168
1-10-80

168 540

COO-4043-2

MASTER

ANALYSIS OF THE ENVIRONMENTAL CONTROL TECHNOLOGY FOR TAR
SAND DEVELOPMENT

By
Noel de Nevers
Bard Glenne
Clifford Bryner

June 1979

Work Performed Under Contract No. EY-76-S-02-4043

University of Utah
College of Engineering
Salt Lake City, Utah

U. S. DEPARTMENT OF ENERGY

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

ANALYSIS OF THE ENVIRONMENTAL CONTROL TECHNOLOGY
FOR TAR SAND DEVELOPMENT

Noel de Nevers, Professor of Chemical Engineering
Bard Glenne, Associate Professor of Civil Engineering
Clifford Bryner, Professor of Civil Engineering

College of Engineering
University of Utah
Salt Lake City, Utah 84112

June 1979

DISCLAIMER
This book was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Prepared for
The Environmental Control Technology Division
Under Contract No. EY-76-S-02-4043

DISTRIBUTION OF THIS REPORT

JP
RECEIVED

TABLE OF CONTENTS

	<u>Page</u>
SUMMARY	1
1. INTRODUCTION	3
1-A. The Tar Sand Resource and Its Potential Application	3
1-A-1. The Nature of Tar Sands	3
1-A-2. The Origin of Tar Sands	13
1-B. Tar Sand Resources and Reserves	15
1-C. The Possible Ways to Process Tar Sands	17
1-D. Some History of Tar Sand Exploitation and Description of the Projects Currently in Progress . .	22
1-D-1. The Athabasca Deposit in Canada	23
1-D-2. The Utah Deposit	29
1-E. Environmental Constraints	30
1-E-1. The Scope and Goals of this Study.	31
1-E-2. General Kinds of Environmental Problems. . .	36
1-F. Proposed Environmental Control Strategies	39
1-F-1. Air Pollution	39
1-F-2. Water Pollution.	40
1-F-3. Processed Tar Sand Disposal.	41
1-G. Environmental Control Difficulties and Questions. . .	42
1-H. Environmental Control Costs	43
2. ENVIRONMENTAL CONSTRAINTS - USA.	44
2-A. Air Pollution	45

2-A-1.	Air Quality Standards.	47
2-A-2.	The Role of Modeling	51
2-A-3.	Emission Standards	54
2-A-4.	Prevention of Significant Deterioration (PSD).	55
2-B.	Water Pollution	59
2-B-1.	Water Pollution Policies and Programs. . . .	59
2-B-2.	The Discharge Permit Program	62
2-B-3.	Water Quality Criteria and Standards	63
2-B-4.	Summary of Water Pollution Constraints. . . .	70
2-C.	Solid Waste Disposal.	71
2-C-1.	Environmental Threats	72
2-C-2.	Wastes to be Dealt With	72
2-C-3.	Lease Stipulation Constraints.	73
2-C-4.	Federal Laws and Regulations	74
2-C-5.	Utah Regulations	80
2-C-6.	Summary of Solid Waste Disposal Regulations.	82
3.	ENVIRONMENTAL CONSTRAINTS - CANADA	83
3-A.	Air Pollution Regulations	85
3-B.	Water Pollution Regulations	89
3-C.	Solid Waste Disposal Regulations.	95
4.	PROPOSED ENVIRONMENTAL CONTROL TECHNOLOGIES.	98
4-A.	Tar Sand Variables Which Influence The Choice of Processing Technology	98
4-B.	Overall Process Scheme-Surface Processing	108
4-C.	Overall Process Scheme In-Situ Recovery	111
4-D.	Technology Transfer	117

4-E.	Air Pollution Control Technology.	120
4-E-1.	Control of Particulates.	120
4-E-2.	Reactions and Compounds of Sulfur and Nitrogen.	124
4-E-3.	The Removal of Nitrogen and Sulfur Compounds from Gas Streams.	128
4-E-4.	Control of Sulfur Oxides	136
4-E-5.	Control of Nitrogen Oxides	140
4-E-6.	The Chemistry and Control of Hydrocarbons and Carbon Monoxide	144
4-F.	Water Pollution Control Technology	148
4-F-1.	Overview of Water Control Technology	148
4-F-2.	Water Use and Quality.	151
4-F-3.	Waste-Water Treatment	155
4-F-4.	Surface Runoff Diversion	156
4-F-5.	Aquifer ReInjection.	157
4-F-6.	Containment and Evaporation (Zero Release Concept)	160
4-F-7.	Leachate Production.	164
4-G.	Solid Waste Disposal and Management	166
4-G-1.	General Premise	166
4-G-2.	Description of Solid Wastes.	166
4-G-3.	Disposal Technology.	168
4-G-4.	Disposal Site Selection and Preparation	168
4-G-5.	Transport of Wastes to the Disposal Facility.	169
4-G-6.	Construction of Disposal Piles	169
4-G-7.	Construction Technique	173
4-G-8.	Control of Surface Erosion	174
4-G-9.	Rehabilitation of the Disposal Facility.	175

4-H.	Environmental Control Technology for In-Situ Combustion.	176
5.	ENVIRONMENTAL CONFLICT WITH UTAH NATIONAL PARKS.	179
6.	THE COST OF ENVIRONMENTAL CONTROL.	183
6-A.	Cost Estimates for a Syncrude-type Plant.	183
6-B.	Cost of Environmental Control	187
7.	POTENTIAL PROBLEMS AND DIFFICULTIES WITH PROPOSED ENVIRONMENTAL CONTROL TECHNOLOGIES.	190
7-A.	Comparison of In-Situ and Surface Processing from an Environmental Viewpoint	190
7-A-1.	Air Pollution.	190
7-A-2.	Water Pollution	191
7-A-3.	Surface Disposal of Waste.	193
7-B.	Proprietary Information	195
7-C.	Potential Air Pollution Difficulties.	196
7-D.	Potential Water Pollution Difficulties.	196
7-D-1.	Dam Safety	196
7-D-2.	Settling and Evaporation Ponds	197
7-D-3.	Aquifer Reinjection.	199
7-D-4.	Potential Difficulties with Tailings Piles	200
7-E.	Underground Fluid Management.	203
8.	POLICY QUESTIONS CONCERNING THE ENVIRONMENTAL CONTROL TECHNOLOGY FOR TAR SAND DEVELOPMENT.	205
8-A.	Interaction with Oil Shale Development.	206
	BIBLIOGRAPHY.	210
Appendix I	Coking	I-1
Appendix II	Thermal and Solvent Bitumen Recovery Processes . .	II-1
Appendix III	Utah Tar Sand Deposits	III-1

Appendix IV	Conventional and Secondary Recovery of Petroleum . .	IV-1
Appendix V	Partial Listing of Commonly Used Slope Equivalents Used to Describe Cross-Section Slopes. .	V-1
Appendix VI	Tailings Dams for Tar Sand Waste	VI-1
Appendix VII	Pollution Control Cost Estimates	VII-1
	VII-1. Electrostatic Precipitator on Carbon Monoxide Boilers	VII-1
	VII-2. Claus Plant and Tail Gas Clean Up	VII-2
	VII-3. Tall Stack	VII-3
	VII-4 Amine Plant Costs	VII-3
	VII-5 Wastewater Treatment Costs	VII-4
	VII-6 Waste Sand Disposal	VII-5
Appendix VIII	The Alsands Cost Estimates	VIII-1

LIST OF FIGURES

		<u>Page</u>
Figure 1-1.	Location of Major Tar Sand and Heavy Oil Deposits in Alberta (Outtrim and Evans, 1977). .	4
Figure 1-2.	Location of the Venezuela Tar Sand Deposit . . .	5
Figure 1-3.	Location and extent of the Utah Tar Sands Deposits	7
Figure 1-4.	The Spectrum of Petroleum Product Properties	11
Figure 1-5	Possible Methods of Removing Bitumen from its Containing Matrix	18
Figure 1-6.	Bitumen Upgrading Possibilities.	21
Figure 1-7.	Capital Cost Index for the Period 1967-77. . . .	25
Figure 2-1.	Schematic View of the Air Pollution Problem.	46
Figure 2-2.	Illustration of Two Different Approaches to Estimating the Ground Level (hillside) Concentration of Pollutant from a Point Source .	53
Figure 4-1.	Viscosity-temperature Relationships for Some Tar Sand Bitumens	101
Figure 4-2	Alberta Energy Resources Conservation Board Estimate of the Criteria for Separating Mineable from Unmineable Tar Sands	103
Figure 4-3	Expanded Version of Figure 4-2, Showing the Surface Mineability Factor	105
Figure 4-4	Estimate of Criteria for Mineability of Utah Tar Sand Deposit by Kuuskraa et al. (1978) . . .	106
Figure 4-5	Overall Flow Diagram of Surface Mining and Processing of Tar Sands as Now Used in Alberta	109
Figure 4-6	Conceptual Comparison of Various Kinds of In-Situ Tar Sand Recovery Processes	114
Figure 4-7	The Oxidation and Reduction of Nitrogen and Sulfur	127

