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The Economics of CO_2 Storage

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EXECUTIVE SUMMARY

The following storage options were evaluated in this study:

- Enhanced oil recovery
- Enhanced coalbed methane recovery
- Depleted oil reservoir storage
- Depleted gas reservoir storage
- Deep saline aquifer storage
- Ocean storage via pipeline
- Ocean storage via tanker

For each option, the CO_2 source is a nominal 500 MW_e gross Integrated Gasification Combined Cycle (IGCC) plant, operating at an 80 percent capacity factor. This plant delivers 7,389 tonnes of CO_2 per day. Given this source of CO_2, a baseline conceptual design was generated for each option. From the baseline conceptual design, capital and O&M costs, and an economic analysis with several figures of merits were developed. These were then used to develop sensitivity and life cycle analyses.

In the case of the ocean storage options, it is assumed that three IGCC power plants supply CO_2 to a shoreline collection point. Based on this, the ocean storage systems need to be designed to handle three times the quantity of CO_2, i.e. 22,167 tonnes of CO_2 per day.

METHODOLOGY

Pipeline Transport

The pipeline inlet CO_2 pressure is set equal to 152 bar, which is equivalent to the pressure of compressed CO_2 supplied by the IGCC plant. Based on a recommendation that the pipeline CO_2 pressure not be allowed to fall below 103 bar, this latter value is used for the pipeline outlet CO_2 pressure. The maximum allowable pressure drop per unit length is found as the difference between the pipeline inlet and outlet pressures divided by the pipeline length. The pipeline diameter is then calculated using the equations for pressure drop and head loss due to frictional resistance in a pipe, assuming turbulent flow.

Land construction cost data for natural gas pipelines are used to estimate construction costs for CO_2 pipelines. The cost data found for natural gas pipelines consists of cost estimates filed with the United States' Federal Energy Regulatory Commission (FERC), and reported in the Oil and Gas Journal. A regression analysis on this data yields a pipeline construction cost of $20,989/in/km ($33,853/in/mile). O&M costs are estimated to be $3,100/km ($5,000/mile), independent of pipeline diameter.

The total annual cost per tonne of CO_2 is found by annualizing the construction cost using a capital charge rate of 15 percent per year and adding this to the annual O&M cost. Figure 1 shows the cost per tonne of CO_2 per 100 km as a function of CO_2 mass flow rate. Economies of scale are reached with annual CO_2 flow rates in excess of 10 Mt (megatonnes or million metric tones) per year. At these flow rates, transport costs are less than $1 per tonne of CO_2 per 100 km. Note that the annual flows evaluated in this study are 2.16 Mt per year, corresponding to the

CO_2 output from the baseline IGCC plant. For this plant, the annual cost per tonne of CO_2 per 100 km is in the order of \$1.50 to \$2.

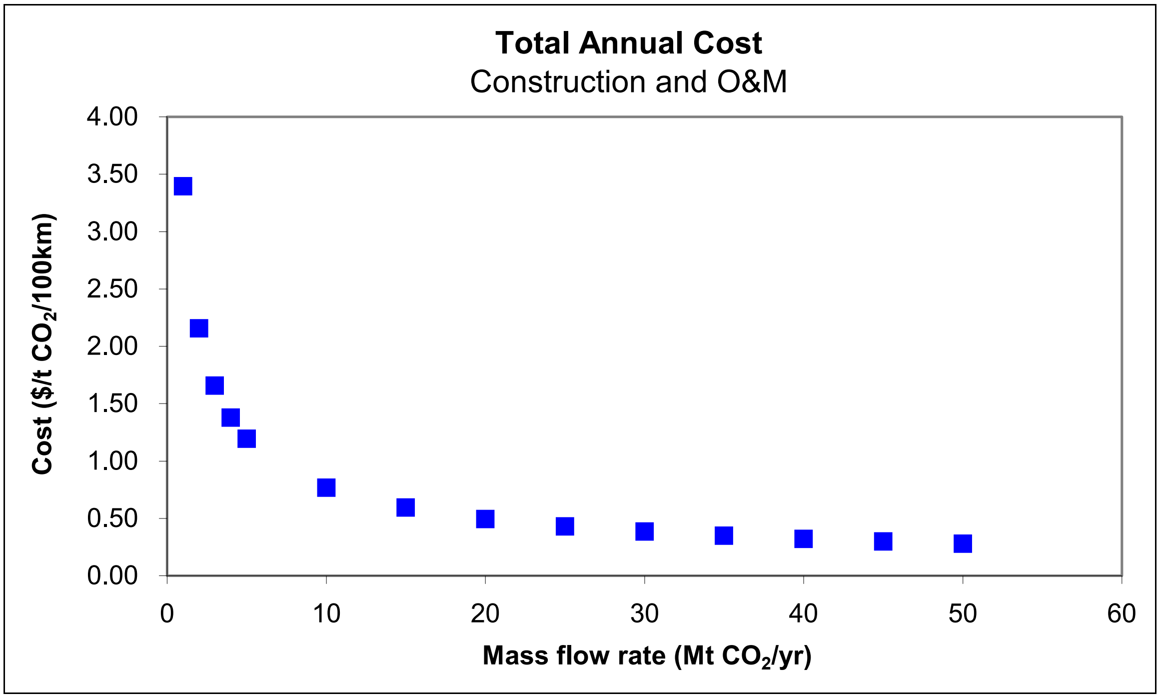

Figure 1: Cost for CO_2 transport via pipeline as a function of CO_2 mass flow rate

Enhanced Oil Recovery

For specific projects, the complex interactions between the injected CO_2 and reservoir oil are modeled to assess the likely performance of a proposed CO_2-EOR project. Based on the output of this modeling, the cost of the proposed CO_2 flood is calculated. However, for developing general costing algorithms, 'rules of thumb' are used to define the engineering parameters needed to estimate the cost of a CO_2-EOR project. These 'rules of thumb' have been derived based on information from experts in the field and the literature.

The method used for costing the EOR process can be split up into a number of steps. The illustration presented here uses numbers from the base case (see Table 1). First, the average amount of enhanced oil produced per day for the given CO_2 mass flow rate is determined using a CO_2 effectiveness factor of 170 scm (6,000 scf) of new CO_2 per bbl of enhanced oil. Second, the number of production wells is found by dividing this total amount of enhanced oil produced per day by an assumed average of 40 bbl of enhanced oil per day being produced at each well. Third, a ratio of producers to injectors of 1 to 1.1 is used to calculate the number of injection wells from the number of production wells. Fourth, the capital cost of the CO_2 recycle plant is determined based on a maximum CO_2 recycle ratio of 3, with an average recycle ratio of 1.1 being used for the plant's O&M costs. Finally, the capital and O&M costs associated with the wells and the field equipment are calculated.

The EIA 'Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations' (Energy Information Administration [Office of Oil and Gas], 2000) report was used as the basis for field equipment and production operations costs. Costs and indices for additional secondary oil recovery equipment and its operation were provided for a representative lease, located in west Texas. This lease, or module, comprises 10 production wells, 11 water injection wells and 1 disposal well, and the wells are nominally 1,219 m (4,000 ft) deep.

Table 1 defines three cases, a base case, a high cost case and a low cost case. EOR operating data were analyzed to determine a base case and range for each critical variable. These values were then used to define the cases described in Table 1. Costs for EOR and the other CO_2 storage options assessed in this project were calculated on a CO_2 equivalent life-cycle, greenhouse gas-avoided basis.

Table 1: EOR case descriptions and costing results

Parameter	**Units**	**EOR Base Case**	**EOR High Cost Case**	**EOR Low Cost Case**
CO_2 Effectiveness	scm/bbl enhanced oil	170	227	85
Oil Production per Well	bbl enhanced oil/day/well	40	20	70
Maximum Recycle Ratio		3	4	1
Oil Price	$/bbl	15	12	20
Depth	m	1,219	2,438	610
Pipeline Distance	km	100	300	0
Previous Waterflooding		Yes	No	Yes
Total Oil Production*	bbl enhanced oil/day	22,142	16,582	44,285
Number of 10/11 Well Modules*		56	83	64
New CO_2*	scm/day/module	68,000	45,000	59,000
Maximum Recycled CO_2*	scm/day/module	204,000	182,000	59,000
Levelized Annual CO_2 Net Storage Cost*	$/tonne CO_2 eq. LC GHG avoided	(12.21)	73.84	(91.26)

* calculated

Enhanced Coalbed Methane Recovery

As in the case of the CO_2-EOR concept design, 'rules of thumb' are used to define the engineering parameters needed to estimate the cost of a CO_2-ECBMR project. The illustration presented here uses numbers from the base case (see Table 2). First, the total amount of enhanced CBM produced per day for the given CO_2 mass flow rate is determined using a CO_2 effectiveness factor of two scm CO_2 per scm of enhanced CBM. Second, the number of production wells is found by dividing this total amount of enhanced CBM produced per day by an assumed 14,000 scm of enhanced CBM per day being produced at each well. Third, a ratio of producers to injectors of 1 to 1 is used to calculate the number of injection wells from the number of production wells. Fourth, it is assumed that no recycling of CO_2 is required. Finally, the cost of drilling and equipping the required production and injection wells is calculated.

Prior to acquiring a lease position, geological expenditures, geophysical expenditures and engineering-based feasibility studies are often conducted. In addition, outlays are generally required for obtaining the lease and its associated permits. These front-end costs will vary greatly but may range from $20,000 to $30,000 per well for a commercial project. For this study, a cost of $25,000 per well is assumed.

All of the other field costs, except for the well drilling cost, are based on data contained in the EIA 'Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations' report. A representative ECBMR lease, or module, comprising 10 CO_2 injection wells and 10 producing wells with dewatering facilities is used for the design basis. The 10 CO_2 injection wells are drilled to a depth of 610 m and equipped with a battery of lease equipment, which includes distribution lines, headers, electrical service and controls. The 10 producing wells, also drilled to a depth of 610 m, are equipped with beam balanced/sucker rod dewatering.

The well drilling cost is calculated based on a relationship derived from data contained in the '1998 Joint Association Survey (JAS) on Drilling Costs' report (American Petroleum Institute – Policy Analysis and Statistics Department, 1999). This relationship between well depth and drilling cost is shown in Figure 2. To determine the relationship, a regression analysis was performed on drilling cost data for onshore gas and oil wells. The total well drilling cost is found by multiplying the cost of drilling a single well for the given reservoir depth, taken from the graph, by the required number of wells.

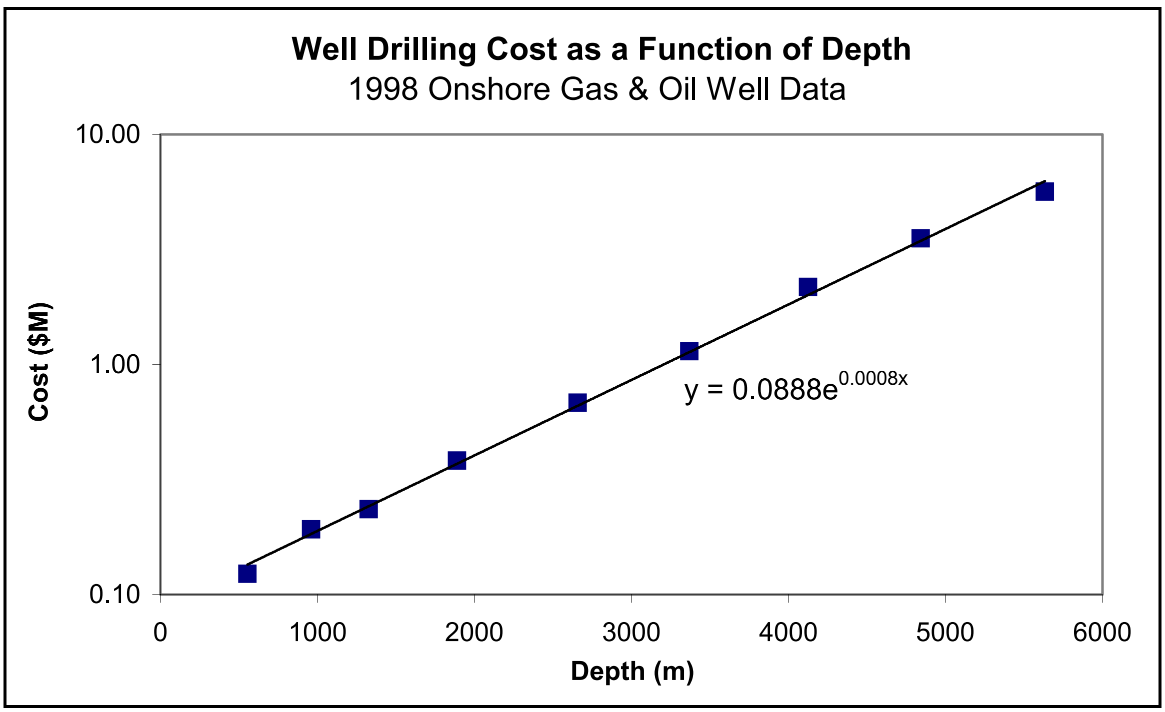

Figure 2: Well drilling cost as a function of depth

Table 2 defines a base case, a high cost case and a low cost case derived from an analysis of typical ECBMR operating data.

Table 2: ECBMR case descriptions and costing results

Parameter	Units	ECBMR Base Case	ECBMR High Cost Case	ECBMR Low Cost Case
CO_2 Effectiveness	scm/scm enhanced CBM	2	10	1.5
CBM Production per Well	scm enhanced CBM/day/well	14,000	3,000	30,000
Gas Price	$/$10^6$ BTU	2	1.80	3
Depth	m	610	1,219	610
Pipeline Distance	km	100	300	0
Total CBM Production*	million scm enhanced CBM/day	1.88	0.38	2.51
Number of 10/10 Well Modules*		135	126	84
Number of CO_2 Wells*		135	126	84
New CO_2*	scm/day/well	28,000	30,000	45,000
Levelized Annual CO_2 Net Storage Cost*	$/tonne CO_2 eq. LC GHG avoided	(5.59)	18.88	(25.72)

* calculated

Depleted Gas/Oil Reservoir and Saline Aquifer Storage

Depleted natural gas and oil reservoirs, and deep saline aquifers, differ quite substantially from each other in terms of typical values of reservoir parameters, such as pressure, thickness, depth and permeability. However, the processes that govern the rate at which CO_2 can be injected into a well, and thus the number of wells required, are essentially identical for the three types of reservoir. Given this, the same costing methodology is applied to each of the three geologic CO_2 storage options.

The cost model for the geologic CO_2 storage options can be broken down into a number of components. First, there is a relationship for calculating the number of wells required for a given CO_2 flow rate, CO_2 downhole injection pressure and set of reservoir parameters. Second, an iterative procedure is used to take into account the interdependent relationship between CO_2 downhole injection pressure and well number. Third, a set of capital and O&M cost factors are used to determine the cost based on the number of wells.

The well number calculation requires inputs for CO_2 mass flow rate, CO_2 downhole injection pressure, and reservoir pressure, thickness, depth, and permeability. The relationship shown in Figure 3 is used to determine CO_2 injectivity from CO_2 mobility. CO_2 injectivity is defined as the mass flow rate of CO_2 that can be injected per unit of reservoir thickness and per unit of downhole pressure difference. CO_2 mobility is defined as the CO_2 absolute permeability divided by the CO_2 viscosity. Given the CO_2 injectivity, the CO_2 injection rate per well can be calculated. Finally, the number of wells required is determined.

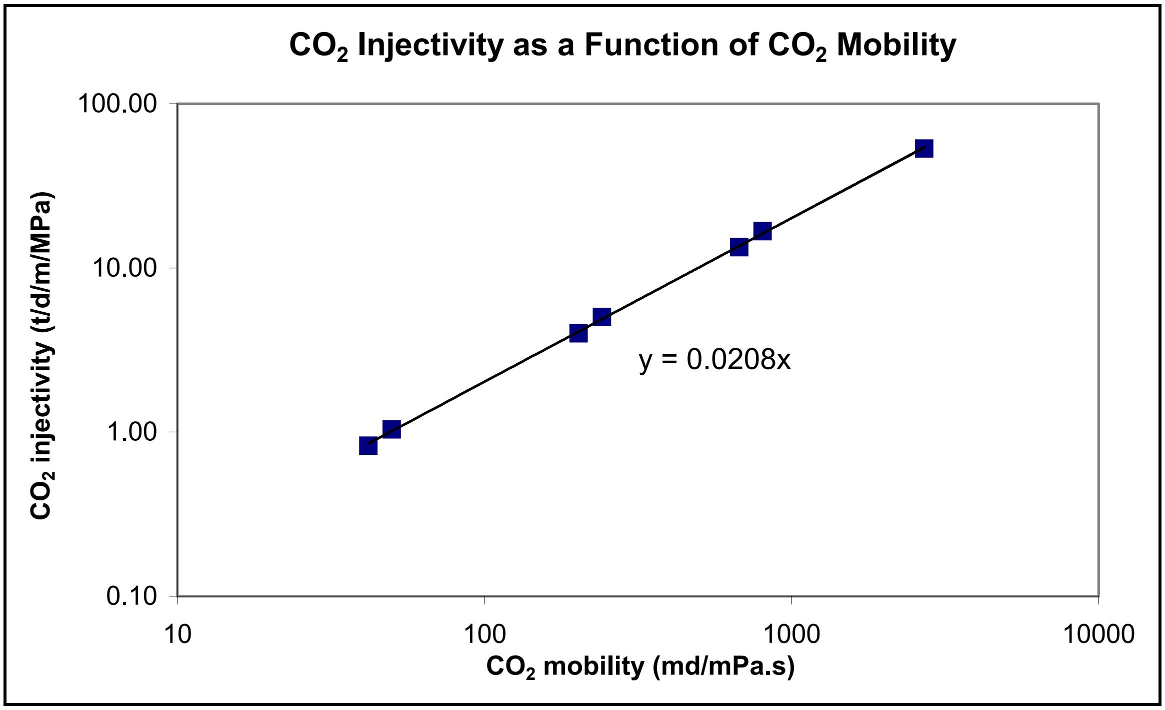

Figure 3: CO_2 injectivity as a function of CO_2 mobility (Law and Bachu, 1996)

The capital cost for site screening and evaluation is based on an estimate given in a recent study by the Battelle Memorial Institute (Smith, 2001). This study estimated the costs for preliminary site screening and candidate evaluation at $1,685,000.

All of the other costs, except for well drilling cost, are calculated based on values given in the EIA 'Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations' report. Average lease equipment costs and O&M costs were developed on a per well basis. In the case of the injection equipment and surface maintenance, these average cost values are adjusted to take into account the number of wells. Similarly, the average cost value for subsurface maintenance is adjusted to take into account the well depth. The well drilling cost is calculated based on the relationship derived from data contained in the '1998 Joint Association Survey (JAS) on Drilling Costs' report.

Table 3, Table 4 and Table 5 define a base case, a high cost case and a low cost case derived from an analysis of typical data for depleted gas reservoirs, depleted oil reservoirs, and deep brine aquifers, respectively.

Table 3: Depleted gas reservoir case descriptions and costing results

Parameter	Units	Gas Reservoir Base Case	Gas Reservoir High Cost Case	Gas Reservoir Low Cost Case
Pressure	MPa	3.5	6.9	2.1
Thickness	m	31	15	61
Depth	m	1,524	3,048	610
Permeability	md	1	0.8	10
Pipeline Distance	km	100	300	0
Injection Rate per Well*	t/d	156	57	2,975
Number of Wells*		48	129	3
Levelized Annual CO_2 Storage Cost*	\$/tonne CO_2 eq. LC GHG avoided	4.87	19.43	1.20

* calculated

Table 4: Depleted oil reservoir case descriptions and costing results

Parameter	Units	Oil Reservoir Base Case	Oil Reservoir High Cost Case	Oil Reservoir Low Cost Case
Pressure	MPa	13.8	20.7	3.5
Thickness	m	43	21	61
Depth	m	1,554	2,134	1,524
Permeability	md	5	5	19
Pipeline Distance	km	100	300	0
Injection Rate per Well*	t/d	360	115	5,690
Number of Wells*		21	65	2
Levelized Annual CO_2 Storage Cost*	\$/tonne CO_2 eq. LC GHG avoided	3.82	11.16	1.21

* calculated

Table 5: Deep saline aquifer case descriptions and costing results

Parameter	Units	Aquifer Base Case	Aquifer High Cost Case	Aquifer Low Cost Case
Pressure	MPa	8.4	11.8	5.0
Thickness	m	171	42	703
Depth	m	1,239	1,784	694
Permeability	md	22	0.8	585
Pipeline Distance	km	100	300	0
Injection Rate per Well*	t/d	9,363	82	889,495
Number of Wells*		1	91	1
Levelized Annual CO_2 Storage Cost*	\$/tonne CO_2 eq. LC GHG avoided	2.93	11.71	1.14

* calculated

Ocean Storage Via Pipeline

The ocean pipeline storage option assumes that three IGCC power plants supply CO_2 to a shoreline collection point. The CO_2 is then transported via a subsea pipeline from the shoreline to a depth of 2,000 m, at which depth the CO_2 is discharged into the deep ocean via a diffuser unit. The method used for calculating the cost of this process can be broken down into a two steps. First, the diameter of the subsea pipeline is determined. It is then possible, as a second step, to calculate the capital and O&M costs, as well as the cost per tonne of CO_2.

The pipeline diameter is calculated using the same method as is used in the CO_2 overland pipeline transport model. The only difference is the means by which the maximum allowable pressure drop per unit length is determined. In the case of CO_2 overland pipeline transport, the pressure drop per unit length is simply found as the difference between the pipeline CO_2 inlet and outlet pressures divided by the pipeline length. The pipeline ocean CO_2 storage model however requires that the pressure drop per unit length calculation also take into account the gravity head gain and diffuser head loss. In addition, it is necessary that the CO_2 be discharged at a pressure equal to the hydrostatic pressure.

The cost of the subsea pipeline has been determined based on cost information contained in McDermott's phase II final report on 'Large-scale CO_2 Transportation and Deep Ocean Sequestration' (Sarv, 2001). The capital cost of an injector unit, based on an estimate given in an IEA report, (Omerod, 1994) is taken to be $14.5 million.

Table 6 gives a base case, a high cost case and a low cost case for ocean storage via pipeline.

Table 6: Ocean Pipeline Storage Case Descriptions and Costing Results

Parameter	**Units**	**Ocean Pipeline Base Case**	**Ocean Pipeline High Cost Case**	**Ocean Pipeline Low Cost Case**
Pipeline Distance	km	100	300	0
Offshore Distance	km	100	300	50
Pressure Drop per Unit Length*	Pa/m	126	42	251
Pipe Diameter*	inches	14.2	17.5	12.4
Nominal Pipe Size*	inches	16	20	14
Levelized Annual CO_2 Storage Cost*	\$/tonne CO_2 eq. LC GHG avoided	5.53	14.23	2.90

* calculated

Ocean Storage Via Tanker

The ocean tanker storage option has been modeled based on design and cost information obtained from McDermott's Phase I (Sarv, 1999) and Phase II (Sarv, 2001) final reports on 'Large-scale CO_2 Transportation and Deep Ocean Sequestration', as well as e-mail communications with the reports' author. The method used for a conceptual design of this process can be broken down into a number of steps. First, the number of tankers required to transport the CO_2 to the offshore platform is determined. Second, the diameter of the vertical pipe to carry the CO_2 from the platform to the injection depth is calculated. Third, the amount of CO_2 emitted by the tankers traveling to and from the offshore storage site, and emitted due to boil off, is found. It is then possible, as a final step, to calculate the capital cost of the tankers, port facility, offshore floating platform and vertical pipe, and the non-fuel and fuel O&M costs as well as the cost per tonne of CO_2.

The total capital cost of the tanker ocean storage option comprises the capital cost of the three required tankers, the offshore floating platform, the port facility, and a 2,000-m long, 8-inch diameter vertical pipe. The total O&M cost is calculated as the sum of the non-fuel and fuel O&M costs. From e-mail communications with Hamid Sarv of McDermott, it was learnt that the total annual O&M cost in the case studies was taken as the sum of 5.6 percent and 0.02 percent of the total tanker and non-tanker capital costs, respectively, where the fuel cost comprised 16.5 percent of the tanker O&M cost. The non-fuel O&M cost is calculated in the model as 4.7 percent of the total tanker capital cost, thus excluding the fuel cost, plus 0.02 percent of the total non-tanker capital costs. The fuel O&M cost is determined as the product of the total annual fuel usage, found from multiplying the tanker fuel usage by the total annual distance traveled, and a diesel fuel price of $0.566 per gal.

Table 7 defines a base case, a high cost case and a low cost case for the ocean tanker storage option.

Table 7: Ocean tanker storage case descriptions and costing results

Parameter	**Units**	**Ocean Tanker Base Case**	**Ocean Tanker High Cost Case**	**Ocean Tanker Low Cost Case**
Pipeline Distance	km	100	300	0
Offshore Distance	km	100	300	50
Boil Off	%/day	1	2	0.5
Diesel Price	$/gal	0.566	0.8	0.45
Number of Tankers*		3	3	3
Total Annual Fuel Usage*	gal/yr	249,001	747,004	124,501
CO_2 Emitted by Tankers*	t/yr	2,395	7,186	1,198
CO_2 Emitted by Boil Off*	t/yr	53,362	139,415	24,638
Levelized Annual CO_2 Storage Cost*	$/tonne CO_2 eq. LC GHG avoided	17.64	22.79	15.76

* calculated

SUMMARY OF RESULTS

Figure 4 and Figure 5 summarize the results for the cost of the various carbon storage technologies analyzed in this study on a life-cycle, greenhouse gas-avoided basis. Figure 4 includes all the direct storage technologies, while Figure 5 expands the scale for storage technologies with no commercial by-products. The points on the graphs are for the base case conditions, while the bars represent the range between the high and low cost cases as outlined in the Tables above.

Several observations about these results are offered:

- Excluding the more expensive ocean tanker option, the typical base case costs for CO_2 storage (transport and injection) without oil or gas by-product credit is in the range of $3 to $5.50 per tonne CO_2 ($11 to $20 per tonne C). The cost range can be characterized as $2 to $15 per tonne CO_2 ($7 to $55 per tonne C).

- With a by-product credit for the gas or oil, the credit will offset the storage costs in many instances. For example, in the base EOR case, one can afford to pay $12.21 per tonne of CO_2 and still break even (i.e., the costs equal the by-product credit).

- With an oil or gas by-product, the net costs have a wide large range. The parameters most responsible for this variability are the by-product (i.e., the gas or oil) price and the ratio of CO_2 stored to the oil or gas produced. With more oil or gas produced per unit of CO_2 stored, the lower net CO_2 storage cost, but the less CO_2 stored.

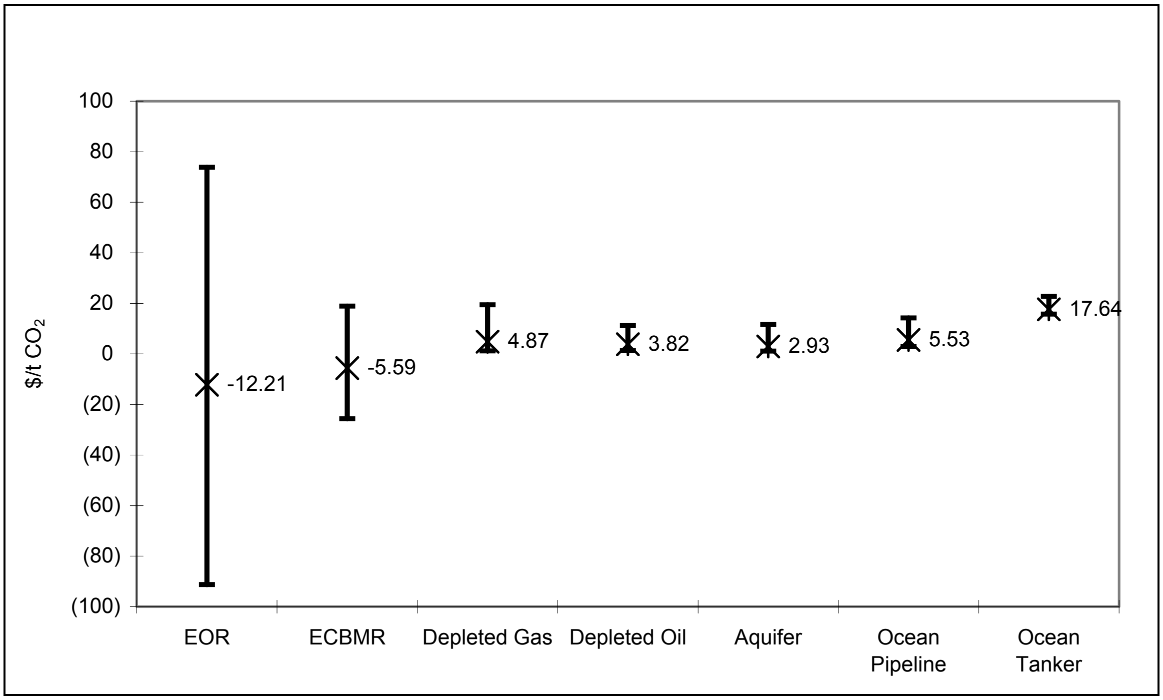

Figure 4: Levelized annual cost comparison of carbon sequestration technologies

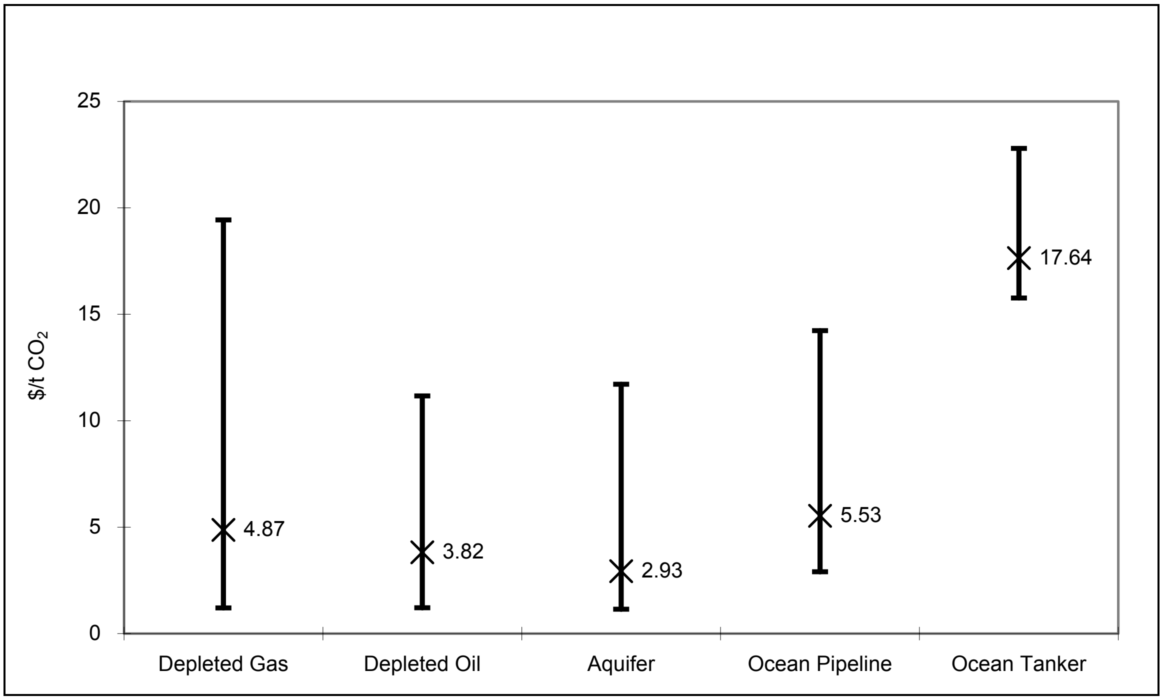

Figure 5: Levelized annual cost comparison of carbon sequestration technologies

1. STORING CAPTURED CO_2 – BASIS & APPROACH

1.1 TECHNOLOGIES EVALUATED

The following transportation and injection technologies for captured CO_2 were evaluated in this study:

- Overland pipeline transport (Chapter 2)
- Enhanced oil recovery (Chapter 3)
- Enhanced coalbed methane recovery (Chapter 4)
- Depleted oil reservoir storage (Chapter 5)
- Depleted gas reservoir storage (Chapter 5)
- Deep saline aquifer storage (Chapter 5)
- Ocean storage via pipeline (Chapter 6)
- Ocean storage via tanker (Chapter 7)

Two other potential sequestration options, mineralization and ocean fertilization were not included in the evaluation because it was determined that there was not enough information at this time to develop meaningful conceptual designs and cost estimates.

Initially, coalbed methane was also to be excluded from the study. However, a recent IEA Greenhouse Gas R&D Programme Report (Advanced Resources International, 1998) assessed the potential of enhanced coalbed methane recovery with CO_2 sequestration and concluded, "Injection of carbon dioxide into deep coal seams has the potential to enhance coal-bed methane recovery, while simultaneously sequestering carbon dioxide. Analysis of production operations from the world's first carbon dioxide-enhanced coal-bed methane demonstration plant, in the San Juan Basin, indicates that the process is technically and economically feasible. A recent pilot scheme in Alberta, Canada, should also help to confirm the technical and economic data of this process." Thus, while there is still uncertainty about the effectiveness of CO_2 in enhancing the recovery of coalbed methane, the potential of the technology is such that it was included in the study.

1.2 APPROACH

Two key components of all the geologic storage options are the injection/production wells and field equipment/production operations. Two annual surveys, "Joint Association Survey on Drilling Costs" (American Petroleum Institute, 1999) and "Costs and Indices for Domestic Field Equipment and Production Operations" (Energy Information Administration, 2000), have for many years tracked costs for drilling and operating domestic oil and gas fields. These costs are disaggregated by depth, region, well type, and production rate. The options were tied as closely as possible to these surveys to provide both up-to-date costs and indices that measure the increase or decrease in costs from year to year.

