in the urban terrain scenario is assumed to be the greater of 10 km or 20% or the pipeline length, because it is unlikely that a long pipeline would be installed entirely in an urban area. The installation cost in urban terrain is assumed to be 20% higher than the cost in normal terrain. Cost for acquiring the right-of-way (ROW) in urban terrain is assumed to be 5 times has high as the ROW cost in normal terrain.

Fuel for the diesel engine that powers the compressor is the largest operating cost for the transmission system. Fuel cost was estimated by assuming that the engine is 40% efficient, diesel fuel provides a net energy output of 129,000 Btu/gal, and diesel fuel cost $1.00 per gallon. The unit cost for disposal of the water removed from the compressed CO_2 by physical separation is assumed to be $0.15/1,000 gal. The energy cost for regenerating the CO_2 adsorbent dryer was estimated by using a cost of $4.20/1,000 lbs for steam at 4,140 kPa (600 psi) assuming that the heating process to regenerate the adsorbent is 50% efficient. The cost for cooling water for the compressor is estimated assuming the cooling water is supplied at 27°C (80°F) and returned at 35°C (95°F) and costs $0.19/1,000 ga. Maintenance materials are assumed to be 4% of the initial material cost. Labor requirements for compressor and pipeline operations are assumed to be 5 maintenance workers, 5 operators, 2 pipeline inspectors, 0.5 full-time equivalent each for quality assurance (QA) and health and safety (H&S) support, and 1 supervisor. This assumes that there will be one QA and one H&S support person for the overall system who split their work time about equally between the transmission system and the injection system. The labor rates are assumed as $30/hr for the maintenance workers and operators, $50/hr for the QA and H&S support personnel, and $70/hr for the supervisor.

A capital costs estimate for preliminary site screening and candidate evaluation was prepared by determining the cost for primary site selection activities. The activities included in the capital cost estimate for preliminary site screening are as follows:

- Definition of screening factors
- Collection of documents describing candidate areas
- Evaluation of candidates with respect to screening factors
- Prepare report identifying and ranking candidate sites.

The activities included in the capital cost estimate for candidate evaluation are as follows:

- Install 10 groundwater sampling wells in USDW associated with the site
- Collect and analyze water samples from the USDW
- Install one test well in the saline aquifer
- Log the test well
- Collect and analyze liquid samples from the injection zone
- Collect and analyze mineral samples from the injection zone
- Perform an injectivity test in the injection zone
- Perform surface geophysical (e.g., seismic) testing of the area
- Install geophones and perform seismic monitoring
- Perform site modeling
- Perform site seismic evaluation
- Prepare candidate evaluation report.

Costs for preliminary site screening and candidate evaluation were estimated as $330,000 and $1,355,000, respectively.

The estimated cost for drilling an injection well into a deep saline aquifer was $645/m ($197/ft). Annual operating costs for the injection system are determined by estimating the utility consumption, analytical needs, and labor amounts expected to be needed to operate and maintain the system. Electricity is provided for the injection pumps (if needed) plus 0.20 MW of additional power consumption for other loads such as smaller pumps, instruments, lighting. An electrical cost of $0.065/kW-hr is used. Maintenance materials are assumed to be 4% of the initial material cost. Labor requirements are assumed to be 2 maintenance workers, 11 operators, 0.5 full-time equivalent each for quality assurance (QA) and health and safety (H&S) support, and 1 supervisor. The labor rates are assumed as $30/hr for the maintenance workers and operators, $50/hr for the QA and H&S support personnel, and $70/hr for the supervisor. Analytical requirements are estimated based on CO_2 samples collected from 3 points weekly at a cost of $200 per analysis and USDW samples from 20 wells quarterly at a cost of $300 per analysis.

TECHNOLOGY DESCRIPTION

The following types of fossil fueled power plant initially considered in the EEA as possible CO_2 sources were:

- Pulverized Coal with Flue Gas Desulfurization (PC/FGD)
- Coal Combustion with Oxygen and Recycled CO_2 (PC/O_2)
- Integrated Coal Gasification Combined Cycle (IGCC)
- Natural Gas Combined Cycle (NGCC).

The main components in these four types of power plants are illustrated in Figure 2. A variety of processes have been studied for capture of CO_2 from the flue gas of these plants as summarized in Table 2.

Carbon dioxide produced by combustion at a power plant and concentrated and purified by a capture system must then be compressed, dehydrated, and moved to the injection site. The main components of the CO_2 compression and dehydration system are shown in Figure 3. Transporting carbon dioxide to a remote site for injection will be done with a high-pressure large-diameter pipeline. Hundreds of thousands of miles of pipelines carry hazardous liquids and gases throughout the United States, operating safely for many years. In addition, high-pressure carbon dioxide pipelines have been used heavily in the oil-recovery business, especially in the last 20 to 30 years. Carbon dioxide pipelines are designed in similar fashion as natural gas or hazardous liquid pipelines, and are regulated by 49 CFR 195, the same code used for hazardous liquid pipelines. Design standards for hazardous liquid pipelines are described in the American Society of Mechanical Engineer's (ASME) code B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*.