Figure 4-8	The Flow Diagram for the Most Common Method of Removing One Component from a Gas Stream	129
Figure 4-9	Sulfur Control Schematic	135
Figure 4-10	Major Sulfur Paths and Daily Tonnages (Elemental Sulfur Basis, in Tonnes) for the Syncrude Operation	139
Figure 4-11	Water Flow in Tar Sand Projects	150
Figure 4-12	Overall water balance for the Alsands Project (Alsands, 1978)	152
Figure 4-13	Schematic Layout for a Typical Tar Sand Operation	167
Figure 4-14	Modes of Embankment Failure.	168
Figure 5-1	Map of Utah Showing National Parks, National Monuments, and National Recreation Areas, and also Tar Sand Deposits	180
Figure I-1	Effect of Temperature (and also Reaction Time) on Product Distributions in Pyrolysis of Hydrocarbons	I-3
Figure I-2	Simplified Flow Diagram of Delayed Coking. .	I-5
Figure I-3	Simplified Flow Diagram of Fluid Bed Coking.	I-7
Figure I-4	Simplified Flow Diagram of Flexicoking . . .	I-10
Figure IV-1	Simplified Illustration of the Conditions Under which Gravity will be a Significant Force Moving Fluids Toward a Producing Well.	IV-3
Figure IV-2	Highly Idealized Representation of an Oil-Bearing Formation in which the Oil is Continuous and therefore Mobile and One in which the Oil is Discontinuous and therefore Immobile. . .	IV-7
Figure VII-6	Typical Section Through a Dike	VII-6

LIST OF TABLES

		<u>Page</u>
Table 1-1	Deposits of Bitumen-Bearing Rocks in the United States with Resource over 1,000,000 Barrels	6
Table 1-2	Comparison of Tar Sand and Oil Shale	9
Table 2-1	Federal Ambient Air Quality Standards	49
Table 2-2	Federal Significant Deterioration Limitations	57
Table 2-3	Numerical Standards for Protection of Beneficial Uses of Water	65
Table 3-1	Comparison of U. S. Federal, Canadian Federal, and Alberta Ambient Air Quality Standards and Goals	86
Table 3-2	Progressive Improvement in Sulfur Recovery for Alberta Tar Sand Projects.	90
Table 3-3	Canadian Petroleum Refinery Liquid Effluents Regulations	92
Table 3-4	Alberta Surface Water Quality Objectives	93
Table 4-1	Particulate Control Technology for Existing, Proposed, and Possible Tar Sand Plants	125
Table 4-2	Summary of Unit Process in Refinery Fuel-Gas Desulfurizing.	133
Table 4-3	Comparison of Sulfur Control Technologies for Various Tar Sand Projects.	141
Table 4-4	Estimated Air Pollutant Emissions from Total U. S. Oil Refining Industry.	147
Table 4-5	Greatest Observed Rainfalls, Grand Junction, Colorado	158
Table 4-6	Mean Monthly Precipitation - Evaporation Data	163
Table 6-1	Capital Cost Estimates for 100,000 B/D (of Product) Tar Sand Project, Using Syncrude Technology	184

Table 6-2	Operating Cost Breakdown for 100,000 B/D (of Product) Tar Sand Project, Using Syncrude Technology	185
Table 6-3	Estimates of the Capital Cost Investment for Environmental Control for a 100,000 B/D Syncrude-Type Plant	188
Table 7-1	Water Use for Tar Sands Operations.	192
Table 7-2	Water Requirements for Tar Sands Operations .	194

SUMMARY

This report examines the environmental control technology for production of liquid fuels from tar sands. The technologies for control of air pollution, water pollution, and for the disposal, stabilization, and vegetation of the waste tar sand were thoroughly investigated. Although some difficulties may be encountered in any of these undertakings, it seems clear that the air and water pollution problems can be solved to meet any applicable standard. There are no published national standards against which to judge the stabilization and vegetation of the waste sand. However, based on the goal of producing an environmentally and aesthetically acceptable finished waste sand pile, it seems probable that this can be accomplished.

We conclude that the environmental control technology is available to meet all current legal requirements, for at least a moderate sized industry.

Currently there are two large-scale plants producing liquid fuels from tar sands in Alberta, Canada. These both use similar technology involving surface mining, hot water extraction, and surface disposal of waste sand. There are pending applications in Alberta for a large-scale in-situ steam-flood recovery project and a third surface mining project. These projects all meet the Canadian environmental control regulations in force at the time they began, or will begin.

The most recent Canadian project (Syncrude) encountered severe financial difficulties because this type of project is very capital intensive. These difficulties were not to any major extent caused by environmental control regulations.

The largest U. S. deposits of tar sands are much smaller than the Canadian; 95 percent are located in the state of Utah. Their future exploitation is problematical because their economics do not appear as attractive

as those of the Canadian deposits. The environmental control costs are not large enough to make an otherwise economic project uneconomic.

The most serious environmental conflict likely to occur over the recovery of liquid fuels from the U. S. deposits of tar sands is that caused by the proximity of the deposits to national parks, national monuments, and a national recreation area in Utah. These areas have very stringent air pollution requirements (National parks are PSD Class I.); and even if the air pollution control requirements can be met, there may still be adequate opposition to large-scale mining ventures in these areas to prevent their commercial exploitation.

Another environmental constraint on Utah tar sands development may be water rights availability. Essentially all of the water running in the Colorado river basin is now legally allocated. New developments are dependant on water rights purchase. Barring new interpretations of the legality of water rights purchase, Utah tar sands developments should be able to obtain water by purchasing existing irrigation water rights.

1. INTRODUCTION

I-A. The Tar Sand Resource and Its Potential Application

Tar sands (whose nature is discussed below) are hydrocarbons, which are potential sources of liquid fuels, (e.g. gasoline, jet fuel, heating oils). The known tar sand deposits of the world are comparable in size or perhaps larger than the known reserves of conventional oil. The two largest such tar sand deposits are located in Canada (Fig. I-1) and Venezuela (Fig. I-2). In the USA there are no known tar sand deposits which are even 1/10 as large as these two massive deposits. However, there are substantial US tar sand deposits, mostly in the state of Utah. These tar sand deposits have potential oil amounting to perhaps 30 billion barrels. It must be emphasized that this potential oil is not necessarily recoverable oil. In the past, it has not been economical to recover this potential oil; its future economics are not known for certain. Table I-1 lists the known U. S. tar sand deposits; Figure I-3 shows the location and extent of the Utah deposits, which are over 95 percent of the US total.

I-A-1. The Nature of Tar Sands

The term tar sand is used more or less interchangeably with other terms such as "oil sand," "bituminous sandstone," "bituminous sand," or "rock asphaltum." All of these indicate that the material of interest is a high-boiling point, high-viscosity hydrocarbon which is present in a porous matrix which is normally an unconsolidated sand but may be consolidated sandstone or limestone.

FIGURE 1-1. Location of Major Tar Sand and Heavy Oil Deposits in Alberta (Outtrim and Evans, 1977). Although the areas of the deposits appear comparable, the Athabasca deposit is thicker than the others, so that it contains roughly twice as much bitumen as all the others combined.

FIGURE 1-2. Location of the Venezuela Tar Sand Deposit (referred to in the literature as the "Orinoco tar sand belt" or the "Oficina-Temblador tar sand belt") (Phizackerly and Scott, 1967).

TABLE 1.1

Deposits of Bitumen-Bearing Rocks in The United States with Resource
over 1,000,000 barrels After Marchant and Johnson (1977)

State and Name of Deposit	Estimated Resources (Millions of Barrels)
California:	
Edna.....	166.4
South Casmalia.....	
North Casmalia.....	
Sisquoc.....	50.0
Santa Cruz.....	
McKittrick.....	9.0
Point Arena.....	
California Total..	323.0
Kentucky:	
Kyrook Area.....	
Davis-Dismal Area....	11.3
Bee Spring Area.....	
Kentucky Total..	37.3
New Mexico: Santa Rosa	
Texas: Uvalde.....	140.7
Utah:	
Tar Sand Triangle....	16,004.0
P. R. Spring.....	4,500.0
Sunnyside.....	4,000.0
Circle Cliffs.....	1,300.0
Asphalt Ridge.....	1,200.0
Hill Creek.....	1,160.0
San Rafael Swell.....	470.0
Raven Ridge.....	150.0
Argyle Canyon.....	125.0
Asphalt Ridge, North- west.....	125.0
Whiterocks.....	125.0
Cottonwood-Jacks Canyon.....	100.0
Wickiup.....	75.0
Minnie Maud Creek..	50.0
Rimrock.....	35.0
Willow Creek.....	25.0
Pariette.....	15.0
White Canyon.....	15.0
Littlewater Hills.....	12.0
Lake Fork.....	10.0
Nine Mile Canyon....	10.0
Chapita Wells.....	8.0
Ten Mile Wash.....	6.0
Tabiona.....	4.6
Thistle.....	2.5
Spring Branch.....	2.0
Cow Wash.....	1.2
Utah Total.....	29,530.3
U.S. Total....	30,088.5

FIGURE 1-3. Location and extent of the Utah Tar Sands deposits which constitute over 95 percent of the known USA tar sands deposits (Marchant and Johnson, 1977)

It would probably be better if the term "tar" were not used, because elsewhere this word is normally reserved for materials obtained by distillation or thermal processing of organic materials (e.g. the "tar" in cigarette smoke). That is not the case with the organic materials in tar sands; however, this organic material (which is most often referred to in the technical literature as "bitumen") has many physical and chemical properties in common with "roofing tar" or "paving tar" (which are both "tars" produced by distillation) and has often been used interchangeably with them. Thus if we insist on purity of nomenclature, we could not use the term "tar sands." But because it is so widely used, we will use it, with this disclaimer to the reader.

In a previous report the same authors considered the Environmental Control Technology for Oil Shale Development (de Nevers et al., 1977). It is interesting and informative to compare the nature of tar sands and oil shales and to compare the prospects of their commercial development. Both oil shales and tar sands have in common: 1) They are potential unconventional sources of liquid fuels which could replace ordinary petroleum, 2) The potential supplies in North America vastly exceed North America's known petroleum reserves and presumably exceed the world's known petroleum reserves, and 3) The locations of the reserves are well known, and 4) in the past they have not been able to compete in the market place with low-cost petroleum. The two materials are contrasted in Table I-2, which is discussed below.

