CO_2 Disposal Study

Volume 1.0 Summary Report
AOSTRA

April 1993

Alberta
OIL SANDS TECHNOLOGY
AND RESEARCH AUTHORITY

OIL SANDS TECHNOLOGY
AND RESEARCH AUTHORITY

(403) 297-3380 • Fax (403) 297-3638
18th Floor, McFarlane Tower
700 - Fourth Avenue S.W.
Calgary, Alberta, Canada
T2P 3J4

AOSTRA DISCLAIMER

The technical information and data presented in the following volumes:

- Volume 1 - Operators Summary Report
- Volume 2 - CO_2 Capture - Design and Estimates
- Volume 3 - Reservoir Studies
- Volume 4 - Field Facilities - Design and Estimates
- Volume 5 - Economic Analysis

is the property of the Alberta Oil Sands Technology and Research Authority (AOSTRA) and shall be held confidential by the recipient.

AOSTRA does not warrant the contents of the report and neither does it warrant the usefulness for any particular purpose of any of the technical information and data therein contained.

LIST OF VOLUMES

Volume 1.0 - Summary Report
AOSTRA

Volume Contents

Volume 2.0 - CO2 Capture - Design and Estimates
SNC Inc.

Volume Contents

Volume 3.0 - Reservoir Studies
TCA Reservoir Engineering Services Inc.

Volume Contents

Volume 4.0 - Field Facilities - Design and Estimates
Optima Engineering and Constructors Inc.

Volume Contents

Volume 5.0 - Economic Analysis
AOSTRA

Volume Contents

TABLE OF CONTENTS

TABLE OF CONTENTS

List of Figures

List of Tables

1.0 SUMMARY AND
CONCLUSIONS

1.0 SUMMARY AND CONCLUSIONS

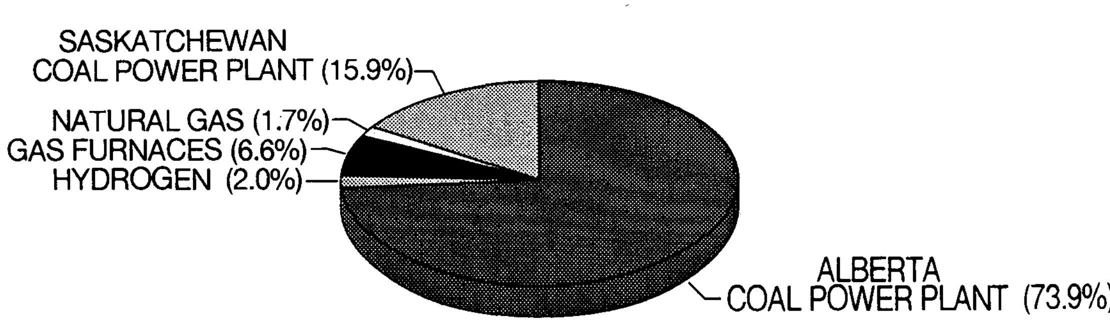
The task of this study was to quantify the potential for CO_2 capture and use for enhanced oil recovery at a scale sufficiently large to have an impact on the rate of growth of CO_2 emissions. The specific target was 50,000 (t/d), about 15% of the current emission rate in Alberta.

The study reviewed CO_2 capture from a variety of major emission sources, CO_2 flooding of a variety of reservoirs for enhanced oil recovery and disposal. The economic justification for implementing such projects was estimated based on the costs for CO_2 capture and benefits from enhanced oil recovery.

1.1 CO_2 CAPTURE:

It is feasible to capture large quantities of CO_2 from major emission sources. A variety of sources were studied including power plants, industrial furnaces and gas plants. The target of 50,000 t/d was met. Coal fired power plants provided the bulk of the captured CO_2. (See Fig. 1.1)

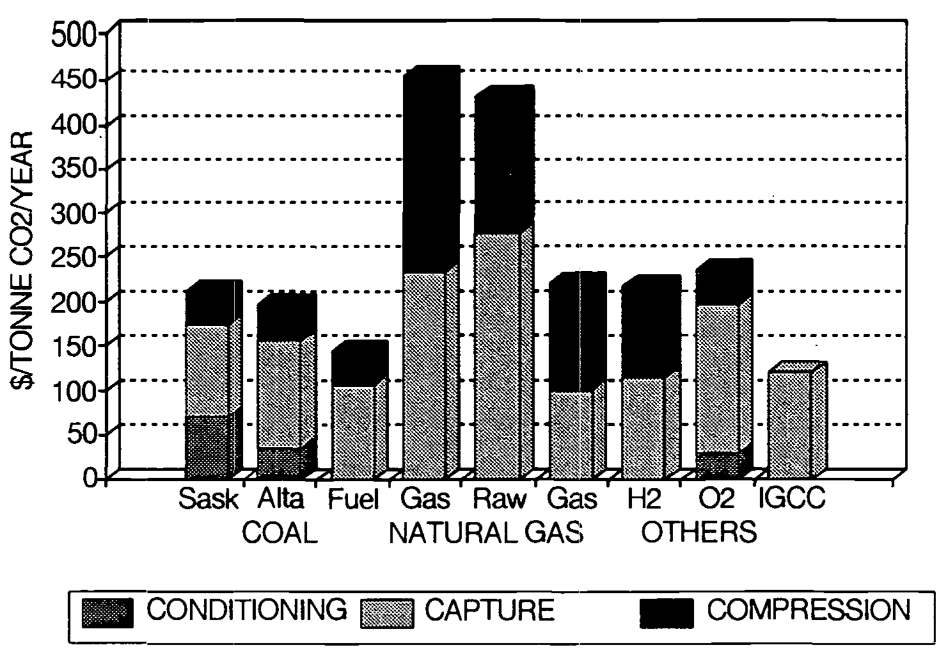
Fig 1.1 SELECTED CO2 SOURCES



A variety of capture processes were selected for the study depending on the CO_2 purity, concentration, and pressure of the source stream. Chemical absorption using amine (MEA) was the dominant process for capturing CO_2 from flue gas streams. This process is used commercially in many natural gas plants and has been demonstrated for CO_2 removal from flue gas.

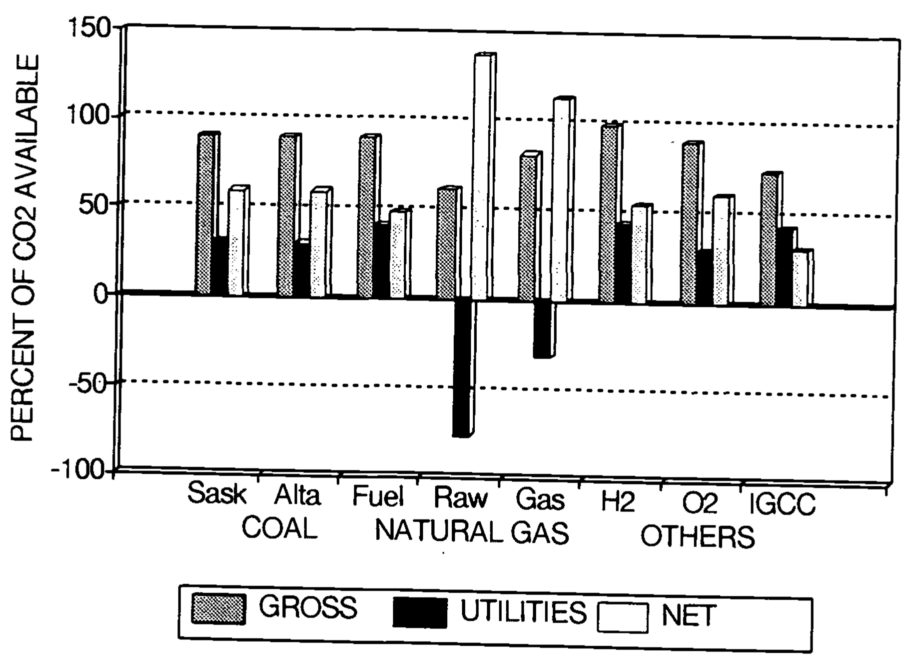
For the cases studied the cost of CO_2 capture is high. It ranges from \$40 to \$76/tonne (\$2 to \$4/mscf) depending on the capture source, process and the economic parameters. The capital costs are high totaling \$3.8 billion for the selected sites capturing 50,685 t/d CO_2. The operating costs totaled \$0.5 billion/year. For a consistent set of economic parameters, the cost variation between cases was not large except for Case 3A, the small scale gas fired furnaces, which is high and Case 7 the hypothetical IGCC Power Plant, which is low. Otherwise the benefits of higher purity and concentration in the small scale cases were offset by the economies of scale for the large scale cases. In spite of the need for flue gas conditioning, the coal fired power plants offered the lowest CO_2 capture costs.

Fig 1.2 NORMALIZED CAPITAL COST



Capture and compression of CO_2 are energy intensive processes resulting in high CO_2 emissions from the utilities required to drive the processes. The steam and electricity requirements for the capture and compression results in CO_2 emissions ranging from 30% to 45% of the quantity of CO_2 captured. The gross CO_2 captured is the amount of CO_2 captured and delivered to the oil field. The net CO_2 captured is the measure of CO_2 emission reduction. The net CO_2 is the gross CO_2 less the CO_2 emitted to drive the processes. Even with capture efficiencies of 90% the typical net CO_2 reduction in emissions is 50% to 60% of the CO_2 available for capture. The gross CO_2 may be the basic parameter for capture and enhanced oil recovery, but the net CO_2 determines the environmental effect, the impact of the rate of growth of CO_2 emissions.

Fig 1.3 CO2 CAPTURE GROSS & NET



A 600km pipeline network is required to transport the CO_2 from the capture sources to the oil fields. Pipe sizes range from 6" to 28" nominal diameter. The CO_2 is transported as a dense phase supercritical fluid at 14 MPa (2000 psi). In this state, CO_2 is like a liquid in density and a gas in viscosity.

Although the total capital cost for the pipeline system is $215 million the volume of flow is large. The unit pipeline transportation costs are low relative to the cost of capture. The costs, including operation costs and capital charges, averaged $2/t ($0.10/mscf) for the Alberta network and $0.58 to $0.76/t ($0.02 to $0.04/mscf) for the shorter lines in Saskatchewan.

1.2 CO_2 DISPOSAL IN HYDROCARBON RESERVOIRS

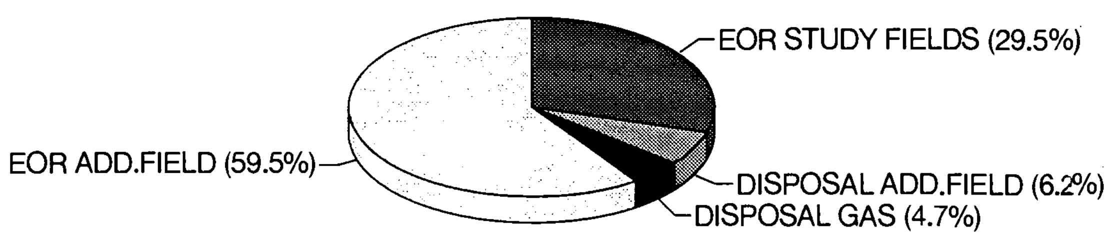
It is feasible to dispose of the target quantity of CO_2 (50,000 t/d for 15 years) in hydrocarbon reservoirs in Western Canada. A variety of reservoirs were studied including carbonate reefs and sandstone formations containing light, medium or heavy oil. EOR recovery schemes included miscible and immiscible flooding using slug, WAG, or continuous injection process.

The fields selected as case studies were expected to be sufficient to dispose of the targeted quantity but the simulation results showed, from an oil recovery perspective, better CO_2 utilization than expected. Although initial CO_2 requirements were close to those expected, the reinjection of produced CO_2 reduced the requirement for fresh CO_2. Only 29.5% of the 50,000 t/d target would be stored in the 15 year target period. The incremental oil produced from the fields studied in the selected reservoirs in the 15 year target period totaled 55.3 million m^3 (348 million barrels) averaging 10,100 m^3/d (63,500 BPD). The CO_2 utilization rate averaged 2.1 tonnes CO_2/m^3 oil (6.3 MSCF/BBL).

The fields selected for detailed case study are representative of many similar reservoirs. A review was undertaken to identify other analogous oil fields suitable for large scale CO_2 flooding to make up the shortfall from the target of 50,000 t/d. Using size, location, and reservoir similarity as selection criteria, a further potential demand of 163 million tonnes (3100 MMSCF) of CO_2 for EOR in Alberta was identified. This is 59.5% of the target quantity. The injection and production quantities, and rates quoted above for the case studies, would be tripled to 166 million m^3 (1044 million barrels) averaging 30,300 m^3/d (190,000 BPD) if CO_2 flooding was undertaken on all the potential oil reservoirs identified.

The remaining 11% can be disposed in depleted gas fields. The disposal potential here is very large. The study included one such field which could sink 12.9 million tonnes (246 MMSCF) or 4.7%. Additional gas fields were estimated to have a capacity for 0.8 to 1.0 billion tonnes (15 to 20 BSCF), which is 3 to 4 times the target volume.

Fig 1.4 CO2 STORAGE
OVER 15 YEAR PERIOD



These estimates are based on known hydrocarbon reservoirs where the reservoir geology is known and trapping of fluids has been demonstrated over geological time periods. Not included are non hydrocarbon bearing rock formations in the western sedimentary basin, or aquifers where water can be displaced. The storage potential of these formations is expected to be an order of magnitude greater than the hydrocarbon reservoirs.

1.3 EOR FIELD FACILITIES

CO_2 flooding for enhanced oil recovery requires a large investment in field facilities. For the EOR case studies, the capital cost of the field facilities is $1.2 billion. This includes the cost of over 2000 injection and production wells, the associated injection and gathering lines and batteries, the separation and treatment of produced fluids, and the compression of recycled CO_2. The annual operating costs, not including the cost of CO_2, averaged $90 million per year.

These case studies utilized 29.5% of the target quantity of CO_2. To meet the target of 50,000 t/d these costs would be multiplied by more than three times.

It is possible to implement CO_2 flooding on such a megaproject scale in Western Canada? Technically the answer is yes. Miscible flooding using light hydrocarbons now produces over 34,000m^3/d (214,000 BPD), or 24% of Alberta's conventional oil production (Scott 1992). CO_2 flooding could be adopted on an equivalent scale. In the United States, CO_2 is the fluid of choice for miscible flooding due to the availability of low cost CO_2 from natural reservoirs. Over 22,500m^3/d (142,000 BPD) is now produced in the US through CO_2 flooding. (Hadlow 1992). Implementation of CO_2 flooding in Canada on the scale proposed in this study is limited by economics, more specifically, the cost of CO_2 vs the price of oil.

1.4 ECONOMICS

The major economic conclusion from this study is that the benefits from enhanced oil recovery provide substantial offsetting benefits against the cost of CO_2 capture. For the most favourable set of economics parameters the EOR revenue can cover the cost of CO_2 capture but for the typical cases these benefits are insufficient to totally pay for the cost of capture.

In this study the economic potential is determined by the transfer price at the oil field battery limits.

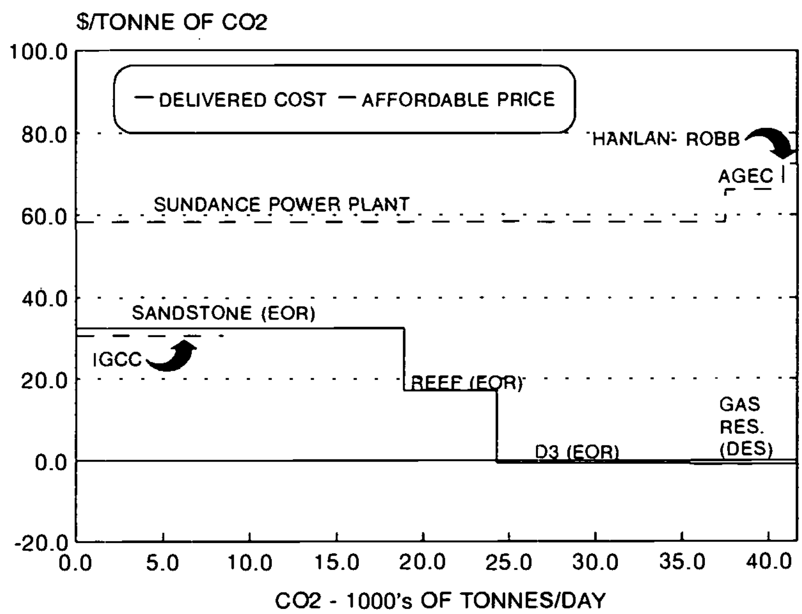
From the supplier's point of view, the transfer price is the cost to capture CO_2 and deliver it to the oil field. This delivered cost is based on operating costs and a return on the capital invested.

From the user's point of view, the transfer price is the affordable price, the price that can be paid for CO_2 as determined by the revenue from incremental oil production less the operating costs and a return on the capital invested. This affordable price is, in effect, the offsetting benefit for CO_2 utilization.

For sales of CO_2 to occur and projects to proceed on only internal economic justifications, the price the user can pay must be at least equal to the delivered cost of CO_2. The profitability of the venture is determined by how much greater the price the user can pay (price available) is compared to the delivered cost.

The figures below for typical cases summarize the delivered cost and price available for EOR. They are based on a normal business analysis for oil and utilities companies. There is a significant gap between the delivered CO_2 cost and price of CO_2 available for EOR use. As the quantity increases towards the target of 50,000 t/d, the gap widens.

Fig 1.5 ECONOMICS OF CO2 DISPOSAL IN ALBERTA

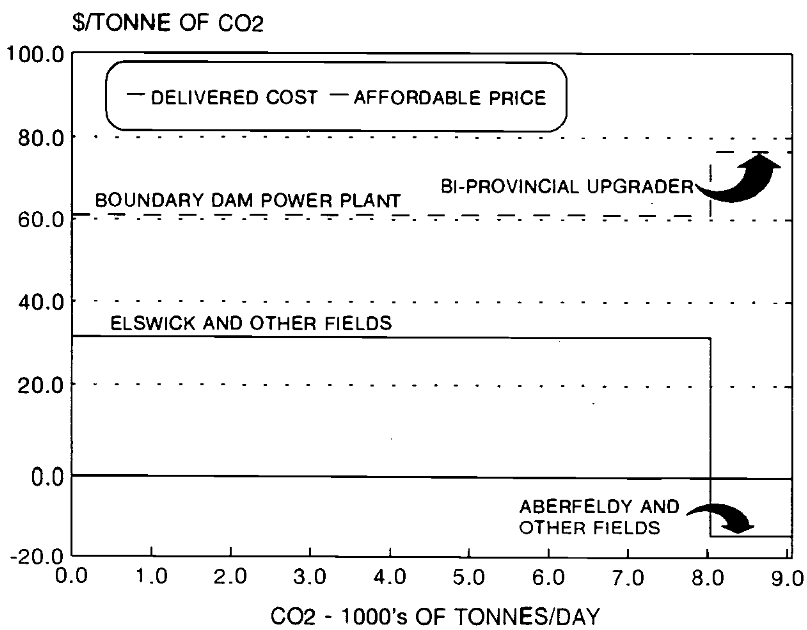


In Alberta the lowest cost is $57/tonne for CO_2 from the Sundance Power Plant and the greatest offsetting benefit (price available) is $32/tonne CO_2 for sandstone reservoirs. The smallest gap is $25/tonne CO_2. This increases to $77/tonne for disposal in depleted gas reservoirs from more costly sources.

The gap is reduced when more favourable economic assumptions are used such as social rate of return, lower return on investment requirements (5%), and low cost option such as IGCC. See section 8 and the economics report for details.

In Saskatchewan the situation is similar. For the normal business approach, the lowest capture costs at Boundary Dam Power plant are $60/tonne. The highest available revenue from EOR is $31.50 for a gap of $28.50.

FIG 1.6 ECONOMICS OF CO2 DISPOSAL IN SASKATCHEWAN



If CO_2 capture is not justified by the benefits from EOR, the justification to proceed with a project must be the environmental benefits. In this case, the measure of merit is the reduction in CO_2 emissions through implementation of the project, the net CO_2. The economic analysis in this study is based upon gross CO_2 captured. The typical gap is $25/tonne CO_2. However, the typical net CO_2 capture is only 2/3 of the gross CO_2 capture. The environmental justification would therefore be based on 2/3 of a tonne net per tonne gross. The typical gap increases by 3/2, from $25/tonne CO_2 gross to $38/tonne CO_2 net. To put these number in perspective: $38/tonne CO_2 is $2/MSCF CO_2 or $139/tonne of carbon.

1.5 ISSUES

1.5.1 Retrofit

The scope of the study was limited to the retrofit of CO_2 capture to large scale facilities in proximity to large oil fields. Some niche opportunities may have been missed. For example, older hydrogen plants which do not use Pressure Swing Absorption (PSA) for purification may have by-product CO_2 available for the cost of compression and transportation.

