University of Alberta

QUANTITATIVE RISK SIMULATION OF CO_2 DISPOSAL ECONOMICS FOR ALBERTA

By

Akihiro Hachiya ©

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The undersigned certify that they have read, and recommended to the Faculty of Graduate Studies and Research for acceptance, a thesis entitled *"Quantitative Risk Simulation of Aquifer CO_2 Disposal Economics for Alberta"* submitted by Akihiro Hachiya in partial fulfillment of the requirements for the degree of Master of Science in Mining Engineering.

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ABSTRACT

Global warming has been a major concern over the last two decades as a result of the continuous growth in green house gases (GHG) emissions. Canada has committed to cut GHG emissions by 6 % below 1990 levels by the year 2012 in the Kyoto Agreement. This means a net reduction of 25 % for Canada in 1997. Alberta emitted 30.5 % of the total carbon dioxide (CO_2) emissions in Canada in 1995 with an economic engine fueled mainly by the fossil fuels industry. Energy generation from coal and the production and burning of oil and natural gas are the main sources of CO_2 emissions in Alberta. Over the next decade, the multi-billion dollar expansion of oil sands production, population growth and the demand for energy will present a major challenge to Alberta. Research is being undertaken to develop appropriate technology for disposing CO_2 emissions. Previous studies have concluded that aquifer disposal technology will help Alberta to deal with the problem in the long-term.

In this study, the author contributes to the body of knowledge in the area of design, economic and risk modeling and analysis of CO_2 disposal under aquifers in Alberta. An analytical survey of the literature has been undertaken to examine the global efforts in dealing with GHG emissions problem. The geology of the Alberta Basin, which contains the host aquifers, and the stability of CO_2 in these aquifers have also been reviewed to develop a basis for the technology. Detailed technical design is also carried out based on the phase dynamics of CO_2, energy changes due to confinement, compression and expansion. The MRT5 technique is used to forecast CO_2 emissions in Alberta within 1999 to 2012. Economic and risk modeling and analysis have been carried to examine the economic implications of this technology. The review results show that it is feasible to store CO_2 aquifers in Alberta. The design results also show that CO_2 can be liquefied and transported over 5 km to the injection sites at 7.5MPa, 27°C. The expected cost of disposal is between \$55.75 and \$67.50 per tonne of CO_2. This will increase energy cost from \$0.043/kWh by 3.5 % up to \$0.0445/kWh. The stochastic simulation results also show that the variability in these estimates is around 1.6%. This shows a relatively stable cost profile, which is very feasible for planning and design purposes.

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ACDS	aquifer CO_2 disposal system
AEC	annual equivalent cost [$]
CC	long-term periodic capital expenditures
CMR	coal-bed methane recovery
CO_2	CO_2 emission rate[kt]
C_s	capital cost for separation
C_l	capital cost for liquefaction
C_{PT}	capital cost for transportation
C_{PI}	capital cost for injection
COV	coefficient of variance
D	diameter of the pipeline [m]
e	error
$E[\gamma_i]$	expected value
EOR	enhanced oil recovery
$f(\gamma_i)$	probability density function
$f(\gamma_i)d\gamma_i$,	probability of the functions between γ_i and $\gamma_i+d\gamma_i$
FCCC	Framework Convention on Climate Change
g	acceleration due to gravity [m/s^2]
GHG	greenhouse gas
h	height of an injector well
HPC	hot potassium carbonate

i	effective interest rate per period
kt	kilo tonne
kW	kilo watts
L	length of the pipeline [m]
Ls	least square function
LM	Levenberg-Marquardt (LM)
m	number of interest periods
MEA	monoethanoamine
MHI	Mitsubishi Heavy Industries, Ltd.
MLE	Maximum Likelihood Estimators
MRT5	Multiple Regression Technique with 5 regressors
MS_E	mean square for error
Mt	million tonne
MW	mega watt
OC	operating costs
OECD	Organization for Economic Co-operation and Development
P_{aqu}	pressure of aquifer [Pa]
P_{co2}	permitted maximum CO_2 emission rate [Mt/year]
P_{Total}	total injection pressure at the surface [Pa]
Pe	period from 1999
PRcap	power requirement for capturing plant [kW]
PRliq	power requirement for liquefaction plant [kW]
PRtrans	power requirement for pipeline system [kW]

PRinj	power requirement for injector system [kW]
PTSA	pressure and temperature swing adsorption
PV	present value [$]
R^2	R squared
R_{CO2}	recovery ratio of CO_2 at capturing system [%]
Re	Reynolds number [-]
S_{t1}	CO_2 sequestration strategy 1 [tonne]
S_{t2}	CO_2 sequestration strategy 2 [tonne]
S_{t3}	CO_2 sequestration strategy 3 [tonne]
S_{t4}	CO_2 sequestration strategy 4 [tonne]
S_{t5}	CO_2 sequestration strategy 5 [tonne]
SS_E	sum of squares of the residuals
t	tonne
T_{CO2}	amount of CO2 emission [t/hour]
TC_{CO2}	total disposal cost function
TEPCO	Tokyo Electronic Company
UP_{cap}	unit power requirement of capturing [kW/ CO_2t]
UP_{liq}	unit power requirement of liquefaction [kW/CO_2t]
$\langle u \rangle$	average velocity of CO_2 [m/s]
V	volumetric flow rate [m^3/s]
$VAR[\gamma_i]$	variance
x_1,	previous year CO_2 Emission Rate [tonne]
x_2,	population Growth Rate [%]

x_3,	industrial Growth Rate
x_4	energy consumption
x_5	technical progress
x_6	period for strategy 1
x_7	period for strategy 2
x_8	period for strategy 3
x_9	period for strategy 4
x_{10}	period for strategy 5
ε	average roughness of the pipe [inch]
ε_i	error
$\phi[A_i]$	increase of energy cost
γ_i	determinants of the capital investment
λ_l	periodic quantity of excess CO_2
μ	viscosity of CO_2 [Pas]
ρ	density of CO_2 [kg/m^3]
ρ_k	fundamental economic parameters
ρ_A	interest rate adjusted for inflation
τ_j	determinants of the operating cost
ξ	cost due to other local-specific conditions and problems
ΔP	pressure drop between surface and aquifer [Pa]

CHAPTER 1
INTRODUCTION

1.1 Background

Global warming has been a major concern since the 1980's as a result of the continuous growth in emissions of GHG. Canada has made a commitment to reduce GHG emissions by 6 percent below 1990 levels by the year 2012 in the Kyoto Agreement [Gunter et al., 1998]. This means a net reduction of 25 % for Canada in 1997. Alberta emitted 28.2 percent of the total CO_2 emissions in Canada in 1990 and 30.5 percent in 1995 with an increasing potential in the future [Jacques, Neitzert and Bolieau, 1997]. Available data show that CO_2 emissions constitute about 80 percent of all GHG, followed by CH_4 (about 18 %) for Alberta [Jacques, Neitzert and Bolieau, 1997]. Thus, in order to control GHG emissions, appropriate technology must be designed to deal with CO_2 emissions. Sources of CO_2 emissions in Alberta include power generation from stationary fuel combustion (70.9%), mobile fuel combustion (14.8 %), industrial process (12.5 %), and agriculture (1.4 %). Stationary fuel combustion includes power generation, industry, commercial, residential, and agricultural uses. Mobile fuel combustion includes cars, air, rail and marine. Industrial process includes upstream oil and gas, cement and lime production.

Research initiatives are being taken to develop technology for capturing, utilizing and disposing CO_2 emissions [Government of Alberta, 1997]. These disposal technologies include enhanced oil recovery (EOR), coal-bed methane recovery (CMR) technology, CO_2/O_2 recycle combustion, and co-transport medium in pipelines and biofixation technology [Government of Alberta, 1997]. In the CMR technology, CO_2 produced from natural gas combustion at generating plants is injected into deep sub-surface coal seams containing methane. The CO_2 is absorbed into the coal, and acting as a "push gas", it displaces the coal-bed methane into a recovery well. Recovered methane is used as fuel for generating electricity. In the CO_2/O_2 combustion technology, hydrocarbon fuel is burnt in an atmosphere of oxygen and the CO_2 produced is recycled with little or no new air. Research has also shown that reduction in CO_2 emissions could be achieved by using long-term CO_2 disposal and storage technology. These disposal and storage options include underground technology (such as, depleted natural gas and oil reservoirs and aquifers) and ocean bed technology [Hitchon, 1996; Macdonald and Gunter, 1996].

This study focuses on long-term disposal and storage of CO_2 emissions in deep aquifers in Alberta. The design of the aquifer CO_2 disposal and storage system (ACDSS) is based on the capture of CO_2 in the flue gas from the Wabamum Plant (TransAlta Utilities). The CO_2 is subsequently liquefied, transported and injected into the Glauconitic aquifer in the Alberta Basin. It makes a significant contribution toward Alberta government's economic policy on global warming. Using the Wabamun results, a scaled model was developed to simulate the total CO_2 economics in Alberta.

1.2 Problem Definition

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change (COP3), the global community made a commitment to reduce GHG emissions to a selected target by the year 2012. Canada made a commitment to reduce greenhouse gas emissions by 6 percent below 1990 levels by the year 2012 at the Kyoto conference [Gunter et al., 1998]. However Canada is expected to emit about 560 million tonnes of CO_2 in the year 2012 which is 22% above the 1990 level [Gunter et al., 1998]. It is generally considered that Canada would find it difficult to reduce the future GHG emissions to that level in spite of new energy technologies and sources.

The continuous growth of industry and population will cause higher energy consumption, especially fossil fuels, resulting in increasing CO_2 emissions. In order to achieve these targets, CO_2 storage and disposal options have been proposed. The option includes CO_2 storage and disposal into geological sinks such as aquifers, depleted oil reservoirs, coal beds or on deep ocean floors. Bachu (1996) states that the ocean disposal option still has numerous hazards associate with its implementation. Disposal into depleted oil, gas reservoirs and salt beds have limited capacity [Bachu, 1996]. Coal beds disposal has not been tested, therefore, CO_2 aquifer disposal option is the most feasible option for the immediate solution for this problem [Bachu, 1996].

The design and valuation of the disposal and storage of CO_2 in land aquifers have not been studied in details to determine its technical and economic viability. There is also the need to understand its economic implications on the fossil fuels industry in Alberta. The associated long-term risks, and hazards must also be studied to ensure that appropriate control measures are taken to reduce their effects. In this study, the author uses a novel approach to study the technical and economic feasibility of CO_2 disposal and storage in land aquifer in Alberta.

1.3 Objective and Scope of the Study

The main objectives of this study include, (1) designing the technical specifications and requirements for the aquifer carbon dioxide disposal system: (2) developing economic models of the aquifer carbon dioxide disposal system: (3) developing quantitative risk models of the ACDSS; and (4) making recommendations on the economics of the aquifer carbon dioxide disposal system and its long-term viability in Alberta. This study contributes to the development of a viable technology for CO_2 disposal and storage in the Glauconitic aquifer in Alberta. An extensive literature survey covering the GHG emissions problems and the progress of developing appropriate technology for solving GHG problems is carried out. The study also covers a review of the geology of the Alberta Basin, a technical design of the aquifer disposal system and a case study using the Wabamum Plant. It also includes a CO_2 emissions forecast for Alberta and the economics and risks of CO2 disposal for the Province of Alberta.

1.4 Research Methodology

An analytical survey of the literature has been undertaken to examine the global efforts in dealing with GHG emissions problem, the geology of the Alberta basin and the Glauconitic aquifer. Detailed design of the aquifer disposal system is carried out using mathematical modeling based on the phase dynamics of CO_2, energy changes due to confinement, compression and expansion. The technical design models are validated using the Wabamum Power Plant flue gas data based on the KS technology developed by Kansai Electric Co. of Japan and Mitsubishi Heavy Industries Co. of Japan. Capacity analysis is carried out to determine the number of injection sites based on injection pressure and local permeability of aquifer.

The multiple regression technique is used to forecast Alberta's CO_2 emissions based on previous year's emission rate, population growth rate, industrial growth rate, energy consumption rate and technical progress. Detailed economic and stochastic simulation modeling is carried out in three stages: the functional economic, sensitivity and stochastic models. The functional economic model is using the annual equivalent cost (AEC) methodology. Sensitivity analysis is carried out using the variance propagation method to obtain the sensitive variables in the functional economic model. The sensitive variables are fitted with probability distribution functions and used as input data for the stochastic model. A comprehensive stochastic modeling using the Latin Hypercube technique is used to study the long-term operating and economic risks associated with the system. The risks modeling experimentation is carried out using the @RISK software package [Palisade, 1996].

1.5 Contribution to Knowledge and Industrial Significance

This study is significant because it outlines the first detailed economic and quantitative risk methodology for assessing the potential viability of CO_2 disposal and storage in land aquifers in Alberta. It provides a basis for the Alberta government's economic policies on carbon emission tax or other taxes for the GHG reduction, application of CO_2 disposal and storage systems and development of new energy sources. This study is also important to the fossil fuel industries in their decision-making on CO_2 disposal economics. It can be used by project managers to make long-term financial planning for CO_2 aquifer disposal. The quantitative risk model identifies and quantifies economic risks and uncertainties associated with CO_2 aquifer disposal.

1.6 Structure of the Study

Chapter 2 comprises a comprehensive literature review of the trend of GHG emissions, CO_2 reduction targets and strategies, and current CO_2 reduction technologies. Chapter 3 discusses the stability and security of aquifer CO_2 storage in aquifers. Design of an aquifer CO_2 disposal system is carried out in Chapter 4. Chapter 5 develops a mathematical model for CO_2 emission forecasts for Alberta. Economic modeling is described in Chapter 6. Quantitative risk modeling of the ACDS is presented in Chapter 7. The conclusions and recommendation for future research are discussed in Chapter 8.

CHAPTER 2
LITERATURE REVIEW

2.1 Global Change/Climate Change

Svante Arrhenius (1896) predicted the climate change due to human activities. Arrhenius suspected that the industrial development would increase the amount of carbon dioxide emissions into the atmosphere increase. He believed that carbon dioxide concentrations would continue to increase by consumption of fossil fuels throughout the world. His understanding of the role of carbon dioxide in warming the Earth, at that early date, made him predict that the earth would become several degrees warmer. Arrhenius was referring to a potential modification of what we now call the greenhouse effect [NASA, 1999]. About 100 years after Arrhenius prediction, it is now evident that carbon dioxide in the atmosphere is increasing. In 1991, the concentration of CO_2 became 354 ppmv that is 60ppmv greater than that of Arrhenius time [ORNL, 1991; Hangerbrauck, 1993]. The United Nations Environment Programme estimates that the average temperature of globe will increase by 1.5^{o}C by 2025, which will raise the sea by 20 cm [Bachu, et al, 1996].

2.2 Mechanism of Greenhouse Gas Effect

Short-wave solar radiation can pass through the clear atmosphere relatively unimpeded, but longwave infrared radiation emitted by the warm surface of the Earth is absorbed partially and then re-emitted by a number of gas layers such as water vapor and carbon dioxide. As a result, both the atmosphere and the surface will be warmer than they would be without the greenhouse gases [NASA, 1999]. It should be realized that there are the "natural" and a possible "enhanced" greenhouse effects. The natural greenhouse effect causes the mean temperature of the Earth's surface to be about 33 °C warmer than it would be if natural GHG were not present. This greenhouse effect creates an appropriate climate for life and man can live on planet Earth, without which the Earth would be a very cold place [NASA, 1999]. On the other hand, an enhanced greenhouse effect can raise the mean temperature of the Earth's surface above that occurring due to the natural greenhouse effect. This occurs as a result of an increase in the concentrations of GHG such as CO_2 and CH_4. This "enhanced" global warming could probably cause deleterious, climate such as storm pattern changes and the level of the oceans [NASA,1999]. Post-World War II industrialization has contributed to a dramatic increase in the amount of CO_2 in the atmosphere [NASA, 1999].

2.3 Reduction Target

The concept of CO_2 emission stabilization in the developed countries was launched at the Ministerial Conference in Noordwijk, the Netherlands, in November 1989 [Vellinga, 1992]. It was reinforced by the Ministerial Conference in Bergen, Norway, in 1990 [Vellinga, 1992]. CO_2 emission stabilization was committed by the Second Climate Change Conference in 1990. Canada signed and ratified the Framework Convention on Climate Change at an international conference in Rio de Janeiro in 1992 [Alberta Energy, 1999]. Canada has also made a commitment to reduce GHG emissions by 6 percent below 1990 level by year 2012 in the Kyoto Agreement [Gunter et al., 1998]. This is a commitment for a serious economic challenge to both Canada and Alberta, which depend on the fossil fuel industries.

2.4 CO_2 Reduction Strategies and technologies

In early 1960's, Steinberg and his research team started studying the use of nuclear energy for decomposing CO_2 to C at Brookhaven National Laboratory because C can produce all kind of organic composites [Steinberg, 1992]. That was one of the earliest studies of CO_2 recovery but that development was not applied because of safety problems associated with the use of nuclear energy. Marchetti proposed the concept of CO_2 storage in the deep ocean in 1977 [Flannery, 1992]. When the GHG effect emerged in the late 1970's and the early 1980's, the Office of Energy Research of the U.S. Department of Energy began to support and look for possible CO_2 removal and disposal technologies from the atmosphere. The possibility of CO_2 removal and ocean disposal, depleted oil reservoir, coal bed and mined salt dome disposals were examined. Hendriks, Blok and Turkenberg (1989) suggested the recovery and disposal of CO_2 from coal-fired plant to depleted gas wells. Williams of the Princeton Energy Institute followed these concepts [Steinberg, 1992]. Herzog of MIT (1990) carried out comparison of various methods of CO_2 removal and recovery, including absorption, adsorption membrane and cryogenic separation. He concluded that using recovered CO_2 to combust fossil fuels with oxygen costs lower than amine absorption-stripping of flue gases.

Van Engelenburg and Blok (1990) proposed the prospect of CO_2 disposal in aquifers. New energy options, natural gas, renewable energy and nuclear energy, have also been suggested to reduce CO_2 emissions [Hendriks and Blok, 1993]. Renewable energy includes wind, solar and biomass. The Dutch Ministry of the Environment initiated research into the possibilities of CO_2 removal from the atmosphere and subsequent disposal of it. The first studies proved that feasibility of this technology. The possibility of CO_2 storage in the ocean and depleted gas fields was discussed in the late 1980's, and safety of ocean storage was a concern at that time [Alders, 1992].

Carbon tax application to OECD countries is suggested by Garribba (1992) to reduce CO_2 emissions based on the IEA's (International Energy Agency) Mid Term Model. The model suggested that carbon taxes are levied at $100 or $200 per 1 ton of CO_2 emission. By the study, 10.5 to 17% of GHG reduction is needed in OECD countries by 2005 because those of countries give strong contribution to the global warming. In order to meet above target, making share of nuclear generation 50% in OECD countries is suggested and furthermore application of carbon tax is also suggested to reduce GHG. By $100 per tonne penalty tax, 10.5% of CO_2 reduction is expected and by $200 penalty tax, 21% of GHG reduction is expected. The other option, which replaces 90% of coal fired plant by natural gas is expected to reduce only 10%of GHG. It was concluded that by options which include $200 carbon tax and combination of $100 carbon tax and 50% nuclear share, OECD's GHG emission rate will stay on the same level as the year 1992 until 2005 [Garribba, 1992].

Reduction in CO_2 emissions can be achieved by (1) using improved alternate energy, (2) capturing and utilizing CO_2 and (3) using long-term CO_2 disposal technology. But improved or alternative energy uses are likely to be very slow so that these cannot be reliable as immediate solutions to the problems of CO_2 emissions [Hachiya and Frimpong, 1999]. The problem with the capture and utilization of CO2 is that many of the uses only delays the CO_2 release back into the atmosphere and cannot permanently solve the problem [Bachu, 1996]. Moreover, there is no commodity which can utilize the recovered CO_2 because of the magnitude of the quantities of excess CO_2. There is a complete mismatch between supply and demand [Steinberg, 1992]. Long-term excess CO_2 disposal using proven technologies are required to address the global warming problem [Hachiya and Frimpong, 1999].

2.5 Global Emission

The atmospheric concentrations of GHG grew rapidly to 360 ppmv in 1995. This indicates a 30% increase from pre-industrial level (before mid-1700's) of 280ppmv. Over the last 40 years, the global CO_2 emission rate has increased from 6Gt to 22.5Gt until the year 1995 [Jaques, et al., 1997].

2.6 Canada's Greenhouse Gas Emissions and Challenges

Canada emitted 619 million tonnes of GHG in 1995 and this was about 2% of total global greenhouse emissions [Jaques et al., 1997]. This is a 9.2% increase from the year 1990. Eighty one percent of the GHG was CO_2 and this share is 1% less than that of 1990 [Jaques et al., 1997]. Approximately 76% of the total GHG emissions in 1995 were attributed to the combustion of fossil fuels. The transportation sector contributed about 27%, industry, 18%, electricity generation, 15%, and fossil fuel production and distribution, 15%. While there are a number of factors responsible for this trend, emissions have increased largely due to an increase in economic activity, population growth and increased energy consumption. Countries at the FCCC agreed to a legally binding Protocol for industrialized countries to cut greenhouse gas emissions by 5.2%. Canada signed the Framework Convention on Climate Change (FCCC) in June, 1992. The convention was ratified by over 100 countries, including Canada, and became official on March 21, 1994.

Also, industrialized nations, as well as countries with economies in transition, have committed to a goal of stabilizing greenhouse gas emissions at 1990 levels by 2000 [Government of Canada, 1999]. Canada has made a commitment to reduce GHG emissions by 6 percent below 1990 level by year 2012 in the Kyoto Agreement [Gunter et al., 1998]. The National Action Program initiated by the government of Canada beginning with the 1990 National Action Strategy on Global Warming, sets a broad framework for actions on mitigation, adaptation and research. In this framework, the governments developed a range of strategies and actions to address climate change. In order to build on these initiatives, the Climate Change Task Group was established in 1993 to develop options for Canada's Action Program. The Task Group consisted of representatives from federal, provincial, and territorial environment and energy departments, industry associations, environmental groups, and other public interest groups [Government of Canada, 1999].

2.7 Alberta's Challenge on CO_2 Reduction

Canada's commitment to reduce GHG emissions by 6 percent below 1990 level by year 2012 in the Kyoto Agreement means a net reduction of 25 % for Canada [Gunter et al., 1998]. Alberta emitted 28.2 percent of the total CO_2 emissions in Canada in 1990 and 30.5 percent in 1995 with an increasing potential in the future [Jacques, Neitzert and Bolieau, 1997]. Available data show that CO_2 emissions constitute about 80 percent of all GHG, followed by CH4 (about 18 %) for Alberta [Jacques, Neitzert and Bolieau, 1997]. Thus, in order to control GHG emissions, appropriate technology must be designed to deal with CO_2 emissions. Sources of CO_2 emissions in Alberta include power generation from stationary fuel combustion (70.9%), mobile fuel combustion (14.8 %), industrial process (12.5 %), and agriculture (1.4 %). Stationary fuel combustion includes power generation, industry, commercial, residential, and agricultural uses. Mobile fuel combustion includes cars, air, rail and marine. Industrial process includes upstream oil and gas, cement and lime production.

To meet the target, a National Action Program on Climate Change outlining the federal-provincial strategy was developed [Alberta Energy, 1999]. The Voluntary Challenge and Registry Program is a key element of the national action program. The program is primarily aimed at activities that reduce or limit emissions of greenhouse gases and includes actions that address climate change through not only by direct effort but also by other means, such as: education, training and research [Alberta Energy, 1999]. The Alberta Government registered its own action plan in October 1995, which includes the following:

- carry out a government-wide action plan which reduces greenhouse gas emissions
- demonstrate the advantages of a voluntary approach
- take effective actions for saving cost
- make profit from doing business in new ways or ideas
- show how others can take cost-effective actions to reduce emissions measure and report on cost-effective actions of green house gas reduction.

Through an implementation team with representation from the government of Alberta departments, greenhouse gas emission actions will be identified, assessed, implemented, monitored, evaluated and reported. The three-year Action Plan focuses on reducing the three major sources of carbon dioxide: energy used in buildings, waste, and operation of fleet vehicles [Alberta Energy, 1999]. The program encourages CO_2 reduction, and research initiatives are being taken to address the problems of CO_2 emissions in Alberta. Research is underway to develop technology for capturing, utilizing and disposing CO_2 emissions [Government of Alberta, 1997]. These disposal technologies include enhanced oil recovery (EOR), coal-bed methane recovery (CMR) technology, CO_2/O_2 recycle combustion, and co-transport medium in pipelines and biofixation technology [Government of Alberta, 1997].

2.8 CO_2 Removal Technology Development

Four CO_2 capturing technologies have been proposed [Goldthorpe, Cross, and Davison, 1992] and some of the concepts have been put in practice. The first technology is the physical adsorption method. When gases including CO_2 are in contact with physical solvent, these gases dissolve in the solvent and are subsequently released from the solvent by reducing the pressure. Selexol and Rectisol (cold methanol) have been used as solvents [Leci and Goldthorpe 1992]. The second technology is the chemical adsorption method. CO_2 combines with a chemical solvent and when it is heated the former is released from the solvent. This method can give a better separation than the physical method but it requires much energy for solvent regeneration [Goldthorpe, Cross, and Davison, 1992]. A hybrid adsorption method also might be suitable for CO_2 separation. Such a method can be licensed from the process developers who hold the rights to the proprietary process [Goldthorpe, Cross, and Davison, 1992]. MEA (monoethanolamine) and HPC (hot potassium carbonate) have been proposed and used as typical solvents for CO_2 separation [Leci and Goldthorpe 1992].

The third technology is the waterscrubbing method. Physical and chemical adsorption methods require regeneration and recycling of the solvent. Therefore seawater was proposed as another option [Goldthorpe, Cross, and Davison, 1992]. Higher pressures are required to yield high solubility of CO_2 in seawater. When the pressure is discharged CO_2 can be captured. This concept can be applied to a seaside area. The fourth concept is a membrane separation method. Currently, high efficient physical and chemical adsorption methods have been developed by some of the industries as following [Goldthorpe, Cross, and Davison, 1992]. Saskatchewan Energy and Mines, Shell Canada Ltd., and Amoco Canada Petroleum Company Ltd. developed the following chemical CO_2 recovery technologies at the Boundary power plant in southeastern Saskatchewan, Canada. That uses chemical adsorption technology with amines. In the early 1980's, studies at the CO_2 recovery pilot plant at the Sundance Power Plant in Alberta showed that amine could be used for CO_2 recovery from flue gases [Wilson, Wrubleski and Yarborough, 1992]. In 1982, two amines, adsorbents of CO_2, were developed for this pilot plant but because of the problem of SO_2 corrosion, the project was stopped [Wilson, Wrubleski and Yarborough, 1992]. After solving the problem, a new pilot plant was constructed in 1986 and operated over a period of time. The analysis showed that 95~99 percent of CO_2 recovery and 99 percent of purity could be achieved in early 1990's [Wilson, Wrubleski and Yarborough, 1992].

The Kree-McGee / Lummus technology recovering food-grade CO_2 was developed by Kree-McGee Chemical Corp and ABB Lummus Crest Inc. based on the monoethanoamine (MEA) [Barchas and Davis, 1992]. This technology achieved 90% of

CO_2 recovery from coal-fired power plant flue gases. For food-grade application, this technology produces greater than 99.995% pure CO_2. For most chemical and EOR applications, the CO_2 product has 99.99% purity [Barchas and Davis, 1992]. The Kansai Electric Power Co., and Mitsubishi Heavy Industries developed CO_2 recovery technology which recovered 90% of CO_2 from flue gas by applying this chemical adsorption method. They performed this method by laboratory tests, bench scale tests, pilot plant tests and feasibility studies [Iijima, 1998 and Miura et al. 1998].

The Fluor Daniel ECONAMINE FG CO_2 removal process was developed by Fluor Daniel, Inc., in 1989. This technology based on Gas/Spec FT-1 developed by Dow Chemical in the late 70's and early 80's with the recovery ratio of CO_2 between 85~95% [Sander and Mariz, 1992]. The Tokyo Electronic Company (TEPCO) and Mitsubishi Heavy Industries, Ltd. of Japan developed the PTSA (Pressure and Temperature Swing Adsorption) technology. The PTSA is a physical adsorption method which uses a combination of heating and desorption. This achieved about a 30% energy saving compared to the conventional method PSA (Pressure Swing Adsorption) with 90% recovery ratio and 99% CO_2 purity [Ishibashi, Otake, Kanamori and Yasutake, 1998].

The physical adsorption method has been developed and is currently in use by TEPCO (Tokyo Electric Power Company) and Mitsubishi Heavy Industries (MHI), Ltd. The chemical adsorption method has been developed by Kansai Electric Power Company and MHI, Ltd. The percentage of recovered CO_2 from flue gas is over 90% and its purity is 99.9%. This chemical adsorption technology proposed by Kansai Electric Power Company and MHI, Ltd. is already in practice at oil-fired, and natural gas power plants in Japan. This KS technology has been used as the capturing system for this study because the results show that it is efficient and reliable [Iijima 1998]. The KS solvents[1] require 20% less energy than conventional solvents and adsorption ratio of recovered CO_2 is over 15% more than that of MEA [Iijima 1998]. Flue gases come out from a power plant and are sent to adsorber to be adsorbed with the solvent KS. Gases are sent to the CO_2 stripper and CO_2 is separated from other gases. The carbon dioxide has highest density

[1] For proprietary purposes, the KS solvents could not be identified in the report.

among the flue gases and is adsorbed by the KS solvent. Thus, it settles at the bottom of the stripper tower and about 90% of the CO_2 is recovered at this stage with a purity of about 99%. Next, CO_2 must be separated from the adsorbent KS. The gas is sent to a reclaimer and KS is removed from CO_2 by heating. At this point, purity of CO_2 becomes 99.9% and the CO_2 gas sent to liquefaction facility.

2.9 Conclusion

This literature shows that GHG emissions into the atmosphere have increased and that there is a call to decrease these emissions within the international community. A number of technologies have been proposed to decrease these emissions. These technologies have safety and economic problems. In order to bring these technologies to the application stage, they must be safe and economic. The thrust of this research will be to examine the technical, safety and economic feasibility of CO_2 disposal and storage in land aquifers in Alberta.

CHAPTER 3
STABILITY OF CO_2 AND GEOLOGY OF ALBERTA AQUIFERS

3.1 Introduction

Naturally occurring aquifer are geological formations of traps bordered by layers of sandstones and limestones that can contain water. Studies in the geological formation of Alberta have confirmed the existence of appropriate aquifers with potential for CO_2 disposal and storage over a considerable long geological period [Bachu et al, 1996]. These aquifers indicate the Glauconitic and Nisku aquifers within the Alberta Basin. CO_2 is an ideal candidate for aquifer disposal because of its high density and solubility in water at relatively high pressures. Discussions and analysis in this chapter will focus on CO_2 disposal in aquifer, phase diagram and behavior of CO_2, and trapping mechanisms for CO_2 disposal. The geology and stability of the aquifer structures will also be discussed and analyzed technical and safety basis for the disposal system.

3.2 The Required Conditions of CO_2 Aquifer Disposal System

Aquifer CO_2 disposal and storage require the following conditions [Bachu, et al., 1996]:

- The top of the aquifer must be below 800m from surface to keep CO_2 in the super critical state.
- The aquifer should be capped by impermeable (sealing) layers, regional aquitard.
- The aquifer should have enough porosity and adequate permeability. The near well permeability should be high (above 100md) to allow good injectivity, but the regional permeability should be low (under 100md) to yield long CO_2 residence time.
- The injection site should be close to CO_2 emission site.

3.3 Characteristics of CO_2

Figure 3.1 is a phase diagram showing the various forms of CO_2 at different temperatures and pressures. CO_2 is in a super-critical state at over 87.98° F (31.1 °C) and 1069.4 psia (7.38MPa). At this state, CO_2 behaves like gas with liquid density. Alberta's aquifers below 1000m have higher temperatures and pressures than the critical point so that CO_2 must be sent to the aquifer in the super-critical state [Bachu, 1995, Bachu, et al.,1996].

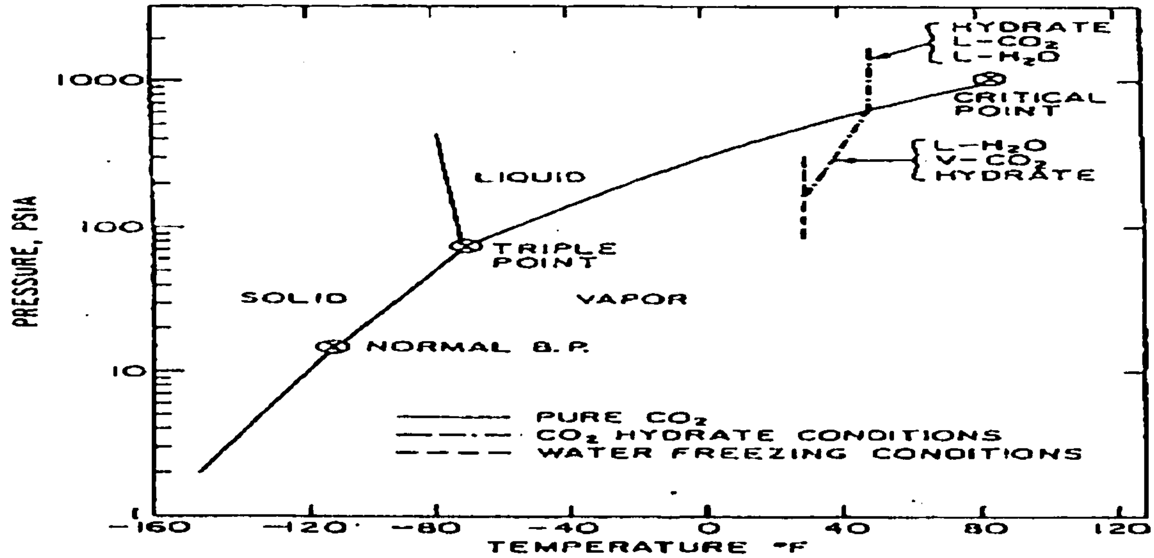

Figure 3.1 Phase diagram of CO_2 [Tanaka, 1996]

In a super-critical state, the solubility of CO_2 in water is much higher than in the gaseous state [Gerrard, 1980]. The reactivity with minerals contained in the formation water is also higher because some of the CO_2 dissolved in the water. This CO_3^- reacts with minerals and become trapped, for example as $CaCO_3$. Also in the super-critical state, CO_2 has a higher density so that the volume rate is more efficient. The target aquifer has a top pressure of 12.5MPa and temperature of 50°C, which show that, under these conditions, CO_2 is in the super-critical phase.

3.4 CO_2 Trapping Mechanism in Aquifers

The injected CO_2 travels in the aquifer in both dissolved and immiscible phases depending on the aquifer permeability. The dissolved CO_2 will travel in an aquifer with extremely low velocity, and residence time in the order of 1 million years. The immiscible CO_2 will also travel with residence time in the order of millions of years [Bachu, Gunter and Perkins, 1994]. Therefore, CO_2 can be trapped in an aquifer for long geological period in the liquid phase. This phenomenon is referred to as hydrodynamic trapping. Formation waters range in composition from pure water to brine. Thus when liquid CO_2 is injected into an aquifer, there is the possibility that it will react with the elements in the formation water or the minerals comprising aquifer rocks [Bachu, Gunter and Perkins, 1994]. By reacting, CO_2 can be trapped as solids in the aquifer. This phenomenon is referred to as chemical or mineral trapping.

3.5 Hydrodynamic Trapping

When CO_2 is injected into an aquifer at an appropriate pressure, it moves away from the injection well and flows within the natural flow regime. Once outside the injection-well radius of influence, the flow of immiscible CO_2 will travel at the same speed as the formation water in the regional flow system. In Alberta, there are many suitable aquifers in the Alberta Basin for hydrodynamic traps of CO_2.

3.6 Chemical (Mineral) Trapping

The chemistry of the formation water and rock mineralogy also increases the potential for CO_2 disposal through chemical reactions. Chemical reactions in a carbonate aquifer immobilise CO_2 as another carbonated substance [Perkins and Gunter, 1995]. Preliminary study shows that aluminosilicate minerals could sequester injected CO_2 in siliciclastic aquifers in two forms depending on the dominant cations. When the dominant cation is Na^+ or K^+, the concentration of bicarbonate is built up in the aqueous phase and forms bicarbonate brine. When the dominant cations are Ca^{++}, Mg^{++} and Fe^{++}, the concentration of bicarbonate is built up because of high solubility of sodium and potassium and the low solubility of calcite, dolomite and siderite which form precipitates [Perkins and Gunter, 1995].

Fracture pressure is the maximum allowable injection pressure to preserve the integrity of the aquifer structure. Injection causes no rock fracture or disruption in the aquifer. The fracture pressure in the Glauconitic aquifer is about 33.5MPa. Therefore, injection pressures lower than 33.5MPa are theoretically safe for CO_2 disposal into this aquifer. Injectivity simulation studies, conducted with an assumed maximum injection pressure of 90% of fracture pressure, have concluded that injection of CO_2 is safe under this condition [Bachu, et al.,1996]. CO_2 is quite soluble in water. It exists in the liquid phase with water and may be stored in an aquifer under proper conditions. CO_2 can thus be trapped in an aquifer for a long geological time scale by this hydrodynamic trapping when the outer permeability of the injection zone is low [Bachu, et al.,1996]. When CO_2 is injected into an aquifer at an appropriate pressure, it moves away from the injection well and flows with the natural flow regime. Beyond the radius of influence of the injection well, the flow of immiscible CO_2 will travel at the same speed as the formation water in the regional flow system. The Glauconitic aquifer is suitable for CO_2 disposal because of the formation water flow and CO_2 is caught in the hydodynamic regime of the formation water [Bachu and Undershultz, 1995].

The Glauconitic aquifer has suitable conditions for CO_2 chemical trapping [Perkins and Gunter, 1995]. In the Glauconitic aquifer, the dominant cations are Ca^{++}, Mg^{++} and Fe^{++}, resulting in equations (3.1) and (3.2).

$$H_2O = H^+ + OH^- \tag{3.1}$$

$$H_2O + CO_2 = HCO_3^- + H^+ \tag{3.2}$$

Some of the CO_2 exists as bicarbonates or as bicarbonate ion with the proton ion at any pressure. The proton results in acidic condition in the aquifer which can affect the silicate minerals in the aquifer. This results in free Ca^{++} ions as in equation (3.3). The fastest chemical reaction is the precipitation of calcium carbonate in equation (3.4).

$$H_2O + CaAl2SiO8 + 2H^+ = Ca^{2+} + Al2Si2O5 \bullet (OH)_4 \tag{3.3}$$

$$Ca^{2+} + HCO_3^- = CaCO_3 + H^+ \tag{3.4}$$

CO_2 can eventually be stored permanently as a solid $CaCO_3$. Gunter and Perkins (1995) estimated that the capacity of CO_2 by this chemical trapping is about 0.5 Mt per square kilometer in the Glauconitic aquifer. By this chemical trapping simulation, there will be complete equilibrium in 820 years and that 6.2 moles of carbon dioxide will be trapped as calcite per kg of formation water in the Glauconitic aquifer [Perkins and Gunter, 1996]. As a result of the above reasons, siliciclastic aquifers are prime targets for mineral trapping of CO_2. In Alberta, the Glauconitic Aquifer has suitable minerals for CO_2 chemical trapping [Perkins and Gunter, 1995].

3.7 Geology of the Alberta Basin

The Western Canadian Sedimentary Basin consists of two basins called the Alberta Basin and Williston Basin with rich coal, oil and gas as shown in Figure 3.2. The Alberta basin is an accumulation of marine and near-shore sedimentary rocks. The basin geometry and structure are the result of two major phases of basin development. The first passive margin phase was dominated by carbonate deposition on the continental margin. The second phase began in the Middle Jurassic with the onset of convergent tectonic activity and the formation of a foreland basin dominated by clastic sedimentation of sandstone and shales [Bachu, Gunter, and Perkins,1994]. The Glauconitic and Nisku Aquifers in the Alberta Basin qualify as suitable aquifers for CO_2 disposal and storage. The Glauconitic has been selected as the target aquifer for this study. The Glauconitic aquifer is capped at the top by the Grand Rapid Formation Aquitard and at the bottom by the Ostracod Beds aquitard. Figure 3.2 shows the location of Alberta Basin and indicates major coal-fired power plants [Bachu, et al., 1996].