Oil shale development is of much greater current interest in the United States than tar sands development because the United States possesses the world's largest single deposit of oil shale. In contrast we have only modest deposits of tar sands.

Tar sands are mixtures of mineral grains (normally sand grains) and an organic material (normally called bitumen) which is a member of the

TABLE 1-2

Comparison of Tar Sand and Oil Shale

	<u>Tar Sand</u>	<u>Oil Shale</u>
Major world deposits (billions of potential barrels of liquid fuels)	Canada (1000) Venezuela (700)	USA (1000)
Estimated total <u>potential</u> oil recoverable from these in USA* (billions of barrels)	30	
Organic material name	bitumen	kerogen
Organic material behaves like	roofing or paving tar	vulcanized rubber
Mineral constituent is	coarse sand fine sand, some consolidated sandstone	marlstone (silicates and carbonates)

*For comparison purposes, the proven oil reserves of the USA are roughly 40 billion barrels, and our annual consumption (domestic and imported) is roughly 7 billion barrels/yr.

petroleum family. Figure I-4 shows a spectrum of petroleum products and crude oils. All petroleums are mixtures of many individual chemical compounds. (Simple hydrocarbons like natural gas may contain only a dozen, while crude oils probably contain tens of thousands of individual chemical compounds). The figure shows that, as we pass from materials such as gasoline to materials such as the bitumen in tar sands, the molecular weight, specific gravity, viscosity, (C/H) ratio and content of S, N, O, and metals all tend to increase. (There is considerable variation in all of these properties).

Figure I-4 shows that the difference between the bitumen in tar sands and a typical heavy crude oil is one of degree, not one of kind. A heavy crude oil is one which has a high viscosity, which is difficult to pump at room temperature, and which because of its viscosity will not flow easily into a well bore. A tar sand bitumen has a higher viscosity (perhaps 10 times as high) which makes it impossible to pump at room temperature and impossible to collect in a well bore.

All members of the petroleum family decrease in viscosity as they are heated. For a simple non-petroleum solid such as ice, there is a fixed temperature at which it converts from a hard solid to a liquid. For a typical petroleum solid, like the paraffin wax used to make candles or seal the tops of canned-fruit jars, there is no such simple transition. At room temperature, the wax is a solid which shatters if struck with a hammer. As the temperature is raised, it converts to a more plastic solid, which can be kneaded with the fingers, then to a mushy liquid-solid mixture, then to a syrupy liquid, then to a mobile liquid. The same is true of the bitumen in tar sands; when heated from room temperature to temperatures of the order of 300°F, it converts from a semi-solid to a syrupy and then to a runny fluid.

FIGURE 1-4. The Spectrum of Petroleum Product Properties

Dorrence (1976) suggests as a definition that a tar sand bitumen is one which has a viscosity of 100,000 cp or higher at 25°C.

Another property of the petroleum family, which is useful for distinguishing member from nonmembers and which has some processing applications for tar sands, is that all members are generally soluble in the strong solvent members of the family (e.g. benzene). Some members of the family are better solvents than others, and some members are harder to dissolve than others; but almost any member of the family will dissolve totally in benzene or some other strong solvent member of the family. If a typical tar sand is mixed thoroughly with benzene and then the benzene is drained off, and the process is repeated with a few benzene rinses, the remaining sand will be clean and shiny with no bitumen residue remaining.

Returning to Table I-2 and comparing the bitumen in tar sand with the organic material in oil shale (called "kerogen"), we see that kerogen is not a member of the petroleum family. It does not dissolve in organic solvents (some small fraction does, perhaps 1 percent, and is called "the bitumen content" of the oil shale to distinguish it from the kerogen). Table I-2 suggests that the kerogen behaves more like vulcanized rubber than like petroleums. This is only partly true but is the best analogy to commonly known substances. When solid rubber is heated, it does not turn into a liquid (as paving or roofing tar does). Instead it becomes a somewhat more flexible solid but retains its solid character until a temperature is reached at which it begins to thermally decompose. In its thermal decomposition, it forms gaseous, liquid, and solid products. So also does oil shale on heating (to about 900°F) decompose, forming liquid and gaseous products and a solid residue. All practical processes for separating the organic constituent of oil shale from the remainder are based on heating it hot enough to cause it to decompose.

Finally, in Table 1-2 it is indicated that the mineral constituent of tar sands is mostly coarse sands, sometimes fine sands, and sometimes sandstones (in which the sand grains are cemented together to form a coherent rock). In contrast the oil shales normally have a mineral constituent which geologists call a "marlstone" which is a mix of silicates, carbonates, and clays (Colony, 1974). One important consequence of this difference in mineral content is that fluids will generally flow through the mineral matrix in which tar sands are present (either the tar when heated or other fluids when the tar is removed) but will not flow through the matrix of oil shale. For this reason, it is necessary to mechanically fracture oil shale (normally with explosives) before any in situ process can be used while such fracturing is not necessary for in situ processing of tar sands.

The most widely accepted theory of the origin of petroleum (Lijmbach, 1975) holds that the original organic matter (bodies of algae, bacteria, pollen grains, plankton) was first converted to kerogen and then later converted by heat to oil, which migrates from the "source rocks" in which it is formed to a closed, porous formation where it is trapped. This conversion by heat took place at perhaps 200 to 300°F. Ordinary oil shale reacts very slowly (on a human time scale) at this temperature; but on a geologic time scale, the rate is reasonably rapid. Thus, in this view, the current oil shale deposits are intermediates in the production of oil, whose development was arrested before they became mature oils.

1-A-2. The Origin of Tar Sands

At present there is no universally-agreed-upon theory of the geologic history and formation of tar sand deposits. At least three theories have been proposed, each of which has some plausibility. These are:

1. That a tar sand deposit is simply a conventional oil field from which the lower-molecular-weight hydrocarbons have been removed by evaporation. (Clark (1949) implies this explanation while not specifically stating it). It is certainly true that if a conventional oil is subject to distillation or is allowed to stand exposed to the atmosphere for long periods of time, the lower-molecular-weight materials will evaporate; and the remaining residue will be a tar which is in many ways quite similar to the bitumen found in tar sands. The difficulty with this proposal is that it requires that enormous amounts of low-molecular-weight hydrocarbons have to escape by diffusion over extremely long diffusion paths. This seems implausible even over geologic time scales. For example, in the Athabasca Tar Sands there are large sections for which the low-molecular-weight hydrocarbons would have to have moved by diffusion for hundreds of miles.

2. A second explanation (Demaision, 1977, Deroo et al., 1974) is that the tar sands are conventional oil from which the low-molecular-weight hydrocarbons have been removed by water washing and by bacterial action. Most of the major tar sand deposits of the world are close to the surface and are found in areas where at present or at sometime in the past it is reasonable to expect that large amounts of surface waters could have percolated through the beds containing tar sand. These surface waters presumably could also have brought bacteria into the beds. Low-molecular-weight hydrocarbons are more soluble in water than the high-molecular-weight ones. There are bacteria which will metabolize low-molecular-weight hydrocarbons preferentially to high-molecular-weight ones. Thus if there were oil fields which did contain massive amounts of conventional oil and which were, for geologic time periods, exposed to the steady flushing action of ground water and exposed to hydrocarbon-consuming

bacteria, these could have converted the original oil into the tarry material now found. This explanation has the advantage that it does not require the long-distance diffusion of low-molecular-weight hydrocarbons, which the first one did, but rather assumes that a mobile water phase provided the necessary transport.

Demaion (1977) shows that major tar sand deposits are normally associated with other oil fields in the same geographic area and that these other oil fields which are deeper (and less accessible to water flushing) are generally lower in molecular weight, lower in viscosity, and lower in density than the tar sands. Furthermore, normally these adjacent oil fields are in many ways chemically similar to the tar sands deposits which supports the hypothesis that they had a common origin.

3. The third explanation which has been advanced (Ball (1941), Lijmbach (1975)) is that the tar sand as now seen is an immature petroleum. Petroleum is formed by the thermal and chemical alteration of organic material which was deposited in oceans and lakes. Modern geochemistry indicates that this material originally is of a high molecular weight and viscosity. In time, under high temperatures and pressures and in the presence of reducing materials, this material converts to lower molecular weight, lower density, lower viscosity materials. Thus it is possible that the tar sand deposits are merely unfinished petroleums.

We need not be certain which, if any, of these three explanations is the correct one nor whether there is one correct explanation for all tar sand deposits in order to discuss the processing and environmental control technology for tar sand development.

1-B. Tar Sand Resources and Reserves

Returning to Table 1-2, we see that the estimated USA deposits of tar sands are roughly 30 billion barrels. The two large deposits in the world

are those of Northern Alberta and of Eastern Venezuela. The Alberta deposits are estimated at 300 to 1,000 billion barrels and the Eastern Venezuela deposits at 700 million barrels. Thus it is clear that although the potential oil in the US tar sand deposits is large (the same order of magnitude as the conventional oil reserves of the USA), it is small compared to the major deposits in Canada and Venezuela.

We can also see from Table 1-2 that, compared to the potential oil in the shale oil deposits in the USA, the tar sand deposit is quite small.

Much of the discussion of tar sand processing and environmental control in this report will concern itself with the deposit in Canada. That deposit is now being exploited on a commercial basis and has been so exploited since 1967. Therefore, we know a great deal about the commercial processing and the environmental control technology used for it. We lack similar knowledge for the US deposits because they have not been exploited commercially on a significant scale.