Systems for pipeline transmission of CO_2 are in many ways similar to the pipelines used for natural gas. However, there are some differences in the properties of CO_2 compared to natural gas that must be accounted for in the design of the transmission system. These property differences raise the following potential concerns:

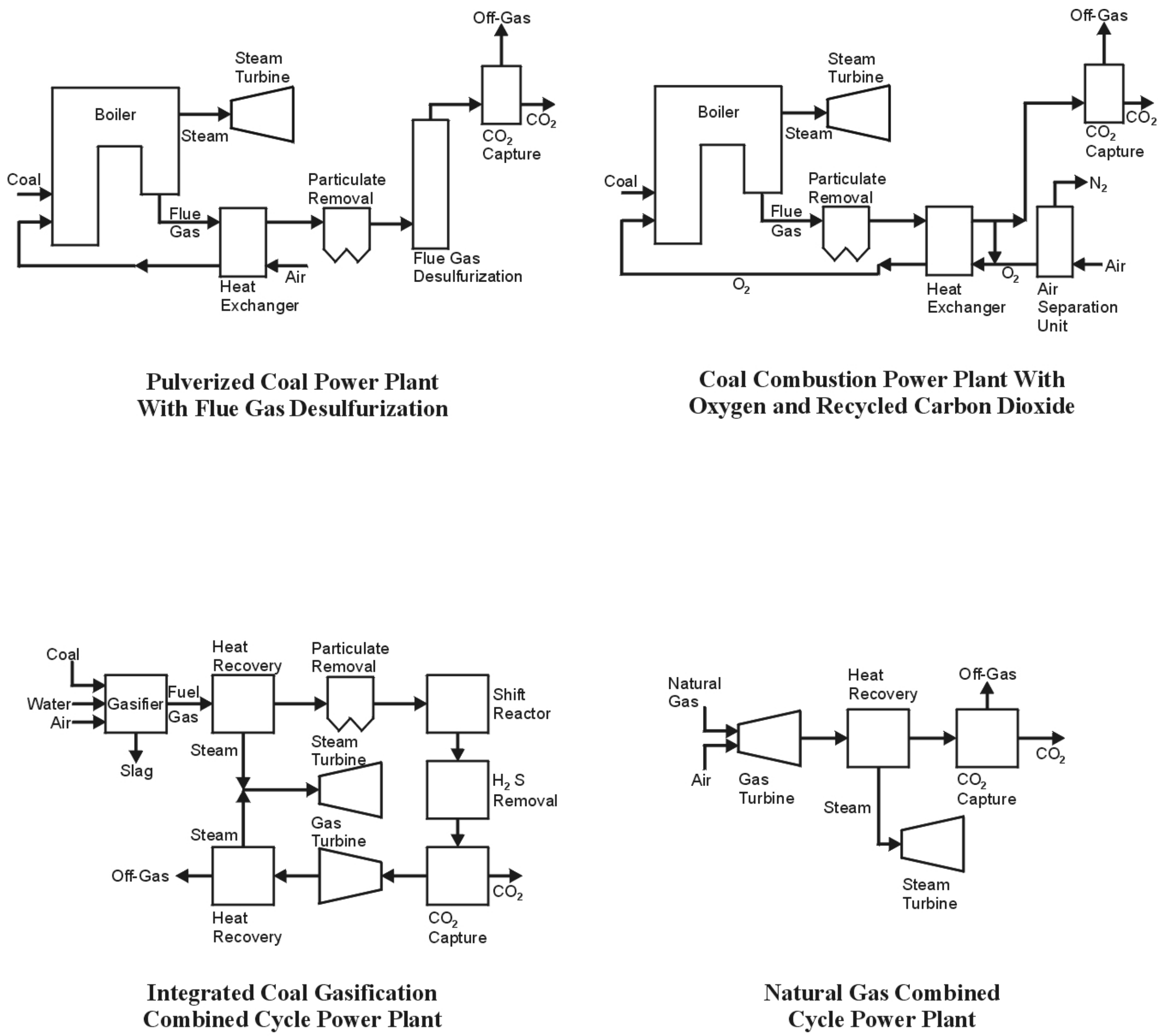

Figure 2. Illustrations of Four Types of Fossil Fuel Power Plants

- Compressibility and density of CO_2 show strong, nonlinear dependence on the system pressure and temperature.
- Condensation of liquid water in the presence of compressed CO_2 allows the formation of carbonic acid of sufficient strength to corrode carbon steel.
- Supercritical CO_2 damages many elastomer sealing materials.
- Petroleum-based and many synthetic lubricants can harden and become ineffective in the presence of supercritical CO_2.
- Careful design and installation of joints, seals and packing is required to prevent CO_2 leakage.
- Compressed CO_2 cools dramatically during decompression.
- Dry supercritical CO_2 has poor lubricating characteristics requiring special design features for compressors, pumps, and pipeline pigging equipment.
- Unlike flow in compressed gas pipelines, CO_2 pipeline flow can experience transients similar to “water hammer” that can occur during flow changes in liquid piping systems.