3.8 The Glauconitic Aquifer

Figure 3.3 and 3.4 show stratigraphy, lithology and hydrostratigraphy of the Alberta Basin and around Glauconitic Aquifer. Figure 3.3 shows the dip cross-section through the Alberta Basin. White layers indicate aquifer groups and black layers indicate aquitard or aquiclude groups and the arrow in Figure3.3 indicates the Wabamun Area [Bachu, Gunter and Perkins, 1996]. The target aquifer, the Glauconitic Aquifer is too small to be shown in the figure but it exists under the Grand Rapids formation. The layers are classified by period, geological group and formations. The Glauconitic Aquifer is the part of upper-Mannville Group. Figure 3.4 shows detailed staratigraphy, lithology and hydrostratigraphy for the Mannville Group, which the Glauconitic Aquifer belongs.

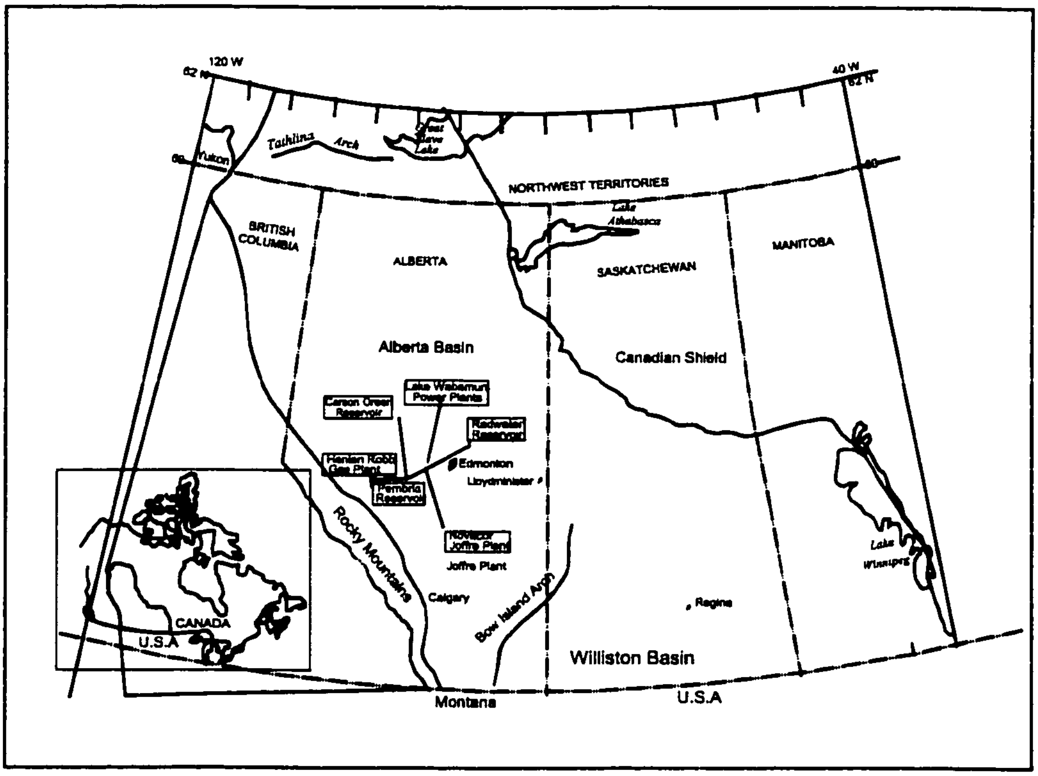

Figure 3.2 Location of Alberta Basin [Bachu, et al., 1996]

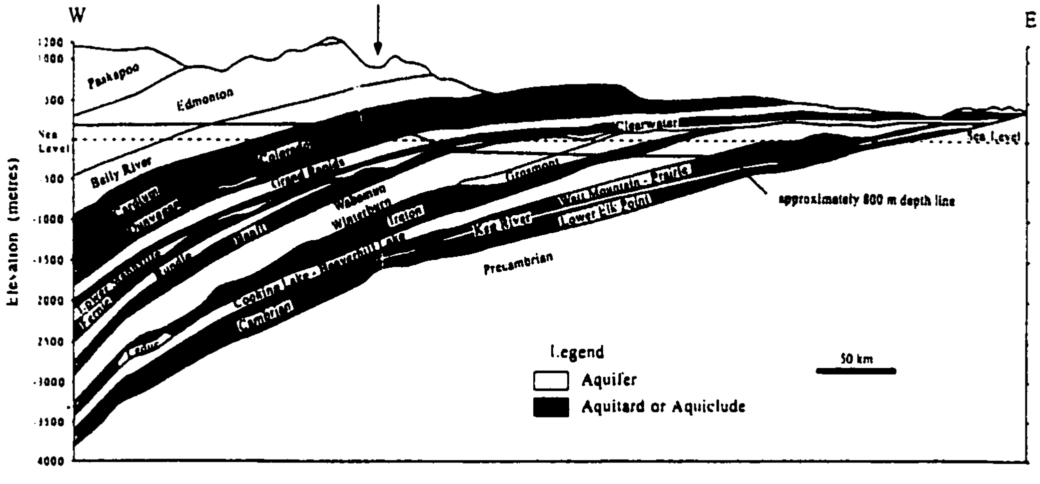

Figure 3.3 Hydrostratigraphic dip cross-section through the Alberta Basin [Bachu, et al.,1996]

Figure 3.4 indicates target aquifer Glauconitic Aquifer, which belong to upper Mannville group and Cretaceous period. The Grand Rapids Formation capping the Glauconitic Aquifer is divided into two layers. The lower layer on the top of the Glauconitic Aquifer has a continuous basal shale zone about 10m thick. The upper layer contains thin interbedded siltstones, shales and limestone [Bachu, et al.,1996]. Shale is any mudrock that exhibits lamination or fissility or both. Siltstone is also mudrock with 50% or more silt-sized material [Prothero and Schwab, 1996]. The Ostracod Beds aquitard is relatively uniform in its lithology and thickness with an average thickness of 18m. This contains black mudstones with abundant shale beds.

Stratigraphy			Lithology	Hydrostratigraphy	
Cretaceous		Post-Mannvile	Shale	Aquitard	
		Joli Fou Formation	Shale	Aquitard	
	Mannville Group	Grand Rapid Formation	Sandstone Shale	Aquifer Aquitard	
		Glauconitic Sandstone	Sandstone	Aquifer	← Target Aquifer
		Ostracod Beds	Shale and Sandstone	Aquitard	
		Ellerslie Member	Sandstone	Aquifer	

Figure 3.4 Staratigraphy, lithology and hydrostratigraphy of Cretaceous [Bachu, et al.,1996]

There are occurrence of quartz sandstone and siltstones [Bachu, et al.,1996]. Sandstones are major reservoirs of groundwater and petroleum [Prothero and Schwab, 1996]. The Glauconitic Aquifer has an average thickness of 14m. From bottom to top, the Glauconitic Sandstone consists of argillaceous sandstone grading upward into thin, stacked cycles of fine- to medium-grained, porous, salt-and-pepper sandstone. Detailed layers are identified by a cross-bedded to massive sandstone base grading upward into bioturbated sandstone at the top. This aquifer is capped by a medium-grained sandstone that grades upward into a white siltstone [Bachu, et al.,1996].

3.9 Rock Properties

The relevant rock properties for aquifer disposal of CO_2 are porosity, permeability and mineralogy. The Glauconitic Aquifer is classified as a mature to sub-mature litharenite. The sandstone is fine-midium grained, sub-angular to sub-rounded, moderately well sorted, and has good porosity for injection. The ratio of quartz, feldspar and rock fragments ranges from 55:4:41 to 40:3:57. Monocrystalline and polycrystalline quartz grains are very clean. A few samples contain kaolinite coatings, with dolomite and calcite crystal growth along grain contacts. Rock fragments include chert, glauconite, mudstone, and dolomite. The high proportion of clay in the Glauconitic Aquifer is due to the presence of glauconite that ranges in size from sand-size grains to clay-size grains [Bachu, et al.,1996]. Figures 3.4 shows the lithology of the Cretaceous and Alberta Basin. Porosity data for this study area were measured by Bachu, et al., (1996) using core analysis, and the results are provided in Table 3.1.

Table 3.1 Porosities of the Mannville Strata Group [Bachu, et al.,1996]

Stratigraphic Unit	Min Porosity[%]	Average Porosity[%]	Max Porosity[%]
Grand Rapids Formation	5.60	6.10	6.60
Glauconitic	11.80	11.90	12.00
Ostracod Beds	1.30	7.80	17.10

Table 3.2 Permeability of the Mannville Strata Group [Bachu, et al.,1996]

Stratigraphic Unit	Min Permeability [md]	Average Permeability [md]	Max Permeability [md]
Grand Rapids Formation	0.01	0.10	1.00
Glauconitic	13.40	14.15	14.95
Ostracod Beds	0.01	1.87	212.73
Ellerslie Member	0.03	4.06	201.93

From the analysis, generally there is no vertical trend in porosity values in any unit. As shown, the porosity of the Mannville strata group of the Grand Rapids Formation, Glauconitic and Ostracod Beds is quite variable, but on the average it is higher within the Glauconitic Aquifer. The Grand Rapids Formation has only half of the porosity of the Glauconitic Aquifer. The high porosity in the Glauconitic aquifer increases its capacity for CO_2 disposal and storage. Rock permeability analysis provided by Bachu, et al

(1996) also shows that there is no vertical trend of permeability values. The data shows that the Glauconitic Aquifer has significantly higher permeability values compared to that of the capping aquitards.

As a result of the porosities and permeabilities, the aquitards confine the flow to the Glauconitic Aquifer. Generally, water flows in the horizontal direction because of the higher permeabilities. No vertical water flow occurs due to the lower permeabilities. In the Grand Rapid Formation, there exist frequent coal layers. This layer acts as the cap for the aquifer. As a result of the hydrodynamic trapping mechanism and permeability distribution, the injected CO_2 can have a long residence time in the aquifer. Erosional rebound leading to reverse flow from aquifers into shaley aquitard with lower permeability was observed by Neuzil (1993) for Williston Basin. A similar result was observed in a sub-Andean foreland basin in Colombia [Villegas 1994, Bachu, et al 1996]. From these results, it can be concluded that other aquifers in the world have similar characteristics and mechanisms of formation water flow system, which enhance the advantage of CO_2 aquifer disposal [Bachu, et al., 1996]. The CO_2 is confined to the aquifer even if there are no chemical reactions to form minerals [Bachu et al.,1996].

3.10 Fracture Pressure

The stability and residence of injected CO_2 in the target aquifer also depend on the fracture pressures of this aquifer. Fracture pressure is the maximum pressure for injection, under which the rock is theoretically stable. The fracture pressure in the Glauconitic aquifer is about 33.5MPa. Therefore, it can be concluded that at an injection pressure lower than 33.5MPa, it is theoretically safe for CO_2 disposal into the Glauconitic Aquifer. The ARC has done injectivity simulations, to study the stability of CO_2 in the Glauconitic aquifer. They assumed maximum injection pressure to be 90% of estimated fracture pressure for CO_2 stability [Bachu, et al., 1996]. Bachu, et al., (1996) carried out this injectivity study under the following conditions.

- The aquifers are homogeneous
- The thickness of the aquifer is constant
- The small dip of the aquifer is ignored

- CO_2 is in the super critical state in the aquifer and is treated as single phase fluid.
- Capillary pressure effects are negligible
- The relative permeability curves for the carbon dioxide-water were not measured

By injecting CO_2 into high permeability zone, fracture will be avoided and the efficiency of injection will be higher [Bachu, et al.,1996]. In addition, if maximum pressure is set as 90% of fracture pressure that would be 30.12 MPa. They concluded that a high injection pressure results in high injection rate. About 50% more carbon oxide can be injected when injection pressure increases from 25.15 MPa to 30.12MPa [Bachu, et al, 1996]. Changes in porosity had minimized effect on injection rate. The carbon dioxide might propagate farther in the case of the lower porosity. The permeability has a very significant effect on the capacity of CO_2 disposal. The total amount of carbon dioxide is more than 15 times greater when permeability changes from 6.2md to 100md [Bachu, et al.,1996]. Here, injection pressure is the pressure at the bottom of well.

3.11 Conclusion

The literature review is carried out on stability of CO_2 and geology of the Alberta Basin. CO_2 can be trapped hydrodynamically in the liquid phase and immobilized chemically in the aquifer for geological time. The Glauconitic aquifer is suitable for aquifer CO_2 disposal because it satisfies the depth, sealing layers, permeability and pressure requirements for disposal. Fracture pressure of the Glauconitic aquifer is 33.5MPa and for safer injection, injection pressure should be less than 30.12 MPa, which is 90% of fracture pressure.

CHAPTER 4

DESIGN OF CO_2 AQUIFER DISPOSAL SYSTEM

4.1 System overview

The aquifer CO_2 disposal system comprises technologies for capturing, liquefaction, transportation and injection. Figure 4.1 indicates the system scheme. After flue gases come out from greenhouse gas emission site, CO_2 is captured to make disposal efficiency high. After capturing, CO_2 is liquefied and sent to injection site. Before injection, CO_2 is more pressurized to meet the injection pressure requirement of the aquifer. In this section, the design of each procedure is discussed and case study is carried out for the Wabamun Thermal Power Plant of TransAlta Corporation.

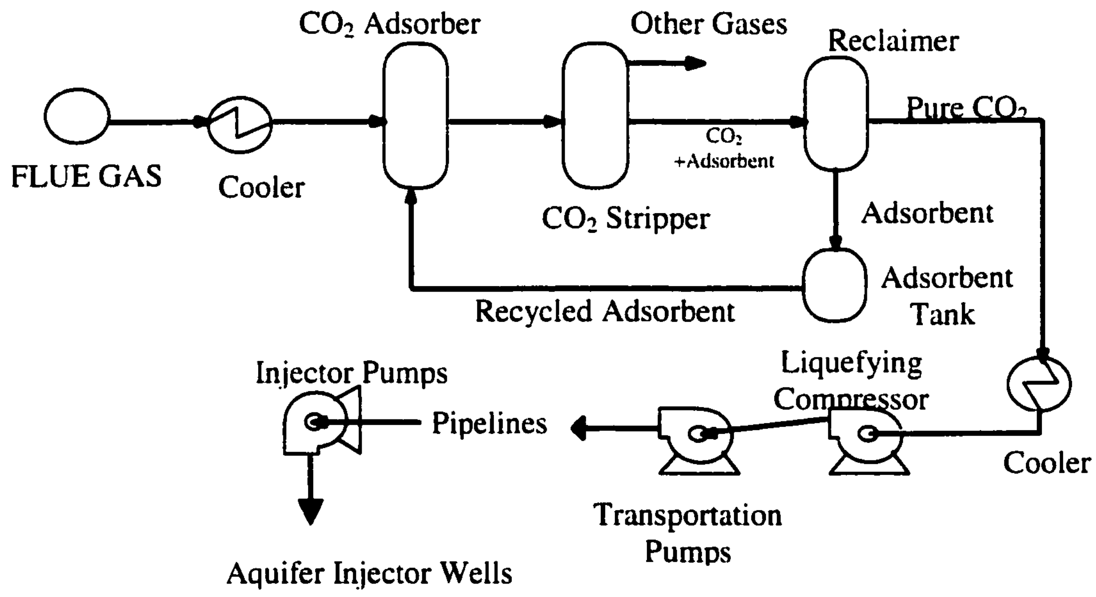

Figure 4.1 Aquifer CO_2 Disposal System (ACDS)

Figure 4.2 illustrates the capturing procedures. Flue gases are cooled down before capturing because the adsorbent, K-S, captures CO_2 at about 60 degree Celsius. After adsorption, the gases are sent to a stripping tower. The gases are removed subsequently from the top to the bottom of the tower depending on the difference in densities from lighter substances to heavier. The CO_2 has the greatest density among gases by absorbent. The CO_2 remain at the bottom of the tower and is recovered at reclaimer. The CO_2 with K-S is heated up to be decomposed with K-S at a temperature of 120°C. The absorbent is sent back to its storage tank to be recycled and CO_2 is sent to the liquefaction plant after cooling down to room temperature 27°C. At this point, 90% of CO_2 is recovered with a purity of 99%.

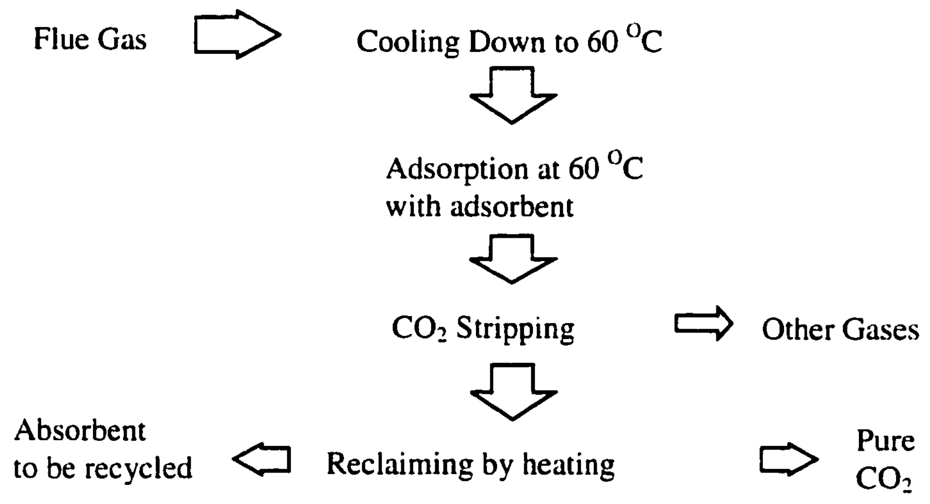

Figure 4.2 CO_2 Capturing by Chemical Adsorption

Figure 4.3 illustrates the procedure for the liquefaction and transportation systems. The pure CO_2 is liquefied by pressurizing at 7.5 MPa in the liquefaction compressor at 300K. The liquefied CO_2 is sent to injection sites through the pipelines by pumping with the pressure equivalent to the pressure loss between pumps and injection sites to keep the liquefied pressure. Figure 4.4 indicates procedure of injection. The liquid CO_2 is injected into the aquifer by pumping through the injector well. CO_2 is pressurized with a pressure, which is greater than the aquifer pressure and the pressure drop occurring in the injector well. The pressure of the Glauconitic aquifer is 12.4 MPa. Pressure drop must be estimated depending on the system design and the environment of the injection sites.

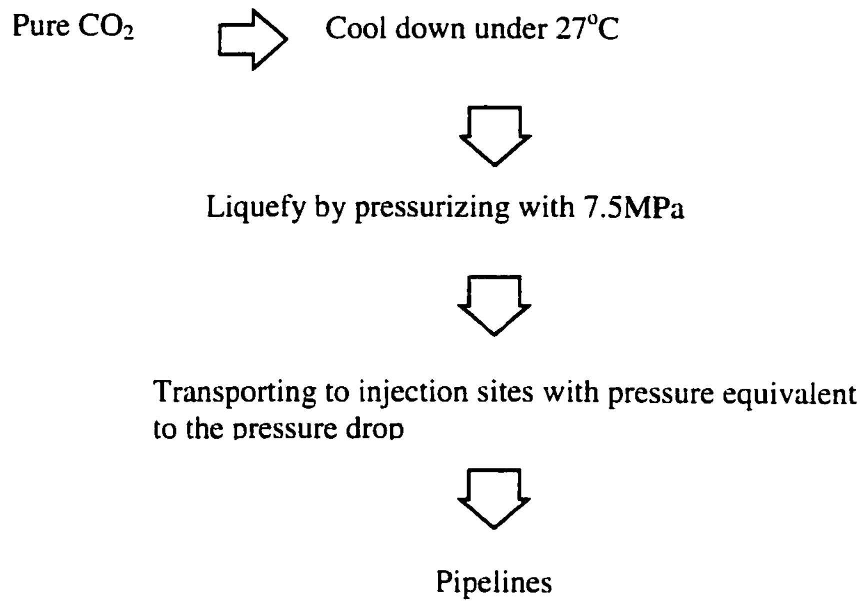

Figure 4.3 ACDS Liquefaction Process

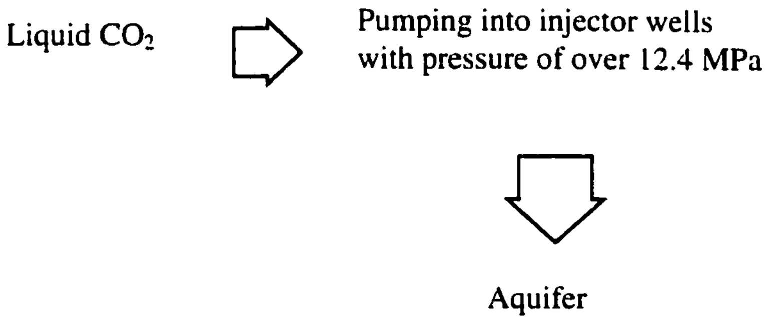

Figure 4.4 ACDS Injection Process

4.2 Mathematical Models of the Capturing and Liquefaction

After the flue gases are released from the plant, CO_2 is separated from other flue gases before injection. The energy efficiency depends on the purity of CO_2 after separation. Therefore, CO_2 must be purified as much as possible. As discussed in Chapter 2, Kansai Electric Power Company of Japan and MHI, Ltd., of Japan have developed a high efficiency CO_2 capturing system, the KS technology. This technology is used in this study. In the KS technology, the energy requirement is given by the following equations.

$$PR_{cap} = UP_{cap} * T_{CO_2} \tag{4.1}$$

Liquefaction is required to change CO_2 from gas to liquid. Liquified CO_2 is efficient to transport to the injection sites as a result of its high density. The CO_2 is compressed by a compressor at pressure of over 7.4 MPa. Extremely high power compressor is required for this step. The required liquefaction energy is estimated from equation (4.2).

$$PR_{liq} = UPl_{iq} * T_{CO_2} * R_{CO2} \tag{4.2}$$

PR_{liq} indicates the total power requirement for liquefaction system. UP_{liq} indicates the unit power requirement kW per a tonne of CO_2. T_{CO2} is the amount of CO_2 emission per hour. R_{CO2} is recovery ratio of CO_2 from the capturing system. Liquefied CO_2 is transported to injection site through pipelines by pumps. Extra pumps might be required when injection site is over 30km away from the CO_2 emission site. The pressure loss for transportation of liquefied CO2 is provided by equation (4.3).

$$\Delta P = 4\lambda\left(\frac{L}{D}\right)\left(\frac{\rho < u >^2}{2}\right) \tag{4.3}$$

The pumps must provide the required energy to transport CO_2 with pressures greater than the pressure losses between the liquefaction station and injection site to prevent phase changes during transportation. The required power is given by equation (4.11) . λ is given by Reynolds Number which is given by following formulas (4.4) and (4.5):

$$Re = \frac{D < u > \rho}{\mu} \tag{4.4}$$

$$\frac{1}{\lambda} = -4\, log\left\{ \frac{\varepsilon}{3.7065} - \frac{5.0452}{Re} log\left[\frac{\varepsilon^{1.1098}}{2.8257} + \left(\frac{7.149}{Re} \right)^{.8981} \right] \right\} \tag{4.5}$$

The average velocity rate <u> in equation (4.3) is shown as following equation (4.6)

$$<u> = V / \pi * n * R^2 \tag{4.6}$$

The volumetric flow rate V in equation (4.6) can be shown as following;

$$V = \frac{CO_2 * 1000}{\rho} \qquad \left| m^3 / sec * site \right| \tag{4.7}$$

By substituting equation (4.6) and (4.7) into (4.3), the following equation (4.8) is given.

$$\Delta P = 4\lambda \left(\frac{L}{D} \right) \left(\frac{\rho V^2}{2 \left(n\pi R^2 \right)^2} \right) \qquad \left[Pa / site \right] \tag{4.8}$$

Substitute equation (4.6) into equation (4.8), then following equation is given;

$$\Delta P = 4\lambda \left(\frac{L}{D} \right) \left(\frac{CO_2^2 * 10^6}{2\rho \left(n\pi R^2 \right)^2} \right) \qquad \left[Pa / site \right] \tag{4.9}$$

The power of injection can be estimated by;

p [Pa] * V [m^3/s] = p [N/m^2] * V [m^3/s] = p* V [N•m^3/s] = p* V [J/s] = p* V [W]

Therefore, the power requirement for the pipeline is:

$$PR_{trns} = \Delta P * V = \lambda\left(\frac{L}{D}\right)\left(\frac{\rho * CO_2^{\,2} * 10^6}{2\left(n\rho\pi R^2\right)^2}\right)\left(\frac{CO_2 * 1000}{\rho}\right) \qquad (4.10)$$

The liquefied CO_2 is injected into the aquifer thorough the injector well. An injector well consists of an inner tubing in contact with the liquefied CO_2 and a casing, which covers and protects the tubing and injection pump/compressor. The required pressures and energy for injection can be calculated by equations (4.11) to (4.14). CO_2 is pressurized to overcome the pressure drop between the injection site and the aquifer environment. The injection pressure at the surface must satisfy following equations (4.11) and (4.12).

$$\Delta P_{total} = \Delta P - \Delta Pg \qquad (4.11)$$

$$P_{total} \geq P_{aqu} + \Delta P_{total} \qquad (4.12)$$

The equations (4.12) becomes (4.13)

$$P_{total} \geq Paqu + 4\lambda\left(\frac{h}{D}\right)\left(\frac{\rho * CO_2^{\,2} * 10^6}{2\left(n\rho\pi R^2\right)^2}\right) - \rho gh \qquad (4.13)$$

The injection pressure at surface is following. When P_{bot} is set greater than aquifer pressure.

$$P_{total} = P_{bot} + 4\lambda\left(\frac{h}{D}\right)\left(\frac{\rho * CO_2^{\,2} * 10^6}{2\left(n\rho\pi R^2\right)^2}\right) - \rho gh \qquad (4.14)$$

For injection, following power is required:

$$PR_{inj} = \Delta P_{Total} * V = \left\{P_{bot} + 4\lambda\left(\frac{h}{D}\right)\left(\frac{\rho * CO_2^{\,2} * 10^6}{2\left(n\rho\pi R^2\right)^2}\right) - \rho gh\right\}\left(\frac{CO_2 * 1000}{\rho}\right) \qquad (4.15)$$

The total power required for the system can be estimated by adding PRcap, PRliq, PRtrans, and Prinj. The detailed economic model is based on the power requirements of the capturing-liquefaction-transportation-injection system. From the equations (4.1), (4.2), (4.10) and (4.15), the total power requirements are derived to form the basis of the economic models in Chapter 6.

4.3 Case Study for Wabamun Thermal Power Plant

In this study, Wabamun Thermal Power Plant (Trans Alta Corporation) in Figure 4.5 is selected as the CO_2 emission site for the case study of the aquifer CO_2 disposal system (ACDS). The Wabamun Thermal Power Plant is located at Wabamun, 65km west of Edmonton, Alberta. In this plant, 2.8 million tonnes of coal is burned annually to generate 548 MW of electricity. The flue gases from this power plant are 4,584 kt of CO_2, 15,400 kt of N_2, 1,357,918 H_2O, and 992,451 of O_2 annually [TransAlta Co., 1998].

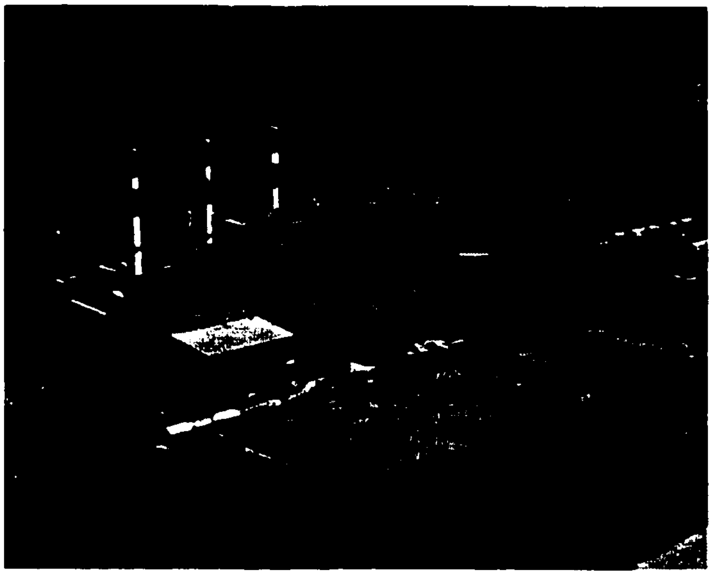

Figure 4.5 Wabamun Thermal Power Plant (Trans Alta Corporation)

According to the data from Kansai Electric Power Company and MHI, Ltd., the KS capturing technology requires total electrical power of 35.5 MW to separate 253t of CO_2 [Iijima, et. al, 1998]. This indicates that 140 kW of electricity is required to capture 1 tonne of CO_2. This conversion factor is applied to the Wabamun case. At the Wabumn plant, 470.77 t of CO_2 is recovered per hour. Equation (4.2) is used to estimate the power requirement for liquefaction. The liquefaction system changes CO_2 from the gases phase to the liquid phase by compression in a compressor. The required unit energy for liquefaction is 0.1036 kWh/kg or 103.6 kWh/t at 300 K (27° C) and 0.1 MPa (atmosphere) [Pak, Nakamura and Suzuki, 1997].

4.4 Injectivity Study for Wabamun Plant and Glauconitic Aquifer

As discussed in Chapter 2, higher injection pressures and greater permeabilities result in greater injectivity and greater aquifer capacity. This is governed by Darcy's Law. Injection pressure is based on the number of injection sites and the local aquifer permeability of the injection site. In this study, the "local" is assumed as the area with a radius of 5000 m from the injector well. Higher injection pressure requires more energy and therefore results in high operating costs. Lower injection pressures require many injection sites and hence higher capital investment. The injection rate and capacity have been studied for the Glauconitic Aquifer depending on injection pressure and local aquifer permeability under the following conditions [Bachu, et al.,1996]:

- The radius of the well is 3 inches
- The aquifer is homogeneous with the permeabilities of 30 md or 100 md
- The thickness of the aquifer is constant at 13 m
- The small dip of the aquifer is ignored
- CO_2 is in the super-critical state in the aquifer and is treated as single phase fluid
- Capillary pressure effects are negligible
- The relative permeability curves for the carbon dioxide-water were not measured

The simulated injection pressures and permeabilities are 30.12 MPa and 25.15 MPa and 100 md , 30 md , and 6.2 md, respectively. From these simulation studies, 2.8 Mt to 22 Mt of CO_2 can be disposed off in aquifers with wells of 3-inch radius, and with injection pressures between 12.4MPa to 30.12MPa [Bachu et al., 1996]. About 42Mt of CO_2 can be disposed off in the Glauconitic Aquifer with 30.12 MPa and permeability of 100 md; 27 Mt of CO_2 with 25.15MPa and permeability of 100 md in 30 years [Bachu et al., 1996]. From those simulation studies, for 30 md permeability zone, 13 Mt of CO_2 can be disposed off with a pressure of 30.12 MPa and 8.6 Mt of CO_2 can be disposed off in the Glauconitic Aquifer with 25.15MPa in 30 years [Bachu et al., 1996]. From these data, annual injection/flow rate and injection/flow rate per sec are estimated. These are shown in Table 4.1. The total CO_2 flow rate at the Wabamun plant is 0.13077 t/s after liquefaction. The number of required injection sites is obtained by dividing this Wabamun rate by estimated injection rate. The injectivity of CO_2 in homogeneous aquifers can be generalized as follows [Bachu, et al.,1996]:

$$Q_{CO_2} = 0.0208 * (k_h * k_v)^{0.5} * T_{aqi} * (P_{hot} - P_{aqu}) / \mu \qquad (4.16)$$

The viscosity of CO_2 between 12.4 MPa and 30.12 MPa is almost constant with the same temperature so that most of the variables are constant except the injection pressure [Yaws, 1995]. This means the injectivity is the function of the injection pressure. From the injectivity study carried out by ARC, the ratio of injectivity is estimated and the injectivities for 26.60 MPa and 20.00 MPa are estimated [Bachu et al. 1996].

By dividing injection rate estimated for 6-inch well by the Wabamun's flow rate, the number of required injection sites is estimated as following and shown as Table 4.1. Four operating wells are required for 30.12 MPa, 5 wells for 26.60 MPa and 25.15 MPa and 8 wells for 20.00 MPa for Wabamun Power Plant when local permeability is 100 md. Eleven operating wells are required for 30.12 MPa, 17-well for 25.15 MPa and 25-well for 12.4 MPa for Wabamun Power Plant when local permeability is 30md. When local permeability is 6.2md, over 500 injection sites are required for any type of pressures. This case is unrealistic and it is not considered in this study. As stated above above, the injectivity and the number of injection sites change depending on local permeability and injection pressure. Eight different injection cases are considered for economic analysis. Based on these results, the experiments for pressure drop and power requirements are carried out. Table 4.2 shows the eight cases studied. As shown, the lower injection pressures and lower permeability require more injection sites.

Table 4.1 Injectivity and Capacity for Glauconitic Aquifer

Porosity	0.12	0.12
Local Permeability	100	30
Injection Rate tonnes for 30yr at 30.12MPa	42000000	13000000
Injection Rate t/year at 30.12MPa	1400000	433333.3333
Injection Rate t/s at 30.12MPa	0.04439371	0.01374091
Injection Rate tonnes for 30yr at 26.6MPa	31440000	9731429
Injection Rate t/year at 26.6MPa	1048000	324381
Injection Rate t/s at 26.6MPa	0.03323186	0.010286053
Injection Rate tonnes for 30yr at 25.15MPa	27000000	8385000
Injection Rate t/year at 25.15MPa	900000	279500
Injection Rate t/s at 25.15MPa	0.0285388	0.008862887
Injection Rate tonnes for 30yr at 20MPa	17473050	5408325
Injection Rate t/year at 20MPa	582435	180278
CO_2 recovered at Wabamun tonne per year	4584000	4584000
CO_2 recovered at Wabamun tonne per second	0.13077	0.13077
# of wells required at 30.12MPa	3.2	10.2
# of wells required at 26.6MPa	4.2	13.6
# of wells required at 25.15MPa	4.6	15.8
# of wells required at 20MPa	7.6	24.5

Table 4.2 Injection Environment Cases

Case	Injection Pressure [MPa]	Local Permeability [md]	# of Wells
1	30.12	100	4
2	26.60	100	5
3	25.15	100	5
4	20.00	100	8
5	30.12	30	11
6	26.60	30	14
7	25.15	30	16
8	20.00	30	25

4.5 Experimental Design and Experimentation

The experiments are carried out using Intel Pentium 120MHz and software of Microsoft Excel 97 in the Windows 95 environment. The CPU time for all experiments are less than one second. The equations used are equation (4.9) for transportation and equation (4.14) for injection. As mentioned in Section 4.5, the injection pressure and permeability play an important role in terms of injection rates, aquifer capacities, and number of injection sites. Equation (4.15) shows the power requirement for an injector well. In this study, the length, radius and diameter of a well are fixed at 1490m, 3 inches and 6 inches, respectively. Also, the length of a well depends on the depth of the Grauconitic aquifer, which is 1480m. The density of CO_2 and CO_2 flow rates are fixed by the environment of injection shown in Table A.1 and A.2 based on the number of injection sites. Only the number of injection sites is varied to obtain the various power requirements.

The flow rate of CO_2 from the Wabamun Power Plant after capturing is estimated as 130.77 kg/s or 470.77 t/h. The design equations are validated using these data. The pressures and power requirements for transporting liquid CO_2 are estimated from equations (4.9) and (4.10). The number of injection sites is shown in Table 4.2. The length of a pipeline is 5 km for the first six sites because CO_2 moves away from injector well up to 5 km [Bachu et al., 1996]. The outer zone's permeability is assumed to be much lower. This means that CO_2 forms a circle, which has maximum radius of 5km and thickness of 13m shown in Figure 4.6.

As discussed above, CO_2 forms the circle, which has maximum radius of 5km. Therefore, to dispose the CO2, the injection sites must have distance from power plant at least 5km. If the circles has radius of 5 km from CO_2 emission site, the maximum number of circles, which can be laid is six geometrically. The sites from seventh site have distance of 10000m from the plant to be located out of the first six injection sites and up to twelve of injection circle can be located geometrically. The sites from nineteenth site have 15000m of distance from the plant. In this case, the average roughness of the pipeline is assumed as 0.06 inch. Top injection pressure and power requirement of the injector well can be estimated using equations (4.14) and (4.15) discussed in Section 4.2. The length of the well is 1490 m. The injection pressure at the bottom is shown as Table 4.2 for each case. These input data are also shown as Tables A.3 and A.4.

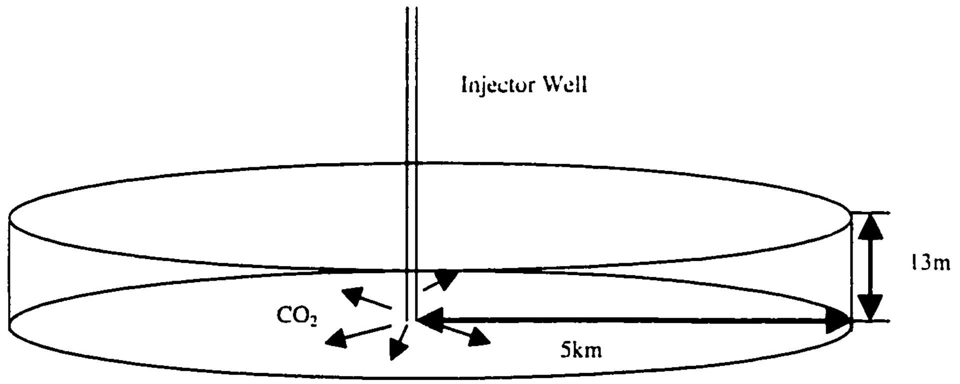

Figure 4.6 CO_2 Flow Model in the Aquifer

4.6 Discussions and Analysis of the Design Results

Figure 4.7 shows the pressure drop and the power requirements for the pipeline and the injector well an injection pressure of 30.12MPa. The results show that as the number of injection sites increases, the pressure drop decreases. The pressuredrop and power requirements for transportation is a steeply decreasing function with decreasing number of sites increases. The maximum pressure drop for transportation is 22.51MPa. This is twenty times as big as that of 4 wells. As the results show, more than four injection sites is required for optimum results.

The power requirements are 68500 kW for CO_2 capturing plant and 48772 kW for liquefaction for all cases. Tables A.67, A.68, A.69, and A.70 show the experiment results. All of results show that fewer numbers of injection sites have higher pressure drops and higher energy requirements. Table A.71 shows the result for total energy requirement for the whole system. Total energy requirement for the system is between 115 MWh and 116 MWh. This is between 21 and 22% of the total generated energy at the Wabamun plant. The capturing and liquefaction systems require about 68.5 and 54.4 MW of power, respectively.

Figure 4.8 and 4.9 show the design of the aquifer CO_2 disposal system for the Wabamun plant. Figure 4.8 shows the physical state of the CO_2 from the results of the experiments and Figure 4.9 shows the energy requirement for all cases. The total injection pressures are shown in Tables A.4 and A.5.