New plants designed for CO_2 capture may also offer lower capture costs. Integrated Gasification Combined Cycle (IGCC) power plants are such an example. The IGCC case reviewed in this study offered the lowest cost capture of CO_2. However the cost of electrical power from a new IGCC power plant would be significantly higher than the existing coal fired power plants.

New natural gas plants or hydrogen production processes optimized for CO_2 capture should offer significant reductions in the cost of CO_2 capture.

Integration of the energy requirements for CO_2 capture processes with the steam cycle of new power plants may also provide significant cost savings.

1.5.2 Reservoir Storage

The EOR simulations were optimized for oil production at minimum cost. Fresh CO_2 input and CO_2 storage were minimized. Project life was determined by oil production. CO_2 remaining in the reservoir was generally displaced by waterflooding. There may be potential for significantly higher CO_2 storage by limiting oil production or by re-injection of CO_2 into depleted oil reservoirs.

1.5.3 Market Factors

Market factors were not considered in developing the economics. It was assumed that all the CO_2 capture capacity was utilized, all the CO_2 captured was used for EOR, and all produced CO_2 was reinjected within the field or made available to other projects. Variations in demand and peak flows were not considered except in project phasing and recycle capacity limitations.

In reality there would be considerable variation in CO_2 requirements leading to shortfalls at peak periods and excess capacity at others. CO_2 disposed in depleted gas fields would be expected to minimize supply/demand imbalances but this has not been included in the economics.

1.5.4 Oil Production

Although the reservoir simulations are based on multiple zones with different parameters, the problem of reservoir heterogeneity remains. There is a risk that the simulated oil production is overestimated. In this study, the economics considered three production levels, 100%, 75% and 50% of the simulation results, with 75% being the base case.

In the Aberfeldy case, the CO_2 for immiscible flooding is transported to the oil dissolved in water. This method offers tremendous potential. The simulation results from this immiscible flood were excellent. There are concerns that the simulation results may not be proven in practice. There is a need to pilot this carbonated water process.

1.5.5 SO_2 Removal

An additional benefit of CO_2 capture is SO_2 removal. The chemical capture processes can tolerate only very low levels of SO_2, so conditioning processes have been added to the power plant cases to capture 95% to 97% of the SO_2 in the flue gas. The cost of SO_2 removal are included in the cost of CO_2 capture. The benefits have not been estimated or attributed to CO_2 capture.

1.5.6 Economic Approaches

The Social approach of calculating the economics provide significantly more attractive results than the Normal Business approach. The intent of the Social approach is to eliminate the effects of royalties, taxation and inflation. The intent is to answer the question "Is there an economic benefit to society?", rather than, "Who benefits: governments, industry or investors?"

2.0 RECOMMENDATIONS

2.1 GENERAL

If CO_2 capture is required to meet CO_2 emission stabilization targets, the use of captured CO_2 for enhanced oil recovery is recommended as the best disposal option. This may not be applicable on a global basis, but this study shows it is appropriate for Western Canada.

2.2 SPECIFIC

The following recommendations are based on the specific issues raised by this study.

2.2.1 Capture Optimization

Review cases which show the potential for reduced CO_2 capture costs through retrofit to small existing high quality sources, or through the design for CO_2 capture integrated into new sources.

2.2.2 Storage Optimization

Review the EOR simulations to determine if different operating strategies, project lives, or CO_2 reinjection can provide more CO_2 storage and disposal.

2.2.3 Immiscible Flooding

Develop a pilot project to demonstrate immiscible flooding using CO_2 dissolved in water.

3.0 INTRODUCTION

3.0 INTRODUCTION

3.1 BACKGROUND

The general responses proposed to reduce the emissions of CO_2 to the atmosphere are conservation, improved efficiency, and fuel substitution. These are valid responses, but they may be limited by the rate of application and the extent of possible changes. To meet short term goals involving major CO_2 emission reductions, other responses may need to be adopted. For different regions, there are alternatives that may be more attractive. This is particularly true in Western Canada where the economy is based on the production, utilization, and sale of hydrocarbons such as coal, oil, and natural gas. It may be more effective to reduce CO_2 emissions locally through capture, utilization, and disposal rather than avoiding CO_2 production from the use of hydrocarbon fuels.

There are good reasons why the capture and disposal option fits the situation in Western Canada. The first and obvious reason is the importance of hydrocarbon energy to the regional economy. Oil production at 250,000m^3/d (1.6 million b/d) allows Canada, on balance, to be self-sufficient in oil. Natural gas production from Western Canada is 300 million m^3/d (10.5 billion SCF/d). Half of this is used to supply the Canadian demand and the other half is exported to meet 10% of the U.S. demand. Coal production in Alberta is over 30 million tonnes per year. Over 70% of this is used locally for electric power generation. The remaining 30% is exported primarily for metallurgical use. The oil sands of Alberta contain over one trillion barrels of bitumen and heavy oil. This is one of the largest known hydrocarbon deposits in the world. About one third of Canada's oil production is now from these reserves. Half of this is upgraded to synthetic crude oil (40,000m^3 or 250,000 b/d), the other half sold as heavy oil bitumen diluted with light hydrocarbons for pipeline shipment. Although many may consider these hydrocarbon reserves and fossil fuel production as part of the greenhouse gas problem, they may offer part of the solution through the capture, utilization and disposal of CO_2.

Capture is facilitated in Western Canada because the majority of the emissions are from large point sources. For example, in Alberta one third of the CO_2 emissions are from coal fired power plants and one third are from the oil and gas industry. Capture from these large sources should be easier and less costly than from smaller dispersed sources. The capture processes are generally the same as the processes used to purify natural gas. This chemical absorption technology is practiced in hundreds of gas processing plants in Western Canada.

Disposal is facilitated by the large underground reservoirs in the Western Canadian sedimentary basin. The porosity, permeability and stratigraphic traps which held oil and gas over geological time can be used for storage of carbon dioxide. In fact, the potential for storage goes far beyond the oil and gas reservoirs and applies to many of the sedimentary deposits in Western North America. The major advantages of utilizing oil and gas reservoirs are that the geology is better known, the storage capability has been demonstrated over geological time and enhanced oil recovery benefits may be obtained. Carbon dioxide at reservoir pressures is a dense supercritical fluid which can mix miscibly with oil. The miscible fluid can displace virtually all the oil that it contacts in the reservoir leading to substantially improved oil recoveries and economic benefits.

The capture, utilization, and disposal option is, therefore, of significant interest in Western Canada. Here there are the sources, the sinks, the technology, and a potential economic incentive.

The option to limit CO_2 emissions through CO_2 capture is generally recognized as an abstract possibility, but is often dismissed in policy discussions because it is not universally applicable and there is a lack of data on feasibility, potential, costs, and benefits. This study was undertaken to correct this deficiency, to define the technology for CO_2 capture, to quantify the amount of CO_2 that can be stored in underground reservoirs, to estimate the cost of capture, purification and transmission and to project the benefits from CO_2 flood enhanced oil recovery.

3.2 PROJECT INITIATION

In 1990 Alberta Oil Sands Technology and Research Authority (AOSTRA) accepted a proposal from industry leaders to undertake a study with the following objective: *to determine the technical and economic feasibility of reducing the rate of growth of CO_2 emissions by collecting CO_2 from major sources and disposing of the collected gases in hydrocarbon bearing reservoirs where hydrocarbon recovery benefits could be obtained.*

The original project sponsors, Imperial, Shell, TransAlta Utilities and the Coal Association were soon joined by more than twenty others representing all aspects of the question. The participants, listed below, include oil and gas companies, power and coal companies, CO_2 supply companies, and the government groups, both federal and provincial, representing research, energy, and environment departments.

TABLE 3.1
STUDY PARTICIPANTS

AOSTRA	Husky Oil
AERCB	Liquid Air
Alberta Department of Energy (AOCRT)	Liquid Carbonic
Alberta Research Council*	Mobil Oil Canada
Alberta Power Limited	Norcen*
Amoco Canada	Nova Husky Research
Canadian Oxy	Petro-Canada
Canadian Petroleum Association*	Sask Oil
Coal Association of Canada*	Saskatchewan Research Council*
Dow Chemical Canada	Sask Power
Edmonton Power	Shell Canada
EMR - CANMET	Suncor
Environment Canada	TransAlta Utilities
Imperial Oil Resources (Esso)	Westcoast Petroleum
Gulf Canada	

* Phase I Only

The initial phase of the study was the definition phase where the participants determined the scope of work, set the budget and schedule, and selected the engineering contractors for the Phase II work. Phase I was complete and Phase II initiated in May, 1991.

The project budget for Phase I, $50,000, was equally split among the participants. For Phase II, the budget was $600,000, one half paid by the Alberta Government and the other half shared equally among the remaining twenty one participants. The Alberta Government share ($300,000) was paid by AOSTRA ($245,000), AOCRT ($30,000) and AECRB ($25,000).

3.3 COMMITTEES

A management committee was established with representatives from all participants to direct the project. With the large number of diverse participants, there was also a need for effective working sub-committees to maximize the technical contributions from the participants. To facilitate the transfer of information and expertise to the project, the following committees were setup with volunteers from the participants.

- CO_2 Recovery, Purification, and Distribution
- EOR and Underground Disposal
- Alternative Disposal/Applied Research
- Contractor Selection
- Economics
- Communications

Each committee elected a chairman, defined objectives, and set up methods to accomplish their tasks.

In Phase I, the major task was to define the scope for the project by gathering data, reviewing alternatives, and recommending specific cases. In Phase II, the major task was to review the various contractors' work progress and technical reports. Since the project covered such a range of scientific engineering disciplines and business interests, the committee system proved to be a very effective way of focusing the expertise from the diverse group of participants on the specific elements of the project. The project could not have been accomplished effectively without this focused support from the participants.

3.4 SCOPE OF WORK

The objective statement was translated into a specific project missions statement which led to specific work packages.

3.4.1 Objective

To determine the technical and economic feasibility of reducing the rate of growth of CO_2 emissions by collecting CO_2 from major sources and disposing of the collected gases in hydrocarbon bearing reservoirs where hydrocarbon recovery benefits could be obtained.

3.4.2 Mission

To capture 50,000 tonnes per day (951 MMSCF/D) and use to optimum benefit in enhanced oil recovery in Alberta and Saskatchewan, beginning in the year 2000 and continuing for a period of at least 15 years.

The specific quantity 50,000, tonnes per day, was chosen as a quantity large enough to have a significant impact on CO_2 emission, but not so large that it became an impossible target. To put this quantity in perspective, 50,000 tonnes/day is about 15% of the current total CO_2 emissions for Alberta or about 12% of the Alberta, Saskatchewan total. It represents about half the emissions from either the electrical power industry or the oil and gas industry. CO_2 use in the U.S. for enhanced oil recovery is currently about 125,000 tonnes/day (Hadlow 1992), so the potential use of 50,000 tonnes/day in Canada seemed to be a reasonable target.

The specific time frame allowed sufficient time for project definition and implementation but recognizes that CO_2 capture is a short term solution tied to specific industries and technologies for both sources and sinks.

3.4.3 Work Packages

The scope of work was based on the CO_2 sources, capture technologies and reservoirs listed on Table 3.2

TABLE 3.2
SCOPE OF WORK SUMMARY

SOURCE	CAPTURE TECHNOLOGY	EOR APPLICATION
Power plant (Boundary Dam, SaskPower)	Boundary Dam Process	Steelman, Weyburn, Midale
Power Plant (Sundance, TransAlta)	Amine	Pembina, Cooking Lake, Rainbow or other
Industrial Complex (Ethylene Plant, Novacor)	Amine	Cooking Lake, Redwater
Natural Gas Plant (Petro Canada Hanlan Robb)	Selexol	Pembina
Hydrogen Plant (Bi-Provincial Upgrader, Husky)	PSA & Amine	Lloydminster

The selection of sources was based on quality, quantity, and location. Represented are the largest sources (coal fired power plants), the most abundance sources (natural gas fired furnaces), and the richest sources (petrochemical byproducts).

Reservoir selection was based on location, reservoir type, crude oil characteristics, and applicable EOR process.

Four work packages were defined and sent out for bids from appropriate engineering contractors.

The contract for design and cost estimation of the CO_2 capture facilities was completed by SNC Inc. for a fixed price of $283,000.

The contract for reservoir simulation to estimate the CO_2 utilization and enhanced oil recovery was completed by TCA Reservoir Engineering Services for a fixed price of $174,000.

The contract for the design and cost estimation of the field facilities was completed by Optima Engineers and Constructors Inc. for a fixed price of $32,200.

The Economics work package was completed by AOSTRA. AOSTRA was also the project operator and provided a Project Manager to integrate the various work programs.

The overall project budget is outlined in Table 3.3.

TABLE 3.3
OVERALL PROJECT BUDGET

Consultants	
SNC	$283,000
TCA	174,000
OPTIMA	30,000
AOSTRA	14,000
Project Management	48,000
Operator Services	
Data Acquisition	5,000
Program Support	15,000
Direct Cost	9,000
Sub Total	$578,000
Overhead @ 2-1/2%	14,000
Contingency	8,000
Total	**$600,000**

4.0 CO_2 SOURCES

4.0 CO_2 SOURCES

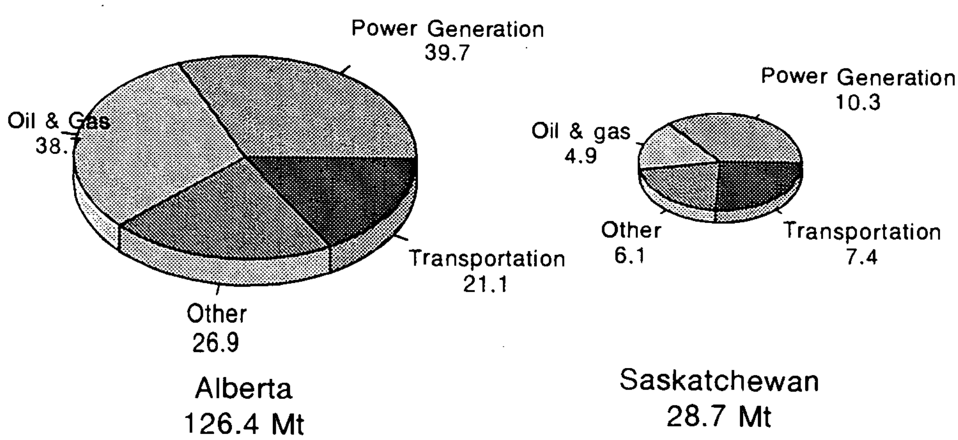
Canada accounts for approximately 2% of the world total anthropogenic carbon dioxide (CO_2) emissions (Legg, 1992). Within Canada, Ontario is the highest source of CO_2 and Alberta is second highest, emitting 126 Mt of CO_2 in 1990 (Jacques, 1992). Alberta is also the highest per capita emitter of CO_2 in Canada (Alberta Energy, 1990). Electrical generation, from coal, natural gas processing and transmission, oil production and refining, and petrochemical manufacturing cause this high emission factor.

A breakdown of Alberta emissions is presented in Figure 4.1. Power generation accounts for 31% of CO_2 emissions and oil, gas, and petrochemicals about 31%. Together these industries account for 62% of Alberta's emissions.

A similar breakdown of Saskatchewan CO_2 emissions is also presented in Figure 4.1. The combined emissions from power generation and oil, gas and petrochemicals is 53% of Saskatchewan's total.

Fig 4.1 CARBON DIOXIDE EMISSIONS

1990 (Million Tonnes)



Jaques 1992

In order to meet the goal of removing 50,000 tonne/day of CO_2, major sources of CO_2 in both Alberta and Saskatchewan were reviewed. Table 4.1 presents the list of major CO_2 sources reviewed by the Management Committee during the early stages of the study. The criteria used to select the study facilities were:

1. Quality and Quantity

   A. Largest sources - These are Novacor/AGE, Bi-Provincial Upgrader (BPU), and coal-fired power plants. The BPU and Novacor are higher quality sources because their flue gases do not contain SO_2 and particulates.

   B. Most abundant sources - These sources include natural gas fired furnaces and natural gas processing plants. Hydrogen sulphide presents a problem. The Petro-Canada Hanlan Robb gas plant is an example.

   C. Richest sources - These sources are hydrogen processing plants which can produce streams with high percentages of CO_2.

2. Strategically Located

   The sites should be close to potential enhanced oil recovery (EOR) sites.

3. Readily Available Information

   Information on plant layouts, process CO_2 sources and process diagrams must be readily available.

4. Retrofit

   Only existing sources of CO_2 were included. No new facilities were studied in detail. Those facilities capable of being retrofitted for CO_2 removal will be emphasized.

On the basis of the above selection criteria the facilities chosen for study were:

Case 1 Boundary Dam (Saskatchewan) Coal-Fired Power Plant

Case 2 Sundance (Alberta) Coal-Fired Power Plant

Case 3 Novacor Chemicals/AGEC Utility Plants, Joffre, Alberta

Case 4 Hanlan Robb Gas Plant, Alberta

Case 5 Bi-Provincial Upgrader Hydrogen Plant, Lloydminster

Case 6 Sundance/Argonne Process

Case 7 Integrated Gasification Combined Cycle (IGCC)

A review of the facilities (Table 4.2) shows that Case 1 Boundary Dam and Case 2 Sundance represent large sources of low quality CO_2. At Boundary Dam the flue gas is about 14% CO_2 with the one unit studied (293 MW) producing about 8,920 tonnes/day. Sundance has six units producing about 45,000 tonnes/day of CO_2. The concentration of CO_2 in the power plant flue gases is about 14%. Both Boundary Dam and Sundance flue gas streams contain particulates, sulphur dioxide (SO_2) and nitrogen oxides (NOx) which affect the conditioning and capture processes chosen.

Case 3 Novacor Chemicals Alberta Gas Ethylene Plant at Joffre, Alberta uses natural gas and process off gas to fuel several heaters, furnaces and boilers. Furnaces and fired boilers provide most of the CO_2 (about 3700 tonnes/day). Case 3A was developed to recover 100 tonnes/day of CO_2 recovery from a flue gas stream smaller than in Case 3. The CO_2 concentration in the flue gas is 8.3%.

Case 4A deals with the Hanlan Robb gas plant owned by Petro-Canada. The study allows for the shutdown of the existing amine unit and replacement with two Selexol units for removal of hydrogen sulphide first (H_2S) and then CO_2.

Case 4B estimates the costs of CO_2 removal adding a Selexol unit for H_2S removal and using the existing amine unit for CO_2 removal.

In both Cases 4A and 4B approximately 1023 tonnes/day of CO_2 are available for capture.

Case 5 develops costs for removal of CO_2 from the hydrogen plant vent gases of the Bi-Provincial Upgrader at Lloydminster, Saskatchewan. During the steam/methane reforming process a 47% vol CO_2 tail gas leaves the pressure swing adsorption (PSA) unit. This high quality gas is treated to remove CO_2. Potentially, 1033 tonnes/day of CO_2 are available for capture.

Case 6 is a variation on Case 2. By using the Argonne Process in the Sundance Power Plant boiler to burn the coal in an atmosphere of pure oxygen diluted to 30% with recycled CO_2, a flue gas with 80% CO_2 is produced. After SO_2 removal a slipstream of flue gases from the boiler is diverted to the CO_2 recovery plant where about 37,440 tonnes CO_2/day are produced.

Case 7 was added to the study to develop comparable information for an Integrated Gasification Combined Cycle power plant with CO_2 removal. The use of gasification and the water gas shift reaction produces a flue gas with high concentrations of hydrogen (50%) and carbon dioxide (35%). IGCC is an exception to the retrofit criteria as no such facilities exist in Alberta or Saskatchewan at this time. An overview for IGCC was added to the scope of work because this technology is expected to be used for future electrical power development and it has the potential for low cost CO_2 capture.

The processes and facilities for CO_2 capture are presented in the next section of this report.