Table 2. Summary of CO_2 Capture Methods

Capture Process	Description	Comments
Chemical absorption	CO_2 captured using a reversible reaction between CO_2 and an aqueous solution of an amine or alkaline salt. The solution is regenerated and recirculated.	Used at the commercial scale to remove low concentrations of acid gases (e.g., CO_2) from natural gas. Solution tends to saturate with high CO_2 loading, so the process is more efficient for lower CO_2 concentrations
Physical absorption	CO_2 captured using physical dissolution in an absorption fluid. The fluid is regenerated and recirculated.	Used at the commercial scale to remove high concentrations of acid gases (e.g., CO_2) from natural gas. More efficient for high CO_2 partial pressure (i.e., concentration and/or pressure) Does not typically remove acid gases as completely as chemical or hybrid absorption
Hybrid absorption	CO_2 captured using a combination of chemical absorption and physical dissolution. The fluid is regenerated and recirculated.	Used at the commercial scale to remove intermediate concentrations of acid gases (e.g., CO_2) from natural gas.
Pressure swing adsorption	CO_2 captured on solid sorbent. The sorbent is loaded at high pressure and regenerated by pressure reduction and, in some cases, heating.	Used at the commercial scale to remove CO_2 and other impurities from H_2. Some H_2 cleanup processes also produce high purity CO_2.
Gas separation membrane	CO_2 captured by preferential permeation through a membrane. CO_2 is collected near atmospheric pressure as a permeate.	Used at the commercial scale to recover CO_2 used for enhanced oil recovery (EOR) (i.e., high CO2 concentration) Requires two or more separation stages to reach a CO_2 removal of 90% and purity of 99%, so the process typically is used for gas with high CO_2 content (e.g., PC/O_2 plants). Membranes are very sensitive to particulate fouling
Gas absorption membrane	The process involves using a microporuous membrane between the flue gas and an absorption fluid. CO_2 is preferentially removed from the gas stream by selective absorption in the fluid.	Innovative process Membrane separation unit is more compact than the tall towers needed for chemical or physical absorption due to high surface area allowed by membrane. Membranes are very sensitive to particulate fouling
Cryogenic separation	Flue gas is cooled and compressed to condense CO_2 which can then be captured and purified by distillation.	Used at the commercial scale to recover CO_2 used for EOR (i.e., high CO2 concentration) Gas fed to the cryogenic separation unit must be dehydrated to prevent formation of solids (e.g., ice and CO_2 clathrates) Due to energy needed to reach cryogenic conditions, cryogenic separation typically is used for gas with high CO_2 content (e.g., PC/O_2 plants)