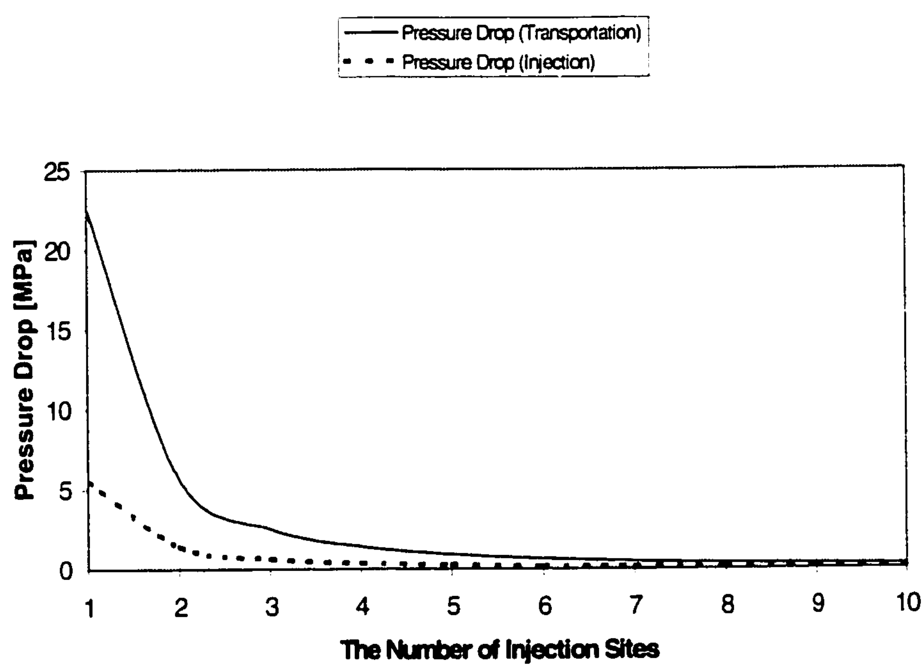

Figure 4.7 Pressure Drop Analysis

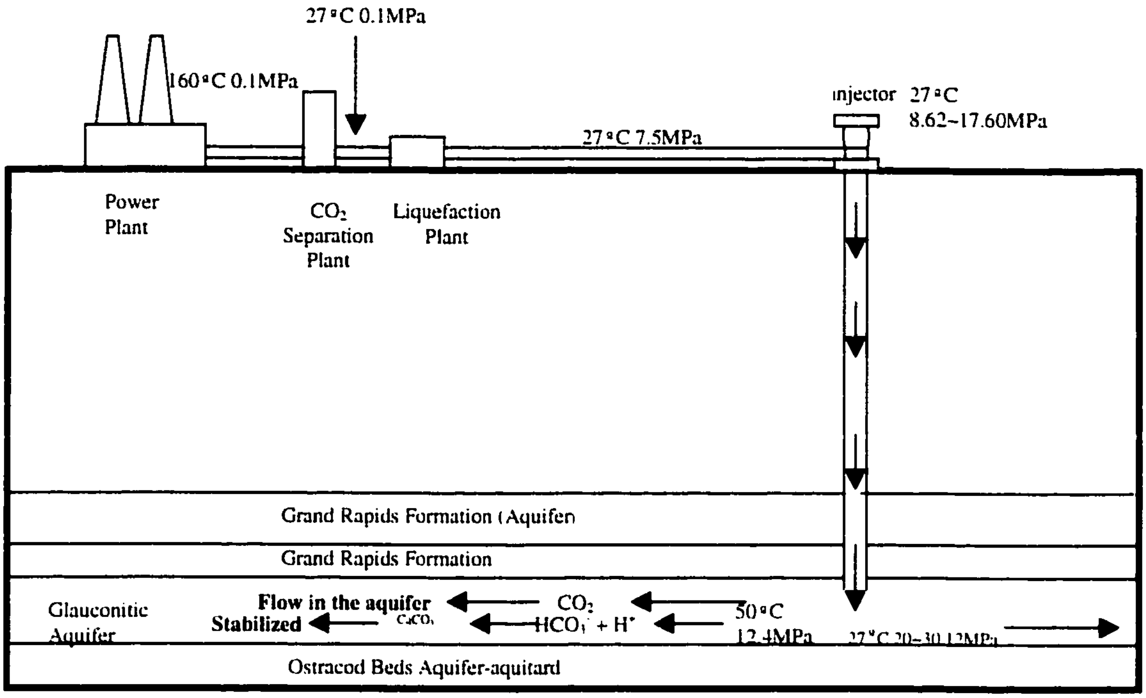

Figure 4.8 System Scheme of ACDS

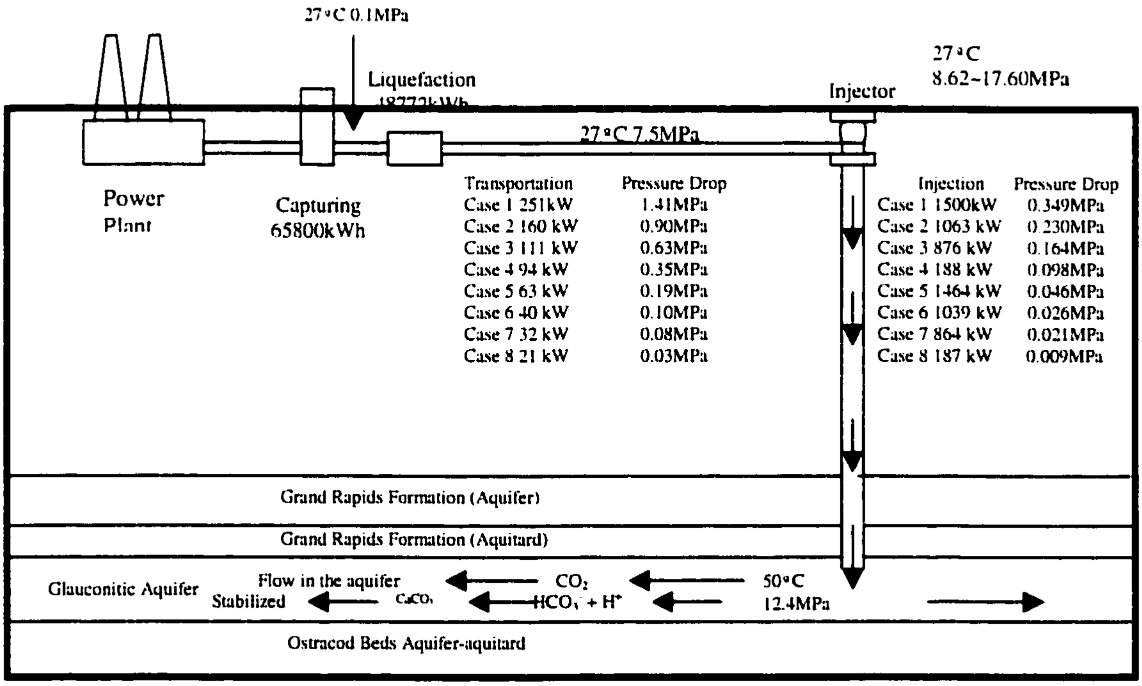

Figure 4.9 Energy Requirements of System

4.6 Conclusion

The mathematical models underlying the capturing, separation, liquefaction, transportation and injection of CO_2 into an aquifer have been developed. The models have been validated with data from the Wabamum Power Plant. Liquified CO_2 injectivity and capacity analyses are carried out based on the ARC study [Bachu et al., 1996]. The pressure drop and power requirements are examined for different ACDS conditions. More than four injection sites are favorable to operate the CO_2 disposal system. The case, which has fewer number of injection sites shows higher pressure drop and higher energy requirement. Total energy requirement for the system for the Wabamun plant is between 115 MWh and 116 MWh.

CHAPTER 5

CO_2 EMISSION FORECAST FOR ALBERTA

5.1 Introduction

In this chapter, Alberta's CO_2 emission forecast is carried out for the period up to the year 2012 based on existing data. The multiple regression technique using five regressor variables is used to carry out the forecast as illustrated in Figure 5.1. The regressor variables directly determine the amount of CO_2 emissions. The mathematical model of the forecast is first carried out using MRT5 and validated with available data on Alberta's CO_2 emissions from 1988 to 1996. Five sequestration strategies are used to reduce excess CO_2 emissions to achieve the Kyoto targets.

5.2 Econometric Model of CO_2 Emissions

The CO_2 emission model of Alberta is an econometric model designed to look at aggregate CO_2 emissions in Alberta using linear multiple function. While a number of factors contributed to (GHG), emissions have increased largely due to an increase in economic activities [Jacques et al., 1997]. The rapid worldwide population growth and industrial growth rates have increased CO_2 emissions. Long-run potential economic growth is largely determined by growth in the fundamental determinants of the level of economic output including labour force, the capital stock and productivity. Furthermore, about 32% of CO_2 was emitted from the power generation sector in 1995. Increasing energy consumption in the model one of the biggest factors affecting CO_2 emissions especially in the industrial countries [Jacques et al, 1997]. In this study the following factors have been chosen as the major determinants of CO_2 emissions in Alberta: (1) previous year CO_2 Emission Rate, (2) population Growth Rate, (3) industrial Growth Rate, (4) energy consumption, and (5) technological progress. The amount of CO_2 emissions increases gradually in the world, in Canada and in Alberta since the industrial revolution.

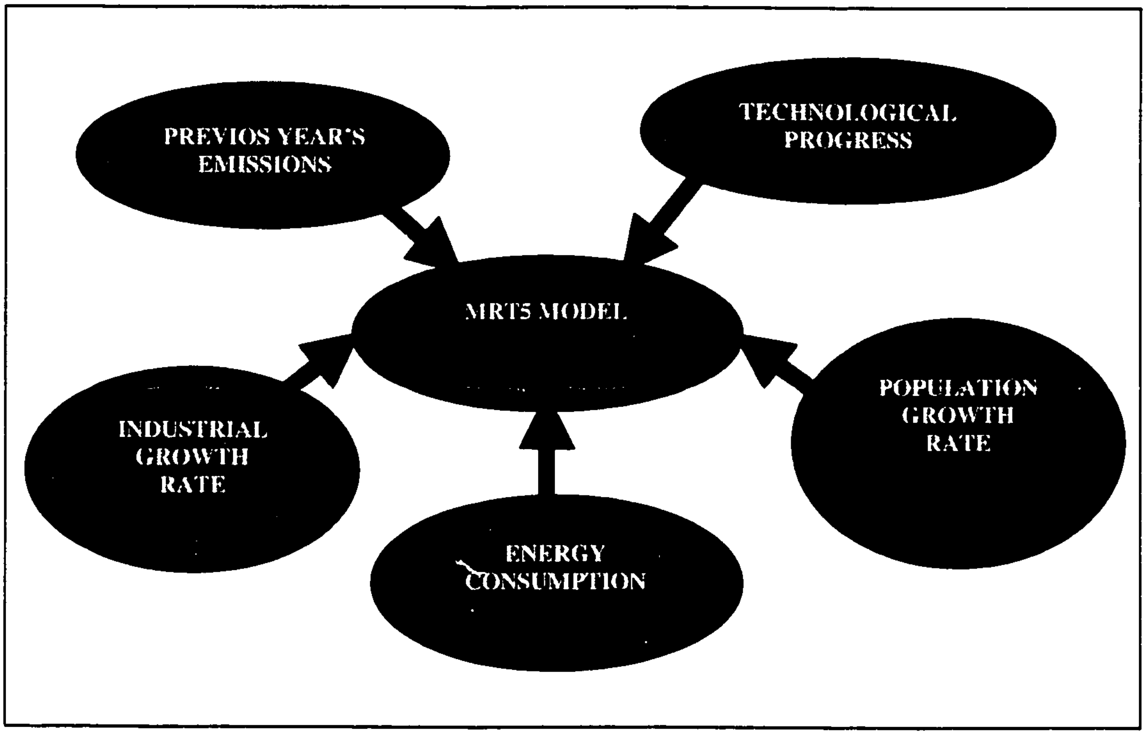

Figure 5.1 The MRT5 Model

Industries have contributed to CO_2 emissions directly by burning fossil fuels and producing products such as cement, oil and coal. If the economy grows, industries also grow and that results in CO_2 emission growth. Industries contribute about 24 % of total CO_2 emissions in Alberta excluding the power generation sector [Jaques. el., 1997]. Furthermore, 97% of electricity is generated by fossil fuel based power stations: this means the energy consumption of electricity plays an important factor in the CO_2 emission forecast [Macdonald, Donner and Nikiforuk, 1996]. Especially in Alberta, power generation is the biggest source of CO_2 emissions sharing 15 % of the total CO_2 emission in 1995 in Alberta [Jaques,et 1997]. Technological progress also contributes to the CO_2 emissions. so that exact CO_2 emission forecast is obtained by offsetting this factor.

The quantity of CO_2 emitted per period, *CO, is* given as equation (5.1). If *CO2* is a linear function of all the determinant variables, then *CO2* is given by equation (5.2).

$$CO2 = f(x_1, x_2, x_3, x_4, x_5) \tag{5.1}$$

$$CO2 = \beta_0 + \beta_1 x_1 + \beta_2 x_2 + \beta_3 x_3 + \beta_4 x_4 + \beta_5 x_5 + \varepsilon_i \tag{5.2}$$

The equation (5.2) can be expressed as (5.3).

$$CO2 = \beta_0 + \sum_{i=1}^{n} \beta_j x_{ij} + \varepsilon_i \tag{5.3}$$

The least square method is used to estimate the regression coefficients in equation (5.3). The least square function L_S is the function of βs determining the differences between raw data and estimated model shown in equations (5.4) and (5.5).

$$L_S = \sum_{i=1}^{n} \varepsilon_i^2 = \sum_{i=1}^{n} \left(CO2 - \hat{\beta}_0 - \sum_{j=1}^{5} \hat{\beta}_j x_{ij} \right)^2 \tag{5.4}$$

$$L_S = \sum_{i=1}^{n} \left(CO2 - \hat{\beta}_0 - \sum_{j=1}^{5} \hat{\beta}_j x_{ij} \right)^2 \tag{5.5}$$

In order to minimize the mean square error associated with the prediction model, equation (5.5) must be differentiated with respect to the coefficients, β_i (i = 0,5) and set to zero as illustrated in equations (5.6) and (5.7).

$$\frac{\partial L_s}{\partial \beta_0} = -2 \sum_{i=1}^{n} \left(CO2_i - \hat{\beta}_0 - \sum_{j=1}^{5} \hat{\beta}_j x_{ij} \right) = 0 \tag{5.6}$$

$$\frac{\partial L_s}{\partial \beta_j} = -2 \sum_{i=1}^{n} \left(CO2_i - \hat{\beta}_0 - \sum_{j=1}^{5} \hat{\beta}_j x_{ij} \right) x_{ij} = 0 \tag{5.7}$$

By simplifying equation 5.6 and 5.7, the least squares normal equations are obtained in equation (5.8).

$$n\hat{\beta}_0+\hat{\beta}_1\sum_{i=1}^{n}x_{i1}+\hat{\beta}_2\sum_{i=1}^{n}x_{i2}+\hat{\beta}_3\sum_{i=1}^{n}x_{i3}+\hat{\beta}_4\sum_{i=1}^{n}x_{i4}+\hat{\beta}_5\sum_{i=1}^{n}x_{i5}=\sum_{i=1}^{n}CO_{2i}$$

$$\hat{\beta}_0\sum_{i=1}^{n}x_{i1}+\hat{\beta}_1\sum_{i=1}^{n}x_{i1}^2+\hat{\beta}_2\sum_{i=1}^{n}x_{i2}x_{i1}+\hat{\beta}_3\sum_{i=1}^{n}x_{i3}x_{i1}+\hat{\beta}_4\sum_{i=1}^{n}x_{i4}x_{i1}+\hat{\beta}_5\sum_{i=1}^{n}x_{i5}x_{i1}=\sum_{i=1}^{n}CO_{2i}x_{i1}$$

$$\hat{\beta}_0\sum_{i=1}^{n}x_{i2}+\hat{\beta}_1\sum_{i=1}^{n}x_{i1}x_{i2}+\hat{\beta}_2\sum_{i=1}^{n}x_{i2}^2+\hat{\beta}_3\sum_{i=1}^{n}x_{i3}x_{i2}+\hat{\beta}_4\sum_{i=1}^{n}x_{i4}x_{i2}+\hat{\beta}_5\sum_{i=1}^{n}x_{i5}x_{i2}=\sum_{i=1}^{n}CO_{2i}x_{i2}$$

$$\hat{\beta}_0\sum_{i=1}^{n}x_{i3}+\hat{\beta}_1\sum_{i=1}^{n}x_{i1}x_{i3}+\hat{\beta}_2\sum_{i=1}^{n}x_{i2}x_{i3}+\hat{\beta}_3\sum_{i=1}^{n}x_{i3}^2+\hat{\beta}_4\sum_{i=1}^{n}x_{i4}x_{i3}+\hat{\beta}_5\sum_{i=1}^{n}x_{i5}x_{i3}=\sum_{i=1}^{n}CO_{2i}x_{i3}$$

$$\hat{\beta}_0\sum_{i=1}^{n}x_{i4}+\hat{\beta}_1\sum_{i=1}^{n}x_{i1}x_{i4}+\hat{\beta}_2\sum_{i=1}^{n}x_{i2}x_{i4}+\hat{\beta}_3\sum_{i=1}^{n}x_{i3}x_{i4}+\hat{\beta}_4\sum_{i=1}^{n}x_{i4}^2+\hat{\beta}_5\sum_{i=1}^{n}x_{i5}x_{i4}=\sum_{i=1}^{n}CO_{2i}x_{i4}$$

$$\hat{\beta}_0\sum_{i=1}^{n}x_{i5}+\hat{\beta}_1\sum_{i=1}^{n}x_{i1}x_{i5}+\hat{\beta}_2\sum_{i=1}^{n}x_{i2}x_{i5}+\hat{\beta}_3\sum_{i=1}^{n}x_{i3}x_{i5}+\hat{\beta}_4\sum_{i=1}^{n}x_{i4}x_{i5}+\hat{\beta}_5\sum_{i=1}^{n}x_{i5}^2=\sum_{i=1}^{n}CO_{2i}x_{i5}$$

(5.8)

The solution to the normal equations will be the least square estimators of the regression coefficients, β_0, β_1, β_2, β_3, β_4 and β_5. The model in terms of actual data will be written in matrix notation as:

(5.9)

$$\underline{\mathbf{CO2}} = \mathbf{X\hat{a}} + \mathbf{\mathring{a}}$$

$$\underline{\mathbf{CO2}} = \begin{bmatrix} CO2_1 \\ CO2_2 \\ \bullet \\ \bullet \\ \bullet \\ CO2_n \end{bmatrix}, \quad \mathbf{X} = \begin{bmatrix} 1 & x_{11} & x_{12} & x_{13} & x_{14} & x_{15} \\ 1 & \bullet & x_{22} & \bullet & \bullet & \bullet \\ \bullet & \bullet & \bullet & \bullet & \bullet & \bullet \\ \bullet & \bullet & \bullet & \bullet & \bullet & \bullet \\ \bullet & \bullet & \bullet & \bullet & \bullet & \bullet \\ 1 & x_{n1} & \bullet & \bullet & \bullet & x_{n5} \end{bmatrix}, \quad \mathbf{\hat{a}} = \begin{bmatrix} \beta_1 \\ \beta_2 \\ \bullet \\ \bullet \\ \bullet \\ \beta_n \end{bmatrix}, \quad \varepsilon = \begin{bmatrix} \varepsilon_1 \\ \varepsilon_2 \\ \bullet \\ \bullet \\ \bullet \\ \varepsilon_n \end{bmatrix} \qquad (5.10)$$

Equation (5.9) is solved to obtain β_i (i=1,n) that minimize the estimation errors, ε_i. The values of β_i are substituted in equation (5.2) to obtain the MRT5 forecast model for Alberta's CO_2 emission. The error variance σ_ε^2 and the coefficient of multiple determination, R^2, are obtained to determine the prediction accuracy in the model.

5.3 A Case Study for Alberta CO_2 Emission Forecast

Projection of CO_2 emissions is carried out using the multiple regression technique in the software package "MINITAB Release 8 for Macintosh" [Addison-Wesley, 1992]. The hardware requirements for this software are: Macintosh® computers except the Macintosh 128K, 512K or 512K enhanced, free hard disk space of more than 20MB and over 4MB of RAM Mac OS 6.0.2 or later is required to run this software [Addison-Wesley, 1994]. The input data for this experiment is shown as Table A.1 in Appendix. Columns 2, 3, 4, 5 and 6 are ,respectively, the previous year's CO_2 emission rate, population growth rate, industrial growth rate, energy consumption and technological progress. The data for population growth, industrial growth and energy consumption is provided by Statistics Canada, National Energy Board and Alberta Energy respectively [Alberta Energy, 1990 and Statistics Canada, 1992, 1994]. The population growth rate is the rate of increase of population in Alberta between the first and end of year in percent [Statistics Canada. 1992. 1994].

The industrial growth rate expresses the average annual economic growth rate of industry sector in percent. The energy consumption expresses the total electricity use in Alberta in a year in peta joule [PJ]. Technological progress is assumed to be the improvement of the rate of heat efficiency of fossil fuel-fired power plant because that is the biggest CO_2 source in Alberta. It is zero at the year 1988. The rate is estimated based on collected information from IEA, Tokyo Electric Power Co. and TransAlta Ltd. and discussion with local utility companies [IEA, 1999, Tokyo Electric Power, 1999 and TransAlta, 1999]. Output data is the six regression coefficients, β_0, β_1, β_2, β_3, β_4 and β_5 as discussed above.

5.4 Validation and Results from MRT5 Model

The MRT5 model in equation (5.8) is developed from the data in Table A.1. The CPU time of this experiment is less than one second. The resulting MRT5 model for CO2 emission forecast for Alberta is in equation (5.11). This equation is used to forecast Alberta's CO_2 emissions within the period from 1988 to 1996. The R-squared is a measurement of the amount of reduction in the variability of CO_2 emissions (CO2) obtained using regressor variables. As the value is close to 1, the model fits adequately.

$$CO2 = -58738 + 0.678x_1 + 4200x_2 + 1475x_3 + 44.4x_4 + 0.678x_5 \qquad (5.11)$$

The R-squared for obtained model is 0.997 and this shows good accuracy of the model. Figure 5.2 shows actual and projected CO_2 emissions from 1988 to 1996 in Alberta. The Figure 5.2 and R2 value show that the MRT5 model is a reliable model for predicting the future CO2 emissions in Alberta based on the assumptions underlying the study. The maximum percentage difference between actual data and projected data is 2.25% of actual data for the year 1996.

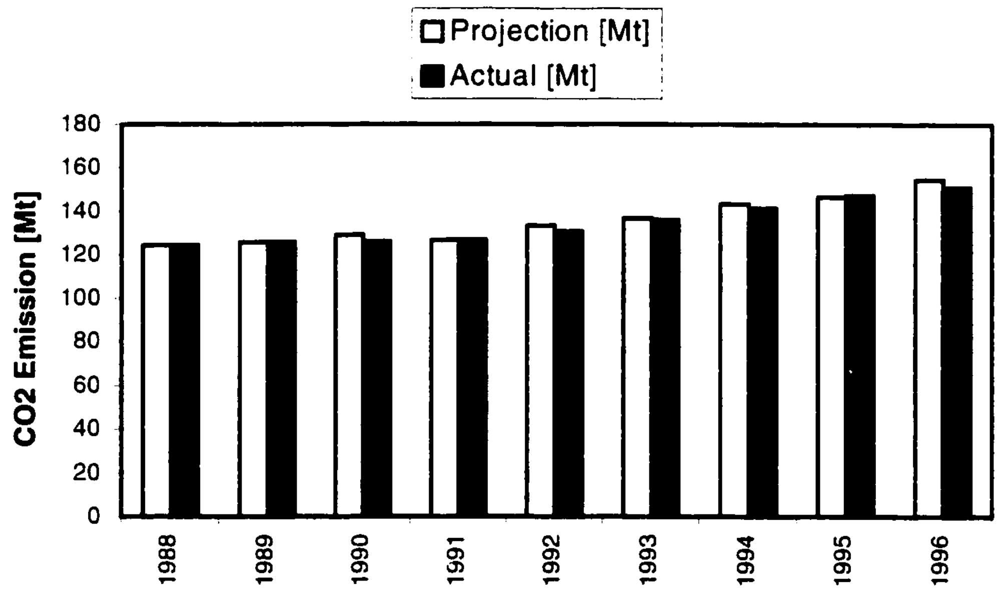

Figure 5.2 Actual Data vs Projection

5.5 Results of the MRT5 Projection of Alberta's CO2 Emission

The projected CO_2 emissions in Alberta within the period from 1988 to 2012 are estimated. The input data for the projection are given in Table A.2. Figure 5.3 shows the projected CO_2 emissions in Alberta up to 2012. As shown, CO_2 emission gradually increases until 2012. At the end of target year 2012, the growth in emissions will become 215Mt and this is 1.7 times greater than the rate of 1990. As shown, if CO_2 emission keeps this growth rate, the excess CO_2, the difference between the CO_2 emitted and the Kyoto target will reach 102.1 Mt.

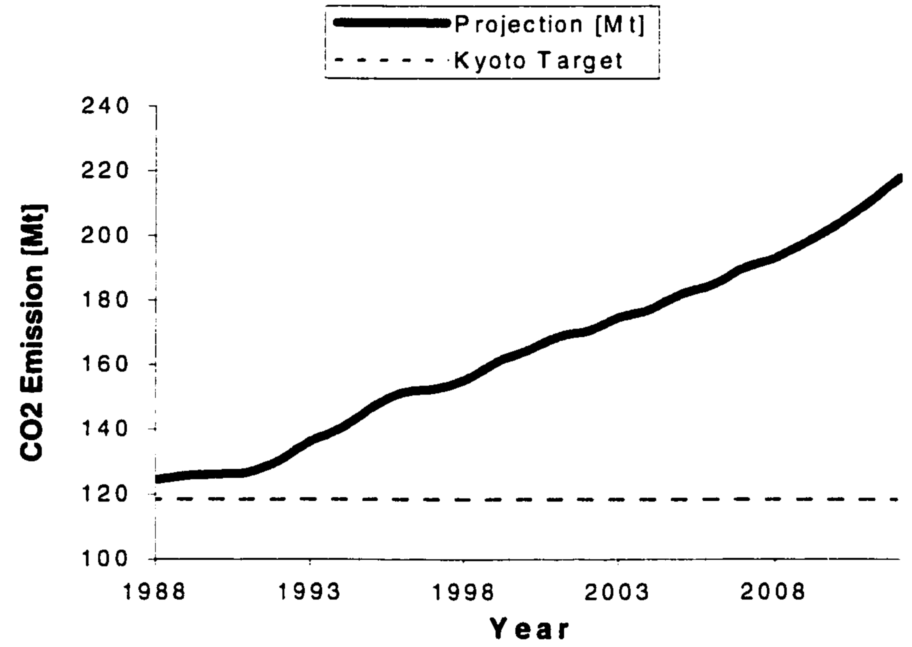

Figure 5.3 CO_2 Emission Projection

5.6 CO_2 Sequestration Strategy Models

In order to achieve the Kyoto target, CO_2 sequestration strategies are required to dispose excess CO_2 in land aquifers in Alberta. According to the Kyoto agreement, Canada must reduce CO_2 emissions up to 6% less than the 1990 levels, which are about 400 million tonnes for Canada and 118.4 million tonnes for Alberta. Here, five possible CO_2 sequestration strategy models are proposed based on the projection results shown as Figure 5.3. It must be noted here that the actual sequestration strategies for CO2 disposal will depend on the Canadian government's policies on reducing GHG in the long term.

5.7 Sequestration Strategy 1 (Gradual Reduction from 2000)

The first CO_2 sequestration strategy is a gradual reduction strategy from the year 2000. In this model, to meet this Kyoto commitment, CO_2 will be reduced every year gradually from 2000 to 2012. For a yearly linear reduction of CO_2 until 2012, the reduction rate will be 3.43 Mt/year from 1999. By using this rate, CO_2 emitted rate can be estimated by the following equation obtained from the projection model (5.11).

$$S_T 1 = 162578 - 3.43x_6 \qquad [x_6 = 1,2....,13] \qquad (5.12)$$

The results are shown in Figure 5.4. It will be really hard to achieve this strategy because there is no time to prepare for the CO_2 disposal project. In order to start the project, the construction of disposal plants must be started in 1999 without enough feasibility study. The aquifer CO_2 disposal requires a detailed geological survey of the injection area as carried out in the petroleum industry. This strategy requires the CO_2 aquifer disposal plant capacity of 20,000 kt for the first two years for smooth operation. From the year 2001, the capacity will be expanded by 20,000 kt every 3 years. Only the last period is adjusted to the final excess CO_2 level.

5.8 Sequestration Strategy 2 (Gradual Reduction from 2002)

The sequestration 2 starts from the year 2002 using a linear CO_2 sequestration strategy with the reduction rate of 4.82 million tonnes per year. This strategy takes three years for preparation. The Alberta government and industries can have the time for feasibility study and construction of the plant but these must be carried out quickly. This strategy requires the CO_2 aquifer disposal plant capacity of 30,000 kt for the first two years. From the year 2001, the capacity is expanded 20,000kt every 3 years. Only the last period is adjusted to the final excess CO_2 level. For year 2000 to 2001, the equation (5.11) is used because there is no reduction for these periods. Equation (5.13) is used for the year 2002 to 2012.

$$St2 = 171424 - 4.82x_7 \qquad [x_7 = 1,2....,11] \qquad (5.13)$$

The total amount of excess CO_2 will be about 580.57 million tonnes. The resulting strategy is shown as Figure 5.4. As shown, the slope of decline is steeper than that of Strategy 1. This fact requires Strategy 2 to expand the capacity of the plant more rapidly than Strategy 1. From the year 1999 to 2001, there is no service for CO_2 reduction. This strategy 2 requires initial capacity of 30,000 kt for the first two years. From the year

2001, the capacity is expanded with a 30,000 kt every 3 years. Only the last two years are adjusted to the final excess CO_2 level with a capacity of 105,000 kt.

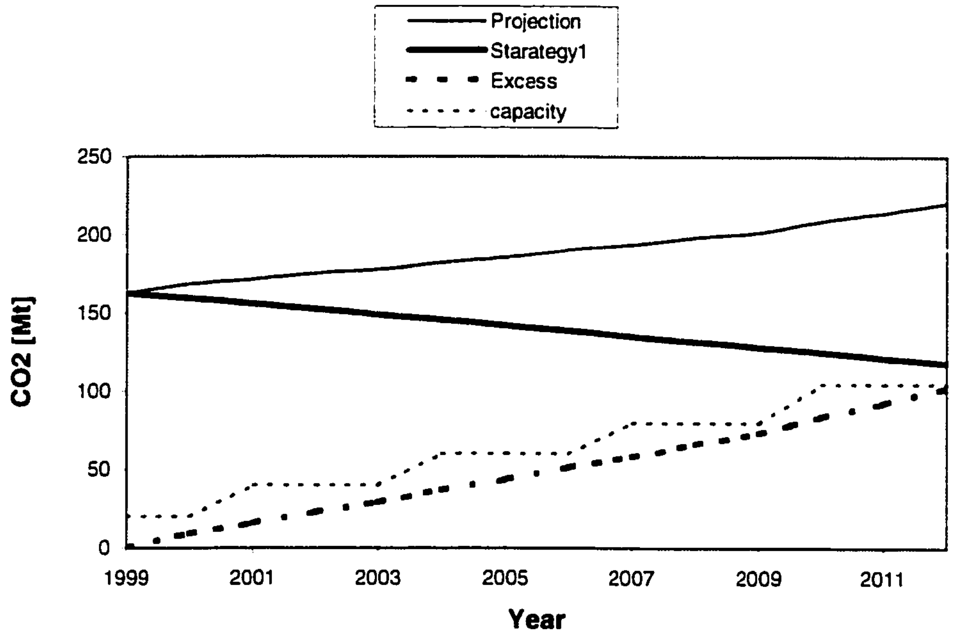

Figure 5.4 Sequestration Strategy 1

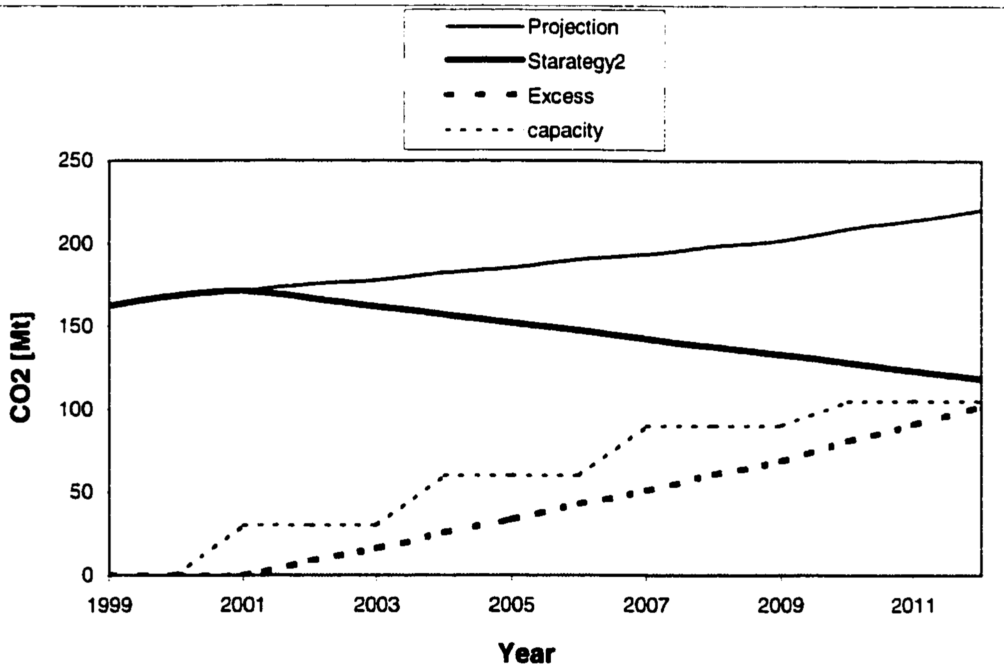

Figure 5.5 Sequestration Strategy 2

5.9 Sequestration Strategy 3 (Gradual Reduction from 2005)

This strategy gives the government and industries enough time to start the CO_2 sequestration project starting from the year 2005. To meet the Kyoto target, CO_2 must be reduced at a rate of 7.99 million tonnes per year from the projected level at the year 2004. Equation (5.11) is used for the period between 1999 and 2004, there is no reduction in this period. For between 2005 and 2012, equation (5.14) is used to model the CO_2 reduction within 2005 and 2012.

$$St3 = 182347 - 7.99x_8 \qquad [x_8 = 1,2....,8] \tag{5.14}$$

The results given by the above model are shown as Figure 5.6. From the figure, the CO_2 emitted is decreased much faster than the previous two. This strategy requires initial capacity of 50,000 kt for the first four years to keep up with the rapid increase of the excess CO_2. At the year 2009, the capacity is expanded to 105,000 kt.

5.10 Sequestration Strategy 4 (Keep 1999 level until 2001)

This strategy presents the government and industries a tough challenge because the allowed CO_2 emissions are fixed with 1999 level for first two years. This means CO_2 disposal or storage project must be started from the year 2000. This strategy allows the small period of time for the preparation of the disposal facilities for CO_2 storage. From the year 2002, CO_2 must be reduced at a rate of 4020 kt per year. For 1999 to 2001, the amount of CO_2 emitted is fixed at 162578 kt per year. After 2001, the model is given by the following equation (5.15):

$$St4 = 162578 - 4020x_9 \qquad [x_9 = 1,2....,13] \tag{5.15}$$

The results of this model are shown in Figure 5.7. X_9 is the period starting from 2001. This strategy requires an initial capacity of 10,000kt for the first two years, after which the capacity is expanded by 20,000kt every two or three years depending on the increase of excess CO_2 as shown Table 5.1. At the year 2010, the capacity is expanded to 105,000 kt.

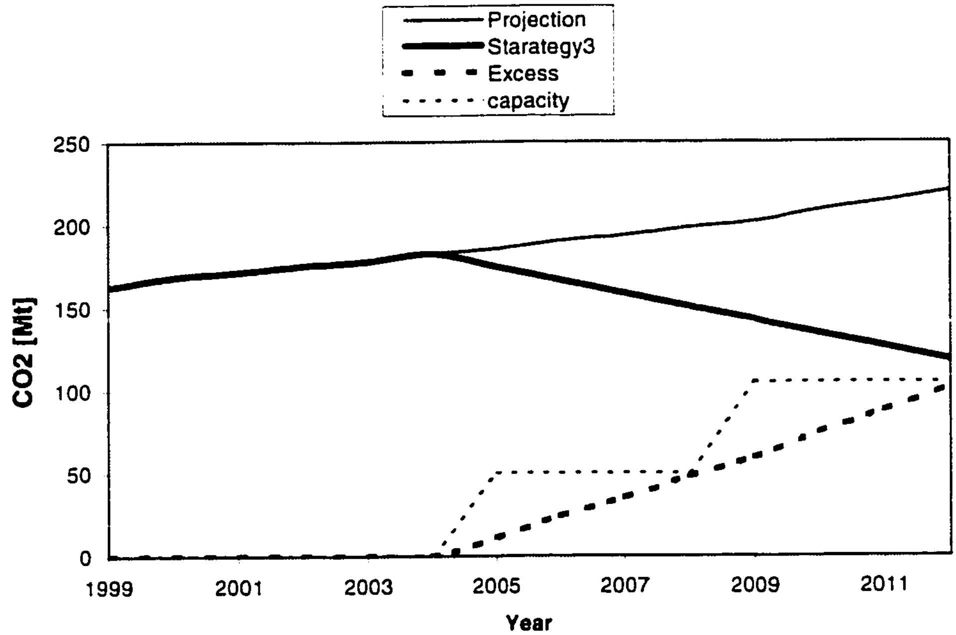

Figure 5.6 Sequestration Strategy 3

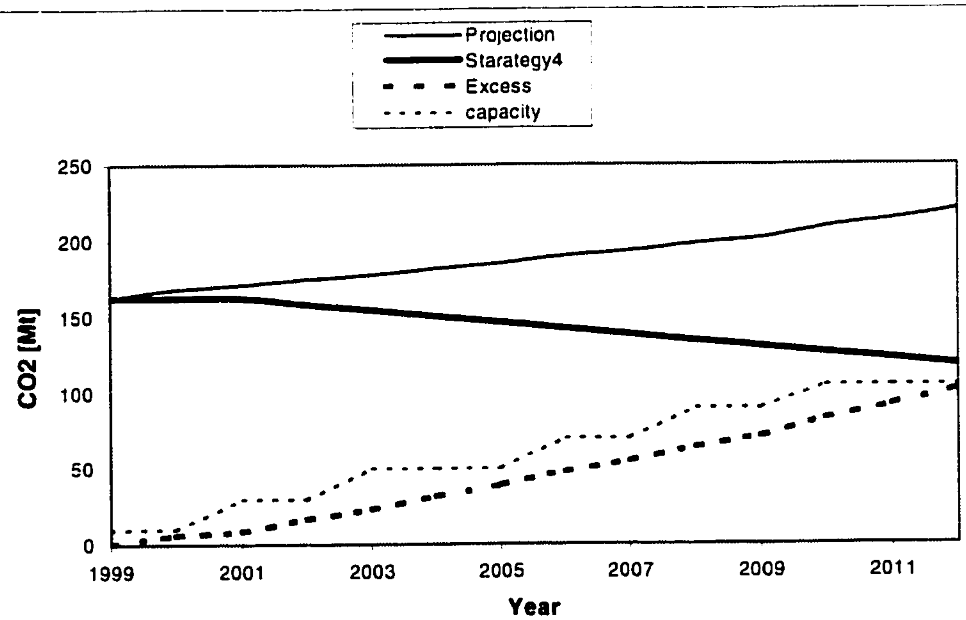

Figure 5.7 Sequestration Strategy 4

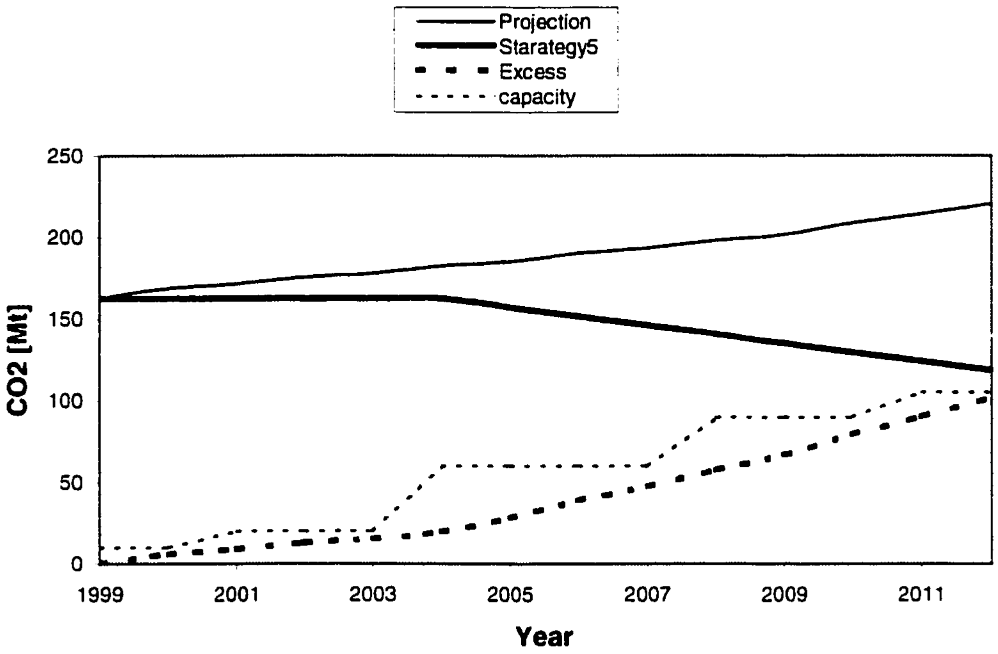

Figure 5.8 Sequestration Strategy 5

5.11 Sequestration Strategy 5 (Keep 1999 level until 2005)

In this strategy, CO_2 reduction starts from the year 2000. The CO_2 emission rate is fixed at the emission level of 1999 for the first four years. This strategy provides the government and industries only a short time to construct the ACDS for CO_2 disposal and storage. From the year 2005, the CO_2 reduction must be increased at the rate of 5520 kt per year. Within the year 1999 and 2004, the amount of CO_2 emitted is fixed at 162578 kt per year. After the year 2005, the amount of CO_2 emitted is given in equation (5.16):

$$St5 = 162578 - 5520x_{10} \quad [\, x_{10} = 1,2....,8\,] \qquad (5.16)$$

The results of this model are shown in Figure 5.7. This strategy requires an initial capacity of 10,000 kt for the first year after which the capacity is expanded to 20,000 kt until 2003. The capacity expansion is continued depending on the increase of excess CO_2 shown in Table 5.1. At the year 2 010, the capacity is expanded to 105,000 kt.