A key component of all the options, including the ocean storage options, is the pipeline used to transport the captured CO_2. The MIT Pipeline Transport Model (Greden, 2000) was used for pipeline sizing and costs.

For each option, a baseline conceptual design was generated based on the assumptions discussed below. From the baseline conceptual design, capital, O&M costs and an economic analysis with several figures of merits were developed in a spreadsheet format. These were then used to develop sensitivity analyses and life cycle analyses, again in a spreadsheet format.

1.3 COMMON DESIGN BASIS

A nominal 500 MW_e gross integrated gasification combined cycle (IGCC) plant operating at an 80 percent capacity factor was utilized as the production source of CO_2. This was based on the DOE/EPRI's recent study on the "Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal" (EPRI, 2000). Table 8 shows a summary of the parameters used in this study taken from the DOE/EPRI report for Case 3a, "IGCC with CO_2 Removal".

Table 8: Summary of parameters for IGCC power plant with CO_2 removal

Parameter	Unit	Value
Thermal Input, HHV	10^6 Btu/hr	3,723
Gross Power Output	MW	490.4
Net Power Output	MW	403.5
Efficiency, HHV	%	37.0
Capacity Factor	%	80
CO_2 Captured	t/d	7,389
	million scm/d	3.76
CO_2 Emitted	kg/kWh	0.073
CO_2 Avoided in Capture	t/d	6,246
CO_2 Capture Cost	$/t captured	14.55
CO_2 Capture Cost	$/t avoided in capture	17.21
Plant Life	Yr	20
Capital Charge Factor	%	15.0
Fuel Cost	$/MMkJ	1.18
Fuel Real Esc. Rate	%/yr	0.00
Fuel Levelization Factor		1.00
TPC	$/kW	1,642
Fixed O&M	$/kW-yr	32.98
Variable O&M	$/MWh	3.90
Heat Rate, HHV	kJ/kWh	9,727
Capital	$/MWh	35.04
O&M	$/MWh	8.61
Fuel	$/MWh	11.44
Levelized Cost of Electricity (LCOE)	$/MWh	55.08

The baseline IGCC plant produces two streams of CO_2 from the double-stage Selexol acid gas removal process. One stream is at 3.4 bar (50 psi), while the second stream at 1.0 bar (15 psi) is boosted to 3.4 bar (50 psi). The combined 3.4 bar (50 psi) CO_2 streams are further compressed and dehydrated in a multi-stage, inter-cooled compressor to 83 bar (1,200 psi). The total amount of CO_2 recovered from the IGCC plant to be sequestered is 7,389 tonnes per day.

Referring to Figure 6, the CO_2 at 83 bar (1,200 psi) and 41°C (105°F) is above the critical point of 31.1°C (88°F) and 73.0 bar (1,073 psi). By increasing the pressure to 152 bar (2,200 psi) and 38°C (100°F) or less, the pipeline pressure can drop to about 103 bar (1,500 psi) before recompression, and the CO_2 is ensured of retaining the flow properties of supercritical CO_2. The boost compression adds an additional power requirement of 2,650 kW_e. The CO_2 stream is dried to a -40°C dewpoint, and contains N_2<300 ppmv, O_2<40 ppmv, and Ar<10 ppmv to prevent corrosion.

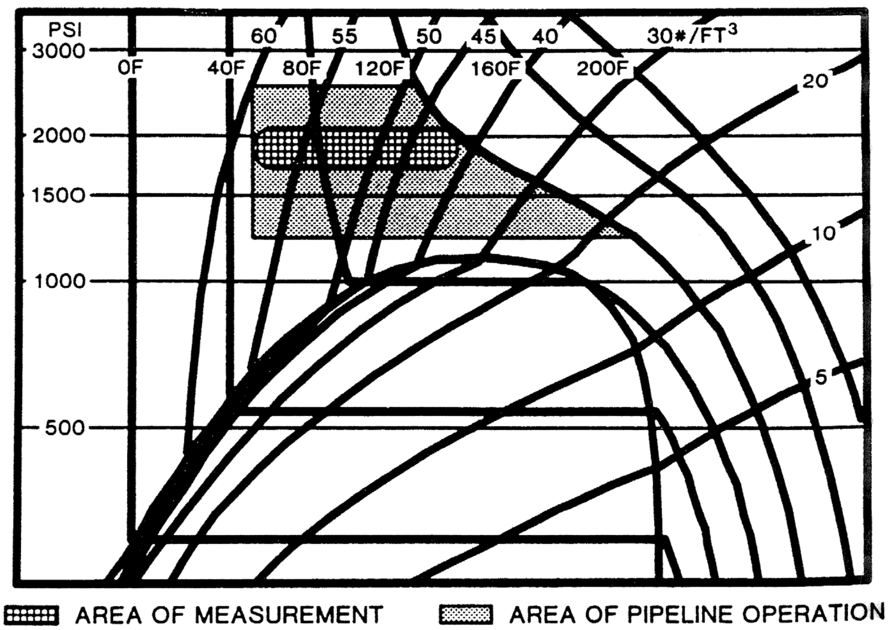

Figure 6: Carbon dioxide pressure enthalpy diagram

1.4 REPORTING BASIS

The costs of CO_2 transport and injection for the various CO_2 storage options can be assessed on several bases. A CO_2 captured basis simply gives the costs for the total amount of CO_2 stored. A CO_2 avoided basis takes into account the CO_2 emissions generated by the storage operation, specifically the CO_2 associated with energy use[1] and, in the case of ocean storage via tanker, boil-off (see Section 7.4.3). It is also possible to give the costs on a life-cycle greenhouse gas avoided (LC GHG) basis, which adds the costs of embedded energy in addition to direct CO_2 emissions, and is the basis used in this report. For the results presented, the difference between CO_2 storage costs on a LC GHG avoided basis and a CO_2 avoided basis is very small, i.e. in the range of 0-6¢ per tonne of $CO_{2.}$

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[1] It is assumed that the energy used comes from the base IGCC plant.

2. PIPELINE TRANSPORT

2.1 INTRODUCTION

This chapter looks at the transport of CO_2 via pipeline from the base case IGCC power plant to the injection site, for geologic storage, or the shoreline collection point, in the case of ocean storage.

2.2 STATE OF THE ART

Over 110 million standard cubic meters (scm) per day of CO_2 are transported by pipeline in the United States, frequently for distances greater than 100 km. Details of currently operating CO_2 pipelines in the United States are given in Table 9 (Moritis, 2001; Kinder Morgan CO_2 Company, 2000; IEAGHG, 2001; Stevens et al, 2001; Petro Source Corporation, 1998; EPRI, 1999).

Table 9: CO_2 pipelines in the United States

Name	Operator	Route	CO_2 Source	Length (km)	Diameter (in)	Capacity (10^6 scm per day)
Cortez Pipeline (Moritis, 2001)	Kinder Morgan CO_2	McElmo Dome to Denver City CO_2 Hub	Natural CO_2 deposit	311	30	28
McElmo Creek Pipeline (Moritis, 2001)	ExxonMobil	McElmo Dome to McElmo Creek Unit (UT)	Natural CO_2 deposit	25	8	2
Bravo Pipeline (Moritis, 2001)	BP	Bravo Dome to Denver City CO_2 Hub	Natural CO_2 deposit	135	20	11
Sheep Mountain I (Moritis, 2001)	BP	Sheep Mountain Field to Rosebud connection with Bravo Dome	Natural CO_2 deposit	114	20	9
Sheep Mountain II (Moritis, 2001)	BP	Rosebud connection to Denver City CO_2 Hub and onward to Seminole San Andres Unit (TX)	Natural CO_2 deposit	139	24	14
Central Basin Pipeline (Moritis, 2001)	Kinder Morgan CO_2	Denver City CO_2 Hub to McCamey, TX	-	-	26,16	17
Este Pipeline (Moritis, 2001)	ExxonMobil	Denver City CO_2 Hub to Salt Creek, TX	-	74	12,14	7
Slaughter Pipeline (Moritis, 2001)	ExxonMobil	Denver City CO_2 Hub to Hockley County, TX	-	25	12	5
West Texas Pipeline (Moritis, 2001)	Trinity Pipeline	Denver City CO_2 Hub to Reeves County, TX	-	79	12,8	3
Llano Lateral Pipeline (Moritis, 2001)	Trinity Pipeline	runs off Cortez main line to Llano, NM	Natural CO_2 deposit	33	12,8	3
Canyon Reef Carriers Pipeline (Moritis, 2001)	Kinder Morgan CO_2	McCamey, TX to SACROC field	-	87	16	7
Val Verde Pipeline (Petro Source Corporation, 1998; EPRI, 1999)	PSCC	connects Mitchell, Gray Ranch, Pucket and Terrell gas processing facilities to Canyon Reef Carriers main line	Gas processing facilities	51	10	4
Weyburn Pipeline (IEAGHG, 2001)	Dakota Gasification Company	Great Plains Synfuels plant (Beulah, ND) to Weyburn field (Saskatchewan, Canada)	Coal gasification plant	330	14,12	3
Choctaw Pipeline (Stevens et al, 2001)	Denbury Resources	Jackson Dome to Bayou Choctaw Field, LA	Natural CO_2 deposit	115	20	6

Transported CO_2 is most commonly used for enhanced oil recovery (EOR). The use of CO_2 for EOR is a proven technology with 72 CO_2 floods in the United States (Oil and Gas Journal, 2000) Most of these floods are dependent upon naturally occurring CO_2, which is obtained from high-pressure, high-purity underground deposits. The most important of these natural CO_2 deposits, in decreasing order of current production, are the McElmo Dome, the Bravo Dome, the Sheep Mountain Field and the Jackson Dome (Stevens, 2001; Kinder Morgan CO_2 Company, 2001). A small fraction of the CO_2 supply comes from anthropogenic sources, including the Mitchell, Gray Ranch, Pucket and Terrell gas processing facilities in the southern Permian basin and the Great Plains coal gasification plant at Beulah, North Dakota (IEAGHG, 2001; EPRI, 1999).

The operation of the Canyon Reef Carriers pipeline, one of the first CO_2 pipelines constructed for EOR, provides a reference for future CO_2 handling systems. Put into operation in 1972, it recorded only five failures (with no injuries) during its first twelve years of operation. Two failures were explosions at compressor stations that resulted from air (oxygen) being drawn into the suction line from the extraction plant stack line. In order to rectify the problem, the emergency shutdown system was adjusted so that the loss of positive pressure on the suction line would cause the compressors to come to an immediate halt. The three other failures were ruptures at the injection station due to localized 'hot spots' in the tubes of the direct-fired line heater. The first was attributed to the build-up of a corrosion product in a pipe that took place before its installation and was not removed by initial cleaning. The other two ruptures occurred near support brackets where the distribution of flow through the parallel tube arrangement was not equal. Provisions for better temperature monitoring and flow distribution in the heater were put in place to prevent further such accidents (Gill, 1985).

An important technical consideration in the design of pipelines for transport of supercritical CO_2 is that the CO_2 remains above critical pressure. This can be achieved by means of recompression of the CO_2 at certain points along the length of the pipeline. Recompression is often needed for pipelines over 150 km (90 miles) in length. It is important to note, however, that recompression may not be needed if a sufficient pipe diameter is used. For example, the Weyburn CO_2 pipeline runs for 330 km (205 miles) from North Dakota to Saskatchewan, Canada, without recompression (Hattenbach et al, 1999).

A survey of North American pipeline project costs yields several pertinent observations. First, for a given pipeline diameter, the per unit distance cost of construction is generally lower the longer the pipeline. Second, pipelines built nearer populated areas tend to be more expensive. Finally, road, highway, river, or channel crossings and marshy or rocky terrain also greatly increase the cost (True, 1998).

2.3 Process Description

The CO_2 for pipeline transport is taken from Case 3a of the DOE/EPRI Report on CO_2 removal from fossil fuel power plants (EPRI, 2000). This case is used for the design basis since potential CO_2 sources from a coal-based power plant would most probably be associated with an IGCC plant. CO_2 recovery from IGCC is most economical because of the CO_2 concentration in syngas at a high partial pressure, enabling the use of conventional recovery processes. The pipeline is to be designed to handle 3.76 million scm (7,389 tonnes) of CO_2 per day. It is important to note that, since the capacity factor of the IGCC power plant is assumed to be 80 percent, this CO_2 is only supplied 80 percent of the time.

The pipeline design must conform to the United States Department of Transportation (DOT) Codes 49 CFR 195, Transportation of Hazardous Liquids by Pipeline, and 49 CFR 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards.

2.4 Methodology Used

The first stage of the CO_2 storage process simply involves the CO_2 being transported via pipeline from the base case IGCC plant to the injection site, for the geologic storage options, and to the shoreline collection point, in the case of the ocean storage options. Overland distances of 100 and 300 km, for the base and sensitivity cases respectively, are considered. The method used to calculate the cost of CO_2 pipeline transport can be broken down into two steps. First, the diameter of the pipeline is calculated. Next, based on the calculated diameter, the capital and O&M costs as well as the total cost per tonne of CO_2 are found. An overview of the cost model is given in Figure 7.

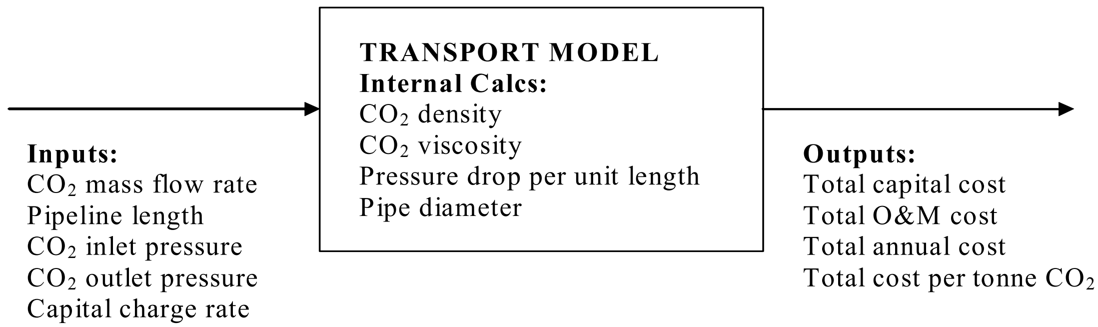

Figure 7: Pipeline transport cost model overview diagram

2.4.1 Diameter Calculation

The pipeline inlet CO_2 pressure is set equal to 152 bar, which is equivalent to the pressure of the CO_2 supplied by the base case IGCC plant. Based on a recommendation that the pipeline CO_2 pressure not be allowed to fall below 103 bar (Fox 1999), this latter value is used for the pipeline outlet CO_2 pressure. The maximum allowable pressure drop per unit length ($\Delta P/\Delta L$) is found as the difference between the pipeline inlet and outlet CO_2 pressures divided by the pipeline length.

Next, based on an assumed temperature of 25ºC, the CO_2 density and viscosity are calculated. The CO_2 density (ρ) is calculated to be 884 kg per m^3, using a correlation based on data from the National Institute of Standards and Technology (NIST) for a temperature range of 5 to 27ºC and a pressure range of 80 to 140 bar (Herzog). The CO_2 viscosity (μ) is found, from a correlation published by Nihous and Bohn, (Nihous and Bohn) to be 6.06×10^{-5} N-s per m^2.

The pipeline diameter is calculated using the equations for pressure drop and head loss due to frictional resistance in a pipe, assuming turbulent flow. This calculation uses an iterative procedure, which initially requires that the diameter be guessed. This guessed value is used to find the Reynolds number (Re) given by

$$Re = 4(\text{m-dot})/\pi\mu D$$

where m is the CO_2 mass flow rate and D is the pipeline diameter. Based on this calculated Reynolds number and a roughness factor of 0.00015, (Perry et al, 1997) the Fanning friction factor (f) is then found using an empirical relationship based on the Moody chart. Combining the equations for pressure drop and head loss gives the simplified formula

$$D^5 = 32f(\text{m-dot})^2/\pi^2\rho(\Delta P/\Delta L)$$

from which the diameter is determined. This calculated value of diameter is then used for the next iteration, and so on. Figure 8 gives the diameter, calculated for the base case, as a function of CO_2 mass flow rate.

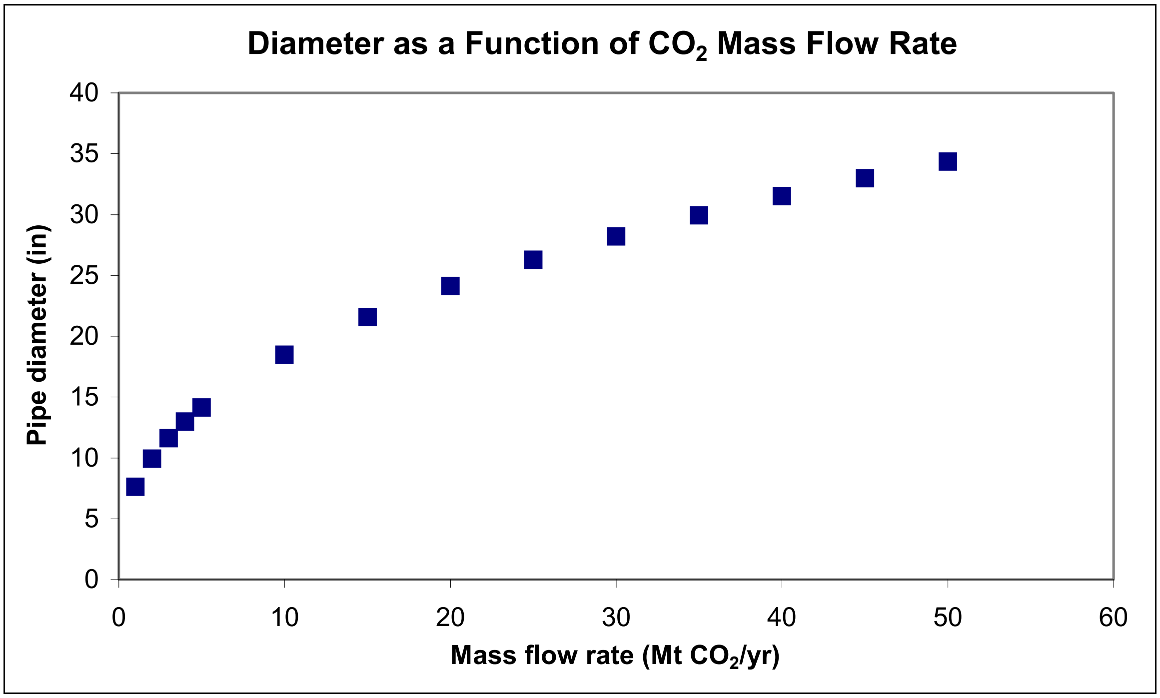

Figure 8: Diameter for the base case as a function of CO_2 mass flow rate (1 in = 0.0254 m)

2.4.2 Cost Calculations

The amount of cost data on CO_2 pipelines in the open literature is very limited, but there is an abundance of cost data for natural gas pipelines. For this reason, land construction cost data for natural gas pipelines were used to estimate construction costs for CO_2 pipelines. This is adequate given that there is little difference between land construction costs for these two types of pipeline (Fox, 1999). It is worth noting, though, that CO_2 pipelines might be slightly more expensive because of the greater wall thickness needed to contain the CO_2, which is transported at higher pressures.

The cost data found for natural gas pipelines consists of cost estimates filed with the United States' Federal Energy Regulatory Commission (FERC), and reported in the Oil and Gas Journal (True, 1998; True, 1990). Figure 9 gives the breakdown of costs on a dollar per mile basis for four pipeline diameters: 8, 16, 24 and 30 inches (0.20, 0.41, 0.61 and 0.76 m). Costs are broken down into material, labor, right-of-way (ROW) and miscellaneous components. Materials can include line pipe, pipe coating, cathodic protection and telecommunications equipment. Right-of-way costs include obtaining the right-of-way and allowing for damages. Miscellaneous costs generally cover surveying, engineering, supervision, contingencies, allowances for funds used during construction, administration and overheads, and regulatory filing fees.

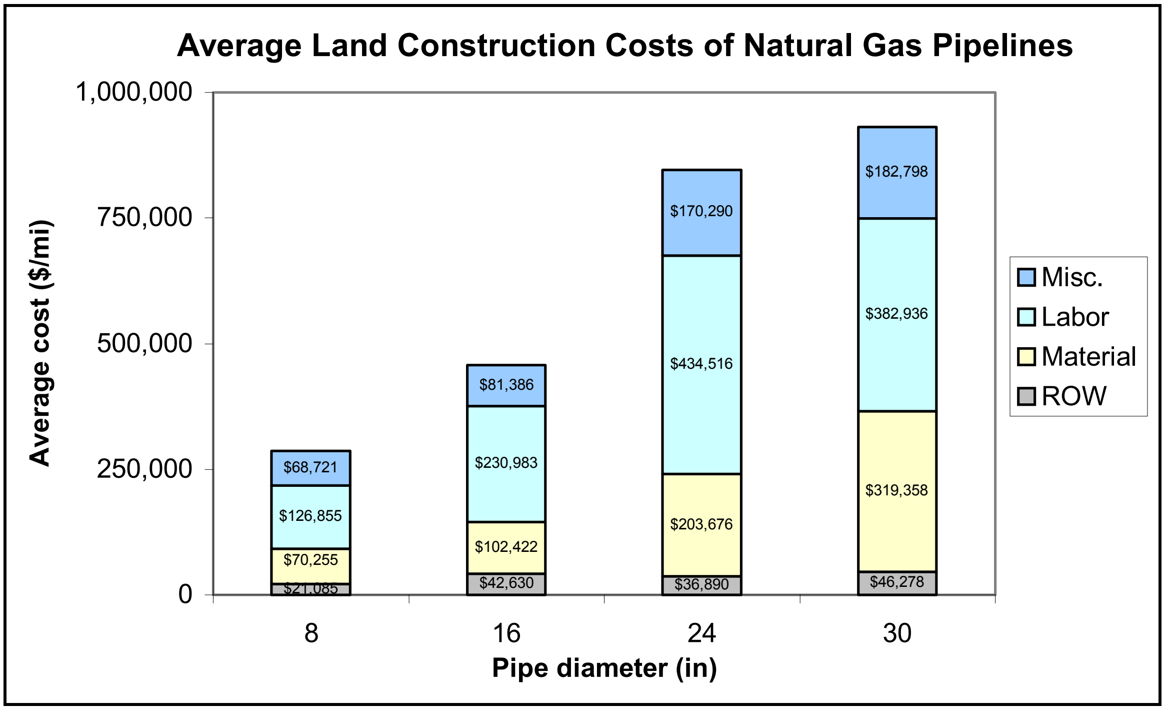

Figure 9: Breakdown of pipeline cost on a dollar per mile basis (True, 1998; True, 1990)

A breakdown of costs on a percentage of total cost basis is given in Figure 10. The graph suggests that right-of-way costs can be estimated at 5 percent of total costs, while labor, material and miscellaneous costs appear to be random percentages of total costs. It is also important to note that each of these costs is independent of pipeline diameter.

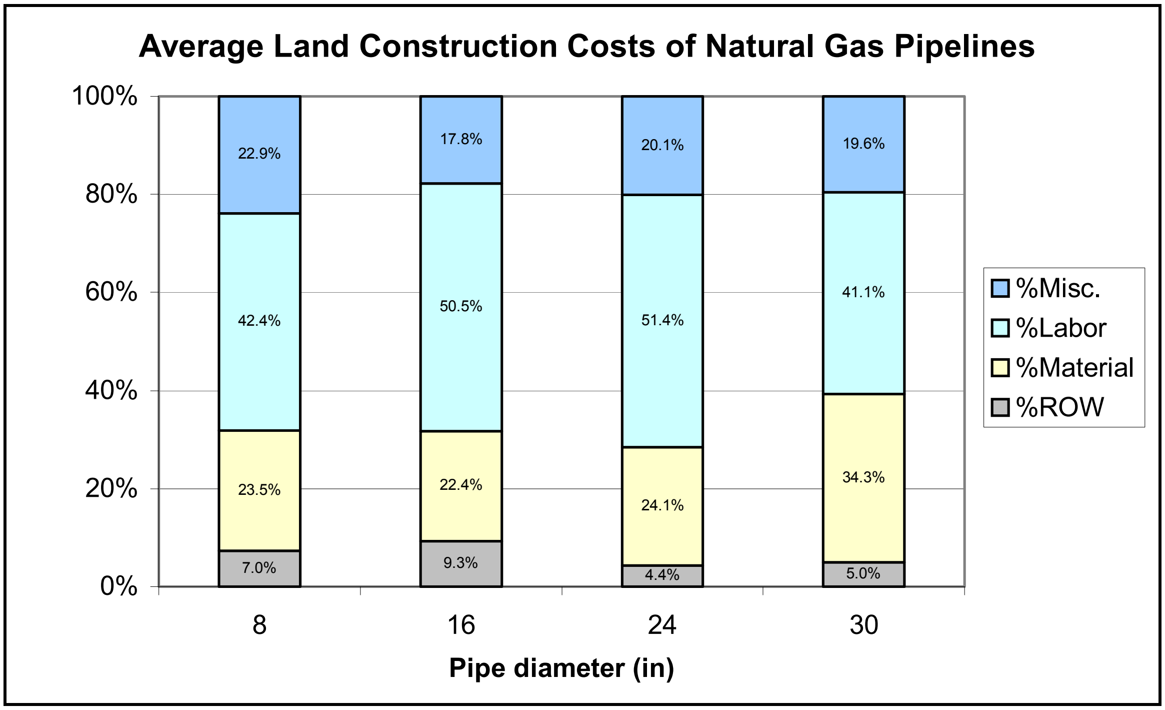

Figure 10: Breakdown of pipeline cost on a percentage of total cost basis (True, 1998; True, 1990)

Total costs in dollars per mile are plotted against pipeline diameter in Figure 11. A regression line fit to this data yields a pipeline construction cost of \$20,989/in/km (\$33,853/in/mile). According to an industry expert (Fox, 1999), the construction cost for CO_2 pipelines should be close to \$12,400/in/km (\$20,000/in/mile). One possible reason for this lower CO_2 pipeline construction cost estimate is that CO_2 pipelines are currently constructed in sparsely populated areas. Another is that the rock in New Mexico and West Texas where most CO_2 pipelines have been laid is easy to dig in. It is important to note that neither cost figure includes recompression costs.

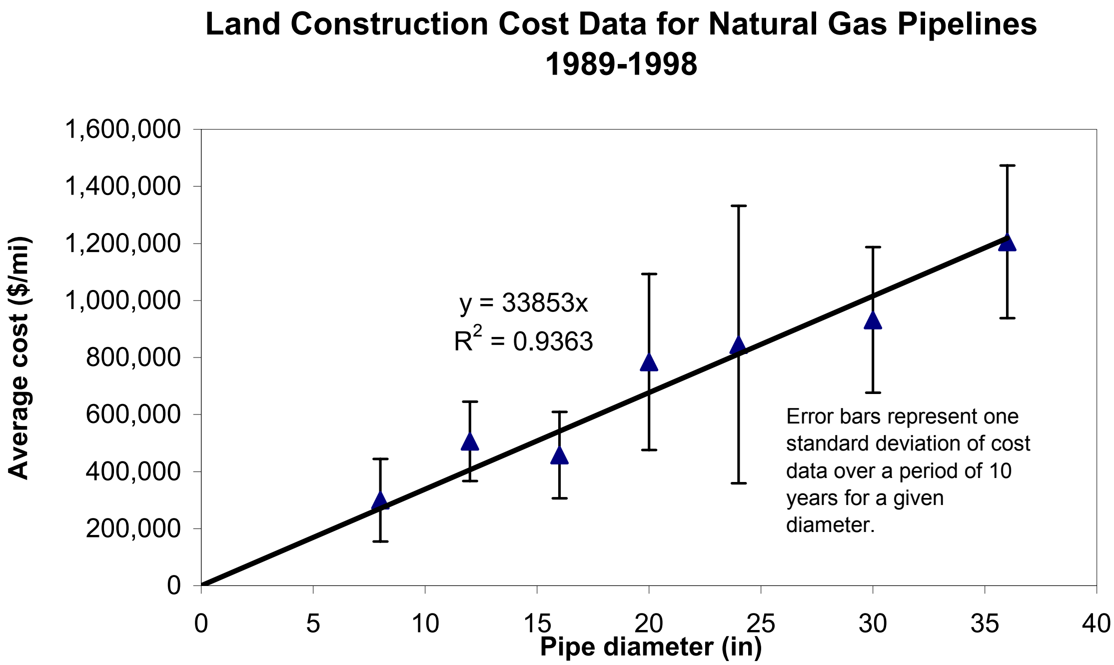

Figure 11: Regression analysis of pipeline construction cost data (True, 1998; True 1990)
(1 in = 0.0254 m, 1 mi = 1.61 km)

It has been reported that it costs about $40,000 to $60,000 per month to operate 480 km (300 miles) of pipeline and that this figure should be doubled to account for associated overhead costs (Fox, 1999). Taking the higher value to be on the conservative side, O&M costs are estimated to be $3,100/km ($5,000/mile) per year, independent of pipeline diameter. It should be noted that this O&M cost estimate does not account for pumping or its associated costs.

Total pipeline construction cost is found using the $20,989/in/km ($33,853/in/mile) cost factor. Applying the O&M cost factor of $3,100/km ($5,000/mile), gives the respective total O&M costs. Finally, the total annual cost per tonne of CO_2 is found by annualizing the construction cost using a capital charge rate of 15 percent per year and adding this to the annual O&M cost. Figure 12 shows the cost per tonne of CO_2, calculated for the base case, as a function of CO_2 mass flow rate.

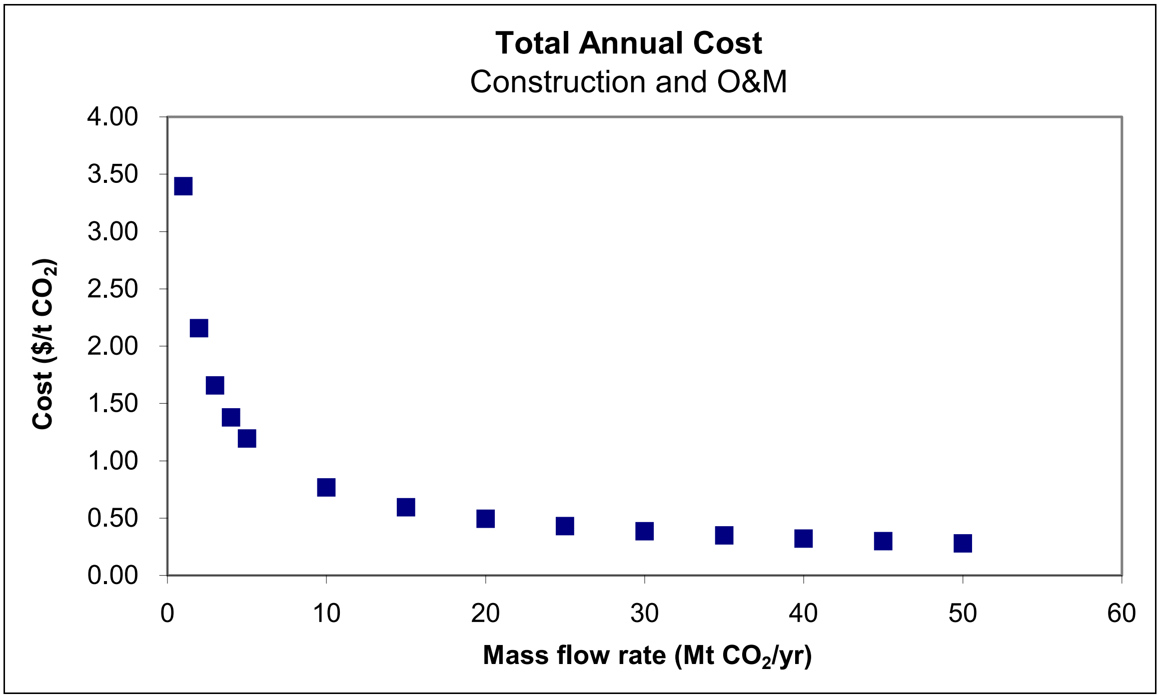

Figure 12: Total cost per tonne of CO_2 for the base case as a function of CO_2 mass flow rate

2.5 DESIGN BASIS

2.5.1 Pipeline Design

The methodology described in Section 2.4.1 was used to determine pressure drop per unit length and pipeline diameter for the base and sensitivity cases. The design bases for pipeline transport are summarized in Table 10.

Table 10: Design bases for pipeline transport
(1 in = 0.0254 m)

Parameter	Unit	Pipeline Transport Base Case	Pipeline Transport Sensitivity Case
Pipeline Length	km	100	300
CO_2 Inlet Pressure	MPa	15.2	15.2
CO_2 Outlet Pressure	MPa	10.3	10.3
Pressure Drop per Unit Length*	Pa/m	49	16
Pipe Diameter*	inches	11.2	13.8
Nominal Pipe Size*	inches	12	16

* calculated

2.5.2 Capital and O&M Cost Inputs

The capital and O&M costs of the pipeline, for the base and sensitivity cases, were calculated using the methodology described in Section 2.4.2. Table 11 shows the results.

Table 11: Capital and O&M cost inputs for the pipeline transport base and sensitivity cases

Parameter	Unit	Pipeline Transport Base (100 km) Case	Pipeline Transport Sensitivity (300 km) Case
Pipe Diameter	Inches	11.2	13.8
Capital Cost	$	23,500,000	87,100,000
O&M Cost	$	310,000	930,000

The total cost of constructing the pipeline is $23.5 and $87.1 million for the 100 and 300 km cases, respectively. The construction cost per mile of the 300 km pipeline is more than the 100 km pipeline due to the fact that a larger diameter pipe is required.

2.6 MODEL RESULTS

The respective values of total annual cost for the base and sensitivity cases are $1.78 and $6.49 per tonne of CO_2 transported.

2.7 COMPARISON TO LITERATURE

2.7.1 Studies Used in Model Evaluation

Data related to overland pipeline transport of CO_2 were taken from the case studies listed in Table 12.