TABLE 4.1

SUMMARY OF MAJOR CO_2 SOURCES REVIEWED BY THE COMMITTEE

PLANT	SOURCE	QUANTITY (T/D) CO_2	QUALITY (% Vol CO_2 wet)
Power Plants:			
Poplar River, Sask.	Coal Fired	13,990	12.7
Boundary Dam, Sask.	Coal Fired	22,280	13.1
Shand, Sask.	Coal Fired	6,610	12.2
Queen Elizabeth, Sask.	Gas Fired	3,390	13.4
Sundance, Alberta	Coal Fired	41,600	13.4
Keephills, Alberta	Coal Fired	16,400	13.4
Wabamun, Alberta	Coal Fired	13,000	13.4
Genesee, Alberta	Coal Fired	10,430	12.0
Queen Elizabeth, Sask.	Gas Fired	2,040	9.0
Success, Sask.	Gas Fired	570	3.3
Landis, Sask.	Gas Fired	1,050	3.3
Meadow Lake, Sask.	Gas Fired	670	3.3
Clover Bar, Alberta	Gas Fired	2,497	9.5
Rossdale, Alberta	Coal Fired	802	9.6
Battle River, Alberta	Coal Fired	18,000	12.6
H.R. Milner, Alberta	Coal Fired	2,800	11.8
Sheerness, Alberta	Coal Fired	16,350	12.8

TABLE 4.1 Cont'd

PLANT	SOURCE	VOLUME OF CO_2 (t/d)	QUALITY (% Vol. CO_2 wet)
Petrochemical Plants:			
Alberta Gas Chemicals, Medicine Hat	Methanol Reformer & Boilers	1653	flue
Celanese, Edmonton			
Methanol plant -	Reformer & Boilers	1368	flue
Chemical plant -	Boilers & Power Plant	1223	flue
CANCARB, Medicine Hat	Carbon Black		
	- Reactor Furnace	123	flue
	- Incinerator	184	flue
Union Carbide, Prentiss	Ethylene Glycol		
	- CO_2 Regeneration Vent	551	53
	- Boilers	90	7.5
Dow Chemical, Fort Sask.	Boilers, Incinerator		
	Power Plant	2550	flue
	Ethylene Plant		high
AGEC Joffre	Ethylene, Boilers	3105	flue
	Hydrogen Plant, Stripped from Ethane	214	99
Oil Sands & Upgraders:			
Syncrude Mildred Lake	Coke	3300	
	Process Gas	6600	
	Natural Gas	2600	
	Hydrogen Plant	2700	48/95
Suncor Tar Island	Coke	5600	9.5
	Process Gas	2000	2.4
	Natural Gas	600	2.4
	Hydrogen Plant	700	66
New Grade Regina	Natural Gas	2200	flue
	Hydrogen Plant	1800	55
Bi-Provincial Upgrader Lloydminster	Hydrogen Plant	1000	45

TABLE 4.1 Cont'd

PLANT	SOURCE	VOLUME OF CO_2 (t/d)	QUALITY (% Vol. CO_2 wet)
Fertilizer Plants:			
CFI, Medicine Hat	CO_2 Vent	1500	93.7
	Reformer Stacks	2120	9
	Boiler	450	flue
Cominco, Calgary	Boiler	42	flue
Cominco, Carseland	CO_2 Vent	342	90
	Reformer stacks	756	5.9
	Boiler	439	7.1
Saferco, Belle Plain Saskatchewan	CO_2 Vent	N/A	N/A
	Reforemer Stacks	N/A	N/A
	Boiler	N/A	N/A
Cominco, Joffre	Boiler	43	flue
Esso, Redwater	CO_2 Vent	1595	90
	Reformer & Boilers	268	flue
Sherritt Gordon, Fort Saskatchewan	CO_2 Vent	667	90
	Reformer & Boilers	1959	flue
Refineries:			
Esso Petroleum Products, Edmonton		2500	N/A
Petro-Canada, Edmonton		1900	N/A
Shell, Scotford		800	N/A
Consumers Co-op, Regina*		700	N/A
Parkland Industries, Bowden**		100	N/A
Turbo, Calgary		400	N/A
Husky, Lloydminster		300	N/A

TABLE 4.1 Cont'd

PLANT	SOURCE	QUANTITY (t/d) CO_2	QUALITY (% Vol CO_2 wet)
Natural Gas Plants:			
Husky, Ram River	Formation	1280	6.99
Shell, Waterton	Formation	1196	7.85
Petro Canada, Robb	Formation	1033	9.54
Chevron, Kaybob	Formation	645	3.40
Mobil, Harmatten	Formation	641	4.74
Shell, Jumping Pond	Formation	633	5.94
Petrogas, Crossfield	Formation	378	7.90
Shell, Burnt Timber	Formation	377	7.96
Amoco, Crossfield	Formation	305	6.81
Amoco, Vulcan	Formation	303	14.62
Gulf, Homeglen-Rimbey	Formation	303	2.14
Home, Carstairs	Formation	296	5.69
Amoco, Windfall	Formation	254	3.66
Amoco, Edson	Formation	214	3.25
Other Industries:			
<u>Lime & Cement</u>:			
Alcan Main Stack Calcinated coke	423	10	
Continental Lime Exshaw	Lime Fuel	490 N/A	N/A
Inland Cement*** Edmonton	Cement Fuel	1500 N/A	 20.0

TABLE 4.1 Cont'd

PLANT	SOURCE	VOLUME OF CO_2 (t/d)	QUALITY (% Vol. CO_2 wet)
Lafarge*** Exshaw	Cement Fuel	2500 N/A	 20.0
Pulp & Paper Mills:			
Weldwood, Hinton	Boilers & Kiln	2788	8.8
Weyerhaeuser, Grande Prairie	Stacks	2281****	N/A
Daishowa, Peace River	Stacks	4750****	N/A
Weyerhaeuser, Prince Albert	Stacks	1875****	N/A

Note:

Refinery emissions based on rated capacity (June 1988) 100% on-stream 5% crude equivalent fuel use as methane

* Some overlap with upgrader

** Processes natural gas condensate

*** These values are based on an assumed distribution of provincial production.

**** These values are based on a ratio of 2.5 Tonnes of CO_2 per Tonne of pulp produced, calculated from Weldwood stack information provided by Environment Canada.

TABLE 4.2
FACILITIES SELECTED FOR CASE STUDIES

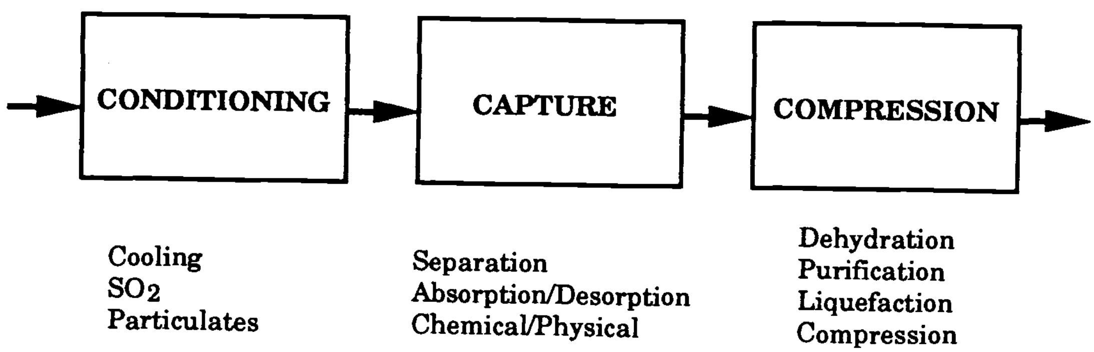
Case No.	Location	CO_2 Source	Characteristics	CO_2 Concentration (%)	CO_2 Available Tonnes/day for Capture
1	Boundary Dam Saskatchewan	Coal-Fired Power Plant	Large Quantity Low Quality Close to EOR	14	8,927
2	Sundance Alberta	Coal-Fired Power Plant	Large Quantity Low Quality Close to EOR	14	45,000
3	Novacor Joffre, Alberta	Natural Gas Utilities	Large Quantity Low Quality Close to EOR	4-9	3,717
3A*	Novacor Joffre, Alberta	Natural Gas Utilities	Small Quatity Low Quality Close to EOR	8	111
4A	Hanlan Robb Alberta	Raw Natural Gas (Selexol)	Small Quantity Low Quality Dispersed Sites	10	1,023
4B	Hanlan Robb Alberta	Raw Natural Gas (Existing Amine Unit)	Small Quantity Low Quality Dispersed Sites	10	1,023
5	Biprovincial Upgrader Lloydminster, Saskatchewan	Hydrogen Plant	Small Quantity High Quality Close to EOR	47	1,033
6	Sundance Alberta	Coal-Fired Power Plant (Argonne)	Large Quantity High Quality Close to EOR	80	40,500
7	Alberta	Coal-Fired IGCC Power Plant	Large Quantity High Concentration Potential Low Cost	35	5210

5.0 CO_2 CAPTURE

5.0 CO_2 CAPTURE

The process used for capture of CO_2 from emission sources depends on the pressure and concentration of CO_2 and the level of impurities which interfere with the capture process. The process steps generally involved conditioning, capture, and compression.

FIGURE 5.1 CO2 CAPTURE PROCESSES



5.1 CONDITIONING

Flue gas streams, particularly from coal fired power plants, require conditioning to cool the streams and remove sulfur dioxide and particulates which will interfere with the subsequent capture process. Although normal stack gas cleaning processes are used for this conditioning, complications arise because of low pressures and large volumes of flue gas, the potential for corrosion and scaling of process equipment, and the degree of clean up required to protect the downstream capture process.

The first step in conditioning is generally a water wash. This cools the flue gas from over 200°C to below 50°C. Fly ash remaining in the flue gas should be scrubbed out. A conclusion based on the operation of the CO_2 Extraction Pilot Plant at Boundary Dam Saskatchewan is that: "The seriousness of the fly ash problem cannot be overemphasized. Fly ash must be satisfactorily dealt with in any future commercial endeavor" (Wilson 1992).

Chemical absorption is the process generally used for CO_2 capture where the CO_2 partial pressure (total pressure times concentration) is low. Because of the strong chemical affinity of CO_2 with chemical solvents such as amines, the process will work and give capture efficiencies over 95% at atmospheric pressures and low CO_2 concentrations. However, this strong chemical affinity also exists for oxygen, sulphur oxides and nitrogen oxides.

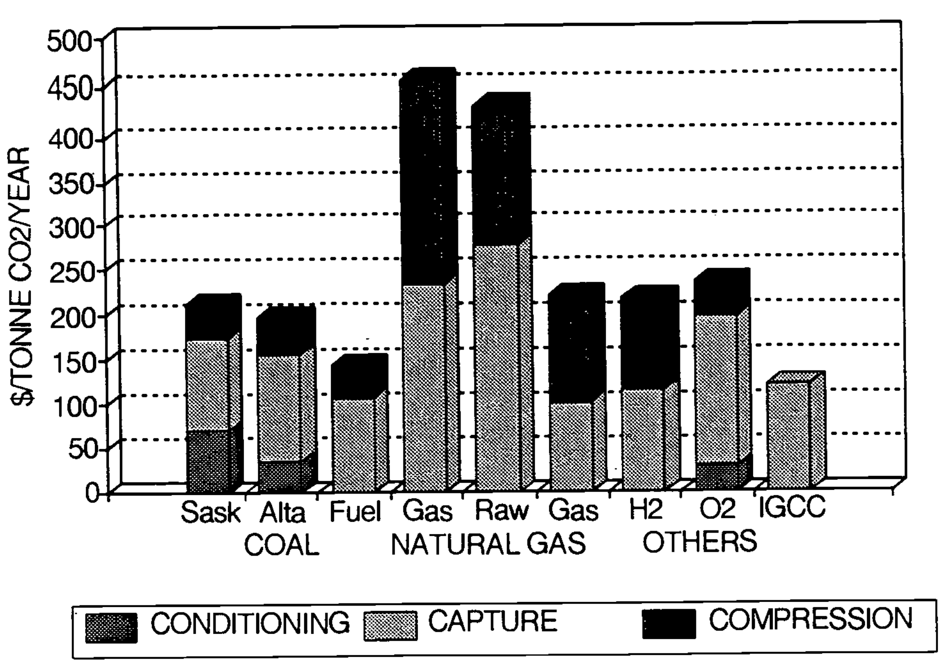
Oxygen from excess combustion air is a normal component of flue gas in the range of 3% to 8%. This can oxidize amines to organic acids and ammonia. Inhibitors are added to control this problem which can otherwise result in amine losses and corrosion problems.

Sulphur oxides form non-regenerable heat stable salts with amines. High levels of sulphur oxides result in high amine consumption. SOx scrubbing systems using lower cost chemical absorbents such as caustic (NaOH) or lime (CaOH) are required to lower SO_2 concentration to below 10 ppm. Although SO_2 scrubbing is commercially practiced on power plant flue gas, the degree of SO_2 removal required prior to CO_2 removal is much greater. For example, at Boundary Dam (Case 1), the design SO_2 removal is 98.7%, from 380 ppm to 5 ppm. For Sundance (Case 2) the design SO_2 removal for the lower sulphur coal is 97.2% from 180 ppm to 5 ppm. There are few SO_2 scrubbing processes capable of performing to this level of removal efficiency. For Boundary Dam (Case 1) the conditioning process selected is the Andersen 2000 process which was tested in the pilot plant. This is a two stage scrubbing process using sodium sulphite formed from caustic sodium hydroxide and sulphur dioxide as the absorbent. For Case 2 (Sundance), a number of alternatives were reviewed before the Dravo Lime "Thiosorb" Process was selected. This is a magnesium enhanced lime scrubbing process which is expected to achieve over 95% SO_2 removal and meet the 5 ppm SO_2 specification.

Although nitrogen oxide (NO), the major component of NOx in flue gas, is non-reactive with most amines, nitrogen dioxide NO_2 will form nitrosamines and heat stable salts. No specific NOx removal processes have been specified. The NO_2 reaction products increase amine consumption and cause spent amine disposal problems.

The requirement for flue gas conditioning adds substantial costs to the capture of CO_2 from coal fired sources. See Figure 5.2. For Case 1, Boundary Dam, the capital costs for the conditioning equipment is 32% of the total constructed cost. For Sundance power plant where the SO_2 removal requirements are less, conditioning represents 17% of the total constructed costs for Case 2 and 12.5% for Case 6 (Argonne).

Fig 5.2 NORMALIZED CAPITAL COST



For natural gas fired sources there is no conditioning requirements because of the low sulphur and particulate concentrations in the flue gas. The simple water wash for flue gas cooling is included as part of the capture process.

For raw natural gas (Case 4) and gasified coal (IGCC Case 7) the removal of hydrogen sulphide (H_2S) prior to CO_2 capture is important. Both CO_2 and H_2S are acid gases and are absorbed by the same physical solvents so separation becomes a problem. This results in a trade off between recovery and purity which affects costs and yields.

5.2 CAPTURE PROCESSES

5.2.1 Chemical Absorption

Because of the low partial pressure of CO_2 in flue gas, chemical absorbents are generally used to separate the CO_2. It is possible to compress the flue gas so physical solvents, cryogenics, membranes or pressure swing absorption can be used for separation but the costs and energy requirements for compression are generally too high for practical consideration. The use of chemical absorption is very common in Western Canada where hundreds of gas processing plants use the technology to separate CO_2 and H_2S from natural gas.

Chemical absorption involves the reaction of CO_2 (or other acid gases) with an organic base, typically an alkanolamine to produce a water soluble salt. This salt can be thermally decomposed releasing the CO_2 and regenerating the alkanolamine. The reaction is shown below for monoethanolamine (MEA).

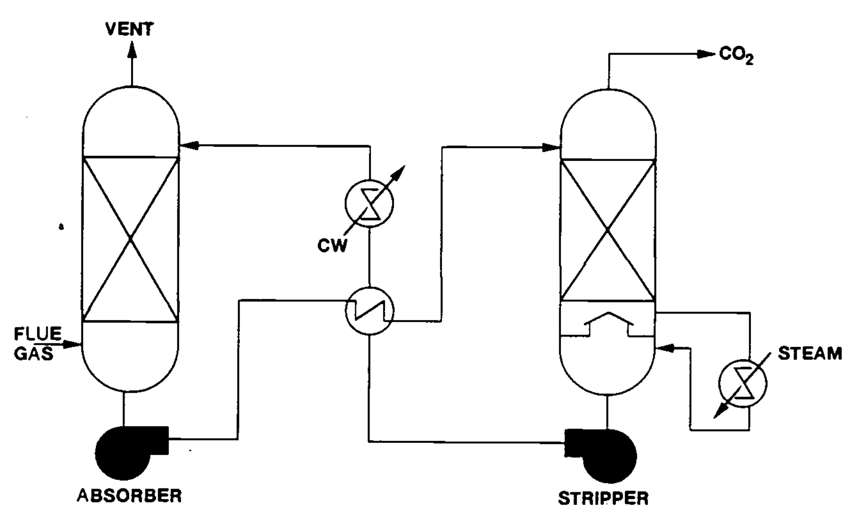
$$C_2H_4OHNH_2 + CO_2 + H_2O = C_2H_4OHNH_3CO_3.$$

Many chemical absorbents are available which can be used for this reaction.

MEA	monoethanolamine
DEA	diethanolamine
TEA	triethanolamine
MDEA	methyl diethanolamine
DIPA	diisopropanalamine
$K2CO_3$	potassium carbonate

Proprietary mixtures of different compounds, concentrations and inhibitors are available under a variety of trade names. Some have proven to be very effective in flue gas service including Union Carbide's "Fluegard"(sm) and "ECONOMINE FG(sm)" developed by Fluor Daniel from Dow's "Gas/Spec. FT-1"(sm). Both are based on MEA with inhibitors to prevent oxidation and corrosion problems. MEA is generally the economic choice for CO_2 capture from flue gas on the basis of reactivity at low CO_2 partial pressure and cost. Other abosorbents are used when selectivity between acid gases such as CO_2 and H2S are important. A simplified flow sheet is shown below.

FIGURE 5.3 AMINE GAS TREATMENT



The major problem with this technology is its energy intensity. It involves the circulation, heating and cooling of large liquid streams to process the gas. With typical alkanolamine concentrations in water of 15% to 30% and typical CO_2 loadings one half to one quarter the stoichiometric ratio, typical recirculation rates are 18 to 30 tonnes of MEA solution per tonne of CO_2 recovered. The steam requirements to regenerate the alkanolamine are typically 1.9 to 2.3 tonnes of steam per tonne of CO_2 recovered. Combustion of coal equivalent to one tonne of CO_2, will only generate about 3.8 tonnes of steam. Over half the energy from coal combustion is required for amine regeneration. Clearly for this technology to be feasible there has to be close integration with the power cycle to co-generate process steam and electrical power.

In a new design for an integrated co-generation power plant, the amine reboiler would act as the steam turbine condenser. In the retrofit options in this study, no modifications were made to the existing power plant steam cycle. Other methods of energy integration are used.

In Case 1 and 2, the coal fired power plant cases, gas turbines are used as the drivers for CO_2 compression. The exhaust gas is used to generate steam for amine regeneration. In addition a natural gas fired steam generator is used to co-generate about 20 MW of electrical power and the remaining steam required for amine regeneration.

In Case 3 for the natural gas furnaces, waste heat boilers are used to cool the flue gas and generate about one third of the steam required for amine regeneration. The remainder is generated from natural gas fired boilers.

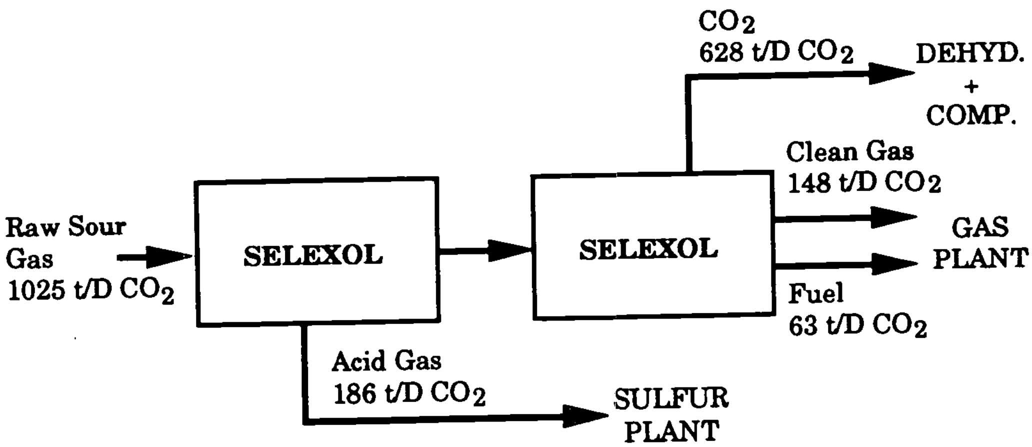
5.2.2 Physical Absorption

Where the partial pressure of CO_2 is high enough, physical absorption can be used to capture CO_2. The choice of solvents is based on selective solubility rather than chemical reactions. The major advantage of physical absorption is the lower energy requirement to regenerate the lean solvent. Most of the absorbed gas can be released through pressure reduction so the steam requirements for a stripper reboiler is much less. The disadvantage of physical absorption is lower CO_2 capture efficiency due to lower CO_2 absorbency from the feed stream and greater CO_2 losses due to H_2S co-absorption.

In Case 4, the Hanlan Robb Gas Plant, Selexol is used as the physical absorbent. Selexol is the dimethyl ether of polyethylene glycol and works well at the pressure levels, 6.6 MPa (957psi), and CO_2 concentrations (10%) of the raw natural gas feedstock in this case.

The two alternatives studied in Case 4 show the differences between physical absorption (Selexol) and chemical absorption (MEA). In the existing gas plant an amine unit is used for CO_2 and H_2S removal. In Case 4A this amine plant is shutdown and replaced with two Selexol units, the first for H_2S removal to less than 20ppm and the second for CO_2 capture. See Figure 5.4. The gross capture is 61% (628 t/d), of the CO_2 in the feedstream. Losses of CO_2 include 18% captured with the H_2S and released through the sulphur plant, and 21% remaining in the gas plant feed and fuel. The CO_2 produced by the utilities for operating the Selexol processes is 256 t/d. The shutdown of the amine plant makes available steam from the sulphur plant which is used to generate electricity. This results in a credit for CO_2 avoidance at a power plant of 1039 t/d of CO_2. The gross CO_2 capture and production rate of CO_2 for EOR is 628 t/d, but the net reduction of CO_2 released to the atmosphere is 1411 t/d (628 - 256 + 1039).