5.12 CO_2 Disposal Options

From the results of injectivity study and sequestration analysis, 40 of CO_2 disposal options are used in this study to deal with the aquifer disposal and storage as illustrated in Figure 5.2. These options depend on the CO_2 reduction strategy, injection pressure, and local permeability of aquifer. The injectivity and capacity analyses discussed in Chapter 3 are applied for this analysis to estimate the number of injection sites. At first, the economics for the Wabamun Thermal Plant are examined and these Wabamun results are used to develop a scaled model for the total CO_2 disposal economics in Alberta.

5.13 Conclusion

CO_2 emission forecast model is developed using the multiple regression technique. The model includes previous year's CO_2 emissions rate, population growth rate, industrial growth rate, energy consumption and technological progress as regressor variables. The model shows high accuracy with the R-squared value of 99.7The MRT5 model for Alberta's CO2 emissions is validated with data on the regressor variables. The CO_2 emission gradually increases until 2012 and at the end of target year 2012, emission rate will become 215 Mt. These results form the basis of the economic and risk modeling in Chapters 6 and 7 of this report.

Table 5.1 CO_2 Sequestration Strategy Models and Excess CO_2 [Mt]

Year	Projec Tion [Mt]	Starategy1 [Mt]	Exces s [Mt]	Capacity [Mt]	Starategy2 [Mt]	Excess [Mt]	Capacity [Mt]	Starategy3 [Mt]	Excess [Mt]	Capacity [Mt]	Starategy4 [Mt]	Exces s [Mt]	Capacity [Mt]	Starategy5 [Mt]	Excess [Mt]	Capacity [Mt]
1999	163	163	0	20	163	0	0	163	0	0	163	0	10	163	0	10
2000	169	159	9	20	169	0	0	169	0	0	163	6	10	163	6	10
2001	171	156	16	40	171	0	30	171	0	0	163	9	30	163	9	20
2002	175	152	23	40	167	3	30	175	0	0	159	17	30	163	13	20
2003	178	149	29	40	162	16	30	178	0	0	155	23	50	163	15	20
2004	182	145	37	60	157	25	60	182	0	0	151	32	50	163	20	60
2005	185	142	43	60	152	33	60	174	11	50	146	39	50	157	28	60
2006	190	139	52	60	147	43	60	166	24	50	142	48	70	152	39	60
2007	193	135	58	80	143	51	90	158	35	50	138	55	70	146	47	60
2008	198	132	67	80	138	61	90	150	48	50	134	64	90	140	58	90
2009	202	128	73	80	133	69	90	142	59	105	130	71	90	135	67	90
2010	209	125	84	105	128	81	105	134	75	105	126	83	105	129	79	90
2011	214	121	93	105	123	91	105	126	88	105	122	92	105	124	90	105
2012	221	118	103	105	118	102	105	118	102	105	118	102	105	118	102	105

Table 5.2 The CO_2 Disposal Options

Option	Sequestration Strategy	Injection Pressure	Local Permeability
1	1	30.12MPa	100md
2	1	26.60MPa	100md
3	1	25.15MPa	100md
4	1	20.00MPa	100md
5	1	30.12MPa	30md
6	1	26.60MPa	30md
7	1	25.15MPa	30md
8	1	20.00MPa	30md
9	2	30.12MPa	100md
10	2	26.60MPa	100md
11	2	25.15MPa	100md
12	2	20.00MPa	100md
13	2	30.12MPa	30md
14	2	26.60MPa	30md
15	2	25.15MPa	30md
16	2	20.00MPa	30md
17	3	30.12MPa	100md
18	3	26.60MPa	100md
19	3	25.15MPa	100md
20	3	20.00MPa	100md
21	3	30.12MPa	30md
22	3	26.60MPa	30md
23	3	25.15MPa	30md
24	3	20.00MPa	30md
25	4	30.12MPa	100md
26	4	26.60MPa	100md
27	4	25.15MPa	100md
28	4	20.00MPa	100md
29	4	30.12MPa	30md
30	4	26.60MPa	30md
31	4	25.15MPa	30md
32	4	20.00MPa	30md
33	5	30.12MPa	100md
34	5	26.60MPa	100md
35	5	25.15MPa	100md
36	5	20.00MPa	100md
37	5	30.12MPa	30md
38	5	26.60MPa	30md
39	5	25.15MPa	30md
40	5	20.00MPa	30md

CHAPTER 6

ECONOMIC MODELING FOR ACDS

6.1 Definition of the Economic Model of ACDS

The economic model of the CO_2 disposal system comprises the capital and operating costs required to design, build, operate and maintain the system within a specified period. The economic model will also be affected by the periodic quantity of excess CO_2 and the fundamental economic parameters like rates of interest, inflation, escalation and taxation. The total disposal cost function, TC_{CO2}, is given in equation (6.1) as

$$\begin{aligned} TC_{CO2} &= \phi\left[\psi_1(\gamma_i),\psi_2(\tau_j),\psi_3(\rho_k),\psi_4(\lambda_l),\psi_5(\xi_m)\right] \\ &\left[i=1,n_1; j=1,n_2; k=1,n_3; l=1,n_4; m=1,n_5\right] \end{aligned} \tag{6.1}$$

The long-term periodic capital expenditures, CC, and operating costs, OC, for building, operating, maintaining and managing the disposal system are given in equations (6.2) and (6.3) and are also shown in Figure 6.1 and 6.2.

$$CC = C_0 + C_1X + C_2X^2 + C_3X^3 + \cdots\cdots\cdots\cdots + C_nX^n \tag{6.2}$$

$$OC = OC_1X + OC_2X^2 + OC_3X^3 + \cdots\cdots\cdots + OC_nX^n \tag{6.3}$$

$$X = (1+\rho_A)^{-t} \tag{6.4}$$

The sum of equations (6.2) and (6.3) is the value of the total costs of the CO_2 disposal and storage under aquifers. If all the periodic capital expenditures are the same and that of the operating costs are also the same, then these equations are geometric series, and the present worth can be written as

$$PV(TC) = \left(\frac{X^n - 1}{X - 1}\right)\left(C_0 + \frac{OC_1}{1 + \rho_A}\right) \tag{6.5}$$

It must be noted that any course of action must be carefully weighed to ensure a balance in energy cost and a sustainable eco-system. The life of the equipment used in the disposal system is expected to exceed the project duration. The above capital and operating costs are estimated based on the case study for Wabamun Thermal Power Plant. The costs are then converted from Wabamun scale to the Alberta scale as shown in Figure 6.3.

6.2 Quantitative AEC Model

The Annual Equivalent Cost (AEC) criterion provides a basis for measuring investment value by determining equal payments on an annual basis. By this method, we can estimate the unit cost of CO_2 aquifer disposal for each year. A present lump-sum cash amount can be converted into a series of equal annual payments for any period as equation (6.6)

$$A = PV(TC)(A/PV(TC),i,m) \tag{6.6}$$

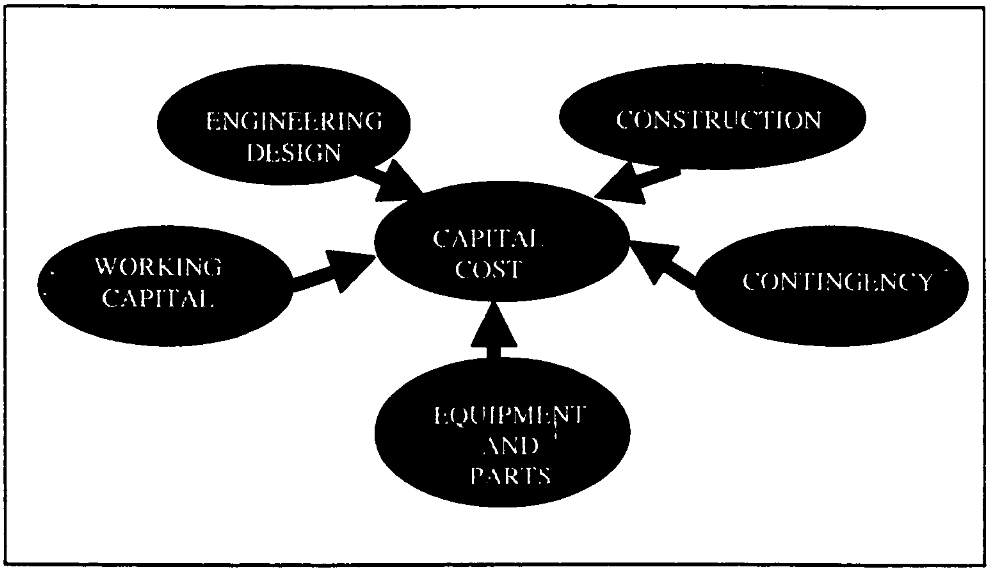

Figure 6.1 Capital Cost Components

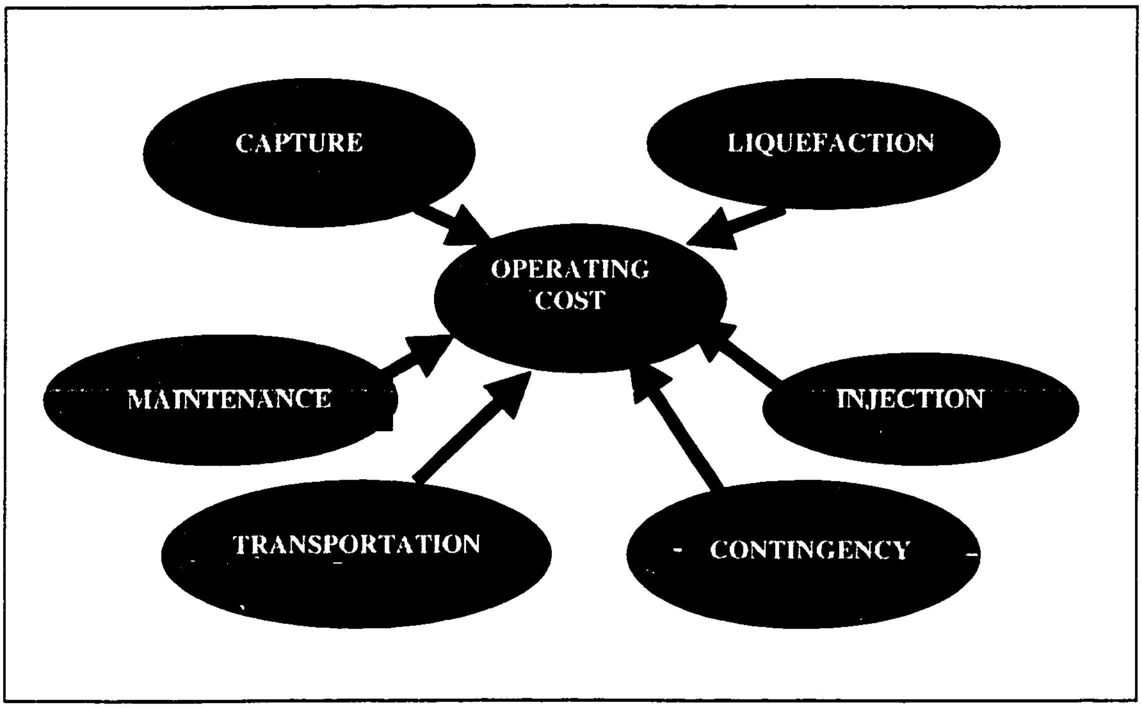

Figure 6.2 Operating Cost Components

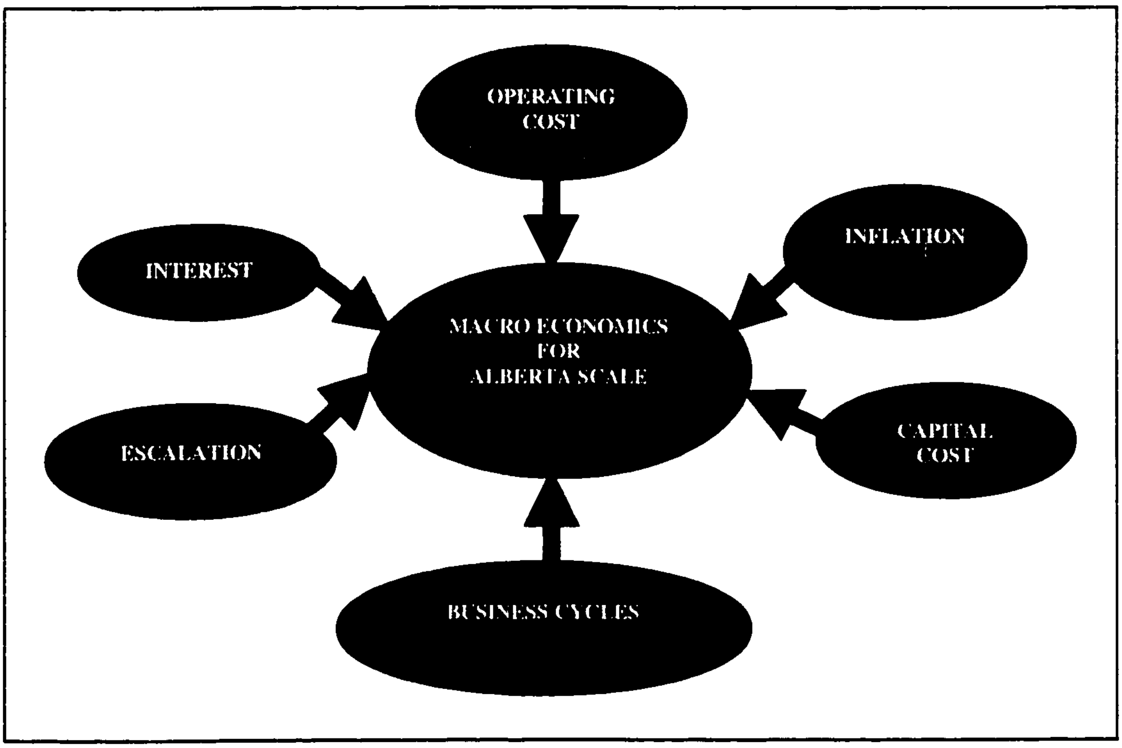

Figure 6.3 CO_2 Disposal Economic Model

The AEC function is defined by following:

$$AEC = A = \frac{iPV(TC)(1+i)^m}{\left[(1+i)^m - 1\right]} \qquad (6.7)$$

In order to obtain a unit cost, in this case energy cost per kWh, we may proceed according to the following steps [Gentry and O'Nell 1984, Park, 1997]:

- Determine the number of units of CO_2 to be disposed each year over the project life.
- Identify the cash flow series associated with disposal over the project life.
- Calculate the PV(TC) of the project cash flow series at a given interest rate and then determine the AEC.
- Divide the AEC by the number of units of CO_2 to be disposed during each year.

The unit energy/electricity cost could be given as:

$$\lambda_C = \lambda_{Ci} + \Phi[Ai] \qquad (6.8)$$

If the disposal is carried out at only power stations, the disposal cost is directly put on the electricity price. The consumer of electricity must take care of this.

6.3 Validation of the AEC Model for the Wabamun Plant

The 40 CO_2 disposal options discussed in the section 5.13 are examined on the basis of their economic implications. These options are based on the the CO_2 reduction strategies, injection pressures, and local. The capital cost of the recovery plant at the Wabamun includes engineering cost, construction, equipment, major parts, contingency, and working.

6.3.1 Capital Cost Estimates for Wabamun

The CO_2 recovery/capturing plant is designed based on KS system developed by Kansai Electric Co, and Mitsubishi Heavy Industries Co, Ltd of Japan. The total capital cost for this plant is estimated as \$1.685US/t times the amount of CO_2 recovery over a lifetime [Iijima, 1998]. There is a lot of uncertainty about this figure because the author did not get access to all the proprietary information about the KS technology. Appropriate discussions are necessary with the MHI and KEPCO to obtain access to the KS technology for CO_2 separation. In this study, the lifetime of this plant is assumed to be 30 years. This is based on the author's discussion with manufacture [Collicut's Mechanical Services Ltd., 1998]. The CO_2 emission is 137510370 tonnes for 30 years. Thus, the capital cost for this plant is:

$$C_s = \$1.685US/t * 137{,}510{,}370t = US\$231{,}721{,}200US \tag{6.9}$$

The liquefaction for the Wabamun plant requires 70,000HP compressor. The capital cost of compressor is \$1100 per HP for compressor with over 1000HP. Engineering design and contingency are 10 % and 20% of the capital cost, respectively. The total capital cost of the liquefaction plant is:

$$C_l = \$77M + 0.1 * \$77M + 0.2 * \$77M = \$100.1M \tag{6.10}$$

The Transportation system requires pumps and pipelines. The CO_2 is a corrosive substance so that corrosion-resistant material is required for this system. Normally, the cost of pipeline is \$50,000 per km in Alberta but anti-corrosion pipeline costs 2.5 times more than normal pipelines. Therefore, the cost of pipeline is \$125,000 per km. The number of compressors and pipelines are different depending on the injection pressure and the local permeability of the injection site.

The capital cost for the transportation, C_{PT}, is given by

$$C_{PT} = \begin{cases} \$2{,}500 / HP & \forall \quad HP < 50 \\ \$2{,}975 / HP & \forall \quad 50 \le HP < 150 \\ \$1{,}870 / HP & \forall \quad 150 \le HP \le 400 \end{cases} \tag{6.11}$$

[Collicut's Mechanical Services Ltd., 1998]

Engineering design and contingency will be 10 % and 20% of pump and pipeline costs respectively.

The carbon dioxide is a corrosive substance so that corrosion-resistant material is required for this system. The cost of injector well is 1.83 million per well with length of 1490m including installation and parts price. The capital cost for injector pumps, C_{PI}, is given by:

$$C_{PI} = \begin{cases} \$2{,}500 / HP & \forall \quad HP < 50 \\ \$2{,}975 / HP & \forall \quad 50 \le HP < 150 \\ \$1{,}870 / HP & \forall \quad 150 \le HP \le 400 \\ \$1{,}150 / HP & \forall \quad 400 \le HP \le 500 \\ \$1100 / HP & \forall \quad HP > 1000HP \end{cases} \tag{6.12}$$

[Collicut's Mechanical Services Ltd., 1998]. Engineering design and contingency will be 10 % and 20% of pump and injector well costs respectively. Tables A.5 ~ A.12 show detailed capital cost analysis of the system for the Wabamun plant.

6.3.2 Operating Cost Estimates for Wabamun

The operating cost is the total energy cost for system operation. At the base case, energy price is \$0.043/kWh. Twenty percent of the total operating cost will be labor and management cost. The base energy requirements are estimated in Section 4.6. Unit cost is estimated based on annual CO_2 emission rate of the Wabamun plant of 4584 kt/year. Table 6.1 shows the total capital cost and annual total operating cost for the Wabamun plant. The results indicate that capital cost increases, increasing number of injection sites. The operating cost decreases as the number of injection sites increases. The fixed and variable costs are estimated based on the annual operating cost shown as Table 6.1.

The fixed operating cost is 40% of the annual operating cost and the variable operating cost is 60% of that.

Table 6.1 Cost Analysis for Wabamun Thermal Power Plant

Option	Total Capital Cost [$M]	Annual Operating Cost [$M]
1, 9, 17, 25, and 33	467.20	65.72
2, 10, 18, 26, and 34	471.18	65.42
3, 11, 19, 27, and 35	471.07	65.29
4, 12, 20, 28, and 36	480.34	64.89
5, 13, 21, 29, and 38	496.52	65.59
6, 14, 22, 30, and 38	502.75	65.34
7, 15, 23, 31, and 39	512.44	65.24
8, 16, 24, 32, and 40	538.09	64.85

Figure 6.4 indicates the capital and operating costs for the Wabamun plant. This indicates the results for only the injection case 1. All the cases show almost the same operating cost trend. The costs for the transportation and injections show small changes. As indicated, the separation is the most expensive section because the CO_2 separation requires huge energy, 65.8 MW, which is about 12% of total electricity generated at Wabamun plant. The capital and operating costs for separation are $8.44 and $7.82 per tonne, respectively. The liquefaction cost is $2.43 and $5.79 per tonne for capital and operating costs. This is also the huge energy requirement. Compare to separation and liquefaction parts, the capital costs for transportation and injection are much smaller.

Figure 6.5 indicates the unit costs including capital cost for each section for the Wabamun plant. This also indicates results for only the injection case 1 as an example but all the cases show almost the same trend in the operating cost. As indicated, the separation is the most expensive section, which costs $16.26 per tonne. The liquefaction cost is about $8.22 per tonne. This is also because of the huge energy requirement. Compare to separation and liquefaction parts, the capital costs for transportation and injection are much smaller and they are $0.27 and $0.42 per tonne respectively. The separation cost is comparable with other separation technologies to KS technology. The using amine separation system, which is developed by Saskatchewan Energy and Mines, Shell Canada and Amoco Canada Petroleum Company shows between \$54 and 57 with separation and liquefaction [Wilson, et al, 1992]. The KS technology shows smaller CO_2 separation cost with \$24 per tonne to separate and liquefy CO_2.

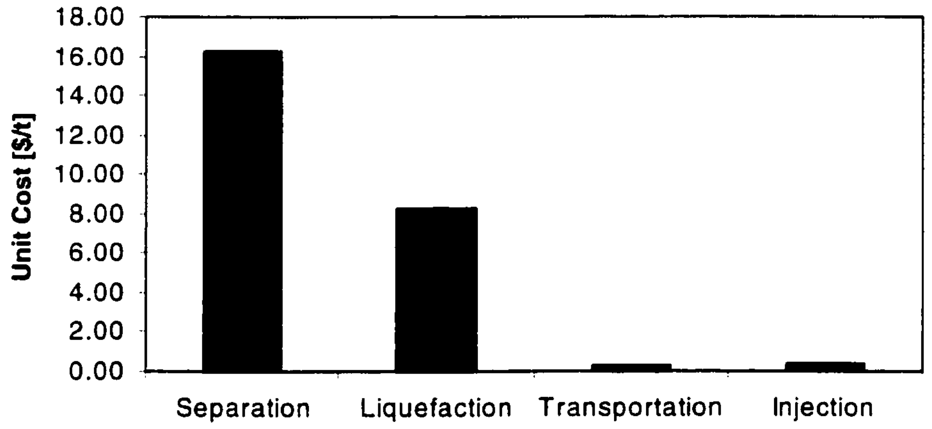

Figure 6.5 Total unit Cost for Wabamun

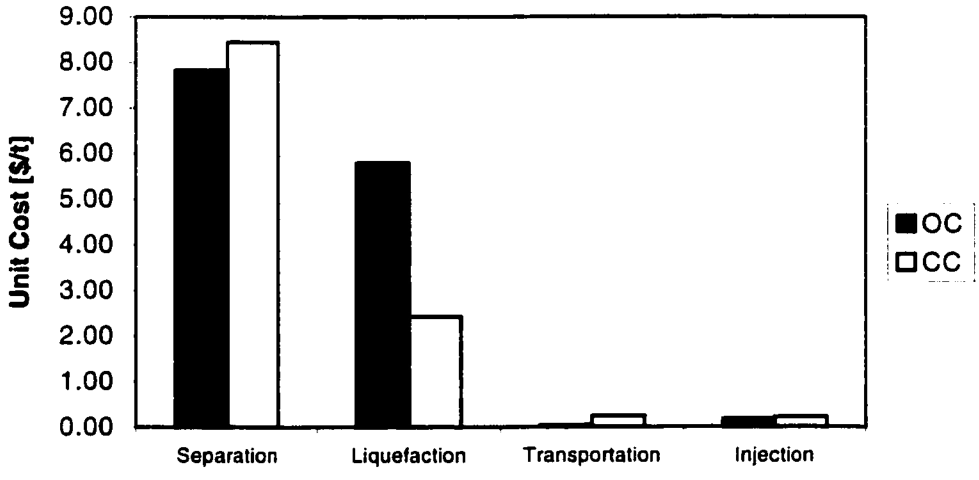

Figure 6.4 Unit CC and OC for Wabamun

6.4 Validation of the Scaled AEC Model for Alberta

As discussed in Chapter 5, five CO_2 sequestration strategies are assumed and the capacity and capacity expansion of CO_2 disposal system are estimated based on these assumptions. In order to convert the capital cost from Wabamun scale to Alberta scale, these capacities are divided by Wabamun capacity. These values called capacity factor, are the number of Wabamun plant scale disposal system for Alberta. We can know that how many Wabamun scale disposal systems are required. These are shown as capital cost estimates in Tables A.21~A.61. The operating costs are also estimated for all forty disposal options. The amount of CO_2 disposed varies depending on year and strategy. To adjust the operating cost for the amount of CO_2 disposed in Alberta, the variable operating cost estimation is applied other than fixed operating cost. Based on the comparison of the Wabamun operating cost, it is assumed that 40% of the operating cost of the Wabamun plant is fixed and 60% is variable.

In this study, the fixed operating cost is based on the capacity of CO_2 disposal system. Similar to capital cost, this fixed cost is estimated by multiplying the capacity factor by the Wabamun scale fixed operating cost, as illustrated in Tables A.13~A.20. These cost are adjusted for escalation using 0.34% for capital cost and 0.16% for operating cost respectively. The escalation rate for the capital cost is the average escalation rate of pump, compressor, construction and petroleum engineering equipment from 1987 to 1998 provided by Statistics Canada [Statistics Canada, 1990, 1994, 1998]. The escalation rate for the operating cost is the average escalation rate of electricity because electricity cost contributes a greatest proportion of the total operation cost. This data is also from 1987 to 1998 provided by Statistics Canada [Statistics Canada, 1990, 1994, 1998] and are illustrated in Tables A.65 and A.66. Both the capital cost and operating cost analysis for each year and options are shown as Tables A.21~A.41. By using the equation (6.5) with estimated capital cost and operating cost, the present values of the total costs are estimated for each year and for each disposal options. The total present value of total costs is used to estimate the AEC.

The annual equivalent costs (AEC s) are estimated using the equation (6.7). For instance, consider the disposal option 1, which is based on CO_2 reduction strategy 1. The injection pressure and local permeability of this option are 30.12 MPa and 100md, respectively. The present value of the total cost for this project is \$ 27,207,094,412. The interest rate adjusted for inflation is 6.55%. Interest rate is provided by the bank of Canada and inflation rate is provided by Statistics Canada [Bank of Canada, 1999 and Statistics Canada, 1990, 1994, 1998]. In this study, average rates of the year 1998 are used for both rates. These are shown as Table A.61 and A.62. The number of interest period is 14 from 1999 to 2012.

$$A = \frac{iP(1+i)^n}{\left[(1+i)^n - 1\right]} = \frac{0.0655 * 27207094412 * (1+0.0655)^{14}}{\left[(1+0.0655)^{14} - 1\right]} \tag{6.8}$$

$$= \$3,027,644,901$$

The annual equivalent cost for the case with 30.12MPa and 100md is \$3,027,644,901. Only the total present values of total costs are different between options. The AEC for all options are shown in Table A.21~A.41. By dividing AEC by the annualized excess CO_2, the unit disposal cost is estimated. Similarly, by dividing AEC by the total energy consumption of electricity, the unit CO_2 disposal cost per kWh of generated electricity. By adding this to present electricity price, the total electricity cost with CO_2 disposal cost can be estimated. These costs are shown as Tables A.21~A.41.

6.5 AEC for Strategy 1

As discussed in Chapter 5, the Strategy 1 is a linear reduction strategy from the year 2000. The AEC and unit costs are estimated and the results are shown in Table A. 21~A.28 for options 1~8 and in Figure 6.6. For sequestration strategy 1, option 1 shows the lowest value of \$3,027M. Basically, high local permeability options shows much lower cost. The options 1, 2, and 3 require almost the same number of injection sites 4~5, the differences come from the operating cost. High injection pressures require high operating costs. Option 4, with the lowest injection pressure shows the highest AEC among options 1, 2, 3, and 4. Option 8 shows the highest AEC of $3,369M. The difference between option 1 and 8 is about $342M. The higher injection pressure requires higher energy price and the lower injection pressure requires higher capital costs. In this strategy, option 1 is the optimum option among the 8 options.

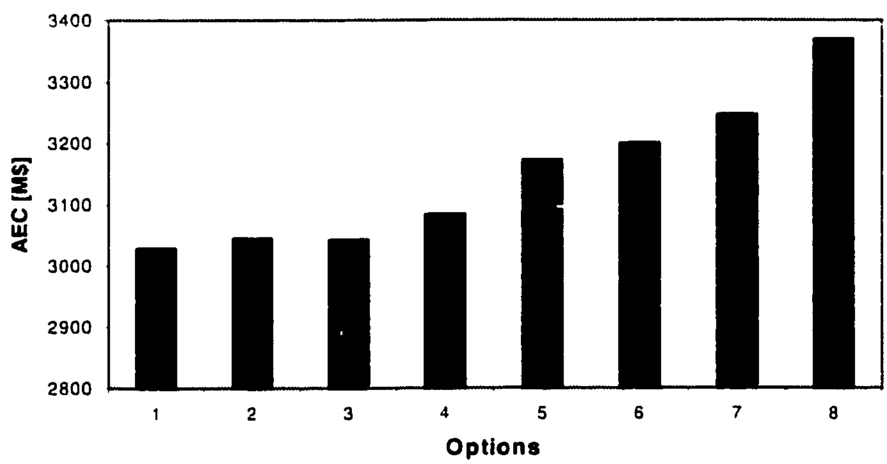

Figure 6.6 AEC for Strategy 1

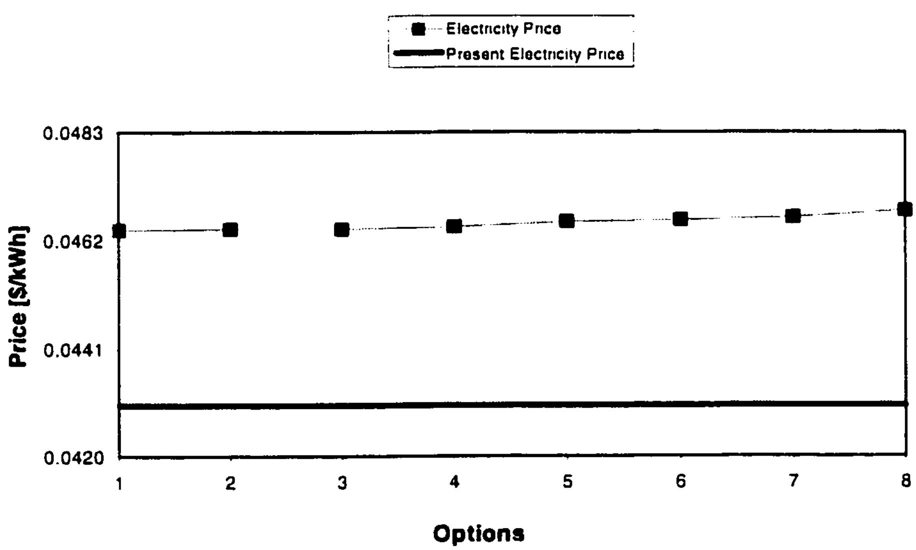

Figure 6.7 Electricity Price for Strategy 1

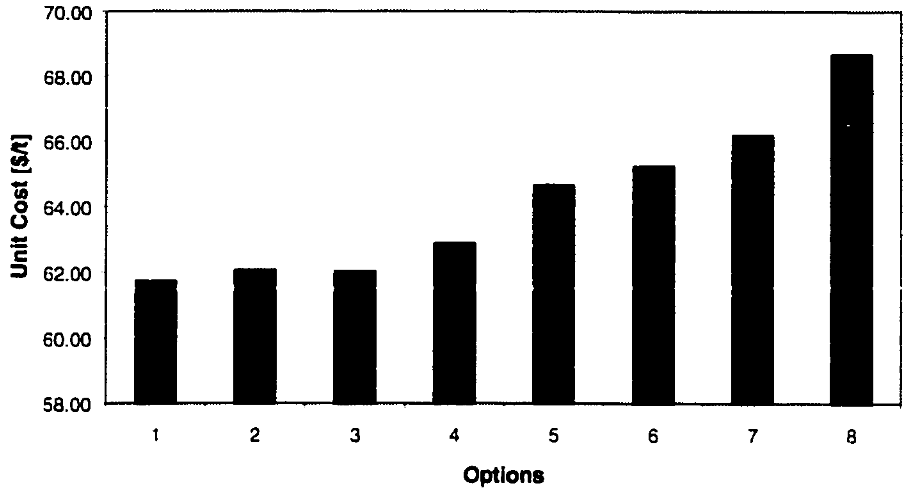

Figure 6.8 Unit Cost for Strategy 1

Changes in electricity prices with CO_2 disposal cost are shown as Figure 6.7. These results also show that option 1 has the lowest price of $0.0464 per kWh. On the other hand, option 8 has the highest price of $0.0468. The electricity price increases about 7.9~8.8% with CO_2 disposal. The unit CO_2 disposal cost is estimated and shown as Figure 6.6. This cost is between $61.72 per tonne and $68.68 per tonne. These are shown as Figure 6.8.

6.6 AEC for Strategy 2

The Strategy 2 takes three years for preparation so that disposal is started from the year 2002. Similar to Strategy 1, the AEC and unit costs for Strategy 2 are estimated and the results are shown in Table A. 29~A.36 for options 9~16 and in Figure 6.9. The AEC value is between $2661M and $2965M. The option showing the lowest AEC is the option 9. The highest AEC option is the option 16. This is also the same as option 8, which has the same disposal system component. But the difference is AEC value. The AECs are $3027M and $2661M for options 1 and 9 respectively. This result shows that taking time for system development and construction reduce the CO_2 disposal cost.

Electricity prices are shown as Figure 6.10. The electricity price including CO_2 disposal cost is estimated by dividing ACE by total electricity consumption and present electricity price. These results also show that option 9 has the lowest price of $0.0460 per kWh. On the other hand, the option 16 shows the highest price of $0.0463. The percent difference between minimum price and maximum price is just 1.1%. The electricity price increases about 7.0~7.7% with CO_2 disposal. The unit CO_2 disposal cost for various options are in Figure 6.11. This cost is between $64.17 per tonne and $71.49 per tonne. These costs are 4 % higher than those of Strategy 1 because the amount of disposed CO_2 is smaller.

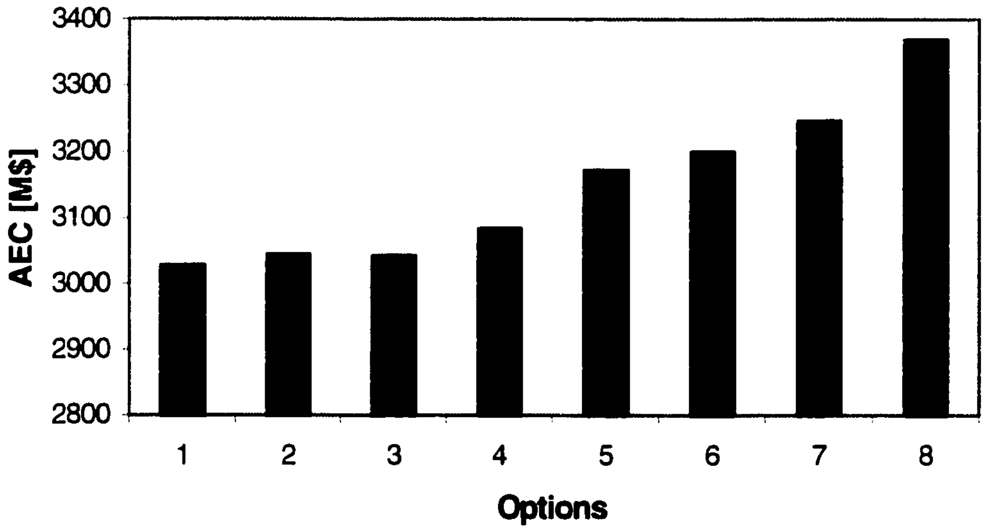

Figure 6.9 AEC for Strategy 2

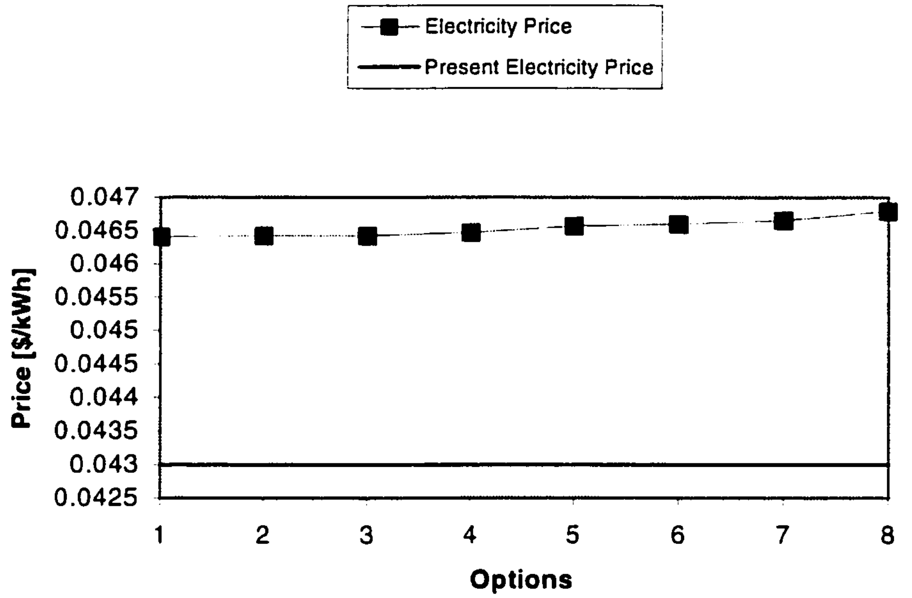

Figure 6.10 Electricity Price for Strategy 2

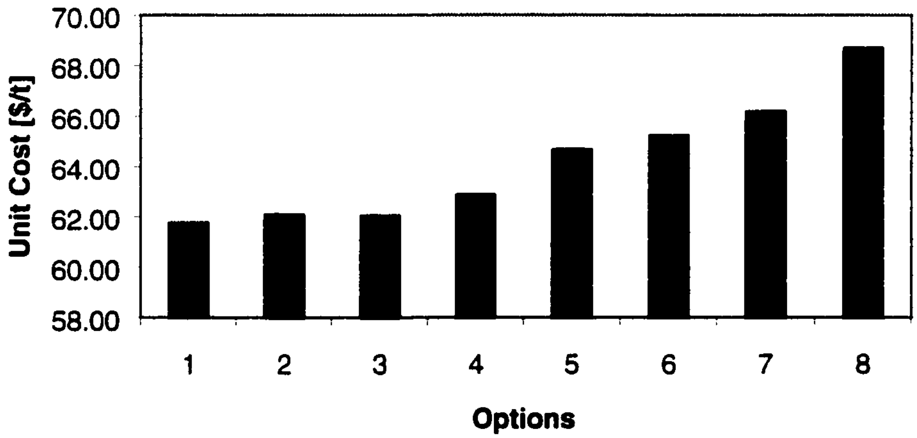

Figure 6.11 Unit Cost for Strategy 1

6.7 AEC for Strategy 3

The same economic analysis is carried out for the Strategy 3. Strategy 3 gives the government and industries enough time to start the CO_2 sequestration project starting from the year 2005. This strategy requirs the smallest amount of CO_2 disposal between five strategies so that the base economics is very small compared to other strategies. The AEC and unit costs are estimated and the results are shown in Tables A. 37~A.45 for options 17~24 and in Figure 6.12. The AEC for the Strategy 3 is between \$1804M and \$2098M. The option showing the lowest AEC is the option 17. This option also has the same injection environment as option 1 and 9 at injection pressure and local permeability of 30.12 MPa and 100md respectively but CO_2 sequestration strategy. The highest AEC option is the option 24. This is also the same as option 8 and 16, which have the same injection environment as option 24. But this strategy has much lower AEC because the CO_2 sequestration starts from the year 2005. As a result, the total amount of excess CO_2 in the project life is also small, which is 441.39 kt. That small amount of excess CO_2 reduces the variable operating cost, which depends on the amount of disposed CO_2. The Electricity price for this strategy is shown in Figure 6.13.