In considering the exploitation of bitumen from tar sands, as with any mineral exploitation project, we must recognize that there exists a spectrum of quality or "grade" in the various deposits. In any such exploitation, the easily reached, high-grade materials are processed earliest. As technology improves, it generally becomes economical to process lower and lower grades of ore. Similarly, the fluctuation in the world price of products (compared to the fluctuations in the cost of production) strongly influences what grade of material is economically recoverable. Thus, although the total amounts of resources listed in the proceeding tables may be quite large, significant parts of them are uneconomical to recover at current prices and current technology or even in very optimistic projections of future prices and technology. For example, a recent study of the heavy oil and tar sands deposits in Southeastern Kansas (Ebanks et al., 1977) concluded that

there are apparently 200 to 225 million barrels of oil in place but that "The amount of this in-place resource which may be considered to be reserves, that is, recoverable under existing technology and economics, is zero." This conclusion was based on the quality and magnitude of the individual known reserves, which showed that they were mostly of low grade, in small deposits, and difficult to exploit. The point of this digression is to make clear that there is a distinction between "resources" and "reserves." A "resource" is customarily defined in mineral technology as a known mineral deposit which contains materials which would be valuable if they could be separated from the other materials with which they are mixed or contained. On the other hand, a "reserve" consists of a resource which is economically exploitable and recoverable by known technology at current prices. Thus it is safe to say that, given current technology and current economics, Canada has very large resources and reserves of tar sand, whereas the US had significant resources and currently has no reserves. In the future the USA may have tar sand reserves as the technology improves or the price situation changes to make exploitation more economically favorable.

1-C. The Possible Ways to Process Tar Sands

The tar sands as they exist in nature appear to have no direct uses. They have in the past been used as paving materials; generally, it is necessary to add additional sand to them to get the right hydrocarbon-to-sand ratio for good road building. However, the principal current interest is not of this type but rather for the production of liquid fuels.

To make liquid fuels from tar sands, it is necessary first to remove the bitumen from the sand in which it is present in nature and second to change its chemical composition.

The overall list of known possibilities for the removal from the sand is illustrated on Figure 1-5. We see that the first possibility is to attempt to remove the bitumen by bulk liquid flow at a viscosity lower than the

FIGURE 1-5. Possible Methods of Removing Bitumen From its Containing Matrix

viscosity which it normally has in its native environment. Bulk liquid flow is the means normally used to produce conventional crude oil; the oil flows to collecting wells and is removed to the surface. The viscosity of the bitumen can be lowered so that it will flow as a bulk liquid in three obvious ways. These are to raise its temperature, to dissolve the bitumen in a low-viscosity liquid solvent, or to create an emulsion of the bitumen in a non-hydrocarbon fluid (most likely water). In the latter two procedures, it would be necessary to recover the solvent or to break the emulsion thereby recovering the bitumen.

All three of these bulk flow possibilities do not envisage mining the solid mineral and processing it at the surface but rather attempt to modify it in place so that it will flow to collection wells as a liquid. The other alternative is not to attempt to produce bulk flow but rather to separate the sand grains from each other and recover the bitumen as individual particles from the separated sand grains. This separation is only possible if the sand grains have been mechanically removed one from each other. This entails mining and transporting the sand to a processing plant.

The methods of removing individual particles of bitumen from the sand grain are in hot-water suspension, cold-water suspension, or in various solvents. In each of these cases, the bitumen, which is sparingly soluble in water, would be separated by gravity and the remaining clean sand rejected. An alternative, which is in some ways similar, would be to heat the sand mixture to a temperature high enough that the bitumen would be converted to a vapor and could be separated from the solid by gas-solid separation. The vapor pressure of the original bitumen is low enough that it is unlikely that this could be accomplished without thermal decomposition of most of the bitumen; this decomposition is apparently not very difficult.

Once the bitumen has been separated from the sand, there remains the problem of converting it to a material suitable for use as a liquid fuel. As shown on Figure 1-6, the three principal objectives of this process must be to remove most of the sulfur from the bitumen, to raise the hydrogen-to-carbon ratio of the liquid fuels above that originally present in the bitumen, and to lower the average molecular weight of the bitumen. As shown on the left, the scheme which has received the most attention so far and which can be considered as totally proven technology is coking followed by hydrotreating of the liquid products. Coking is performed by heating the liquid bitumen to a temperature at which it begins to thermally decompose and holding it at that temperature long enough for decomposition to be completed. This decomposition produces a gaseous product which is easily separated from the remaining material and which, on condensation, is quite similar to ordinary liquid hydrocarbons. The remaining material is a solid coke which is mostly carbon but which can contain up to 8 percent sulfur. This process contributes to all three of the objectives listed above. Much of the sulfur is immobilized in the coke (which is a by-product of the process) and therefore removed from the valuable liquid fuel. The coke which remains behind is mostly carbon with relatively little hydrogen in it. Therefore, one could think of this process as being one of taking carbon away from the mixture of hydrogen and carbon in the bitumen so that the remaining liquid product has a higher hydrogen-to-carbon ratio. Finally, this kind of process always lowers the average molecular weight of the liquid.

The liquids produced by coking require further hydrotreating to lower their sulfur content to the level which is acceptable in finished liquid fuels.

Although this type of technology is thoroughly proven, alternatives are actively considered because this technology produces only about 75 percent

FIGURE 1-6. Bitumen Upgrading Possibilities

as much liquid fuel as there is input bitumen. Thus there is an incentive to try to develop processes which will be less costly and which will produce a higher yield of liquid fuels per unit of bitumen input. An alternative (shown in the right on Figure 1-6), which has been proposed and presumably pilot tested but not used commercially, would be to use vacuum distillation followed by solvent deasphalting of the residue and hydrotreating of all liquids. This combination would have the potential advantage of a higher yield of liquid hydrocarbons per unit of bitumen.

In summary, the required operations to make liquid fuels from the bitumen in tar sands are separation, chemical processing to remove sulfur, etc. All of the processes known to the authors as having been used commercially or used experimentally or discussed in the literature can be fit into the matrix of operations shown in Figures 1-5 and 1-6.

1-D. Some History of Tar Sand Exploitation and a Description of the Projects Currently in Progress

The existence of near-surface deposits of tar sand has been widely known in many areas for over a century. Wherever such deposits have been found, it has normally been economical to use them for road-building and other similar uses. For example, Glassett and Glassett (1976) report that the Asphalt Ridge tar sand deposit near Vernal, Utah, has been used to pave roads in that area for 70 years and that more than 1100 miles of roads in that area have been paved with this material. However, asphalt-sand mixtures which can be obtained by mining such deposits in shallow pits have a low value per ton and hence cannot generally be economically transported over great distances.

The current interest in tar sands is not for their use in road building but for their use to supply liquid hydrocarbon fuels for heating, transportation, etc.

1-D-1. The Athabasca Deposit in Canada

The history of the Athabasca Deposit has been reviewed by Carrigy (1973), Clark (1949), and Ball (1941). The early history can be summarized by saying that after the deposit was discovered and its magnitude appreciated, there were various efforts to utilize it as a tar, including paving some streets in Edmonton, and various small-scale attempts to produce liquid hydrocarbons from it. These were generally too small to be economical, and the plants were destroyed by fire with disturbing regularity.

Extensive development work done by the Alberta Research Council (principally by Karl A. Clark) led to the development of the hot-water separation process, which is the basis of the two commercial operations now in progress near Ft. McMurray. The first was Great Canadian Oil Sands (GCOS) (mostly owned by Sun Oil Company) which produces roughly 50,000 barrels per day of "synthetic crude oil" from the Athabasca deposit. This plant began operation in 1967; after considerable technical and financial difficulty, it has now become a steadily functioning, profitable operation (Camp (1970), Science Policy (1974), Allen (1973), Allen and Sanford (1974), Carrigy (1973)).

Syncrude, a consortium of oil companies and governments, is building an extraction facility about ten miles from the GCOS plant (Goforth (1977), Gray (1974), Maxwell (1975), Pratt (1976)). It is fundamentally the same kind of operation as GCOS but uses some different technologies. Its anticipated production will be about twice that of GCOS. Its started one-half of the plant in the summer of 1978 and plans to start the second half of the plant (the "second train") in summer of 1979.

The GCOS project was a pioneering one carried on largely through the technical and entrepreneurial efforts of the Sun Oil Company. Their plant encountered considerable technical difficulties and operated for many years at a loss before eventually solving most of these difficulties and having its economics greatly improved by the increased world price of oil.

The Syncrude Project was originally started by a group of US oil companies. In 1973-74 the estimated cost of the project increased two to three fold. This was due to the spectacular increase in the cost of all major process facilities which occurred at that time (as shown on Figure 1-7). This cost increase caused one of the major partners in Syncrude to withdraw and the others to announce that the project would be cancelled if there were not significant equity participation from various Canadian governmental bodies. After much negotiation, the final settlement was one in which the participants are Imperial Oil Company (subsidiary of the Exxon Company), Cities Service Oil Company, Gulf Oil Company, the federal government of Canada, and the provincial governments of Alberta and Ontario. The estimated capital cost of the Syncrude project is now \$2 billion.

One may see how this increase in capital costs affects such a project by noting that the capital cost works out to approximately \$20,000 per barrel per day of installed capacity. If one assumes an annual capital charge (depreciation, interest, insurance, taxes) of 20 percent, then the annual capital charge is \$4,000 per barrel per day of capacity. If one produces a barrel per day for 365 days per year, that corresponds to a capital charge against production ($\$4,000 \div 365 = \11 per barrel). This is capital charge alone, allowing nothing for operating costs, royalty payments, etc. At this point, with a world oil price of \$12 to \$13 per barrel, the entire project is economically marginal. If the capital charge were only one-third as much, as it appeared to be in 1972, then the capital charge would have been a much more manageable fraction of the world price of the product.