FIGURE 5.4 CASE 4A TWO STAGE SELEXOL GAS TREATMENT

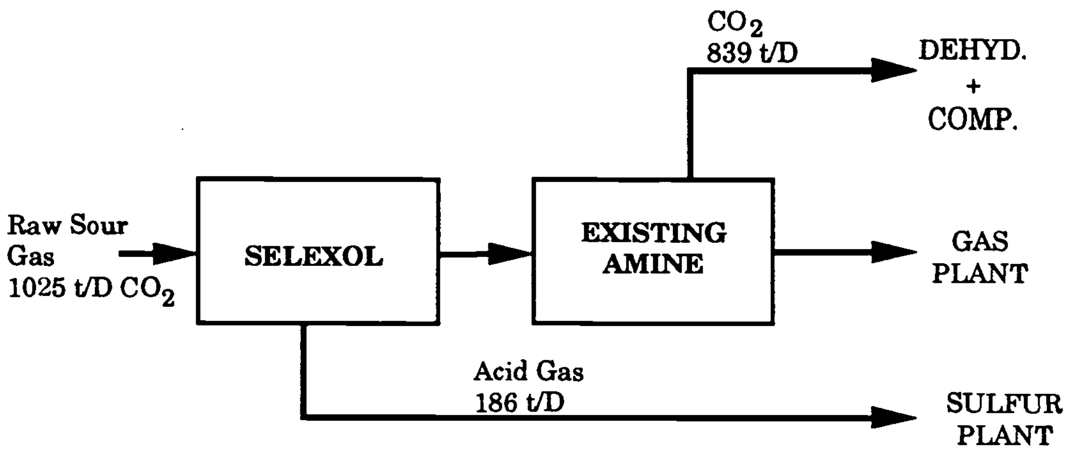


CO_2 Recovery	61%
CO_2 to SRU	18%
CO_2 to Gas Plant	21%

In Case 4B (Figure 5.5), the existing amine plant is utilized for CO_2 capture following H_2S removal using Selexol. The capital cost savings using the existing amine plant is \$31 million (99 - 68) but the energy requirements and resultant operating costs are over twice as high, \$34.93 vs \$16.21 per tonne of CO_2 captured, more than compensating for the higher capital costs.

Although the gross CO_2 recovery at 82% (840 t/d) is higher in the amine/Selexol case, the net reduction in CO_2 released to the environment is more (1158 t/d vs 1411). The higher steam requirement of CO_2 desorption from amine results in less surplus steam from the sulphur plant being available for electrical power generation.

FIGURE 5.5 CASE 4B UTILIZE EXISTING AMINE GAS TREATMENT



CO_2 Recovery	81%
CO_2 Losses to SRU	18%

5.2.3 Argonne Process

In Case 6 the Sundance Power Plant is modified for combustion in pure oxygen (30%) and recycled CO_2 (70%). This concept for CO_2 capture was pioneered by the Argonne National Laboratory near Chicago. A capture process is not required because the CO_2 concentration is raised through the elimination of nitrogen from the combustion air. The capture process is replaced with an air separation plant to supply oxygen and a CO_2 purification system, based on CO_2 liquefaction and distillation, to separate the excess oxygen, residual nitrogen, and argon from the CO_2 product. A conditioning system for SO_2 removal is still required to meet the CO_2 product specification for EOR.

The table below compares the two options for CO_2 capture at the Sundance Power Plant.

TABLE 5.1
SUNDANCE POWER PLANT OPTIONS

		CASE 2 AMINE	CASE 6 ARGONNE
Gross CO_2 Capture (t/d)		37440	37440
CO_2 From Utilities (t/d)		12481	12307
Net CO_2 Capture (t/d)		24959	25133
Capital Cost	($Million)	207.16	247.45
	($/gross tonne)	310.76	368.45
Operating Costs	($Million/y)	341	307.9
	($/gross tonne)	24.95	22.52

Within the accuracy of this study there is no clear advantage of one option over the other.

5.3 COMPRESSION AND PURIFICATION

In all cases the captured CO_2 has to be dehydrated and compressed to dense phase conditions for pipeline transmission. Water removal is required to prevent corrosion from carbonic acid, two phase flow and freezing problems. Interstage cooling and condensed water knockout during compression removes most of the water. The remainder is removed using triethylene glycol, the normal dehydration process used in natural gas processing.

Compression of CO_2 from atmospheric pressure to pipeline conditions of 14 MPa (2030 psia) is another energy intensive process typically requiring 110 kWh per tonne of CO_2. Since coal fired power stations typically produce 1100 kWh per tonne of CO_2 emitted, the CO_2

compression alone will require the equivalent of about 10% of the power plant output.

As shown on Figure 5.2 compression is a major portion of the plant, (with a range from 19% to 57%) typically representing 30% of capital cost.

For the large scale cases, compression is provided by multistage centrifugal compressors similar to those used as major natural gas pipeline compressors. In the power plant cases these are driven by gas turbines which also cogenerate electricity and steam for amine regeneration. For the smaller cases (4 and 5) where CO_2 capture is about 1000 t/d, four stage reciprocating compressors are used. Once the CO_2 is compressed to dense supercritical conditions it is handled like a liquid using centrifugal pumps.

Where amine has been used as the capture process no further purification is required to meet the EOR specification. There are no potential savings for reducing the specifications except in the gas plant case where the H_2S specification (20ppm) has limited process choices and reduced CO_2 capture efficiency.

Liquefaction and distillation is used to purify CO_2 in Case 6 (Sundance-Argonne). The CO_2 stream from the power plant contains about 2% to 3% excess oxygen which is separated from the CO_2 product and recycled back to the power plant. A refrigeration system using propane as the refrigerant to provide the liquefaction temperature of -4°C (25°F) at a reasonable pressure (4.8 MPa) (693 psia). A similar refrigeration/liquefaction process is used in the EOR field facilities for purification of recycled CO_2 and the removal of inerts such as nitrogen and light hydrocarbon gases.

5.4 GROSS AND NET CO_2 CAPTURE

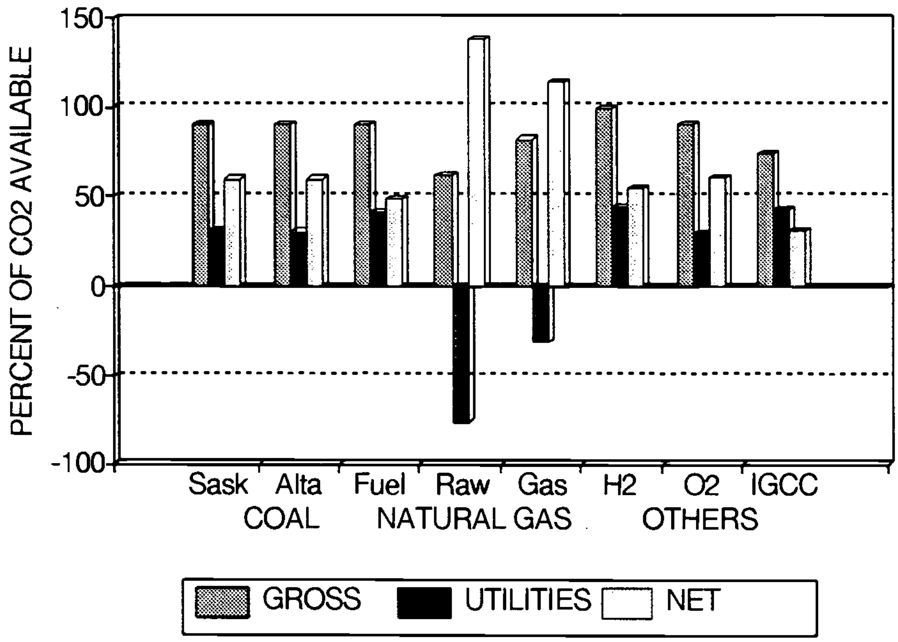
The basic task of this study has been to determine the cost of CO_2 capture and the benefits from enhanced oil recovery through CO_2 flooding. The key parameter is the amount of CO_2 captured and injected into the reservoir, the "Gross CO_2". The economics of capture and utilization are based in this study on the Gross CO_2 captured.

However, the main reason for capturing CO_2 is to achieve an environmental benefit, to have a major impact on the rate of growth of CO_2 emissions to the atmosphere. To measure this, a "Net CO_2" is calculated which takes into consideration the CO_2 emissions related to capture and utilization. From the Gross CO_2, the CO_2 emissions to drive the capture and compression processes and the CO_2 emission in EOR are deducted. Any CO_2 emission avoidance due to the recovery process is added as a credit.

The capture of CO_2 is an energy intensive process particularly for amine regeneration and CO_2 compression. Figure 5.6 summarizes the Gross and Net CO_2 captured with respect to the CO_2 available. Even with typical capture efficiencies of 90%, the typical net CO_2 reduction in emissions is 50% to 60% of the CO_2 available for capturing. The net CO_2 is typically 67% of the Gross CO_2 captured.

Case 4, the natural gas processing plant, is anomalous due to the substitution of physical absorption (Selexol) for the existing chemical absorption (amine) process and surplus energy available from the Claus Process furnaces of the sulphur plant.

Fig 5.6 CO2 CAPTURE GROSS & NET



The use of CO_2 for EOR also has the potential for large CO_2 emissions. Breakthrough of CO_2 from the injection well to the producing well occurs early in the life of the projects. This produced CO_2 is captured and recycled while CO_2 injection continues. Ultimately, CO_2 injection stops while CO_2 and oil production continue. An assumption made is that this produced CO_2 can be utilized in subsequent but undefined EOR projects. As long as the use of CO_2 for EOR is increasing there will be a market for produced CO_2. Eventually the requirement for more CO_2 for EOR will diminish as all viable projects are in service. At the end of the EOR projects the CO_2 left in all the reservoirs is only a fraction of the captured CO_2 which was injected.

It is assumed that CO2 produced when there is no demand for CO_2 for EOR would be disposed either in the depleted oil reservoir or a depleted gas field. The cost to dispose of this gas is relatively small because there is no capture cost and the infrastructure would be in place for compression, transmission and injection.

5.5 PIPELINE TRANSPORTATION

The design and cost estimates pipeline networks to deliver CO_2 from the various sources to the oil field is descibed in the SNC report as Case 1A. The map below outlines the network for the Alberta sources and sinks and the two Saskatchewan pipelines directly conncecting sources to adjacent field.

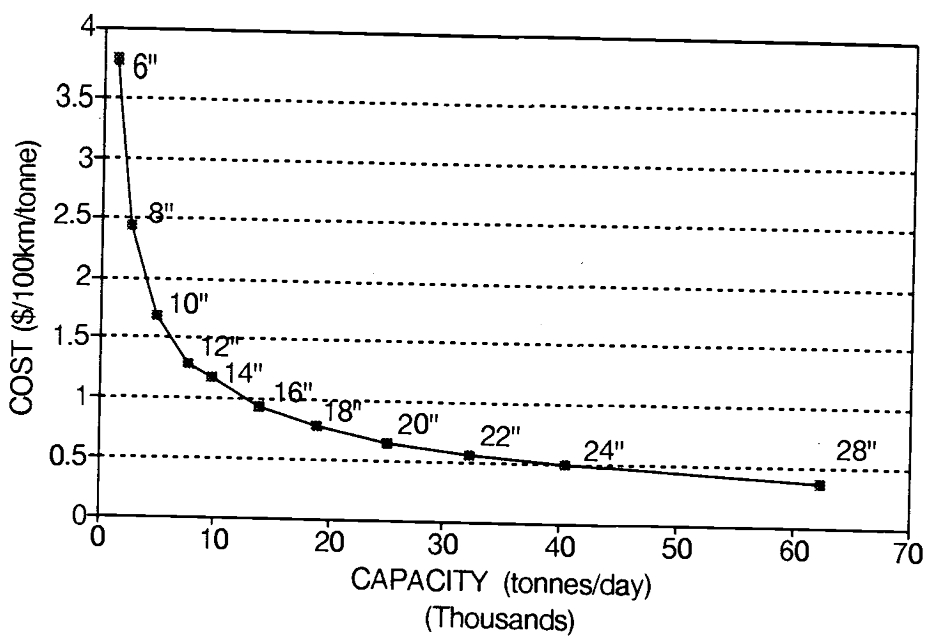
FIGURE 5.7 PIPELINE SYSTEMS

The pipeline design is based on the AGA Equation which has been recommended for dense phase CO_2 pipelining (Farris, 1983). The pipeline capital costs are based on a cost factor of $18,750 per diameter inch per kilometer. The cost of transporting CO_2 by pipeline are derived in the Economics report and summarized in Chapter 8.0 of this report.

The cost of transporting CO_2 from the sources by the pipeline network is relatively small due to the large volume moved, the relatively short distances and the low pressure drop for dense phase fluids. For the Alberta pipeline network typical transportation costs were $2/tonne. For the shorted dedicated lines in Saskatchewan the costs were only $.58 to $.76/tonne. The delivered price for CO_2 is dominated by the cost of capture which is typically over $50/tonne.

The design and cost equations can be worked together to produce the generalized pipeline cost/capacity curve shown in Figure 5.8. This is based on annual capital charges of 16% and does not include compression costs.

Fig 5.8 CO2 TRANSPORTATION
PIPELINE CAPACITY vs COST



6.0 ENHANCED
OIL RECOVERY

6.0 ENHANCED OIL RECOVERY (EOR)

6.1 INTRODUCTION

Conventional oil recovery leaves most of the original oil in place (OOIP) in the reservoir. Primary recovery methods using the natural reservoir energy and artificial lift methods typically recover 5% to 20% of OOIP. Secondary recovery techniques such as water flood or gas injection for pressure maintenance are used to recover a further 10% to 20% but most of the oil remains underground. This residual oil saturation is a small film of oil held by surface tension and capillary forces to the pores and voids in the rock.

Enhanced Oil Recovery processes are used to reduce this residual oil saturation and obtain further oil production. A number of EOR techniques are in commercial use including miscible and immiscible flooding, solvent flooding, and polymer flooding. All techniques attempt to mobilize and recover the oil by reducing the capillary forces due to interfacial tension.

Carbon dioxide is used in EOR as both a miscible and immiscible solvent. The initial effect of CO_2 is to dissolve in the oil reducing the viscosity and causing the oil to swell. These effects can be large even when the oil and CO_2 are separate (immiscible) phases. Viscosity reductions by orders of magnitude are possible due to the very low viscosity of CO_2. Swelling of up to 50% is possible with sufficient dissolved CO_2. Both effects can increase oil mobility and production.

At a high enough pressure, defined as the minimum miscibility pressure (MMP), sufficient CO_2 will dissolve in the oil, and oil in the CO_2, that the interface between the fluids disappears. They become a single phase fluid, like ethanol mixed with water rather than like oil mixed with water. The interfacial tension vanishes with the disappearance of the interface. The capillary forces holding the oil in the pore are dramatically reduced so the oil can be mobilized and displaced to the production well.

In Western Canada, light hydrocarbon gases, in particular ethane, have been effectively used for miscible flooding. The choice of ethane has been based on availability (from natural gas), price, and expected recovery of both oil and gas. Hydrocarbon miscible flooding accounted for almost 30% of the oil produced in Canada in 1990. The total established reserves for hydrocarbon floods are 513 x 10^6 m^3 (3.2 billion barrels) in 53 pools representing 23% of Alberta's total conventional crude oil reserves. Further miscible floods could add 175 x 10^6 m^3 (1.1 billion barrels) to these reserves (Scott, 1992).

In the U.S., CO_2 is the fluid of choice for miscible flooding. In 1990 over 50 projects produced almost 16,000 m^3/day (100,000 BPD) (Moritis, 1990, Hadlow, 1992). Low cost CO_2 from natural reservoirs has been used for most of these projects but CO_2 capture from flue gas has been commercially practiced in Texas.

For successful CO_2 flooding the following reservoir conditions and oil characteristics are important. The reservoir temperature must be above 31°C, the critical point for CO_2 to exist as a supercritical fluid with no gas/liquid interface. The reservoir pressure must be above the minimum miscibility pressure (MMP) for the oil in order to ensure miscible mixing. The reservoir fracture pressure must be above MMP to prevent fracturing of the reservoir rock creating high permeability thief zones. The mobility (relative permeability divided by viscosity) of the oil and CO_2 should be similar. If the mobility ratio is not close to 1, flow instabilities such as viscous fingering can occur. The fluid densities should also be similar to avoid gravity override. Both viscous fingering and gravity override can result in early breakthrough and poor sweep efficiency. Both mobility ratio and density indicate that the best candidates for CO_2 flooding are light, low viscosity crude oils.

CO_2 flooding can be improved using water as the driving fluid following the injection of a CO_2 slug or as an alternating process, water alternating gas (WAG).

The amount of CO_2 used will vary with the oil, the reservoir, and the process used. Literature values indicated a range of 1.7-6.6 tonnes/m^3 (5-20 MSCF/BBL) (Bardon & Denoyelle, 1984) and an average of 2.0 tonnes/m^3 (6 MSCF/BBL). The simulation results were significantly more favorable for CO_2 utilization ranging from 0.20-3.14 tonnes/m^3(0.61 to 9.51) with a weighted average of 2.1 tonnes/m^3 (6.3 MSCF/BBL).

As a result of Phase I of this study, the following objective was identified for the EOR studies:

> To analyze and predict the performance of carbon dioxide in a range of Alberta and Saskatchewan light and heavy oil and gas reservoirs.
>
> The results would be used to do the economic studies.

This objective was reviewed and changed in Phase II to:

- provide disposal with maximum economic benefits.
- leave as much CO_2 in the ground as possible.
- consider the logistics of pool size and location relative to sources of CO_2.
- use typical pools which could be extrapolated to other cases.
- narrow the selection down to six cases which could be simulated to yield useful results.

The database used to screen the oil and gas reservoirs came from the Energy Resources Conservation Board (ERCB). During Phase I five EOR areas of interest were identified:

Area 1	Saskatchewan Williston Basin Pools: Midale and others, Weyburn-Estevan area.
Area 2, 3, 4	Alberta Light Crude Reservoirs

Pools: Cooking Lake System-Leduc, Woodbend, Bonnie Glenn, Redwater, Acheson, Cardium-Pembina, Keg River, Rainbow

Note: Fenn Big Valley and Buffalo Coulee were added to the screening list in Phase II.

Area 2A Depleted Natural Gas Reservoir

Area 5 Saskatchewan Heavy Crude Oil

Reservoirs: Senlac, Tangleflags, Aberfeldy, Lloydminster

It was important to select reservoirs from different geographical areas with different crude oil characteristics and different reservoir geological settings.

The screening criteria for the CO_2 miscible horizontal floods were:

1. Areal Extent
2. Oil Density $\leq$ 876 kg/m^3
3. Depth > 915 m
4. Area > 70 ha

For CO_2 miscible vertical floods the criteria were:

1. Pay Thickness
2. Oil Density $\leq$ 876 kg/m^3
3. Depth > 915 m
4. Area < 1650 ha.

The CO2 immiscible floods were selected using:

1. Pay Thickness
2. Oil Density 876-970 kg/m^3
3. Pool Area $\leq$ 70ha

The screening criteria for CO_2 injection was that the pools must currently be undergoing enhanced recovery.

It was expected that the potential project life would be at least 10 years. The selected reservoirs would be used to dispose of 50,000 tonnes of CO_2/day over a 15 year period. Both EOR fields and depleted gas fields could be used to dispose of the targetted quantity of CO_2.

Additional characteristics for the gas reservoirs were:

- high relief
- carbonate reef
- sealed
- depleted

The types of gas wells considered are:

- active bottom aquifer e.g. Leduc gas blowdown
- fully completed gas reservoir e.g. Westrose
- dry gas reservoir e.g. Pine Creek.

Carson Creek gas field was chosen by the EOR Committee as the study case for CO_2 injection into depleted gas reservoirs.

The final selections for oil reservoirs, outlined on Table 6.1, were:

- Elswick for a Saskatchewan light crude extrapolatable to the larger Weyburn, Midale and Steelman reservoirs. It is a dolomite limestone reef from the Midale Beds of Mississipian age.

- Pembina with five prototypes i.e. Pembina Sandstone, Pembina Conglomerate, Cynthia-Cardium, Berrymoor, and Amoco "A". All are predominantly sandstone structures in the Upper Cretaceous Cardium formation.