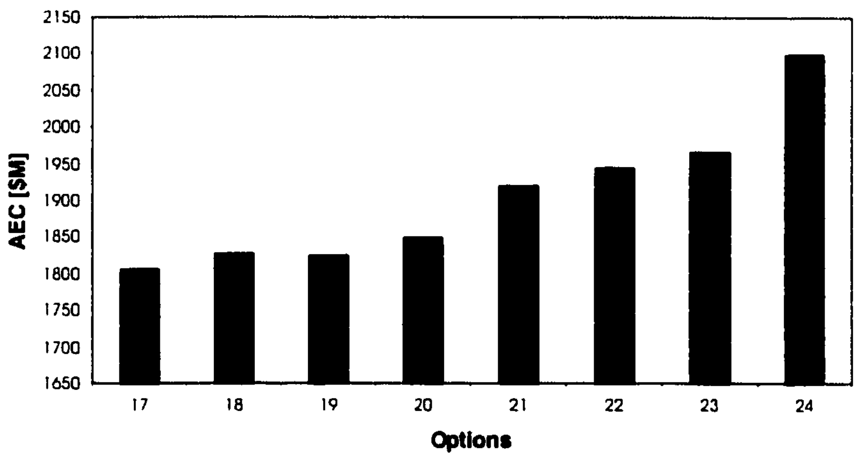

Figure 6.12 AEC for Strategy 3

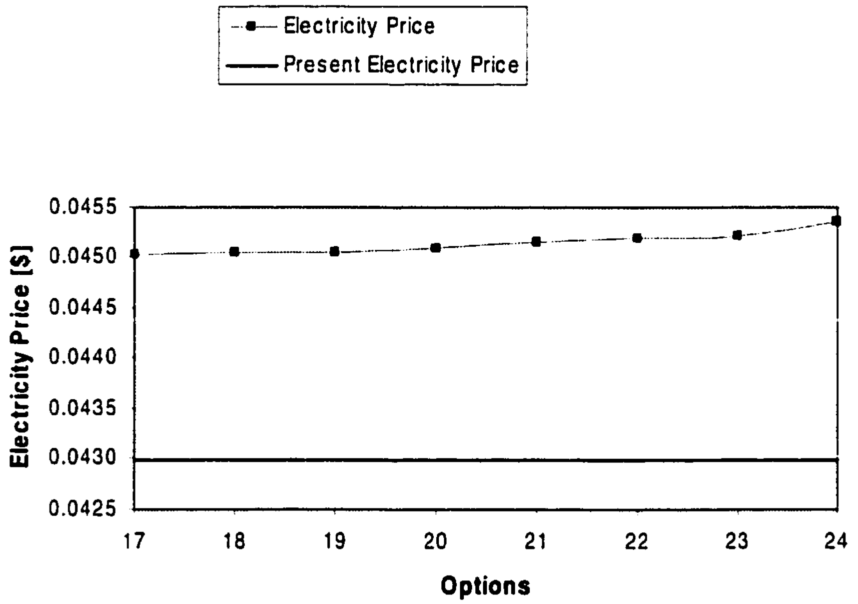

Figure 6.13 Electricity Price for Strategy 3

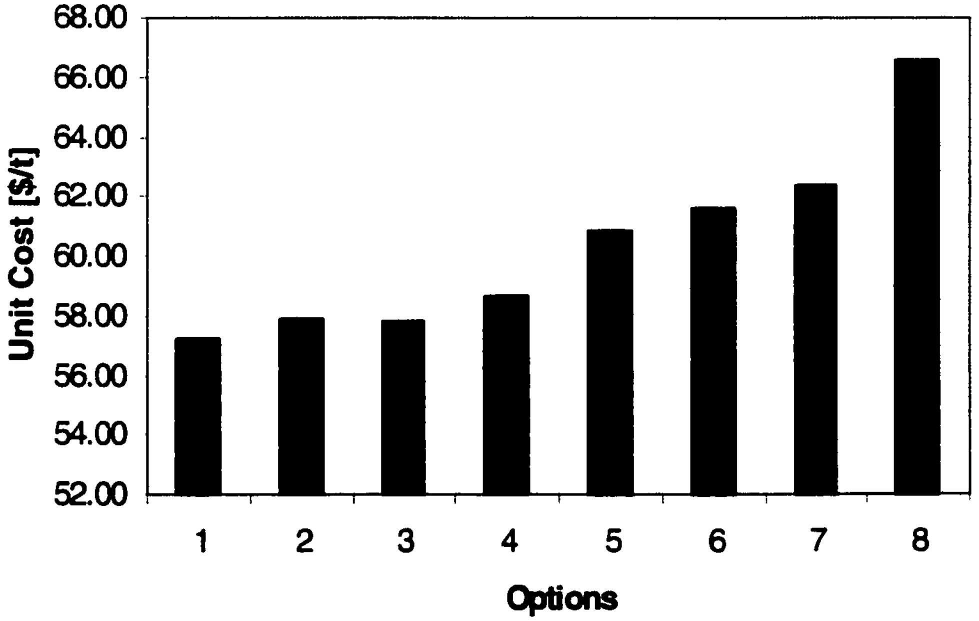

Figure 6.14 Unit Cost for Strategy 3

This result also shows that option 17 has the lowest price of \$0.0450 per kWh. On the other hand, option 24 shows the highest price of \$0.0454. The electricity price increases just about 4.7~5.6% with CO_2 disposal. The unit CO_2 disposal cost is estimated and shown in Figure 6.14. This cost is between \$57.23 per tonne and \$66.53 per tonne. These cost are lower than those of Strategies 1 and 9 because the amount of disposed CO_2 is smaller but also AEC is much smaller. In this strategy, option 17 shows the lowest AEC, electricity price, and unit cost so that this option is the optimum option.

6.8 AEC for Strategy 4

The AEC and unit costs for this strategy are estimated and shown in Table A. 37~A.45 for options 25~32 and in Figure 6.15. The AEC for the Strategy 4 is between \$2561M and \$2899M. The option with the lowest AEC value is the option 25. This has the same environment as options 1, 9, and 17 except the CO_2 sequestration strategy. The highest AEC option is the option 32. This is also the same as options 8, 16, and 24, which have the same disposal environment. The electricity price for this strategy is shown in Figure 6.16. The result also shows that option 25 has the lowest price of \$0.0459 per kWh. On the other hand, the option 32 shows the highest price of \$0.0463. The electricity price increases just about 6.7~7.7% with CO_2 disposal. The unit CO_2 disposal cost is estimated and shown in Figure 6.17. This cost is between \$56.03 per tonne and \$63.42 per tonne. In this strategy, option 25 shows the lowest AEC, electricity price, and unit cost so that this option is the optimum option.

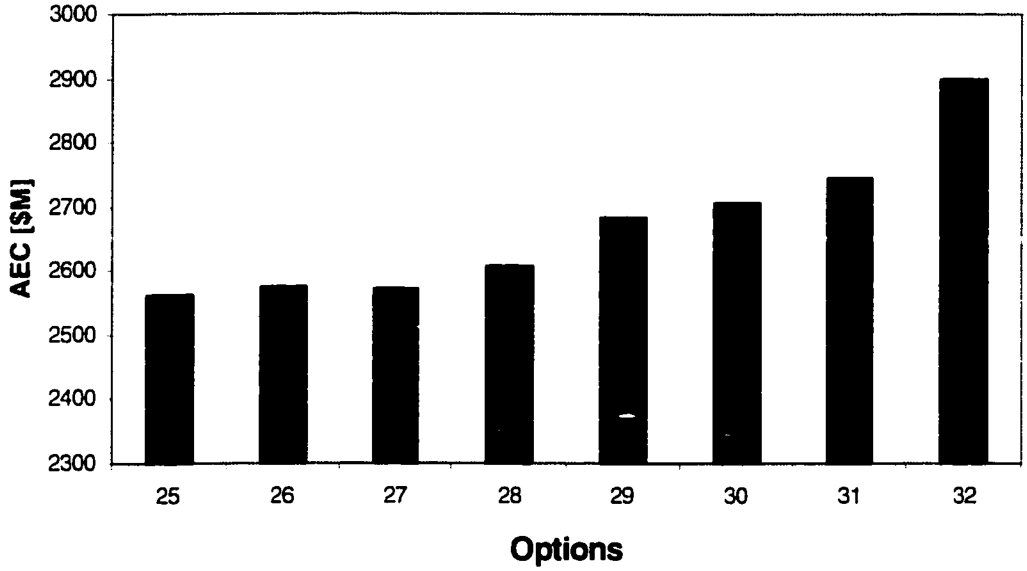

Figure 6.15 AEC for Strategy 4

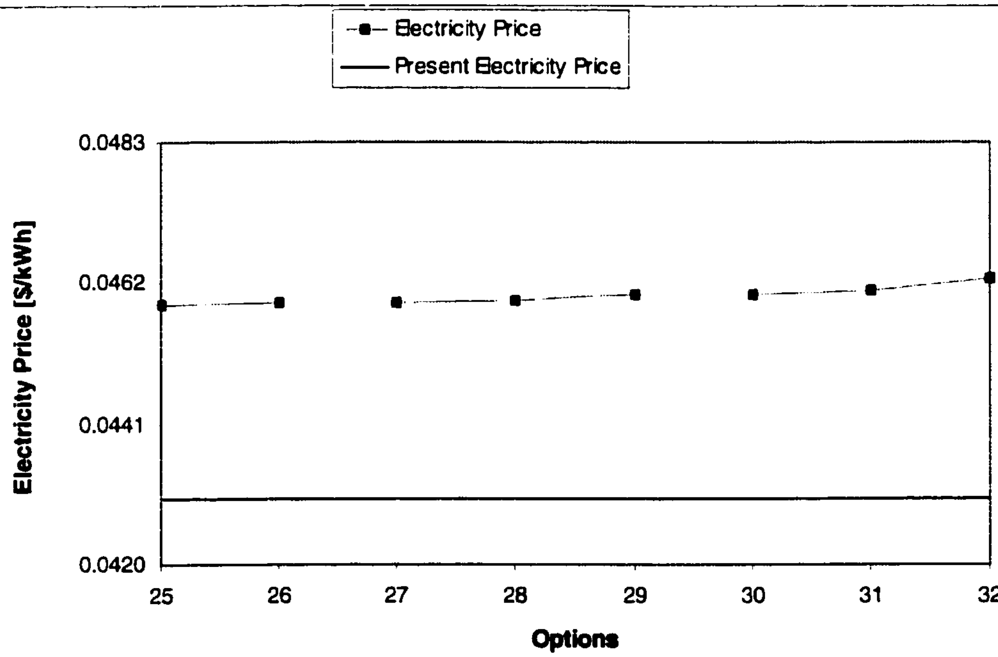

Figure 6.16 Electricity Price for Strategy 4

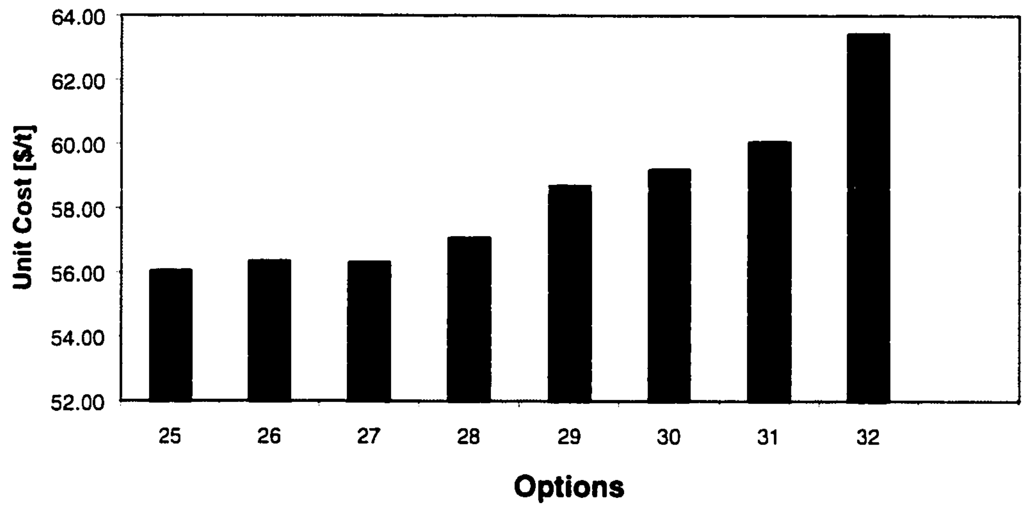

Figure 6.17 Unit Cost for Strategy 4

6.8 AEC for Strategy 5

The amount of excess CO_2 in the sequestration strategy 5 is 573.32 kt which is similar to that of strategy 2. The AEC value and unit costs are estimated and the results are shown in Table A. 52~A.60 for options 33~40 and AEC is shown in Figure 6.18. The AEC for the Strategy 5 is between $2546M and $2894M. The option showing the lowest AEC is the option 33. This has the same environment as options 1, 9, 17, and 25 at injection pressure and local permeability of 30.12 MPa and 100md respectively. The highest AEC option is the option 40. This is also the same as options 8, 16, 24, and 32. The electricity price for this strategy is shown in Figure 6.19. The result also shows that option 33 has the lowest price of $0.0459 per kWh and option 24 shows the highest price of $0.0463. The electricity price increases just about 6.7~7.7% with CO_2 disposal. The unit CO_2 disposal cost is estimated and shown in Figure 6.20. This cost is between $60.29 and $68.52 per tonne. In this strategy, option 33 shows the lowest AEC, electricity price, and unit cost.

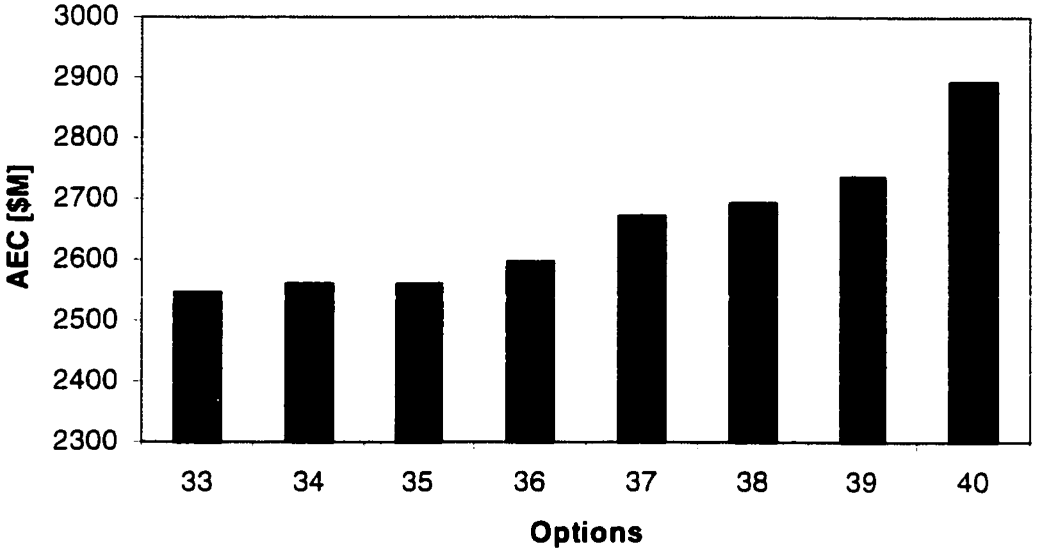

Figure 6.18 AEC for Strategy 5

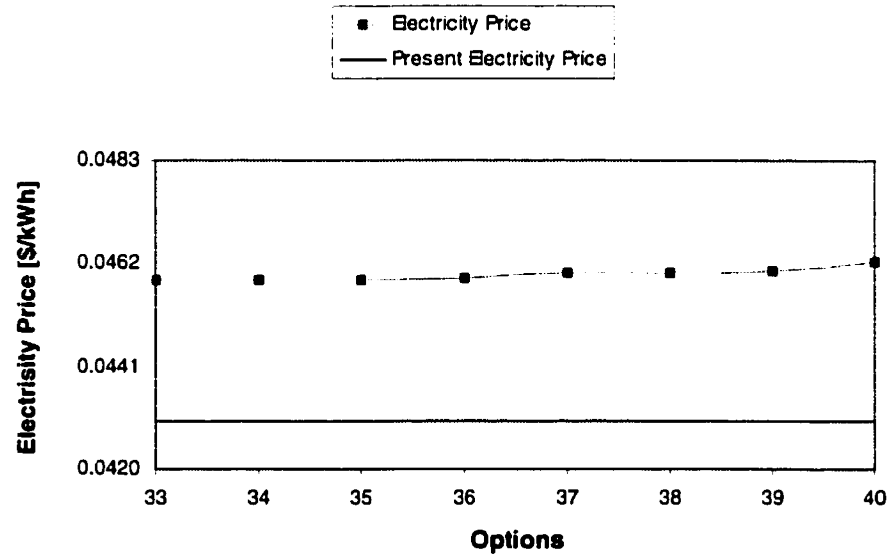

Figure 6.19 Electrisity Price for Strategy 5

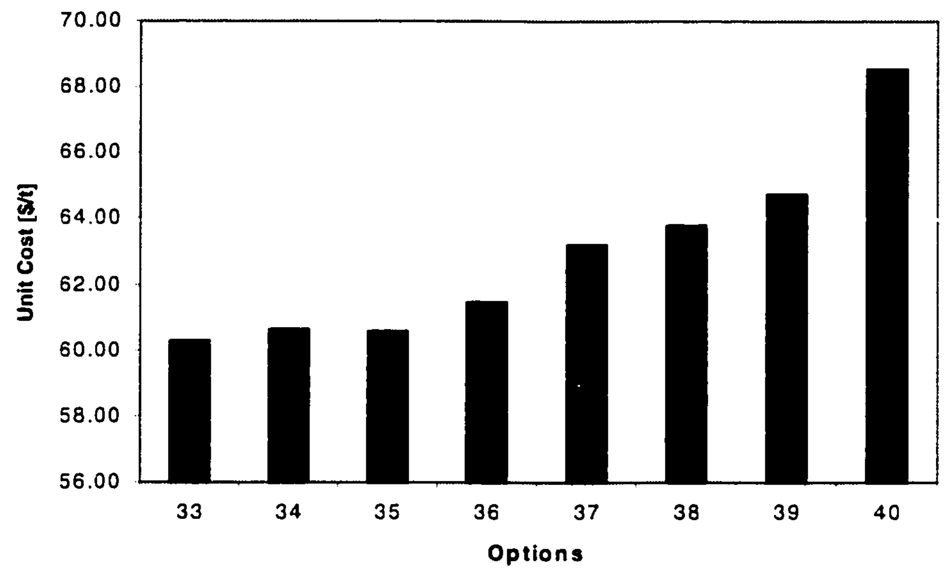

Figure 6.20 Unit Cost for Strategy 5

6.10 Conclusion

The economic modeling for the Wabamun Thermal Power Plant is carried out based on CO_2 disposal options. The capital cost of ACDS for the Wabamun plant is between 467 million dollars and 538 million dollars. The operating cost for the Wabamun plant is 65.72 million dollars to dispose 4584 kt of CO_2 in a year. Forty options are examined in this study and these options are combinations of CO_2 sequestration strategy, injection pressures at the aquifer, and local permeabilities at the injection sites. Based on these Wabamun result, a scaled model for CO_2 disposal options and their respective economic models are thoroughly examined for the total CO_2 emissions in Alberta by using annual equivalent cost (AEC) model. The options, which have injection environment with injection pressure of 30.12MPa and local permeability of 100md show the lowest AEC among the options. The sequestration strategy 3 is the optimum strategy because of its lowest cost and the 4-year preparation period before, which is four years before operation.

CHAPTER 7
QUANTITATIVE RISK SIMULATION FOR ACDS

7.1 Quantitative Stochastic Model

The underlying uncertainties, errors and the opportunity costs associated with the design, construction and operation of the disposal system constitute periodic risks that must be addressed to ensure the viability of this project. These design and operating risks are captured in a quantitative model and simulated over an extended period using the Latin Hypercube simulation technique [Palisade, 1996]. The results of this simulation experiment will assist analysts in predicting and controlling the associated short- and long-term risks.

The significance of the input variables and the definition of their stochastic processes are determined using the variance propagation and bestfit algorithms [Palisade, 1996]. The variance propagation algorithm uses the Taylor series expansion process to determine the sensitive random variables which ultimately determines the system variability [Frimpong and Whiting, 1992; Griffin and Hamilton, 1991]. The bestfit algorithm uses the Maximum Likelihood Estimators (MLE) and the Levenberg-Marquardt (LM) optimization techniques to determine an appropriate stochastic process under the Chi-Square, Kologoro-Smirnov and Anderson-Darling test criteria [Palisade, 1994].

The sources and magnitude of the project uncertainties must be understood and defined using variance propagation in order to model the project risks. For a generalized multivariate random function, the expected value and variance can be used to capture the underlying stochastic processes. The total cost function in equation (6.1) comprises many functions, which are also dependent on other random variables. For example, the capital cost function, CC, depends on many random variables, γ_i, $E[\gamma_i]$, , $VAR[\gamma_i]$, $f(\gamma_i)$, and $f(\gamma_i)d\gamma_i$,. E[CC] and VAR[CC] are defined by equations (7.1) and (7.2) [Frimpong and Whiting, 1992; Griffin and Hamilton, 1991].

$$E[CC]=\int_{-\infty}^{\infty}\cdots\int_{-\infty}^{\infty}\phi(\gamma_1,\gamma_2,\cdots,\gamma_n)*f(\gamma_1)d\gamma_1*f(\gamma_2)d\gamma_2*\cdots*f(\gamma_n)d\gamma_n \tag{7.1}$$

$$VAR[CC]=\int_{-\infty}^{\infty}\cdots\int_{-\infty}^{\infty}[\phi(\gamma_1)-E(CC)]^2*[\phi(\gamma_2)-E(CC)]^2*\cdots*[\phi(\gamma_n)-E(CC)]^2* \\ f(\gamma_1)d\gamma_1*f(\gamma_2)d\gamma_2*\cdots*f(\gamma_n)d\gamma_n \tag{7.2}$$

Numerical models can be formulated and solved to obtain approximate expected value and the variance estimates, respectively, in equations (7.1) and (7.2). This is achieved by expanding these equations in a multivariable Taylor series expansion to the second order about E[γ_i] as illustrated in equations (7.3) and (7.4).

$$E[CC]=\phi[E(\gamma_1),E(\gamma_2),\cdots,E(\gamma_n)]+\frac{1}{2}*\sum\frac{\partial^2\phi}{\partial\gamma_i^2}*VAR[\gamma_i]+ \\ \sum_{i=1}^{n-1}\sum_{j=2}^{n}\frac{\partial^2\phi}{\partial\gamma_i\partial\gamma_j}*E\{[\gamma_i-E(\gamma_i)]*[\gamma_j-E(\gamma_j)]\} \tag{7.3}$$

$$VAR[CC]=\sum_{i=1}^{n}\left(\frac{\partial\phi}{\partial\gamma_i}\right)^2 VAR[\gamma_i]+2*\sum_{i=1}^{n-1}\sum_{j=2}^{n}\frac{\partial^2\phi}{\partial\gamma_i\partial\gamma_j}*E\{[\gamma_i-E(\gamma_i)]*\sum_{i=1}^{n}\left(\frac{\partial\phi}{\partial\gamma_i}\right)\left(\frac{\partial^2\phi}{\partial\gamma_i^2}\right)\mu_3[\gamma_i] \\ +2*\sum_{i=1}^{n-1}\sum_{j=2}^{n}\left(\frac{\partial\phi}{\partial\gamma_i}\right)\left(\frac{\partial^2\phi}{\partial\gamma_j^2}\right)*E\{[\gamma_i-E(\gamma_i)]*[\gamma_j-E(\gamma_j)]^2\}+2\sum_{i=1}^{n-1}\sum_{j=2}^{n}\left(\frac{\partial\phi}{\partial\gamma_i}\right)\left(\frac{\partial^2\phi}{\partial\gamma_i\partial\gamma_j}\right) \\ *E\{[\gamma_j-E(\gamma_j)]^2*[\gamma_j-E(\gamma_j)]\}+2\sum_i\sum_j\sum_s\left(\frac{\partial\phi}{\partial\gamma_i}\right)\left(\frac{\partial^2\phi}{\partial\gamma_j\partial\gamma_s}\right) \\ *E\{[\gamma_i-E(\gamma_i)]*[\gamma_j-E(\gamma_j)]*[\gamma_s-E(\gamma_s)]\} \tag{7.4}$$

VAR[CC] and the contribution of each variable to this variance, a measure of the first derivative of the function with respect to each variable, are the two important determinants of the variability in CC. The variability in the total cost is also a function of the variability in each of the variables that determine its magnitude. In order to manage the design and operating risks, the variability in the component variables must be controlled with adequate and reliable data and information over an extended period of time.

7.2 Marginal Sensitivity Analysis

Sensitivity analysis must be carried out to determine the sensitive variables in the economic model of the ACDS using equations (7.3) and (7.4). The result will help to select the appropriate variables for simulation experiments. In the economic model, the variables, which might change the NPV and AEC, are system efficiency, energy price, interest rate, escalation rates of capital cost and operating cost, and inflation rate. The variance propagation method is used for the analysis. In this analysis, each variable is varied in the range of -50% and 50% and percent changes of AEC are observed.

7.3 Stochastic Process Characterization of Variables

The stochastic modeling is carried out using BestFit and @RISK software package [Palisade,1996]. The sensitive random variables form the marginal sensitivity analyses are used as input in the AEC stochastic model. Bestfit fits probability distribution functions for these variables. BestFit uses two methods called Maximum Likelihood Estimators (MLE) and Levenberg-Marqurdt as shown in Figure 7.1 [Palisade, 1996]. The selection of a method mostly depends on the integrity of the input data. MLEs attempt to fit distribution to the input data by initial guess for parameters, such as the mean and standard deviation for a normal distribution. The MLE method is appropriate for input distribution with very smooth curve. The Levenberg-Marquardt method is used to maximize the goodness-of-fit between input data and a given distribution function. This method is generally used when the input distribution is incomplete, or not very smooth.

The three goodness-of-fit tests used in BestFit are the Chi-Square, Kolmogorov-Smirnov and Anderson-Darling tests. A goodness-of-fit test statistic is used to test the hypothesis that a random variable has a specified theoretical distribution function. The Chi-Square, goodness-of-fit test is based on the sequence of the difference between the observed frequencies in and the theoretical class frequencies, if the random variable conformed to the assumed theoretical distribution [Pfaffenber and Patterson, 1987]. This method can be used for both continuous and discrete probability distributions. The Kolmogorov-Smirnov goodness-of-fit test can be used for any hypothesized, continuous, cumulative distribution. The one weakness is inability to detect tail discrepancies [Palisade, 1995]. Anderson-Darling goodness-of-fit test is similar to the Kolmogorov-Smirnov. This method is also for continuous distribution and it has the ability to deal with distribution function with tail discrepancies.

7.4 Latin Hypercube Simulation

The selected BestFit PDFs for the uncertain random variables are entered into the stochastic economic model in the @RISK environment. For setting up the simulation experiment, the sampling type, standard recalculation, and outputs are selected with an appropriate random seed. The outputs of the function in the spreadsheet can be calculated by using the expected value, Monte Carlo, and the true expected value. The flow chart for @RISK simulation is shown in Figure 7.2. The expected value recalculation method causes the distribution functions to return their expected mean each time Excel undertakes a recalculation.

The first step in the expected value recalculation method is to specify the probability distribution functions (PDFs). The expected values are calculated for all specified PDFs, and serve as inputs in the stochastic economic model. Excel uses the expected values to recalculate the function's output which are displayed in the spreadsheet. The second recalculation method is the Monte Carlo Method. The first step in the Monte Carlo Method is to specify the PDFs. The random samples are generated from each PDFs, and serve as inputs in the model. These recalculation procedures are shown in Figure 7.3.

Excel uses these sample values to recalculate the function's output which are displayed in the spreadsheet. The third recalculation method is the true expected value method. This is basically the same as the expected value method. The @RISK package contains two sampling techniques-the Latin Hypercube and Monte Carlo techniques. In this research, the Latin Hypercube technique is selected as the sampling type. The Latin Hypercube sampling technique is designed to accurately recreate the input distribution through sampling in fewer iterations when compared with the Monte Carlo sampling technique.

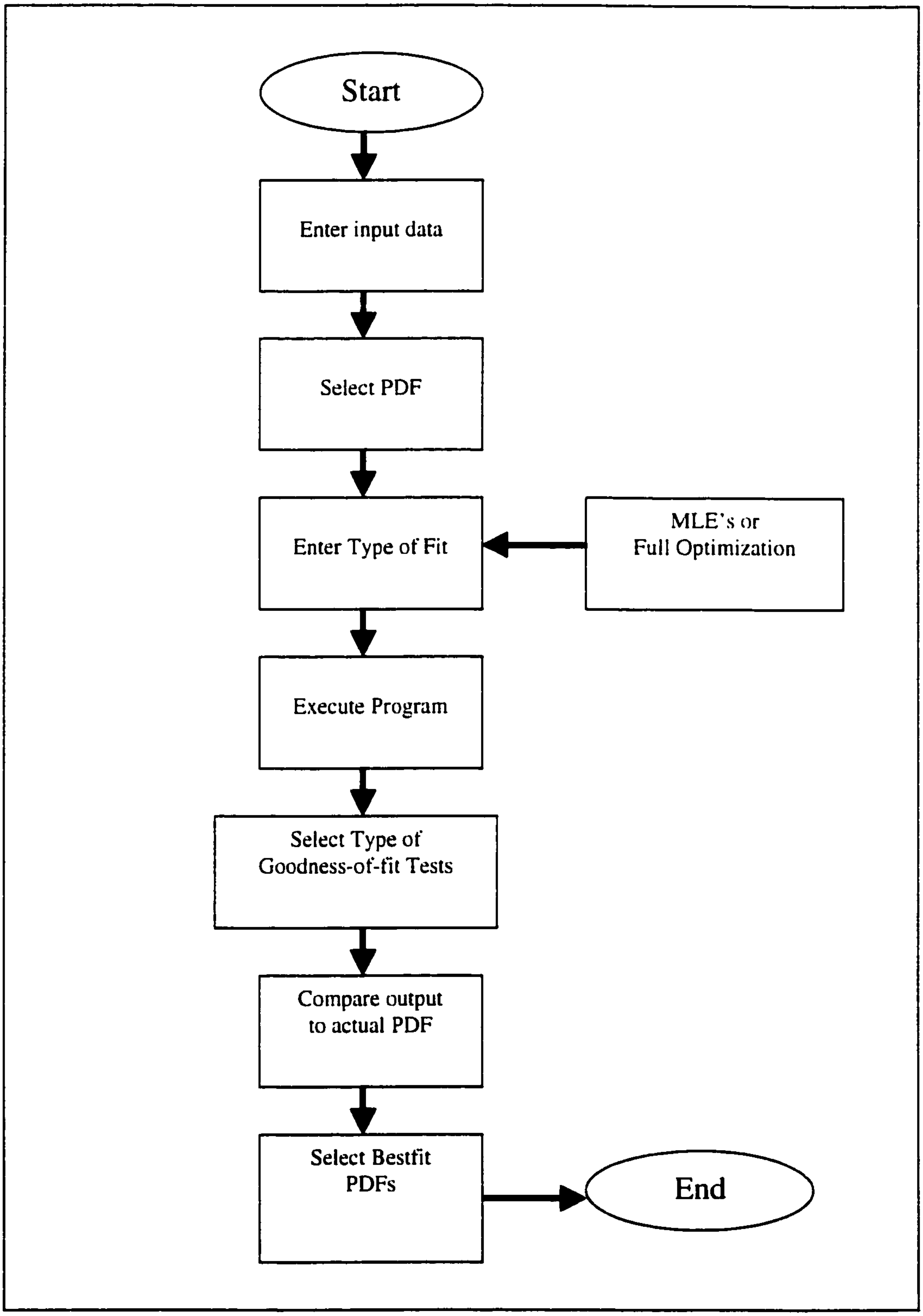

Figure 7.1 Flowchart for Bestfit

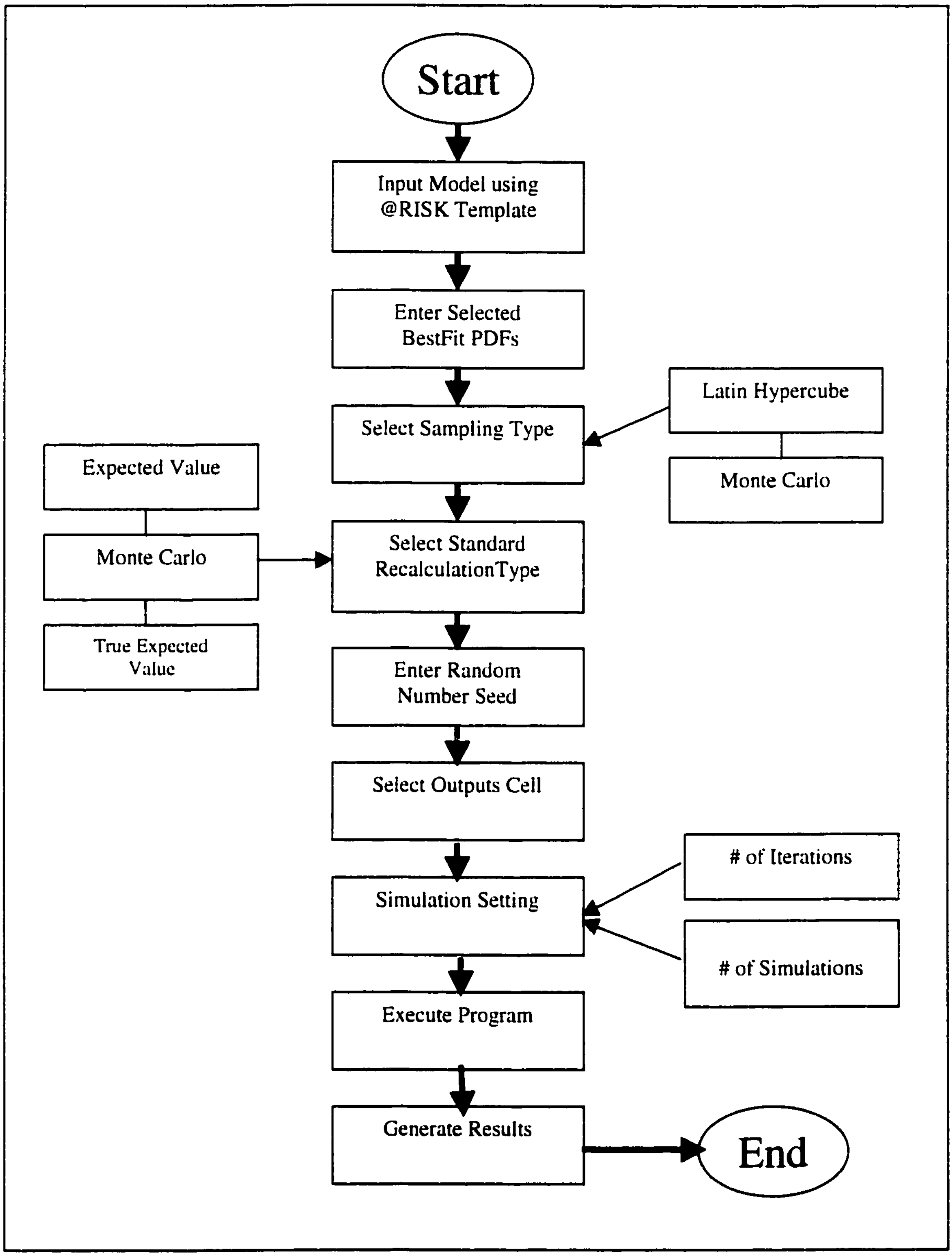

Figure 7.2 Flowchart for Risk Simulation with @RISK

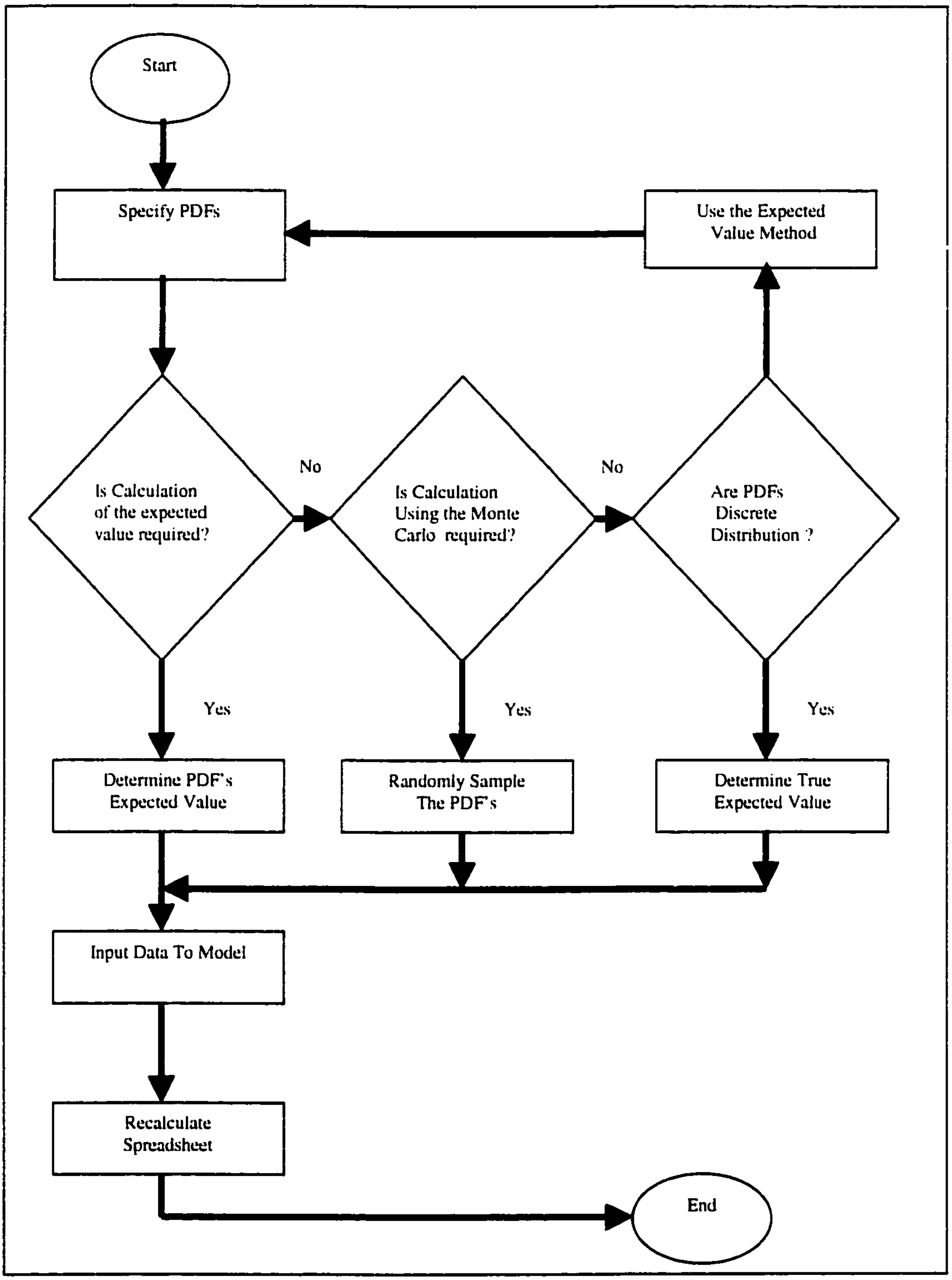

Figure 7.3 Flowchart for the Simulation Model Recalculation Methods

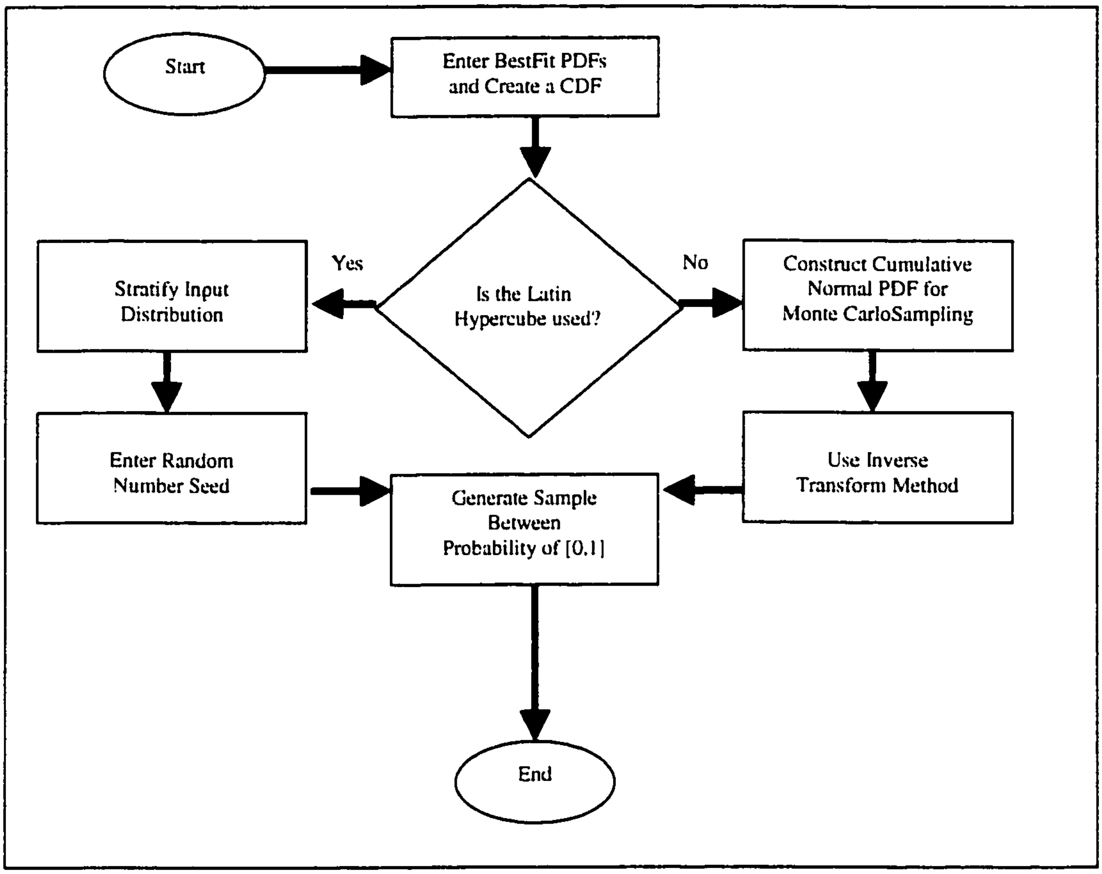

Figure 7.4 Flowchart for Simulation Model Sampling Techniques

The key to Latin Hypercube sampling technique is stratification of the input probability distributions. Stratification divides the cumulative curve into equal intervals on the cumulative probability scale from 0 to 1.0. This stratification is the basic distinction between Latin Hypercube and Monte Carlo technique. During sampling, a sample is drawn from each interval. There is no sample replacement during Latin Hypercube sampling, this means that no other value is sampled from the same interval in a simulation. Therefore, the number of stratification is equivalent to the number of iterations performed. Entering a seed value for the random number generator ensures that exactly the same sequence of random numbers will be repeated during each simulation run. The random number generator seed permits the user to enter a seed value, which is useful in controlling the simulation environment. Output selections ensure that only entered cells are going to show the simulation results. The final step for the simulation run is to decide the number of iterations and simulation runs. The brief procedures of Latin Hypercube and Monte Carlo techniques are shown as Figure 7.4.