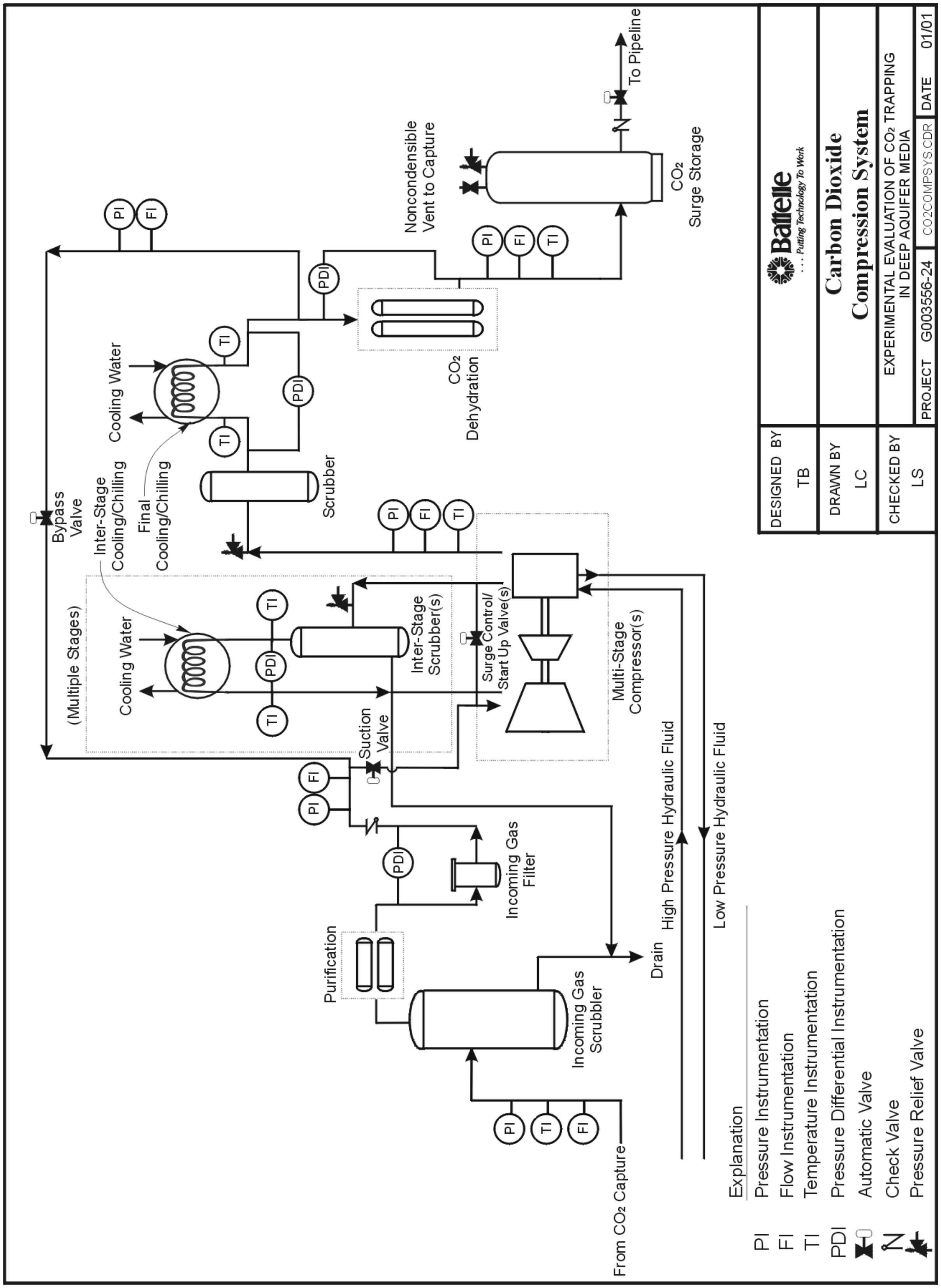

Figure 3. Carbon Dioxide Compression System

Methods to overcome these concerns have been developed during design and operation of pipelines used to move supercritical CO_2 for EOR projects (Mohitpour et al., 2000).

Equipment must be available at the injection site to accept pressurized CO_2 from the pipeline and transfer it to the injection well at the flow rate and pressure required for injection. The primary components are a pressurized surge storage tank, injection pumps (if needed), piping to distribute CO_2 to the injection wells, CO_2 flow control equipment, and equipment to monitor well condition. The need for injection pumps at the site depends on the depth to the injection zone. For sites shallower than about 1,500 m (4,920 ft), pipeline pressure should be adequate to allow injection. The conceptual arrangement of these components is shown in Figure 4.

The injection wells function as conduits for moving supercritical CO_2 fluid from the surface down into the deep saline aquifer. The well consists of three or more concentric casings (Figure 5) extending to various depths as follows:

- Exterior surface casing
- Intermediate protective (long-string) casing(s)
- Injection tubing (hang down tube).

The exterior surface casing is designed to protect underground sources of drinking water (USDWs) in surface aquifers that the well passes through and to reduce corrosion potential by preventing water contact with the intermediate protective casing. The exterior surface casing extends from the surface into the first competent aquitard below the deepest USDW and is cemented along is full length. The intermediate protective casing extends from the surface into the injection zone and is cemented along is full length. The injection tubing extends from the surface into the top of the injection zone. The injection tubing should be designed so as to be removable to facilitate well maintenance, if needed. The discharge end of the injection tubing is equipped with a backflow preventer to prevent CO_2 escape in the event of a well casing failure. Carbon dioxide injection wells will be regulated under the provisions of the Underground Injection Control (UIC) program under the Federal Safe Drinking Water Act (SDWA) as either Class I or Class V wells.

Determining the operating pressure at the top of the well requires consideration of the pressure required at the bottom of the well to force CO_2 into the injection zone, the pressure increase in the pipe due to the height of the CO_2 column, and the pressure loss due to flow in the pipe. The reported rate of pressure rise with depth in most reservoirs ranges from 0.105 to 0.124 bar/m (0.464 to 0.548 psi/ft) with a few sites having gradients as high as 0.23 bar/m (1.02 psi/ft) (Hendriks and Blok, 1993). Moving the CO_2 into the aquifer requires raising the CO_2 sufficiently above the in situ pressure to provide a driving force but not so high as to risk hydrofracturing the injection interval. Typically the CO_2 injection pressure is about 9 to 18% above the in situ pressure (Hendriks and Blok, 1993). Pressure caused by the weight of the column of CO_2 in the injection tubing provides some of the required pressure. This pressure contribution is a function of the density of the CO_2 at the pressure and temperature conditions in the injection tubing. The results of calculations to determine the well head pressure for various depths are shown in Table 3.