Table 12: Overland pipelines' characteristics

Study	CO_2 flow rate (Mt/yr)	Initial CO_2 pressure (bar)	Diameter (m)	Length (km)	Recompression station included
IEA aquifer (Ormerod, 1994)	3.90	208	0.400	30	No
IEA depleted reservoir (Ormerod, 1994)	3.16	110	0.400	50	No
British Coal (Summerfield, 1993)	3.63	136	0.350	425	Yes
Weyburn (Hattenbach et al 1999)	2.00	170	0.305	330	No

A pumping station is required for the 'British Coal' CO_2 pipeline, of which only the onshore section is considered here, due to its extreme length. For the purpose of comparing the capital cost of this pipeline with that determined by the model, the pumping station was ignored. It should also be noted that cost data were not available for the 'Weyburn' pipeline.

2.7.2 Comparison of Values from Model and Studies

Figure 13 shows the pipe diameter as a function of CO_2 mass flow rate. Also shown in the figure is the value of pipe diameter, for a specific CO_2 mass flow rate, given in each of the four case studies. The model's calculation of pipe diameter is in reasonable agreement with the studies' estimates.

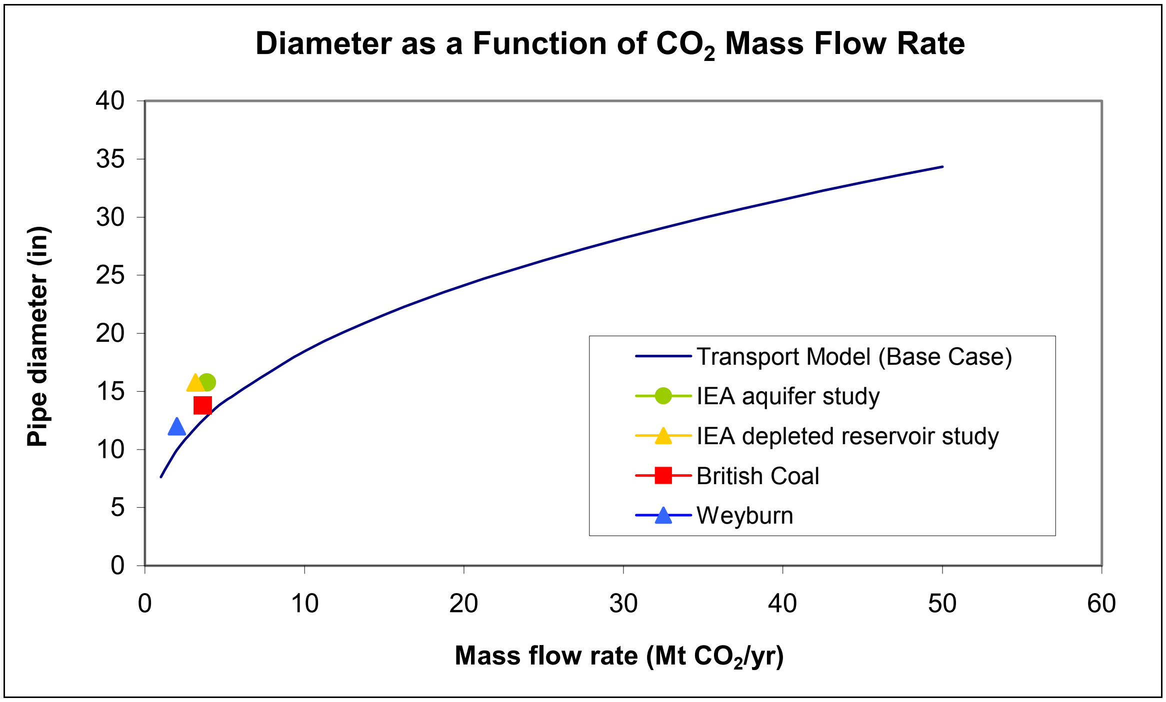

Figure 13: Comparison of pipe diameter values

Figure 14 shows the estimated capital costs of the pipeline versus mass flow rate, and a comparison with three other studies. Our model shows generally lower costs, especially when compared to the 'British Coal' study. The discrepancy can be attributed in part to the geographical differences associated with pipelines located in Europe as opposed to North America.

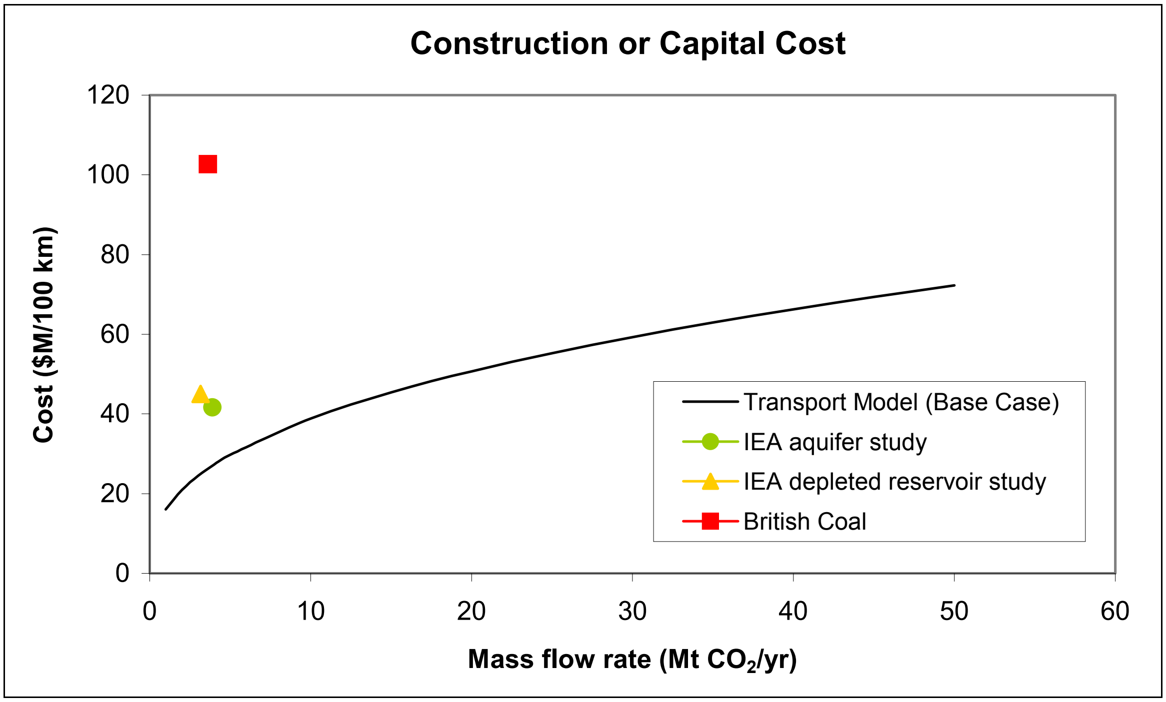

Figure 14: Comparison of pipeline capital cost values

3. ENHANCED OIL RECOVERY

3.1 INTRODUCTION

This chapter deals with the storage of CO_2 in depleted oil reservoirs where enhanced oil production results in a value-added product. The use of depleted oil reservoirs for CO_2 storage without enhanced production is treated separately in Chapter 5.

3.2 STATE OF THE ART

3.2.1 Applications

There were a total of 84 commercial or research-level applications of enhanced oil recovery using CO_2 floods (CO_2-EOR) worldwide in 2000. The amount of enhanced oil production from these CO_2-EOR projects during that year averaged 200,772 barrels (bbl) of oil per day[2], which is only a very small amount (0.3 percent) of that year's total worldwide oil production of 67.2 million bbl of oil per day. The United States account for 72 of the 84 projects, or 96 percent of worldwide enhanced oil production from CO_2 floods, and is as such the world leader in the use of CO_2-EOR technology. Currently, Turkey is the only other country with a commercial-scale application of CO_2-EOR, with Canada and Trinidad having only pilot-scale projects (Oil and Gas Journal, 2000; Oil and Gas Journal, 2001).

The 72 CO_2 floods in the United States in 2000 resulted in 192,209 bbl of oil per day, which is equivalent to 5 percent of total U.S. oil production during the same period. Most of these CO_2 floods (53) are located in the southwestern United States within the Permian basin of western Texas and eastern New Mexico. The next largest concentrations of CO_2 floods in the United States are in the Rocky Mountain and Mid-continent regions. The details of the six largest CO_2-EOR projects in 2000 are given in Table 13. It should be noted that these six projects are all situated in the United States and that together they accounted in 2000 for 47 percent of worldwide enhanced oil production from CO_2 floods (Oil and Gas Journal, 2000; Oil and Gas Journal, 2001).

[2] Only the oil recovered due to the CO_2 flood is included here as enhanced oil production. Quoted enhanced oil production figures may thus account for only a fraction of the total amount of oil produced during the tertiary recovery process.

Table 13: Six largest CO_2-EOR projects (Oil & Gas Journal, 2000)

Operator	Field	Basin/Region	Area (km^2)	Production Wells	Injection Wells	EOR Production (bbl/day)
Altura	Wasson (Denver)	Permian	113	735	385	29,000
Amerada Hess	Seminole (Main)	Permian	64	408	160	25,900
Chevron	Rangely Weber Sand	Rocky Mountain	61	341	209	11,208
ExxonMobil	Salt Creek	Permian	49	137	100	9,300
Devon Energy	SACROC	Permian	202	325	57	9,000
Altura	Wasson (ODC)	Permian	32	293	290	9,000

Currently, there is no commercial-scale CO_2-EOR project that utilizes CO_2 from a power plant. In the 1980s, there were three small-scale CO_2-EOR projects that utilized CO_2 from gas boiler power plants. These plants were shut down when the price of oil dropped in the mid-1980s, making this source of CO_2 too expensive (Herzog, 1999). The main obstacle to the utilization of this source of CO_2 for EOR is the significant cost of CO_2 capture. Most of the CO_2-EOR projects, particularly those located in the Permian basin, are dependent upon naturally occurring CO_2, which is obtained from high-pressure, high-purity underground deposits. The most important of these natural CO_2 deposits, in decreasing order of size, are the McElmo Dome, the Bravo Dome and the Sheep Mountain Field (Kinder Morgan CO_2 Company, 2001). A small fraction of the Permian basin CO_2 supply has also come from anthropogenic sources, namely the Mitchell, Gray Ranch, Pucket and Terrell gas processing facilities in the southern Permian basin. In contrast, the Rocky Mountain and Mid-continent regions are almost wholly supplied by anthropogenic CO_2 from gas processing and fertilizer production facilities. The Rangely Weber Sand CO_2-EOR project, for example, is supplied by the La Barge gas processing plant in southwestern Wyoming, and as such is the world's largest single sequestration site of anthropogenic CO_2 (EPRI, 1999).

3.2.2 Storage Potential

The Weyburn Field in southeastern Saskatchewan, Canada, is the only CO_2-EOR project to date that has been monitored specifically to understand CO_2 sequestration. In the case of most CO_2-EOR projects, much of the CO_2 injected into the oil reservoir should be considered as being only temporarily stored. This is because the decommissioning of an EOR project usually involves the "blowing down" of the reservoir pressure to maximize oil recovery. This "blowing down" results in CO_2 being released[3], with a small but significant amount of the injected CO_2 remaining dissolved in the immobile oil. In the case of the Weyburn Field, no "blow-down" phase is planned, thereby allowing for permanent CO_2 sequestration. Over the anticipated 25-year life of the project, it is expected that the injection of some 18 Mt of CO_2 from the Dakota Gasification Facility in North Dakota will produce around 130 million bbl of enhanced oil. This will prevent approximately 14 Mt of CO_2 from reaching the atmosphere, taking into account the CO_2 emitted by the generation of the required electricity (EPRI, 1999; Brown, 2001).

[3] The CO_2 from 'blow down' may be either vented or reused in other EOR fields.

3.2.3 Storage Mechanics

Most CO_2 floods achieve enhanced oil production through miscible, as opposed to immiscible, displacement. The six largest CO_2-EOR projects described above, for example, are all miscible CO_2 floods. Miscible displacement involves the injected CO_2 mixing thoroughly with the oil in the reservoir whereas, in the case of immiscible displacement, the CO_2 remains physically distinct from the oil. The type of displacement that occurs is dependent on the reservoir pressure and crude oil composition, with a reservoir depth greater than 1,200 m and an oil density less than 22º API typically leading to miscible conditions. Miscible displacement leads to an ultimate recovery of about 7 to 15 percent of the original oil in place (OOIP). Immiscible displacement yields lower recoveries compared to miscible conditions, but can still achieve a high recovery rate due to oil swelling and viscosity reduction. Currently, only one large CO_2-EOR project, located in Turkey, utilizes immiscible processes. However, it is expected that the number of immiscible CO_2 floods will increase as the use of CO_2-EOR becomes increasingly widespread (Oil and Gas Journal, 2000; EPRI, 1999; Moritis, 2001; Marle, 1991; Klins et al, 1991).

In CO_2-EOR projects, it is most common for the CO_2 not to be injected as a continuous fluid stream, but for CO_2 to be alternated with water injection in a water-alternating-gas (WAG) process. This WAG process is carried out to help overcome the problem of high CO_2 mobility that greatly reduces the effectiveness of CO_2 flooding. This high CO_2 mobility problem, caused by the CO_2 having a lower density and viscosity than the reservoir oil, is responsible for the phenomena of gravity tonguing and viscous fingering. These phenomena are undesirable as they lead to injected CO_2 flowing through areas that have already been swept. Taking advantage of the fact that water is less mobile than CO_2, the WAG process is able to significantly improve the sweep efficiency through reducing CO_2 mobility. This, in turn, results in improved oil recovery while also preventing early CO_2 breakthrough in producing wells. The world's largest CO_2-EOR project, Wasson (Denver), is an example of a WAG flood (EPRI, 1999; Klins, 1991; Morel, 1991).

3.2.4 Feasibility of Storage Option

The use of CO_2 floods for EOR presents a very attractive CO_2 storage option. Even without CO_2 sequestration credits, most of the active CO_2-EOR projects are profitable. In addition to a value-added product, CO_2-EOR has the advantage that it has been widely applied and is a proven technology. Furthermore, significant advances continue to be made in the computer simulation of CO_2 flood performance. This CO_2 storage option also has the added bonus that most oil fields have already undergone primary and secondary recovery prior to CO_2 flooding. This means that certain components of the existing infrastructure, such as the wells, are able to be simply adapted for CO_2 storage purposes. There is the downside that CO_2 floods require significant additional infrastructure to handle the processing and recycling of CO_2. On a positive note, however, the cost of anticorrosive equipment to deal with the problem of CO_2 reacting with water to form carbonic acid has recently been reduced (EPRI, 1999; Moritis, 2001).

3.3 PROCESS DESCRIPTION

The CO_2 for the EOR case is taken from Case 3a of the DOE/EPRI Report on CO_2 removal from fossil fuel power plants (EPRI, 2000). This case is used for the design basis since potential CO_2

sources from a coal-based power plant would most probably be associated with an IGCC plant. CO_2 recovery from IGCC is most economical because of the CO_2 concentration in the syngas is at a high partial pressure, enabling the use of physical rather than chemical absorption. The storage system is to be designed to handle 3.76 million scm (7,389 tonnes) of new CO_2 per day as outlined in Chapter 1.

Figure 15 is a block flow diagram, indicating the overall flow and distribution of CO_2 from the IGCC power plant to the EOR field. First, the CO_2 leaving the plant is fed to an additional stage of compression to bring it up to the required pipeline inlet pressure. Second, the pipeline transports the CO_2 a distance of 100 km to the EOR field, where it is mixed with recycled CO_2 and injected into the EOR CO_2 injection wells. Third, the oil produced at the EOR wells is separated from water and CO_2 at the surface. Finally, the CO_2 is dehydrated, compressed, and mixed with fresh incoming CO_2.

The CO_2 injection wells are an important component of the EOR field. These wells function as conduits for moving supercritical CO_2 fluid from the surface down into the reservoir. The wells are 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 (Smith, 2001).

The EOR field also consists of a distribution system, which serves the following functions:

- Receives CO_2 from the pipeline terminal and distributes it to the EOR CO_2 injection wells
- Gathers oil from the EOR production wells and delivers it to the tank battery
- Compresses separated CO_2 and mixes it with pipeline CO_2 for injection into EOR CO_2 injection wells

The oil from the EOR production wells is carried by small pipelines called flow lines to a part of the production site known as the tank battery. In addition to storage tanks, the tank battery contains equipment for preparing the oil before further distribution. The fluid coming out of nearly all wells is actually a mixture of oil, gas (in this case CO_2), salt water, and sediment. First, most of the CO_2 present is separated from the oil and water at 7 bar, recompressed and recycled, then re-injected to help maintain reservoir pressure, and thereby, production. Separation of the remaining mixture is accomplished in special tanks where the settling process separates water and oil, or it may be assisted by special equipment such as a heater treater. Vapor recovery units recover the remaining CO_2, which is also recompressed and recycled.

Testing of the oil to determine its properties is conducted at the well site by taking samples of oil from the storage tanks. Today, oil volumes are measured with Lease Automatic Custody Transfer facilities (LACTs), which do most of the measuring, sampling, and testing without human intervention. Oil that has been completely prepared is stored in tanks at the well site until it is transported to the refinery.

Most CO_2-EOR projects take place at fields that have already undergone secondary recovery, i.e. water flooding. The modification of water-flooded fields for CO_2 flooding involves:

- Makeover and equipping of injection wells
- Installation of CO_2 distribution and recycle systems
- Provision of high-pressure injection equipment and related piping
- Replacement of selected production facilities

The production phase of the Weyburn field is expected to be more than 25 years. The Millennium Energy CO_2 flood in West Texas has been going on since 1983. It is assumed that this flood has, like the power plant, a lifetime of 20 years. As a final note, the design/construction time is taken to be the same as the power plant, namely, 4 years.

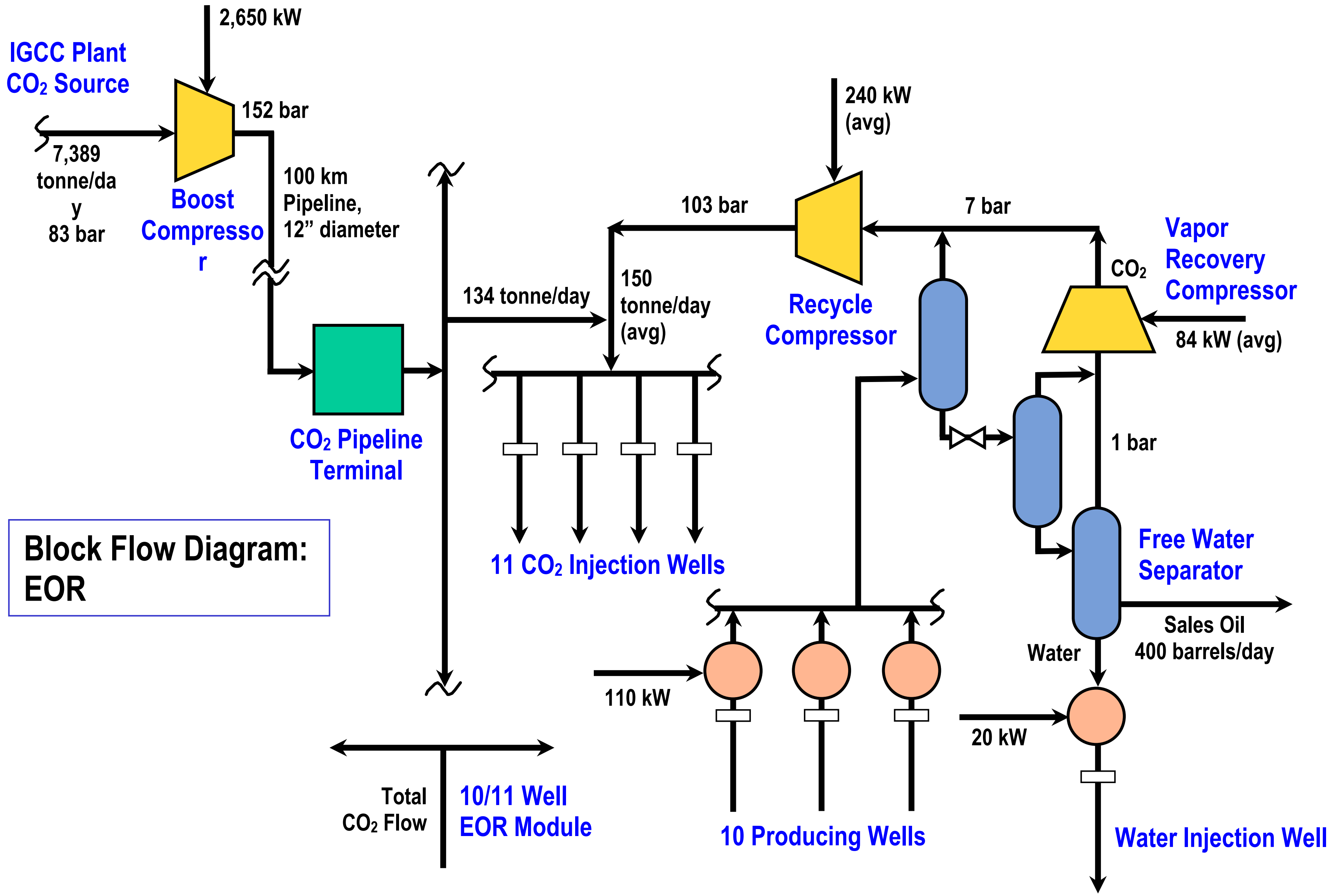

Figure 15: EOR block flow diagram

3.4 METHODOLOGY USED

For specific projects, the complex interactions between the injected CO_2 and reservoir oil would be modeled to assess the likely performance of a proposed CO_2-EOR project. Based on the output of this modeling, the cost of the proposed CO_2 flood is calculated. However, for our purposes of developing general costing algorithms, 'rules of thumb' are used to define the engineering parameters needed to estimate the cost of a CO_2-EOR project. These 'rules of thumb' have been derived based on information from experts in the field and the literature.

The method used for costing the EOR process can be split up into a number of steps. First, the average amount of enhanced oil produced per day for the given CO_2 mass flow rate is determined using a CO_2 effectiveness factor of 170 scm (6,000 scf) of new CO_2 per bbl of enhanced oil. Second, the number of production wells is found by dividing this total amount of enhanced oil produced per day by an assumed average of 40 bbl of enhanced oil per day being produced at each well. Third, a ratio of producers to injectors of 1 to 1.1 is used to calculate the number of injection wells from the number of production wells. Fourth, the capital cost of the CO_2 recycle plant is determined based on a maximum CO_2 recycle ratio of 3, with an average recycle ratio of 1.1 being used for the plant's O&M costs. Finally, the capital and O&M costs associated with the wells and the field equipment are calculated. Figure 16 provides an overview of the cost model, with the assumptions made in each of these steps being discussed below in more detail.

3.4.1 CO_2 Effectiveness

For the EOR-design basis, an average of 170 scm (6,000 scf) of CO_2 is taken to remain in the ground for each bbl of enhanced oil production. It is important to note, however, that the effectiveness of CO_2-EOR varies both from one basin to another and within a basin itself. In the case of the Permian basin, Malcolm Wilson from the Petroleum Technology Research Center indicated that around 170 to 227 scm (6,000 to 8,000 scf) of CO_2 per bbl of enhanced oil would remain in the ground (Wilson, 2001). In contrast, the CO_2 effectiveness in the Weyburn Field, according to Ray Hattenbach from the Dakota Gasification Company, is closer to 85 scm (3,000 scf) per bbl of enhanced oil (Hattenbach, 2001). In view of these differences, it was deemed necessary that the sensitivity of the cost of EOR to a range of CO_2 effectiveness values be determined. Based on the rough estimates given above, and the values given in the literature (see Table 14), a range of 85 to 227 scm (3,000 to 8,000 scf) of CO_2 per bbl of enhanced oil was chosen.

The CO_2-EOR projects in Table 14 illustrate the range of CO_2 effectiveness. The projects chosen include two of the largest CO_2 floods in the Permian basin. In addition, two other smaller CO_2-EOR projects in this basin, namely Dollarhide (Devonian) and Vacuum, are provided as examples of CO_2 floods displaying relatively high and low CO_2 effectiveness, respectively. CO_2-EOR projects located in the other two main CO_2-flood regions are also included. These projects comprise the two largest CO_2 floods in the Rocky Mountain region while, for the Mid-continent region, data was only available for two medium-sized floods. Finally, a last case study is made of the highly efficient CO_2 flood at the Weyburn Field.

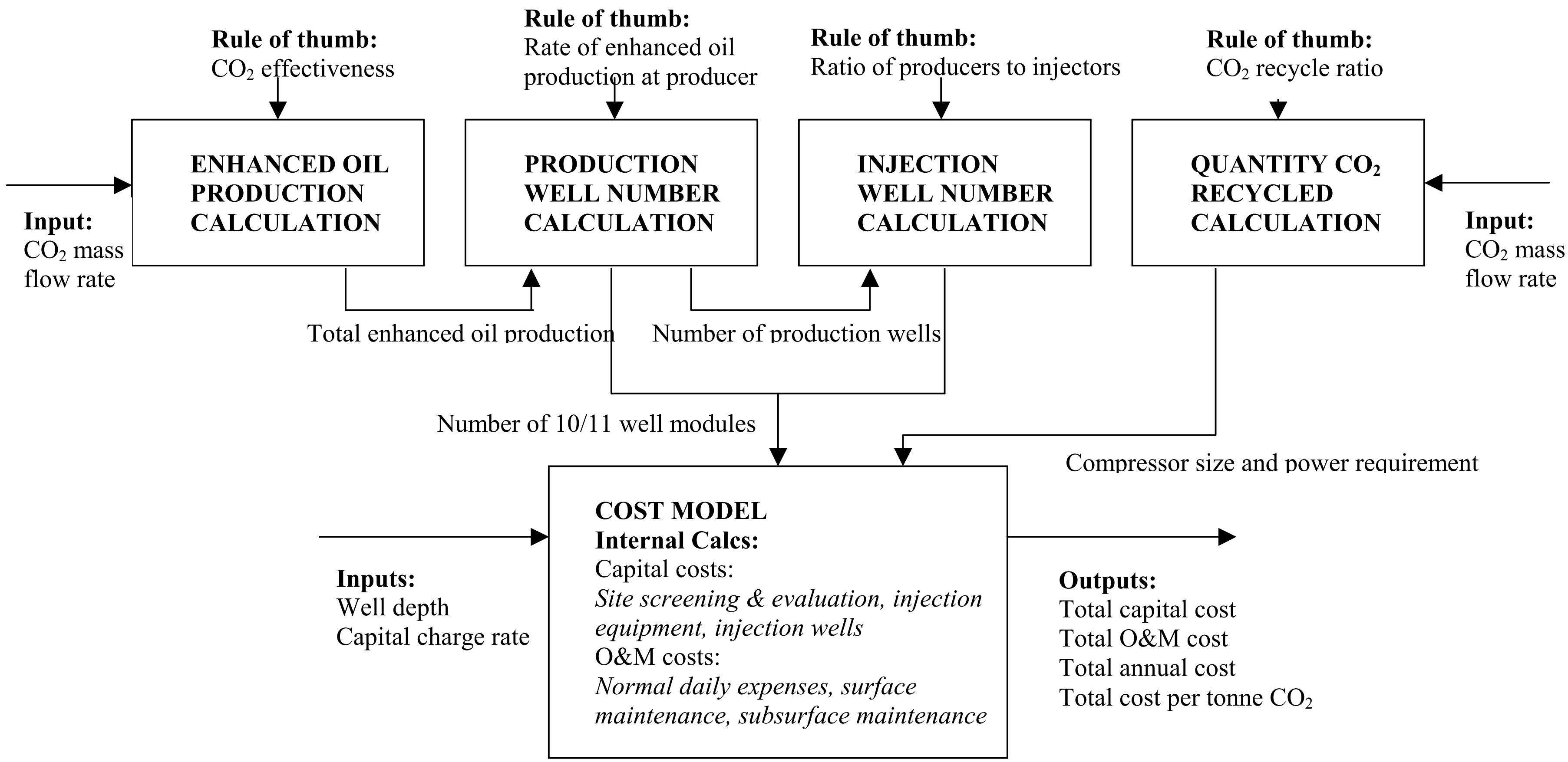

Figure 16: EOR cost model overview diagram

Table 14: Estimated CO_2 effectiveness for selected CO_2-EOR projects (EPRI, 1999).

Operator	Field	Basin/Region	Est. Ultimate EOR (million bbl)	Est. Ultimate CO_2 Sequestered (billion scm)	Est. CO_2 Effectiveness (scm/bbl)
Altura	Wasson (Denver)	Permian	348	47	136
Devon Energy	SACROC	Permian	169	26	153
Texaco	Vacuum	Permian	33	3	94
Spirit Energy	Dollarhide (Devonian)	Permian	28	5	177
Chevron	Rangely Weber Sand	Rocky Mountain	136	17	127
Merit Energy	Lost Soldier (Tensleep)	Rocky Mountain	24	3	117
Anadarko	Northeast Purdy	Mid-continent	17	2	117
Henry Petroleum	Sho-Vel-Tum	Mid-continent	10	3	292
PanCanadian	Weyburn	Saskatchewan	130	9	70

The CO_2 effectiveness has been calculated for the above CO_2-EOR projects by dividing the estimated total amount of CO_2 to be sequestered, taken as being equal to 90 percent of the CO_2 purchased (EPRI, 1999), by the estimated total amount of enhanced oil to be recovered over the lifetime of the project. The resulting estimates of CO_2 effectiveness are all, except for those for the Sho-Vel-Tum and Weyburn Field CO_2 floods, within the selected range of 85 to 227 scm (3,000 to 8,000 scf) of CO_2 per bbl of enhanced oil. In the case of the Sho-Vel-Tum flood, the use of the less-efficient immiscible displacement process to recover enhanced oil is the likely cause of the exceedingly high CO_2 effectiveness value (Oil & Gas Journal, 2000).

3.4.2 Rate of Enhanced Oil Production at Producer

The average amount of enhanced oil produced per day per well over the 20-year life of the field is taken to be 40 bbl. Unfortunately, there is no industry 'rule of thumb' for the amount of enhanced oil production that should be allowed at each production well on a daily basis. This is primarily because, as explained below, such a value is not used in practice as a basis for determining the number of production wells required. A value equal to the average amount of enhanced oil produced per day per well at the Weyburn Field has been adopted. Based on the calculated values of average daily enhanced oil production per well for the six largest CO_2-EOR projects, given in Table 15, this assumed base-case value of 40 bbl seems adequate, and a sensitivity range of 20 to 70 bbl appropriate.

There is no evidence to suggest that the amount of enhanced oil produced per day per well is dependent on the basin in which the CO_2 flood is located. The values of average daily enhanced oil production per well for the six largest CO_2-EOR projects, all but one of which are located in the Permian basin, can therefore be considered typical. The fact that the average of these enhanced oil production per well values is 44 bbl, which is very close to the assumed base-case value of 40 bbl, is reassuring.

Table 15: Average enhanced oil production per day per well for six largest CO_2-EOR projects (Oil and Gas Journal, 2000).

Operator	Field	Basin/Region	Production Wells	EOR Production (bbl/day)	EOR Production (bbl/day/well)
Altura	Wasson (Denver)	Permian	735	29,000	40
Amerada Hess	Seminole (Main)	Permian	408	25,900	64
Chevron	Rangely Weber Sand	Rocky Mountain	341	11,208	33
ExxonMobil	Salt Creek	Permian	137	9,300	68
Devon Energy	SACROC	Permian	325	9,000	28
Altura	Wasson (ODC)	Permian	293	9,000	31

It should be noted that the EOR industry determines the number of production wells based, not on an optimal level of enhanced oil production per day per well, but rather, on a required well spacing. The required spacing of wells, set by a state's gas and oil commission, can vary significantly. In one state it might be one well per 0.08 km^2 (20 acres), while in another it might be one well per 1.30 km^2 (320 acres). It has not been possible here to calculate the well numbers using this method, as doing so would require that the typical amount of enhanced oil produced per acre be known (Hattenbach, 2001).

3.4.3 Ratio of Producers to Injectors

A ratio of producers to injectors of 1 to 1.1 is used in the EOR concept design. Since this ratio depends largely on the injection strategy used, it is important to note here that use of WAG injection is assumed. For WAG injection, the 'rule of thumb' is that there be a rough balance between producers and injectors. The specific choice of a 1 to 1.1 ratio can be attributed to the fact that modules comprising 10 production and 11 injection wells are used as the basis for costing in the EIA's 'Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations' report and this report is used here for cost data (Wilson, 2001; Hattenbach, 2001).

Table 16 gives the ratio of producers to injectors for each of the six largest CO_2-EOR projects. It can be seen that, for those projects using the WAG process, the number of production and injection wells is roughly equal. However, this is not the case for the Seminole (Main) and SACROC projects for which CO_2 is injected continuously. The Lost Soldier (Tensleep) CO_2-EOR project, the second largest in the Rocky Mountain region, is also included in the table as it provides an example of a CO_2 flood having a producer to injector ratio of 1 to 1.1.

Table 16: Ratio of producers to injectors for selected CO_2-EOR projects (EPRI, 1999).