TABLE 6.1

GEOLOGICAL CHARACTERISTICS OF RESERVOIRS STUDIED

FIELD	POOL	AGE	LITHOLOGY	FACIES
Elswick	Midale	Mississippian	Upper: Dolomites and limestones Limestone: oolitic & skeletal Dolomite: burrowed, vuggy Lower: Nodular anyhydrites	Forereef/Intertidal Backreef/platform
Pembina	Cardium	Upper Cretaceous	Sandstone/Conglomerate salt and pepper texture	offshore marine bars to beach
Redwater	D-3	Late Devonian	Dolomitized limestone	Pinnacle reef
Carson Creek North	Beaverhill Lake A & B	Middle Devonian	Limy shales, argillaceous micrites, anyhidrites	Reefal to platform
Aberfeldy	Mannville	Lower Cretaceous	Sandstone/siltstones, shales	Marine to continental

- Redwater D-3 pool since it is large, with 50 m thick pay and high horizontal and low vertical permeability.

- Carson Creek North, a Devonial reef typical of the Beaver Hill Lake group. Extension is possible to similar reservoirs such as Swan Hills, Virginia Hills and Judy Creek.

- Aberfeldy for a Saskatchewan heavy crude oil, because of its proximity to the Bi-Provincial Upgrader, its history of waterflooding, well to well continuity and its similarity to other Lloydminster pools. This is a sandstone in the Sparky Formation of the Mannville Group of Lower Cretaceous age.

Once the reservoirs were selected, TCA Engineering carried out mechanistic studies and then field project studies. Both of these types of studies were done with close interaction with the operators of the fields. The operators were responsible for economic and technical questions and the EOR Committee was responsible for policy, project and general direction of the overall study. The mechanistic studies were essentially screening runs of the MULTIFLOOD numerical simulator for geological prototypes representative of the entire reservoir. A geological prototype is a combination of well configuration and a geological model. This screening was carried out to determine the best CO_2 displacement process for the candidate reservoir. Throughout the reservoir studies the emphasis was on the most attractive oil recovery process providing the best economics. This recognizes that any process optimizing CO_2 storage at the expense of economical oil recovery would not be undertaken by a prudent operator. This approach will also identify the true costs of using CO_2 for EOR and the amount of CO_2 potentially stored. These numbers are required before any consideration could be given to maximizing CO_2 storage.

MULTIFLOOD is a numerical reservoir simulator described in TCA's report. The reservoirs were simulated using parameters provided by the operators. Optimization included vertical versus horizontal floods, various drilling patterns, differing locations of injectors and producers, recognition of reservoir anisotropies, various slug processes, and different WAG procedures.

The most important parameters used in the screening were:

1. **Original Oil In Place (OOIP):** The larger the reservoir the larger the potential for CO_2 disposal and oil recovery.

2. **Ultimate recovery (%OOIP):** This value, and the value of the current recovery, provide measures of the reservoir susceptibility and conformance to flooding, the target for an enhanced recovery process, and where the reservoir stands with regard to its exploitation history.

3. **Recovery Mechanism:** This reflects the pool exploitation history, and suggests whether the field has been considered for a recovery process other than primary depletion.

4. **Depth, Initial Pressure, Saturation Pressure, Fracture Pressure and Temperature:** CO_2 displacement processes are highly sensitive to pressure. Generally, for a given reservoir temperature, there is a pressure above which CO_2 is miscible with the reservoir crude oil. This is the minimum miscibility pressure (MMP). It is possible to estimate this pressure using the reservoir temperature. The miscibility pressure is higher than the current saturation pressure. Therefore, the saturation pressure provides the lower limit for the MMP.

   There is a maximum pressure above which the reservoir will fracture known as the reservoir fracture pressure. It is known directly or estimated as a function of depth. Miscible floods can only occur when the reservoir fracture pressure is greater than the MMP. The initial reservoir pressure is also important. If it is low relative to the MMP and the reservoir fracture pressure is higher than the MMP then further pressure can be put on the reservoir. The difference between MMP and current reservoir pressure is a measure of the effort required to prepare a reservoir for miscible displacement.

5. **Reservoir Type:** By comparing certain attributes of the candidate reservoirs with known CO_2 performance parameters, some likely features of a CO_2 displacement can be anticipated. For example, sandstone reservoirs, if strongly water-wet, are less responsive than carbonate or limestone reservoirs to the water-alternating-gas (WAG) processes. This is because, in strongly water-wet reservoirs, water tends to shield the residual oil from contact by the CO_2 miscible solvent. Further, in reservoirs that exhibit mixed or oil-wetness, there appears to be an intrisic mobility control for the injected CO_2 solvent that probably derives from hysteresis in the relative permeability functions. Except for one case, where the operator actually provided TCA with relative permeability functions that included the hysteresis loop, this feature was not included in the mechanistic studies as results would have been unsupported by laboratory data. This omission adds a small element of conservatism to the predicted oil recovery performances.

   As another example of the influence of reservoir type, conglomerate zones within reservoirs tend to have high flow capacities and hence, tend to be thief zones for any injected fluid. This lowers the vertical sweep efficiency of a process and can result in economically unacceptable oil recovery levels.

6. **Oil Density (deg API):** This is another qualitative measure of the responsiveness of the reservoir to CO_2 flooding. For a given temperature, the higher the API, the lower the oil viscosity is likely to be. This, in turn, results in a better CO_2-oil mobility ratio and, usually, a more efficient miscible displacement process. In heavier oil reservoirs, immiscible CO_2 processes can be considered. Here, incremental oil recovery is obtained by

improving the mobility ratio of a waterflood and thus, extending the economic life of the displacement process.

7. **Operator:** The intent of an operator to support the study was critical to its success. Only the operator could provide details of reservoir description, fluid description, saturation functions, operating constraints, and field history.

Once the parameters for the mechanistic studies were computed the individual prototype information was put into a numerical simulator called FLDPROJ. The input data are provided in Table 6.2. The results have been summarized in Table 6.3.

6.2 RESERVOIR ANALYSES

6.2.1 Carson Creek North

This is a reef formation. The input parameters are summarized in Table 6.2. A vertical miscible flood using a 1:1 WAG process was chosen for the computer simulations. There are 3 geological zones: B-Pool transition region, B-Pool rim region and A-Pool.

Recovery was not what was expected. This was caused by incomplete sweep of the reservoir volume increased geological heterogenity and low recovery in the lagoonal area of the reservoir.

The CO_2 scheme was implemented in two phases in order to optimize costs and use of surface facilities.

Results of the EOR process are provided in Table 6.3. The injection of 24.6×10^6 tonnes (468 BSCF) CO_2 recovers an additional 49.2 million standard barrels of oil (MMSTBO) over a 16.5 year period. This represents an additional 13.4% of the original oil in place (OOIP). While doing this 7.8×10^6 tonnes (148 BSCF) of CO_2 are stored in the ground. Based on cumulative numbers, it takes 1.84 tonnes/m^3 (5.57 MSCF/STBO) to recover this oil.

TABLE 6.2 - ENHANCED OIL RECOVERY DATA INPUT PARAMETERS

Reservoir	Location	Operator	Formation	Production	Miscibility	CO2 Flood	Well Configuration	Slug Process	Prototype	Water Cut	OOIP MMSTB
Carson Creek North	Central Alberta	Mobil	Reef	Light Crude	Miscible	Vertical	1/4 - 5 spot/320 ac	0.45 HPV	3	0.99	366
Pembina NPCU #1*	Central Alberta	Mobil	Sandstone	Light Crude	Miscible	Vertical	325/5 spot/80 ac	0.6 HPV	1	0.98	738
	Central Alberta	Mobil	Conglomerate/ Sandstone	Light Crude	Miscible	Vertical	106/5 spot/80 ac	0.6 HPV	1	0.98	382
Amoco "A"	Central Alberta	Amoco	Conglomerate/ Sandstone	Light Crude	Miscible	Horizontal	120/1/2 5 spot/80 ac	0.4 HPV	1	0.98	186
Cynthia-Cardium Unit #3	Central Alberta	Esso	Sandstone	Light Crude	Miscible	Vertical	96/1/4 5 spot/80 ac	0.4 HPV	1	0.98	47
Berrymoor Unit #10	Central Alberta	Esso	Conglomerate/ Sandstone	Light Crude	Miscible	Vertical	160/1/4 5 spot/40 ac	0.64 HPV	1	0.98	217
Redwater	Central Alberta	Esso	D-3	Light Crude	Miscible	Vertical	480/1/2 5 spot	1.0 HPV	1	0.99	1060
Elswick	South Eastern Saskat-chewan	West Coast	Carbonate	Light Crude	Miscible	Vertical	16/1/4 9 spot/80 ac	0.5 HPV	1	0.95	27
Aberfeldy	Western Saskat-chewan	Husky	Sandstone	Heavy Crude	Immiscible	Vertical	259/5 spot/40 ac	2 mol %	1	0.94	594
Carson Creek Gas	Central Alberta	Mobil	Reef	Gas	N/A	Vertical	N/A	N/A		N/A	N/A

TABLE 6.3 - ENHANCED OIL RECOVERY STUDY RESULTS

Reservoir	Location	Operator	Formation	Production	Miscibility	CO2 Flood	Incremental Oil Recovery (MMSTB)	Net MSCF/ Incr. bb. of Oil	1.1 WAG	CO2 Disposal (Bscf)	CO2 Inj. (Bscf)	OOIP MMSTB
Carson Creek North	Central Alberta	Mobil	Reef	Light Crude	Miscible	Vertical	49.2	3.2	1:1	148	469	366
Pembina NPCU #1*	Central Alberta	Mobil	Sandstone	Light Crude	Miscible	Vertical	89.3	1.8	1:2	165	1121	738
	Central Alberta	Mobil	Conglomerate/ Sandstone	Light Crude	Miscible	Vertical	51.5	2.5	1:2	107	574	382
Amoco "A"	Central Alberta	Amoco	Conglomerate/ Sandstone	Light Crude	Miscible	Horizontal	27.6	.01	0	6	206	186
Cynthia-Cardium Unit #3	Central Alberta	Esso	Sandstone	Light Crude	Miscible	Vertical	4.2	6.5	Water Drive	25	54	47
Berrymoor Unit #10	Central Alberta	Esso	Conglomerate/ Sandstone	Light Crude	Miscible	Vertical	27.6	2.2	1:1	61	387	217
Redwater	Central Alberta	Esso	D-3	Light Crude	Miscible	Vertical	69.4	7.8	1:1	660	689	1060
Elswick	South Eastern Saskat-chewan	West Coast	Carbonate	Light Crude	Miscible	Vertical	5.6	2.4	1:1	10	25.5	27
Aberfeldy	Western Saskat-chewan	Husky	Sandstone	Heavy Crude	Immiscible	Vertical	118.4	0.73	2 mol%	66	167	594
Carson Creek Gas	Central Alberta	Mobil	Reef	Gas	N/A	Vertical	N/A	N/A	N/A	300	307	N/A

6.2.2 Mobil Pembina Cardium Sandstone

This case represents one of five Pembina Cardium geological prototypes. All are dominated by sandstone and are found in the Cardium unit. This prototype, operated by Mobil, is a moderately stratified sandstone zone.

A vertical CO_2 flood with a 1:2 WAG process is used to produce incremental quantities of light crude. Production is affected by an unfavorable mobility ratio, and heterogenous reservoir structure which result in poor vertical sweep efficiency. Within the reservoir there is a shale layer with a low permeability zone below it. Stratification and gravity effects change responses in the oil saturation zone. The 1:2 WAG improves the reservoirs response.

The incremental oil production is 89.3 MMSTBO or 12.1% of the 738 MMSTBO in place. CO_2 storage was 8.7 x 10^6 tonnes (165.4 BSCF). Approximately 1.70 tonnes/m^3 (5.13 MSCF/STBO) are required to recover the incremental oil.

6.2.3 Mobil Pembina Cardium Conglomerate/Sandstone

Another Pembina Cardium prototype represents a conglomerate over sandstone geological sequence. The conglomerate region is 1.7 times as permeable as the sandstone. This causes the conglomerate to act as a thief zone for the sandstone. The input parameters to the simulator are provided in Table 6.2.

A miscible vertical flood with a 1:2 WAG process produced an incremental 8.19 x 10^6 m^3(51.5 MMSTBO) on 13.5% of the OOIP. Over 30.6 x 10^6 tonnes (574 BSCF) CO_2 are injected to recover this oil. Once the process is complete 5.6 x 10^6 tonnes (107 BSCF) of CO_2 are stored in the reservoir. About 1.43 tonnes/m^3 (4.32 MSCF/STBO) are required for the incremental oil production.

6.2.4 Pembina Amoco "A" Lease

This Cardium formation prototype represents leases operated by Amoco. It consists of four zones. Uppermost is a conglomerate followed by Zone 2, a sandstone. Under this is Zone 3 which is unproductive followed by a sandstone in Zone 4. The conglomerate is highly permeable and reduces production capacity. In addition, the sandstones have a lot of vertical variation in horizontal permeability, which reduces the sweep efficiency of CO_2 floods.

The oil in the Zone 2 sandstone and the conglomerate (Oil 1) is heavier than that in Zone 4 (Oil 2).

The permeability in the SW-NE direction is 1.8 times that of the offtrend direction.

Additional recovery problems result from the wide well spacing and tightness of the geological formation. The best results came from the placement of one horizontal well at the bottom of Zone 2 and another at the bottom of Zone 4. Injection of 0.4 Hydrocarbon Pore Volumes (HPV) CO_2 followed by a water drive to a 0.98 watercut provided an incremental recovery of 13.7% OOIP over a 50 year period.

The incremental oil recovery was 4.38×10^6 m^3 (27.55 MMSTB). This required injection of 10.8×10^6 tonnes (206 BSCF) of CO_2 over 28 years. In order to obtain the oil 1.13 tonnes/m^3 (3.41 MSCF/STBO) have to be injected. Approximately 0.32×10^6 tonnes (6.1 BSCF) of CO_2 are disposed in the reservoir.

6.2.5 Esso Pembina Cynthia Cardium Unit #3

The leases containing this prototype are operated by Imperial Oil Canada Limited. There are three sandstone zones with poor continuity. Only 55% of the sands connect through to the injection well. The formation has a low permeability (6 md).

A miscible vertical flood using a water drive recovers 6.7 x 10^6 m^3 (4.2 MMSTBO). This takes over 50 years. The results were very poor.

Redoing the study using horizontal wells as in the Amoco "A" Lease, may have provided better results but was beyond the scope of this project.

6.2.6 Esso Pemina Berrymoor Unit #10

Imperial Oil Canada Limited also operates this reservoir. A miscible vertical flood with 1:1 WAG followed by a water drive was recommended for the final simulations.

The pay zone has a highly permeable conglomerate over a highly permeable sandstone. The conglomerate would act as a thief zone reducing performance of the reservoir. About 4.37 x 10^6 m^3 (27.5 MMSTBO) of incremental oil would be produced. This is 12.7% of OOIP. After 28 years 23.6 x 10^6 tonnes (387 BSCF) of CO_2 would be injected into the ground. Only 3.2 x 10^6 tonnes (61.0 BSCF) would be stored. The requirement for CO_2 is 1.20 tonnes/m^3 (3.63 MSCF/STBO).

6.2.7 Redwater

This lease is a Devonian Leduc Reef reservoir operated by Imperial Oil Canada Limited. A vertical miscible CO_2 flood with a 1:1 WAG process was recommended. Recovery is affected by a poor CO_2 mobility ratio and a high geological heterogeneity. The poor mobility ratio would lead to fingering of CO_2 through the oil bank. The geological heterogenity would reduce recovery efficiency. These factors are enhanced due to density differences between oil and CO_2 and the presence CO_2 and brine in the formation. The CO_2 would tend to override the fluids present.

Other simulation problems could be the result of:

- poor miscible process description.
- bad reservoir description.
- less field heterogeneity than the models.
- effects of permeability curve hysteresis.
- asphalt precipitation.

The incremental oil recovered was predicted to be 11.03 x 10^6 m^3 (69.4 MMSTB) oil. This requires the injection of 36.2 x 10^6 tonne (689 BSCF) of CO2 over 14 years. This would leave 34.7 x 10^6 tonnes (660 BSCF) of CO2 stored in the reservoir. About 3.14 tonnes/m^3 (9.51 MSCF/STBO) would be required for recovery.

6.2.8 Elswick

The Elswick Lease is southeast of Weyburn, Saskatchewan. It is a geological analog of the Midale reservoir. The operator of this field is West Coast Petroleum. Models were based on work done at Canadian Roxy Petroleum Limited's North Elswick Oil Pool.

The Elswick sands consist of marly and vuggy rocks with a SW-NE oriented fracture system. These fractures create a noticeable permeability anisotropy.

Early CO_2 breakthrough and poor conformance due to the fracture induced anisotropy yielded poor results with continuous CO_2 injection.

By adding an infill producer well and converting an ontrend producer to an injector along with a 1:1 WAG process yields were improved. The project lasts 30 years with 18 years of CO_2 injection. The incremental oil produced is 8.9 x 10^5 m^3 (5.6 MMSTBO). This requires 13.4 x 10^6 tonnes (25.5 BSCF) of CO_2 for injection and leaves 0.5 x 10^6 tonne (10 BSCF) in the reservoir. About 0.79 tonnes /m^3 (2.4 MSCF/STBO) are required for this miscible flood.

6.2.9 Aberfeldy

The Aberfeldy field is a heavy oil (API=15, Viscosity = 800 cp) field in Western Saskatchewan. The operator is Husky Oil Company.

Poor water-oil mobility ratios have resulted in recovery of less than 10% OOIP using primary depletion and waterflooding. Due to the shallow depth of the fields and the high molecular weight of the crude oils, CO_2 will not dissolve into the oil sufficiently to cause miscibility. Thus immiscible flooding was used. These have been quite successful elsewhere according to the literature. At Aberfeldy, the equilibrium concentration of CO_2 in oil at 3.4 MPa (500 psi) caused oil viscosity to decrease from 800 cp to 28.4 cp, i.e. a 60 fold improvement in water-oil mobility ratio.

An immiscible flood using CO_2 disolved in water was chosen. Several tests proved that a CO_2-brine injection would give better yields. The final solution contained 2 mol% CO_2-in-water. The total CO_2 used was 8.8×10^6 tonnes (16.7 BSCF) of CO_2. The resulting incremental oil recovery was 18.8×10^6 m^3 (118.4 MMSTB). There were 3.5×10^6 tonnes (66.3 BSCF) stored. This was done using about 0.18 tonnes/m^3 CO_2 (0.53 MSCF CO_2/STBO).

6.2.10 Carson Creek Gas Field

This gas field is located in Central Alberta close to the Carson Creek oil field and is operated by Mobil Oil Canada.

The initial reservoir pressure was 26.1 MPa (3780 psi) at a depth of 5750 feet below sea level. It has been produced since 1962 to a pressure of 5.5 MPa (800 psi) in 1991. Present production is a retrograde gas condensate. It was agreed that this study would only address the use of the 'A' pool for CO_2 storage and not for possible hydrocarbon recovery benefits.

Both hydrocarbon liquids remaining in the reservoir (8%) and connate water saturation (21%) reduce potential CO_2 storage capacity.

The injected CO_2 required time to move away from the well into the rest of the reservoir. If no allowance was made for this, injection rates would have had to be reduced. By varying injection rate and injection pressure, it was found that injection pressure is also a constraint. These constraints are probably a function of reservoir flow capacity. Injection pressure and rate function independently. Together they determine the duration of injection. For any given pressure, the lower the injection rate the longer the pressure can be maintained. Therefore, the cost of maintaining pressure and the length of time the rate is maintained affect cost significantly.

The most favorable results for this study were a 27.6 MPa (4000 psi) injection pressure, injecting 2.6×10^3 tonnes/day (50 MMSCF/d) of CO_2 over 13.5 years which resulted in the storage of 16.1×10^6 tonnes (307 BSCF) of CO_2.

6.3 CONCLUSIONS

The EOR simulation results are fundamental to the study objective of disposing of 50,000 tonnes/day of CO_2. The results show that EOR recovery is possible and that good recoveries are attainable. Recoveries between 1-2 tonnes of CO_2/m^3 of oil (3-5 MSCF of CO_2/incremental barrel of oil) are expected to produce good results. Nevertheless, the CO_2 required for EOR in the study fields was less than expected at the start of the project.

The results have been summarized in Table 6.3. These results and the studies show that each reservoir must be handled specifically on its own and that responses to EOR vary with:

- geological formation
- geological structure
- miscibility pressure
- slug process
- oil viscosity (cp)
- oil gravity (°API)
- depth
- temperature
- original reservoir pressure
- well pattern (number, spacing, configuration)
- type of flood (horizontal or vertical)
- water alternating gas (WAG) process
- formation fracture pressure, and
- permeability

to mention a few important parameters.

Modelling and laboratory work help to refine estimates of oil production. Frequently, pilot tests are required to confirm simulations and improve production procedures.

It is very difficult to maximize enhanced oil recovery and to maximize storage of CO_2 in the ground at the same time. The question of when to stop oil production and maximize CO_2 storage will be determined by economics, government policies, incentives and public demand.