The history of the conversion of Syncrude from a private oil company venture to a combined oil-company/government partnership has been reviewed by Maxwell (1975) and Pratt (1976).

FIGURE 1-7. Capital cost index for the period 1967-77, showing the rapid rise in the period 1973-1975 (Sitter, 1977).

The two projects in Canada operate on deposits which are located relatively close to the surface. For each of them, the ratio of overburden to be removed to tar sand to be processed is of the order of one-half a cubic yard of overburden per cubic yard of tar sand (Frazier et al., 1976). It is clear that as the ratio of overburden to be moved to tar sand increases, the economics of the project become less attractive. There are various estimates of the maximum value this ratio can have for an economical project; but regardless of which estimate one chooses, it is clear that the majority of the Athabasca Deposit may be too deep for surface processing. Only about 10 percent of the Athabasca Deposit has overburdened thickness of less than 200 ft, which may prove to be the economic maximum. Therefore, if the total resource is to be exploited, some way must be found to exploit the resources which cannot be economically open-pit mined. Although it is occasionally suggested that one might underground mine the tar sand and process it at the surface as is done with open-pit mined tar sand, this will probably be uneconomical. A high-grade tar sand has an organic content of perhaps 15 percent which means that a ton of such sand contains up to 300 lbs of bitumen. If the value of the finished synthetic crude oil is estimated at \$15 per barrel, then these roughly 30 gallons of potential oil would have a value of \$10. However, this is a value associated with the finished product; a crude bitumen certainly is worth less than half of this, so that a maximum possible value to assign to the tar sand as mined would be to the order of \$5 a ton. Based on experience at GCOS (Allen, 1974), it is clear that tar sand is a very difficult material to mine--much more difficult, for example, than coal. Since underground mined coal normally sells for prices significantly greater than \$10 a ton, it seems prudent to suggest that underground mined tar sand would prove highly uneconomical at today's prices.

For this reason, most of the attention given to recovering the deeper tar sands has been given to in-situ processes in which an effort is made to cause bulk movement of the bitumen to the producing wells.

It is interesting to compare this situation with the one which exists in the oil shale deposits of Colorado, Utah, and Wyoming. Some of the oil shale resource is also close to the surface and accessible for simple open-pit mining. However, the bulk of the resource is too deep for open-pit mining and must be underground mined if it is to be mined at all. In the original Detailed Development Plans submitted by the holders of the Federal Prototype Leases, two of the three projects planned underground mining of the shale followed by surface retorting. In addition, the privately funded Colony project intended to use the same method. After the large increase in capital costs shown in Figure I-7, all of these projects were suspended at least temporarily. Currently, the only two projects showing much activity are both working towards in-situ processing. The underground mining of oil shale has been demonstrated on a large scale by the Bureau of Mines; it is not a particularly difficult mining operation because the oil shale in place has high structural integrity and can be easily broken apart by straightforward, high-explosive methods. In contrast, the tar sands are mostly soft and friable. It is unlikely that they could be successfully mined by room-and-pillar methods which depend upon the structural strength of the material being mined nor that the technology would be as simple as with oil shale. Thus, in comparing tar sand with oil shale, we see that underground mining has been originally proposed for oil shale but currently appears uneconomical and that the mining problems should be significantly more difficult if we wished to underground mine tar sands. The underground mining of tar sands is most likely very uneconomical and unlikely to be practiced. This is certainly true for

the unconsolidated deposits in Alberta. Some of the Utah deposits are consolidated (i.e., the sand component is cemented together to form a sandstone). For these deposits, underground mining is more likely to be feasible; even so, it is of doubtful economic potential.

Because so much of the Alberta Deposit is too deep for practical surface mining, considerable efforts have gone on in Alberta to develop in-situ technology for recovering the bitumen. Referring to Figure I-5, we see that this must be accomplished by obtaining bulk flow of the liquid at a reduced viscosity or by thermal decomposition and evaporation from the individual sand grains. Camp (1970) reviewed the history of various pilot projects to develop in-situ technology for the Athabasca Tar Sands. All of them attempted to make the bitumen mobile in the reservoir by applying heat or forming an emulsion with water and then using air or water to drive the mobile fluid to the collecting well. These projects are all outgrowths or modifications of conventional oil field secondary recovery projects. Each has been adapted to some extent to the situation in Athabasca where the deposits are much more viscous at reservoir temperature than are conventional oil fields. To date, none has progressed beyond pilot testing although at one point Shell Canada Limited did request a permit for a commercial-size in-situ project. This permit was denied for internal political reasons in Alberta.

As shown in Figure 1-1, Alberta contains four major tar sand deposits of which the largest by far is the Athabasca deposit. However, the Cold Lake deposit, which is shown on the map, is, in some technical details, more suitable for an in-situ recovery operation. Its principal advantages are greater depth and a thicker bitumen-bearing formation with fewer inclusions of low permeability strata than at Athabasca. For this reason, there has been more progress in developing in-situ recovery technology for Cold Lake than for Athabasca.

The Imperial Oil Co. has submitted to the Alberta Government an application with numerous supporting documents (Imperial Oil, 1978a, 1978b, Foster Research, 1978, Resources Management Consultants, 1978) for a project at Cold Lake which would recover 160,000 barrels per day of bitumen by an in-situ, steam secondary recovery process. This will be described in more detail later in this report. If this project is economically successful, the knowledge gained there will certainly be transferable in some form to the Athabasca deposit. Imperial Oil indicates that if the necessary regulatory approvals can be obtained by mid-summer of 1979, the project construction could begin in 1980; and the project could be producing significant amounts of oil by late 1985.

In December of 1978 the Alsands Project Group formally applied to the Alberta Government for the necessary permits to begin a tar sand operation which would be substantially identical to the Syncrude operation. Alsand is a Consortium of nine oil companies, of which two Shell companies hold 45% of the total interest. The project envisages producing 140,000 B/D of synthetic crude oil from an open pit mine approximately 15 miles north (and across the Athabasca River) from the GCOS and Syncrude sites. If they obtain prompt regulatory approvals (and tax and royalty agreements) they hope to be in production in 1986.

1-D-2. The Utah Deposits

Glassett and Glassett (1976) have reviewed the historical efforts to exploit Utah tar sands. To date there has been no commercial production although in 1974 there was sufficient interest that the Sohio Oil Company, which controls a large amount of the Asphalt Ridge Deposit, submitted a mining plan to the State regulatory authorities for production of enough tar sand to support two large-scale pilot operations. These were subsequently discontinued.

The Laramie Research Center of the U. S. Bureau of Mines has conducted several in-situ tests in the Asphalt Ridge area. These have resulted in

interesting data but have not led to commercial production.

Currently, there is considerable interest in recovering oil from the tar sands (Lowe, 1976) but no indication that any of the interested parties are currently planning to enter large-scale production. Probably the closest firm to commercialization is the Great National Corporation, which has acquired mineral rights on roughly 0.5 billion barrels of bitumen in the Sunnyside deposit. They have contracted with the Salt Lake City office of Ford, Bacon and Davis to conduct an economic feasibility study and tentative pilot plant design. They intend to open-pit mine the tar sand and process it by a method yet to be selected. Their time schedule calls for a pilot plant in several years and commercialization no sooner than several years after that.

1-E. Environmental Constraints

The GCOS and Syncrude are large-scale mining, chemical processing, and waste-disposal projects. The Cold Lake in-situ project will not involve any mining nor significant waste disposal but will involve a large number (8,000) of shallow wells either for injection or for production, with resulting land surface disturbance. These projects are all located on oil leases in Alberta which are regulated by the Alberta government.

In comparison, if we were to have large-scale processing of US oil shales, we might have open-pit mining at sites like Asphalt Ridge and more likely would have some form of in-situ processing either at Asphalt Ridge or at the other large deposits in Utah. Although we know in considerable detail what is done at GCOS and what will be done at Syncrude and Cold Lake, we do not know in as much detail what environmental control technology would be used in the Utah deposits.

The environmental constraints which must be considered are air quality, water quality, solid waste disposal, noise, wildlife disturbance, plant disturbance, etc. By far the most important constraints are air quality, water quality, and solid waste disposal.

For air quality, there exists in the USA a very detailed set of regulations describing what conditions these projects must meet. These are spelled out in Section 2-A below. The Canadian situation is different, as described in Section 3 below. Similarly for water quality, there exist reasonably detailed constraints which are spelled out in Section 2-B below. For the solid-waste disposal and treatment problem (Section 2-C below), which is one of the most complex and difficult parts of the GCOS operation and may also be difficult in U.S. processing, there does not appear to be as clear, concrete, and straightforward a set of guidelines. The additional environmental constraints are generally not formulated in as clear and concrete a way and will probably be dealt with on an *ad hoc* basis rather than by direct formal compliance to written regulations.

1-E-1. The Scope and Goals of this Study

The purpose of this study is to review, in a comprehensive way, the environmental control technology which is used at the existing GCOS plant in Canada and at the Syncrude plant, which started up in Canada in the summer of 1978, and at the Cold Lake project in Canada which is anticipated to start in 1985. The results of this review will then be applied to the question of potential future processing of the tar sand deposits in the United States (mostly in Utah). Where practical, both will be treated in parallel to make clear what environmental control technology will be the same for both and what will probably be different.