Operator	Field	Basin/Region	Injection Strategy	Production Wells	Injection Wells	Producers : Injectors
Altura	Wasson (Denver)	Permian	WAG	735	385	1.9:1
Amerada Hess	Seminole (Main)	Permian	Continuous	408	160	2.6:1
Chevron	Rangely Weber Sand	Rocky Mountain	WAG	341	209	1.6:1
ExxonMobil	Salt Creek	Permian	WAG	137	100	1.4:1
Devon Energy	SACROC	Permian	Continuous	325	57	5.7:1
Altura	Wasson (ODC)	Permian	WAG	293	290	1:1
Merit Energy	Lost Soldier (Tensleep)	Rocky Mountain	WAG	54	60	1:1.1

3.4.4 CO_2 Recycle Ratio

The CO_2 recycle ratio is taken to have an average value of 1.1 (CEED, 1995) This value is used to calculate the power requirements of the CO_2 recycle plant. The CO_2 recycle ratio increases over the lifetime of the CO_2 flood, from effectively zero to its maximum value, as the amount of CO_2 produced with the oil at the production wells increases while the amount of oil produced decreases. This increase in the recycle ratio is well illustrated in the case of the Rangely Weber Sand CO_2-EOR project. During the first 10 years of CO_2 flooding, 9 billion scm of net CO_2 purchases and 10 billion scm of recycled CO_2 were injected, giving an average recycle ratio of 1.1. In contrast, the recycle ratio in 1998 was close to 2.8, with an average of 1.2 million scm per day of net CO_2 purchases and 3.3 million scm per day of recycled CO_2 being injected (EPRI, 1999).

3.4.5 Reworking of Existing Wells

It is assumed that only the reworking of existing wells, as opposed to the drilling of new wells, is required. The maturity of the field and the choice of injection strategy together determine whether or not extra wells are needed. For the purpose of the EOR-concept design, the assumptions are made that the field has undergone primary and secondary flooding and that the CO_2 flood uses WAG injection. A field that has been subject to secondary flooding, i.e., water flooding, has both production and injection wells. For WAG injection, it is adequate to assume that no additional injection wells are required. While the concept design as such requires that no extra wells be drilled, it is important to note that the existing production and injection wells and production surface facilities need to be reworked for the changed reservoir conditions. Also, it is necessary to provide the appropriate injection surface facilities (Wilson, 2001; Hattenbach, 2001).

3.4.6 Cost Calculations

The total capital cost comprises the injection and production equipment costs, and the cost of refurbishing the existing wells. The O&M costs include normal daily expenses, and surface and subsurface maintenance costs.

The EIA 'Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations' report (Energy Information Administration, 2000) includes a scenario for secondary oil recovery using water flooding. Costs and indices for additional secondary oil recovery equipment and its operation are provided for a representative lease, located in west Texas. This lease, or module, comprises 10 production wells, 11 water injection wells and 1 disposal well, and the wells are nominally 4,000 feet, or 1,219 m, deep. This scenario was modified for CO_2 flooding, and used as the basis for field equipment and production operations costs. The capital and O&M costs on a per module basis, as well as the cost of power on a per kilowatt-hour basis, are given in Table 17.

Table 17: Capital and O&M cost estimation factors

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

3.5 DESIGN BASIS

3.5.1 Module design

The EOR design is tied as closely as possible to the EIA 'Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations' report (Energy Information Administration, 2000) in order to make use of the cost data. This report is a continuation of the EIA series on equipment and operating costs, and cost indices for oil and gas leases. In addition to cost comparisons within the petroleum industry, the reported data are often used to assess the economic effects of specific plans and policies relating to the industry. Standardization of this data has occurred over the past 23 years.

The costs and cost indices provided in this report are for representative 10-well lease operations, with equipment and operating procedures designed by EIA staff engineers. As previously mentioned, each EOR lease has 10 producing wells, 11 injection wells, and 1 disposal well, and the wells are nominally 4,000 feet, or 1,219 m, deep. The design criteria have taken into account the predominant methods of operation in each region. Individual items of equipment have been priced by using price lists, and by communication with the manufacturer or supplier of the item in each region. Freight and installation costs have been determined based on regional rates. All costs presented in the report are current to their year and are not adjusted for inflation.

The base case design is based on a CO_2 effectiveness factor of 170 scm (6,000 scf) per bbl of enhanced oil and an enhanced oil production rate of 40 bbl per day per well. From the design flow rate of 3.76 million scm (7,389 tonnes) of CO_2 per day, the total enhanced oil production is calculated using the CO_2 effectiveness factor to be 22,142 bbl. Dividing this total enhanced oil production by the enhanced oil production rate per well, the required number of production wells is found to be 554. Given a producer to injector ratio of 1 to 1.1, 609 injection wells are required. In keeping the design consistent with the EIA modular approach, the EOR field for the base case therefore consists of 56 10/11 well modules. Finally, the quantities of new CO_2 and CO_2 to be recycled, assuming a maximum recycle ratio of 3, per module are 68,000 and 204,000 scm per day, respectively. Table 18 summarizes the base case for EOR.

Table 18: Design basis for the EOR base case

Parameter	Unit	EOR Base Case
CO_2 Effectiveness	scf/bbl enhanced oil	6,000
	scm/bbl enhanced oil	170
Oil Production per Well	bbl enhanced oil/day/well	40
Total Oil Production*	bbl enhanced oil/day	22,142
Number of Production Wells*		554
Number of Injection Wells*		609
Number of 10/11 Well Modules*		56
New CO_2*	scm/day/module	68,000
Maximum Recycled CO_2*	scm/day/module	204,000
Well Depth	m	1,219

* calculated

A key component of the EOR field is the recycle compressor because it requires a large amount of energy and capital investment. The compressor use is initially minimal but, after 20 years of operation, it is assumed that the ratio of CO_2 produced with the enhanced oil production to the new CO_2 will reach the maximum value of 3.

The compressor is sized to handle all of the CO_2 that is recycled in the 10/11 well module. The actual compressor is a Superior Model WG74, sized by Cooper Energy Services and priced by Gas Packagers, Inc. To meet the CO_2 recycle requirements of the 10/11 well module, two compressors, each delivering 71 scm per minute are required. The base cost for each compressor was adjusted by Parsons to include shipping, foundations, installation and a cooling system. Table 19 gives the recycle compressor's parameters and cost.

Table 19: Recycle compressor's parameters and cost

Parameter	Unit	Individual Compressor	Total for 10/11 Module
Maximum CO_2 to be Compressed	scm/day	102,000	204,000
Compressor Type		Reciprocating	Reciprocating
Suction Pressure	bar	7	7
	psia	100	100
Discharge Pressure	bar	103	103
	psia	1,500	1,500
Compressor Displacement	scm/min	71	142
Overall Compression Ratio		14.7	14.7
Number of Stages		2	2
Horsepower		4.2	4.2
Connected Horsepower		500	1,000
Maximum Power Consumption	kW	319	638
Average Power Consumption	kW	120	240
Power Consumption	kW/thousand scm/day	3.1	3.1
Capital Cost per Compressor	$/compressor	737,000	1,473,000
Total Compressor Cost	$		82,500,000

A summary of the lease equipment required for the EOR design is given in Table 20.

Table 20: Lease equipment

Equipment Description	Specification	Quantity
Tubing	2.375 inch, Grade J-55	40,000 feet
Sucker Rod	API Class K	40,000 feet
Pump Rod	API Type RWBC	10
Pumping Unit	API Size M160D 173-74, 12 hp	10
Oil Flowline	2.375 inch, PVC	16,000 feet
Manifold	10 valves, 2 inch 3-way	1
Production Separator	Vertical, 30 inch x 10 feet, 2,700 barrels per day of fluid, 5.7 million scf/day gas	1
Vapor Compressor	500 scf/min, 0-100 psig, 115 hp	1
Test Separator	1.0 barrel per day	1
Oil Storage Tank	2,000 barrels	2
Water Disposal Pump	Quintuplex, 1,000 psi, 20 hp	1
Water Disposal Line	2.375 inch, 2,500 psi yield	2,000 feet
LACT Unit	2,000 bbl/day	1

3.5.2 Capital and O&M Cost Inputs

All of the capital and O&M costs, except for the power costs, are found by multiplying the per module costs, given in Table 17, by the required number of modules, as detailed in Section 3.5.1. In the case of the pumping and field, and recycle compressor, power costs, the costs per kilowatt-hour are multiplied by 8,760, the total hours of operation per year, and the respective power requirement. Table 21 summarizes the capital and O&M costs for the base case EOR design.

Table 21: Capital and O&M cost inputs for the EOR base case

Parameter	Input
Number of Modules	56
CAPITAL COSTS	
Injection Equipment:	
Recycle & Vapor Compressors	$99,300,000
Injection Plant Confines	$6,360,000
Distribution Lines	$4,320,000
Header	$3,420,000
Electrical Service	$5,450,000
Makeover of Existing Injection Wells	$33,900,000
Producing Equipment:	
Tubing Replacement	$5,080,000
Rods & Pumps	$2,300,000
Equipment	$22,700,000
Subtotal	$182,800,000
O&M COSTS	
Normal Daily Expenses:	
Supervision & Overhead	$2,970,000
Labor	$3,510,000
Consumables	$420,000
Operative Supplies	$431,000
Pumping & Field Power (7,196 kW)	$2,770,000
Recycle Compressor Power (17,946 kW)	$6,910,000
Surface Maintenance (Repair & Services):	
Labor (roustabout)	$1,800,000
Supplies & Services	$2,480,000
Equipment Usage	$913,000
Other	$129,000
Subsurface Maintenance (Repair & Services):	
Workover Rig Services	$2,600,000
Remedial Services	$846,000
Equipment Repair	$627,000
Other	$554,000
Subtotal	$27,000,000

3.6 RESULTS

This section presents costs for CO_2 storage for EOR. The storage costs comprise transaction, transportation, sequestration and monitoring costs. The results, which include the revenue generated from the sale of the enhanced oil produced, are given as levelized annual CO_2 storage costs on a life-cycle, greenhouse gas-avoided basis.

High and low cost cases have been chosen for EOR, and are presented together with the base case in Table 22. The price of oil at the wellhead is taken to have a base-case value of $15 per bbl, a low-end value of $12 per bbl and a ceiling price of $20 per bbl; an Oil Royalty of 12.5 percent is assumed. It should also be noted that the high cost case assumes no previous water flooding, while the low cost case assumes the field has been water flooded as for the base case.

Table 22: EOR base, high cost and low cost cases

Parameter	Units	EOR Base Case	EOR High Cost Case		EOR Low Cost Case	
CO_2 Effectiveness	scm/bbl enhanced oil	170	227	+34%	85	-50%
Oil Production per Well	bbl enhanced oil/day/well	40	20	-50%	70	+75%
Maximum Recycle Ratio		3	4	+33%	1	-67%
Oil Price	$/bbl	15	12	-20%	20	+33%
Depth	m	1,219	2,438	+100%	610	-50%
Pipeline Distance	km	100	300	+200%	0	-100%
Previous Water flooding		Yes	No	-	Yes	-

The results for the high and low cost cases as well as the base case are given in Table 23. The CO_2 storage cost for EOR is widely different for the high and low cost cases. In reality, a CO_2-EOR project with parameter values approaching those of the high cost case would not be carried out.

Table 23: Results for EOR base, high cost and low cost cases

Parameter	Units	EOR Base Case	EOR High Cost Case	EOR Low Cost Case
Total Oil Production	bbl enhanced oil/day	22,142	16,582	44,285
Number of 10/11 Well Modules		56	83	64
New CO_2	scm/day/module	68,000	45,000	59,000
Maximum Recycled CO_2	scm/day/module	204,000	182,000	59,000
Levelized Annual CO_2 Storage Cost	$/tonne CO_2	(12.21)	73.84	(91.26)

3.7 Sensitivity Analysis

The sensitivity of the CO_2 storage cost for EOR is determined for six key parameters as well as for the case of no previous water flooding. It can be seen in Figure 17 that increases in well depth, CO_2 effectiveness, recycle ratio, and pipeline distance cause an increase in the cost of storage, while increases in oil production rate and oil price decrease the storage cost. More noteworthy, the figure shows that changes in oil price have the greatest effect on storage cost, followed closely by changes in CO_2 effectiveness. As is to be expected, the case of no previous water flooding results in an upward shift in the cost.

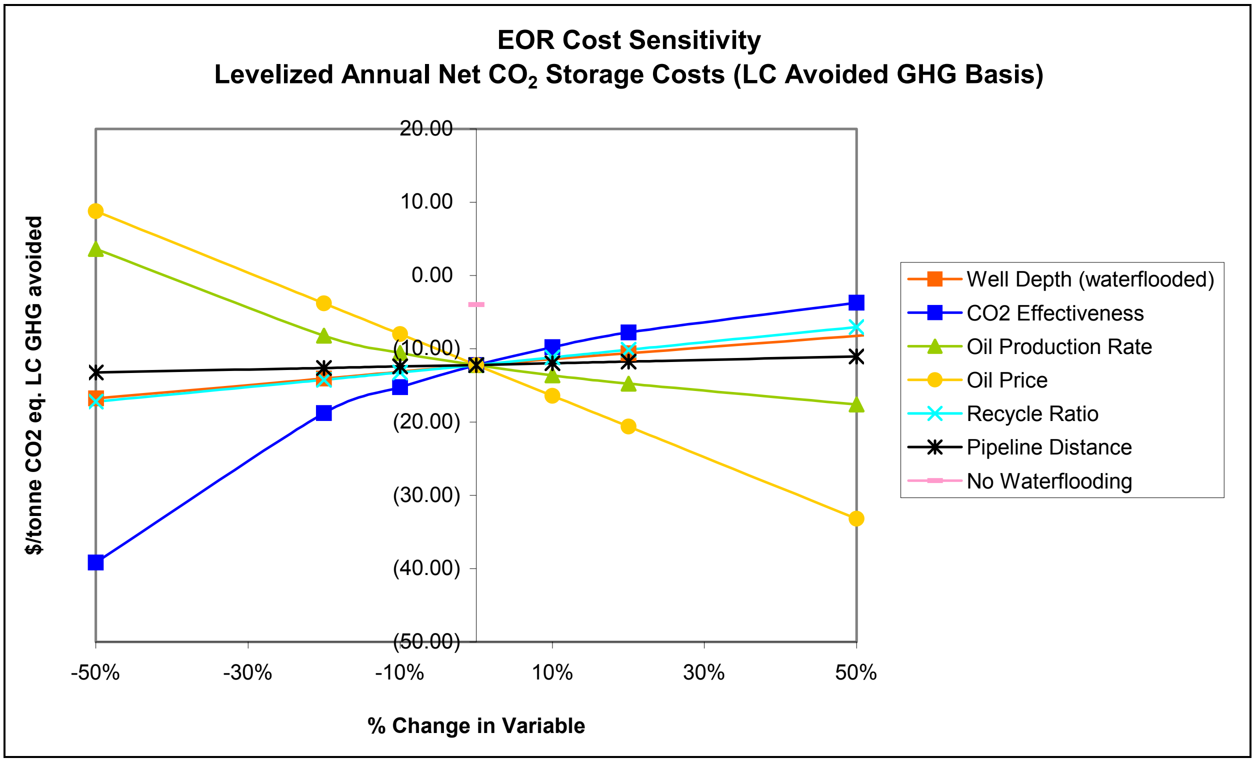

Figure 17: Sensitivity analysis for EOR

For the high and low cost values for each of the six key parameters, the percentage change in the value from the base case is shown in Table 22. This is done to illustrate the fact that the range in the values of some parameters is expected to be greater than for others.

3.8 Comparison to Literature

A comparison is made between the costs obtained for the EOR base-case design using the EIA 'Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations' report and those calculated using cost estimation functions (CEED, 1995). The relevant cost functions are shown in Table 24.

Table 24: EOR cost estimation functions (CEED, 1995)

Item	Unit	Value
CAPITAL COSTS		
Workover of existing injector	$	5 * depth(ft) + 35,000
Workover of existing producer	$	40,000
Provision of injection surface facilities	$/well	22,000
Workover of production surface facilities	$/well	10,000
CO_2 recycle plant	$	457,000 * CO_2 recycled (million scf per day)
O&M COSTS		
CO_2 recycle compression operating costs	$/yr	200 * CO_2 recycled (million scf per day) * 365

Using these cost functions, the capital and O&M costs of EOR for the base-case design were calculated. Table 25 shows the results of these calculations together with the previously determined base-case EOR costs.

Table 25: Comparison of EOR cost results (CEED, 1995; Energy Information Administration, 2000)

Item	Unit	Using EIA Report Data	Using Cost Functions
CAPITAL COSTS			
Workover of injectors	$	33,900,000	33,495,000
Provision of injection surface facilities	$	13,190,000	13,398,000
Total cost injection equipment	$	**47,090,000**	**46,893,000**
Workover of producers	$	27,780,000	22,160,000
Workover of production surface facilities	$	2,300,000	5,540,000
Total cost production equipment	$	**30,080,000**	**27,700,000**
CO_2 recycle plant	$	105,660,000	182,354,000
Total Capital Cost	$	**182,800,000**	**256,947,000**
O&M COSTS			
CO_2 recycle compression operating costs	$/yr	12,232,000	14,540,000
TOTAL O&M COSTS	$/yr	**27,000,000**	**-**

Except for the CO_2 recycle plant, it can be seen from the table that the cost of the EOR base-case design is very similar for the two sets of cost data. The CO_2 recycle plant costs were not included in the EIA report and were developed from vendor quotations and in-house data. It is concluded that using the EIA report for costs was reliable, given the uncertainties and variation in the data.

4. ENHANCED COALBED METHANE

4.1 INTRODUCTION

This chapter looks at the injection of CO_2 into deep coal seams as a means of enhancing coalbed methane production while simultaneously sequestering CO_2.

4.2 STATE OF THE ART

4.2.1 Applications

The injection of CO_2 into deep, unmineable coal seams to enhance coalbed methane production (CO_2-ECBMR) is a nascent technology. It was not until 1996 that the world's first, and to date only, pilot-scale application of CO_2-ECBMR began operation. In contrast, EOR using CO_2 floods (CO_2-EOR) is a mature technology with over three decades of commercial-scale application. The one CO_2-ECBMR project, comprising nine coal-bed methane (CBM) production and four CO_2 injection wells, is located in the southwestern United States within the Allison production unit of the San Juan basin and is operated by Burlington Resources, the United States' largest producer of coal-bed methane. Analysis of operations at the Allison unit has shown the CO_2-ECBMR process to be technically and economically feasible (EPRI, 1999; Stevens et al, 1998; Reeves, 2001).

4.2.2 Storage Potential

CBM production has become an increasingly important component of natural gas supply in the United States during the last decade. In 2000, approximately 40 billion scm of CBM was produced, accounting for about 7 percent of the nation's total natural gas production. The most significant CBM production, some 85 percent of the total, occurs in the San Juan basin of southern Colorado and northern New Mexico. Another 10 percent is produced in the Black Warrior basin of Alabama and the remaining 5 percent comes from rapidly developing Rocky Mountain coal basins, namely the Uinta basin in Utah, the Raton basin in Colorado and New Mexico, and the Powder River basin in Wyoming (EPRI, 1999; EIA, 2001).

Essentially all current CBM production utilizes primary recovery methods. Primary recovery involves pumping off large volumes of formation water to lower reservoir pressure and cause methane desorption from the coal. Primary production of CBM recovers only 20 to 60 percent of original gas-in-place (OGIP), depending on reservoir properties such as coal seam permeability and gas saturation, and operational practices, such as well spacing. In comparison, over 90 percent of the OGIP can theoretically be recovered using CO_2-ECBMR. Furthermore, CO_2-ECBMR can accelerate CBM recovery, providing greater real value for a given reserve (EPRI, 1999; Stevens et al, 1998).

Significant potential for CO_2-ECBMR exists worldwide. In order for CO_2-ECBMR to be successfully applied, reservoirs must have laterally continuous and permeable coal seams, concentrated seam geometry, and minimal faulting and reservoir compartmentalization. In the United States, the geologically most favorable reservoirs are located within the San Juan, Uinta, and Raton basins, while additional potential exists in the Greater Green River and Appalachian basins. A number of coal basins in Australia, Russia, China, India, Indonesia, and other countries have also been identified as having large CO_2-ECBMR potential. Indeed, the total worldwide potential for CO_2-ECBMR, taking into consideration only those reservoirs where CO_2-ECBMR could be profitably developed without CO_2 sequestration credits or free or reduced-cost CO_2 supplies, is estimated at around two trillion scm of CBM, with about 7.1 Gt (gigatonnes or billion metric tones) of associated CO_2 sequestration potential (Wong et al, 2000).

4.2.3 Storage Mechanics

Four patents have been issued over the past two decades relating to the CO_2-ECBMR process. Each of these patents is based on the principle that CO_2 is adsorbed more readily onto the coal matrix than methane. Specifically, CO_2-ECBMR involves injected CO_2 being adsorbed at the expense of methane, which having been displaced can be recovered as a free gas at production wells. Sorption isotherm measurements in the laboratory indicate that two unit volumes of CO_2 are required to displace one unit volume of methane. This ratio of CO_2 effectiveness is however expected to vary in the field according to the thermal maturity of the coal (EPRI, 1999; Stevens et al, 1998; Wong et al, 2000; Hamelinck, 2001)

A successful demonstration of CO_2-ECBMR technology has been provided by the Allison unit pilot project. Prior to CO_2 injection, CBM was produced within the unit using conventional pressure-depletion methods. Since the start of CO_2 injection, enhanced CBM production has been observed. A marked increase in water production was also observed initially, signaling improved sweep of bypassed reservoir areas that should lead to higher ultimate gas recovery. Finally, there has been negligible CO_2 breakthrough, despite around one billion scf of CO_2 being injected each year since the project began in 1996. The injected CO_2 comes from the McElmo Dome, which is a natural CO_2 deposit in southwestern Colorado (EPRI, 1999; Stevens et al, 1998; Reeves et al, 2001).

4.2.4 Feasibility of Storage Option

CO_2-ECBMR presents an attractive option for the sequestering of CO_2. Like CO_2-EOR, it has the distinct advantage over other CO_2 storage options that it sequesters CO_2 while also generating a value-added product. While CO_2-ECBMR as a technology is still in the development stage and has not been widely applied, it has been successfully demonstrated in a pilot-scale application. Also, given the broad similarities between EOR and ECBMR, the technology required to implement CO_2-ECBMR in the field can be largely based on that used for CO_2-EOR operations. The fact that CO_2 is adsorbed onto the coal surface means that there should be little risk of leakage of CO_2 from the reservoir. Also on a positive note, coal, and so CBM, typically lies at relatively shallow depths so that well drilling and completion costs are generally lower than for other geologic options.

On the downside, CO_2-ECBMR is a very energy intensive process, requiring significant electricity both for pumping large volumes of formation water to the surface and for compressing the produced methane to a suitable pressure for pipeline transport and sale. Another disadvantage is that the large volumes of formation water produced by CO_2-ECBMR are most often saline and need to be disposed of in an environmentally acceptable manner.

4.3 PROCESS DESCRIPTION

Figure 18 is a block flow diagram, indicating the overall flow and distribution of CO_2 from the IGCC plant to the ECBMR field. First, the CO_2 leaving the plant is fed to an additional stage of compression to bring it up to the required pipeline inlet pressure. Second, the pipeline transports the CO_2 a distance of 100 km to the ECBMR field, where it is injected into the ECBMR CO_2 wells. Third, the ECBMR product is dewatered, and dry gas from the ECBMR wells is compressed to the gathering line pressure. Finally, the gas from the gathering line is then further compressed for sale to a nearby pipeline.

The source and quantity of CO_2 supplied to the ECBMR field is the same as for the EOR storage option. It should also be noted that the pipeline outlet pressure of 103 bar is assumed to be at or above the required surface injection pressure.

Very simple vertical wells from 300 to 1,200 m in total depth are common to this type of production. These wells produce gas at very low pressures; wellhead pressures of between 2 to 3 bar are common. Because these wells are generally operated at low backpressures (assumed to be 1.7 bar), compression is required to increase the wellhead pressure to the gas gathering line pressure of 4.5 bar. The gathered gas is then further compressed to 25.1 bar for delivery to a nearby pipeline.

Developing an ECBMR lease for production involves:

- Lease acquisition activities
- Drilling and equipping production/injection wells
- Installation of high-pressure injection equipment and related piping
- Installation of ECBMR production equipment and facilities
- Installation of product gas compressors

The ECBMR field is a novel facility, which has not produced CBM in the past. The ECBMR field therefore requires a new distribution and injection/ECBMR production system, which serves the following purposes:

- Receives CO_2 from the pipeline terminal and distributes it to the ECBMR CO_2 injection wells
- Gathers gas from the ECBMR production wells and delivers it to a central gas/liquid separator
- Dewaters the ECBMR production wells and conveys water to a central disposal well
- Compresses the separated gas to 4.5 bar for distribution to a regional gathering line
- Compresses the gathered gas to 25.1 bar for sale to a nearby pipeline

Most CBM reservoirs are low-pressure, water-bearing gas reservoirs. Under conditions of high water saturation, the water volume and the hydrostatic pressure must be reduced by artificial lift to initiate gas desorption and flow to the wellbore (GRI-81/0159, 1983). This dewatering process produces large quantities of saline water that must be disposed of carefully. In the Warrior Basin, water is usually piped to a central treatment facility and disposed into a surface stream. In the San Juan Basin, because of the higher total dissolved solids in the water, disposal wells are used (IEAGHG, 1998). For this study, the use of disposal wells is assumed.

A productive life span of 20 to 30 years is typical for CBM fields (Pashin et al, 2001). The life of this field is assumed to be the same as that of the power plant, 20 years. As a final note, the design/construction time is taken to be the same as the power plant, namely, 4 years.

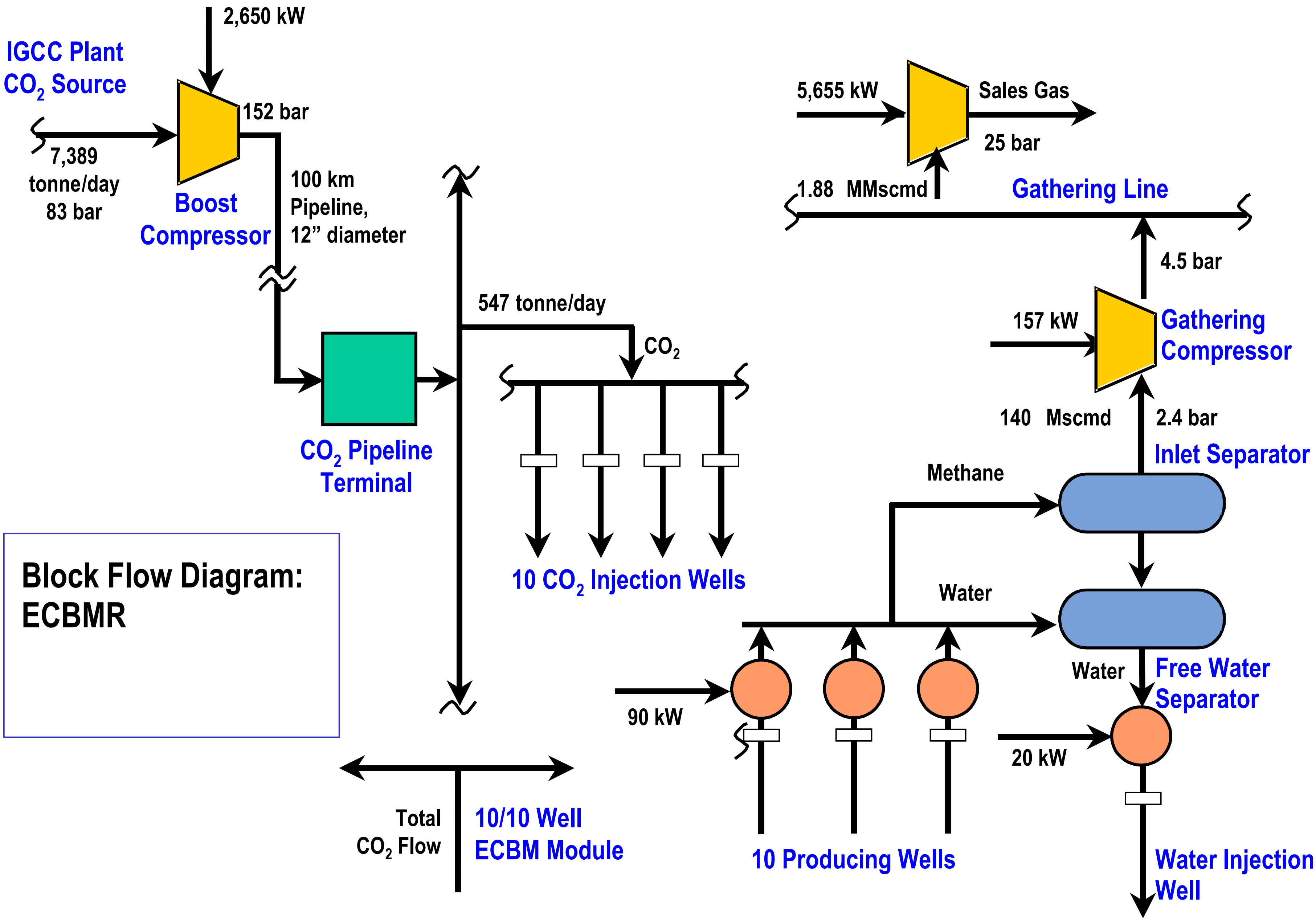

Figure 18: ECBMR block flow diagram

4.4 METHODOLOGY USED

As in the case of the CO_2-EOR concept design, 'rules of thumb' are used to define the engineering parameters needed to estimate the cost of a CO_2-ECBMR project. As for CO_2-EOR, the method for costing the CO_2-ECBMR process is also split up into a number of steps. First, the total amount of enhanced CBM produced per day for the given CO_2 mass flow rate is determined using a CO_2 effectiveness factor of two scm CO_2 per scm of enhanced CBM. Second, the number of production wells is found by dividing this total amount of enhanced CBM produced per day by an assumed 14,000 scm of enhanced CBM per day being produced at each well. Third, a ratio of producers to injectors of 1 to 1 is used to calculate the number of injection wells from the number of production wells. Fourth, it is assumed that no recycling of CO_2 is required. Finally, the cost of drilling and equipping the required production and injection wells is calculated. An overview of the cost model is provided in Figure 19.

4.4.1 CO_2 Effectiveness

For the design basis, it is assumed that 2 scm of CO_2 needs to be injected to produce 1 scm of enhanced CBM. This CO_2 effectiveness ratio is based on the results of sorption isotherm measurements carried out on bituminous coals in the laboratory. These measurements indicate that coal can adsorb roughly twice as much CO_2 by volume as methane. This may vary, however, as a result of other physical processes active within a coal reservoir. Based on data collected in the field, one source (Reeves, 2001) has reported the amount of CO_2 injected to CBM produced as being between 1.5 and 2 while another (Wong, 2002) has reported it as being closer to 3 than 2. It is important to note that the ratio is also dependent on the thermal maturity of the coal and that it can be as high as 10 to 1 for sub-bituminous coals. Based on these values, a sensitivity range of 1.5 to 10 scm of CO_2 per scm of enhanced CBM was chosen (EPRI, 1999; Stevens et al, 1998; Wong et al, 2000).

4.4.2 Rate of Enhanced CBM Production

The amount of enhanced CBM produced per day at each well is taken to be 14,000 scm. As in the case of EOR, there is no industry 'rule of thumb' for the production at each well on a daily basis. Instead, the CBM production rate depends on reservoir parameters such as coal seam permeability, gas saturation and thickness, and operational practices such as the recovery method used and well spacing (Stevens et al, 1996).

The variation in the CBM production rate that results from different values of reservoir parameters can be seen from a comparison of values for the San Juan and Black Warrior basins. Average production in the San Juan basin exceeds 23,000 scm per day per well, with many wells in the most productive area averaging over 85,000 scm per day. In contrast, the Black Warrior basin wells average 3,400 scm per day, reflecting the fact that this basin has lower permeability, thinner coal seams.

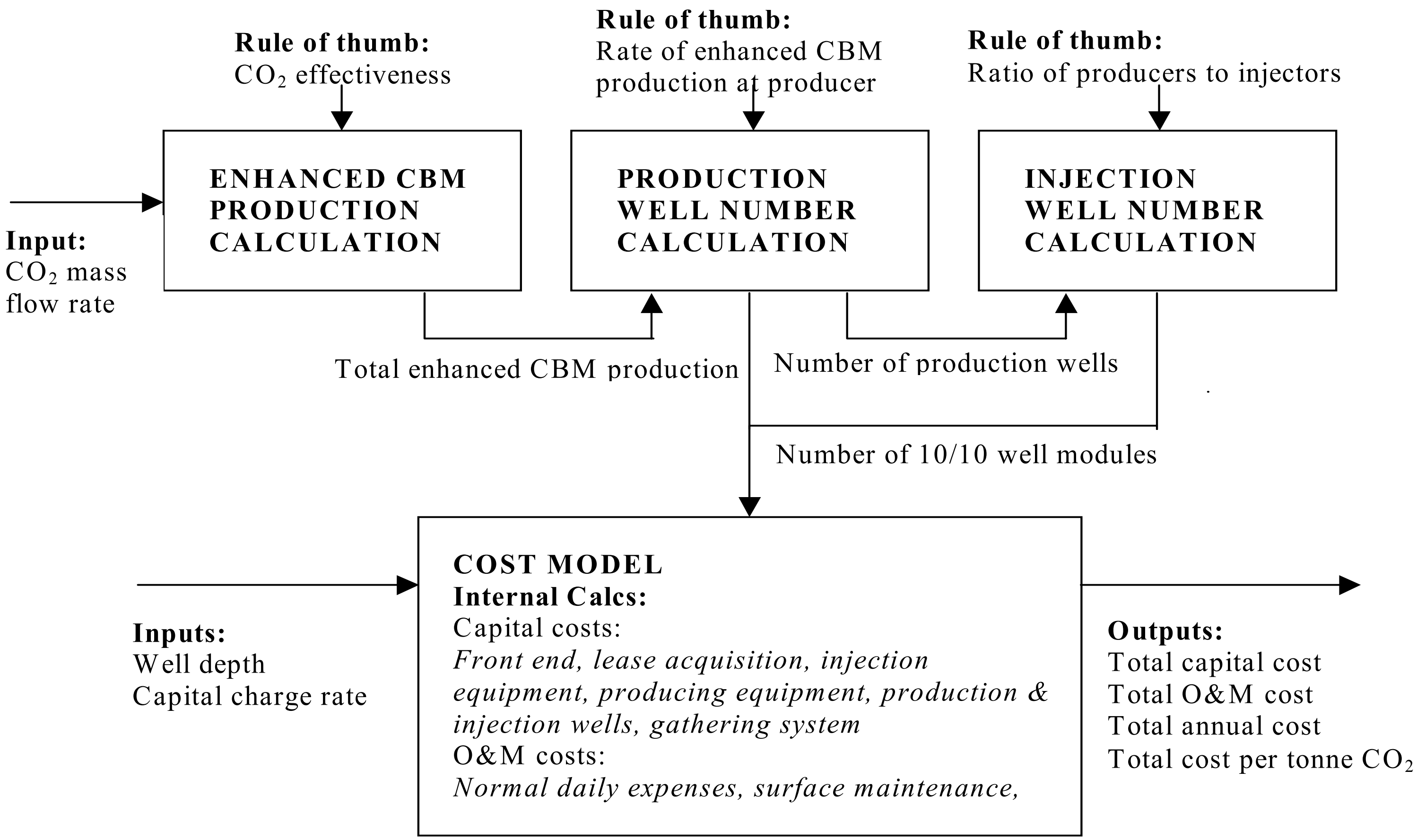

Figure 19: ECBMR cost model overview diagram

The effect of the recovery method on the CBM production rate is evident from a look at the production history of the #115 well within the Allison unit of the San Juan basin. Prior to CO_2 injection, the #115 well had been a sub-average performer, with a CBM production rate of 14,000 scm per day. However, following CO_2 injection, the daily CBM production rate rose sharply to 37,000 scm (Stevens et al, 1998; Stevens et al, 1996).