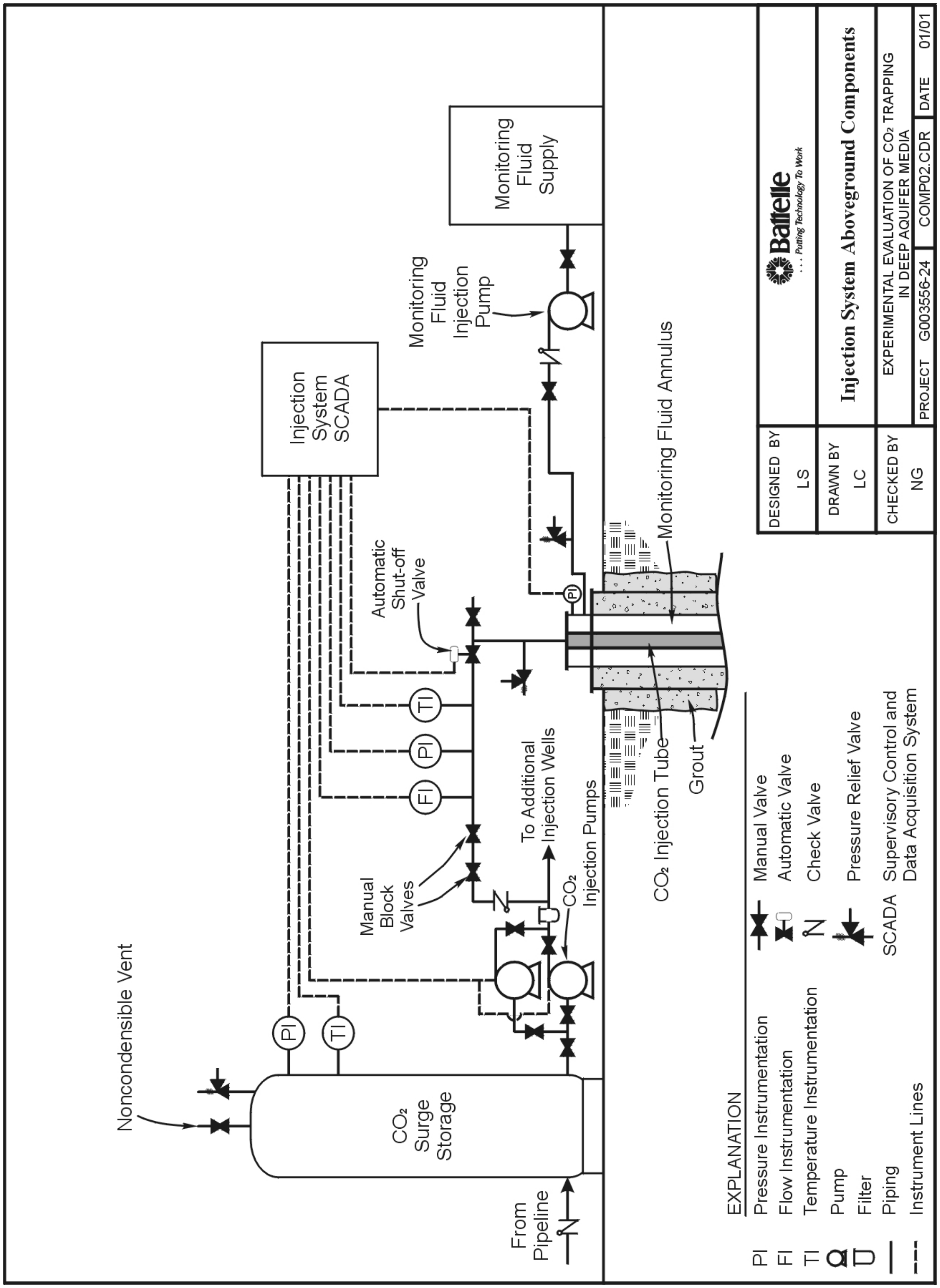

Figure 4. Injection System Aboveground Components

Table 3. Estimated Injection Tubing Pressure

Depth (m [ft])	CO_2 pressure at well head (MPa [psi])	CO_2 specific gravity at well head	CO_2 pressure at injection point (MPa [psi])	CO_2 specific gravity at injection point
1000 (3,281)	7.50 (1,090)	0.71	14.7 (2,140)	0.77
2,000 (6,562)	12.8 (1,860)	0.83	29.5 (4,278)	0.87
3,000 (9,843)	18.7 (2,710)	0.83	44.2 (6,417)	0.91

COST RESULTS

The EEA was conducted to review the status of existing technologies that could be used for CO_2 sequestration, develop a preliminary engineering concept for accomplishing the required operations, and estimate capital and operating costs for sequestration systems under various design condition. This review did not identify any technical obstacles to implementing CO_2 sequestration. Although injecting CO_2 into a deep saline aquifer is an emerging technology with limited application history, design, construction, operation, and maintenance of such a system can draw on a significant body of existing experience. Carbon dioxide injection into oil bearing formations to stimulate production has been done at the commercial scale in since the mid-1980's. These EOR operations use compression, dehydration, pipeline transmission, and deep well injection equipment that is, in many ways, directly analogous to the systems that will be needed for CO_2 sequestration.