Although our original objective was to dispose of 50,000 tonnes/day (950.5 MMSCF/d) of CO_2, the total from the selected capture sources show that a slightly greater amount would be captured i.e. 50,684 tonnes/day (964.0 MMSCF/day). Over 15 years this amounts to 277.5 x 10^6 tonnes (5280 MMMSCF) of CO_2.

For the fields studied in this project, the total capability of CO_2 disposal in EOR and gas reservoirs over 15 years was 93.7 x 10^6 tonnes (1,783 MMMSCF). There was a shortfall of 183.7 x 10^6 tonnes (3,494 MMMSCF). The shortfall from the study target was due to a lower CO_2 utilization requirement than the industry average and a high recycle of produced CO_2 during the injection period.

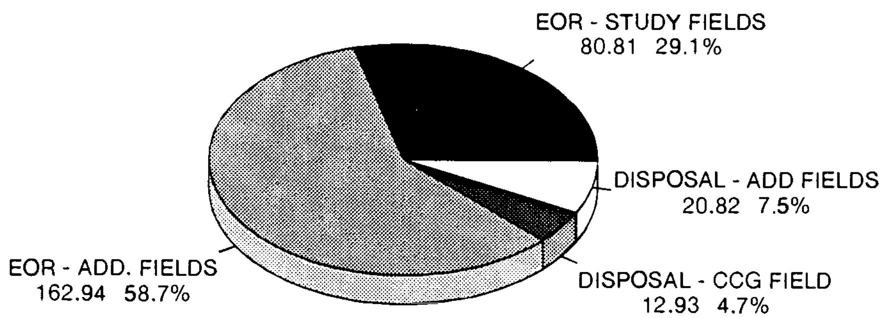
Information on alternative pools was derived from the ERCB FT 92-18 report for "Alberta's Reserves of Crude Oil, Oil Sands, Gas, Natural Gas Liquids and Sulphur", and was reviewed with the EOR Committee and is presented in AOSTRA's economics report. Recognition was given to three oil reservoir types (sandstone, reef and D-3), differing fractors of IOIP available for EOR (sandstone 50%, reef 90% and D-3 100%) and to CO_2 utilization per barrel of IOIP (sandstone 481 SCF/BB, reef 434 SCF/BBL and D-3 623 SCF/BB) (sandstone 0.16 tonnes/m^3, reef 0.14 tonnes/m^3, D-3 0.21 tonnes/m^3). Over 15 years the Alberta oil fields could utilize 194.1 x 10^6 tonnes (3,692 MMMSCF) of CO_2 for EOR. This represents 85.1% of the total quantity of CO_2 captured in Alberta.

The 14.9% shortfall in Alberta would have to be disposed in the depleted gas reservoirs identified in this study. Estimates were made of disposal capability using various injection pressures and recognizing differences in compressability between CO_2 and CH_4 (methane). Between 829.9 x 10^6 tonnes (15,784 MMMSCF) and 1,105.3 x 10^6 tonnes (21,023 MMMSCF) could be disposed in depleted gas reservoirs. This is 3 to 4 times the total CO_2 captured over 15 years and therefore much larger than the shortfall.

No analysis of this type was done for Saskatchewan as the data was not readily available.

The overall balance for Alberta and Saskatchewan was derived and is shown in Figure 6.1.

FIGURE 6.1 - BREAK DOWN OF CO2 DISPOSAL OVER THE 15 YEAR PERIOD (MM TONNES)



Of the 278 x 10^6 tonnes (5280 MMMSCF) of CO_2 (100%) being captured over a period of 15 years, 244 x 10^6 tonnes (4636 MMMSCF) of CO_2 (87.8%) would be utilized for EOR and the balance of 33.8 x 10^6 tonnes (640 MMMSCF) of CO_2 (12.2%) would be disposed in depleted gas reservoirs. Figure 6.1 also gives a breakdown of CO_2 disposition between the study fields and additional fields.

Thus it is possible to satisfy our objective of disposing of 50,000 tonnes CO_2/day over 15 years. It will require the additional oil reservoirs within 160 km of the study's pipeline infracstructure plus a small proportion of the gas reservoirs within the same area capable of storing CO_2.

7.0 FIELD FACILITIES

7.0 FIELD FACILITIES

The field facilities studies were developed to determine the capital and operating costs related to the injection of CO_2 for either EOR or disposal in a gas reservoir. In these studies it was assumed that CO_2 would be delivered to the battery limits at 13.8 MPa (2000 psi). The processing options and EOR processes were discussed with the operators of the leases in order to develop the most realistic operational approach for the specific reservoir.

Costs were developed for the nine different geological prototypes discussed in section 6. The Esso Cynthia-Cardium Pembina lease had been dropped from the list because preliminary economic calculations had demonstrated that it would be uneconomic as studied. The application of horizontal wells might prove this to be a viable project but this was beyond the scope of the study.

The nine reservoirs for which costing was developed are provided in Table 7.1. These reservoirs represent geological prototypes modelled as mechanistic and field project studies in the EOR studies done for this project.

TABLE 7.1
FIELD FACILITY STUDY RESERVOIRS

Carson Creek North

Mobil Pembina NPCU #1 - Conglomerate and Sandstone

Amoco "A" Lease

Esso Berrymoor Unit #10

Redwater

Elswick

Aberfeldy

Carson Creek Gas

The field facilities design and cost estimates were done by Optima Engineers and Constructors Inc.

Each reservoir represents a case study. Each case is broken into a number of modules. These modules are printed in Optima's report. Figure 7.1 provides a conceptual flow sheet for the field facilities studies. Variations on this theme occurred and are discussed below.

Modules were selected through consultation with the operator. The base module was constructed from a modular factored estimate for a 6000 t/d CO_2 EOR flood with 3000 t/d CO_2 recycle. Each base module for the estimates had risk and contingency factored into it.

Estimate consistency was ensured by scaling the modules up or down using the following criteria:

- pump - ratio of brake horse power (BHP) raised to power of 0.60
- compressor - ratio of BHP raised to power of 0.80
- heat exchanger - ratio of bare area to power of 0.85
- plant - ratio of total capacity raised to power of 0.60

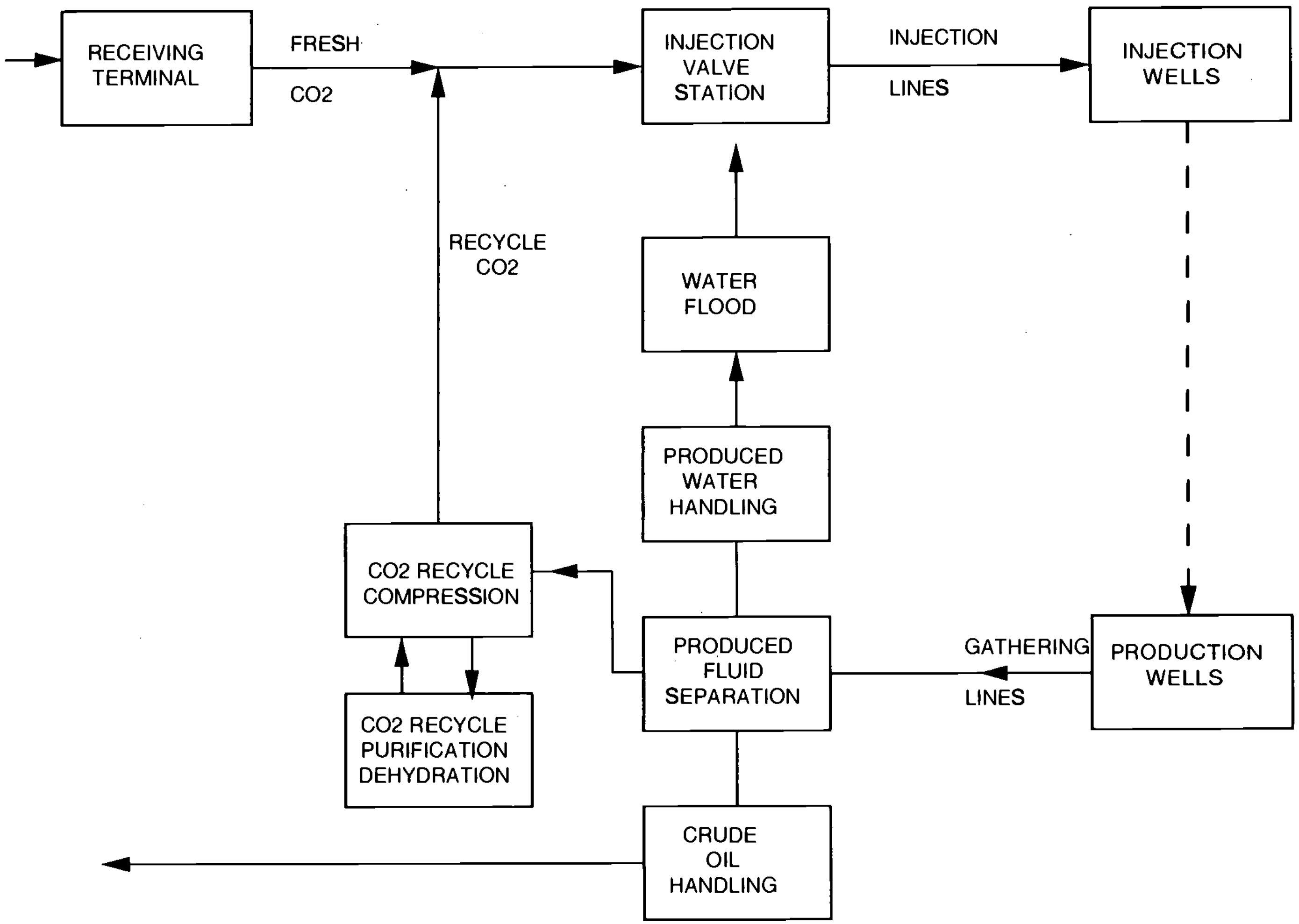
The total operating cost for each module is based on the utility cost, a percentage of the capital cost for maintenance and the cost of the operators. The utility cost is calculated based on the electric consumption at $ .04/kWh and fuel gas use at $ 1.00/MMBTU. The number of operators required for a particular facility is based on historical experience in oil plants, gas plants and field facilities.

The annual operating cost is the sum of the utility cost (including electricity and fuel), the maintenance cost (based on percentage of the capital cost), and operating cost (based on a loaded cost of $100,000 per operator).

The utility costs for the different cases are scaled up or down based on the required horsepower ratio for a given module.

FIGURE 7.1

CONCEPTUAL FLOW DIAGRAM FOR FIELD FACILITIES STUDIES



The data from TCA Reservoir Consulting was reformatted on an annual basis for economic modelling by AOSTRA. This reformatted data was used to do the field facilities design and estimate.

Detailed estimates were done for Carson Creek North Phases 1 and 2, Redwater Phases 1 and 2, Aberfeldy, Carson Creek Gas, Elswick, and Pembina Conglomerate. The other Pembina fields were scaled up from the Pembina Conglomerate Case using parameters recommended by the operators and the ratio of the CO_2 injection rates to that for the Pembina Conglomerate raised to the power of 0.6. Important parameters used in the design estimates are provided in Table 7.2.

The production wells are of two types. Some have a high risk of CO_2 breakthrough and others a low risk of CO_2 breakthrough. These are identified in each case. The high risk of breakthrough wells have a choke in the wellhead to prevent blowout problems.

The design is based on 80% of the peak injection rate in order to even out the demand for compression. Elswick is an exception where 100% of the peak rate was used.

Existing facilities are used where possible. This includes the water injection systems and existing emulsion separation facilities.

A conceptual design is presented in Figure 7.1. There are three variations on this concept. They include:

- the basic approach with no purification at Redwater, Pembina and Carson Creek Gas fields.
- the requirement for purifying the recycled CO_2 to 90% purity at Carson Creek North and Elswick leases.
- a special approach saturating water with CO_2 for an immiscible flood at Aberfeldy.

TABLE 7.2

DESIGN ESTIMATE PARAMETERS FOR FIELD FACILITY STUDIES

FIELD	INJECTION WELLS	PRODUCING WELLS	CO2 RECYCLE RATE (tonne/day)		CO2 INJECTION RATE (tonne/day	PEAK PRODUCTION RATE		INCREMENTAL OIL RECOVERY (x 10^6 m3/)	CO2 DISPOSAL (x 10^6 tonnes)
			PEAK	DESIGN		OIL (m3/day)	WATER (m3/day)		
Carson Creek North									
Phase 1	21	34	8,940	9,300	10,652	3,385	17,155		
Phase 2	22	22	9,251	9,300	10,620	3,498	16,678	7.8	7.8
Carson Creek Gas	2	-	-	-	2,700	-	-	N/A	15.7
Redwater									
Phase 1	49	148	1,754	1,800	3,871	4.367	10,915		
Phase 2	52	156	1,754	1,800	7,374	4,367	10,915	11.0	34.7
Aberfeldy	259	259	1,318	1100	1,633	5,150	31,353	18.8	3.5
Elswick	13	29	203	203	242	288	370	0.9	0.5
Pembina									
Conglomerate	106	106	13,211	10,600	15,668	2,177	17,950	8.2	5.6
Sandstone	325	325	11,150	8,900	9,102	1,227	18,157	14.2	12.1
Berrymoor	40	50	3,179	2,550	3,509	816	4,414	4.4	3.2
Amoco "A"	180	120	3,520	2,850	5,248	2,030	1,917	4.0	0.3
Total	1069	1249	N/A	N/A	N/A	N/A	N/A	69.3	75.6

In the basic approach, produced water and CO_2 are separated and handled for disposal, recycling, or venting. The recycled CO_2 requires dehydration and compression before it can be reinjected.

At Redwater costs for recycle represent 8% of Phase 1 capital costs and 31% of Phase 1 annual operating costs. At Mobil Pembina Conglomerate CO_2 recycle costs are about 45% of capital costs and 82% of annual operating costs.

Because of a requirement for 90% CO_2 purity for reinjection at Carson Creek North and Elswick, the gas, oil and water emulsion is dehydrated in a two tower 3 bed mole sieve dehydration unit. The gas goes on to a purification plant. This process is discussed in the Optima report.

At Carson Creek North, the recycle facilities represent 60% of the capital costs and 90% of the annual operating costs for Phase 1, and are not required for Phase 2. Purification costs represent 51.4% of the Phase 1 recycling capital costs and 82.2% of the Phase 1 recycling annual operating costs.

Elswick recycle costs are only 25% of capital costs and 71% of annual operating costs. Purification accounts for 12.9% of recycling capital costs and 47.4% of recycling operating costs.

At Aberfeldy, the recycled CO_2 is compressed and mixed with water before reinjection. Fresh CO_2 arriving as a liquid at the receiving terminal is vaporized and mixed with produced water for reinjection. The costs for recycle, compression and mixing are 10.6% of capital costs and 22% of annual operating costs.

The Carson Creek Gas field is used to dispose of CO_2. Two high rate gas wells will be used to inject the CO_2. Methane and other hydrocarbon gases will be displaced in the reservoir. The design does not consider CO_2 recycle gas.

The Total Installed Capital Operating Costs are summarized in Table 7.3. It is important to note that normal commercial operations in the existing regulatory environment would not require CO_2 recycle. This is done in this study to maximize storage of CO_2.

TABLE 7.3

FIELD FACILITY STUDIES COST SUMMARY

FIELD	OPERATOR	TOTAL INSTALLED CAPITAL COST	OPERATING COSTS
ELSWICK	WESTCOAST PETROLEUM	26,352,348	1,446,756
CARSON CREEK NORTH-PHASE 1	MOBIL OIL CANADA	151,385,668	21,425,813
CARSON CREEK NORTH-PHASE 2	MOBIL OIL CANADA	23,714,525	529,016
REDWATER PHASE 1	IMPERIAL OIL RESOURCES	126,448,335	3,675,104
REDWATER PHASE 2	IMPERIAL OIL RESOURCES	132,727,616	2,201,849
ABERFELDY	HUSKY OIL	130,433,233	7,220,952
CARSON CREEK GAS	MOBIL OIL CANADA	3,673,780	136,313
PEMBINA CONGLOMERATE	MOBIL OIL CANADA	164,215,227	19,400,966
PEMBINA SANDSTONE	MOBIL OIL CANADA	258,469,860	21,261,550
PEMBINA AMOCO 'A'	AMOCO	102,895,707	7,624,913
PEMBINA BERRYMOOR	IMPERIAL OIL RESOURCES	49,870,636	5,598,255
TOTAL		1,170,186,935	90,521,487

NOTE: 1. Total Installed Cost is in 1992 $ (Canadian).

2. Utility, Maintenance and Operator Cost is for a 1 year period.

8.0 ECONOMICS

8.0 ECONOMICS

8.1 INTRODUCTION AND BACKGROUND

AOSTRA undertook the work outlined in the scope document for the Economics Package of this study. The objective was to quantify the cost/benefit relationship for recovering CO_2 from defined sources and using it for enhanced oil recovery (EOR), or disposing it in depleted gas reservoirs. The study mission statement was based on capturing 50,000 tonnes/Day (951 x 10^6 SCF/Day) and using this to optimum benefit for EOR in Alberta and Saskatchewan, beginning in the year 2000 and continuing for a period of at least 15 years.

To quantify the cost/benefit relationship an economic criteria based on the Differential (Differential) between cost of capturing and delivering CO_2 to the field (EOR or depleted gas) (Delivered Cost) and the price affordable (Affordable Price) at the field was established. The Delivered Cost includes all the capital charges and operating costs incurred over the life of the project. The Affordable Price at the field is the price that an oil field operator can afford to pay after deducting from the revenue, due to incremental oil production, the operating costs and capital charges over the life of the project. The Differential, calculated as Affordable Price less the Delivered Cost of CO_2 to field, therefore indicates project viability. If the Differential is positive there is net benefit being accrued and the project is economically viable. On the other hand, if the Differential is negative there is a net cost being incurred and the project is not economically viable based solely on the revenue from EOR.

The Differential was expressed in \$/tonne (\$/MSCF) of CO_2 and was derived using both the Social (5% and 10% rate of return (ROR)) and Normal Business (full flow through (FFT) and project limited (PL) taxation) approaches. The Social approach is a test of project economic viability independent of inflation factors and fiscal policies. The Normal Business approach, on the other hand, is a test of project economic viability which includes inflation factors, royalties, and taxation. All the Delivered Costs and Affordable Prices were developed and expressed in 1 Q 1992 Canadian $.

In situations where the CO_2 is being disposed in depleted gas reservoirs, the Affordable Price is zero, instead an additional cost of disposal is being incurred. In this case the Differential is negative, with total cost of disposal equal to cost of capture, pipelining and disposal.

AOSTRA utilized the cost and performance data developed by other contractors on CO_2 sources, pipeline systems, EOR fields, and depleted gas reservoirs to derive the Delivered Costs and Affordable Prices. AOSTRA developed in-house models to evaluate all cases except for EOR using the Normal Business approach. For this AOSTRA used the Petroleum Economics Evaluation Program (PEEP) software marketed by Merak Projects Limited and widely used in the oil industry.

In addition to developing the Delivered Cost and Affordable Price, AOSTRA also reviewed data on oil and gas fields that could be used as CO_2 sinks in Alberta. This review was undertaken to check what fraction of CO_2 captured over a period of 15 years could be utilized for EOR, and how much of the balance could be disposed in depleted gas reservoirs. The results of this review permitted the establishment of the overall net cost or net benefit associated with utilizing or disposing the total captured CO_2.

8.2 REVIEW OF RESULTS

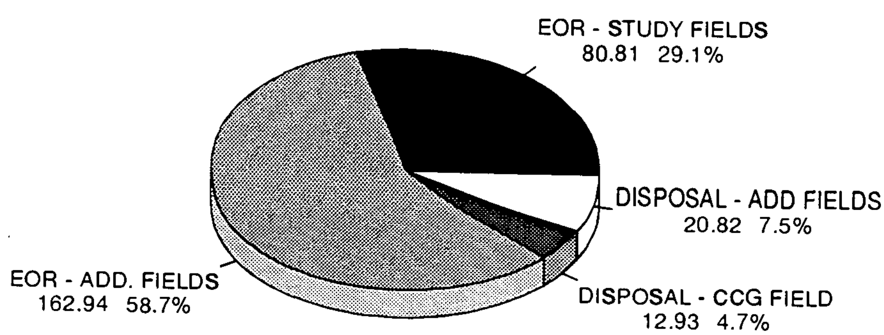
8.2.1 CO_2 Sources and Sinks

An initial review of the CO_2 disposal indicated that only 29.1% (80.8 x 10^6 Tonnes) [1.54 x 10^{12} SCF]) of the captured CO_2 was being utilized for EOR in the fields selected for the study. This was mainly due to the following:

- Simulation results indicating that the CO_2 requirement was lower than the industry average.
- Recycle of produced CO_2 during the injection period.