Based on the values given above for projects without CO_2 injection as well as the Allison unit CO_2-ECBMR pilot project, and advice from experts in the field (Reeves, 2002; Wong, 2002), the assumed base-case value of 14,000 scm of enhanced CBM per day per well was chosen. Also selected was a sensitivity range of 3,000 to 30,000 scm of enhanced CBM per day per well. It is important to note that the values for the base-case and sensitivity range were chosen to be somewhat lower than those values quoted for the San Juan basin. This is simply because the San Juan basin, being the world's most prolific basin for CBM, is expected to have higher CBM production rates than other coal basins with CO_2-ECBMR potential.

4.4.3 Ratio of Producers to Injectors

A ratio of producers to injectors of 1 to 1 is assumed for the CO_2-ECBMR concept design. It is an industry standard for production and injection wells to be arranged in a five-spot configuration, where this entails each injector being surrounded by four producers. This well configuration is used in the case of the Allison unit CO_2-ECBMR pilot project, which comprises nine CBM production and four CO_2 injection wells. The ratio of producers to injectors resulting from the five-spot configuration for this small number of wells is just over 2 to 1. However, as the number of production and injection wells increases, a repeating five-spot configuration results and the ratio of producers to injectors steadily approaches 1 to 1. For the CO_2-ECBMR concept design, which comprises a relatively large number of wells, a ratio of producers to injectors of 1 to 1 is therefore used.

4.4.4 CO_2 Recycle Ratio

The CO_2-ECBMR concept design assumes that CO_2 breakthrough at the production wells is negligible and that there is, therefore, no need for CO_2 recycling. At the Allison unit, breakthrough of CO_2 has been minimal during the life of the project. Following almost five years of injection, the CO_2 concentration in the produced gas was about 0.6 percent, which is only slightly above pre-injection levels of 0.4 percent (Reeves, 2001).

4.4.5 Drilling and Equipping of Production and Injection Wells

The cost of the CO_2-ECBMR process is calculated based on both production and injection wells needing to be drilled and equipped. If a coal bed is viewed primarily as a source of CBM, it makes more economic sense to partially deplete the reservoir of CBM before injecting CO_2. However, in the case that the primary role of the coal bed is as a repository for CO_2, early use of CO_2-ECBMR is favored. Given that the concern here is CO_2 sequestration, it is assumed for the purpose of the concept design that no CBM production has taken place at the coal bed prior to CO_2 injection. This assumption implies that production and injection wells need to be provided (Wong et al, 2000).

4.4.6 Cost Calculations

The total capital cost comprises front end and lease acquisition, injection and production equipment, well drilling and gathering system costs. The O&M costs include normal daily expenses, and surface and subsurface maintenance costs.

Prior to acquiring a lease position, geological expenditures, geophysical expenditures, and engineering-based feasibility studies are often conducted. In addition, outlays are generally required for obtaining the lease and its associated permits. These front-end costs will vary greatly but may range from \$20,000 to \$30,000 per well for a commercial project (GRI-81/0159, 1983). For this study, a cost of \$25,000 per well is assumed.

All of the other field costs, except for the well drilling cost, are based on data contained in the EIA 'Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations' report (Energy Information Administration, 2001). A representative ECBMR lease, or module, comprising 10 CO_2 injection wells and 10 producing wells with dewatering facilities is used for the design basis. The 10 CO_2 injection wells are drilled to a depth of 610 m and equipped with a battery of lease equipment, which includes distribution lines, headers, electrical service, and controls. The 10 producing wells, also drilled to a depth of 610 m, are equipped with beam balanced/sucker rod dewatering.

The well drilling cost is calculated based on a relationship derived from data contained in the '1998 Joint Association Survey (JAS) on Drilling Costs' report (American Petroleum Institute, 1999). This relationship between well depth and drilling cost is shown in Figure 20.

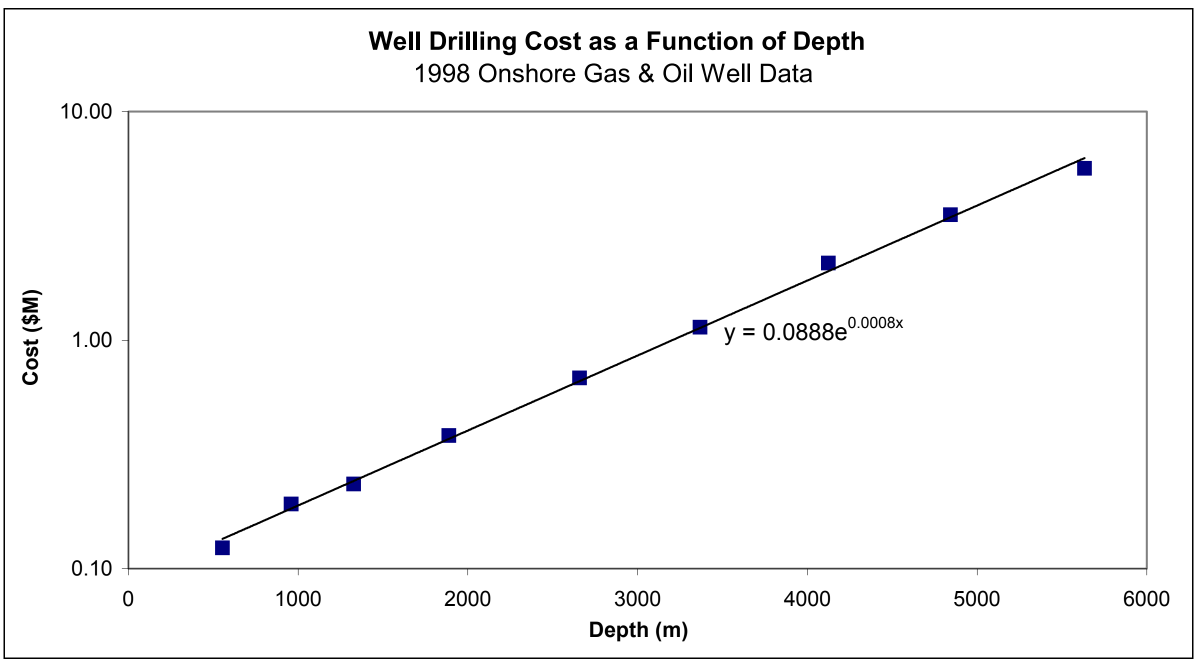

Figure 20: Well drilling cost as a function of depth

The field equipment and well drilling capital costs, and the associated O&M costs, are shown on a per module basis in Table 26. This table also gives the power costs associated with the gathering and sales gas compressors on a per kilowatt-hour basis.

Table 26: Capital and O&M cost estimation factors

Parameter	Unit	Value
CAPITAL COSTS		
Injection Equipment:		
Plant	$/module	104,455
Distribution Lines	$/module	70,182
Header	$/module	55,545
Electrical Service	$/module	87,818
Producing Equipment:		
Tubing	$/module	40,800
Rods & Pumps	$/module	39,200
Pumping Equipment	$/module	340,000
Gathering System:		
Flowlines	$/module	42,500
Manifold	$/module	42,600
Gathering Compressor	$/module	105,000
Sales Gas Compressor	$/module	3,970,000
Lease Equipment:		
Producing Separator	$/module	12,400
Storage Tanks	$/module	76,600
Accessory Equipment	$/module	35,800
Disposal System	$/module	96,700
Production & Injection Wells	$/module	1,446,601
O&M COSTS		
Normal Daily Expenses:		
Supervision & Overhead	$/module	50,245
Labor	$/module	39,936
Consumables	$/module	7,664
Operative Supplies	$/module	4,518
Auto Usage	$/module	7,900
Pumping & Field Power	$/kW-hr	0.044
Gathering Compressor	$/kW-hr	0.044
Sales Gas Compressor	$/kW-hr	0.044
Surface Maintenance (Repair & Services):		
Labor (roustabout)	$/module	18,282
Supplies & Services	$/module	27,182
Equipment Usage	$/module	7,064
Other	$/module	2,782
Subsurface Maintenance (Repair & Services):		
Workover Rig Services	$/module	30,518
Remedial Services	$/module	8,145
Equipment Repair	$/module	7,400
Other	$/module	6,764

4.5 DESIGN BASIS

4.5.1 Module Design

The ECBMR design is tied as closely as possible to the EIA 'Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations' report (Energy Information Administration, 2000) in order to make use of the cost data. This report is described in detail in Section 3.5.1.

The base case design is based on a CO_2 effectiveness factor of 2 scm per scm of enhanced CBM and an enhanced CBM production rate of 14,000 scm per day per well. From the design flow rate of 3.76 million scm (7,389 tonnes) of CO_2 per day, the total enhanced CBM production is calculated using the CO_2 effectiveness factor to be 1.88 million scm. Dividing this total enhanced CBM production by the enhanced CBM production rate per well, the required number of production wells is found to be 135. Given a producer to injector ratio of 1 to 1, 135 injection wells are required. In keeping the design consistent with the EIA modular approach, the ECBMR field for the base case therefore consists of 14 10/10 well modules. Finally, a well depth of 610 m, which is slightly more than the average depth of the CBM wells reported in the '1998 JAS on Drilling Costs' report, is selected as typical. Table 27 summarizes the base case for ECBMR.

Table 27: Design basis for ECBMR base case

Parameter	Unit	ECBMR Base Case
CO_2 Effectiveness	scm/scm enhanced CBM	2.0
CBM Production per Well	scm enhanced CBM/day/well	14,000
Total CBM Production*	million scm enhanced CBM/day	1.88
Number of CBM Wells*		135
Number of CO_2 Wells*		135
New CO_2*	scm/day/well	28,000
Well Depth	m	610

Each ECBMR field requires a gathering line compressor to transfer dewatered methane from the 10 producing wells to a connecting pipeline. The methane from the wells is fed to a common pipe at 1.7 bar and compressed to 4.5 bar. Table 28 indicates the basis for the gathering compressor design and the compressor requirements.

Table 28: ECBMR gathering compressor design basis

Parameter	Unit	Value
Maximum Methane Rate	thousand scm/day	140
Suction Pressure	bar	2.4
	psia	24.7
Discharge Pressure	bar	4.5
	psia	64.7
Compressor Displacement	cmm	41
Compression Ratio		1.875
Compressor Configuration		Motor Driven Reciprocating
Maximum Horsepower		210
Maximum Connected Power	kW	157
Compressor Cost	$	105,000

A second compressor is required for sending the gathered gas from all the modules through a common sales gas line to a nearby pipeline. The gas must be compressed to 25.1 bar for transfer to the pipeline. Table 29 indicates the basis for the sales gas compressor design and the compressor requirements.

Table 29: ECBMR sales gas compressor design basis

Parameter	**Unit**	**Value**
Maximum Methane Rate	million scm/day	1.88
Suction Pressure	bar	4.5
	psia	64.7
Discharge Pressure	bar	25.1
	psia	364.7
Compressor Displacement	cmm	291
Compression Ratio		5.637
Compressor Configuration		Motor Driven Reciprocating
Maximum Horsepower		7,580
Maximum Connected Power	kW	5,655
Sales Gas Compressor Cost	$	3,970,000

A summary of the lease equipment required for the ECBMR design is given in Table 30.

Table 30 : Lease equipment
(1 in = 0.0254 m, 1 hp = 746 J/s, 1 ft = 0.305 m, 1 cf = 0.028 m, 1 psig = 0.069 bar)

Equipment Description	Specification	Quantity
Tubing	2.375 inch, Grade J-55	20,000 feet
Sucker Rod	API Class K	20,000 feet
Pump Rod	API Type RWBC	10
Pumping Unit	API Size M160D 173-74, 20 hp	10
Flowline	4 inch, Schedule 40 Steel	16,000 feet
Manifold	10 valves, 2 inch 3-way	1
Production Separator	Vertical, 30 inch x 10 feet, 5.0 million scf/day gas	1
Storage Tank	50,000 gallon	2
Water Disposal Pump	Quintuplex, 1,000 psi, 20 hp	1
Water Disposal Line	3 inch, Schedule 40 Steel	2,000 feet
Gas Meter	million scf/day	1

4.5.2 Capital and O&M Cost Inputs

All of the capital and O&M costs, except for the power costs, are found by multiplying the per module costs, given in Table 26, by the required number of modules, as detailed in Section 4.5.1. In the case of the gathering compressor and sales gas compressor power costs, the costs per kilowatt-hour are multiplied by 8,760, the total hours of operation per year, and the respective power requirement. Table 31 summarizes the model inputs for the capital and O&M costs for the base case EOR design.

Table 31: Capital and O&M cost inputs for the ECBMR base case

Parameter	Input
Number of Modules	
CAPITAL COSTS	
Front End & Lease Acquisition Costs	$6,750,000
Injection Equipment:	
Plant	$1,410,000
Distribution Lines	$947,000
Header	$750,000
Electrical Service	$1,190,000
Producing Equipment:	
Tubing	$551,000
Rods & Pumps	$529,000
Pumping Equipment	$4,590,000
Gathering System:	
Flowlines	$574,000
Manifold	$575,000
Gathering Compressor	$1,420,000
Sales Gas Compressor	$3,970,000
Lease Equipment:	
Producing Separator	$167,000
Storage Tanks	$1,030,000
Accessory Equipment	$483,000
Disposal System	$1,310,000
Production & Injection Wells	$39,100,000
Subtotal	$65,300,000
O&M COSTS	
Normal Daily Expenses:	
Supervision & Overhead	$678,000
Labor	$539,000
Consumables	$103,000
Operative Supplies	$61,000
Auto Usage	$107,000
Pumping & Field Power (1,485 kW)	$572,000
Gathering Compressor (2,120 kW)	$817,000
Sales Gas Compressor Power (6,654 kW)	$2,180,000
Surface Maintenance (Repair & Services):	
Labor (roustabout)	$247,000
Supplies & Services	$367,000
Equipment Usage	$95,400
Other	$37,600
Subsurface Maintenance (Repair & Services):	
Workover Rig Services	$412,000
Remedial Services	$110,000
Equipment Repair	$100,000
Other	$91,300
Subtotal	$6,520,000

4.6 RESULTS

This section presents costs for CO_2 storage for ECBMR. The storage costs comprise transportation, injection and monitoring costs. The results, which include the revenue generated from the sale of the enhanced CBM produced, are given as levelized annual CO_2 storage costs on a life-cycle, greenhouse gas-avoided basis.

High and low cost cases have been chosen for ECBMR, and are presented together with the base case in Table 32. The price of gas at the wellhead is taken to have a base-case value of $2 per GJ (gigajoule), a low-end value of $1.80 per GJ and a ceiling price of $3 per GJ; a Gas Royalty of 12.5 percent is assumed.

Table 32: ECBMR base, high cost and low cost cases

Parameter	Units	ECBMR Base Case	ECBMR High Cost Case		ECBMR Low Cost Case	
CO_2 Effectiveness	scm/scm enhanced CBM	2	10	+400%	1.5	-33%
CBM Production per Well	scm enhanced CBM/day/well	14,000	3,000	-79%	30,000	+114%
Gas Price	$/GJ	2	1.80	-10%	3	+50%
Depth	m	610	1,219	+100%	610	0%
Pipeline Distance	Km	100	300	+200%	0	-100%

The results for the high and low cost cases as well as the base case are given in Table 33. The CO_2 storage cost for ECBMR can be seen to be widely different for the high and low cost cases. In reality, a CO_2-ECBMR project with parameter values approaching those of the high cost case would not be carried out.

Table 33: Results for ECBMR base, high cost and low cost cases

Parameter	Units	ECBMR Base Case	ECBMR High Cost Case	ECBMR Low Cost Case
Total CBM Production	(million scm enhanced CBM/day)	1.88	0.38	2.51
Number of CBM Wells		135	126	84
Number of CO_2 Wells		135	126	84
New CO_2	scm/day/well	28,000	30,000	45,000
Levelized Annual CO_2 Storage Cost	$/tonne CO_2 eq. LC GHG avoided	(5.59)	18.88	(25.72)

4.7 Sensitivity Analysis

The sensitivity of the CO_2 storage cost for ECBMR is determined for five key parameters: well depth, CO_2 effectiveness, CBM production rate, gas price and pipeline distance. It can be seen in Figure 21 that increases in well depth, CO_2 effectiveness and pipeline distance cause an increase in the cost of storage, while increases in CBM production rate and gas price decrease the storage cost. More noteworthy, the figure shows that changes in gas price have the greatest effect on storage cost, followed closely by changes in CO_2 effectiveness.

For the high and low cost values for each of the five key parameters, the percentage change in the value from the base case is shown in Table 32. This is done to illustrate the fact that the range in the values of some parameters is expected to be greater than for others.

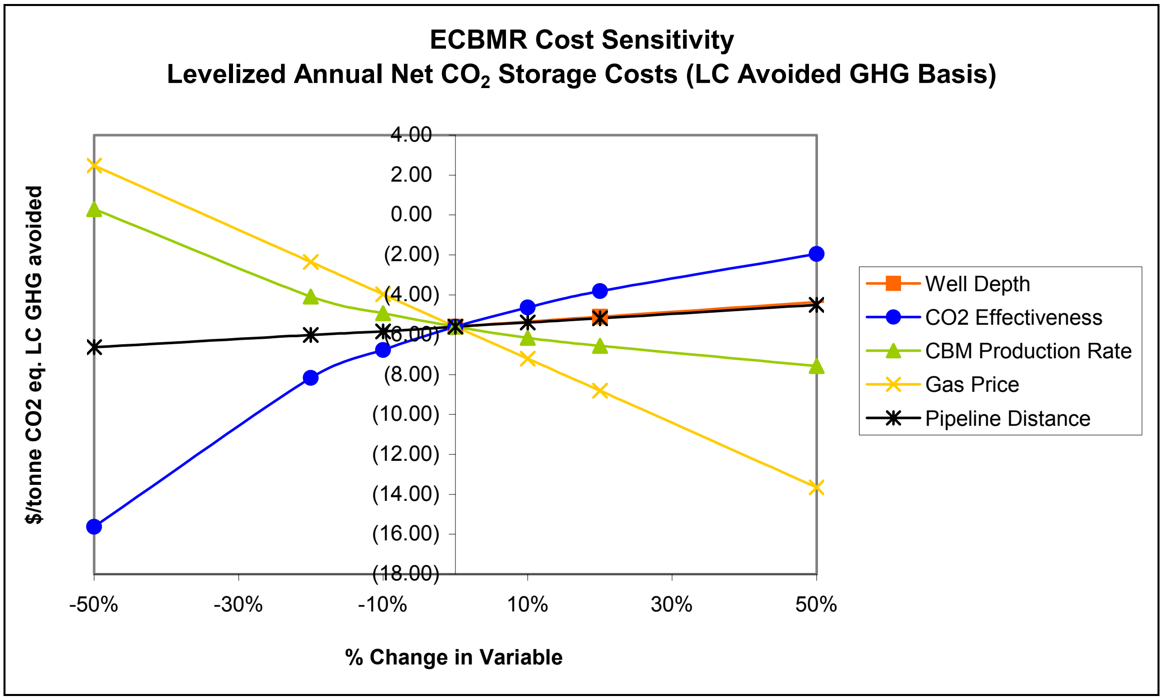

Figure 21: Sensitivity analysis for ECBMR

4.8 COMPARISON TO LITERATURE

A comparison is made between the costs obtained in this study for the CO_2-ECBMR base case design and those calculated using cost estimates from a paper by Wong, et al (Wong et al, 2000). The costs for this study were based on the EIA 'Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations' report (Energy Information Administration , 2000) and the API 'Joint Association Survey on Drilling Costs' report (American Petroleum Institute, 1999). Wong, et al., cost estimates are given for a conceptual 50-well pair CO_2-ECBMR field development in the Alberta Plains region and are shown in Table 34. It is to be noted that the well drilling and completion cost estimates are based on a reservoir depth of 1,280 m.

Table 34: CO_2-ECBMR cost estimates (Wong et al, 2000).

Item	Unit	Value
CAPITAL COSTS		
Wells:		
Drilling	\$/well pair	346,840
Completion	\$/well pair	113,390
Equipment:		
Tie-in	\$/well pair	113,390
Stimulation	\$/well pair	6,670
O&M COSTS		
Well maintenance	\$/well pair/yr	21,344

Using these cost estimates, the capital, the well surface, and subsurface maintenance, costs of CO_2-ECBMR were calculated for the 1,219 m case design. Table 35 shows the results of these calculations together with the previously determined CO_2-ECBMR costs from this study. It should be noted that the latter, in order to make the results comparable, have been given for a reservoir depth of 1,219 m and do not include the front end lease expense of the sales gas compressor.

Table 35: Comparison of CO_2-ECBMR cost results (Wong et al, 2000; Energy Information Administration , 2000).

Item	Unit	Using EIA and JAS Report Data	Using Cost Estimates
CAPITAL COSTS			
Total cost of wells	\$	63,600,000	62,131,000
Total cost of equipment	\$	17,980,000	16,208,000
Subtotal	\$	81,580,000	78,339,000
O&M COSTS			
Well maintenance	\$/yr	2,204,000	2,881,000
Subtotal	\$/yr	7,660,000	not reported

This comparison shows that the cost of the CO_2-ECBMR design is very similar for the two sets of cost data.

5. DEPLETED GAS/OIL RESERVOIR, AND SALINE AQUIFER STORAGE

5.1 INTRODUCTION

The CO_2 sequestration options considered here include CO_2 storage in depleted natural gas and oil reservoirs, and deep saline aquifers. Geologic CO_2 storage options with value-added products, specifically EOR and ECBMR, are treated in previous chapters.

5.2 STATE OF THE ART

5.2.1 Applications

The first, and to date only, commercial-scale project dedicated to geologic CO_2 storage is in operation at the Sleipner West field. Sleipner West is a natural gas/condensate field operated by Statoil and located in the North Sea about 250 km off the coast of Norway. The natural gas produced at the field has a CO_2 content of about 9 percent which, to meet commercial specifications, must be reduced to 2.5 percent. It is standard practice in natural gas production for the byproduct CO_2 to be vented to the atmosphere. At Sleipner, however, the CO_2 is compressed and injected via a single well into the Utsira Formation, a 250-m-thick, brine-saturated aquifer located at a depth of 800 m below the seabed. About one Mt of CO_2 has been sequestered annually at Sleipner since October 1996, with a total of 20 Mt of CO_2 expected to be sequestered over the lifetime of the project. A second scheme is planned that would involve about 0.7 Mt per year of CO_2 produced at the Snohvit gas field in the Barents Sea off northern Norway being injected into a deep sub-sea formation (Holloway et al, 1996; Royal Commission on Environmental Pollution, 2000; Herzog, 2001; IEAGHG, 2002; Kaarstad, 2001).

5.2.2 Storage Potential

Depleted Natural Gas Reservoirs

One type of geologic reservoir with significant potential for CO_2 sequestration is the abandoned natural gas field. Nearly all of the volume of abandoned gas fields should be available for CO_2 storage. The first reason for this is that the exploitation of a gas field normally extracts up to 95 percent of the available gas. Second, only a very small fraction of the abandoned reservoir's pore space is likely to be invaded by formation water because water is more viscous than low-pressure methane. In the unlikely case that an abandoned reservoir does become water saturated, due to the reservoir being highly permeable and/or having been abandoned for many years prior to CO_2 injection, the injected CO_2 would simply displace the formation brine. It should be noted here that abandoned gas fields are quite widespread, with an estimated 98 to 133 Gt of total carbon sequestration potential (Holloway et al, 1996; Royal Commission on Environmental Pollution, 2000; Stevens et al, 2000; U.S. Department of Energy, 1999; Ormerod, 1994).

In active natural gas fields, it has been proposed that CO_2 injection could prolong the economic life of a field by maintaining the reservoir pressure longer than would otherwise be possible. It is important to note that, to date, there have been no demonstrations of CO_2-enhanced gas production. Furthermore, this technology is unlikely to be implemented in the future due to the risks of contaminating the hydrocarbon reserve. For these reasons, CO_2 injection into active gas fields is not considered here as a geologic CO_2 storage option (Holloway et al, 1996; Stevens et al, 2000; U.S. Department of Energy, 1999).

Depleted Oil Reservoirs
The other type of hydrocarbon reservoir in which CO_2 could possibly be sequestered is the depleted oil field. In the case of the depleted oil field, it is important to note that production ceases not because all the oil has been recovered, but rather because the field is no longer economic to produce. It is typical for primary production to result in only about 30 percent of the original oil in place (OOIP) being recovered. Even in fields in which secondary recovery by water flooding has taken place, around 50 percent of the OOIP may remain in the reservoir.

Depleted Saline Aquifers
Deep saline aquifers have the greatest CO_2 sequestration potential, with these reservoirs being the most widespread and having the largest volumes. The latter is very important given that, unlike exhausted hydrocarbon reservoirs where the reservoir pressure has been very substantially reduced by the production of reservoir fluids, the pressure in aquifers is hydrostatic or greater. In order to ensure that the fracture pressure of an aquifer is not exceeded, it is necessary that CO_2 injection wells be located in regions of high permeability and that the total amount of CO_2 injected be limited. Modeling suggests that, on average, only two percent of the pore volume of an aquifer can be safely occupied by CO_2, but this number is highly uncertain (Holloway et al, 1996).

To give an illustration of the aquifer volumes needed to store the CO_2 emissions from power plants, the aquifer volume required to store the CO_2 captured at the baseline IGCC plant was determined. Estimating that the total quantity of CO_2 to be supplied by the base-case plant over its 20-year lifetime is 43 Mt, and assuming a supercritical CO_2 density of 0.7 kg/m^3, it is found that an aquifer with an effective pore volume of approximately 0.0617 km^3 is needed. Given a realistic effective porosity of 30 percent and a storage efficiency of two percent, this is equivalent to a total aquifer volume of about 10.28 km^3. This can be visualized as a circular-shaped aquifer with a diameter of 11.4 km and a thickness of 100 m (Holloway et al, 1996; Ormerod, 1994).

CO_2 can be sequestered in two types of deep saline aquifer. The first type is directly analogous to a hydrocarbon field, where the reservoir acts as a geologic trap. It should also be possible to inject the CO_2 into aquifers that do not have lateral seals. An impermeable caprock to prevent the buoyant CO_2 from escaping vertically and a down-directed flow regime to transport the CO_2 away from the surface should theoretically be sufficient to provide secure CO_2 storage (Gunter et al, 1996; Hitchon, 1996). This possibility vastly increases the total potential CO_2 sequestration capacity of aquifers. A lack of information about aquifers that are not located near where oil and gas exploration has taken place has led to greatly varying estimates of global CO_2 storage potential. An assessment of the varying estimates has, however, suggested that the global storage potential lies somewhere between 100 and 3,000 Gt of carbon (Holloway et al, 1996; Ormerod, 1994; Stevens et al, 2000).

5.2.3 Storage Mechanics

CO_2 is stored in geologic formations by a number of different trapping mechanisms, with the exact mechanism depending on the formation type. To make full use of storage capacity, the CO_2 should be stored in its dense or supercritical phase, i.e., above the critical pressure of 7.4 MPa and critical temperature of 31°C. For a hydrostatic pressure gradient of 10.5 MPa per km, this condition is met at depths below about 700 m. At 800-m depth, the density of supercritical CO_2 is 740 kg per m^3. Since the CO_2 under these pressure and temperature conditions will still be less dense than formation water, it will naturally rise to the top of the reservoir, and a trap is needed to ensure that it does not reach the surface. In oil and gas reservoirs, as well as aquifers directly analogous to hydrocarbon fields, geologic traps immobilize the CO_2. In the case of aquifers with no distinct geologic traps, however, an impermeable caprock above the underground reservoir is needed. This forces the CO_2 to be entrained in the groundwater flow and is known as hydrodynamic trapping (Holloway et al, 1996; U.S. Department of Energy, 1999; Ormerod, 1994; Hitchon, 1996).

Two other very important trapping mechanisms are solubility and mineral trapping. Solubility trapping involves the dissolution of CO_2 into the reservoir fluids; mineral trapping involves the reaction of CO_2 with minerals present in the host formation to form stable, solid compounds, e.g. carbonates. These latter two mechanisms are particularly important in the case of an aquifer with no lateral seals. As the CO_2 moves through the reservoir along the flow path, it comes into contact with uncarbonated formation water and reactive minerals. A proportion of the CO_2 dissolves in the formation water and some of this dissolved CO_2 becomes permanently fixed by reactions with minerals in the host rock. If the flow path is long enough, the CO_2 might all dissolve or become fixed by mineral reactions before it reaches the basin margin, essentially becoming permanently trapped in the reservoir (Holloway et al, 1996; Herzog, 2001; Gunter et al, 1996; Hitchon, 1996).

5.2.4 Feasibility of Storage Option

The injection of CO_2 into geologic formations is a promising CO_2 sequestration option. First, the technology for injecting CO_2 into exhausted hydrocarbon reservoirs and deep saline aquifers already exists. Oil producers in the Permian Basin of western Texas and eastern New Mexico, and in the Rocky Mountain and Mid-continent regions have been injecting CO_2 for EOR for more than 25 years. Underground natural gas storage projects also provide a considerable base of relevant geologic and engineering experience. Second, even though no direct economic benefits are derived, it should be noted that the CO_2 sequestration potential associated with the injection of CO_2 into exhausted oil and natural gas reservoirs and deep saline aquifers greatly exceeds that of EOR and ECBMR using CO_2 floods (U.S. Department of Energy, 1999).

Exhausted hydrocarbon reservoirs have the advantage over aquifers that these fields are proven long-term traps, their geology is well characterized, and their existing surface and subsurface infrastructures could readily be converted for CO_2 distribution and injection. On the downside, the locating and sealing of abandoned wells could present a n ongoing challenge. Deep saline aquifers, however, have a larger CO_2 capacity, are more widespread and are generally located closer to CO_2 emission sources (Stevens et al, 2000; U.S. Department of Energy, 1999; Ormerod, 1994).

5.3 PROCESS DESCRIPTION

Figure 22 is a block flow diagram, indicating the overall flow and distribution of CO_2 from the IGCC plant to the depleted gas and oil fields, and deep saline aquifers. Developing a depleted reservoir or aquifer for CO_2 storage involves:

- Screening and evaluation of sites
- Drilling and equipping injection wells
- Installation of high-pressure injection equipment and related piping

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 include piping to distribute CO_2 to the injection wells, CO_2 flow control equipment, and equipment to monitor well conditions.

The source and quantity of CO_2 supplied to the field is the same as for the EOR storage option, i.e. the system must be able to handle 3.76 million scm (7,389 tonnes) of CO_2 per day. Determining the required CO_2 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. Moving the CO_2 into the reservoir 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 (Energy Information Administration, 2000). It is found that the pipeline delivery pressure, 103 bar, is adequate for injection.

The CO_2 injection wells are as described in Section 5.3. For geologic CO_2 storage, these wells are equipped with a battery of lease equipment that includes distribution lines, headers, electrical service and controls. This equipment enables the CO_2 to be taken from the pipeline terminal and injected at a pressure that maintains the downhole injection point pressure.

As a final note, it is assumed that this facility, like the power plant, has a lifetime and design/construction time of 20 and 4 years, respectively.