The costs estimated for the scenarios analyzed for PC/FGD and IGCC plant in this EEA, reported as cost per metric ton of CO_2 avoided, are summarized in Table 4. The total cost for capture, compression, pipeline transmission, and injection (including capital and present worth of operating cost for 25 years at 4.1% interest) is $1.00 billion for a PC/FGD plant assuming a 15-km pipeline and 2,000-m injection depth. The total cost of sequestration for an IGCC plant is estimated as $0.583 billion. As indicated in the comparison shown in Table 5 and Figure 6, capture and compression is the most expensive portions of the sequestration system, with the greatest contribution coming from the capital and operating cost for the compressor and associated cooling and dehydration equipment. The cost to construct and operate injection wells contributes only a small portion of the total cost for the system. However, it is important to note that efficient injection requires that the CO_2 be in the form of a supercritical fluid so compression, cooling, and dehydration are required prior to injection and to overcome the in situ pressure of the formation. Therefore, even if the injection zone is directly under the power plant, the cost of the compression system must be incurred to allow injection.

The costs calculated in this study can be compared to the costs reported in the literature for CO_2 capture and compression. Costs from a variety of studies range from $33 to $72/metric ton of CO_2 avoided for PC/FGD plants and $21 to $62/metric ton of CO_2 avoided for IGCC plants (Gottlicher and Pruschek, 1999; Herzog, 1999). To directly compare the costs calculated for the EEA with the literature results the costs for transmission and injection would need to be deleted. However, capture and compression are the main contributors to cost, particularly for the shortest pipeline and shallowest injection case, so the adjustment is small. Even without adjustment, the EEA values are well within the range reported in the literature. With a small reduction to convert the estimates to a common basis, the EEA values would shift somewhat nearer the middle of the reported range.