There exists a considerable literature on tar sands and tar sand processing. The Alberta Research Council maintains a service of technical publications entitled "Alberta Oil Sands Index." This contains several thousand entries and is growing at the rate of several thousand entries per year. Furthermore, the Industrial Environmental Research Lab of the Environmental Protection Agency commissioned from Batelle Columbus Laboratories a report entitled "Production and Processing of U. S. Tar Sands; an Environ-

mental Assessment" (Frazier et al., 1976). This study summarizes and reviews the available literature as of 1976. The Cold Lake Project and Alsands Project have submitted to the Canadian Government Environmental Impact Assessments, and Environmental Impact Assessments have been made for the pilot in-situ projects conducted by the Laramie Energy Center at Asphalt Ridge, Utah.

In this report we have assumed that the audience we are addressing is technically trained in some aspect of the tar sand environmental problem, but not in all aspects of it. (Each of the authors is technically trained in some aspect of it; none of us is an expert in all aspects.) Our goal is to show such an audience the whole view of the existing and potential projects, their probable impacts, what control technology is used or envisaged by the current and potential tar sand developers, and what the potential problems are. In order to keep the main text accessible to the reader who is not expert in each phase, we have made liberal use of appendices in which the specialist can pursue his own area of interest.

The emphasis in this report is on control technology. The other materials presented are background, intended to make clear what the problem is and within what legal constraints the control technology must operate.

In developing a tar sand project in a remote area, the developers are bound to make a major change in the region where the project is taking place. The Athabasca Tar Sands are located approximately 260 miles north of the major city which supports them (Edmonton). The GCOS and Syncrude projects have placed major strains on the town of Ft. McMurray which is nearest to the project. The developers have made considerable efforts to minimize this impact and to control the growth of Ft. McMurray to produce a long-term, high-quality community. Any similar projects in the United States will not face as severe a community development problem because none of the major US deposits are as remote from existing cities and town as are the Athabasca Tar Sands. Both for Canada and for the USA, such projects cause

a major change in the region where the projects take place. These areas are currently very sparsely inhabited, and some have few signs of human activity. The Canadian projects each employed several thousand people at the peak of construction and up to a thousand each at the time of full commercial operation. Large-scale US projects would be similar. The people so employed would cause automobile-type air pollution. The places they live would cause all the typical urban-type pollution including noise, solid waste disposal, sewage problems, run-off contamination, etc. New roads would contribute to ambient dust loads, etc.

For the purposes of this report, it is proposed that none of this type of off-site pollution shall be considered in the question of control technology for tar sand development. None of the problems of the type discussed above are significantly different from those faced by any new or growing city in a remote non-industrial area. To the extent that solutions are known to those problems or are being worked on elsewhere, those solutions will be applicable to the tar sand development (if the companies and governments involved have the resources and the willingness to apply them). They are in no way peculiar to the development of the tar sand industry.

In addition, the synthetic crude oil made from tar sand, after leaving the plant sites, would travel (most likely by pipeline) to distant oil refineries where it would be refined to produce conventional petroleum products which would enter the normal channels of commerce. The pipelines would be in no significant way different from other oil pipelines traversing similar areas. Because new oil pipelines are expected to meet more stringent environmental standards than those constructed in the past, these pipelines would be subject to such stringent standards (Klipp, 1973). But the pipelines would not be subjected to standards significantly different from those which new, conventional petroleum pipelines must meet, nor will the technology of building and constructing them be significantly different from that for conventional petroleum. Thus, we will not include the technology of pipeline transport

of tar sand synthetic crude oil in our study.

At the oil refinery, the tar sand syncrude will replace an equivalent amount of conventional oil. (This assumes that the demand for petroleum products is not significantly influenced by the existing Canadian tar sand projects and will not be significantly influenced by USA tar sand projects. Thus, if we do not develop US tar sands, that demand will be met from other sources; tar sand syncrude, if available, simply displaces these sources.)

The situation with tar sand development is somewhat simpler than that with oil shale development. The original Detailed Development Plans for oil shale included upgrading of the shale oil at the plant site to a "synthetic crude oil" which would then enter normal refineries on more or less the same terms as conventional crude oil. More recent plans in the oil shale industry suggest that only minimal processing will take place at the plant site to produce a pipelineable material which will be sent to existing oil refineries (or other uses), where the major processing will take place. This latter option is not apparently open to tar sand processors. Without major processing, they cannot produce a material which can be easily transported through pipelines. Therefore, they will almost certainly follow the procedure used with the Athabasca Tar Sands, processing the bitumen at or near the recovery site to produce a synthetic crude oil which can then be sent by pipeline. The synthetic crude oil produced by GCOS and by Syncrude is a higher quality material than conventional oil (lower in sulfur content, better molecular weight distribution) which commands a higher price in the market than conventional crude oil.

There is no indication that the oil companies intend to significantly modify their processing technology when tar sand syncrude replaces conventional oil (in whole or in part) in their refinery operations. Hence, we will not consider in our study any possible environmental control technology issues resulting from displacement of conventional refinery feed oil by tar sand syncrude.

The Canadian projects intend to process sanitary sewage in the same ways as any new project in the same area would, and their automobiles and trucks will have the same air pollution control devices as would be applied to any other autos and trucks sold in Canada at the same time. The same would presumably be true for USA tar sand projects. We will not investigate these control technologies nor include them in this study.

The two major tar sand projects in Canada are consumptive water users, withdrawing water from the Athabasca River watershed. Similarly, the Cold Lake project will be a consumptive water user, taking water from Cold Lake. A Canadian government study of water supply from the Athabasca River (Shewchuck, 1975) concludes up to 80 projects the size of Syncrude could be installed in the Ft. McMurray area without causing serious depletion of the water resources of the area.

If similar technology is used to process the USA (Utah) tar sands, the processors will presumably also be consumptive water users which will draw water from the Colorado River or its tributaries and not return it. The Colorado River currently has a salinity problem which has led to conflict with Mexico and for which expensive correction programs are underway. By removing fresh water from the Colorado River or its tributaries, future tar sands projects would contribute to that salinity problem. But their contribution will be no different from the contribution of any other consumptive water user who withdrew a comparable amount of water. Thus, whatever technology is being used or developed to correct that problem will be the same for tar sand water users and other kinds of water users. This study will not include the technology of dealing with the Colorado River salinity problem; that technology is in no way specific to the tar sand industry.

In summary, for this study we intend to draw a boundary around the actual plant sites of the tar sands projects and study the technology for controlling on-site air pollutant emissions, on-site water pollutant emissions,

on-site solid waste disposal problems, and whatever other on-site environmental control technology seems appropriate. The other questions alluded to above are interesting and important but are not treated in this study.

1-E-2. General Kinds of Environmental Problems

It seems worthwhile to categorize environmental problems into those we might call "first order" and those we might call "second order." First-order environmental problems are major, obvious, clearly harmful, and normally the subject of current regulatory control. On the other hand, second-order environmental problems are more subtle, not obviously as harmful, and generally not the subject of explicit environmental control regulations.

A typical first-order environmental problem is the large-scale, steady emission of pollutants which are believed to be harmful to human health and life; e.g., sulfur-dioxide, carbon-monoxide, and total suspended particulates emitted to the atmosphere, or pathogenic bacteria emitted into surface waters. A second example would be small-scale emissions of extremely hazardous substances; e.g., the relatively small-scale emission of mercury in metallic form into Minimata Bay which resulted in the formation of methylmercury which concentrated in shellfish which caused death and permanently disabling disease to a large number of people. The emissions of radioactive waste might be of the same type. The third type would be gross destruction of existing biotic communities; as, for example, by vigorous overgrazing or deforestation with the result of greatly increased run-off, greatly increased soil destruction, and down-cutting of streams, etc. A fourth type would be occasional, very large emissions due to one-time catastrophic failures. Examples of this type would be the destruction of a large oil tanker close to productive fisheries as in the Torrey Canyon example or the Teton Dam failure which resulted in the destruction of much property and loss of human life. A nuclear reactor run-away with release of the contained radioactivity would also be an example of this type if one were to occur.

The final example of first-order problems are those where serious pollution results from the combination of small emissions from a very large number of sources; i.e., the automobile-related pollution in the Los Angeles basin. There, no single source is emitting a large amount of the pollutants of interest, but the population of sources is so large that a first-order effect is produced.

Second-order problems, on the other hand, are normally of quite different kinds. Examples would be the small-scale emissions of harmful materials which will not cause a local problem but may contribute to a regional or global problem. For example, the best-controlled sources of sulfur dioxide will emit still some small amount. (Probably the best-controlled copper smelter in the world is one in Japan which captures 99 percent of the sulfur in the ore (Rosenbaum, 1976). Nonetheless, 1 percent is emitted). Such plants normally meet environmental standards wherever they are located and are not considered local problems, but they do contribute to regional or world problems. A second example would be an extremely small emission of a very hazardous substance; for example, a well-controlled chlorine caustic plant will still emit very small amounts of mercury to the environment, and any combustion source will emit small amounts of polynuclear organic materials which are suspected carcinogens. A third example would be minor changes in local environmental conditions caused by, for example, the introduction of exotic species into systems where the species have no natural predator. A local (Southwest) example is the introduction of the tamarisk plant for wind-breaks in the Southwest with the resulting proliferation of the tamarisk along all of the water courses in the area, or the lowering of water tables by mine dewatering resulting in the drying up of springs, etc. A fourth type of second-order problem would be the occasional medium-sized emissions of a harmful material. All pollution-control devices have occasional breakdowns

or malfunctions of some kind in which the emission rate will temporarily go above the allowed steady-state value. Most pollution-control regulations have provisions in them for such unavoidable breakdowns and provisions requiring that such breakdowns be promptly repaired and not occur more than a certain fraction of the time.