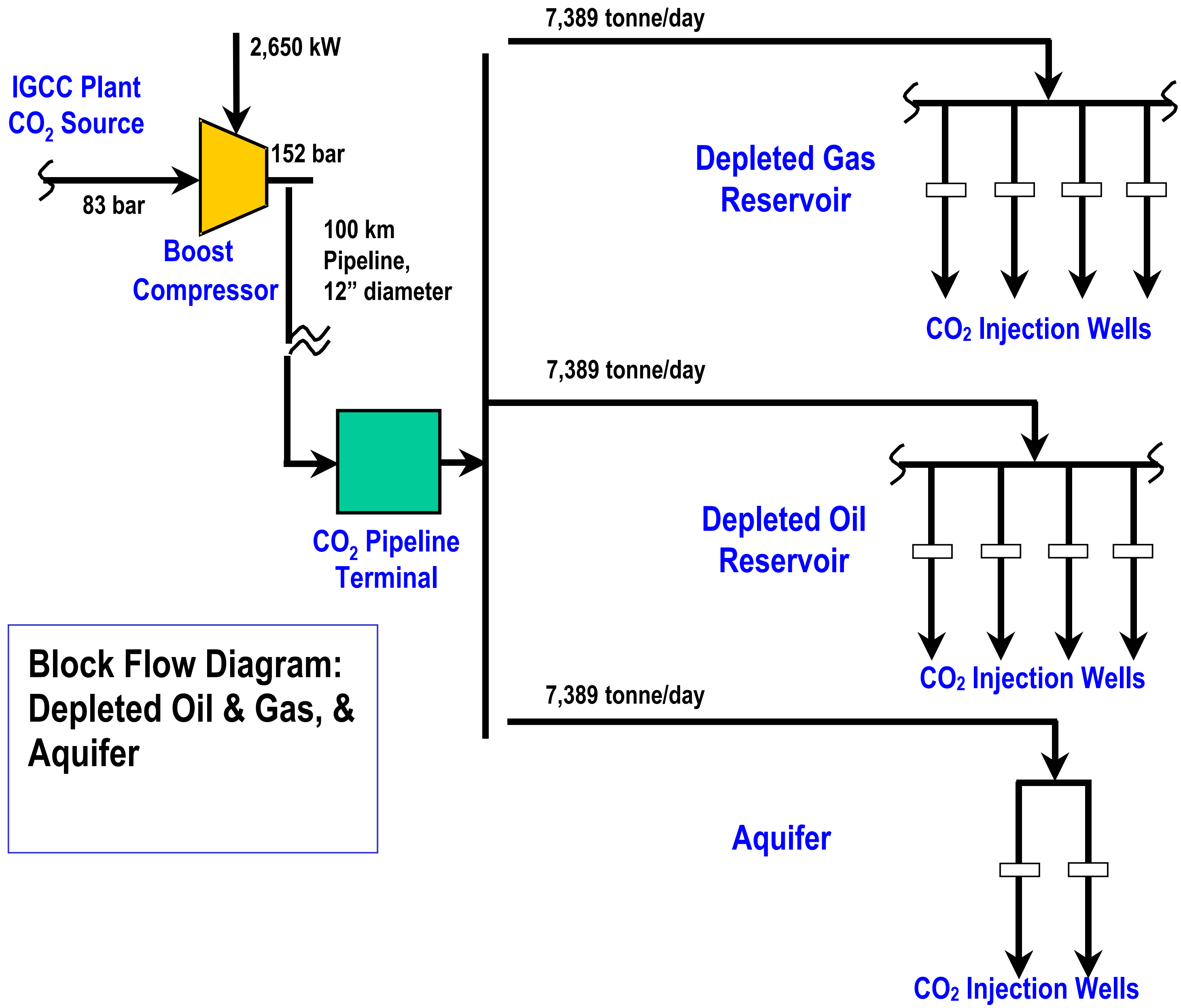

Figure 22: Depleted Oil/Gas Reservoir and Aquifer Block Flow Diagram here

5.4 METHODOLOGY USED

Depleted natural gas and oil reservoirs, and deep saline aquifers, differ quite substantially from one another in terms of typical values of reservoir parameters such as pressure, thickness, depth, and permeability. The processes that govern the rate at which CO_2 can be injected at a well, and thus the number of wells required, are however essentially identical for the three types of reservoir. Given this, the same costing method is applied to each of the three geologic CO_2 storage options.

The cost model for the geologic CO_2 storage options can be broken down into a number of components. First, there is a relationship for calculating the number of wells required for a given CO_2 flow rate, CO_2 downhole injection pressure, and set of reservoir parameters. Second, an iterative procedure is used to take into account the interdependent relationship between CO_2 downhole injection pressure and well number. Third, a set of capital and O&M cost factors are used to determine cost based on well number. Each of these components, illustrated in the overview diagram in Figure 23, is described below in greater detail.

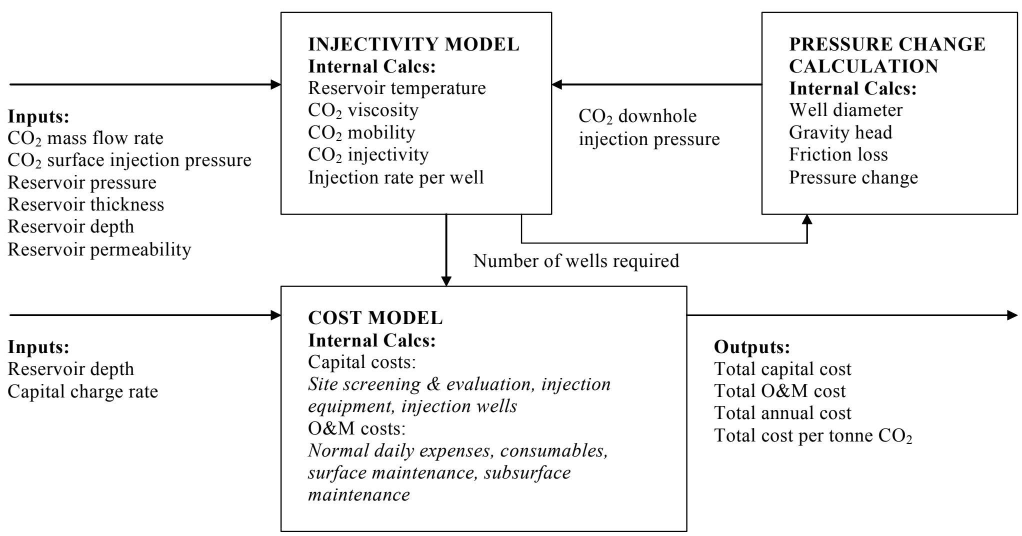

Figure 23: Geologic storage cost model overview diagram

The value of reservoir parameters, even when the same type of geological reservoir is being considered, can vary significantly. This variation is important because it has the potential to greatly affect the cost estimate of the geologic CO_2 storage option. In order to take account of this variation, base and sensitivity cases are run for each of the three storage options. These design bases, which comprise different sets of reservoir parameters, are detailed in Section 5.5.1.

5.4.1 Well Number Calculation

The calculation of the number of wells requires inputs for the CO_2 mass flow rate, CO_2 downhole injection pressure, and reservoir pressure, thickness, depth, and permeability. Given the depth of the reservoir, reservoir temperature is calculated assuming a surface temperature of 15ºC and a geothermal gradient of 25°C/km. The viscosity of the CO_2 (μ_{CO2}) is then calculated based on a correlation published by McHugh and Krukonis (McHugh et al, 1986). Next, the absolute permeability (k_a) is found from

$$k_a = (k_h \text{ x } k_v)^{0.5}$$

where k_v = the vertical permeability and is equal to 0.3 times the horizontal permeability and k_h = the given horizontal permeability (Law et al, 1996).

A relationship, derived by Law and Bachu (Law et al, 1996) is used to determine CO_2 injectivity from CO_2 mobility. This relationship is shown in Figure 24. The equation for CO_2 injectivity is

$$CO_2 \text{ injectivity} = 0.0208 \text{ x } CO_2 \text{ mobility}$$

where CO_2 injectivity is equal to the mass flow rate of CO_2 (m) that can be injected per unit of reservoir thickness (h) and per unit of downhole pressure difference ($P_{inj} – P_{res}$), and CO_2 mobility equals the CO_2 absolute permeability (k_a) divided by CO_2 viscosity (μ_{CO2}). Given the injectivity, the injection rate per well ($Q_{CO2/well}$) can be found from

$$Q_{CO2/well} = CO_2 \text{ injectivity x h x } (P_{inj} – P_{res})$$

Finally, the number of wells required (n) is given by

$$n = m/Q_{CO2/well}$$

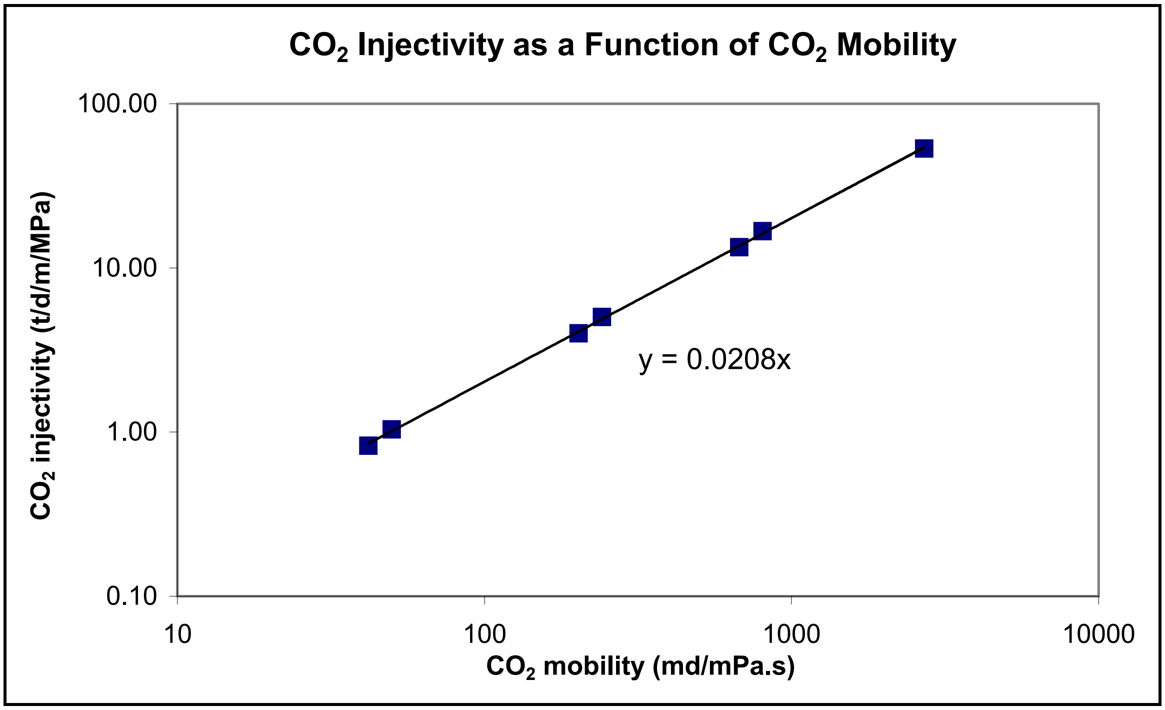

Figure 24: CO_2 injectivity as a function of CO_2 mobility

5.4.2 CO_2 Downhole Injection Pressure Calculation

The surface CO_2 injection pressure is equal to the 10.3 MPa minimum CO_2 pipeline outlet pressure used in the design of the pipeline for CO_2 transport. Based on this value, no additional recompression of CO_2 is required at the wellhead. A well diameter of 0.059 m is used for the injection pipe.

An iterative procedure is used to calculate the CO_2 downhole injection pressure and the required number of wells. This is because the downhole injection pressure and well number are mutually dependent. Downhole injection pressure is found by adding the pressure increase due to the gravity head to the surface pressure and then subtracting from this the pressure decrease due to friction loss, which depends on the velocity of CO_2 in each well. Well number, on the other hand, is determined by CO_2 injectivity, which is dependent on the difference between the downhole injection and reservoir pressures.

It is important to note that, for the aquifer base and low-cost cases, it is necessary to increase the pipe diameter to 0.1 and 0.5 m, respectively. This is because smaller diameters in these cases result in unacceptable friction losses.

5.4.3 Cost Calculations

The total capital cost comprises site screening and evaluation, injection equipment and well drilling costs, while the total O&M cost includes the costs of normal daily operations, consumables, and surface and subsurface maintenance.

The capital cost for site screening and evaluation is based on an estimate given in a recent study by the Battelle Memorial Institute (Smith, 2001). This study estimated the costs for preliminary site screening and candidate evaluation at $1,685,000.

All of the other costs, except for the well drilling cost, are calculated based on values given in the EIA 'Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations' report (Law et al, 1996). Average lease equipment costs and O&M costs were developed on a per well basis. In the case of the injection equipment and surface maintenance, these average cost values are adjusted to take into account the number of wells. Similarly, the average cost value for subsurface maintenance is adjusted to take into account the well depth. These capital and O&M cost factors/functions are given in Table 36.

Table 36: Capital and O&M cost estimation factors/functions

Parameter	Unit	Value
CAPITAL COSTS		
Injection Equipment (Flowlines & Connections)	$/well	43,600*(7,389/(280*Number_of_wells))^0.5
O&M COSTS		
Normal Daily Expenses	$/well	6,700
Consumables	$/well	17,900
Surface Maintenance (Repair & Services)	$/well	13,600*(7,389/(280*Number_of_wells))^0.5
Subsurface Maintenance (Repair & Services)	$/well	5,000*Well_depth/1219

The well drilling cost is calculated based on a relationship derived from data contained in the '1998 Joint Association Survey (JAS) on Drilling Costs' report (American Petroleum Institute, 1999). This relationship between well depth and drilling cost is shown in Figure 25. To determine the relationship, regression analysis was performed on drilling cost data for onshore gas and oil wells. The total well drilling cost is found by multiplying the cost of drilling a single well for the given reservoir depth, taken from the graph, by the required number of wells.

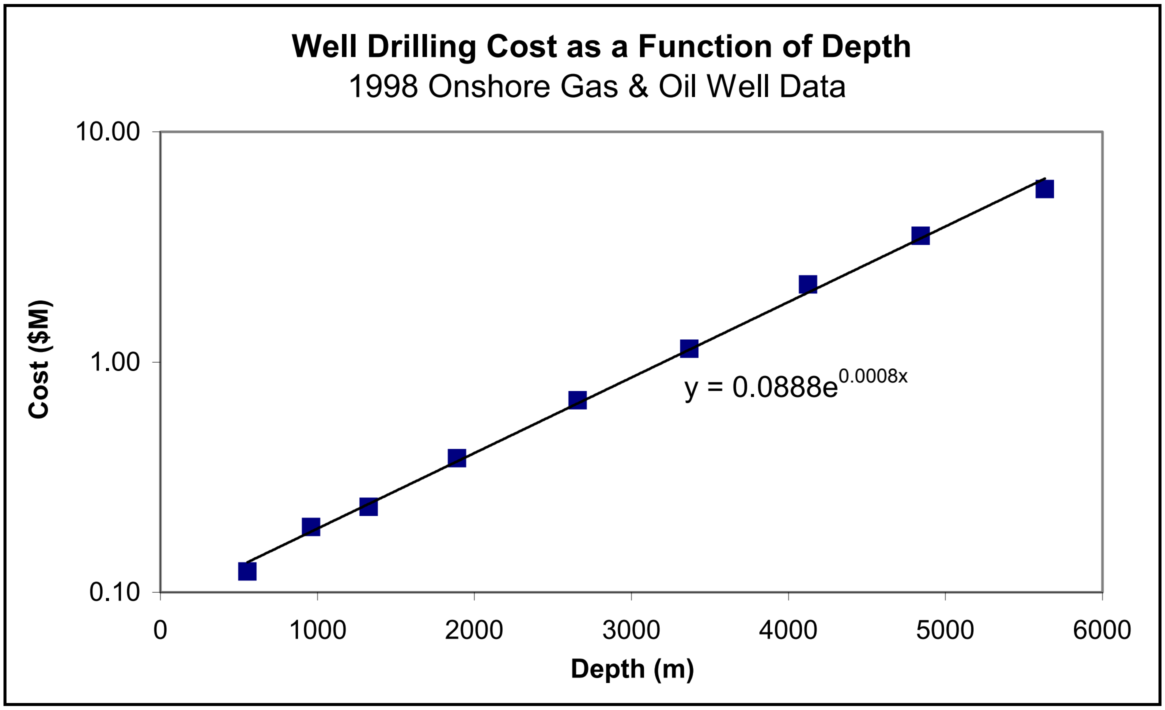

Figure 25: Well drilling cost as a function of depth

5.5 DESIGN BASIS

5.5.1 Reservoir Parameters and Well Numbers for Base and Sensitivity Cases

Typical, as well as a range of, values for reservoir properties of exhausted natural gas and oil fields, suggested by Vello Kuuskraa of Advanced Resources International, (Kuuskraa , 2001) are given in Table 37. It should be noted that these values are representative of the properties of gas and oil reservoirs found in the Permian Basin.

Table 37: Natural gas and oil reservoir property data

Parameter	Units	Gas Reservoir Typical	Gas Reservoir Range	Oil Reservoir Typical	Oil Reservoir Range
Pressure	MPa	3.45	2.07 – 6.89	13.78	3.45 – 20.7
Thickness	m	30.5	15.24 – 61.0	42.7	21.3 – 61.0
Depth	m	1,524	610 – 3,048	1,554	1,524 – 2,134
Permeability	md	1	0.01 – 100	5	5 – 19

Based on these reservoir parameter values, a base case as well as high-cost and low-cost cases were selected for both the depleted gas and oil reservoir options. It should be noted that, in the case of the gas reservoir, the range of permeability values considered was limited to give a reasonable number of wells. The parameter values for the base, high-cost and low-cost cases, as well as the corresponding number of wells required, are given in Table 38 and Table 39, respectively.

Table 38: Design bases for natural gas reservoir storage option

Parameter	Units	Gas Reservoir Base Case	Gas Reservoir High Cost Case	Gas Reservoir Low Cost Case
Pressure	MPa	3.5	6.9	2.1
Thickness	m	31	15	61
Depth	m	1,524	3,048	610
Permeability	md	1	0.8	10
Injection Rate per Well*	t/d	154	58	2,985
Number of Wells*		48	127	3

* calculated

Table 39: Design bases for oil reservoir storage option

Parameter	Units	Oil Reservoir Base Case	Oil Reservoir High Cost Case	Oil Reservoir Low Cost Case
Pressure	MPa	13.8	20.7	3.5
Thickness	m	43	21	61
Depth	m	1,554	2,134	1,524
Permeability	md	5	5	19
Injection Rate per Well*	t/d	358	116	5,720
Number of Wells*		21	64	2

* calculated

The aquifer base and sensitivity cases are based on aquifer property data given in the literature, (Ormerod, 1994; Law et al, 1996) including data obtained from the Bureau of Economic Geology's website (The University of Texas at Austin, 2001). This property data is presented in Table 40. In addition, the calculated values of well number are shown. It can be seen from this table that aquifer properties, and thus the number of wells that would be required and the cost, can vary considerably.

Table 40: Aquifer property data

Aquifer	Pressure (MPa)	Thickness (m)	Depth (m)	Permeability (md)	Number of wells
Sleipner West	9.0	184	1,020	10	2
IEA Study Aquifer	11.3	55	1,459	13	6
Glauconitic Sandstone, Albert Basin	12.4	13	1,480	30	11
Repetto Formation, Los Angeles Basin	6.9	800	2,400	250	1
Arbuckle Group, Oklahoma	2.1	600	2,400	0.005	418
Paluxy Sandstone, East Texas Basin	10.3	75	1,000	400	1
Jasper Interval, East Texas Gulf Coast	8.4	1,500	800	100	1
Pottsville Formation, Black Warrior Basin	6.9	1,100	500	15	1
Cedar Key Dolomite, Central Florida Region	1.0	325	1,000	15	1

Incomplete sets of data for 13 aquifers were also available from the Bureau of Economic Geology. This data is shown in Table 41.

Table 41: Incomplete sets of aquifer property data

Aquifer	Pressure (MPa)	Thickness (m)	Depth (m)	Permeability (md)
Glen Canyon Group, Sevier/Kaiparowitz Basin		175	2,000	
Morrison Formation, San Juan Basin		250	1,600	
Fox Hills Sandstone, Power River Basin		175	800	
Madison Group, Williston Basin		250	1,400	
Lyons Sandstone, Denver Basin		300	2,000	
Granite Wash, Palo Duro Basin	9.1	800	1,000	
Woodbine Formation, East Texas Basin	12.4	100	1,000	
Frio Formation, Texas Gulf Coast		500	800	500
St. Peter Sandstone, Illinois Basin	5.3	50	50	
Mt. Simon Formation, Michigan Basin	11.4	100	100	
Tuscaloosa Group, Alabama Gulf Coastal Plain	10.9	40	40	
Oriskany Formation, Appalachian Basin	10.0	5	5	
Lower Potomac Group, Eastern Coastal Plain	6.9	225	225	

The data given in these two tables were used in a statistical analysis to determine appropriate base, high-cost and low-cost cases for the aquifer storage option. The calculation of the values of aquifer pressure and depth for the base, high-cost and low-cost cases used the standard statistical functions. In the case of aquifer thickness and permeability, however, a logarithmic regression was necessary. This was due to the fact that the values of these two latter variables varied by more than two orders of magnitude.

The base values for aquifer pressure and depth were based on the arithmetic mean. The high-cost values of each of these parameters were then taken as the mean plus the standard deviation and the low-cost values as the mean minus the standard deviation. This corresponds to an increase in pressure and depth causing an increase in cost, and a decrease in these parameters causing a reduction in cost. The values for thickness and permeability were calculated in a similar manner, but taking into account that a reduction in these parameters increases the cost, and an increase reduces the cost. The final value for each parameter for the base, high-cost and low-cost cases is given Table 42. The number of wells required for each of these cases is also shown.

Table 42: Design bases for aquifer storage option

Parameter	Units	Aquifer Base Case	Aquifer High Cost Case	Aquifer Low Cost Case
Pressure	MPa	8.4	11.8	5.0
Thickness	m	171	42	703
Depth	m	1,239	1,784	694
Permeability	md	22	0.8	585
Injection Rate per Well*	t/d	9,363	82	889,495
Number of Wells*		1	91	1

* calculated

Reservoirs that are thick, shallow, and have high permeability require a smaller number of wells and, therefore, have a lower storage cost. A higher reservoir pressure results in lower injectivity (not desired), but higher CO_2 densities (desired). Therefore, a moderate pressure is optimal. In general, the permeability is the most critical parameter in determining costs.

5.5.2 Capital and O&M Cost Inputs

The capital cost of site screening and evaluation of $1,685,000 is taken for each of the three geologic storage options. The other capital and O&M costs are calculated using the cost estimation factors/functions given in Section 5.4.3. Based on the respective values of well depth and required number of wells, as detailed in Section 5.5.1, it is possible to determine the costs on a per well basis for each of the storage options. These per well costs are then multiplied by the total number of wells. The model inputs for the capital and O&M costs for the base cases are given in Table 43.

Table 43: Capital and O&M cost inputs for gas and oil reservoir, and aquifer base cases

Parameter	Gas Reservoir	Oil Reservoir	Aquifer
Number of Wells	48	21	1
CAPITAL COSTS			
Screening and Evaluation of Sites	$1,685,000	$1,685,00	$1,685,000
Injection Equipment (Flowlines & Connections)	$1,552,000	$1,026,000	$224,000
Injection Wells	$14,426,000	$6,465,000	$239,000
Subtotal	$17,700,000	$9,180,000	$2,150,000
O&M COSTS			
Normal Daily Expenses	$322,000	$141,000	$7,000
Consumables	$859,000	$376,000	$18,000
Surface Maintenance (Repair & Services)	$484,000	$320,000	$70,000
Subsurface Maintenance (Repair & Services)	$300,000	$134,000	$5,000
Subtotal	$1,970,000	$970,000	$100,000

5.6 RESULTS

This section presents costs for CO_2 storage for depleted gas and oil reservoirs, and deep saline aquifers. The storage costs comprise transaction, transportation, injection and monitoring costs. The results are given as levelized annual CO_2 storage costs on a life-cycle, greenhouse gas-avoided basis.

5.6.1 Depleted Gas Reservoir

High and low cost cases have been chosen for the depleted gas reservoir option, and are presented together with the base case in Table 44.

Table 44: Depleted gas reservoir base, high cost and low cost cases

Parameter	Units	Gas Reservoir Base Case	Gas Reservoir High Cost Case		Gas Reservoir Low Cost Case	
Pressure	MPa	3.5	6.9	+97%	2.1	-40%
Thickness	m	31	15	-52%	61	+97%
Depth	m	1,524	3,048	+100%	610	-60%
Permeability	md	1	0.8	-20%	10	+900%
Pipeline Distance	km	100	300	+200%	0	-100%

The results for the high and low cost cases as well as the base case are given in Table 45. The CO_2 storage cost for the depleted gas reservoir option does not widely differ for the high and low cost cases.

Table 45: Results for depleted gas reservoir base, high cost and low cost cases

Parameter	Units	Gas Reservoir Base Case	Gas Reservoir High Cost Case	Gas Reservoir Low Cost Case
Injection Rate per Well	t/d	156	57	2,975
Number of Wells		48	129	3
Levelized Annual CO_2 Storage Cost	\$/tonne CO_2 eq. LC GHG avoided	4.87	19.43	1.20

5.6.2 Depleted Oil Reservoir

High and low cost cases have been chosen for the depleted oil reservoir option, and are presented together with the base case in Table 46.

Table 46: Depleted oil reservoir base, high cost and low cost cases

Parameter	Units	Oil Reservoir Base Case	Oil Reservoir High Cost Case		Oil Reservoir Low Cost Case	
Pressure	MPa	13.8	20.7	+50%	3.5	-75%
Thickness	m	43	21	-51%	61	+42%
Depth	m	1,554	2,134	+37%	1,524	-29%
Permeability	md	5	5	0%	19	+280%
Pipeline Distance	km	100	300	+200%	0	-100%

The results for the high and low cost cases as well as the base case are given in Table 47. As for the depleted gas reservoir option, the CO_2 storage cost for the depleted oil reservoir option does not widely differ for the high and low cost cases.

Table 47: Results for depleted oil reservoir base, high cost and low cost cases

Parameter	Units	Oil Reservoir Base Case	Oil Reservoir High Cost Case	Oil Reservoir Low Cost Case
Injection Rate per Well	t/d	360	115	5,690
Number of Wells		21	65	2
Levelized Annual CO_2 Storage Cost	\$/tonne CO_2 eq. LC GHG avoided	3.82	11.16	1.21

5.6.3 Aquifer

High and low cost cases have been chosen for the aquifer option, and are presented together with the base case in Table 48.

Table 48: Aquifer base, high cost and low cost cases

Parameter	Units	Aquifer Base Case	Aquifer High Cost Case		Aquifer Low Cost Case	
Pressure	MPa	8.4	11.8	+40%	5.0	-40%
Thickness	m	171	42	-75%	703	+311%
Depth	m	1,239	1,784	+44%	694	-44%
Permeability	md	22	0.8	-96%	585	+2559%
Pipeline Distance	km	100	300	+200%	0	-100%

The results for the high and low cost cases as well as the base case are given in Table 49. As for the other geologic storage options, the CO_2 storage cost for the aquifer option does not widely differ for the high and low cost cases.

Table 49: Results for aquifer base, high cost and low cost cases

Parameter	Units	Aquifer Base Case	Aquifer High Cost Case	Aquifer Low Cost Case
Injection Rate per Well	t/d	9,363	82	889,495
Number of Wells		1	91	1
Levelized Annual CO_2 Storage Cost	\$/tonne CO_2 eq. LC GHG avoided	2.93	11.71	1.14

It is important to note that the injection rate per well of 889,495 tonnes of CO_2 per day for the low cost case was calculated without setting any limit on the well diameter. Indeed, this injection rate requires a well diameter of 0.5 m, which is too large to be used in practice. Given that the standard well diameter used for the other cases for each of the geologic options is 0.059 m, it would seem reasonable to limit the diameter to double this at 0.120 m. This gives a maximum flow rate of around 25,100 tonnes of CO_2 per day.

5.7 SENSITIVITY ANALYSES

5.7.1 Depleted Gas Reservoir

The sensitivity of the CO_2 storage cost for the depleted gas reservoir option is determined for five key parameters: well depth, pressure, thickness, permeability and pipeline distance. It can be seen in Figure 26 that increases in well depth, reservoir pressure and pipeline distance increase the cost of storage, while increases in reservoir thickness and permeability decrease the storage cost. More noteworthy, the figure shows that, for the chosen base case values, changes in thickness and permeability have the greatest effect on storage cost.

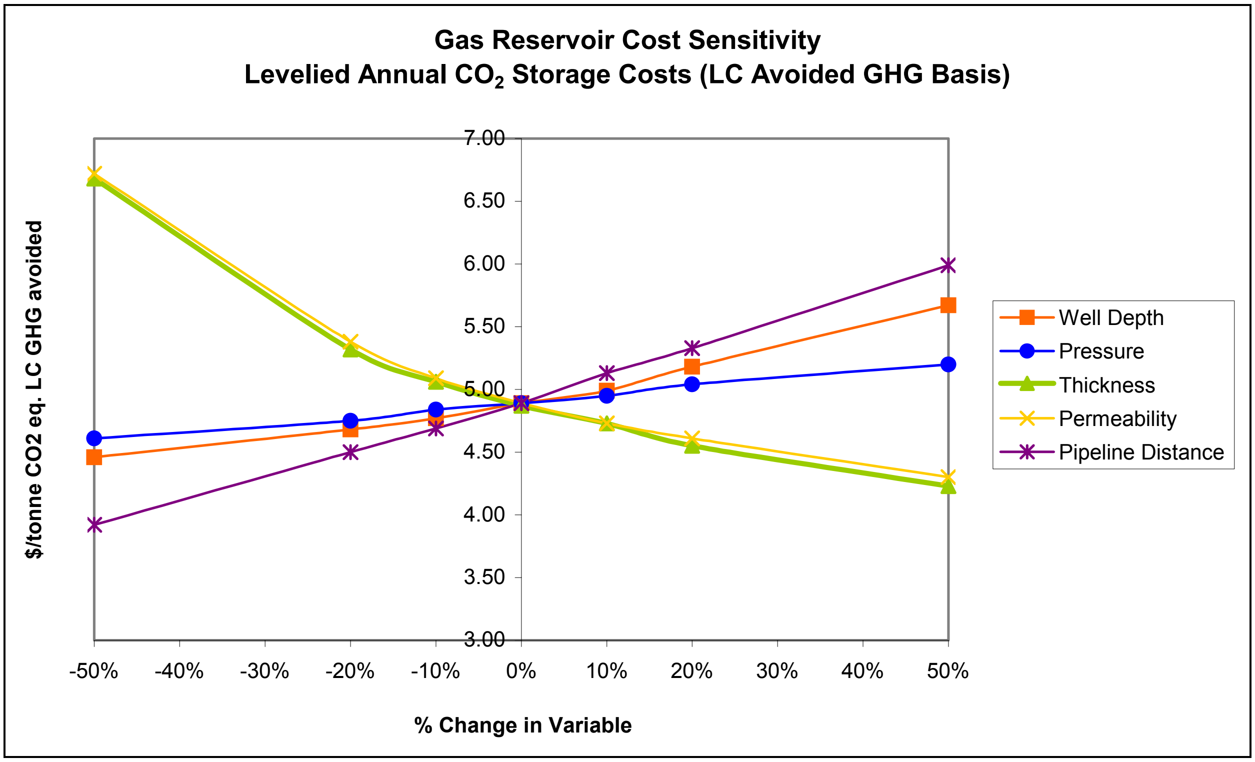

Figure 26: Sensitivity analysis for depleted gas reservoir

For the high and low cost values for each of the five key parameters, the percentage change in the value from the base case is shown in Table 44. This is done to illustrate the fact that the range in the values of some parameters is expected to be greater than for others.

5.7.2 Depleted Oil Reservoir

The sensitivity of the CO_2 storage cost for the depleted gas reservoir option is determined for the same five key parameters as used in the case of the depleted oil reservoir. It can be seen in Figure 27 that increases in reservoir pressure and pipeline distance cause an increase in the cost of storage, while increases in well depth, reservoir thickness and permeability decrease the storage cost. In contrast to the depleted gas reservoir option, increased well depth results in a decrease in the number of wells required, the resulting decrease in cost of which outweighs the increase in well drilling cost. The figure shows that, for the chosen base case values, changes in pressure have the greatest effect on storage cost.

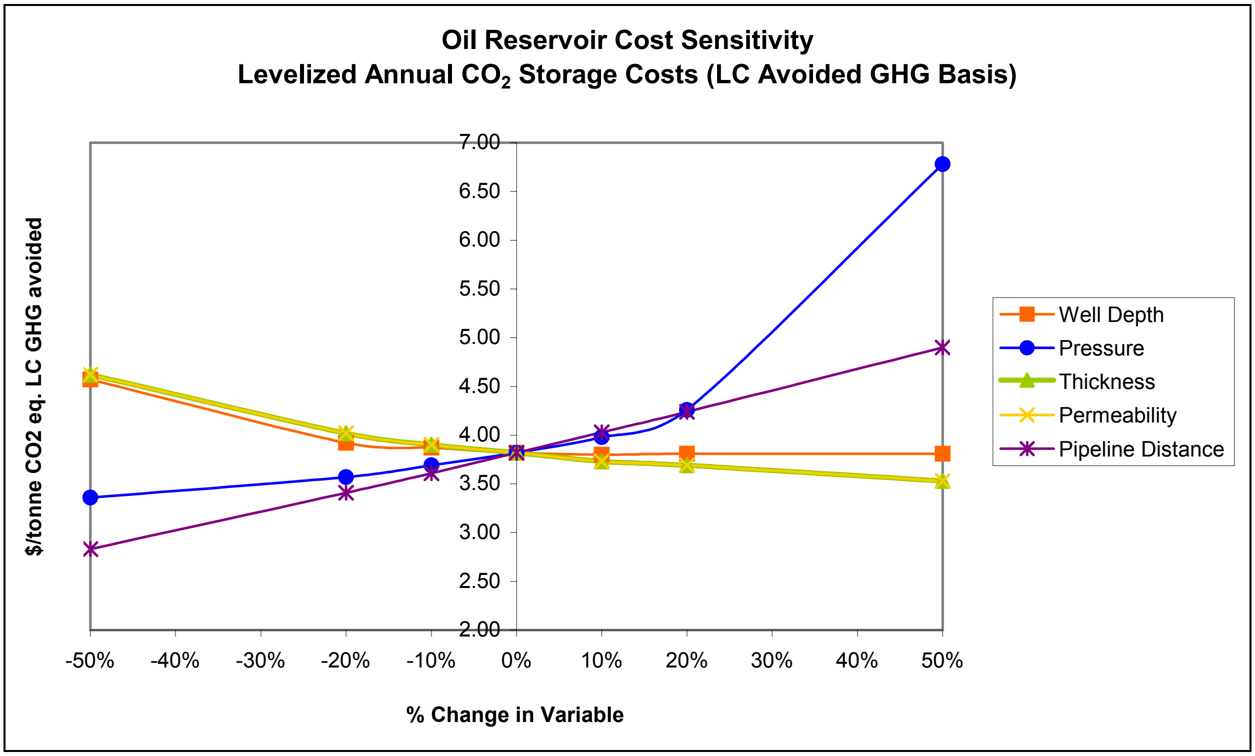

Figure 27: Sensitivity analysis for depleted oil reservoir

For the high and low cost values for each of the five key parameters, the percentage change in the value from the base case is shown in Table 46.