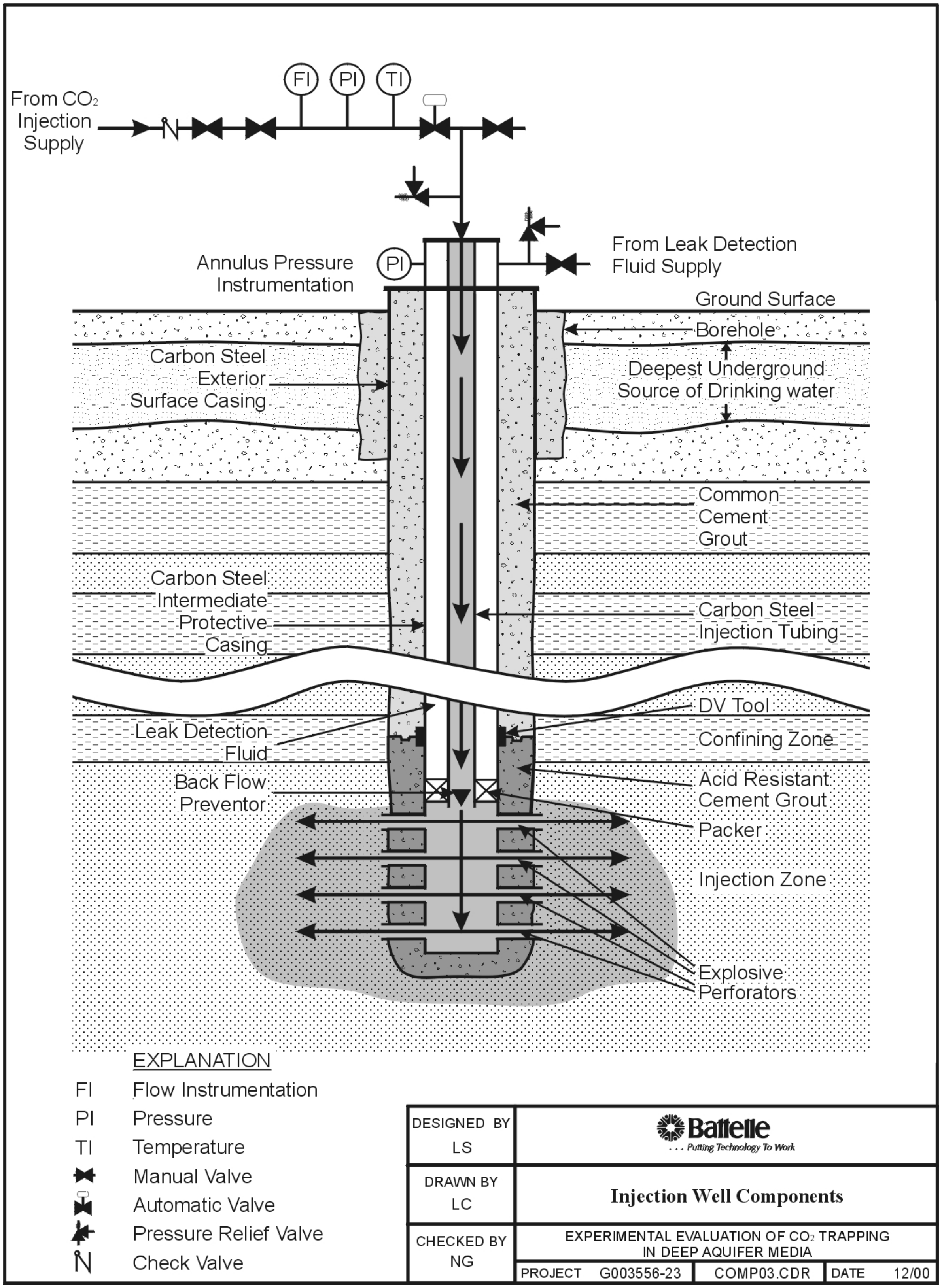

Figure 5. Injection Well Components

Table 4. Summary of Costs for Transmission/Sequestration Scenarios[(a)]

	Cost of CO_2 Avoided for Various Scenarios ($/metric ton)				
Well Depth (m/ft)	**15 km (9.3 mi) and Normal Terrain**	**100 km (62.1 mi) and Normal Terrain**	**400 km (249 mi) and Normal Terrain**	**15 km (9.3 mi) and Rocky/Hilly Terrain**	**15 km (9.3 mi) and Urban Terrain**
PC/FGD Plants[(b)]					
1,000/3,281	62.48	NA	NA	NA	NA
2,000/6,562	63.26	66.05	76.49	63.56	63.45
3,000/9,843	65.40	NA	NA	NA	NA
IGCC Plants[(c)]					
2,000/6,562	39.77	NA	NA	NA	NA

(a) NA indicates a cost estimate was not prepared for this case.
(b) Sequestration cases estimated for a 500 MWe plant burning pulverized coal with flue gas desulfurization and CO_2 capture by amine absorption
(c) Sequestration cases estimated for a 500 MWe IGCC plant and CO_2 capture by physical absorption

APPLICATION

The information collected during this project can serve as a starting point for the conceptual design of a CO_2 injection system. Reported experience with industrial handling and injection of CO_2 for commercial application (e.g., enhanced oil recovery [EOR]) did not indicate any technical obstacles to implementing CO_2 sequestration. Although injecting CO_2 into a deep saline aquifer is an emerging technology with limited application history, design, construction, operation, and maintenance of such a system can draw on a significant body of existing experience. Carbon dioxide injection into oil bearing formations to stimulate production has been done at the commercial scale in since the mid-1980's. These EOR operations use compression, dehydration, pipeline transmission, and deep well injection equipment that is, in many ways, directly analogous to the systems that will be needed for CO_2 sequestration.

Procedures for design and operation of CO_2 handling systems can, for the most part, be based on accepted practices used for hazardous liquids and gases in the oil and gas industry. However, some special properties of CO_2 require special design features for a sequestration system. Methods to account for these properties are well documented in the design of existing CO_2 pipeline and injection projects literature. Appropriate materials and methods have been developed to account for the special properties of CO_2.

The cost estimates developed for this project provide a preliminary budget evaluation (+50% to –30% accuracy) of the costs of sequestration of CO_2 from coal-fired power generation stations and a basis for assessing the effects of different storage conditions. For example, the tradeoff of increasing pipeline length (which increases transmission cost) to reach as shallower aquifer (which decrease injection cost) can be evaluated.

Table 5. Summary of Cost Contributions for CO_2 Sequestration[a,b]

Plant Type	Depth (m)	Pipeline Length (km)	Terrain Type	Cost for Capture ($mil/yr) A	Cost for Compression ($mil/yr) B	Cost for Capture and Compression ($mil/yr) C[c]	Cost for Pipeline ($mil/yr) D	Cost for Injection ($mil/yr) E	Total Cost ($mil/yr) F[d]
PC/FGD[e,f]	2,000	15	Normal	20.04	33.39		1.79	3.88	
Scenario totals						53.43			59.10
PC/FGD	2,000	100	Normal	20.04	33.39		7.66	3.88	
Scenario totals						53.43			64.97
PC/FGD	2,000	400	Normal	20.04	33.39		28.89	3.88	
Scenario totals						53.43			86.20
PC/FGD	1,000	15	Normal	20.04	33.39		1.79	2.79	
Scenario totals						53.43			58.01
PC/FGD	3,000	15	Normal	20.04	33.39		1.79	6.11	
Scenario totals						53.43			61.33
PC/FGD	2,000	15	Rocky	20.04	33.39		2.06	3.88	
Scenario totals						53.43			59.37
PC/FGD	2,000	15	Urban	20.04	33.39		2.19	3.88	
Scenario totals						53.43			59.50
IGCC[g]	2,000	15	Normal	4.07	28.28		1.79	3.59	
Scenario totals						32.35			37.73

(a) Capital costs annualized assuming a useful life of 25 yrs and an effective interest rate of 4.1% (capital recover factor = 0.0647)
(b) Totals not exact due to rounding
(c) C = A + B
(d) F = C + D + E
(e) These conditions are used as the base case. Variations from the base case are indicated by shading.
(f) 500 MWe conventional coal fired power plant with CO_2 capture by amine absorption.
(g) 500 MWe IGCC power plant with CO_2 capture by physical absorption.