A further review of Alberta oil and gas fields, shortlisted by the EOR committee, indicated that over a period of 15 years, 87.8% (243.8 x 10^6 tonnes [4.64 x 10^{12} SCF]) of the CO_2 captured in Alberta and Saskatchewan could be utilized for EOR. The balance, 12.2% (33.8 x 10^6 tonnes [0.64 x 10^{12} SCF]), would be disposed in depleted gas reservoirs. The total volume of CO_2 that can be disposed in depleted gas reservoirs is approximately 3-4 times the total amount being captured over a 15 year period. Figure 8.1 depicts the disposition of total captured CO_2.

FIGURE 8.1 - BREAK DOWN OF CO2 DISPOSAL OVER THE 15 YEAR PERIOD (MM TONNES)



8.2.2 Economic Analysis

A total of 344 individual case studies were conducted. This large number of case studies resulted since there were 22 base cases (10 CO_2 sources, 3 pipeline system, 8 EOR fields and 1 depleted gas field), and each of the base cases was analyzed using the following four approaches:

- Social utilizing 5% rate of return
- Social utilizing 10% rate of return
- Normal Business utilizing full flow through taxation
- Normal Business utilizing project limited taxation.

In addition, each EOR field was analyzed at three levels of oil production (50%, 75% and 100% of simulated results) and three flat crude price profiles which remained constant in 1992 Canadian $ throughout the project life. These price levels were analyzed for both crude types. These were for light oil $125.79, $157.24 and $188.69/M³ ($20.00, $25.00 and $30.00/Barrel), and for heavy oil $31.45, $62.90 and $94.35/M³ ($5.00, $10.00 and $15.00/Barrel). Three levels of crude production were utilized to reflect the impact of reservoir factors such as heterogeneity and sweep efficiency on simulation results.

In order to avoid the debate concerning which crude oil price forecast was 'right', the methodology of using a range of flat crude oil prices was adopted. This range was intended to cover the spectrum of individual forecasts that are routinely published by various engineering consulting firms, the National Energy Board, and other agencies. In addition, this approach has enabled the study to examine the relative sensitivity of economics to crude oil prices.

All the results of economic analysis have been summarized in the Economics report. In this section, only the results obtained using the following approaches are presented and discussed:

- Social utilizing 10% rate of return
- Normal Business utilizing full flow through taxation.

Please note that the results presented for the EOR fields are based on an oil production level of 75% of simulated results.

The results of economic analysis of the individual cases, namely the Delivered Costs, Affordable Prices, and the resulting Differentials, have been plotted on the following figures:

Figure 8.2A - Alberta CO_2 Sources and EOR Fields - Summary of Economic Analysis based on Social approach.

Figure 8.2B - Alberta CO_2 Sources and EOR Fields - Summary of Economic Analysis based on Normal Business approach.

Figure 8.3A - Saskatchewan CO_2 Sources (Boundary Dam) and EOR Fields (Elswick) - Summary of Economic Analysis based on Social approach

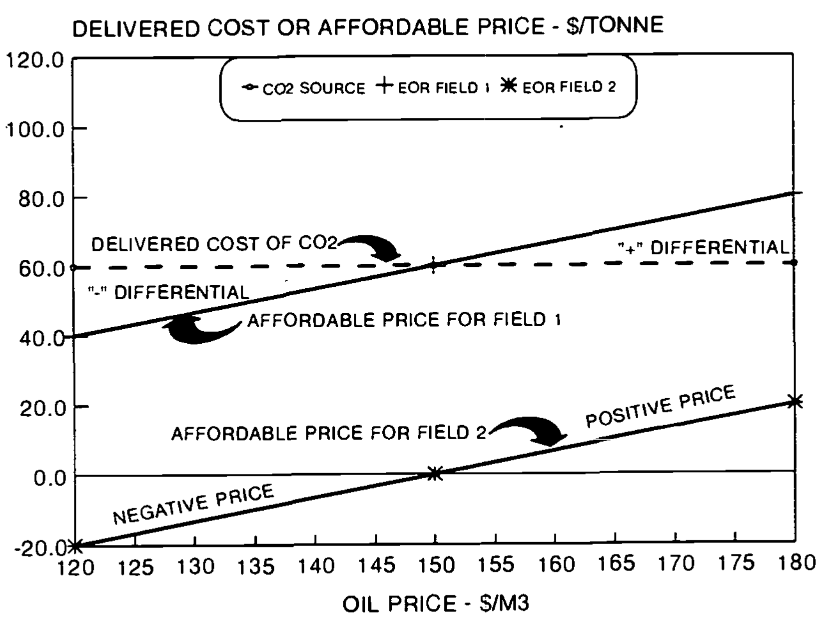
Figure 8.3B - Saskatchewan CO_2 Sources (Boundary Dam) and EOR Fields (Elswick) - Summary of Economic Analysis based on Normal Business approach

Figure 8.4A - Saskatchewan CO_2 Sources (Bi-Provincial Upgrader) and EOR Fields (Aberfeldy) - Summary of Economic Analysis based on Social approach

Figure 8.4B - Saskatchewan CO_2 Sources (Bi-Provincial Upgrader) and EOR Fields (Aberfeldy) - Summary of Economic Analysis based on Normal Business approach

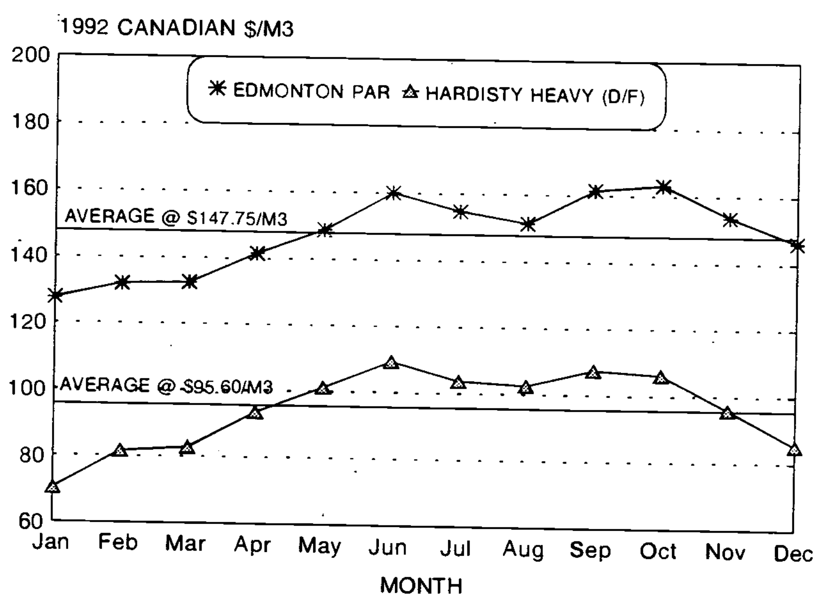
The dotted lines on these figures represent the Delivered Cost for a given CO_2 source. The solid lines on the graph represent the Affordable Price, for a given EOR field. (Please note that a negative Affordable Price represents the price that an EOR field operator would have to be paid for utilizing the CO_2). The gap between the lines represents the Differential which is a net benefit (if the Affordable Price is above the Delivered Cost) or a net cost (if the Affordable Price is below the Delivered Cost).

EXAMPLE GRAPH DEPICTING SUMMARY OF ECONOMIC ANALYSIS



The oil price shown is the field gate price. This price, compared to Edmonton Par or Hardisty Heavy, is generally lower due to the cost of transportation from the field to the terminal, and for heavy crudes by the additional cost associated with diluent blending. The Edmonton Par Price and Hardisty Heavy (Diluent Free) for 1992 is depicted in Figure 8.5. The Edmonton Par averaged at \$147.75/M^3 (\$23.50/Barrel) and Hardisty Heavy (Diluent Free) averaged at \$95.60/M^3 (\$15.20/Barrel).

FIGURE 8.5 - 1992 OIL PRICE PROFILES



SOURCE - DAILY OIL BULLETEN

FIGURE 8.2A - ALBERTA CO2 SOURCES AND EOR FIELDS
SUMMARY OF ECONOMIC ANALYSIS BASED ON SOCIAL APPROACH

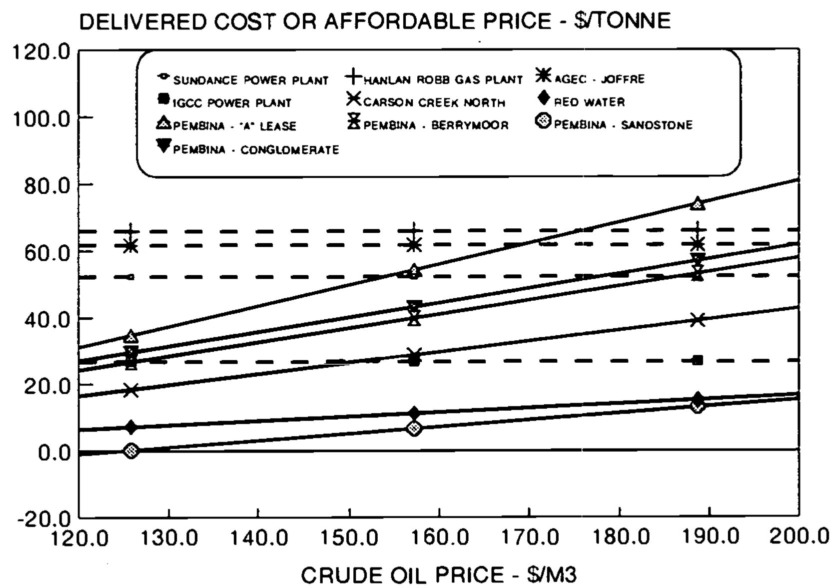


FIGURE 8.2B - ALBERTA CO2 SOURCES AND EOR FIELDS
SUMMARY OF ECONOMIC ANALYSIS BASED ON NORMAL BUSINESS APPROACH

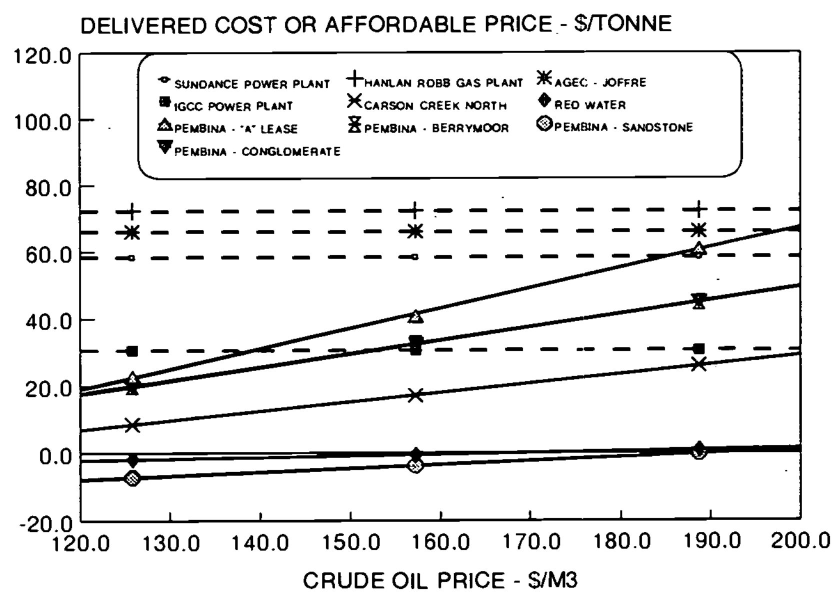


FIGURE 8.3A - SASKATCHEWAN CO2 SOURCES AND EOR FIELDS
SUMMARY OF ECONOMIC ANALYSIS BASED ON SOCIAL APPROACH

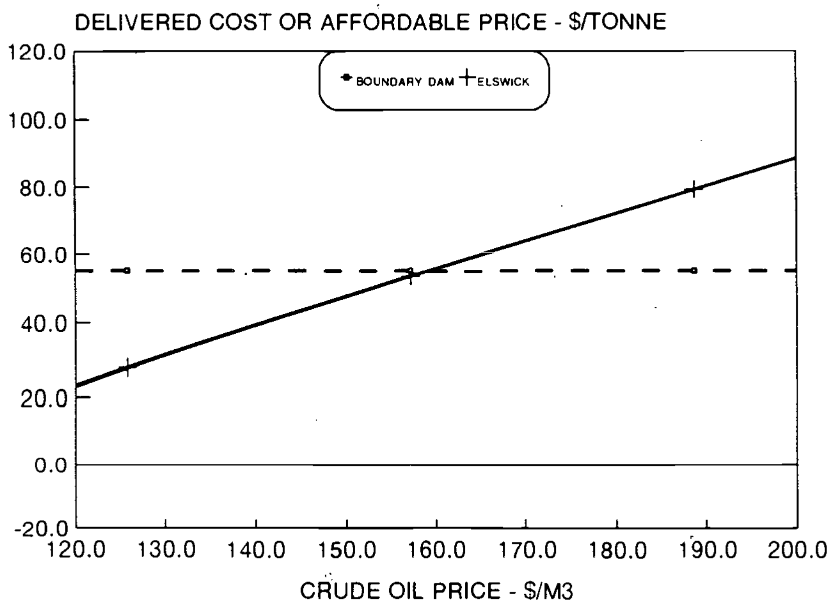


FIGURE 8.3B - SASKATCHEWAN CO2 SOURCES AND EOR FIELDS
SUMMARY OF ECONOMIC ANALYSIS BASED ON NORMAL BUSINESS APPROACH

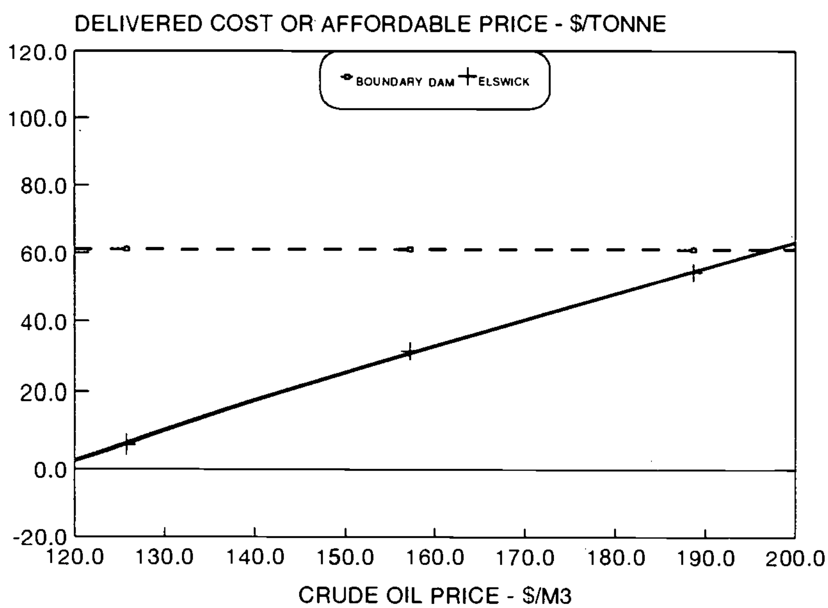


FIGURE 8.4A - SASKATCHEWAN CO2 SOURCES AND EOR FIELDS

SUMMARY OF ECONOMIC ANALYSIS BASED ON SOCIAL APPROACH

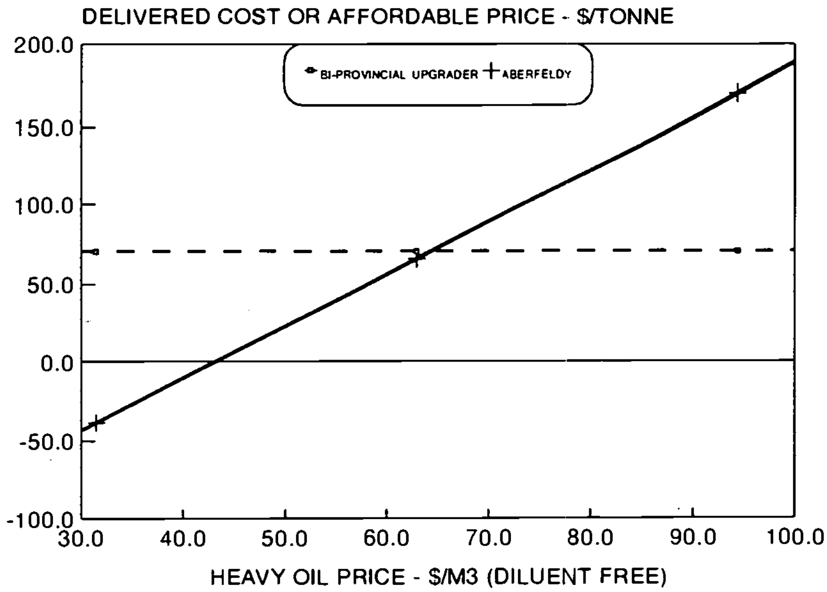
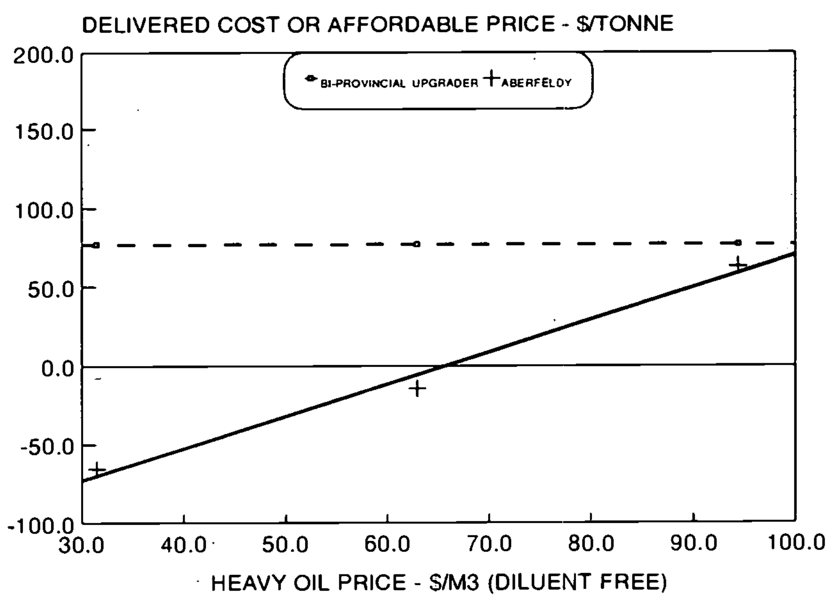


FIGURE 8.4B - SASKATCHEWAN CO2 SOURCES AND EOR FIELDS

SUMMARY OF ECONOMIC ANALYSIS BASED ON NORMAL BUSINESS APPROACH



The results summarized in Figures 8.2A and 8.2B indicate that there is significant variation in the Differential for Alberta. The magnitude of the Differential depends on the CO_2 source, EOR field, oil price, and the economic analysis approach used. Using the Social approach and an oil price of \$157.24/M^3 (\$25/Barrel), the Differential varies from +\$1.90/tonne (+\$0.10/MSCF) (net benefit) to -\$59.35/tonne (-\$3.10/MSCF) (net cost). The positive Differential (net benefit) is based on the lowest cost CO_2 source (Sundance Power Plant) and the best performing EOR field (Pembina 'A" Lease). The negative Differential (net cost), on the other hand, is based on the highest cost CO_2 source (Hanlan Robb) and the worst performing EOR field (Pembina - Sandstone). Using the Normal Business approach, the Differential (net cost) varies from -\$17.50/tonne to -\$76.25/tonne (-\$0.90/MSCF to -\$4.00/MSCF) for the same best and worst cases. The increase in Differential (net cost) between the two approaches can be attributed to taxes and royalties.

Please note that in deriving these Differentials the hypothetical IGCC case was not considered. If this case is considered, the Differential (net benefit) is significantly increased since the cost of producing CO_2 by IGCC is \$27.75/tonne (\$1.50/MSCF) lower than the cheapest CO_2 source (Sundance Power Plant).

For the Boundary Dam/Elswick case in Saskatchewan (Figures 8.3A and 8.3B) the Differential (net cost) is -\$1.53/tonne (-\$0.07/MSCF) using the Social approach and an oil price of \$157.24/M^3 (\$25.00/Barrel). This Differential (net cost) increases to -\$29.67/tonne (-\$1.55/MSCF) if Normal Business approach is utilized. This increase in Differential (net cost) can be attributed to taxes and royalties.

For the Bi-Provincial Upgrader/Aberfeldy case in Saskatchewan (Figures 8.4A and 8.4B) the Differential (net cost) is -\$4.75/tonne (-\$0.25/MSCF) using the Social approach and an oil price of \$62.90/M^3 (\$10.00/Barrel). This Differential increases to -\$91.25/tonne (-\$4.75/MSCF) (net cost) if Normal Business approach is utilized. This drastic change can be attributed mostly to royalties.

The cost of CO_2 disposal in depleted gas reservoirs is not depicted on Figures 8.2A and 8.2B. This cost is equal to the cost of capture, the cost of delivery, and the cost of disposal. The cost of disposal into depleted gas reservoirs, exclusive of capture and delivering, is \$0.57/tonne to \$0.95/tonne (\$0.03/MSCF to \$0.05/MSCF). The lower cost reflects the Social approach while the higher cost reflects the Normal Business approach. The total disposal cost, including the cost of capture and delivery from various CO_2 sources, ranges from \$53.00/tonne (\$2.80/MSCF) to \$73.40/tonne (\$3.85/MSCF).