Which, if either, of these classes of environmental problems is likely to occur in tar sand development? Most of the possible first-order environmental problems which could occur in a tar sand development are covered by specific environmental law; e.g., the Clean Air Act, the Federal Water Quality Act of 1972, the Toxic Substances Control Act, etc.

The existing tar sand projects in Canada and those which are nearing commercialization are covered by the Canadian equivalents of these regulations which also cover all first-order environmental problems, at least as perceived by the environmental regulatory agencies of Alberta. Presumably, US tar sand operations, by complying with provisions of the above-listed acts, would be protected against possibility of creating a first-order environmental problem. Therefore, if we conclude that occasional malfunctions of equipment are indeed second-order problems, we must conclude that first-order problems most likely will not occur in tar sand developments.

On the other hand, the tar sand developers in Canada have, in general, not paid much attention to second-order problems. They believe that since the existing environmental law requires them to prevent first-order problems and it does not require them to prevent second-order problems, that they are not obliged to make large expenditures to prevent them. In this sense, they are following the guidance of the governing bodies in Canada which have largely directed their environmental legislation toward first-order problems.

What is the likelihood that the proposed tar sand developers are right in their view that they can prevent first-order environmental problems from

occurring and that they can meet applicable federal laws? The tar sand developers in Canada and potential tar sand developers in the USA are oil companies or are groups which include oil companies in their makeup. In the past 25 years, the oil companies have made big political and economic errors but few very big technical ones. One obvious example of serious technical errors in the oil industry has had to do with the safety of large oil tankers and with occasional oil-well blow-outs. One can argue whether these are really errors, since these are taken as calculated risks in the oil industry; and they simply take the view that it is more desirable for society to tolerate some fraction of these than to make the expenditures which would reduce the probability of their occurrence to near zero. The other possible major technical error made by the oil industry has been their conclusion from available seismic data that the large structures off the west coast of Florida and east of New Jersey were probably oil-bearing. Apparently they are not (Stuart, 1976). However, oil exploration is an inherently probabilistic undertaking; thus the fact that they were disappointed there is probably better classed as "the breaks of the game" than as a major technical error. (It was, however, a very expensive disappointment to them.)

It seems clear that on a steady-state basis with all their environmental control equipment functioning properly, the tar sand developers will have solved the problems of first-order environmental problems, but that one can be certain that there will be occasional plant malfunctions or possibly disasters such as a retention dam rupture which would lead to a temporary first-order or possibly second-order environmental problem.

1-F. Proposed Environmental Control Strategies

1-F-1. Air Pollution

The basic air-pollution-control strategy used by the tar sand operators

in Canada, and likely to be used in the USA, is to minimize the emissions of recognized air contaminants by applying technology which is transferred from other related industries, principally mining and oil refining. The gas streams leaving the projects will be mostly the products of combustion from various heat-generating steps in the processing scheme. These will be treated to obtain satisfactorily low air-pollutant concentrations and then released by stacks tall enough so that ground-level concentrations will be below applicable ambient air quality standards.

1-F-2. Water Pollution

The water budgets of tar sand projects show that they are net consumers of water. The proposed in-situ tar sand project at Cold Lake, Alberta, for example, estimates a water use of 3.65 m^3 per cu. meter of bitumen produced (Imperial Oil, 1978a). Water may be used for the recovery operation (steam stimulation), the tar sand processing (water washing), and the waste sand disposal (stabilization, revegetation). Conversely, water may be gained by dewatering bogs (especially in Canada) and by draining subsurface aquifers.

Due to existing antidegradation policies regarding stream water quality, the basic water control strategy must be one of preventing contaminated water (surface and subsurface) from leaving the project sites. This usually implies treatment of effluent water and wastewater with reuse and containment. This reuse strategy also helps to minimize the total project water need. Since evaporation ponds are not very efficient at high altitudes and latitudes containment may mean irrigation (of spent sands, roads, vegetation), percolation into deep wells, or use in cooling towers. The technology for accomplishing the water treatment and containment is fairly well developed by the oil refining industry and the electric power generating utilities.

Problems with high salinities in southwest U.S. rivers (Colorado River) prevent discharges of silt and water high in dissolved solids into water-courses in this area. This presents a challenge to construction in the arid Southwest where vegetation is sparse, and the runoff often of a torrential nature. The strategy is usually one which minimizes surface disturbances and incorporates by-passes for upstream runoff and catchment basins for storm runoff and leachates generated on project sites.

In Canada where dewatering of the mining site is necessary (GCOS) and large amounts of steam are used (Cold Lake), considerable amounts of water may be discharged from the mining sites to nearby rivers. The fines of the processed Canadian tar sands are so fine as to cause difficulty in separating them from the wash-water. In the U.S., due to the larger sand matrix, this is not expected to be as much of a problem.

1-F-3. Processed Tar Sand Disposal

The surface mining operation required to satisfy the needs of a 50,000-barrel-per-day oil extraction plant would rival the largest of the current mining operations in the United States. Assuming an average oil content of twenty gallons of oil per cubic yard of tar sand and complete oil recovery (actually 85 to 90 percent), 105,000 cubic yards of such sands must be mined and delivered for processing each day. Assuming that tar sands weigh 3,500 pounds per cubic yard, then 184,000 tons per day must be mined. Such a mining operation compares with the mining operation of the Kennecott Copper Corporation at their Bingham Canyon mine which is geared to a production of 110,000 tons of ore per day and is believed to be the largest surface mining operation in the world (Glassett and Glassett, 1976).

Projects using in-situ technology will have a much smaller and easier solid waste disposal problem. Whether the selected methodology is steam

flood, fire flood, or combinations, the solid wastes will be limited to materials removed from the drilled holes along with drill site preparation as well as the disposition of surplus materials encountered in the road building process.

The basic strategy proposed for the disposition of the processed sands from a mining operation is to select in or near each of the processing sites a natural or mined depression, accompanied by appropriate dikes and dams, which can be filled with the mixture of sands, water, and minor amounts of fines, etc., providing storage through a period of time that is great enough to allow dewatering to take place. The site must be naturally impermeable or must be sealed to prevent leaching of salts, etc. The previously removed surface overburden (top soil) will then be placed over the processed sands in a thickness great enough to provide a bed for revegetation processes in keeping with local characteristics. This effort will be to establish native or other plants which can adapt to the local environment to get them growing well enough to aid in the stabilization of the soil, thus resisting wind and water erosion.

1-G. Environmental Control Difficulties and Questions

If there were no fears on anyone's part that there would be environmental control difficulties and if there were no environmental control questions, then this study would have never been commissioned and undertaken. The companies exploiting tar sands believe that they understand the situation well enough and that they understand the performance of the environmental control technologies which they now use and which they plan to use in the future. Many of the reviewers of their environmental statements have been skeptical of that belief. This uncertainty is at least in part the result of a communication failure; the backgrounds of the writers and readers of those documents are quite different, and they often do not speak the same language.

The authors of the air pollution, water pollution, and solid disposal sections of the Environmental Assessment Statement are mostly engineers. They have written their sections to be read and understood by other engineers. Many of the reviewers of these documents have backgrounds in other disciplines; e.g., biology, forestry, etc., and the other disciplines which lead to careers in BLM and other parts of the Department of the Interior. Their background does not necessarily prepare them to read and comprehend the engineering parts of the Environmental Assessment which are written in "engineering shorthand."

The first task undertaken here is to attempt to bridge that communication gap by presenting the environmental constraints and technology in as clear a way as possible. The second task is to analyze the control technology with an eye to difficulties and research needs.

1-H. Environmental Control Costs

An additional question addressed in this report is that of environmental control costs. What fraction of the cost of such a project is due to environmental control? Are there such projects which would be economical if regulations were relaxed but which are not economical with current environmental regulations? Answering these questions is difficult because the tar sand developers have generally not provided detailed cost breakdowns to the public. But estimates are presented, later in the report, of the environmental costs and of the most plausible answers to these questions.

2. ENVIRONMENTAL CONSTRAINTS - USA

Although the topic of this report is environmental control technologies, those control technologies are best examined against the constraints which they are designed to meet.

The audience for this study is mostly interested in the potential for development of US tar sand deposits and the environmental control technology which will be needed for them. For this reason, this section will discuss the environmental constraints which exist in the USA. However, the two existing tar sand recovery operations are in Canada. They have a different set of environmental constraints to operate within. The differences and similarities of Canadian and US environmental constraints will be discussed in the next section of this report.

As we shall see later in this section, there are laws and regulations limiting the amount of various pollutants which can be emitted to the environment; any company proposing to develop a major tar sand recovery project must control its emissions to meet these laws and regulations.

Before the late 1960's, environmental laws and regulations in the United States and in most of the industrial world were relatively weak, seldom vigorously enforced, and largely ineffective in controlling industrial sources of pollution. In general, industries were restrained by the threat of damage suits and by the threat of community pressure or ostracism if they emitted more than the community judged appropriate. Similarly, we tended to use zoning as a way of separating industry from residential use because it was considered inappropriate, uneconomical, or impossible to have non-polluting industry; therefore, we simply provided distance between industry and those areas which we wished unpolluted.

In the late 1960's and early 1970's, there was a rapid increase in awareness in our society that we had pollution and environmental problems. As a result of this increasing awareness, there was a great increase in the role of the federal government in environmental control. As a result of this history, we have now fairly comprehensive federal legislation in many environmental areas. However, the states have the right to enact more stringent environmental regulations than the federal ones if they so choose.