5.7.3 Aquifer

The sensitivity of the CO_2 storage cost for the aquifer option is determined for the same five key parameters as for the other geologic storage options. It can be seen in Figure 28 that, for the limited range of values considered, the storage cost is only sensitive to pipeline distance. This is because, for the base case values chosen, the value of CO_2 injectivity is very large. This in turn results in only one well being required, where this is relatively insensitive to changes in reservoir properties.

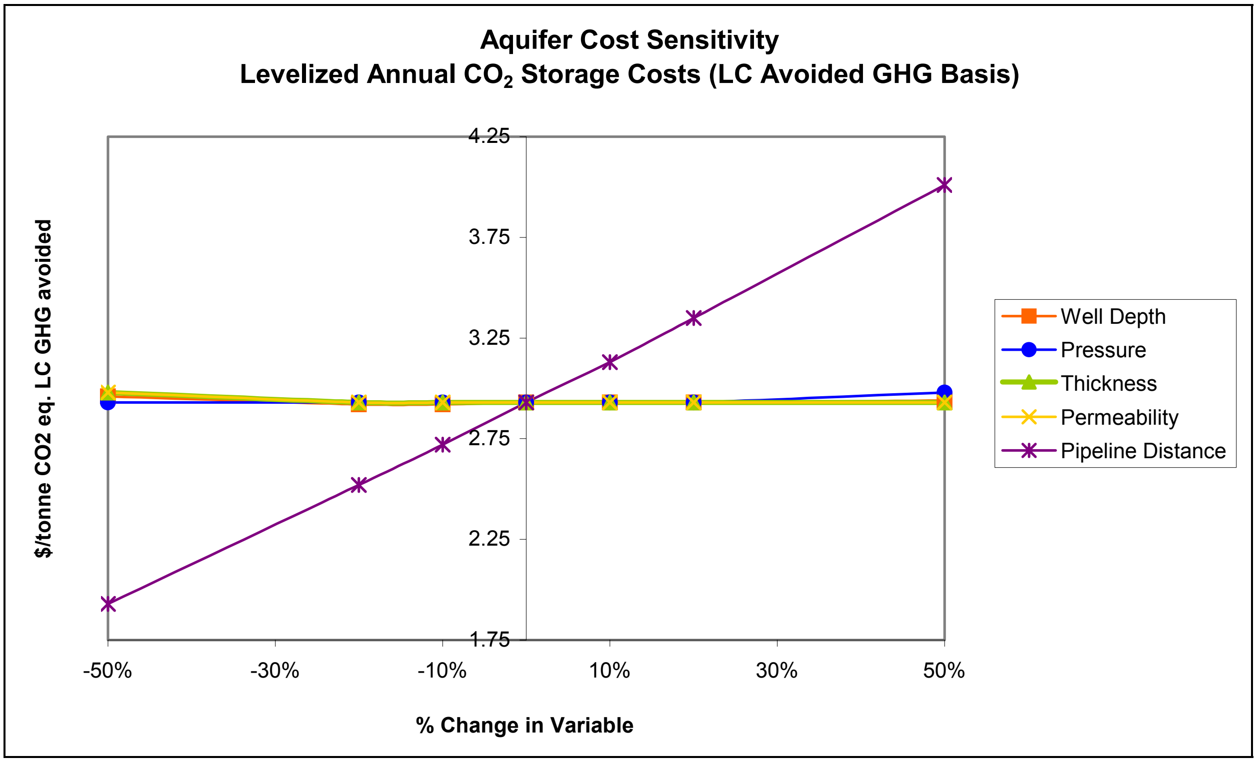

Figure 28: Sensitivity for aquifer

For the high and low cost values for each of the five key parameters, the percentage change in the value from the base case is shown in Table 48. As compared to the depleted gas and oil reservoir options, thickness and permeability can vary to a far greater degree.

It is important to note that an aquifer could have a permeability value 2 or 3 orders of magnitude less than the base case value. A reduction in the permeability of this magnitude would in turn cause a dramatic increase in the CO_2 storage cost. For example, for the base case, reducing the base case permeability value from 22 to 0.22 md gives a storage cost of $5.37, while a permeability of 0.022 md gives a cost of $25.23. Similarly, as the thickness of the reservoir decreases, the storage cost increases.

5.8 Comparison To Literature

5.8.1 Studies Used in Model Evaluation

Injection scheme details and reservoir properties, as well as cost data, were collected from the studies listed in Table 50. All of the studies are concerned with the injection of CO_2 into a saline aquifer, except for the 'IEA depleted reservoir' study that looks at storing CO_2 in an exhausted gas reservoir.

Table 50: Injection schemes' characteristics

Study	CO_2 Flow Rate (t/d)	Downhole Injection Pressure (MPa)	Reservoir Pressure (MPa)	Thickness (m)	Depth (m)	Permeability (md)	Number of Wells	Location
IEA aquifer (Ormerod, 1994)	10,685	28.0	11.3	55	1,459	13	6	Onshore
IEA depleted reservoir (Ormerod, 1994)	8,560	10.4	3.0	-	2,500	100	4	Onshore
Elsamprojekt (Krom, 1993)	3,770	-	-	-	1,100	-	12	Onshore
GEODISC (Allinson et al, 2000)	15,780	17.4	17.2	400	1,600	300	4	Offshore
Sleipner West (Steefel, 2001)	2,740	11.0	9.0	184	1,020	10	1	Offshore

The aquifer in both the 'GEODISC' and 'Sleipner West' studies is located offshore, in a depth of water of 100 and 80 m respectively. Due to certain reservoir properties not being specified, a benchmark for CO_2 injectivity cannot be obtained from either of the 'IEA depleted reservoir' or the 'Elsamprojekt' studies. It should also be noted that cost data are not available for the 'Sleipner West' project.

5.8.2 Comparison of Values from Model and Studies

Figure 29 shows that, for CO_2 injectivity, the value calculated by the model generally agrees with the value used in each of the studies. Indeed, the same relationship between CO_2 mobility and injectivity, as is used in the model, has been used in the 'GEODISC' study (Nguyen, 2001) and possibly also the 'IEA aquifer' study. In the case of the 'Sleipner West' study, it should be noted that the model underestimates, rather than overestimates, the injectivity.

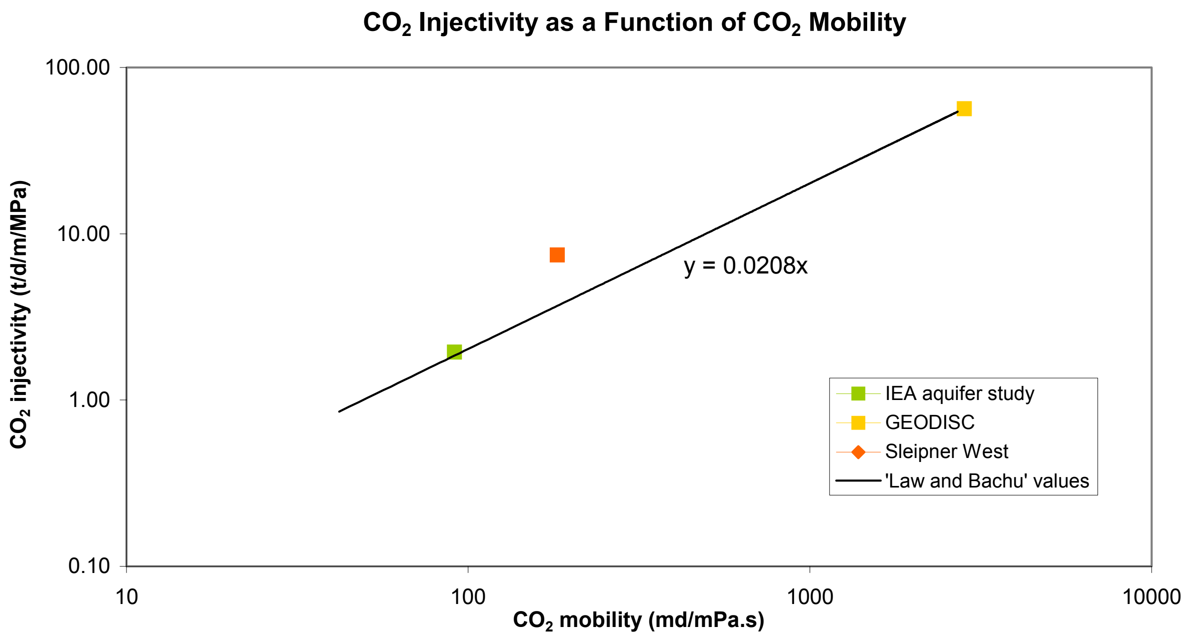

Figure 29: Comparison of CO_2 injectivity values

A comparison of well drilling cost as calculated by the model and given in various studies is shown in Figure 30. The drilling cost in three. The drilling cost in three of the studies can be seen to be about four times that calculated by the model, with the value in the 'GEODISC' study being exceedingly higher. The significant difference between the model's and the 'GEODISC' study's drilling cost can be attributed in part to the fact that the aquifer is located offshore. The drilling costs in the other three studies, one of which is based on conditions in Europe, and the other two in Canada, are likely to be higher due to less drilling activity in these regions.

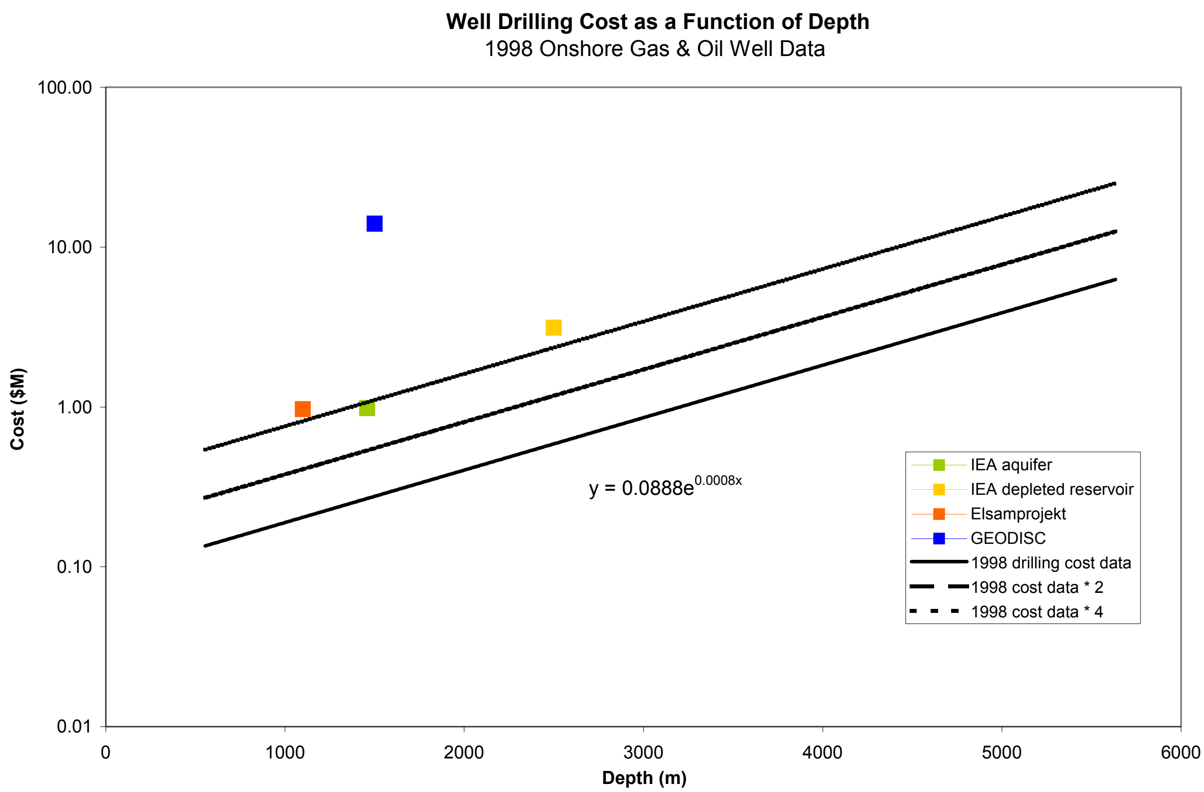

Figure 30: Comparison of onshore well drilling cost values

Injecting CO_2 into an offshore reservoir can be expected to be significantly more expensive than for a reservoir in an onshore location. Firstly, offshore drilling costs are higher. This can be seen from a comparison of Figure 30, which gives the cost of offshore well drilling based on 1998 JAS data for offshore gas and oil wells, with

Figure 29. From Figure 30 it can also be sent that the offshore well drilling cost given in the 'GEODISC' study is about four times the JAS value. Secondly, CO_2 injection into an offshore reservoir requires that a platform be installed. The cost of a platform depends primarily on the water depth and the number of wells it accommodates, with an unmanned platform with ten wells in a water depth of around 100 and 200 m costing around \$4 million and \$6.5 million per meter water depth, respectively (Allinson et al, 2000). If CO_2 injection into offshore reservoirs were to be considered, these factors would need to be taken into account.

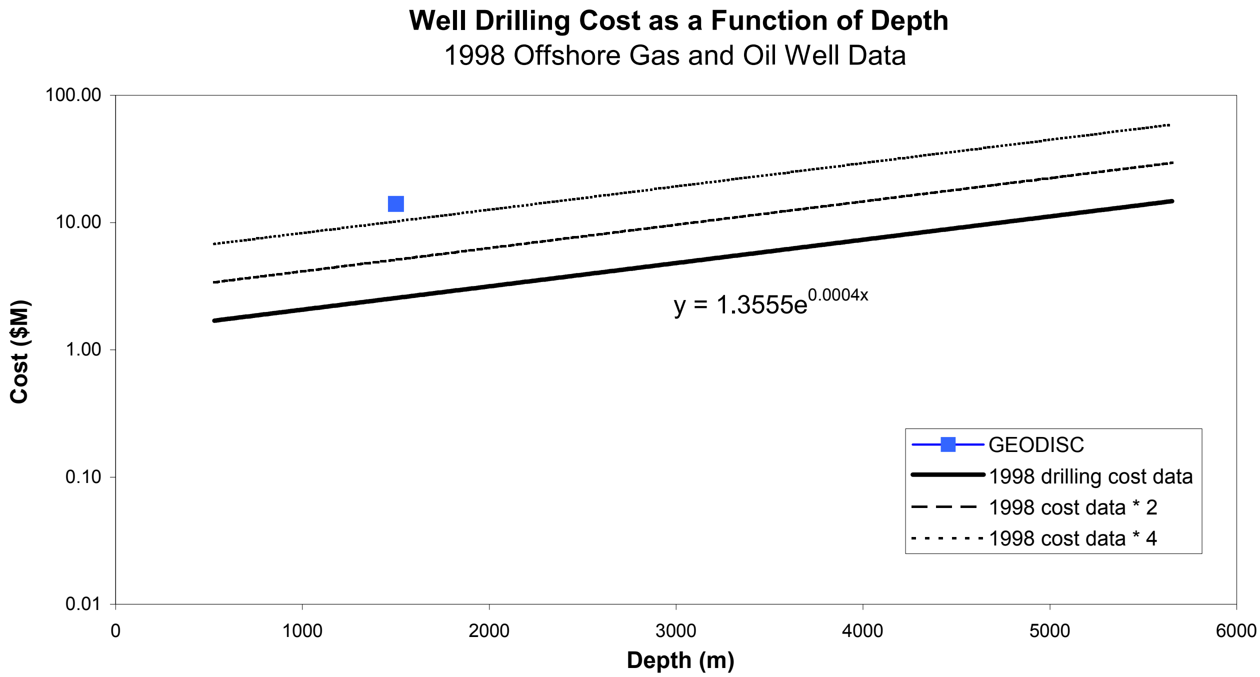

Figure 31: Comparison of offshore well drilling cost values

6. OCEAN STORAGE VIA PIPELINE

6.1 INTRODUCTION

This chapter looks at the injection of CO_2 into the deep ocean via a pipeline laid on the seabed.

6.2 STATE OF THE ART

The direct injection of CO_2 into the ocean requires starting with pressurized liquid CO_2 from a coastal power plant or a coastal transfer station. The CO_2 is piped via a pipeline laid on the continental shelve and injected to a depth where it will be effectively sequestered for hundreds of years, if not longer (Herzog, 1998). The CO_2 may be injected through a diffuser at intermediate depths of 1,000 to 2,000 m. At these depths, the injected CO_2 droplet plume will ascend by buoyancy while dissolving in seawater before it reaches a depth of 500 m where the liquid droplets will flash into vapor and bubble up to the surface. Laboratory experiments and *in situ* releases show that a hydrate film may form around the droplets making them heavier than seawater and thus negatively buoyant. CO_2 may also be injected at depths greater than 3,000 m, in which case the liquid CO_2 will become heavier than seawater and so sink to the ocean bottom.

Led by offshore exploration and production activities of the oil and gas industry, great strides have been made in the development of undersea offshore technology. It is becoming routine for work to be done at depths approaching 2,000 m (6,600 feet). Work at much greater depths, even approaching 10,000 m, is possible at reduced scales and over longer time horizons, as has been shown in deep exploratory drilling and other scientific programs. However, there are still many technical challenges in laying pipes at a great depth. Therefore, as a first step, it appears that the best strategy is to discharge the CO_2 at intermediate depths of 1,000 to 2,000 m (US Dept of Energy, 1999).

The technology to proceed with this option is available. There is however a lack of information regarding how to adequately optimize the costs, determine the effectiveness of the sequestration and understand the resulting changes in the biogeochemical cycles of the oceans. This storage option is also limited by the fact that it is best suited to large, stationary CO_2 sources with access to deep-sea sequestration sites — sources that may account for only about 15 to 20 percent of anthropogenic CO_2 emissions.

Figure 32 illustrates that about 18 percent of worldwide power plant emissions are within a 400 km offshore distance of 1,500 m water depth. Given that power plant CO_2 emissions account for about 35 percent of total anthropogenic CO_2 emissions, about 6 to 6.5 percent of CO_2 emissions could be sequestered in the deep ocean from coastal power plants.

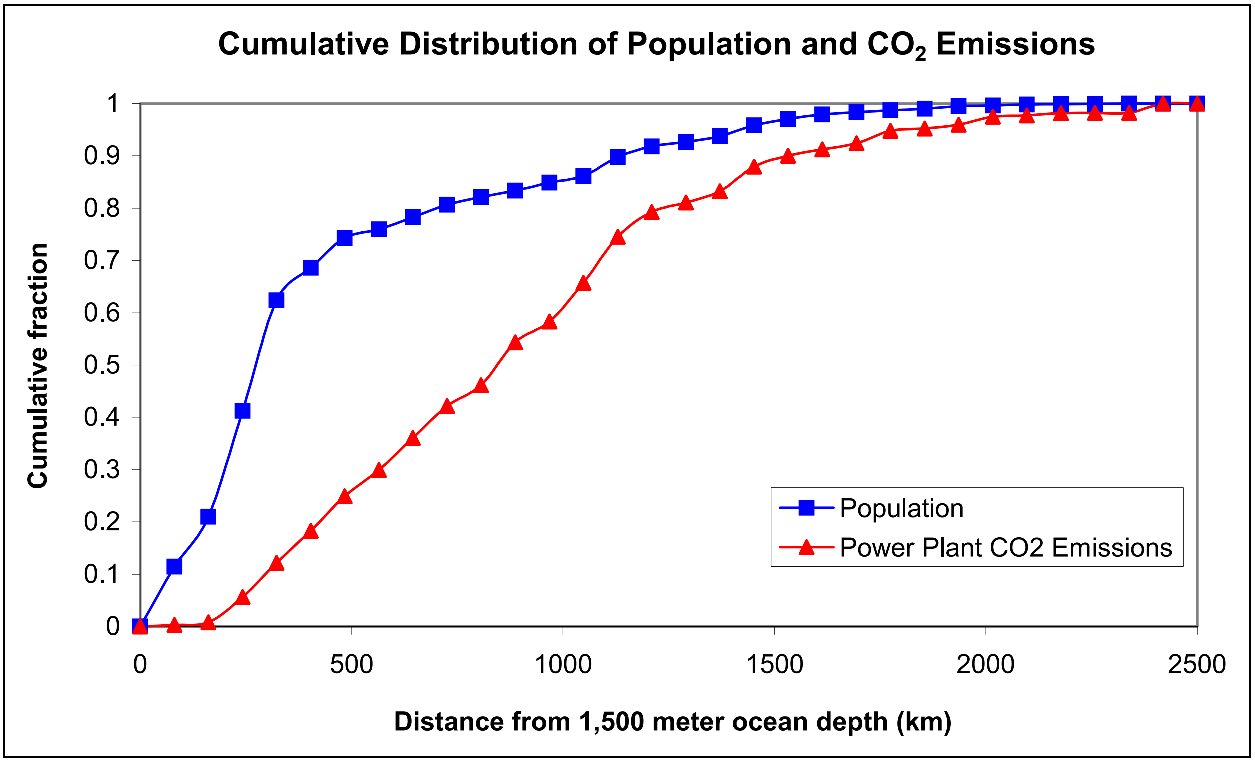

Figure 32: Cumulative distribution of population and power plant CO_2 emissions

6.3 Process Description

It is assumed that three IGCC power plants supply CO_2 to a single ocean pipeline, amounting to 11.29 million scm (22,167 tonnes) per day. At the shoreline collection point, additional compression is needed to bring the CO_2 to the ocean pipeline's required inlet pressure of 152 bar. It is assumed that this facility, like the power plants, has a lifetime and design/construction time of 20 and 4 years, respectively.

6.4 Methodology Used

The ocean pipeline storage option involves transporting the CO_2 via a subsea pipeline from the shoreline to a depth of 2,000 m, at which depth the CO_2 is discharged via a diffuser unit. For the base case, an offshore distance of 100 km is considered. The method used for calculating the cost of this process can be broken down into two steps. First, the diameter of the subsea pipeline is determined. It is then possible, as a second step, to calculate the capital and O&M costs as well as the cost per tonne of CO_2. These two steps are explained in greater detail below. Figure 33 gives an overview of the ocean pipeline cost model.

Inputs:
CO_2 mass flow rate
Pipeline length
Injection depth
CO_2 inlet pressure
Diffuser head loss
Capital charge rate

OCEAN PIPELINE MODEL
Internal Calcs:
CO_2 outlet pressure
Gravity head
Pressure drop per unit length
Pipe diameter
Capital costs:
Pipeline, injector unit, boost compressor
O&M costs:
Subsea maintenance, boost compressor power & maintenance

Outputs:
Total capital cost
Total O&M cost
Total annual cost
Total cost per tonne CO_2

Figure 33: Ocean pipeline cost model overview diagram

6.4.1 Diameter Calculation

The pipeline diameter is calculated using the same method as is used in the CO_2 overland pipeline transport model. The only difference is the means by which the maximum allowable pressure drop per unit length ($\Delta P/\Delta L$) is determined. In the case of CO_2 overland pipeline transport, the pressure drop per unit length is simply found as the difference between the pipeline CO_2 inlet and outlet pressures divided by the pipeline length. The pipeline ocean CO_2 storage model however requires that the pressure drop per unit length calculation also take into account the gravity head gain and diffuser head loss. In addition, it is necessary that the CO_2 be discharged at a pressure equal to the hydrostatic pressure.

The pipeline CO_2 inlet pressure for the subsea pipeline is set at 152 bar, the same as the outlet value in the land-based cases. Given that the CO_2 outlet pressure for the overland pipelines is set at 103 bar, this requires the use of booster pumps. The required pipeline outlet pressure, taken to be equal to the hydrostatic pressure of water at a depth of 2,000 m, is calculated to be approximately 200 bar. A diffuser head loss of 20 bar is then assumed. Next, calculating the average value of CO_2 specific gravity over both the 0 to 1,000 m depth and 1,000 to 2,000 m depth intervals, and adding the respective CO_2 pressure head gains, gives a gravity head of 194 bar. Based on the set inlet pressure, assumed diffuser head loss, and the calculated values of outlet pressure and gravity head, maximum allowable pressure drops per unit length for the base and sensitivity cases are found. Finally, the equations for pressure drop and head loss due to frictional resistance in a pipe, assuming turbulent flow, are used to determine the respective diameters. Figure 34 gives the calculated pipe diameter for the base case as a function of CO_2 mass flow rate.

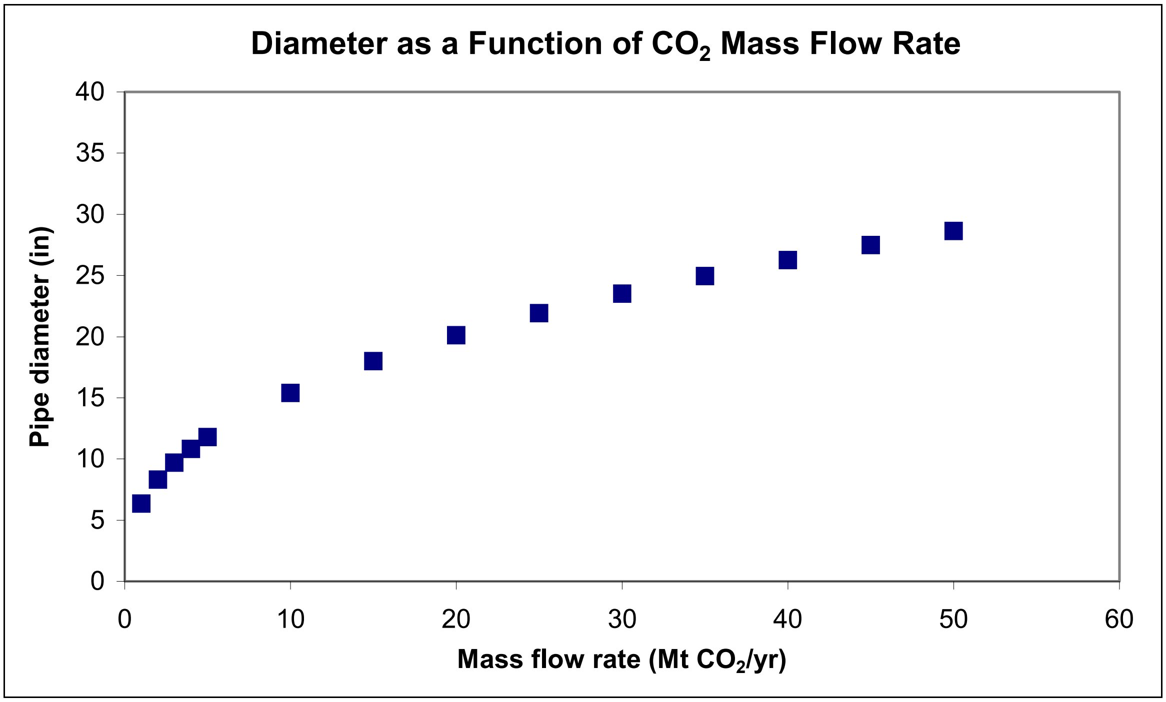

Figure 34: Diameter for the base case as a function of CO_2 mass flow rate

6.4.2 Cost Calculations

The cost of the subsea pipeline has been determined based on cost information contained in McDermott's phase II final report 'Large-scale CO_2 Transportation and Deep Ocean Sequestration' (Sarv, 2001). Based on McDermott's total capital cost of $3,224.5 million for six 30-inch, 500-km long pipelines, a capital cost factor of $35,749/in/km ($57,659/in/mi) is calculated. It should be noted that this capital cost factor neither includes the cost of pumping stations nor the one-time cost of upgrading the pipe-lay barge to handle larger pipe sizes. The total annual O&M cost for the six pipelines was found by McDermott to be $75,400,000, excluding the cost of pump operation (Sarv, 2002). Based on this figure, an O&M cost factor of $25,078/yr/km ($40,448/yr/mi) is calculated. The capital cost of an injector unit, based on an estimate given in an IEA report (Ormerod, 1994), is taken to be $14.5 million.

Taking the injector capital cost together with the subsea pipeline capital and O&M costs, the annual total cost was determined to be $1.90 and $5.87 per tonne of CO_2 for the base and sensitivity cases, respectively. Figure 35 shows the calculated cost for the base case as a function of CO_2 mass flow rate. It is important to note that this cost neither includes the cost of the required booster pumps nor transaction and monitoring costs.

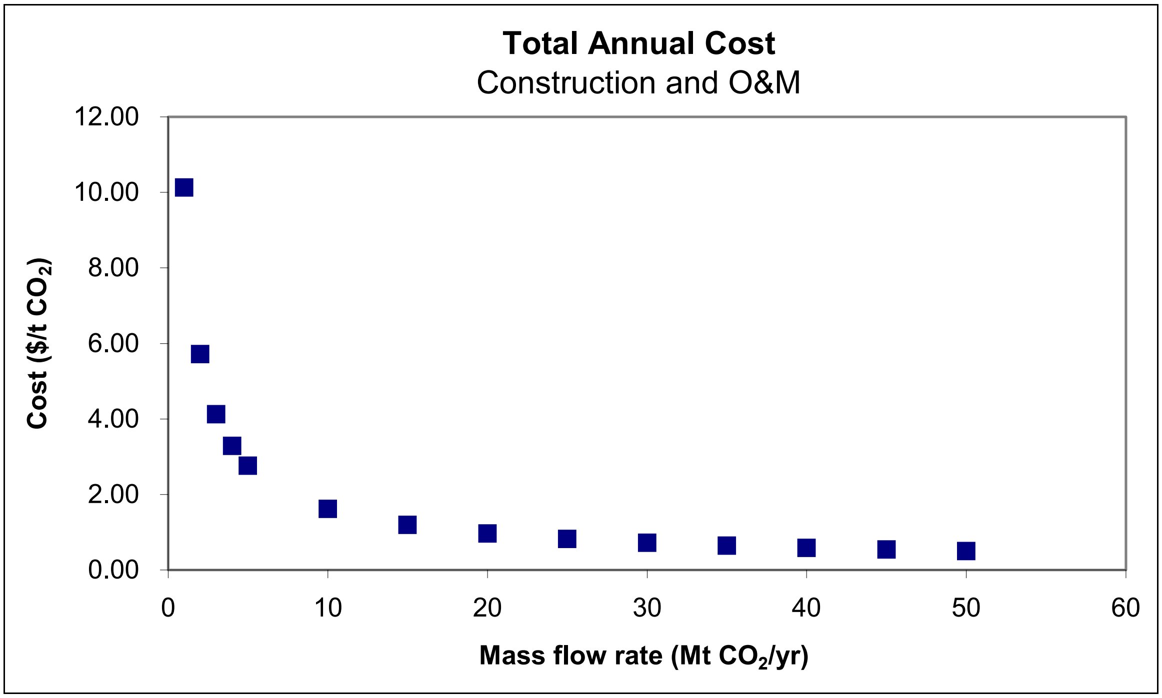

Figure 35: Total cost per tonne of CO_2 for the base case as a function of CO_2 mass flow rate

The capital and yearly maintenance costs of the boost compressor are estimated at $9,355,000 and $432,000, respectively. The cost of the power used by the compressor is taken to be $0.055 per kilowatt-hour. These costs together with the costs associated with the subsea pipeline and injector unit are summarized in Table 51.

Table 51: Capital and O&M cost estimation factors

Parameter	Unit	Value
CAPITAL COSTS		
Subsea Pipeline	$/in/km	35,749
Injector Unit	$	14,500,000
Boost Compressor	$	9,355,000
O&M COSTS		
Subsea Maintenance	$/yr/km	25,078
Boost Compressor Power	$/kW-hr	0.055
Boost Compressor Maintenance	$	432,000

6.5 DESIGN BASIS

6.5.1 Pipeline Design

The methodology described in Section 6.4.1 was used to determine pressure drop per unit length and pipeline diameter for the base case. The design basis for ocean storage via pipeline is summarized in Table 52.

Table 52: Design basis for ocean storage via pipeline

Parameter	Unit	Ocean Pipeline Base Case
Subsea Pipeline Length	km	100
Injection Depth	m	2,000
CO_2 Inlet Pressure	MPa	15.2
CO_2 Outlet Pressure*	MPa	20.0
Gravity Head*	MPa	19.4
Diffuser Head Loss*	MPa	2.0
Pressure Drop per Unit Length*	Pa/m	126
Pipe Diameter*	inches	14.2
Nominal Pipe Size*	inches	16

* calculated

The calculated nominal pipe size for the base case is 16 inches. This pipe diameter is larger than the 12-inch diameter for the case of CO_2 overland pipeline transport. This is despite the value of maximum allowable pressure drop per unit length also being larger. This can be explained by the fact that the design CO_2 mass flow rate used here is 11.29 million scm (22,167 tonnes) per day as opposed to 3.76 million scm (7,389 tonnes) per day.

6.5.2 Capital and O&M Cost Inputs

The capital and O&M costs of ocean storage via pipeline for the base case are calculated using the methodology described in Section 6.4.2. The results are shown in Table 53.

Table 53: Capital and O&M cost inputs for the ocean pipeline base case (1 in = 0.0254 m)

Parameter	Unit	Ocean Pipeline Base Case
Subsea Pipe Diameter	inches	14.2
Subsea Pipeline	$	50,900,000
Injector Unit	$	14,500,000
Boost Compressor	$	9,355,000
Subtotal	$	74,755,000
Subsea Maintenance	$	2,507,776
Boost Compressor Power (5,650 kW)	$	2,726,000
Boost Compressor Maintenance	$	432,000
Subtotal	$	5,665,776

6.6 MODEL RESULTS

This section presents costs for CO_2 storage for the ocean pipeline option. The storage costs comprise transportation, injection and monitoring costs. The results are given as levelized annual CO_2 storage costs on a life-cycle, greenhouse gas-avoided basis.
High and low cost cases have been chosen for the ocean pipeline option, and are presented together with the base case in Table 54.