Figures 8.2A to 8.4B do not reflect the CO_2 quantities involved. The impact of CO_2 quantities is reflected in Figures 8.6A to 8.7B. In developing these figures it was assumed that all the sandstone type reservoirs shortlisted in Alberta would have economics similar to those of the Pembina (Conglomerate and Berrymoor) field. Similarly, the reef type reservoirs and D-3 type reservoirs would have economics similar to those of Carson Creek North and Redwater fields, respectively.

These figures depict the Delivered Cost (dotted line), the Affordable Price (solid line), and the resulting Differential (net cost) as a function of CO_2 captured. The Affordable Price for CO_2 is based on an oil price of \$157.24/M^3 (\$25.00/Bbl) for light oil, and \$62.90/M^3 (\$10.00/Barrel) for heavy oil. These figures have been drawn to reflect increasing Differential (net cost) with quantity.

For Alberta (Figures 8.6A and 8.7B) based on results obtained using Social approach, the Differential (net cost) varies from -\$10.85/tonne (-\$0.55/MSCF) to -\$66.60/tonne (-\$3.50/MSCF), with an average Differential of -\$27.96/ tonne (-\$1.47/MSCF). Based on results obtained using the Normal Business approach, the Differential (net cost) varies from -\$25.87/tonne to -\$73.41/tonne (-\$1.35/MSCF to-\$3.85/MSCF), with an average Differential of -\$42.60/tonne (-\$2.24/MSCF).

For Saskatchewan (Figures 8.7A and 8.7B) based on results obtained using Social approach, the Differential (net cost) varies from -\$1.53/tonne (-\$0.08/MSCF) to -\$4.75/tonne (-\$0.25/MSCF), with an average Differential (net cost) of -\$1.90/tonne (-\$0.10/MSCF). Based on results obtained using the Normal Business approach, the Differential (net cost) varies from -\$29.67/tonne to -\$90.91/tonne (-\$1.55/MSCF to -\$4.78/MSCF), with an average Differential (net cost) of -\$36.52/tonne (-\$1.92/MSCF).

8.3 CONCLUDING REMARKS

The results of economic analysis have indicated that under the following conditions the benefits from EOR do not totally offset the cost of capture and delivery of CO_2.

- Economic analysis approach is based on either Social utilizing 10% rate of return or Normal Business.
- Flat oil price profile of \$157.24/M^3 (\$25.00/Barrel) or lower is utilized.
- Crude production profile for the EOR fields is based on 75% or lower of TCA's predictions.

There are, however, other conditions, such as oil price of \$188.69 M^3 (\$30.00/Barrel), Social approach utilizing 5% rate of return, and crude production profile for EOR fields based on 100% of TCA's prediction, under which the Affordable Price for certain EOR fields either totally offset, or exceed, the Delivered Cost of CO_2. In order to establish these conditions for the various EOR fields please refer to Section 7.0 of Volume 5 (Economic Analysis).

FIGURE 8.6A - DELIVERED COST vs. AFFORDABLE PRICE FOR CO2 DISPOSAL IN ALBERTA (BASED ON SOCIAL APPROACH)

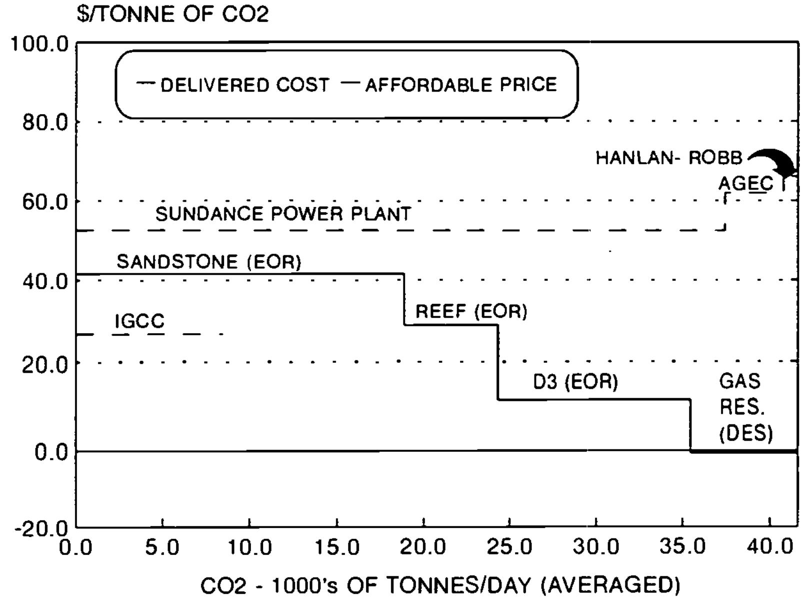


FIGURE 8.6B - DELIVERED COST vs. AFFORDABLE PRICE FOR CO2 DISPOSAL IN ALBERTA (BASED ON NORMAL BUSINESS APPROACH)

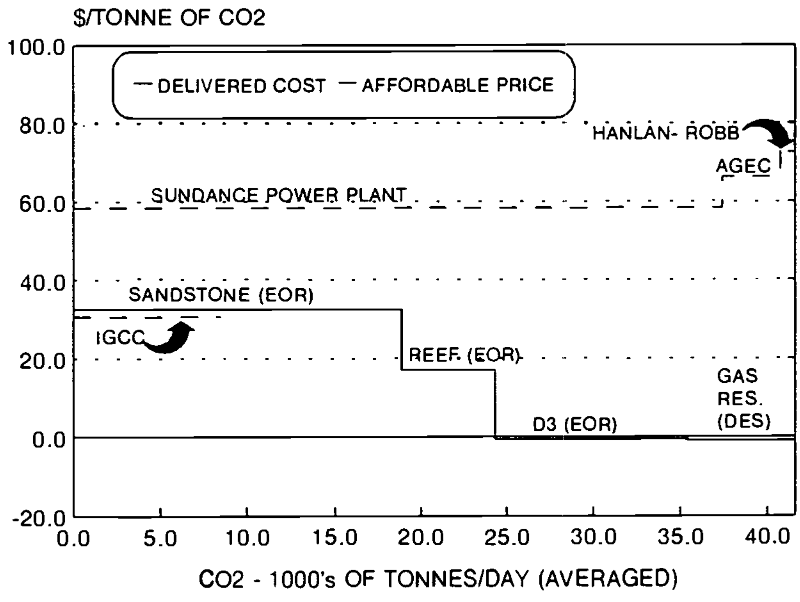


FIGURE 8.7A - DELIVERED COST vs. AFFORDABLE PRICE FOR CO2 DISPOSAL IN SASKATCHEWAN (BASED ON SOCIAL APPROACH)

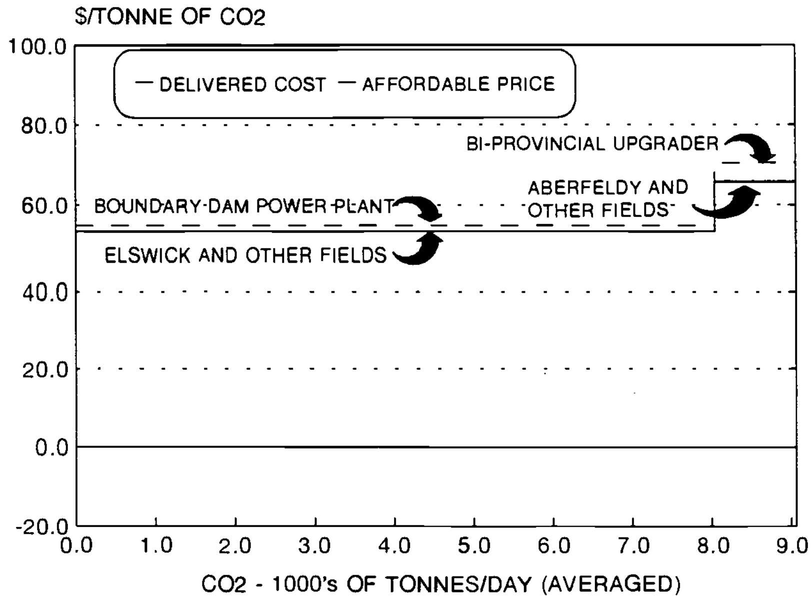
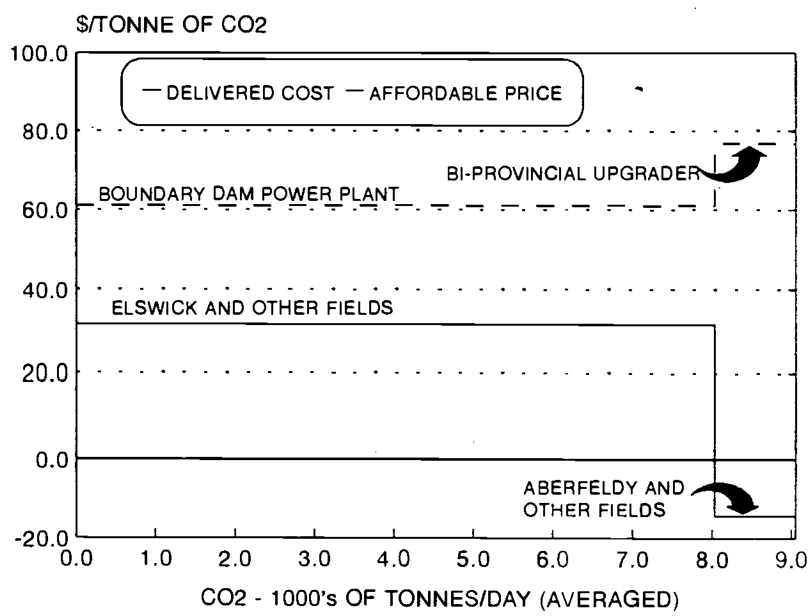


FIGURE 8.7B - DELIVERED COST vs. AFFORDABLE PRICE FOR CO2 DISPOSAL IN SASKATCHEWAN (BASED ON NORMAL BUSINESS APPROACH)



9.0 REFERENCES

9.0 REFERENCES

Bardon, C. and L. Denoyelle, 1984. CO_2 Injection to Enhance Oil Recovery, pp. 177-210 In: Heavy Crude Oil Recovery, NATO ASI Series E: Applied Services No. 76 Edited by: E. Okandan

Bondor, P.L., 1992. Applications of Carbon Dioxide In Enhanced Oil Recovery. Energy Conservation Management. 33 (5-8): 579-586.

Energy Resources Conservation Board, 1991. Alberta's Reserves of Crude Oil, Oil Sands, Gas, Natural Gas Liquids and Sulphur. ERCB FT 92-18.

Farris, C.B., "Unusual Design Factors for Supercritical CO_2 Pipelines" Energy Progress Vol. 3 No. 3, Sept. 1983.

Hadlow, R.E., 1992. Update of Industry Experience with CO_2 Injection. SPE 24 928.

Jaques, A.P., 1992. Canada's Greenhouse Gas Emissions: Estimates for 1990. Environment Canada Report.

Scott, J.D., 1992. The Quiet Success of Miscible Flood Enhanced Oil Recovery. In: Fueling The Future New Horizons In Oil Sands, Heavy Oil and Enhanced Oil Recovery. June 10, 11, 12, 1992. Calgary, Alberta. AOSTRA/Canadian Heavy Oil Association 1992 Conference.

APPENDIX
CASE 7 - IGCC

APPENDIX IGCC POWER PLANTS

A1 SUMMARY

Integrated gasification combined cycle (IGCC) power plants offer the potential for not only higher efficiency and lower emissions, but lower costs for the recovery of CO_2 . This option was originally not included in this project because no IGCC plants are operational in Canada. Since future coal fired power plants may use IGCC, the scope of this project was changed to include a review of CO_2 capture for IGCC power plants.

The basis for this review is a report "Evaluation of IGCC Design Options" by Bechtel Canada for TransAlta Utilities and Alberta Power Limited. Interpreting this report on the same basis as other cases in this study gives the following results on the incremental costs for capture of 75% of the CO_2 emissions from a 500 MW_e IGCC power plant.

In summary with CO_2 recovery of 8487 tonnes per day, 10% more coal is used to produce 9% less power. The thermal efficiency drops from 38.8% to 32.5%, the imputed CO_2 emission for CO_2 capture utilities is 2092 tonnes/day, so the resulting net capture is 6395 tonnes/day. The capital costs of the capture facilities increases the capital cost by 22% or $369 million. The annual incremental operating costs on a comparable basis with other cases in this report is $24.6 million.

	Gross	Net
CO_2 Captured (Tonnes/day)	8487	6395
Unit Operating Costs ($/Tonnes)	7.96	10.56
Capital Cost ($ Million)	368.8	368.8

These costs are significantly lower than any of the CO_2 capture costs in this study. However, the costs do not include the cost of implementing the IGCC technology. The cost of new IGCC power plants is expected to be significantly higher than the coal fired power plants now in service in Western Canada.

A2 SCOPE OF WORK

The scope of this study was to include only existing CO_2 emission sources. The capture processes were to be retrofitted to plants now in service and expected to remain in service for the study period (to 2015). It was recognized that opportunities to capture CO_2 from new sources at lower costs may be missed since it is generally cheaper to incorporate changes at the design stage than to retrofit changes to existing facilities. This decision to limit the scope to existing facilities and not to include hypothetical cases, was made to maintain the accuracy and reality of the study.

One exception to this retrofit policy is the inclusion of integrated gasification combined cycle (IGCC) technology because of the expectation that future coal fired power plants in Western Canada are likely to be based on IGCC. The study would have been considered deficient if this technology was not included. Not only is IGCC viewed as the basis for future power generation, but it offers substantial advantages for CO_2 capture at higher pressure and concentration resulting in much lower costs and efficiency losses.

The interest in IGCC technology for electrical power production is based on the higher energy efficiencies available (typically around 40%), lower emissions of CO_2, NO_X, and SO_X and the potential for staged construction. To provide the initial increment of power the gas turbine/generator can be installed and fired with natural gas. To gain capacity and improve efficiency the heat recovery steam generator can be added. Finally, the coal gasifier can be added when justified by the price differential between coal and natural gas.

To enable IGCC to be included in this study without duplicating previous work, TransAlta Utilities and Alberta Power Limited agreed to provide access for AOSTRA to a recent study "Evaluation of IGCC Design Options" by Bechtel Canada Ltd. AOSTRA agreed to review the report and comparative data on CO_2 capture for an IGCC power plant. The IGCC case was added to AOSTRA's scope of work, as project operator, but it was not added to the scope of work for SNC, the facilities contractor or other contractors. The Bechtel Report provided the necessary technical information (technical description, flow diagrams, mass balances and cost estimates) to the same level of detail and accuracy as the SNC reports.

A3 IGCC TECHNOLOGY

Electrical power production by IGCC (Figure A1) involves the gasification of coal through partial oxidation to a synthesis gas (syngas) mixture of carbon monoxide (CO), hydrogen (H_2) and carbon dioxide (CO_2). The syngas is scrubbed of impurities and burned in a gas turbine to generate electric power. In the combined cycle process, exhaust from the gas turbine is passed through a heat recovery steam generator (HRSG) and the steam is used to drive a steam turbine and generator to produce more electric power.

The base case in the Bechtel Report is a nominal 500 MW_e power plant which uses the Shell Coal Gasification Process, two GE MS7001F gas turbines producing 350 MW_e, and two heat recovery steam generators producing 226 MW_e. In plant power consumption was 83.5 MW_e, mostly for the air separation plant, (54.8 MW_e). This results in a net output of 492.5 MW_e, an efficiency of 38.8%, and a net heat rate of 9278 kJ/kWh. The capital cost for an Alberta installation was estimated to be $1679 million in 1989 Canadian (1704.5 $/kW).

A4 IGCC WITH CO_2 CAPTURE

To capture CO_2 from an IGCC plant, the cleaned syngas is reacted with steam in a Water Gas Shift. This converts the carbon monoxide to hydrogen and carbon dioxide.

$$CO + H_2O \longrightarrow CO_2 + H_2$$

The CO_2 is then scrubbed out of the gas leaving the hydrogen as the fuel for the gas turbine. Because of the CO_2 concentration (35 V%) and pressure (2.5 MPa), a physical solvent such as Selexol can be used to absorb CO_2. The CO_2 flashed from the Selexol is then dried and compressed for delivery to the pipeline system. (See Figure A2).

The design case in the Bechtel report utilizes the same gas turbine system. More coal (10%) must be gasified to make up for the lower heating value of hydrogen compared to syngas. The power production is 350 MW_e from the gas turbines and 236.5 MW_e from the steam turbine. The in plant power consumption is increased to 134.5 MW_e due to the CO_2 recovery and compression (42.7 MW_e) and the increased air compression and separation energy requirements (now 60 MW_e). The net power output is reduced to 452 MW_e. The overall plant efficiency drops to 32.5% or a net heat rate of 11,080 kJ/kWh. The capital cost is increased by 22% to $2,047.8 million or 2,265 $/kWh,

The CO_2 emissions are reduced from 10,481 tonnes/day (887 kg/MWh) to 3,000 tonnes/day (276 kg/MWh) through the recovery of 8,487 tonnes/day.

In the IGCC CO_2 capture case, 10% more coal goes in, 9% less power comes out, the capital cost is increased by 22%, but 8,487 tonnes per day of CO_2 are captured and available as a product.

This case was designed for 75% CO_2 capture. CO_2 is still released from unshifted CO in the turbine fuel and CO_2 losses with the gas clean-up system.

A5 COMPARATIVE PARAMETERS

To provide comparable numbers on CO_2 capture with the other cases, the following assumptions have been made:

1. Capital Cost: The difference in the capital cost between the two cases is used as the capital cost to the plant to product 8487 tonnes/day of CO_2

   2047.8 - 1679.0 = $368.8 million or $119/tonne/year

2. Operating Costs: The costs for CO_2 recovery are taken as the difference between the annual operating and maintenance costs in the Bechtel Report:

Annual O & M Costs - $1,000

	IGCC	IGCC R	Delta
Fixed Operating Costs	10,167	10,579	412
Variable Oper. Costs	21,357	28,286	6,929
Sulfur By-Product Credits	(960)	(1,051)	(91)
TOTAL O & M			7,250

3. Efficiency: The increased coal feed requirement of 566 tonnes/day is treated as a utility cost for CO_2 recovery. An operating cost of 20 $/tonne of coal or $4.13 million per year is allocated and a CO_2 emission penalty of 1.79 tonnes CO_2 /tonne of Coal or 1013 tonnes of CO_2 per day is assessed to calculate the net CO_2 produced.

   The decreased electrical output is treated as a process power requirement of 50.5 MWe (492.5-452). This is charged to CO_2 recovery at the basic rate used in the study $0.03/kWh or $13.3 million/year. The CO_2 emission penalty is charged at the average rate used in the study of 890 kg/MWh or 1079 tonnes/day. The net CO_2 capture is 8487 - (1013 + 1079) = 6395 tonnes/day.

The annual operating costs to capture 8487 tonnes per day of CO_2 are:

	($1,000)
O & M	7,250
Fuel	4,132
Electricity	13,271
Annual Operating Costs	$24,653

SUMMARY TABLE:

	IGCC with CO_2 Recovery	
	Gross	**Net**
CO_2 Captured (Tonnes/day)	8487	6395
Unit Operating Costs ($/Tonne)	7.96	10.56
Capital Cost ($ MM)	368.8	368.8

FIGURE A1
CASE 7
INTEGRATED GASIFICATION COMBINED CYCLE

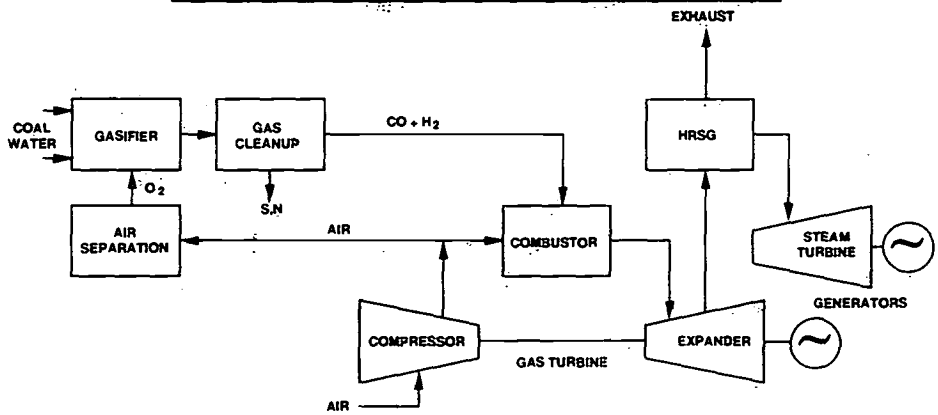


FIGURE A2
CASE 7
IGCC WITH CO_2 CAPTURE