7.5 Marginal Sensitivity Analysis

The economic model described in Chapter 6 has six sensitive random variables in the AEC model . Sensitivity analysis is carried out for these input variables, and the results are illustrated in Figure 7.5. It can be seen from the results that energy price, system efficiency, and escalation rate of operating cost contribute toward the total variance of the AEC model. The other three variables, interest rate, inflation rate and escalation rate of capital cost show less than 1 percent change in AEC. Therefore, three variables, system efficiency, energy cost, and escalation rate of operating cost are selected as sensitive variables.

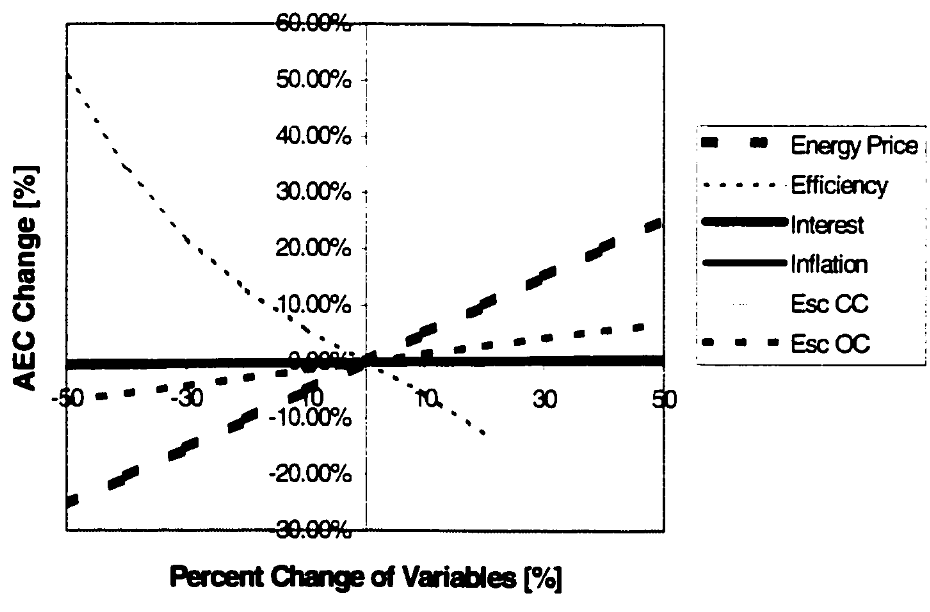

Figure 7.5 Sensitivity Analysis

7.6 Stochastic Process Characterization of Sensitive Variables

The BestFit package is used to fit appropriate distributions to the sensitive variables. The result of distribution analysis is the results of the stochastic process characterization using the BestFit software are provided in Table 7.1. Energy prices of electricity and escalation rate of operating cost data used for the analysis are shown as Tables A.63 and A.64. Escalation is the difference between each month. These data are provided by Statistics Canada [Statistics Canada, 1994, 1998]. Data on electricity is given by price index shown as Table A.64 and it is converted to the electricity price $0.043 per kWh in 1998. The escalation rate of operating cost was distributed with logistic density function. The energy price data have periodic trends so that recent period from 1995 to 1998 is used for this study. The lognormal distribution is selected as BestFit distribution for energy price. The lognormal distribution is truncated at a lower price of $0.04 per kW and a higher value of $0.06 per kW based on observed data in Table A.57. The uniform distribution is used to describe the system efficiency stochastic process with a maximum of 0.95 and minimum of 0.75. The input distributions are illustrated in Table A.66.

Table 7.1 BestFit Analysis Results

Parameter	BestFit Distribution	Mean	Standard Deviation
Energy Price	Lognormal	0.0422	0.00526
Escalation Rate of OC	Logistic	0.16	0.28

7.7 Stochastic Simulation Results and Analysis

The stochastic economic model is carried out with 10000 iterations in one simulation run using Latin Hypercube technique. The probability distribution functions (PDFs) for sensitive variables are used as inputs variables for stochastic economic models. The data for capital cost and operating cost are based on the results of economic analysis in Chapter 6. These data are shown as Table A5 ~ A20.

7.8 Simulation Results for the CO_2 Sequestration Strategy 1

The results of the simulation for the CO_2 Sequestration Strategy 1 are shown in Table 7.2 and the distributions of these eight options are shown in Figures 7.6 and 7.7. From Table 7.1, it can be seen that the expected value for the option 1 is \$2976M with standard deviation of \$48.1M and a range of \$284M between the minimum and maximum values. Figure 7.6 shows the AEC distributions for options 1 to 4. The percentage difference in expected value from options 1 to 3 is about 5.3 per cent. Option 4 has a much higher expected value among the options. These distributions have COV of 1.61%, 1.60%, 1.60% and 1.56% for options 1, 2, 3, and 4, respectively. These small variations of distributions indicate the stability of the cost in the future.

Table 7.2 Summary Statistics of the CO_2 Sequestration Strategy 1

Option	Minimum [\$]	Maximum [\$]	Mean [\$]	Std Deviation	Expected Cost [\$/t]	Min EC	Max EC
1	2861430000	3144751000	2976181000	48100550	60.67	58.34	64.11
2	2876201000	3132880000	2992949000	47903320	61.02	58.64	63.87
3	2864249000	3132233000	2991077000	47722960	60.98	58.39	63.86
4	2907441000	3178130000	3032812000	47280100	61.83	59.27	64.79
5	3008359000	3263339000	3119924000	47831960	63.61	61.33	66.53
6	3033778000	3326371000	3148149000	47838700	64.18	61.85	67.81
7	3058212000	3315545000	3178326000	47635950	64.80	62.35	67.59
8	3208553000	3476349000	3317884000	47358720	67.64	65.41	70.87

Table 7.3 Expected AEC and Associate Risk for Strategy 1

Options	Expected AEC [\$M]	Risk [%]
1	2976	48.13%
2	2993	48.35%
3	2991	48.09%
4	3033	48.24%
5	3120	48.45%
6	3148	48.09%
7	3178	47.66%
8	3318	47.93%

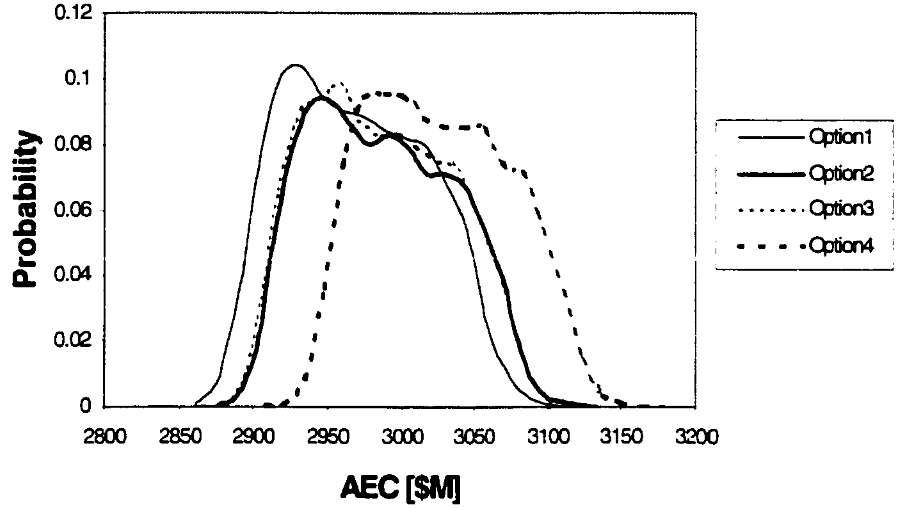

Figure 7.6 AEC Distribution for Options 1-4

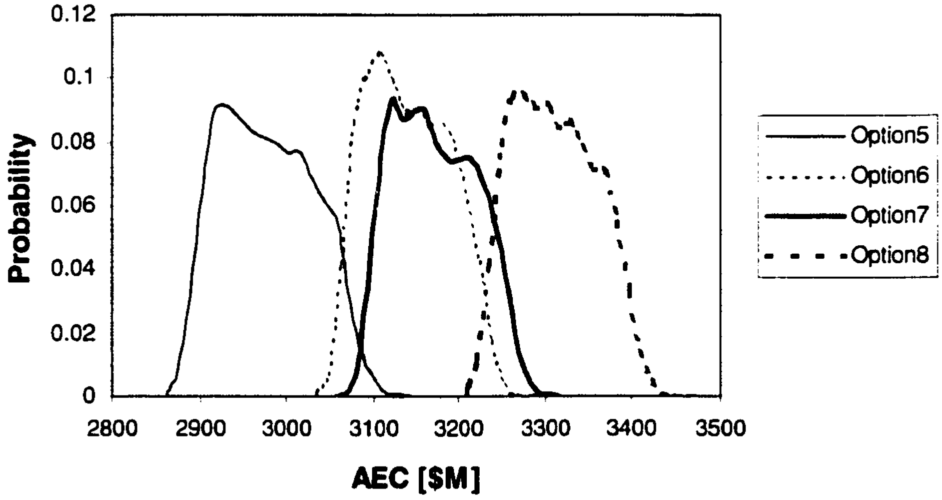

Figure 7.7 AEC Distribution for Options 5-8

Figure 7.7 shows the AEC distributions for options 5, 6, 7, and 8. These distributions have COV of 1.53%, 1.52%, 1.50% and 1.43% for options 5, 6, 7, and 8 respectively. These small variations also indicate the stability of the cost in the future. The most cost-effective option is option 1 among the eight options is Strategy 1. The expected unit costs per tonne are given in Table 7.2 and it varies between \$60.67 per tonne and \$67.64 per tonne. Table 7.3 indicates the risk associated with the expected value discussed in Chapter 6 for options 1 to 8 in Strategy 1. The option 1 has 48.13% of risk expected AEC of \$2,976. All the options for this strategy show the probability range 47.5 and 48.5%.

7.9 Simulation Results for the CO_2 Sequestration Strategy 2

The results of the simulation for the CO_2 Sequestration Strategy 2 are shown in Tables 7.4 and 7.5 and in Figures 7.8 and 7.9. From Table 7.4, it can be seen that the expected AEC for this strategy is between \$2,600 and \$3,038 with COV of between 1.39 and 1.59%. This shows a small variation in the distributions and indicates the stability of the cost in the future. The option 9 shows the lowest AEC with standard deviation of \$41M. The options 10 and 11 have similar distribution to the option 9 with the expected value of \$2,633M and \$2,331M, respectively. The option 12 shows a different distribution among the four options, which are at the same local permeability shown in Figure 7.8. The options, which are at the local permeability of 30md, show quite different distributions as shown in Figure 7.9. The option 13 shows the lowest expected value of AEC among options. As the same as strategy 1, the difference of the number of injection sites affects to the AEC.

Table 7.4 Summary Statistics of the CO_2 Sequestration Strategy 2

Option	Minimum	Maximum	Mean	Std Deviation	Expected Cost [\$/t]	Min EC	Max EC
9	2475369000	2735148000	2599983000	41356960	62.70	59.69	65.95
10	2523384000	2757010000	2632907000	41557810	63.49	60.85	66.48
11	2527578000	2766623000	2631270000	41091170	63.45	60.95	66.71
12	2563095000	2835521000	2668708000	40881450	64.35	61.81	68.38
13	2663523000	2918753000	2771031000	41190730	66.82	64.23	70.38
14	2693392000	2951795000	2807088000	41120170	67.69	64.95	71.18
15	2741154000	2980753000	2841200000	40981180	68.51	66.10	71.88
16	2940931000	3180483000	3037619000	40932140	66.82	70.92	76.69

The expected unit cost is between \$62.70 per tonne and \$66.82 per tonne. If these unit costs apply to the Wabamun plant the annual CO_2 disposal cost will be \$287 million for option 9 and \$306 million for option 16. Figure 7.8 shows the AEC distributions for options 9, 10, 11, and 12. These distributions COV of 1.59%, 1.58%, 1.56% and 1.53% for options 9, 10, 11, and 12 respectively. This means that the distributions have tight range of distribution so that the economics are very stable. Figure 7.9 shows AEC distribution for options 13, 14, 15, and 16. The AEC distributions have COV of 1.94%, 1.84%, 1.79% and 1.49% for options 13, 14, 15, and 16 respectively.

Table 7.5 Expected AEC and Associated Risk for Strategy 2

Options	Expected AEC [$M]	Risk [%]
9	2600	48.15%
10	2633	48.40%
11	2631	47.58%
12	2669	48.12%
13	2771	48.27%
14	2841	48.00%
15	2841	48.00%
16	3038	47.91%

Table 7.5 indicates the risks associated with expected values and base cases for options 9 to 10. The option 9 has 48.15 % risk associated with the expected AEC of \$2,600M. The probability range for these options is between 47.57 and 48.44 percent. The small variances show the reliability of the base economics of the ACDS. Among these options, option 9 is the most cost-effective option.

7.10 Simulation Results for the CO_2 Sequestration Strategy 3

Table 7.6 shows the results of the simulation for the CO_2 Sequestration Strategy 3. This strategy required the smallest amount of CO_2 disposal among the five strategies. From Table 7.6, it can be seen that the expected value of AEC is between \$1,774M and \$2,067M with COV of between 1.41 and 1.67%. This low COV indicates a long-term stability in the cost. Options 17 shows the lowest expected AEC value. The expected unit cost is between \$56.26 and \$65.57 per tonne. The difference of AEC between the lowest and the highest AEC options becomes \$43 million. The difference between minimum and maximum unit cost for option 17 is \$3.44 per tonne.

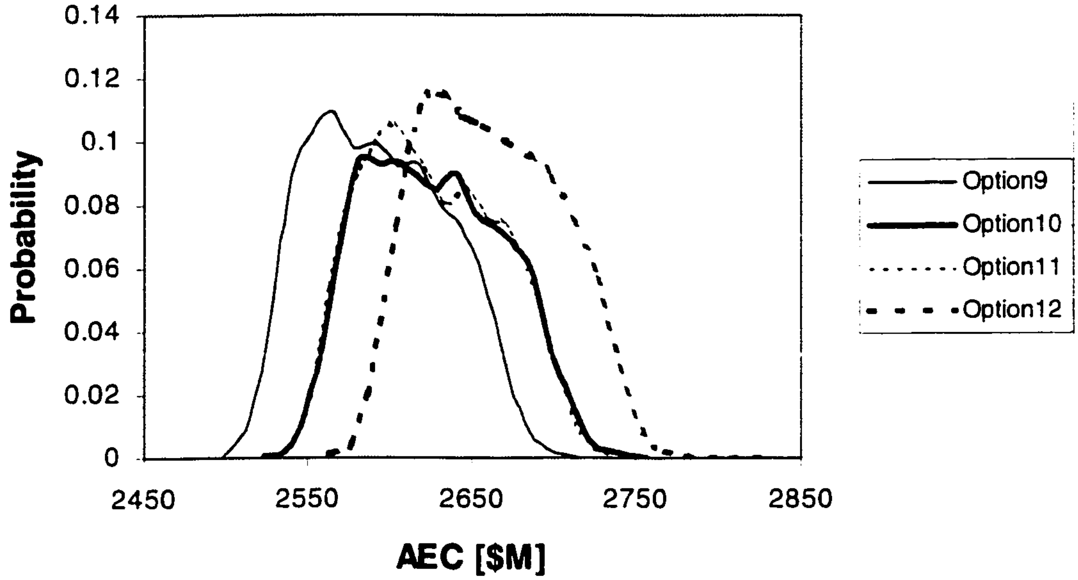

Figure 7.8 AEC Distribution for Options 9-12

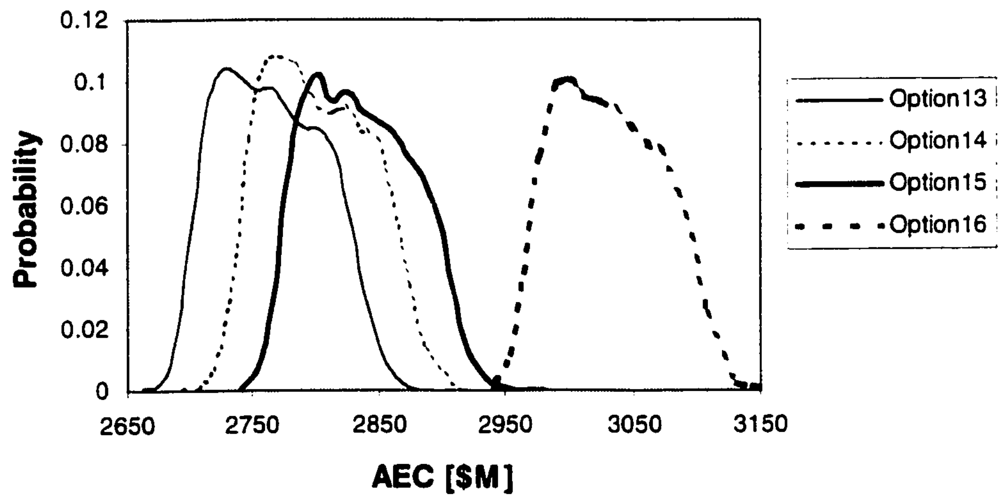

Figure 7.9 AEC Distribution for Options 13-16

Table 7.6 Summary Statistics of the CO_2 Sequestration Strategy 3

Option	Minimum	Maximum	Mean	Std Deviation	Expected Cost [$/t]	Min EC	Max EC
17	1697196000	1882252000	1773641000	29682960	56.26	53.83	59.70
18	1722265000	1897002000	1795517000	29533890	56.95	54.63	60.17
19	1703055000	1890554000	1793348000	29637250	56.88	54.02	59.97
20	1745294000	1918765000	1819306000	29128710	57.71	55.36	60.86
21	1808132000	2005760000	1888166000	29433940	59.89	57.35	63.62
22	1826316000	2017332000	1911925000	29358160	60.64	57.93	63.99
23	1851444000	2048054000	1935052000	29450400	61.38	58.73	64.96
24	1982413000	2158363000	2067214000	29077340	65.57	62.88	68.46

The distributions of these eight options are shown in Figures 7.10 and 7.11. The COV ranges between 1.41% and 1.67%. Figure 7.11 shows the AEC distribution for options 21, 22, 23, and 24. The COVs are1.56%, 1.54%, 1.52%, and 1.41% for options 21, 22, 23, and 24, respectively. These low COVs indicate a long-term stability of the costs.

Table 7.7 Expected AEC and Associated Risk for Strategy 3

Options	Expected AEC [$M]	Risk [%]
17	1774	48.27%
18	1796	48.01%
19	1793	47.86%
20	1819	48.54%
21	1888	48.28%
22	1912	48.00%
23	1935	48.07%
24	2067	48.51%

Table 7.7 indicates the risks associated with the expected values for options from17 to 24. The option 17 has 48.27 percent risk to achieve the expected. The probability range for the options is between 47 and 49%.

7.11 Simulation Results for the CO_2 Sequestration Strategy 4

Table 7.8 shows the results of the simulation for the CO_2 Sequestration Strategy 4. From this table, it can be seen that expected value for the option 25 is $2548M. The expected unit cost is between $55.75 per tonne and $65.29 per tonne as shown in Table 7.8.

The distributions of these eight options are very similar as shown in Figures 7.12 and 7.13. These distributions have COV of 1.77%, 1.74%, 1.74% and 1.71% for options 25, 26, 27, and 28, respectively. Figure 7.13 shows the AEC distributions for options 29, 30, 31, and 32.

Table 7.9 indicates the risks associated with the expected values for options 25 to 32. The option 25 has 47.99 % risk to achieve the expected AEC of $597.99M. The probability range for all the option is between 48 and 49%. These distributions have COV of 1.66%, 1.63%, 1.63% and 1.506% for options 29, 30, 31, and 32, respectively.

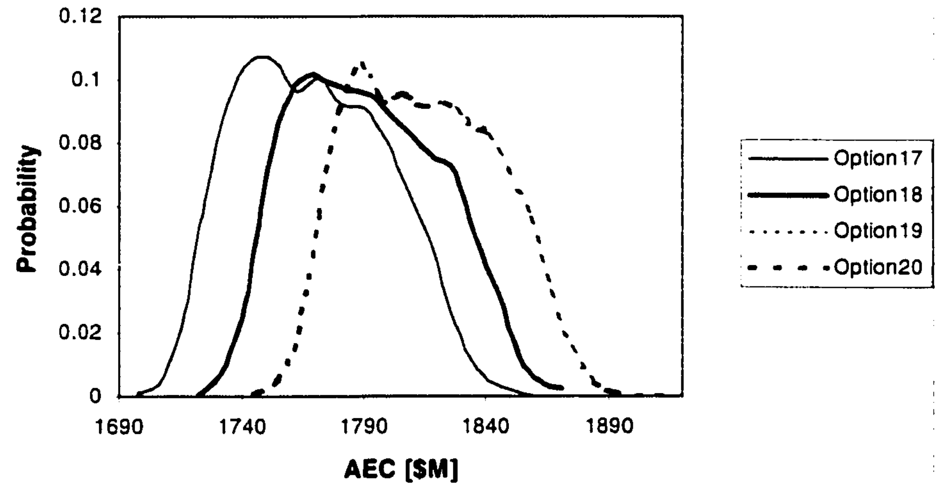

Figure 7.10 AEC Distribution for Options 17-20

Table 7.8 Summary Statistics of the CO_2 Sequestration Strategy 4

Option	Minimum	Maximum	Mean	Std Deviation	Expected Cost [$/t]	Min EC	Max EC
25	2438278000	2683564000	2548037000	45165030	55.75	53.34	58.71
26	2451416000	2714910000	2578748000	44939040	56.42	53.63	59.40
27	2457737000	2715356000	2577046000	44735250	56.38	53.77	59.41
28	2492414000	2776528000	2611935000	44694040	57.14	54.53	60.75
29	2597493000	2856891000	2709669000	44973480	59.28	56.83	62.50
30	2634104000	2879555000	2743436000	44840270	60.02	57.63	63.00
31	2651074000	2908185000	2775562000	44689430	60.72	58.00	63.63
32	2870764000	3118945000	2984348000	44716160	65.29	62.81	68.24

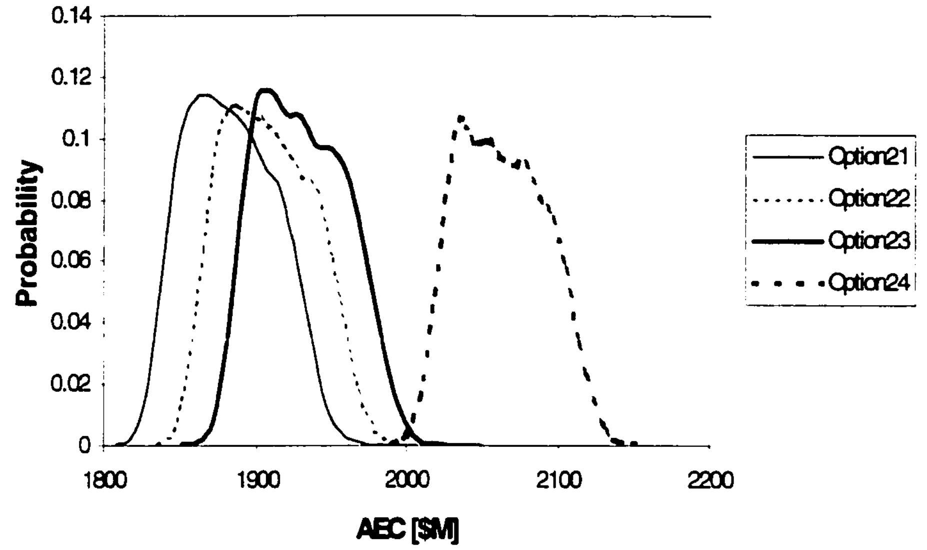

Figure 7.11 AEC distributions for Option 21-24

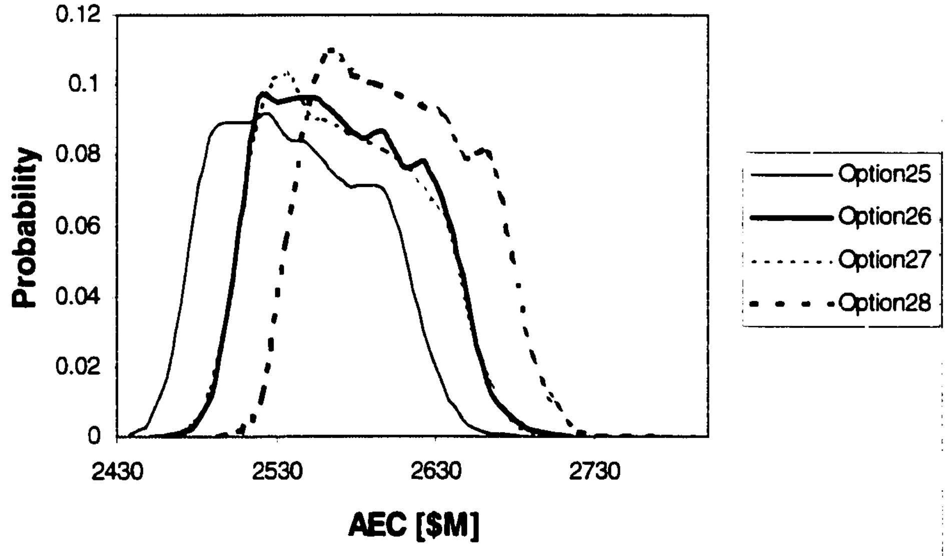

Figure 7.12 AEC Distribution for Options 25-28

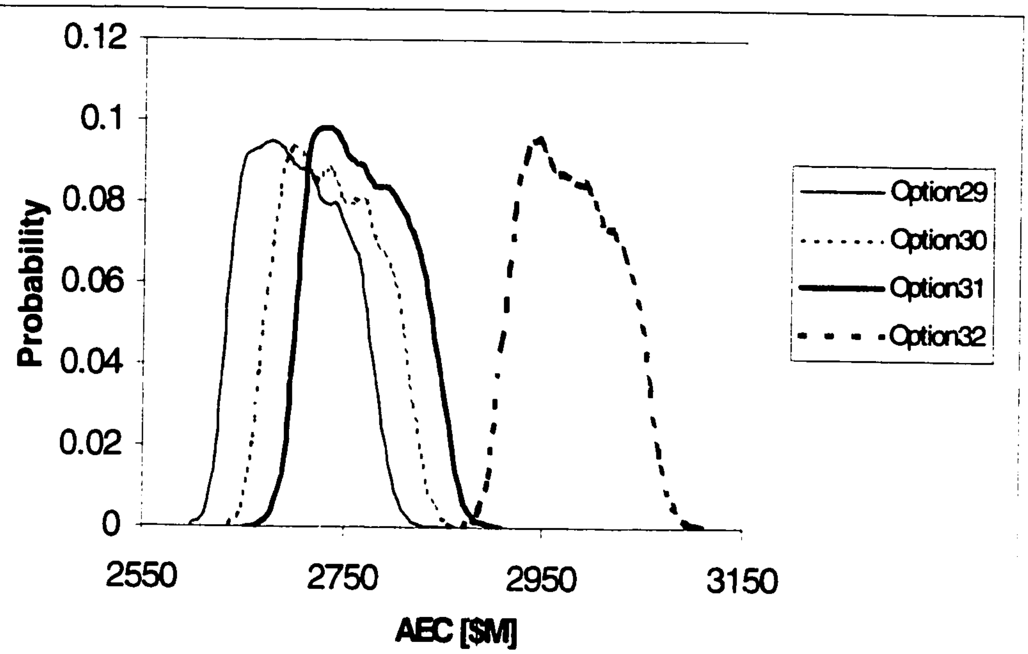

Figure 7.13 AEC Distribution for Options 29-32

Table 7.9 Expected AEC and Associate Risk for Strategy 4

Options	Expected AEC [$M]	Risk [%]
25	2548	47.99%
26	2579	47.99%
27	2577	48.03%
28	2612	48.32%
29	2710	48.08%
30	2743	48.31%
31	2776	47.90%
32	2984	48.23%

Table 7.9 indicates the risks associated with the expected values from 25 to 32. The option 25 has 47.99% chance to achieve the expected AEC of $2548 million. The probability range for all the options is between 47 and 49 percent.

7.12 Simulation Results for the CO_2 Sequestration Strategy 5

Table 7.10 shows the results of the simulation experiment for the CO_2 Sequestration Strategy 5. This strategy keeps 1999 emission level for first five years and starts decreasing CO_2 emission levels from the year 2005. From Table 7.10, it can be seen that expected value of AEC for this strategy is between $2,053M and $2,851M. The option

33, which is with the highest injection pressure and local aquifer permeability, shows the lowest expected AEC of $2,053M. Figures 7.14 and 7.15 shows the AEC distributions for all options from 33 to 40. These distributions have COV of 1.64%, 1.62%, 1.61%, 1.59, 1.56%, 1.54%, 1.51% and 1.42% respectively.

Table 7.10 Summary Statistics of the CO_2 Sequestration Strategy 5

Option	Minimum	Maximum	Mean	Std Deviation	Expected Cost [$/t]	Min EC	Max EC
33	2400004000	2637530000	2502958000	41077930.00	59.26	56.82	62.45
34	2403136000	2648655000	2517470000	40844540.00	59.60	56.90	62.71
35	2407677000	2640637000	2515874000	40625560.00	59.57	57.00	62.52
36	2454024000	2675099000	2551963000	40452470.00	60.42	58.10	63.34
37	2524762000	2758874000	2626997000	40956620.00	62.20	59.78	65.32
38	2551376000	2778785000	2651380000	40770290.00	62.77	60.41	65.79
39	2586622000	2838855000	2691851000	40685450.00	63.73	61.24	67.21
40	2757715000	3037940000	2851078000	40488150.00	67.50	65.29	71.93

Table 7.11 indicates the risks associated with the expected values for options 33 to 40. The probability of achieving the expected AEC value is 48.30% for option 33. The small variances show the reliability of economics of CO_2 disposal for the future.

Table 7.11 Expected AEC and Associate Risk for Strategy 5

Options	Expected AEC [$M]	Risk [%]
33	2503	48.30%
34	2517	47.86%
35	2516	47.83%
36	2552	47.59%
37	2627	48.20%
38	2651	48.00%
39	2692	48.29%
40	2851	48.25%

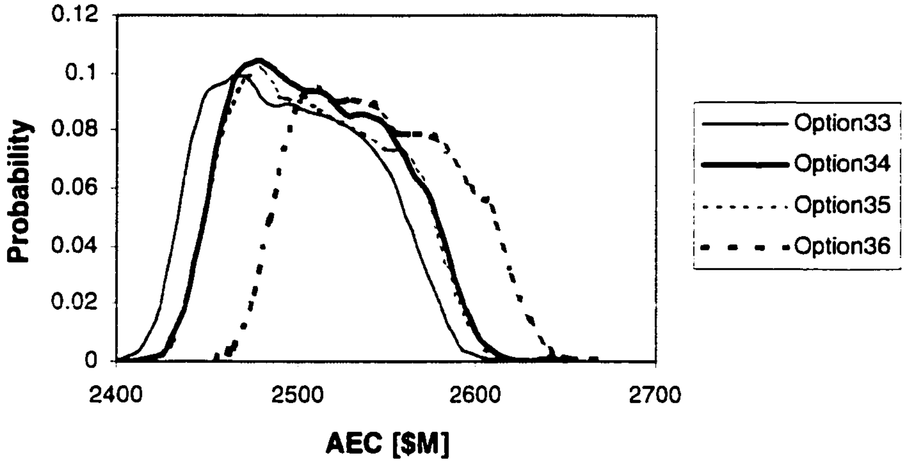

Figure 7.14 AEC Distribution for Option 33-36

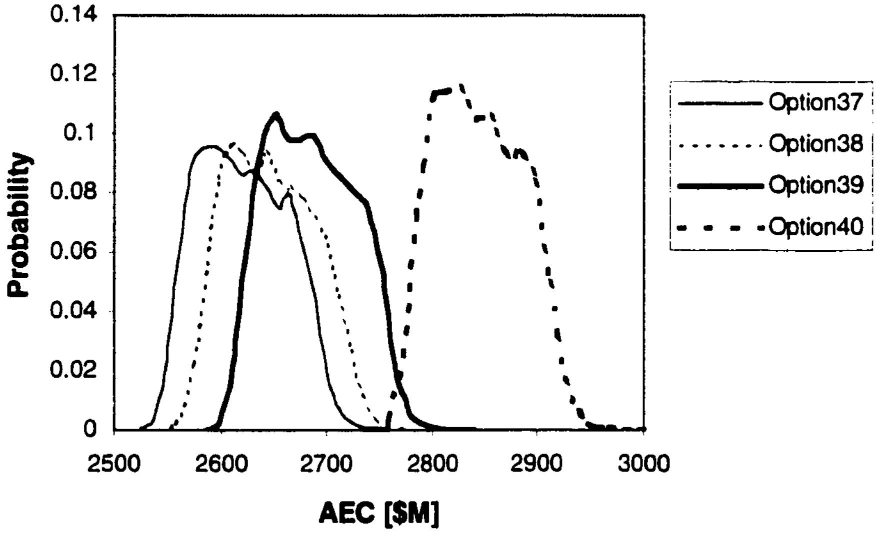

Figure 7.15 AEC Distribution for Option 37-40

7.13 Cost-Effective Option and Energy Price

The most cost-effective options in the various strategies are options 1, 9, 17, 25 and 33. These options have injection pressure of 30.12MPa and local aquifer permeability of 100md. The most cost-effective strategy is strategy 3 in which CO_2 reduction begins from the year 2005. Furthermore, this can be shown by comparing the energy price including the disposal cost. Table 7.12 indicates the expected energy price including CO_2 disposal cost for all the 40 options. The options 17 to 24 in strategy 3 show lower expected energy prices with a range of $0.04500 per kWh and $0.04533 per kWh. These values are 4.7% and 5.4% higher than the original energy price of $0.043 per kWh, respectively. The result implies that CO_2 sequestration strategy 3 is much more attractive because the total amount of excess CO_2 is the least among all the strategies. This means that the further the sequestration strategy is delayed, the better economic outcome. However, if the Kyoto agreement is to be implemented, there will be a timing constraint, which may have to be taken into consideration.

Table 7.12 Expected Energy Price

Strategy 1		Strategy 2		Strategy 3	
Option	Expected Energy Price [$/kWh]	Option	Expected Energy Price [$/kWh]	Option	Expected Energy Price [$/kWh]
1	0.04635	9	0.04593	17	0.04500
2	0.04637	10	0.04596	18	0.04502
3	0.04637	11	0.04596	19	0.04502
4	0.04641	12	0.04600	20	0.04505
5	0.04651	13	0.04612	21	0.04513
6	0.04658	14	0.04616	22	0.04515
7	0.04674	15	0.04620	23	0.04518
8	0.04654	16	0.04642	24	0.04533
Strategy 4		Strategy 5			
Option	Expected Energy Price [$/kWh]	Option	Expected Energy Price [$/kWh]		
25	0.04590	33	0.04582		
26	0.04590	34	0.04583		
27	0.04605	35	0.04583		
28	0.04609	36	0.04587		
29	0.04613	37	0.04596		
30	0.04636	38	0.04599		
31	0.04453	39	0.04603		
32	0.04590	40	0.04621		

7.14 Conclusion

Sensitivity analysis is carried out for six variables, system efficiency, energy price, interest rate, inflation rate, and escalation rate of capital cost and operating cost contributing the total CO_2 disposal costs. Three variables indicates the system efficiency, energy price, and escalation rate of operating cost, are sensitive random variables and they are used as input data for the stochastic models. Probability distributions are fitted to these variables by using the BestFit software package. The stochastic models of the CO_2 disposal economics are developed using the stochastic processes governing these variables. These stochastic models are simulated using the Latin Hypercube sampling methodology. The results show that the most cost-effective options are 1, 9, 17, 25, and 33, which have injection pressure and local permeability of 30.12MPa and 100md. The most cost- effective strategy is strategy 3, in which CO_2 reduction is started from the year 2005.

CHAPTER 8

CONCLUSIONS AND RECOMENDATIONS

In this research study, the author has examined the technical feasibility, the economic viability and the risks implication for aquifer CO_2 disposal in Alberta. A comprehensive literature survey of previous work on CO_2 capturing, liquefaction and disposal form the basis for the design of the aquifer disposal system. The literature review also shows a lack of comprehensive economic and risk analysis in this field. A detailed study is carried out on the geology of the Alberta Basin, the stability of the host aquifer for CO_2 disposal, and the physico-chemical behaviour of CO_2. Technically feasible disposal systems are designed based on injection pressures and local aquifer permeabilities at injection site. These models are validated using data from the Wabamun coal-fired power plant.

The MRT5 methodology is used to develop a CO_2 emission forecast model for Alberta. The Wabamun scale economics are projected to study the economics of CO_2 disposal in Alberta. A comprehensive quantitative risk simulation model is developed to examine the inherent variability in the economics of the CO_2 disposal in Alberta. From the literature survey, design of the ACDS, CO_2 emission forecast, economic and quantitative risk simulation and analysis, the following conclusions are drawn:

- The Glauconitic aquifer in the Alberta Basin is suitable for CO_2 disposal and storage. The average depth and thickness of the aquifer are 1480m and 13m respectively. The permeability is between 6.2 and 100md. Porosity is between 6 and 12%. The top pressure is 12.4 MPa. Capacity of CO_2 in the Glauconitic aquifer are between $2.8*10^6$ and $2.2*10^7$ tonnes over a period of 30 years.
- Ninety percent of CO_2 can be captured by the KS technology with a purity of 99.9%.
- At the Wabamun plant, if injection sites are less than three, extremely high energy is required to transport CO_2 to injection site through the pipelines and inject to the aquifer. More than four injection sites are desirable.

- The energy requirement for the disposal system for Wabamun plant is between 115 MWh and 116 MWh. This is about between 21 and 22 % of the total generated energy at Wabamun plant.
- CO_2 emission will continue to increase at least by the year 2012, which is the target year, committed at the Kyoto conference in 1997.
- Excess CO_2 in Alberta will reach 104 million tonnes at the year 2012
- The capital cost for capturing, separation, transportation, and injection systems is between 467.20 million dollars and 538.09 million dollars for the Wabamun Thermal Power Plant that generates 546MW of electricity.
- The operating cost is between 64.85 million dollars and 65.72 million dollars per year for the Wabamun Thermal Power Plant.
- The options, which have condition of 30.12 MPa injection pressure and local aquifer permeability of 100md (higher) show low AEC between 1,804 and 3,369 million dollars.
- The system efficiency, energy price and escalation rate of operating cost significantly contribute to the total AEC variance for all options.
- The stochastic process governing the energy price, operating cost escalation rate, and system efficiency are captured with the truncated lognoprmal, logistic, and uniform distributions, respectively.
- The expected AEC is between 1,774 million dollars and 3,318 million dollars
- The expected cost of disposal within this period is between \$55.75 and \$67.50 per tonne of CO_2.
- All the options show COV of around 1.6% with similar distributions.
- The cost-effective option is the one with 30.12MPa injection pressure and 100md local permeability.
- The most cost-effective strategy is strategy 3.