Table 54: Ocean pipeline base, high cost and low cost cases

Parameter	Units	Ocean Pipeline Base Case	Ocean Pipeline High Cost Case		Ocean Pipeline Low Cost Case	
Pipeline Distance	km	100	300	+200%	0	-100%
Offshore Distance	km	100	300	+200%	50	-50%

The results for the high and low cost cases as well as the base case are given in Table 55. The CO_2 storage cost for the ocean pipeline option does not widely differ for the high and low cost cases.

Table 55: Results for ocean pipeline base, high cost and low cost cases

Parameter	Units	Ocean Pipeline Base Case	Ocean Pipeline High Cost Case	Ocean Pipeline Low Cost Case
Pressure Drop per Unit Length	Pa/m	126	42	251
Pipe Diameter	inches	14.2	17.5	12.4
Nominal Pipe Size	inches	16	20	14
Levelized Annual CO_2 Storage Cost	\$/tonne CO_2 eq. LC GHG avoided	5.53	14.23	2.90

6.7 Sensitivity Analysis

The sensitivity of the CO_2 storage cost for the ocean pipeline option is determined for offshore and onshore pipeline distance. It can be seen in Figure 36 that an increase in both offshore and onshore distance increases the storage cost. The storage cost is more sensitive to onshore than offshore distance due to the fact that the ocean pipeline cost includes a fixed injector unit cost.

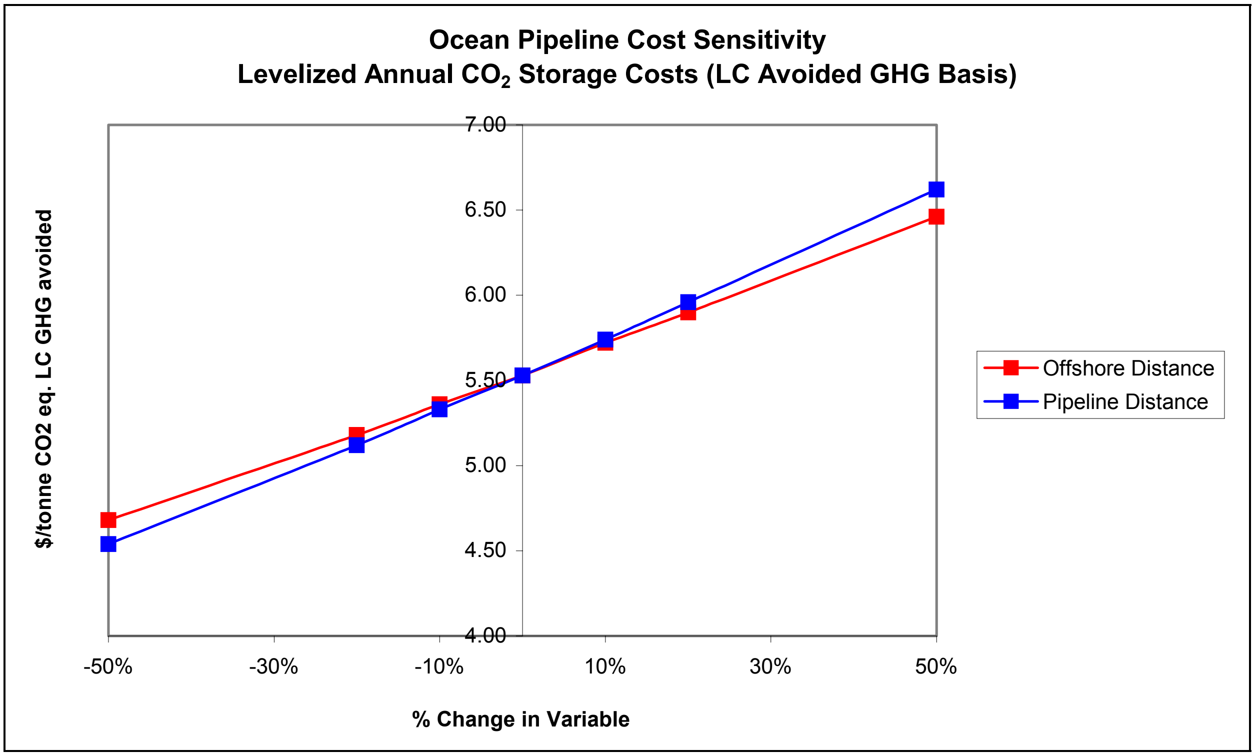

Figure 36: Sensitivity analysis for ocean pipeline

6.8 Comparison to Literature

6.8.1 Studies Used in Model Evaluation

The studies given in Table 56 contain design and cost information for the transport of CO_2 by subsea pipeline. In all cases, except the 'GEODISC' study, the pipeline is to be used for the purpose of injecting CO_2 into the ocean. 'GEODISC' looks at subsea pipeline CO_2 transport in the context of storing the gas in an offshore aquifer.

Table 56: Subsea pipelines' characteristics

Study	CO_2 flow rate (Mt/yr)	Initial CO_2 pressure (bar)	Diameter (m)	Length (km)	Injection depth (m)	Recompression station included
IEA Ocean (Ormerod , 1994)	19.00	74 (liquid CO_2)	0.800	100	500	Ignored
British Coal (Summerfield , 1993	3.63	136	0.350	517	2,000	Yes
GEODISC (Allinson et al, 2000)	5.67	205	0.660	200	100	No
McDermott (Sarv, 1999)	200 (total) 33.3 (each)	130	0.760 (6 pipes)	500	3,000	Yes
Umass (Golomb , 1997)	8.20	140	0.600	200	1,000	No

It should be noted that in the 'McDermott' study there is a large quantity of CO_2 injected into the ocean, taken to be the emissions from forty 500 MW_e coal-burning power stations. This large quantity of CO_2, 200 Mt per year, is determined in the study to require the use of one 1.63-m-diameter pipe or six 0.760-m-diameter pipes. For purposes of making a diameter comparison with the model, allowing for bundling, one 0.760 m diameter pipe carrying 33.3 Mt per year of CO_2 is assumed. It should be noted that a cost comparison is not made with the 'McDermott' study due to the fact that this study was used as a basis for costing.

The 'GEODISC' and 'IEA ocean' studies require the installation of a subsea pipeline up to a maximum depth of 100 and 500 m, respectively. The installation of pipelines at these relatively shallow depths requires only the use of a 'S-lay' barge and lies within the capabilities of existing technology. However, in the 'UMass', 'British Coal,' and 'McDermott' studies, which require pipeline installation at depths of 1000, 2000, and 3000 m, respectively, a combination of 'S-lay' and 'J-lay' techniques is needed. In addition, in the case of 'British Coal', as for 'McDermott,' modifications to the existing 'J-lay' barge would be necessary. As this upgrade would only be a one-time cost, it is not included in the cost analysis.

The 'British Coal' study, like 'McDermott', requires a shore-based pumping station to transport the CO_2 over a long distance. The cost of this pumping station is not included in the total cost of the scheme, calculated for the purpose of comparing the study value with the model output. The requirement of a pumping station in the 'IEA Ocean' study is ignored as this study deals with liquid, not supercritical, CO_2.

6.8.2 Comparison of Values from Model and Studies

The graph below in Figure 37 shows pipe diameter as a function of CO_2 mass flow rate. Also shown in the figure, is the value of pipe diameter given in each of the five studies.

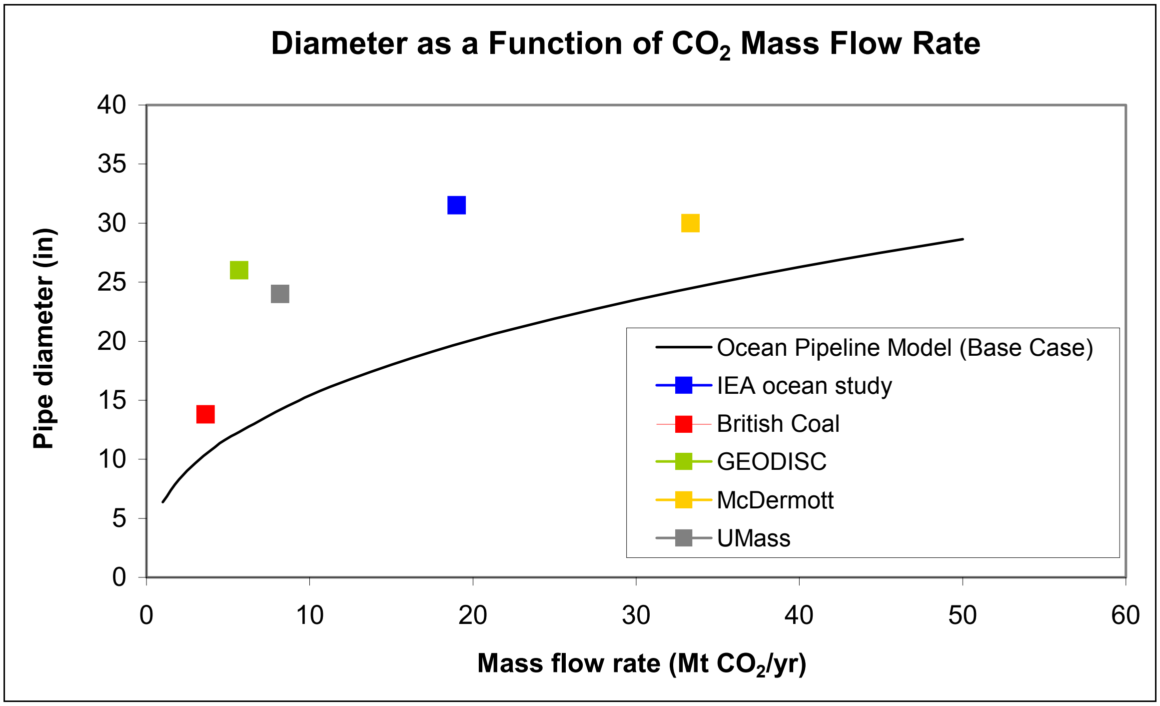

Figure 37: Comparison of pipe diameter values

Figure 38 shows the capital cost of the subsea pipeline as calculated by the model, where this excludes the cost of the boost compressor and transaction costs, as a function of CO_2 mass flow rate. As for pipe diameter, the capital cost values given in the studies are reasonably close to those calculated by the model considering the uncertainties in the data.

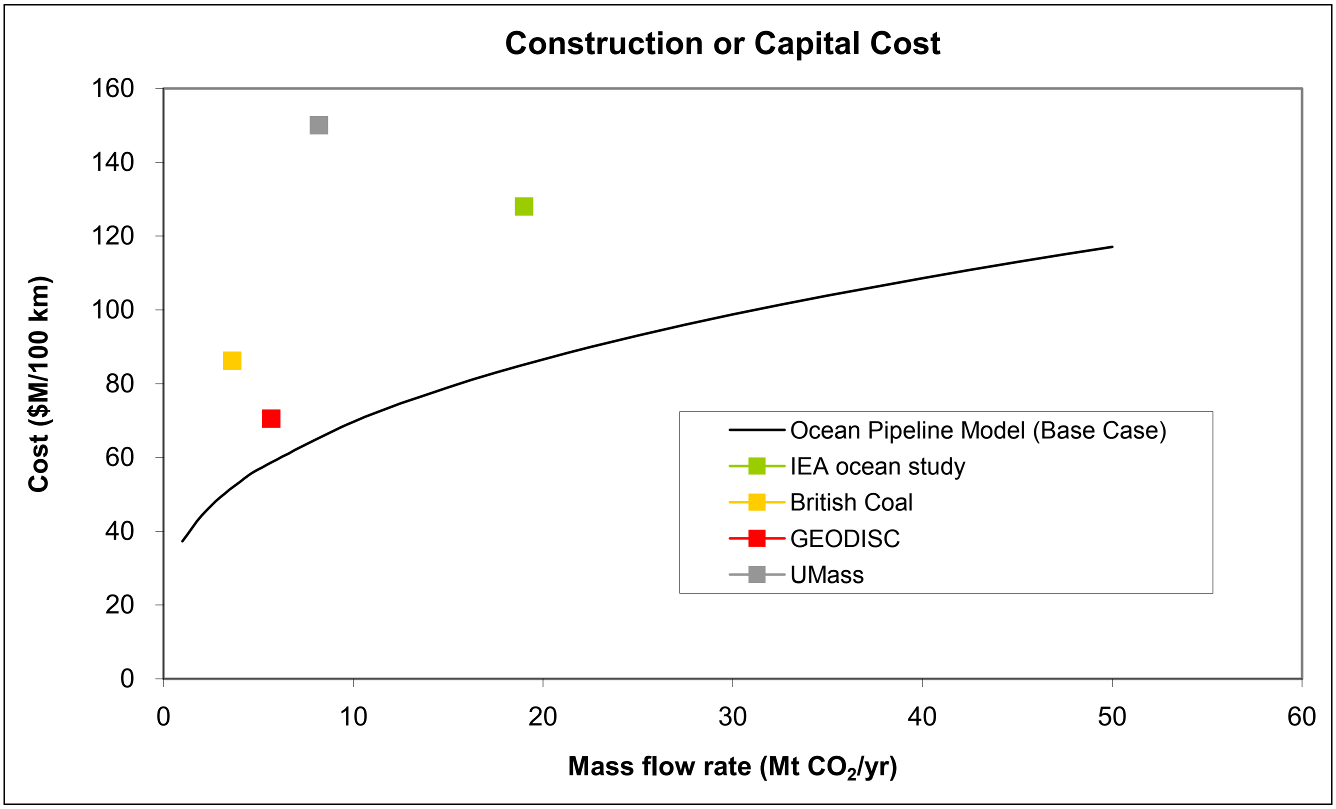

Figure 38: Comparison of subsea pipeline capital cost values

7. OCEAN STORAGE VIA TANKER

7.1 INTRODUCTION

The ocean storage via tanker option involves transporting the CO_2 by refrigerated tanker from a port facility to an offshore floating platform, where the CO_2 is injected into the deep ocean through a vertical pipe.

7.2 STATE OF THE ART

To date, there have been no commercial or pilot-scale applications of this ocean storage option. However, the use of tankers to transport pressurized refrigerated liquids, e.g. ammonia and LPGs, is within the current state of technology. Transport of LNG in large refrigerated tankers is also common practice; although the LNG is transported at atmospheric pressure. Floating platforms with attached large diameter vertical pipes would have to be developed for deep sea injection of liquid CO_2 (Sarv, 1999).

For relatively small offshore distances, say up to 500 km, pipeline transport appears to be more economical. Transport via tanker would only be considered for larger distances. The latter does however have the advantage that it would allow for easy relocation of the injection site.

7.3 PROCESS DESCRIPTION

It is assumed, as in the case of ocean storage via pipeline, that three IGCC power plants supply CO_2 to the shoreline collection point. Accordingly, the ocean tanker system needs to be designed to handle 11.29 million scm (22,167 tonnes) of CO_2 per day. It is assumed that this facility, like the power plants, has a lifetime and design/construction time of 20 and 4 years, respectively.

7.4 METHODOLOGY

The storage option has been modeled based on design and cost information obtained from McDermott's Phase I and Phase II final reports on 'Large-scale CO_2 Transportation and Deep Ocean Sequestration' (Sarv, 2001; Sarv, 1999) as well as e-mail communications with the reports' author (Sarv, 2002). The method used for a conceptual design of this process can be broken down into a number of steps. First, the number of tankers required to transport the CO_2 to the offshore platform is determined. Second, the diameter of the vertical pipe to carry the CO_2 from the platform to the injection depth is calculated. Third, the amount of CO_2 emitted by the tankers traveling to and from the offshore storage site due to the fuel combusted in the tanker engines and due to boil off is found. Finally, the capital cost of the tankers, port facility, offshore floating platform and vertical pipe, and the non-fuel and fuel O&M costs are calculated. An overview of the ocean tanker cost model is given in Figure 39.

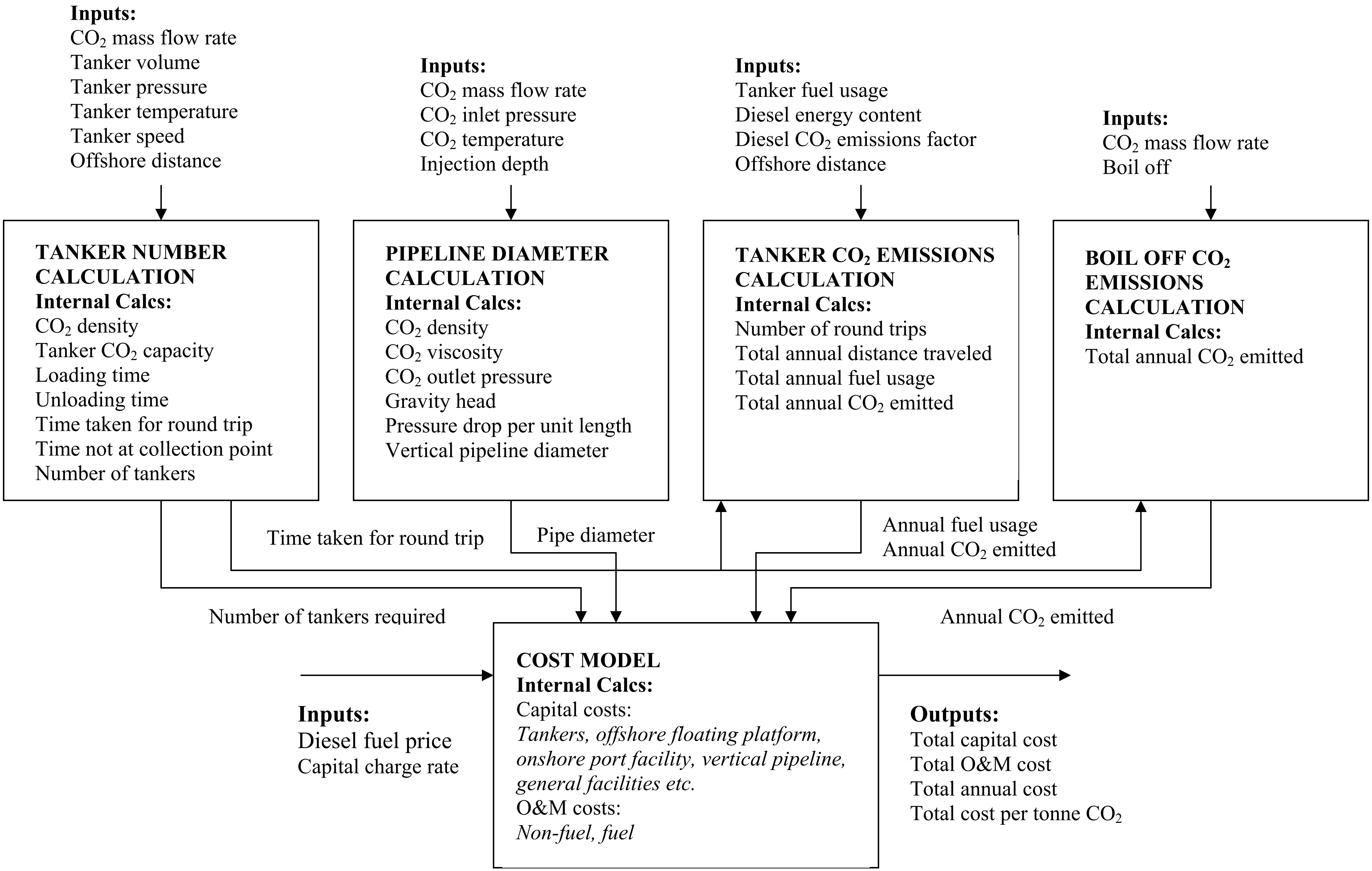

Figure 39: Ocean tanker cost model overview diagram

7.4.1 Tanker Number Calculation

The number of tankers required is determined assuming that each tanker is able to carry 22,000 m^3 of liquid CO_2 at 7 bar and minus 50ºC. A tanker of this description is, according to McDermott, within the current state of shipbuilding technology. At these conditions, CO_2 has a density of 1155 kg per m^3 and the tanker capacity, in terms of weight, is 25,410 tonnes of CO_2. Given this latter tanker CO_2 capacity, it is found from the design CO_2 flow rate of 22,167 tonnes per day that the loading time for each tanker is approximately 27.5 hours. The unloading time at the platform is taken to be six hours. Assuming a tanker speed of 33 km per hour, it is then possible to calculate the time taken for a round trip and the amount of time for which a tanker is not at the CO_2 collection point. Finally, the number of tankers required to be en route at any given time is determined. For the base case, it is found that two tankers would be needed. An additional tanker is, however, added, bringing the total number required to three, to allow for tanker downtime.

7.4.2 Vertical Pipe Diameter Calculation

The same method as is used for sizing the subsea pipeline is used to calculate the diameter of the vertical pipe. The required pipe outlet pressure, taken to be equal to the hydrostatic pressure of water at a depth of 2,000 m, is calculated to be approximately 200 bar. Next, calculating the average value of CO_2 specific gravity over both the 0 to 1,000-m depth and 1,000 to 2,000-m depth intervals, and adding the respective CO_2 pressure head gains, gives the gravity head. Based on the set inlet pressure of 152 bar and the calculated values of outlet pressure and gravity head, a maximum allowable pressure drop of 7,281 Pa per m is found. Finally, the diameter is determined from the equations for pressure drop and head loss due to frictional resistance in the pipe, assuming turbulent flow. For the base case, a nominal 8-inch-diameter vertical pipe is required.

7.4.3 Tanker CO_2 Emissions Calculation

The quantity of CO_2 to be emitted by the tankers needs to be determined. This requires that the quantity of fuel used by a 22,000 m^3-tanker, in terms of gallons per km, first be calculated. In order to do this, it was necessary to refer to the small tanker case study given in the McDermott reports. In this case study, the total capital cost of the required 38 22,000-m^3 tankers is \$2,100 million. According to Hamid Sarv of McDermott, the annual tanker O&M cost was taken as being equal to 5.6 percent of the tanker capital cost, of which the tanker fuel cost comprised 16.5 percent. Based on these percentages, the tanker fuel cost is equal to \$19.4 million per year. Given that the price of diesel fuel is about \$0.566 per gallon, the total annual quantity of fuel used by the tankers is found to be approximately 34.3 million gallons. The corresponding total annual distance traveled by the tankers is calculated to be 8.76 million km. Dividing the total annual distance traveled by the total annual fuel used, gives a tanker fuel usage of 3.91 gallons per km.

Given this calculated value of tanker fuel usage, it is possible to determine the CO_2 emitted by the tankers. Diesel fuel has an energy content of around 137 million joule per gallon and a CO_2 emissions factor of close to 70 milligrams per joule. Given that the fuel used by a tanker is 3.91 gallons per km, the amount of CO_2 emitted by a tanker per km traveled can be found to be

37,614 grams. The total annual distance traveled is calculated by multiplying the total number of round trips per year, equal to the number of hours in a year divided by the loading time of 27.5 hours, by the respective round-trip distance. The total distance traveled by the tankers is found to be 63,683 km. Multiplying the amount of CO_2 emitted per km by the total annual distance traveled gives a total annual amount of CO_2 emitted due to the tanker engines of 2,395 tonnes.

The amount of CO_2 emitted due to boil off is taken as one percent per day of the amount of CO_2 transported by tanker, based on industry experience with CO_2 truck tankers. It is important to note that the calculation assumes that CO_2 boil-off occurs for only half of the time the tanker is en route. This CO_2 quantity is then multiplied by 365 days to give the amount of CO_2 emitted per year. The annual quantity of CO_2 emitted due to boil off is calculated to be 53,362 tonnes.

7.4.4 Cost Calculations

The total capital cost of the tanker ocean CO_2 storage option comprises the capital cost of the three tankers, the offshore floating platform, the port facility, and a 2,000-m long, 8-inch diameter vertical pipe. The capital cost of the tankers is found using McDermott's cost estimate of \$55.3 million for a single 22,000-m^3 tanker. For the offshore floating platform, the capital cost of \$200 million also given in the McDermott report is used. In the case of the port facility, for which no cost estimate was provided, a capital cost of \$50 million is assumed. Next, based on cost data in the report, the capital cost of the vertical pipe is calculated. The vertical pipe's capital cost is taken to include \$351,445/in/km (\$566,847/in/mi) for pipe marshalling and the attaching of buoys and corrosion anodes, a \$0.3 million cost for towing the pipe to the offshore structure and a \$3 million cost for pipe upending, securing, and anchoring. Finally, a 30 percent surcharge is added to all capital expenses to cover costs associated with general facilities, engineering, permitting, and contingencies.

The total O&M cost is calculated as the sum of the non-fuel and fuel O&M costs. From e-mail communications with Hamid Sarv (Sarv, 2002), it was learnt that the total annual O&M cost in the case studies was taken as the sum of 5.6 percent and 0.02 percent of the total tanker and non-tanker capital costs, respectively, where the fuel cost comprised 16.5 percent of the tanker O&M cost. The non-fuel O&M cost is calculated in the model as 4.7 percent of the total tanker capital cost, thus excluding the fuel cost, plus 0.02 percent of the total non-tanker capital costs. The fuel O&M cost is determined as the product of the total annual fuel usage, found from multiplying the tanker fuel usage by the total annual distance traveled, and a diesel fuel price of \$0.566 per gallon.

The capital and O&M cost estimation factors are summarized in Table 57.

Table 57: Capital and O&M cost estimation factors
(1 in = 0.0254 m)

Parameter	Unit	Value
CAPITAL COSTS		
Tanker	$/tanker	55,263,000
Offshore Platform	$	200,000,000
Onshore Port Facility	$	50,000,000
Vertical Pipeline:		
Construction	$/in/km	351,445
Towing to Offshore Structure	$	300,000
Upending, Securing & Anchoring	$	3,000,000
General Facilities, Engineering, Permitting etc.	$	0.3*(Tanker_capital_cost + Offshore_platform_capital_cost + Onshore_port_facility_capital_cost + Vertical_pipeline_capital_cost)
O&M COSTS		
Non-fuel	$/yr	(Tanker_capital_cost*0.047) + ((Offshore_platform_capital_cost + Onshore_port_facility_capital_cost + Vertical_pipeline_capital_cost)*0.02)
Fuel	$/gal	0.566

7.5 DESIGN BASIS

7.5.1 System Design

The methodology described in Section 0 through Section 7.4.3 was used to calculate the required number of tankers, the diameter of the vertical pipeline, and the CO_2 emissions from the tankers and due to boil-off. Table 58 shows the results.

Table 58: Design basis for ocean storage via tanker

Parameter	Unit	Ocean Tanker Base Case
Offshore Distance	km	100
Injection Depth	m	2,000
Tanker Volume	m^3	22,000
Tanker Pressure	bar	7
Tanker Temperature	deg C	-50
Tanker CO_2 Capacity	kg/m^3	25,410
Loading Time	hrs	27.5
Unloading Time	hrs	6
Tanker Speed	km/hr	33
Time Taken for Round Trip	hr	39.6
Number of Tankers		3
Vertical Pipe Inlet Pressure	MPa	15.2
Vertical Pipe Outlet Pressure	MPa	20.0
Gravity Head	MPa	19.4
Pressure Drop per Unit Length	Pa/m	7,281
Vertical Pipe Diameter	inches	6.5
Nominal Vertical Pipe Size	inches	8
Tanker Fuel Usage	gal/km	3.91
Diesel Energy Content	million joule/gal	137
Diesel CO_2 Emissions Factor	mg/joule	70
Total Annual Distance Traveled	km/yr	63,683
Total Annual Fuel Usage	gal/yr	249,001
CO_2 Emitted by Tankers	t/yr	2,395
Boil Off	%/day	1
CO_2 Emitted by Boil Off	t/yr	53,362

7.5.2 Capital and O&M Cost Inputs

The capital and O&M costs of ocean storage via tanker for the base case were calculated using the methodology described in Section 7.4.4. The results are shown in Table 59.

Table 59 : Capital and O&M cost inputs for the ocean tanker base case (1 in = 0.0254 m)

Parameter	Unit	Ocean Tanker Base Case
Number of Tankers		3
Vertical Pipeline Diameter	Inches	6.5
Total Annual Fuel Usage	gal/yr	249,001
CAPITAL COSTS		
Tanker	$	166,000,000
Offshore Floating Platform	$	200,000,000
Onshore Port Facility	$	50,000,000
Vertical Pipeline:		
Construction	$	4,580,000
Towing to Offshore Structure	$	300,000
Upending, Securing & Anchoring	$	3,000,000
General Facilities, Engineering, Permitting etc.	$	127,000,000
Subtotal	$	550,880,000
O&M COSTS		
Non-fuel	$	12,900,000
Fuel	$	140,935
Subtotal	$	13,040,935

7.6 RESULTS

This section presents costs for CO_2 storage for the ocean tanker option. The storage costs comprise transaction, transportation, sequestration and monitoring costs. The results are given as levelized annual CO_2 storage costs on a life-cycle, greenhouse gas-avoided basis.

High and low cost cases have been chosen for tanker transport and are presented together with the base case in Table 60.

Table 60: Ocean tanker base, high cost and low cost cases

Parameter	Units	Ocean Tanker Base Case	Ocean Tanker High Cost Case		Ocean Tanker Low Cost Case	
Pipeline Distance	km	100	300	+200%	0	-100%
Offshore Distance	km	100	300	+200%	50	-50%
Boil Off	%/day	1	2	+100%	0.5	-50%
Diesel Price	$/gal	0.566	0.8	+41%	0.45	-20%

The results for the high and low cost cases as well as the base case are given in Table 61. The CO_2 storage cost varies very little for the base and low cost cases.

Table 61: *Results for ocean tanker base, high cost and low cost cases*

Parameter	Units	Ocean Tanker Base Case	Ocean Tanker High Cost Case	Ocean Tanker Low Cost Case
Number of Tankers		3	3	3
Total Annual Fuel Usage	gal/yr	249,001	747,004	124,501
CO_2 Emitted by Tankers	t/yr	2,395	7,186	1,198
CO_2 Emitted by Boil Off	t/yr	53,362	139,415	24,638
Levelized Annual CO_2 Storage Cost	\$/tonne CO_2 eq. LC GHG avoided	17.64	22.79	15.76

7.7 SENSITIVITY ANALYSIS

The sensitivity of the CO_2 storage cost for the ocean tanker option is determined for four key parameters: onshore and offshore distance, boil off and diesel price. It can be seen in Figure 40 that offshore distance, boil off and diesel price have little effect on the cost, but the onshore distance has a great effect on the cost.

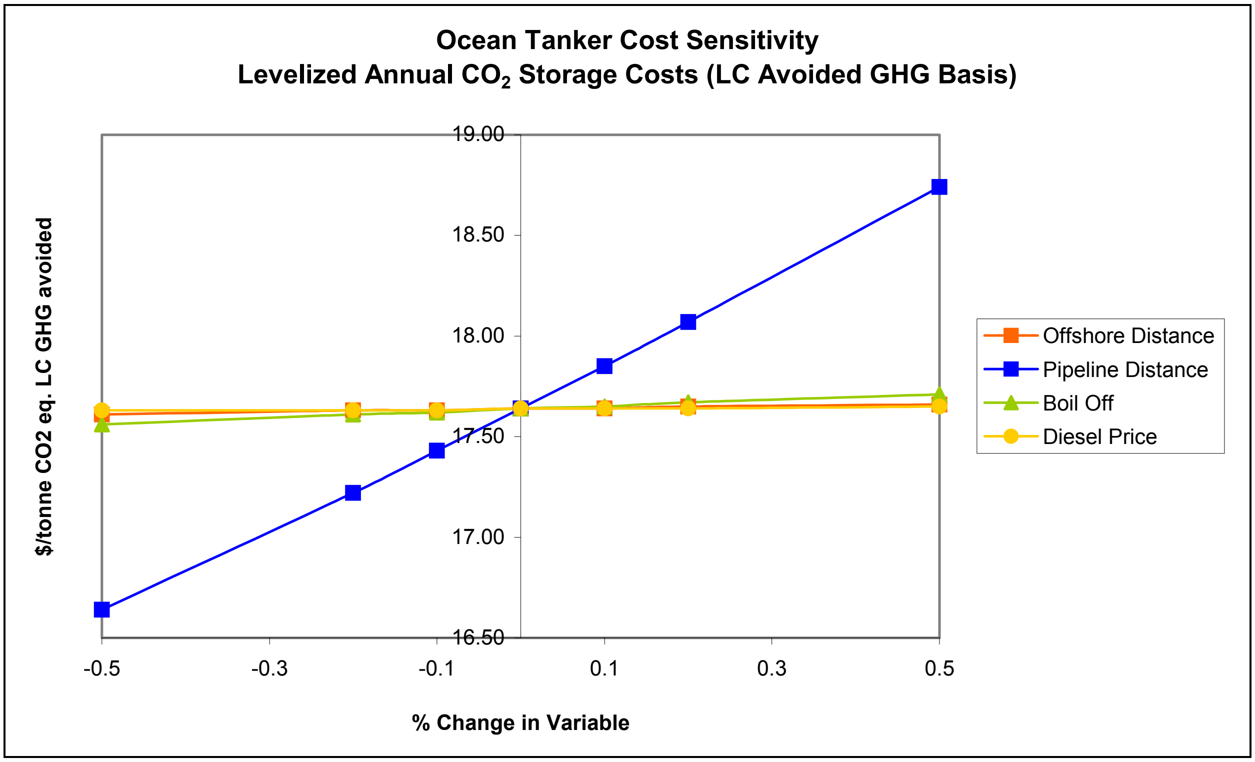

Figure 40: Sensitivity analysis for ocean tanker

For the high and low cost values for each of the four key parameters, the percentage change in the value from the base case is shown in Table 60. This is done to illustrate the fact that the range in the values of some parameters is expected to be greater than for others.

7.8 COMPARISON TO LITERATURE

There is no cost data in the literature with which to make a comparison.

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