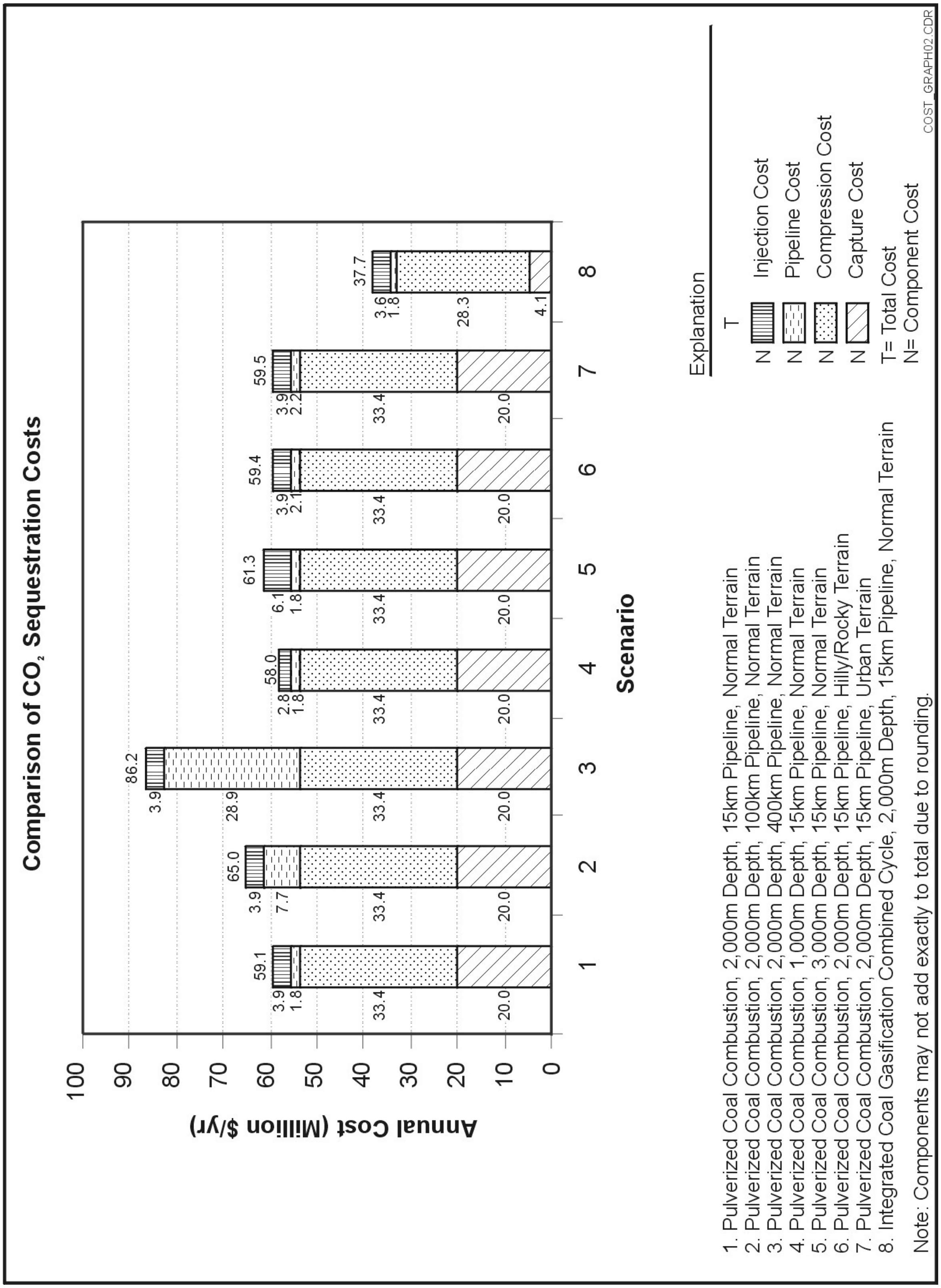

Figure 6. Comparison of Cost Elements in a CO_2 Sequestration System

FUTURE ACTIVITIES

Future activities related to this study will involve efforts to improve the accuracy of cost estimation for system to sequester CO_2 in deep saline aquifers. The review and evaluation of the current status of CO_2 handling and injection methods provides a firm engineering basis for conceptual design of processes and mechanical equipment to implement sequestration in a deep aquifer. More detailed understanding of the system performance requirements and design features will allow development of preliminary specifications to support more accurate cost estimation.

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