Based on the findings in the research, the following recommendations for further study are made

- Rock characteristics of local aquifer and surface must be studied in detail before the project.
- The data collection process must be improved for more accurate analysis especially in the project management section.
- Appropriate discussions are necessary with the MHI and KEPCO to obtain access to the KS technology for CO_2 separation.
- Continuous effort should be carried out by researchers into this problem for a rigorous definition of the economic threshold values for government policy on global warming that maintains a balance between economic development and the environment.
- The field of the study must be expanded to other CO2 sequestration options such as biological disposal, deep ocean disposal, disposal into depleted oil and gas reservoirs, salt domes and coal beds.

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APPENDIX

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Table A.1 Data used for Multiple Regression Model for CO_2 Emission Fore Cast

Year	Previous Year [%]	Population growth Rate[%]	Industrial Growth Rate[%]	Enrgy Consumption [PJs]	Technical Progress [-]
1988	123500	1.56	0.8	2064	0
1989	124300	1.95	0.8	2109	-0.05
1990	125800	1.99	0.8	2158	-0.05
1991	125994	1.69	0.8	2199	-0.1
1992	126753	1.3	4.3	2258	-0.1
1993	130548	1.44	4.3	2323	-0.15
1994	135861	1.39	4.3	2401	-0.15
1995	141174	1.24	4.3	2474	-0.20
1996	147246	1.23	4.3	2557	-0.20

Table A.2 Input Data for CO_2 Emission Projection

Year	Previous Year [kt]	Pop.growth Rate[%]	Industrial Growth Rate %]	Enrgy Consumption [PJs]	Technical Progress	Year	Previous Year [kt]	Pop. growth Rate[%]	Industrial Growth Rate [%]	Enrgy Consumption [PJs]	Technical Progress
1988	123500	1.56	0.8	2064	0	2001	164313	0.88	2.5	2904	-0.35
1989	124300	1.95	0.8	2109	-0.05	2002	168532	0.84	2.5	2953	-0.4
1990	125800	1.99	0.8	2158	-0.1	2003	170478	0.78	2.5	3021	-0.4
1991	125994	1.69	0.8	2199	-0.1	2004	174564	0.72	2.5	3089	-0.45
1992	126753	1.3	4.3	2258	-0.15	2005	177180	0.7	2.5	3157	-0.45
1993	130548	1.44	4.3	2323	-0.15	2006	181888	0.65	2.5	3224	-0.5
1994	135861	1.39	4.3	2401	-0.2	2007	184923	0.6	2.5	3292	-0.5
1995	141174	1.24	4.3	2474	-0.2	2008	189790	0.55	2.5	3360	-0.55
1996	147246	1.23	4.3	2557	-0.25	2009	192977	0.53	2.5	3427	-0.55
1997	151041	1.13	2.5	2592	-0.25	2010	198029	1	2.5	3495	-0.6
1998	2010	1.07	2.5	2704	-0.3	2011	203525	0.9	2.9	3563	-0.6
1999	2011	1	2.5	2784	-0.3	2012	210440	0.89	2.9	3630	-0.6
2000	2012	0.93	2.5	2861	-0.35						

Table A.3 Pressure Loss and Energy Requirement for 100md

	Pipe Lines	Injector Well	Pipe Lines	Injector Well	Pipe Lines	Injector Well	Pipe Lines		Injector Well
Injection Pressure at the end	7.5	30.12	7.5	26.6	7.5	25.15	7.5	7.5	20
Flow Rate [kg/s]	130.77	130.77	130.77	130.77	130.77	130.77	130.77	130.77	130.77
# of Sites	4	4	5	5	6	6	8	8	8
Density[kg/m^3]	734.08	880.70	734.08	849.82	734.08	836.15	734.08	734.08	784.88
V[m^3/s]	0.04454	0.03712	0.03563	0.03078	0.02969	0.02607	0.02227	0.02227	0.02083
T [K]	300.5	300.5	300.5	300.5	300.5	300.5	300.5	300.5	300.5
Viscosity [Ps's]	0.00006002	0.00006002	0.00006002	0.00006002	0.00006002	0.00006002	0.00006002	0.00006002	0.00006002
r [m]	0.0762	0.0762	0.0762	0.0762	0.0762	0.0762	0.0762	0.0762	0.0762
<u> [m/s]	2.44	2.03	1.95	1.69	1.63	1.43	1.22	1.22	1.14
Re	4550788	4550788	3640630	3640630	3033859	3033859	2275394	2275394	2275394
f(Re>3000)	0.0049	0.0049	0.0049	0.0049	0.0049	0.0049	0.0049	0.0049	0.0049
Diameter [m]	0.1524	0.1524	0.1524	0.1524	0.1524	0.1524	0.1524	0.1524	0.1524
Length [m]	5000	1490	5000	1490	5000	1490	5000	10000	1490
Pressure Drop[Pa]	1406839	349445	900377	231770	625262	163583	351710	703419	98026
Pressure Drop[MPa]	1.41	0.349	0.90	0.23	0.63	0.164	0.35	0.70	0.098
Power Requirement[kw]	62.65	12.97	32.08	7.13	18.56	4.26	7.83	15.66	2.04
System Total[kw]	251	52	160		111	26	63	125	16
Total Injection [MPa]	1.41	17.60	0.90	14.41	0.63	13.10	0.35	0.70	8.63
Total Required Injection [MPa]		10.10		6.91		5.60			1.13
Power Requirement [kW]	63	375	32	213	19	146	8	16	24
Sub Total [kW]	251	1500	160	1063	111	876	63	31	188
System Total [kW]	251	1500	160	1063	111	876	94		188

Table A.4 Pressure Analysis for 30md

	Pipe Lines		Injector Well	Pipe Lines		Injector Well	Pipe Lines		Injector Well	Pipe Lines			Injector Well
Injection Pressure at the end	7.5		30.12	7.5		26.6	7.5		25.15	7.5			20
Flow Rate [kg/s]	130.77		130.77	130.77		130.77	130.77		130.77	130.77			130.77
# of Sites	11		11	15		15	17		17	26			26
Density[kg/m^3]	734.08		878.21	734.08		848.03	734.08		835.29	734.08			784.76
V[m^3/s]	0.01619		0.01354	0.01188		0.01028	0.01048		0.00921	0.00685			0.00641
T [K]	300.5		300.5	300.5		300.5	300.5		300.5	300.5			300.5
Viscosity [Ps's]	0.00006002		0.00006002	0.00006002		0.00006002	0.00006002		0.00006002	0.00006002			0.00006002
r [m]	0.0762		0.0762	0.0762		0.0762	0.0762		0.0762	0.0762			0.0762
<u> [m/s]	0.89		0.74	0.65		0.56	0.57		0.50	0.38			0.35
Re	1654832		1654832	1213543		1213543	1070774		1070774	700121			700121
f(Re>3000)	0.0049		0.0049	0.005		0.005	0.005		0.005	0.005			0.005
Diameter [m]	0.1524	0.1524	0.1524	0.1524	0.1524	0.1524	0.1524	0.1524	0.1524	0.1524	0.1524	0.1524	0.1524
Length [m]	5000	10000	1490	5000	10000	1490	5000	10000	1480	5000	10000	15000	1480
Pressure[Pa]	186028	372057	46338	102084	204167	26333	79477	158954	20675	33978	67955	101933	9408
Pressure[MPa]	0.186	0.37	0.046	0.102	0.20	0.026	0.079	0.16	0.0207	0.0340	0.07	0.10	0.0094
Energy[kw]	3.01	6.03	0.63	1.21	2.42	0.27	0.83	1.67	0.1904	0.2328	0.47	0.70	0.0603
System Total[kw]	33.1	66	6.9	18.2	36	4.1	14.2	28	3.2367	6.0528	12	18	1.5677
Total Injection [MPa]	0.19	0.37	17.33	0.10	0.20	14.24	0.08	0.16	13.02	0.03	0.07	0.10	8.62
			9.83			6.74			5.52				1.12
Energy [kW]	3.0	6.0	133	1.2	2.4	69	0.8	1.7	51	0.2	0.5	0.7	7
Sub Total [kW]	33	30	1464	18	22	1039	14	18	864	6	9	6	187
System Total [kW]	63		1464	40		1039	32		864	21			187

Table A.5 Capital Cost for Option 1, 9, 17, 25, and 33

CO2 Separation Plant Costs [$M]		Liquefaction Plant Costs	[$M]	Pumps and Pipelines Costs [$M]		Injection Plant Cost [$M]	
CO2[US$/t]	1.685	Compressors	77	Pumps	1.26	Pumps	3.5
Lifetime CO2 Emissions	137520000	Eng.Design	7.7	Pipelines	6.25	Injector wells	3.65
		Contingency	15.4	Eng.Design	0.75	Eng.Design	0.72
				Contingency	1.50	Construction	1.43
Total [US$]	231721200						
Total [C$]	348045242						
Total [$M]	348.05		100.1		9.76		9.30
Total capital cost	467203242						

Table A. 6 Capital Cost for Option 2, 10, 18, 26, and 34

CO2 Separation Plant Costs [$M]		Liquefaction Plant Costs	[$M]	Pumps and Pipelines Costs [$M]		Injection Plant Cost [$M]	
CO2[US$/t]	1.685	Compressors	77	Pumps	0.64	Pumps	2.4
Lifetime CO2 Emissions	137520000	Eng.Design	7.7	Pipelines	3.75	Injector wells	10.95
		Contingency	15.4	Eng.Design	0.44	Eng.Design	1.34
				Contingency	0.88	Construction	2.67
Total [US$]	231721200						
Total [C$]	348045242						
Total [$M]	348.05		100.1		5.71		17.36
Total capital cost	471207242						

Table A.7 Capital Cost for Option 3, 11, 19, 27, and 35

CO2 Separation Plant Costs [$M]		Liquefaction Plant Costs	[$M]	Pumps and Pipelines Costs [$M]		Injection Plant Cost [$M]	
CO2[US$/t]	1.685	Compressors	77	Pumps	0.38	Pumps	2.58
Lifetime CO2 Emissions	137520000	Eng.Design	7.7	Pipelines	3.75	Injector wells	10.95
		Contingency	15.4	Eng.Design	0.41	Eng.Design	1.35
				Contingency	0.83	Contingency	2.71
Total [US$]	231721200						
Total [C$]	348045242						
Total [$M]	348.05		100.1		5.37		17.59
Total capital cost	471103242						

Table A.8 Capital Cost for Option 4, 12, 20, 28, and 36

CO2 Separation Plant Costs [$M]		Liquefaction Plant Costs	[$M]	Pumps and Pipelines Costs [$M]		Injection Plant Cost [$M]	
CO2[US$/t]	1.685	Compressors	77	Pumps	0.32	Pumps	0.54
Lifetime CO2 Emissions	137520000	Eng.Design	7.7	Pipelines	7.50	Injector wells	16.425
		Contingency	15.4	Eng.Design	0.78	Eng.Design	1.70
				Contingency	1.56	Contingency	3.39
Total [US$]	231721200						
Total [C$]	348045242						
Total [$M]	348.05		100.1		10.17		22.05
Total capital cost	480365742						

Table A.9 Capital Cost for Option 5, 13, 21, 29, and 37

CO2 Separation Plant Costs [$M]		Liquefaction Plant Costs	[$M]	Pumps and Pipelines Costs [$M]		Injection Plant Cost [$M]	
CO2[US$/t]	1.685	Compressors	77	Pumps	0.18	Pumps	5.2
Lifetime CO2 Emissions	137520000	Eng.Design	7.7	Pipelines	8.13	Injector wells	23.725
		Contingency	15.4	Eng.Design	0.83	Eng.Design	2.89
				Contingency	1.66	Contingency	5.79
Total [US$]	231721200						
Total [C$]	348045242						
Total [$M]	348.05		100.1		10.80		37.60
Total capital cost	496544242						

Table A.10 Capital Cost for Option 6, 14, 22, 30, and 38

CO2 Separation Plant Costs [$M]		Liquefaction Plant Costs	[$M]	Pumps and Pipelines Costs [$M]		Injection Plant Cost [$M]	
CO2[US$/t]	1.685	Compressors	77	Pumps	0.1	Pumps	2.72
Lifetime CO2 Emissions	137520000	Eng.Design	7.7	Pipelines	10.00	Injector wells	29.2
		Contingency	15.4	Eng.Design	1.01	Eng.Design	3.19
				Contingency	2.02	Contingency	6.38
Total [US$]	231721200						
Total [C$]	348045242						
Total [$M]	348.05		100.1		13.13		41.50
Total capital cost	502771242						

Table A.11 Capital Cost for Option 7, 15, 23, 31, and 39

CO2 Separation Plant Costs [$M]		Liquefaction Plant Costs	[$M]	Pumps and Pipelines Costs [$M]		Injection Plant Cost [$M]	
CO2[US$/t]	1.685	Compressors	77	Pumps	0.08	Pumps	2.85
Lifetime CO2 Emissions	137520000	Eng.Design	7.7	Pipelines	11.88	Injector wells	34.68
		Contingency	15.4	Eng.Design	1.20	Eng.Design	3.75
				Contingency	2.39	Contingency	7.51
Total [US$]	231721200						
Total [C$]	348045242						
Total [$M]	348.05		100.1		15.54		48.78
Total capital cost	512469242						

Table A.12 Capital Cost for Option 8, 16, 24, 32, and 40

CO2 Separation Plant Costs [$M]		Liquefaction Plant Costs	[$M]	Pumps and Pipelines Costs [$M]		Injection Plant Cost [$M]	
CO2[US$/t]	1.685	Compressors	77	Pumps	0.05	Pumps	0.56
Lifetime CO2 Emissions	137520000	Eng.Design	7.7	Pipelines	17.50	Injector wells	51.1
		Contingency	15.4	Eng.Design	1.76	Eng.Design	5.17
				Contingency	3.51	Contingency	10.33
Total [US$]	231721200						
Total [C$]	348045242						
Total [$M]	348.05		100.1		22.82		67.16
Total capital cost	538118242						

Table A.13 Operating Cost for Option 1, 9, 17, 25, and 33

	Liquefaction	Transportation	Injection	Capture	Other Cost	Total
Base energy[kW]	48772	251	1500	65800		116323
Efficiency	0.8	0.8	0.8	0.8		
Total Energy[kW]	60965	313.75	1875	82250		
Unit cost [$/kW]	0.043	0.043	0.043	0.043		
Total OC $	22964296	118183	706275	30981930	10954137	65724821
Fixed operating cost	26289929	Variable operating	39434893	Unit variable	8603	

Table A.14 Operating Cost for Option 2, 10, 18, 26, and 34

	Liquefaction	Transportation	Injection	Capture	Other Cost	Total
Base energy[kW]	48772	160	1063	65800		115795
Efficiency	0.8	0.8	0.8	0.8		
Total Energy[kW]	60965	200	1328.75	82250		
Unit cost [$/kW]	0.043	0.043	0.043	0.043		
Total OC $	22964296	75336	500514	30981930	10904415	65426491
Fixed operating cost	26170596	Variable operating	39255895	Unit variable	8564	

Table A.15 Operating Cost for Option 3, 11, 19, 27, and 35

	Liquefaction	Transportation	Injection	Capture	Other Cost	Total
Base energy[kW]	48772	111	876	65800		115559
Efficiency	0.8	0.8	0.8	0.8		
Total Energy[kW]	60965	138.75	1095	82250		
Unit cost [$/kW]	0.043	0.043	0.043	0.043		
Total OC $	22964296	52264	412465	30981930	10882191	65293146
Fixed operating cost	26117258	Variable operating	39175888	Unit variable	8546	

Table A.16 Operating Cost for Option 4, 12, 20, 28, and 36

	Liquefaction	Transportation	Injection	Capture	Other Cost	Total
Base energy[kW]	48772	94	188	65800		114854
Efficiency	0.8	0.8	0.8	0.8		
Total Energy[kW]	60965	117.5	235	82250		
Unit cost [$/kW]	0.043	0.043	0.043	0.043		
Total OC $	22964296	44260	88520	30981930	10815801	64894807
Fixed operating cost	25957923	Variable operating	38936884	Unit variable	8494	

Table A.17 Operating Cost for Option 5, 13, 21, 29, and 37

	Liquefaction	Transportation	Injection	Capture	Other Cost	Total
Base energy[kW]	48772	63	1464	65800		116099
Efficiency	0.8	0.8	0.8	0.8		
Total Energy[kW]	60965	78.75	1830	82250		
Unit cost [$/kW]	0.043	0.043	0.043	0.043		
Total OC $	22964296	29664	689324	30981930	10933043	65598257
Fixed operating cost	26239303	Variable operating	39358954	Unit variable	8586	

Table A.18 Operating Cost for Option 6, 14, 22, 30, and 38

	Liquefaction	Transportation	Injection	Capture	Other Cost	Total
Base energy[kW]	48772	40	1039	65800		115651
Efficiency	0.8	0.8	0.8	0.8		
Total Energy[kW]	60965	50	1298.75	82250		
Unit cost [$/kW]	0.043	0.043	0.043	0.043		
Total OC $	22964296	18834	489213	30981930	10890855	65345128
Fixed operating cost	26138051	Variable operating	39207077	Unit variable	8553	

Table A.19 Operating Cost for Option 7, 15, 23, 31, and 39

	Liquefaction	Transportation	Injection	Capture	Other Cost	Total
Base energy[kW]	48772	32	864	65800		115468
Efficiency	0.8	0.8	0.8	0.8		
Total Energy[kW]	60965	40	1080	82250		
Unit cost [$/kW]	0.043	0.043	0.043	0.043		
Total OC $	22964296	15067	406814	30981930	10873622	65241729
Fixed operating cost	26096692	Variable operating	39145038	Unit variable	8539	

Table A.20 Operating Cost for Option 8, 16, 24, 32, and 40

	Liquefaction	Transportation	Injection	Capture	Other Cost	Total
Base energy[kW]	48772	21	187	65800		114780
Efficiency	0.8	0.8	0.8	0.8		
Total Energy[kW]	60965	26.25	233.75	82250		
Unit cost [$/kW]	0.043	0.043	0.043	0.043		
Total OC $	22964296	9887.85	88048.95	30981930	10808832.60	64852995.60
Fixed operating cost	25941198	Variable operating	38911797	Unit variable	8488.61	

Table A.21 Cost Analysis for Option 1

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	2038408562	0	0	2038408562	3027644901	0.0464	61.72
2000	0	196140026.8	196140026.8	184081924.4	3027644901	0.0464	61.72
2001	0	365505748	365505748	3937370901	3027644901	0.0464	61.72
2002	0	429291337.2	429291337.2	354884369.3	3027644901	0.0464	61.72
2003	0	480928265.1	480928265.1	373129825	3027644901	0.0464	61.72
2004	0	664991507.4	664991507.4	5013272261	3027644901	0.0464	61.72
2005	0	721295188.7	721295188.7	492926910.9	3027644901	0.0464	61.72
2006	0	793023274.6	793023274.6	508628091.6	3027644901	0.0464	61.72
2007	8378070291	966542163.2	966542163.2	5624975294	3027644901	0.0464	61.72
2008	0	1039578060	1039578060	587301818.3	3027644901	0.0464	61.72
2009	0	1098484104	1098484104	582428921.1	3027644901	0.0464	61.72
2010	0	1337176650	1337176650	6193293663	3027644901	0.0464	61.72
2011	0	1412345225	1412345225	659598793.8	3027644901	0.0464	61.72
2012	0	1498458311	1498458311	656793078.3	3027644901	0.0464	61.72
SUM	10416478852	11003759861	11003759861	**27207094412**	**42387028616**		

Table A.22 Cost Analysis for Option 2

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	Annual Equiv. [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	2055878021	0	0	2055878021	3044178317	0.0464	62.06
2000	0	195249730.5	195249730.5	183246360.9	3044178317	0.0464	62.06
2001	0	363846686.3	363846686.3	3966894270	3044178317	0.0464	62.06
2002	0	427342747.3	427342747.3	353273518.9	3044178317	0.0464	62.06
2003	0	478745290.7	478745290.7	371436156.9	3044178317	0.0464	62.06
2004	0	661973054.3	661973054.3	5049889014	3044178317	0.0464	62.06
2005	0	718021168.5	718021168.5	490689473.7	3044178317	0.0464	62.06
2006	0	789423674.5	789423674.5	506319385.4	3044178317	0.0464	62.06
2007	8449871576	962154946	962154946	5665555090	3044178317	0.0464	62.06
2008	0	1034859327	1034859327	584636005.3	3044178317	0.0464	62.06
2009	0	1093497991	1093497991	579785226.7	3044178317	0.0464	62.06
2010	0	1331107091	1331107091	6237648210	3044178317	0.0464	62.06
2011	0	1405934470	1405934470	656604818.7	3044178317	0.0464	62.06
2012	0	1491656681	1491656681	653811838.6	3044178317	0.0464	62.06
SUM	1.0506E+10	10953812858	10953812858	**27355667390**	**42618496444**		

Table A.23 Cost Analysis for Option 3

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	2055424269	0	0	2055424269	3042207277	0.0464	62.02
2000	0	194851795.1	194851795	182872889.3	3042207277	0.0464	62.02
2001	0	363105136	363105136	3965436296	3042207277	0.0464	62.02
2002	0	426471786.6	426471787	352553517.6	3042207277	0.0464	62.02
2003	0	477769567.3	477769567	370679138.6	3042207277	0.0464	62.02
2004	0	660623897.2	660623897	5047898444	3042207277	0.0464	62.02
2005	0	716557780.6	716557781	489689407	3042207277	0.0464	62.02
2006	0	787814762.3	787814762	505287463.7	3042207277	0.0464	62.02
2007	8448006608	960193992.9	960193993	5663252082	3042207277	0.0464	62.02
2008	0	1032750196	1032750196	583444467.7	3042207277	0.0464	62.02
2009	0	1091269349	1091269349	578603575.4	3042207277	0.0464	62.02
2010	0	1328394182	1328394182	6235067708	3042207277	0.0464	62.02
2011	0	1403069056	1403069056	655266602.5	3042207277	0.0464	62.02
2012	0	1488616559	1488616559	652479314.8	3042207277	0.0464	62.02
SUM	1.0503E+10	10931488061	1.0931E+10	**27337955175**	**42590901872**		

Table A.24 Cost Analysis for Option 4

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	2095836572	0	0	2095836572	3083642373	0.0465	62.87
2000	0	193663047.2	193663047	181757222.1	3083642373	0.0465	62.87
2001	0	360889911.6	360889912	4035162368	3083642373	0.0465	62.87
2002	0	423869976.2	423869976	350402666.3	3083642373	0.0465	62.87
2003	0	474854800.5	474854800	368417706.9	3083642373	0.0465	62.87
2004	0	656593576.4	656593576	5134754144	3083642373	0.0465	62.87
2005	0	712186219.5	712186219	486701919.9	3083642373	0.0465	62.87
2006	0	783008478	783008478	502204816.2	3083642373	0.0465	62.87
2007	8614105361	954336060.9	954336061	5759708801	3083642373	0.0465	62.87
2008	0	1026449615	1026449615	579885001.5	3083642373	0.0465	62.87
2009	0	1084611756	1084611756	575073642.4	3083642373	0.0465	62.87
2010	0	1320289942	1320289942	6340627717	3083642373	0.0465	62.87
2011	0	1394509241	1394509241	651268965.4	3083642373	0.0465	62.87
2012	0	1479534837	1479534837	648498682.2	3083642373	0.0465	62.87
SUM	1.071E+10	10864797461	1.0865E+10	**27710300226**	**43170993229**		

Table A.25 Cost Analysis for Option 5

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	2166423396	0	0	2166423396	3171303636	0.0466	64.65
2000	0	195762325.4	195762325	183727443	3171303636	0.0466	64.65
2001	0	364801903.6	364801904	4163804498	3171303636	0.0466	64.65
2002	0	428464662.7	428464663	354200978	3171303636	0.0466	64.65
2003	0	480002154.7	480002155	372411299	3171303636	0.0466	64.65
2004	0	663710951.5	663710952	5296770610	3171303636	0.0466	64.65
2005	0	719906210.4	719906210	491977695	3171303636	0.0466	64.65
2006	0	791496171.5	791496172	507648641	3171303636	0.0466	64.65
2007	8904224517	964680919.6	964680920	5940572659	3171303636	0.0466	64.65
2008	0	1037576173	1.038E+09	586170867	3171303636	0.0466	64.65
2009	0	1096368783	1.096E+09	581307354	3171303636	0.0466	64.65
2010	0	1334601685	1.335E+09	6539171566	3171303636	0.0466	64.65
2011	0	1409625511	1.41E+09	658328623	3171303636	0.0466	64.65
2012	0	1495572771	1.496E+09	655528310	3171303636	0.0466	64.65
SUM	11070647913	10982570223	1.098E+10	**655528310**	**44398250899**		

Table A.26 Cost Analysis for Option 6

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	2193591808	0	0	2193591808	3199319902	0.0466	65.22
2000	0	195006922.4	195006922.4	183018479.9	3199319902	0.0466	65.22
2001	0	363394214.9	363394214.9	4210751835	3199319902	0.0466	65.22
2002	0	426811313.6	426811313.6	352834196.1	3199319902	0.0466	65.22
2003	0	478149934.1	478149934.1	370974247.5	3199319902	0.0466	65.22
2004	0	661149839.8	661149839.8	5355270076	3199319902	0.0466	65.22
2005	0	717128253.8	717128253.8	490079263.5	3199319902	0.0466	65.22
2006	0	788441965.3	788441965.3	505689738.3	3199319902	0.0466	65.22
2007	9015889503	960958432.3	960958432.3	6005548483	3199319902	0.0466	65.22
2008	0	1033572400	1033572400	583908965.4	3199319902	0.0466	65.22
2009	0	1092138142	1092138142	579064219.1	3199319902	0.0466	65.22
2010	0	1329451757	1329451757	6610286009	3199319902	0.0466	65.22
2011	0	1404186082	1404186082	655788280	3199319902	0.0466	65.22
2012	0	1489801691	1489801691	652998773.2	3199319902	0.0466	65.22
SUM	11209481311	10940190948	10940190948	**28749804374**	**44790478624**		

Table A.27 Cost Analysis for Option 7

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	2235904199	0	0	2235904199	3246130356	0.0467	66.18
2000	0	1.95E+08	194698354	182728881.2	3246130356	0.0467	66.18
2001	0	3.63E+08	362819199	4285292735	3246130356	0.0467	66.18
2002	0	4.26E+08	426135950	352275890	3246130356	0.0467	66.18
2003	0	4.77E+08	477393335	370387237.5	3246130356	0.0467	66.18
2004	0	6.6E+08	660103671	5448520430	3246130356	0.0467	66.18
2005	0	7.16E+08	715993508	489303788.1	3246130356	0.0467	66.18
2006	0	7.87E+08	787194377	504889561.7	3246130356	0.0467	66.18
2007	9189797812	9.59E+08	959437863	6109317021	3246130356	0.0467	66.18
2008	0	1.03E+09	1.032E+09	582985018.9	3246130356	0.0467	66.18
2009	0	1.09E+09	1.09E+09	578147938.6	3246130356	0.0467	66.18
2010	0	1.33E+09	1.327E+09	6723984788	3246130356	0.0467	66.18
2011	0	1.4E+09	1.402E+09	654750595.5	3246130356	0.0467	66.18
2012	0	1.49E+09	1.487E+09	651965502.6	3246130356	0.0467	66.18
SUM	11425702010	1.09E+10	1.092E+10	**29170453587**	**45445824983**		

Table A.28 Cost Analysis for Option 8

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	2347810831	0	0	2347810831	3368673913	0.0468	68.68
2000	0	193538270.8	193538270.8	181640116.6	3368673913	0.0468	68.68
2001	0	360657391.5	360657391.5	4481871802	3368673913	0.0468	68.68
2002	0	423596878.4	423596878.4	350176903.2	3368673913	0.0468	68.68
2003	0	474548853.3	474548853.3	368180336.7	3368673913	0.0468	68.68
2004	0	656170535.6	656170535.6	5694297147	3368673913	0.0468	68.68
2005	0	711727360.6	711727360.6	486388339.6	3368673913	0.0468	68.68
2006	0	782503988.6	782503988.6	501881247.5	3368673913	0.0468	68.68
2007	9649745657	953721185.8	953721185.8	6382740784	3368673913	0.0468	68.68
2008	0	1025788277	1025788277	579511383.8	3368673913	0.0468	68.68
2009	0	1083912944	1083912944	574703124.6	3368673913	0.0468	68.68
2010	0	1319439284	1319439284	7023525174	3368673913	0.0468	68.68
2011	0	1393610764	1393610764	650849355.2	3368673913	0.0468	68.68
2012	0	1478581579	1478581579	648080857	3368673913	0.0468	68.68
SUM	11997556488	10857797313	10857797313	**30271657402**	**47161434775**		

Table A.29 Cost Analysis for Option 9

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	2661295466	0.0460	64.17
2000	0	0	0	0	2661295466	0.0460	64.17
2001	0	0	0	2711426662	2661295466	0.0460	64.17
2002	0	248362139.8	248362140	205314744.8	2661295466	0.0460	64.17
2003	0	311797619.8	311797620	241909240.5	2661295466	0.0460	64.17
2004	0	565557216.4	565557216	4940632297	2661295466	0.0460	64.17
2005	0	633923983.4	633923983	433218182.7	2661295466	0.0460	64.17
2006	0	717628989.9	717628990	460271817.1	2661295466	0.0460	64.17
2007	9424837392	961214524.6	961214525	6251868199	2661295466	0.0460	64.17
2008	0	1046234121	1046234121	591062109.8	2661295466	0.0460	64.17
2009	0	1117296342	1117296342	592403386.7	2661295466	0.0460	64.17
2010	0	1309690048	1309690048	6179327528	2661295466	0.0460	64.17
2011	0	1396835544	1396835544	652355403.8	2661295466	0.0460	64.17
2012	0	1494839386	1494839386	655206857.8	2661295466	0.0460	64.17
SUM	9424837392	9803379914	9803379914	**2.3915E+10**	**37258136522**		

Table A.30 Cost Analysis for Option 10

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	2676118700	0.0460	64.53
2000	0	0	0	0	2676118700	0.0460	64.53
2001	0	0	0	2734665197	2676118700	0.0460	64.53
2002	0	247234802.9	247234802.9	204382803.7	2676118700	0.0460	64.53
2003	0	310382343.9	310382343.9	240811193.8	2676118700	0.0460	64.53
2004	0	562990104.1	562990104.1	4977577696	2676118700	0.0460	64.53
2005	0	631046548.4	631046548.4	431251768.5	2676118700	0.0460	64.53
2006	0	714371610.8	714371610.8	458182604.2	2676118700	0.0460	64.53
2007	9505613838	956851490.1	956851490.1	6297865136	2676118700	0.0460	64.53
2008	0	1041485175	1041485175	588379228.6	2676118700	0.0460	64.53
2009	0	1112224839	1112224839	589714417.3	2676118700	0.0460	64.53
2010	0	1303745253	1303745253	6223744160	2676118700	0.0460	64.53
2011	0	1390495188	1390495188	649394307.1	2676118700	0.0460	64.53
2012	0	1488054182	1488054182	652232818.1	2676118700	0.0460	64.53
SUM	9505613838	9758881538	9758881538	**24048201331**	**37465661806**		

Table A.31 Cost Analysis for Option 11

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	2674426018	0.0460	64.49
2000	0	0	0	0	2674426018	0.0460	64.49
2001	0	0	0	2734061598	2674426018	0.0460	64.49
2002	0	246730917.4	246730917.4	203966254.2	2674426018	0.0460	64.49
2003	0	309749758.5	309749758.5	240320400.3	2674426018	0.0460	64.49
2004	0	561842682.6	561842682.6	4975734021	2674426018	0.0460	64.49
2005	0	629760422.2	629760422.2	430372840.9	2674426018	0.0460	64.49
2006	0	712915661.1	712915661.1	457248789.3	2674426018	0.0460	64.49
2007	9503515749	954901345.9	954901345.9	6295428308	2674426018	0.0460	64.49
2008	0	1039362540	1039362540	587180062	2674426018	0.0460	64.49
2009	0	1109958031	1109958031	588512529.4	2674426018	0.0460	64.49
2010	0	1301088110	1301088110	6221191408	2674426018	0.0460	64.49
2011	0	1387661241	1387661241	648070786.6	2674426018	0.0460	64.49
2012	0	1485021402	1485021402	650903512.4	2674426018	0.0460	64.49
SUM	9503515749	9738992112	9738992112	**24032990511**	**37441964257**		

Table A.32 Cost Analysis for Option 12

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	2711421129	0.0461	65.38
2000	0	0	0	0	2711421129	0.0461	65.38
2001	0	0	0	2787819572	2711421129	0.0461	65.38
2002	0	245225666.5	245225666.5	202721901.1	2711421129	0.0461	65.38
2003	0	307860043.4	307860043.4	238854258.4	2711421129	0.0461	65.38
2004	0	558415004.2	558415004.2	5063028540	2711421129	0.0461	65.38
2005	0	625918392.6	625918392.6	427747231	2711421129	0.0461	65.38
2006	0	708566319.7	708566319.7	454459215.2	2711421129	0.0461	65.38
2007	9690376846	949075703.1	949075703.1	6404402325	2711421129	0.0461	65.38
2008	0	1033021618	1033021618	583597805.8	2711421129	0.0461	65.38
2009	0	1103186421	1103186421	584922144.1	2711421129	0.0461	65.38
2010	0	1293150458	1293150458	6326834314	2711421129	0.0461	65.38
2011	0	1379195426	1379195426	644117049.5	2711421129	0.0461	65.38
2012	0	1475961614	1475961614	646932493.5	2711421129	0.0461	65.38
SUM	9690376846	9679576667	9679576667	**24365436850**	**37959895803**		

Table A. 33 Cost Analysis for Option 13

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	0	Unit Cost [$/t]
1999	0	0	0	Present Value	2789007262	Energy cost with CO2 disposal	67.25
2000	0	0	0	0	2789007262	0.0461	67.25
2001	0	0	0	0	2789007262	0.0461	67.25
2002	0	247883875.6	247883875.6	2881716833	2789007262	0.0461	67.25
2003	0	311197199.8	311197199.8	204919375.8	2789007262	0.0461	67.25
2004	0	564468138.5	564468138.5	241443402.5	2789007262	0.0461	67.25
2005	0	632703253.4	632703253.4	5224270072	2789007262	0.0461	67.25
2006	0	716247071.5	716247071.5	432383946.4	2789007262	0.0461	67.25
2007	10016760896	959363540.3	959363540.3	459385484.4	2789007262	0.0461	67.25
2008	0	1044219417	1044219417	6607061457	2789007262	0.0461	67.25
2009	0	1115144795	1115144795	589923917.8	2789007262	0.0461	67.25
2010	0	1307168013	1307168013	591262611.8	2789007262	0.0461	67.25
2011	0	1394145696	1394145696	6525231770	2789007262	0.0461	67.25
2012	0	1491960815	1491960815	651099181	2789007262	0.0461	67.25
SUM	10016760896	9784501815	9784501815	**653945144**	**39046101662**		

Table A.34 Cost Analysis for Option 14

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	2814014292	0.0462	67.86
2000	0	0	0	0	2814014292	0.0462	67.86
2001	0	0	0	2917857282	2814014292	0.0462	67.86
2002	0	246927347.4	246927347	204128637.9	2814014292	0.0462	67.86
2003	0	309996359.6	309996360	240511726.6	2814014292	0.0462	67.86
2004	0	562289982.5	562289983	5283048390	2814014292	0.0462	67.86
2005	0	630261793.4	630261793	430715473.7	2814014292	0.0462	67.86
2006	0	713483234.7	713483235	457612818.8	2814014292	0.0462	67.86
2007	10142384006	955661571.6	955661572	6680451703	2814014292	0.0462	67.86
2008	0	1040190008	1040190008	587647533.7	2814014292	0.0462	67.86
2009	0	1110841702	1110841702	588981062	2814014292	0.0462	67.86
2010	0	1302123945	1302123945	6596398891	2814014292	0.0462	67.86
2011	0	1388766000	1388766000	648586735.3	2814014292	0.0462	67.86
2012	0	1486203672	1486203672	651421716.3	2814014292	0.0462	67.86
SUM	10142384006	9746745617	9746745617	**25287361970**	**39396200094**		

Table A.35 Cost Analysis for Option 15

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	2855655927	0.0462	68.86
2000	0	0	0	0	2855655927	0.0462	68.86
2001	0	0	0	2974142823	2855655927	0.0462	68.86
2002	0	246536622.6	246536622.6	203805635.6	2855655927	0.0462	68.86
2003	0	309505837.8	309505837.8	240131153.6	2855655927	0.0462	68.86
2004	0	561400244.7	561400244.7	5376412649	2855655927	0.0462	68.86
2005	0	629264500.7	629264500.7	430033932.4	2855655927	0.0462	68.86
2006	0	712354256.7	712354256.7	456888716.6	2855655927	0.0462	68.86
2007	10338030853	954149383.5	954149383.5	6797310767	2855655927	0.0462	68.86
2008	0	1038544067	1038544067	586717671.4	2855655927	0.0462	68.86
2009	0	1109083965	1109083965	588049089.6	2855655927	0.0462	68.86
2010	0	1300063533	1300063533	6710119188	2855655927	0.0462	68.86
2011	0	1386568491	1386568491	647560446.1	2855655927	0.0462	68.86
2012	0	1483851983	1483851983	650390941.2	2855655927	0.0462	68.86
SUM	10338030853	9731322884	9731322884	**25661563014**	**39979182978**		

Table A.36 Cost Analysis for Option 16

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	Annual Equiv. [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	2964720252	0.0463	71.49
2000	0	0	0	0	2964720252	0.0463	71.49
2001	0	0	0	3123005254	2964720252	0.0463	71.49
2002	0	245067668.5	245067669	202591288.1	2964720252	0.0463	71.49
2003	0	307661690.3	307661690	238700365.5	2964720252	0.0463	71.49
2004	0	558055219.5	558055220	5622617603	2964720252	0.0463	71.49
2005	0	625515115.8	625515116	427471635.1	2964720252	0.0463	71.49
2006	0	708109793.1	708109793	454166408.8	2964720252	0.0463	71.49
2007	10855472180	948464217.2	948464217	7105361611	2964720252	0.0463	71.49
2008	0	1032356046	1032356046	583221795.9	2964720252	0.0463	71.49
2009	0	1102475642	1102475642	584545281	2964720252	0.0463	71.49
2010	0	1292317286	1292317286	7009740472	2964720252	0.0463	71.49
2011	0	1378306815	1378306815	643702047.3	2964720252	0.0463	71.49
2012	0	1475010657	1475010657	646515677.3	2964720252	0.0463	71.49
SUM	10855472180	9673340152	9673340152	**26641639440**	**41506083531**		

Table A.37 Cost Analysis for Option 17

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	1804388972	0.0450	57.23
2000	0	0	0	0	1804388972	0.0450	57.23
2001	0	0	0	0	1804388972	0.0450	57.23
2002	0	0	0	0	1804388972	0.0450	57.23
2003	0	0	0	0	1804388972	0.0450	57.23
2004	0	0	0	3744912092	1804388972	0.0450	57.23
2005	0	385387793.6	385387794	263370694.2	1804388972	0.0450	57.23
2006	0	496552827.8	496552828	318478316.2	1804388972	0.0450	57.23
2007	5195643447	593384491.2	593384491	3484696587	1804388972	0.0450	57.23
2008	0	705587213.1	705587213	398616197.4	1804388972	0.0450	57.23
2009	0	1124921155	1.125E+09	596446150.1	1804388972	0.0450	57.23
2010	0	1257499816	1.257E+09	6110730984	1804388972	0.0450	57.23
2011	0	1372205580	1.372E+09	640852625.2	1804388972	0.0450	57.23
2012	0	1497879376	1.498E+09	656539323.9	1804388972	0.0450	57.23
SUM	5195643447	7433418253	7.433E+09	**16214642971**	**25261445606**		

Table A.38 Cost Analysis for Option 18

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	1826103341	0.0451	57.92
2000	0	0	0	0	1826103341	0.0451	57.92
2001	0	0	0	0	1826103341	0.0451	57.92
2002	0	0	0	0	1826103341	0.0451	57.92
2003	0	0	0	0	1826103341	0.0451	57.92
2004	0	0	0	3810233298	1826103341	0.0451	57.92
2005	0	383348005.1	383348005.1	261976720.3	1826103341	0.0451	57.92
2006	0	493924662.6	493924662.6	316792667.5	1826103341	0.0451	57.92
2007	5286269258	590243813.4	590243813.4	3537358131	1826103341	0.0451	57.92
2008	0	701852666.4	701852666.4	396506393.3	1826103341	0.0451	57.92
2009	0	1118967149	1118967149	593289267.5	1826103341	0.0451	57.92
2010	0	1250844095	1250844095	6203091590	1826103341	0.0451	57.92
2011	0	1364942742	1364942742	637460707.1	1826103341	0.0451	57.92
2012	0	1489951369	1489951369	653064378.9	1826103341	0.0451	57.92
SUM	5286269258	7394074502	7394074502	**16409773153**	**2.5565E+10**		

Table A.39 Cost Analysis for Option 19

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	1823872254	0.0451	57.85
2000	0	0	0	0	1823872254	0.0451	57.85
2001	0	0	0	0	1823872254	0.0451	57.85
2002	0	0	0	0	1823872254	0.0451	57.85
2003	0	0	0	0	1823872254	0.0451	57.85
2004	0	0	0	3806032578	1823872254	0.0451	57.85
2005	0	382729787.1	382729787	261554235.5	1823872254	0.0451	57.85
2006	0	493128119.9	493128120	316281782.1	1823872254	0.0451	57.85
2007	5280441232	589291938.6	589291939	3533276979	1823872254	0.0451	57.85
2008	0	700720802.2	700720802	395866955.1	1823872254	0.0451	57.85
2009	0	1117162612	1117162612	592332481.4	1823872254	0.0451	57.85
2010	0	1248826883	1248826883	6195935215	1823872254	0.0451	57.85
2011	0	1362741525	1362741525	636432686.6	1823872254	0.0451	57.85
2012	0	1487548553	1487548553	652011194.6	1823872254	0.0451	57.85
SUM	5280441232	7382150221	7382150221	**1.639E+10**	**25534211562**		

Table A.40 Cost Analysis for Option 20

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	1849636573	0.0451	58.67
2000	0	0	0	0	1849636573	0.0451	58.67
2001	0	0	0	0	1849636573	0.0451	58.67
2002	0	0	0	0	1849636573	0.0451	58.67
2003	0	0	0	0	1849636573	0.0451	58.67
2004	0	0	0	3884428526	1849636573	0.0451	58.67
2005	0	380015579.1	380015579	259699369.1	1849636573	0.0451	58.67
2006	0	489630999	489630999	314038803.9	1849636573	0.0451	58.67
2007	5389206775	585112852	585112852	3596232638	1849636573	0.0451	58.67
2008	0	695751494.5	695751495	393059582	1849636573	0.0451	58.67
2009	0	1109240021	1109240021	588131832.1	1849636573	0.0451	58.67
2010	0	1239970566	1239970566	6306350670	1849636573	0.0451	58.67
2011	0	1353077359	1353077359	631919291.5	1849636573	0.0451	58.67
2012	0	1476999293	1476999293	647387321.2	1849636573	0.0451	58.67
SUM	5389206775	7329798163	7329798163	**16621248035**	**25894912019**		

Table A.41 Cost Analysis for Option 21

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	1918819293	0.0452	60.86
2000	0	0	0	0	1918819293	0.0452	60.86
2001	0	0	0	0	1918819293	0.0452	60.86
2002	0	0	0	0	1918819293	0.0452	60.86
2003	0	0	0	0	1918819293	0.0452	60.86
2004	0	0	0	4060648757	1918819293	0.0452	60.86
2005	0	384032342.5	384032342.5	262444390.7	1918819293	0.0452	60.86
2006	0	494806397.1	494806397.1	317358193.1	1918819293	0.0452	60.86
2007	5.634E+09	591297493	591297493	3747123275	1918819293	0.0452	60.86
2008	0	703105585.7	703105585.7	397214220.6	1918819293	0.0452	60.86
2009	0	1120964684	1120964684	594348383.7	1918819293	0.0452	60.86
2010	0	1253077051	1253077051	6570973334	1918819293	0.0452	60.86
2011	0	1367379383	1367379383	638598676.4	1918819293	0.0452	60.86
2012	0	1492611171	1492611171	654230203.2	1918819293	0.0452	60.86
SUM	5.634E+09	7407274107	7407274107	**1.7243E+10**	**26863470098**		

Table A.42 Cost Analysis for Option 22

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	1942445671	0.0452	61.61
2000	0	0	0	0	1942445671	0.0452	61.61
2001	0	0	0	0	1942445671	0.0452	61.61
2002	0	0	0	0	1942445671	0.0452	61.61
2003	0	0	0	0	1942445671	0.0452	61.61
2004	0	0	0	4129803121	1942445671	0.0452	61.61
2005	0	382445473	382445473	261359937.7	1942445671	0.0452	61.61
2006	0	492761795.4	492761795.4	316046829.4	1942445671	0.0452	61.61
2007	5729636369	588854178	588854178	3803405801	1942445671	0.0452	61.61
2008	0	700200265.7	700200265.7	395572881.9	1942445671	0.0452	61.61
2009	0	1116332718	1116332718	591892462.1	1942445671	0.0452	61.61
2010	0	1247899181	1247899181	6669683569	1942445671	0.0452	61.61
2011	0	1361729200	1361729200	635959907.1	1942445671	0.0452	61.61
2012	0	1486443515	1486443515	651526842.4	1942445671	0.0452	61.61
SUM	5729636369	7376666327	7376666327	**17455251352**	**27194239390**		

Table A.43 Cost Analysis for Option 23

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	1965517609	0.0452	62.34
2000	0	0	0	0	1965517609	0.0452	62.34
2001	0	0	0	0	1965517609	0.0452	62.34
2002	0	0	0	0	1965517609	0.0452	62.34
2003	0	0	0	0	1965517609	0.0452	62.34
2004	0	0	0	4194389200	1965517609	0.0452	62.34
2005	0	381866926.8	381866926.8	260964564.2	1965517609	0.0452	62.34
2006	0	492016367.7	492016367.7	315568728.1	1965517609	0.0452	62.34
2007	5819242275	587963386.1	587963386.1	3856807730	1965517609	0.0452	62.34
2008	0	699141034.5	699141034.5	394974477.2	1965517609	0.0452	62.34
2009	0	1114643981	1114643981	590997074	1965517609	0.0452	62.34
2010	0	1246011415	1246011415	6763340083	1965517609	0.0452	62.34
2011	0	1359669238	1359669238	634997855.7	1965517609	0.0452	62.34
2012	0	1484194891	1484194891	650541242.1	1965517609	0.0452	62.34
SUM	5819242275	7365507240	7365507240	**17662580955**	**27517246532**		

Table A.44 Cost Analysis for Option 24

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	0	0	0	0	2097506961	0.0454	66.53
2000	0	0	0	0	2097506961	0.0454	66.53
2001	0	0	0	0	2097506961	0.0454	66.53
2002	0	0	0	0	2097506961	0.0454	66.53
2003	0	0	0	0	2097506961	0.0454	66.53
2004	0	0	0	4560902076	2097506961	0.0454	66.53
2005	0	379536212.2	379536212.2	259371774	2097506961	0.0454	66.53
2006	0	489013358.9	489013358.9	313642662.8	2097506961	0.0454	66.53
2007	6327737581	584374767.3	584374767.3	4160735544	2097506961	0.0454	66.53
2008	0	694873845.8	694873845.8	392563761	2097506961	0.0454	66.53
2009	0	1107840781	1107840781	587389939.1	2097506961	0.0454	66.53
2010	0	1238406418	1238406418	7296368197	2097506961	0.0454	66.53
2011	0	1351370533	1351370533	631122163.3	2097506961	0.0454	66.53
2012	0	1475136147	1475136147	646570681	2097506961	0.0454	66.53
SUM	6327737581	7320552063	7320552063	**1.8849E+10**	**29365097458**		

Table A.45 Cost Analysis for Option 25

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	991950228.6	0	0	991950228.6	2561087518	0.0459	56.03
2000	0	109142202.6	109142203	102432466.4	2561087518	0.0459	56.03
2001	0	248861455	248861455	2858262865	2561087518	0.0459	56.03
2002	0	317638716.8	317638717	262583951.5	2561087518	0.0459	56.03
2003	0	489706037.3	489706037	379940089.3	2561087518	0.0459	56.03
2004	0	563321790.2	563321790	4083474003	2561087518	0.0459	56.03
2005	0	624616701.6	624616702	426857666.6	2561087518	0.0459	56.03
2006	0	817329730.4	817329730	524217730.2	2561087518	0.0459	56.03
2007	7134781793	879845691.9	879845692	4824392859	2561087518	0.0459	56.03
2008	0	1074237712	1074237712	606882528.5	2561087518	0.0459	56.03
2009	0	1138320577	1138320577	603550678.1	2561087518	0.0459	56.03
2010	0	1323821091	1323821091	6038828979	2561087518	0.0459	56.03
2011	0	1404073395	1404073395	655735652.5	2561087518	0.0459	56.03
2012	0	1495270210	1495270210	655395693.5	2561087518	0.0459	56.03
SUM	8126732022	10486185311	1.0486E+10	**23014505391**	**35855225252**		

Table A.46 Cost Analysis for Option 26

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	1000684958	0	0	1000684958	2574676845	0.0459	56.33
2000	0	108646796.9	108646797	101967516.7	2574676845	0.0459	56.33
2001	0	247731851.7	247731852	2880506416	2574676845	0.0459	56.33
2002	0	316196927.6	316196928	261392060.6	2574676845	0.0459	56.33
2003	0	487483219.9	487483220	378215508.9	2574676845	0.0459	56.33
2004	0	560764824.6	560764825	4113957682	2574676845	0.0459	56.33
2005	0	621781513.2	621781513	424920123.3	2574676845	0.0459	56.33
2006	0	813619801.2	813619801	521838261.3	2574676845	0.0459	56.33
2007	7197607918	875851997.4	875851997	4859806951	2574676845	0.0459	56.33
2008	0	1069361656	1069361656	604127837.1	2574676845	0.0459	56.33
2009	0	1133153643	1133153643	600811110.2	2574676845	0.0459	56.33
2010	0	1317812154	1317812154	6083213693	2574676845	0.0459	56.33
2011	0	1397700186	1397700186	652759212.5	2574676845	0.0459	56.33
2012	0	1488483051	1488483051	652420796.7	2574676845	0.0459	56.33
SUM	8198292876	10438587623	1.0439E+10	**23136622127**	**36045475836**		

Table A.47 Cost Analysis for Option 27

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	1000458082	0	0	1000458082	2572882080	0.0459	56.29
2000	0	108425365.5	108425365.5	101759698.3	2572882080	0.0459	56.29
2001	0	247226953.2	247226953.2	2879458091	2572882080	0.0459	56.29
2002	0	315552491.6	315552491.6	260859321.5	2572882080	0.0459	56.29
2003	0	486489687.9	486489687.9	377444673.7	2572882080	0.0459	56.29
2004	0	559621938.5	559621938.5	4112285338	2572882080	0.0459	56.29
2005	0	620514269.9	620514269.9	424054100.2	2572882080	0.0459	56.29
2006	0	811961575.2	811961575.2	520774710.8	2572882080	0.0459	56.29
2007	7195976071	874066937	874066937	4857750149	2572882080	0.0459	56.29
2008	0	1067182206	1067182206	602896573.4	2572882080	0.0459	56.29
2009	0	1130844180	1130844180	599586606.3	2572882080	0.0459	56.29
2010	0	1315126341	1315126341	6080646675	2572882080	0.0459	56.29
2011	0	1394851555	1394851555	651428834.1	2572882080	0.0459	56.29
2012	0	1485449397	1485449397	651091107.9	2572882080	0.0459	56.29
SUM	8196434153	10417312899	10417312899	**23120493960**	**36020349114**		

Table A.48 Cost Analysis for Option 28

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	1020664234	0	0	1020664234	2607300176	0.0459	57.04
2000	0	107763886.3	107763886.3	101138884.8	2607300176	0.0459	57.04
2001	0	245718676	245718676	2931887536	2607300176	0.0459	57.04
2002	0	313627375.3	313627375.3	259267876.3	2607300176	0.0459	57.04
2003	0	483521721.5	483521721.5	375141966.9	2607300176	0.0459	57.04
2004	0	556207808.3	556207808.3	4184624654	2607300176	0.0459	57.04
2005	0	616728649.1	616728649.1	421467039.6	2607300176	0.0459	57.04
2006	0	807007976.5	807007976.5	517597579	2607300176	0.0459	57.04
2007	7341312480	868734447.2	868734447.2	4942025296	2607300176	0.0459	57.04
2008	0	1060671563	1060671563	599218434.3	2607300176	0.0459	57.04
2009	0	1123945149	1123945149	595928660.5	2607300176	0.0459	57.04
2010	0	1307103045	1307103045	6186246962	2607300176	0.0459	57.04
2011	0	1386341873	1386341873	647454610.3	2607300176	0.0459	57.04
2012	0	1476386997	1476386997	647118944.5	2607300176	0.0459	57.04
SUM	8361976714	10353759168	10353759168	**2.343E+10**	**36502202469**		

Table A.49 Cost Analysis for Option 29

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	1055957646	0	0	1055957646	2681715317	0.0460	58.67
2000	0	108932030.5	108932031	102235215	2681715317	0.0460	58.67
2001	0	248382229.4	248382229	3028130922	2681715317	0.0460	58.67
2002	0	317027048.7	317027049	262078300.9	2681715317	0.0460	58.67
2003	0	488763023.8	488763024	379208449.1	2681715317	0.0460	58.67
2004	0	562237016.9	562237017	4319709781	2681715317	0.0460	58.67
2005	0	623413894.4	623413894	426035678.6	2681715317	0.0460	58.67
2006	0	815755821	815755821	523208258.5	2681715317	0.0460	58.67
2007	7595166741	878151397.3	878151397	5100501002	2681715317	0.0460	58.67
2008	0	1072169082	1072169082	605713871.5	2681715317	0.0460	58.67
2009	0	1136128544	1136128544	602388437.1	2681715317	0.0460	58.67
2010	0	1321271845	1321271845	6384719680	2681715317	0.0460	58.67
2011	0	1401369609	1401369609	654472920.4	2681715317	0.0460	58.67
2012	0	1492390809	1492390809	654133616.1	2681715317	0.0460	58.67
SUM	8651124387	10465992352	1.0466E+10	**24098493778**	**37544014435**		

Table A.50 Cost Analysis for Option 30

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	1069541852	0	0	1069541852	2705003814	0.0460	59.18
2000	0	108511686.2	108511686.2	101840712.2	2705003814	0.0460	59.18
2001	0	247423778	247423778	3063427142	2705003814	0.0460	59.18
2002	0	315803712.4	315803712.4	261066999.5	2705003814	0.0460	59.18
2003	0	486876997	486876997	377745168.8	2705003814	0.0460	59.18
2004	0	560067470.4	560067470.4	4368433642	2705003814	0.0460	59.18
2005	0	621008280	621008280	424391702.4	2705003814	0.0460	59.18
2006	0	812608002.3	812608002.3	521189315.2	2705003814	0.0460	59.18
2007	7692873604	874762808	874762808	5157275744	2705003814	0.0460	59.18
2008	0	1068031822	1068031822	603376557.6	2705003814	0.0460	59.18
2009	0	1131744479	1131744479	600063955.3	2705003814	0.0460	59.18
2010	0	1316173353	1316173353	6455859719	2705003814	0.0460	59.18
2011	0	1395962038	1395962038	651947456.2	2705003814	0.0460	59.18
2012	0	1486632008	1486632008	651609461.2	2705003814	0.0460	59.18
SUM	8762415456	10425606435	10425606435	**2.4308E+10**	**37870053401**		

Table A.51 Cost Analysis for Option 31

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	1090698047	0	0	1090698047	2744245466	0.0461	60.04
2000	0	108339983	108339983	101679564.9	2744245466	0.0461	60.04
2001	0	247032268	247032268	3119367831	2744245466	0.0461	60.04
2002	0	315304001	315304001	260653900.9	2744245466	0.0461	60.04
2003	0	486106589	486106589	377147444.9	2744245466	0.0461	60.04
2004	0	559181249	559181249	4446131774	2744245466	0.0461	60.04
2005	0	620025629	620025629	423720167.5	2744245466	0.0461	60.04
2006	0	811322175	811322175	520364612.9	2744245466	0.0461	60.04
2007	7845043374	873378630	873378630	5248040902	2744245466	0.0461	60.04
2008	0	1066341826	1066341826	602421806.5	2744245466	0.0461	60.04
2009	0	1129953667	1129953667	599114445.9	2744245466	0.0461	60.04
2010	0	1314090710	1314090710	6569568954	2744245466	0.0461	60.04
2011	0	1393753142	1393753142	650915849.1	2744245466	0.0461	60.04
2012	0	1484279640	1484279640	650578389	2744245466	0.0461	60.04
SUM	8935741421	1.0409E+10	1.0409E+10	**24660403690**	**38419436529**		

Table A.52 Cost Analysis for Option 32

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	1173852247	0	0	1173852247	2898664961	0.0463	63.42
2000	0	107694454.4	107694454	101073721.4	2898664961	0.0463	63.42
2001	0	245560360.4	245560360	3339301058	2898664961	0.0463	63.42
2002	0	313425306.4	313425306	259100831	2898664961	0.0463	63.42
2003	0	483210190.2	483210190	374900264.3	2898664961	0.0463	63.42
2004	0	555849445.7	555849446	4751633753	2898664961	0.0463	63.42
2005	0	616331293.1	616331293	421195489.9	2898664961	0.0463	63.42
2006	0	806488024.3	806488024	517264092.8	2898664961	0.0463	63.42
2007	8443145029	868174724.9	868174725	5604934803	2898664961	0.0463	63.42
2008	0	1059988176	1.06E+09	598832360.1	2898664961	0.0463	63.42
2009	0	1123220995	1.123E+09	595544705.9	2898664961	0.0463	63.42
2010	0	1306260884	1.306E+09	7016679025	2898664961	0.0463	63.42
2011	0	1385448658	1.385E+09	647037457.7	2898664961	0.0463	63.42
2012	0	1475435767	1.475E+09	646702008.2	2898664961	0.0463	63.42
SUM	9616997276	10347088280	1.035E+10	**26048051818**	**40581309458**		

Table A.53 Cost Analysis for Option 33

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	991950228.6	0	0	991950229	2546443189	0.0459	60.29
2000	0	109142202.6	109142203	102432466	2546443189	0.0459	60.29
2001	0	191326281.2	191326281	1927897964	2546443189	0.0459	60.29
2002	0	225373198.2	225373198	186310364	2546443189	0.0459	60.29
2003	0	247271159.4	247271159	191846167	2546443189	0.0459	60.29
2004	0	517218709.3	517218709	4784561302	2546443189	0.0459	60.29
2005	0	591530854.1	591530854	404247084	2546443189	0.0459	60.29
2006	0	681267403.5	681267403	436950277	2546443189	0.0459	60.29
2007	0	756615304.4	756615304	455443435	2546443189	0.0459	60.29
2008	0	1022021785	1.022E+09	5777385424	2546443189	0.0459	60.29
2009	0	1099029384	1.099E+09	582718035	2546443189	0.0459	60.29
2010	0	1209901128	1.21E+09	602065793	2546443189	0.0459	60.29
2011	0	1390631671	1.391E+09	5715949660	2546443189	0.0459	60.29
2012	0	1649850035	1.65E+09	723149970	2546443189	0.0459	60.29
SUM	991950228.6	9691179116	9.691E+09	**2.29E+10**	**3.565E+10**		

Table A.54 Cost Analysis for Option 34

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	1000684958	0	0	1000684958	2560762224	0.0459	60.63
2000	0	108646796.9	108646797	101967516.7	2560762224	0.0459	60.63
2001	0	190457835	190457835	1942625371	2560762224	0.0459	60.63
2002	0	224350210.1	224350210	185464685.4	2560762224	0.0459	60.63
2003	0	246148774.5	246148775	190975361.3	2560762224	0.0459	60.63
2004	0	514871009.5	514871010	4821666468	2560762224	0.0459	60.63
2005	0	588845845.2	588845845	402412171.9	2560762224	0.0459	60.63
2006	0	678175072.7	678175073	434966922.2	2560762224	0.0459	60.63
2007	0	753180963.2	753180963	453376138.4	2560762224	0.0459	60.63
2008	0	1017382741	1017382741	5820553833	2560762224	0.0459	60.63
2009	0	1094040796	1094040796	580073028.4	2560762224	0.0459	60.63
2010	0	1204409284	1204409284	599332965	2560762224	0.0459	60.63
2011	0	1384319475	1384319475	5757615278	2560762224	0.0459	60.63
2012	0	1642361225	1642361225	719867531	2560762224	0.0459	60.63
SUM	1000684958	9647190029	9647190029	**23011582229**	**35850671140**		

Table A.55 Cost Analysis for Option 35

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	1000458082	0	0	1000458082	2559086636	0.0459	60.59
2000	0	108425365.5	108425365.5	101759698.3	2559086636	0.0459	60.59
2001	0	190069665.8	190069665.8	1941881063	2559086636	0.0459	60.59
2002	0	223892965.4	223892965.4	185086692.7	2559086636	0.0459	60.59
2003	0	245647102.5	245647102.5	190586137.3	2559086636	0.0459	60.59
2004	0	513821658.9	513821658.9	4819894204	2559086636	0.0459	60.59
2005	0	587645727.6	587645727.6	401592021.9	2559086636	0.0459	60.59
2006	0	676792894.6	676792894.6	434080422.9	2559086636	0.0459	60.59
2007	0	751645916.7	751645916.7	452452119.5	2559086636	0.0459	60.59
2008	0	1015309229	1015309229	5818193088	2559086636	0.0459	60.59
2009	0	1091811049	1091811049	578890790.5	2559086636	0.0459	60.59
2010	0	1201954596	1201954596	598111473.8	2559086636	0.0459	60.59
2011	0	1381498115	1381498115	5755138842	2559086636	0.0459	60.59
2012	0	1639013954	1639013954	718400380.1	2559086636	0.0459	60.59
SUM	1000458082	9627528240	9627528240	**22996525016**	**35827212902**		

Table A.56 Cost Analysis for Option 36

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	1020664234	0	0	1020664234	2594907110	0.0459	61.44
2000	0	107763886.3	107763886.3	101138884.8	2594907110	0.0459	61.44
2001	0	188910092.6	188910092.6	1976698331	2594907110	0.0459	61.44
2002	0	222527043.8	222527043.8	183957519.6	2594907110	0.0459	61.44
2003	0	244148463.7	244148463.7	189423413.3	2594907110	0.0459	61.44
2004	0	510686946.2	510686946.2	4907402047	2594907110	0.0459	61.44
2005	0	584060630.5	584060630.5	399141997.4	2594907110	0.0459	61.44
2006	0	672663930.2	672663930.2	431432193.8	2594907110	0.0459	61.44
2007	0	747060290.5	747060290.5	449691808.8	2594907110	0.0459	61.44
2008	0	1009115051	1009115051	5920618431	2594907110	0.0459	61.44
2009	0	1085150150	1085150150	575359105.3	2594907110	0.0459	61.44
2010	0	1194621736	1194621736	594462527.5	2594907110	0.0459	61.44
2011	0	1373069900	1373069900	5854407741	2594907110	0.0459	61.44
2012	0	1629014691	1629014691	714017577.6	2594907110	0.0459	61.44
SUM	1020664234	9568792811	9568792811	**2.3318E+10**	**36328699542**		

Table A.57 Cost Analysis for Option 37

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	1055957646	0	0	1055957646	2670401903	0.0460	63.23
2000	0	108932030.5	1.09E+08	102235215	2670401903	0.0460	63.23
2001	0	190957849.5	1.91E+08	2041100221	2670401903	0.0460	63.23
2002	0	224939203.3	2.25E+08	185951591.3	2670401903	0.0460	63.23
2003	0	246794996.1	2.47E+08	191476734.5	2670401903	0.0460	63.23
2004	0	516222715.5	5.16E+08	5068266857	2670401903	0.0460	63.23
2005	0	590391759.4	5.9E+08	403468636.3	2670401903	0.0460	63.23
2006	0	679955505.6	6.8E+08	436108853.6	2670401903	0.0460	63.23
2007	0	755158311.2	7.55E+08	454566400.1	2670401903	0.0460	63.23
2008	0	1020053706	1.02E+09	6111813280	2670401903	0.0460	63.23
2009	0	1096913013	1.1E+09	581595911	2670401903	0.0460	63.23
2010	0	1207571255	1.21E+09	600906411.4	2670401903	0.0460	63.23
2011	0	1387953770	1.39E+09	6041623728	2670401903	0.0460	63.23
2012	0	1646672964	1.65E+09	721757420.2	2670401903	0.0460	63.23
SUM	1055957646	9672517079	9.67E+09	**2.3997E+10**	**37385626635**		

Table A.58 Cost Analysis for Option 38

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	1069541852	0	0	1069541852	2694618833	0.0460	63.80
2000	0	108511686.2	108511686.2	101840712.2	2694618833	0.0460	63.80
2001	0	190220986	190220986	2064544805	2694618833	0.0460	63.80
2002	0	224071213.3	224071213.3	185234045.8	2694618833	0.0460	63.80
2003	0	245842669.6	245842669.6	190737868.7	2694613833	0.0460	63.80
2004	0	514230727.8	514230727.8	5127180734	2694618833	0.0460	63.80
2005	0	588113570.1	588113570.1	401911741.4	2694618833	0.0460	63.80
2006	0	677331709.8	677331709.8	434426007.4	2694618833	0.0460	63.80
2007	0	752244324.6	752244324.6	452812330.3	2694618833	0.0460	63.80
2008	0	1016117547	1016117547	6180800707	2694618833	0.0460	63.80
2009	0	1092680272	1092680272	579351662.9	2694618833	0.0460	63.80
2010	0	1202911508	1202911508	598587648.3	2694618833	0.0460	63.80
2011	0	1382597968	1382597968	6108505222	2694618833	0.0460	63.80
2012	0	1640318823	1640318823	718972320.2	2694618833	0.0460	63.80
SUM	1069541852	9635193005	9635193005	**2.4214E+10**	**37724663657**		

Table A.59 Cost Analysis for Option 39

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	1090698047	0	0	1090698047	2735021716	0.0461	64.76
2000	0	108339983.1	108339983	101679564.9	2735021716	0.0461	64.76
2001	0	189919990.4	189919990	2101803375	2735021716	0.0461	64.76
2002	0	223716655	223716655	184940941.3	2735021716	0.0461	64.76
2003	0	245453661.2	245453661	190436055.2	2735021716	0.0461	64.76
2004	0	513417036.4	513417036	5220600368	2735021716	0.0461	64.76
2005	0	587182970.4	587182970	401275777.6	2735021716	0.0461	64.76
2006	0	676259936.1	676259936	433738594.7	2735021716	0.0461	64.76
2007	0	751054013.2	751054013	452095824.1	2735021716	0.0461	64.76
2008	0	1014509697	1014509697	6290797380	2735021716	0.0461	64.76
2009	0	1090951273	1090951273	578434927.6	2735021716	0.0461	64.76
2010	0	1201008085	1201008085	597640475	2735021716	0.0461	64.76
2011	0	1380410218	1380410218	6215541016	2735021716	0.0461	64.76
2012	0	1637723269	1637723269	717834656.6	2735021716	0.0461	64.76
SUM	1090698047	9619946788	9619946788	**24577517004**	**38290304020**		

Table A.60 Cost Analysis for Option 40

Year	Capital Cost Estimates[$]	Operation Cost Estimates[$]	Total Cost [$]	Present Value [$]	AEC [$]	Energy cost with CO2 disposal	Unit Cost [$/t]
1999	1173852247	0	0	1173852247	2893988115	0.0463	68.52
2000	0	107694454.4	107694454	101073721.4	2893988115	0.0463	68.52
2001	0	188788378.6	188788379	2248293103	2893988115	0.0463	68.52
2002	0	222383670.4	222383670	183838996.5	2893988115	0.0463	68.52
2003	0	243991159.7	243991160	189301368.5	2893988115	0.0463	68.52
2004	0	510357912.5	510357912	5587886511	2893988115	0.0463	68.52
2005	0	583684322.4	583684322	398884831.7	2893988115	0.0463	68.52
2006	0	672230535.4	672230535	431154223.7	2893988115	0.0463	68.52
2007	0	746578962.4	746578962	449402074.1	2893988115	0.0463	68.52
2008	0	1008464882	1.008E+09	6723293389	2893988115	0.0463	68.52
2009	0	1084450992	1.084E+09	574988403.6	2893988115	0.0463	68.52
2010	0	1193852046	1.194E+09	594079517.5	2893988115	0.0463	68.52
2011	0	1372185236	1.372E+09	6636418702	2893988115	0.0463	68.52
2012	0	1627965123	1.628E+09	713557538.8	2893988115	0.0463	68.52
SUM	1173852247	9562627674	9.563E+09	**26006024627**	**40515833604**		

Table A.61 Interest rate of Canada 1976 - 1988 (Per cent)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1976	9.53	9.62	9.98	9.82	9.82	9.90	9.89	9.62	9.59	9.49	9.22	8.85
1977	8.99	9.14	9.34	9.30	9.22	9.14	9.14	9.01	9.08	9.10	9.15	9.22
1978	9.49	9.54	9.48	9.48	9.50	9.52	9.44	9.42	9.43	9.81	9.81	9.95
1979	10.17	10.31	10.22	9.92	9.92	9.98	10.11	10.45	10.73	11.43	11.21	11.60
1980	12.55	13.47	13.83	12.19	11.77	11.63	12.55	12.69	13.26	13.52	13.38	13.04
1981	13.35	13.76	13.89	15.28	15.42	15.30	17.56	17.17	18.14	17.07	14.62	15.52
1982	16.33	15.50	15.62	15.35	15.32	16.48	16.04	14.63	14.10	13.34	12.39	11.92
1983	12.48	12.06	11.97	11.45	11.63	11.93	12.19	12.55	12.15	12.09	12.15	12.29
1984	12.21	12.61	13.28	13.54	14.12	14.05	13.66	13.11	12.87	12.48	12.10	11.99
1985	11.71	12.52	12.20	11.69	11.01	11.13	11.18	10.80	11.03	10.74	10.40	9.99
1986	10.41	10.06	9.62	8.95	9.14	9.11	9.17	8.94	9.16	9.24	8.95	8.90
1987	8.51	8.76	8.59	9.45	9.76	9.53	10.04	10.36	11.18	10.12	10.43	10.29
1988	9.66	9.51	10.05	10.27	10.24	9.99	10.22	10.47	10.21	9.89	10.05	10.00
1989	9.82	10.19	10.30	10.00	9.65	9.42	9.41	9.36	9.66	9.28	9.49	9.37
1990	9.75	10.34	10.71	11.35	10.75	10.49	10.54	10.70	11.49	11.14	10.65	10.40
1991	10.15	9.88	9.79	9.88	9.83	10.23	10.08	9.89	9.53	9.16	9.16	9.00
1992	8.92	8.94	9.16	9.40	9.07	8.83	8.34	8.12	8.33	8.21	8.50	8.36
1993	8.51	8.13	8.18	8.15	8.17	8.01	7.85	7.47	7.57	7.41	7.56	7.28
1994	7.16	7.53	8.33	8.22	8.58	9.27	9.46	8.87	9.07	9.36	9.26	9.13
1995	9.40	8.87	8.76	8.52	8.26	8.19	8.66	8.41	8.27	8.28	7.63	7.63
1996	7.64	8.08	8.14	8.26	8.09	8.17	8.06	7.83	7.75	7.12	6.75	7.09
1997	7.38	7.08	7.24	7.18	7.15	6.73	6.32	6.63	6.26	6.05	5.96	5.95
1998	5.81	5.78	5.70	5.76	5.61	5.52	5.61	5.83	5.32	5.45	5.47	5.23

Table A.62 Inflation rate of Canada 1972 - 1988 (Per cent)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1972	5.1	4.8	5.1	4.4	4.4	4.1	4.7	4.6	5.3	5.0	5.3	4.9
1973	5.5	5.8	5.8	6.7	6.9	8.2	7.8	8.3	8.6	8.8	9.4	9.4
1974	9.3	9.8	10.3	9.9	11.3	11.5	11.1	10.9	10.9	11.7	11.8	12.3
1975	11.9	11.5	11.2	11.1	10.2	10.3	11.2	10.8	10.5	10.4	10.3	9.5
1976	9.5	9.4	9.1	8.8	8.8	7.7	6.7	6.2	6.4	6.2	5.7	5.9
1977	6.3	6.5	7.5	7.7	7.6	7.8	8.4	8.4	8.5	8.9	9.1	9.4
1978	9.0	8.9	8.8	8.3	9.1	9.2	9.7	9.5	8.6	8.7	8.9	8.4
1979	8.8	9.1	9.2	9.7	9.2	9.0	8.3	8.5	9.5	9.3	9.5	9.7
1980	9.7	9.6	9.3	9.2	9.5	9.9	9.8	10.8	10.7	10.9	11.2	11.1
1981	12.0	12.1	12.6	12.5	12.2	12.8	12.9	12.6	12.5	12.6	12.0	12.2
1982	11.3	11.5	11.6	11.3	11.9	11.4	10.9	10.5	10.4	10.0	9.8	9.2
1983	8.4	7.5	7.2	6.7	5.5	5.5	5.5	5.6	5.0	4.9	4.3	4.6
1984	5.3	5.5	4.5	5.0	4.7	4.2	4.2	3.6	3.7	3.4	4.0	3.7
1985	3.7	3.6	3.8	3.8	4.0	4.0	4.0	4.0	4.1	4.1	4.0	4.4
1986	4.4	4.2	4.2	3.9	4.2	3.7	4.1	4.4	4.1	4.4	4.5	4.2
1987	3.9	4.0	4.1	4.5	4.6	4.8	4.6	4.5	4.5	4.3	4.2	4.2
1988	4.1	4.0	4.2	4.0	3.9	3.9	3.9	4.0	4.1	4.2	4.1	4.0
1989	4.3	4.6	4.5	4.5	5.1	5.3	5.4	5.3	5.3	5.1	5.2	5.2
1990	5.4	5.5	5.3	5.0	4.4	4.4	4.1	4.1	4.2	4.8	5.1	5.0
1991	6.9	6.2	6.3	6.3	6.1	6.2	5.9	5.9	5.4	4.4	4.1	3.8
1992	1.5	1.6	1.5	1.6	1.4	1.1	1.2	1.1	1.3	1.5	1.7	2.1
1993	2.1	2.3	1.9	1.8	1.8	1.6	1.7	1.8	1.8	1.9	1.9	1.7
1994	1.3	0.2	0.2	0.2	-0.2	0.0	0.1	0.1	0.2	-0.2	-0.1	0.2
1995	0.6	1.9	2.2	2.5	3.0	2.8	2.5	2.3	2.3	2.4	2.0	1.8
1996	1.6	1.3	1.4	1.4	1.4	1.4	1.2	1.4	1.5	1.8	2.0	2.2
1997	2.1	2.2	2.0	1.7	1.5	1.7	1.7	1.9	1.6	1.5	0.8	0.7
1998	1.1	1.0	0.9	0.8	1.1	1.0	1.0	0.8	0.7	1.0	1.2	1.0
1999	0.6	0.7										

Table A.63 The Electricity Price Index for Canada 1987-1998, 1996=100

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Jan	102.4	107	110.9	116.2	133.5	127.9	132.5	137.5	104.7	104.7	106.1	107.7
Feb	102.8	107.2	111.1	116.5	133.5	127.9	132.7	138.1	104.7	104.7	106.1	107.7
Mar	103	107.3	111.2	116.7	133.5	128.2	132.7	138.2	104.7	104.9	106.1	107.7
Apl	103.4	107.4	111.5	117.6	134.1	127.6	133.3	136.3	103.4	105.3	106.7	107.7
May	104.9	108.7	113.2	120	137.5	128.3	133.4	136	103.4	105.8	106.7	108.2
Jun	104.9	108.7	113.2	120.2	137.5	128.3	133.4	136	104.5	105.8	106.8	108.2
Jul	104.8	108.7	113.2	120.6	137.9	128.9	133.7	136.1	104.5	105.9	107	
Aug	104.9	108.7	113.3	120.7	138	128.9	133.7	136.2	104.5	105.9	107	
Sep	104.9	108.7	113.3	120.7	138	128.9	133.6	136.1	104.5	105.9	107.2	
Oct	104.9	108.7	113.3	120.7	138	129.1	134.1	136.1	104.5	106.1	107.4	
Nov	104.9	108.7	113.7	120.7	137.8	129.6	135.7	136.9	104.5	106.1	107.4	
Dec	104.9	108.7	113.7	120.7	137.8	130.1	136.4	137.8	104.5	106.1	107.4	

Table A.64 The Electricity Price Index for Canada 1987-1998, 1998=100

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Jan	0.949	0.992	1.028	1.077	1.237	1.185	1.228	1.274	0.970	0.970	0.983	0.998
Feb	0.953	0.994	1.030	1.080	1.237	1.185	1.230	1.280	0.970	0.970	0.983	0.998
Mar	0.955	0.994	1.031	1.082	1.237	1.188	1.230	1.281	0.970	0.972	0.983	0.998
Apl	0.958	0.995	1.033	1.090	1.243	1.183	1.235	1.263	0.958	0.976	0.989	0.998
May	0.972	1.007	1.049	1.112	1.274	1.189	1.236	1.260	0.958	0.981	0.989	1.003
Jun	0.972	1.007	1.049	1.114	1.274	1.189	1.236	1.260	0.968	0.981	0.990	1.003
Jul	0.971	1.007	1.049	1.118	1.278	1.195	1.239	1.261	0.968	0.981	0.992	
Aug	0.972	1.007	1.050	1.119	1.279	1.195	1.239	1.262	0.968	0.981	0.992	
Sep	0.972	1.007	1.050	1.119	1.279	1.195	1.238	1.261	0.968	0.981	0.994	
Oct	0.972	1.007	1.050	1.119	1.279	1.196	1.243	1.261	0.968	0.983	0.995	
Nov	0.972	1.007	1.054	1.119	1.277	1.201	1.258	1.269	0.968	0.983	0.995	
Dec	0.972	1.007	1.054	1.119	1.277	1.206	1.264	1.277	0.968	0.983	0.995	

Table A.65 The Electricity Price 1987-1998, $/kWh

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Jan	0.0408	0.0426	0.0442	0.0463	0.0532	0.0510	0.0528	0.0548	0.0417	0.0417	0.0423	0.0429
Feb	0.0410	0.0427	0.0443	0.0464	0.0532	0.0510	0.0529	0.0550	0.0417	0.0417	0.0423	0.0429
Mar	0.0410	0.0428	0.0443	0.0465	0.0532	0.0511	0.0529	0.0551	0.0417	0.0418	0.0423	0.0429
Apl	0.0412	0.0428	0.0444	0.0469	0.0534	0.0509	0.0531	0.0543	0.0412	0.0420	0.0425	0.0429
May	0.0418	0.0433	0.0451	0.0478	0.0548	0.0511	0.0532	0.0542	0.0412	0.0422	0.0425	0.0431
Jun	0.0418	0.0433	0.0451	0.0479	0.0548	0.0511	0.0532	0.0542	0.0416	0.0422	0.0426	0.0431
Jul	0.0418	0.0433	0.0451	0.0481	0.0550	0.0514	0.0533	0.0542	0.0416	0.0422	0.0426	
Aug	0.0418	0.0433	0.0452	0.0481	0.0550	0.0514	0.0533	0.0543	0.0416	0.0422	0.0426	
Sep	0.0418	0.0433	0.0452	0.0481	0.0550	0.0514	0.0532	0.0542	0.0416	0.0422	0.0427	
Oct	0.0418	0.0433	0.0452	0.0481	0.0550	0.0514	0.0534	0.0542	0.0416	0.0423	0.0428	
Nov	0.0418	0.0433	0.0453	0.0481	0.0549	0.0516	0.0541	0.0546	0.0416	0.0423	0.0428	
Dec	0.0418	0.0433	0.0453	0.0481	0.0549	0.0518	0.0544	0.0549	0.0416	0.0423	0.0428	

Table A.66 Input PDFs for Risk Simulation

Sensitive Variable	Unit cost [$/kW]	Efficiency [%]	Escalation Rate of OC [%]
Distribution	Lognormal	Uniform	Logistic
@RISK Description	RiskTlognorm(0.043,0.004,0.04,0.06)	RiskUniform(0.75,0.95)	RiskLogistic(0.0016,0.0028)
Minimum	0.04000113	0.75001200	0.16335500
Maximum	0.05976451	0.94999130	0.16335500
Mean	0.04452742	0.85000000	0.16335500
Std Deviation	0.00313909	0.05773493	0.50760700
Variance	0.00000985	0.00333332	0.25766500