In the environmental control area, economics, technology, and regulations are strongly interconnected. Most engineers believe that we can lower industrial emission rates to any arbitrarily specified level if we are willing to pay the cost and to allow adequate lead times for development of the technology. The authors of this report share that belief.

It is certainly true that extremely low emission levels are extremely expensive. For this reason, we have rarely attempted to have zero discharge of pollutants and have generally attempted to find some level of discharge of pollutants which will be considered acceptable. In selecting the pollution control technology and the degree of its application, a future tar sand recovery industry will be guided by the regulations of the federal and state governments with which they are expected to comply.

We will now examine the appropriate environmental constraints in detail.

2-A Air Pollution

Before we can discuss the legislative basis and structure of the air quality constraints, we must discuss the nature of the air pollutant problem. Figure 2-1 shows a schematic view of the air pollution problem for the situation in which there is a large, single source of air pollution. Such large sources are normally referred to as "point" sources to distinguish them from the ubiquitous automobiles and house heating sources which are called

FIGURE 2-1 Schematic view of the air pollution problem.

"area" sources. In Figure 2-1, we see the emissions from a source exiting from the smoke stack of that source. In the atmosphere they are transported by the wind, diluted by mixing with the surrounding air, chemically converted into "secondary pollutants," which may be quite different chemically and physically from the "primary pollutants," originally emitted from the source, and are removed in whole and part by natural removal mechanisms of which rainfall and snowfall are the most important. Finally, at the right we see the pollutants coming to ground level where there are exposed populations in cities and towns, wildlife, crops, pasture, etc.

Our logical goal in air pollution control regulation must be to eliminate or minimize air pollution damages to exposed populations. Ultimately, this must be accomplished by limiting or preventing the emission to the atmosphere of pollutants which either in their originally emitted form or through their conversion to secondary pollutants can or do cause harm to exposed populations.

There has been strong disagreement among professionals in air pollution and among legislators as to the best way to structure our air pollution law to accomplish this goal (de Nevers, 1977). The two basic approaches which have been most widely used and which each have very strong adherents are "Air Quality Standards" and "Emission Standards." Virtually all of the air pollution law and regulation in the United States and in most of the other countries in the world is based on air quality standards or on emission standards. Future tar sand recovery undertakings will be obliged to comply with regulations of both kinds.

2-A-1 Air Quality Standards

An air quality standard is a permitted level of atmospheric contamination. In general, it must apply to a single pollutant rather than to "air pollution" in general. Currently in the United States there are federal air quality standards for six pollutants; these are total suspended particulates,

sulfur dioxide, nitrogen dioxide, carbon monoxide, photochemical oxidant and lead. In addition to these six pollutants, there is an additional standard for hydrocarbons. This is not seen as a pollutant in itself but is a precursor of photochemical oxidant. The hydrocarbon standard exists only as a way of meeting the photochemical oxidant standard. There are also some state standards for other pollutants. Air quality standards do not, in general, impose restrictions upon single individual sources since they are concentrations in the ambient atmosphere which are not to be exceeded and which can be contributed to by many sources. Particularly in urban areas, it is very difficult to show which particular source caused the violation of an ambient air quality standard. However, in the areas where major tar sand deposits exist, there are very few other major sources of most of the pollutants likely to be emitted by a tar sand industry. Most US tar sand deposits are located near the major oil shale deposits of the USA. If both oil shale and tar sand developments take place simultaneously, then that area will have several major potential pollution sources. However, if only tar sands are developed, then the tar sand projects will probably be the only major emitters in their areas; and the measured concentrations of pollutants of the types they emit will be readily traceable to them.

In the current versions of the United States air pollution law, a plant may only receive a permit to commence construction, if it appears, (based on air quality modeling) that its emissions will not result in a violation of the air quality standards. Thus, these air quality standards with their predictive air quality models could be quite restrictive as to what type of tar sands development can occur.

The applicable national air quality standards which have been promulgated by the Environmental Protection Agency (EPA), using its authority under the Clean Air Act of 1970, are summarized in Table 2-1. These

TABLE 2-1

Federal Ambient Air Quality Standards

Pollutant	Averaging Time	National Standards	
		Primary ^(b,c)	Secondary ^(d)
Photochemical oxidants	1 hour	240 $\mu\text{g}/\text{m}^3$ ^(f) (0.12 ppm)	Same as primary standards
Carbon monoxide	8 hours	10 mg/m^3 (9 ppm)	Same as primary standards
	1 hour	40 mg/m^3 (35 ppm)	
Nitrogen dioxide	Annual average	100 $\mu\text{g}/\text{m}^3$ (0.05 ppm)	Same as primary standards
Sulfur dioxide	Annual average	80 $\mu\text{g}/\text{m}^3$ (0.03 ppm)	-
	24 hours	365 $\mu\text{g}/\text{m}^3$ (0.14 ppm)	-
	3 hours	-	1.300 $\mu\text{g}/\text{m}^3$ (0.05 ppm)
Suspended particulate matter	Annual geometric mean	75 $\mu\text{g}/\text{m}^3$	60 $\mu\text{g}/\text{m}^3$
	24 hours	260 $\mu\text{g}/\text{m}^3$	150 $\mu\text{g}/\text{m}^3$
Lead	Annual average	1.5 $\mu\text{g}/\text{m}^3$	Same as primary standard
Hydrocarbons	3 hours (6-9 a.m.)	160 $\mu\text{g}/\text{m}^3$ (0.24 ppm)	Same as primary standards

- (a) National standards, other than those based on annual averages or annual geometric means, are not to be exceeded more than once per year.
- (b) Concentration expression first in units which it was promulgated. Equivalent units given in parentheses are based upon a reference temperature of 25°C and a reference pressure of 760 mm of mercury. All measurements of air quality are to be corrected to a reference temperature of 25°C and a reference pressure of 760 mm of Hg (1,013.2 millibar); ppm in this table refers to ppm by volume, or micromoles of pollutant per mole of gas.
- (c) National Primary Standards: the levels of air quality necessary, with an adequate margin of safety, to protect the public health. Each state must attain the primary standards no later than 3 years after that state's implementation plan is approved by the Environmental Protection Agency (EPA).

Table 2-1 continued

- (d) National Secondary Standards. The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant. Each state must attain the secondary standards within a "reasonable time" after implementation plan is approved by the EPA.
- (e) Reference method as described by the EPA. An "equivalent method" of measurement may be used but must have a "consistent relationship to the reference method" to be approved by the EPA.
- (f) Corrected for SO_2 in addition to NO_2 .

standards are of two types: primary and secondary. The primary standards are designed to "protect the public health . . . with an adequate margin of safety" They are believed to be below the lowest concentrations at which one can demonstrate any harm to human health. The secondary standards are designed to "protect human welfare" (EPA, 1971). Mostly they relate to plant damage or damage to material objects which is expected to occur at concentrations below the concentrations likely to be harmful to human health. Currently in the United States the major effort in air pollution control in most American cities is to reduce emissions enough so that these national primary ambient air quality standards will not be exceeded.

It is unlikely that currently foreseeable tar sand recovery projects will have serious difficulties with the national ambient air quality standards. This statement may be challenged because monitoring at the nearby oil shale sites (White River, 1976) has shown that while the annual average standards are much higher than the values normally measured at these sites, the short-term standards for particulates and ozone are occasionally violated at these sites. It seems highly unlikely that these violations are due to human actions (unless the removal of predators and resulting overgrazing leading to easily wind-blown soil is considered a human activity). The same set of problems occurs in many other areas of the arid West; most likely the Clean Air Act will be interpreted to permit construction of new facilities in areas where the short-term standards are exceeded due to "natural causes."

A related, but more difficult, problem for a future tar sand industry is the prevention-of-significant deterioration (PSD) doctrine. This is covered in Section 2-A-4.

2-A-2 The Role of Modeling

One interesting problem in evaluating air pollution control technology is that if, as stated above, the true requirement is to meet an ambient air

quality standard (or a PSD standard, see Section 2-A-4) and the standard determination is to be made by calculation before the plant receives its construction permit rather than by actual test after the plant is in operation, then it follows that the required control technology level is a function of the calculation method. If we had calculation methods capable of making such predictions with accuracies of a few percent, this would be no problem. That is not the case. The best calculation methods now available for computing ambient air concentrations as a function of meteorology and instantaneous emission rate are, at best, estimation methods which have uncertainties of a factor of two; i.e., the observed value may be between one-half and twice the calculated value. This assumes that the meteorology is known. That also introduces a large measure of uncertainty because the detailed meteorology of the sites to be used for tar sand recovery plants is not well known. Most of the meteorological models which are used in making this type of calculation have had their validation experiments and experimental coefficient determinations carried out in grassland areas like Nebraska or the Salisbury Plain of England under conditions of well-defined wind flow. However, the meteorology in the regions where tar sands occur in the US is quite complex because the topography of these regions is complex. There are deep canyons which tend to channel wind flow and tend to be involved in up- and down-draft flows. For this reason, one cannot at present predict the ambient air concentration corresponding to a given emission rate with a confidence better than perhaps a factor of two or three. Part of the difficulty with modeling with mountainous terrain is that it is hard to know whether a "plume" from a stack will rise over an obstruction (a hill or bluff) or run into it. The two possibilities are sketched in Figure 2-2. Both are used in modeling estimates; the resulting values can vary by a factor of 10.

FIGURE 2-2. Illustration of two different approaches to estimating the ground level (hillside) concentration of pollutant from a point source. Under neutral and unstable conditions the plume moves up and over the hill, and the concentrations on the hill are low. Under stable conditions, the plume may pass very close to the hill and the concentrations may be high.

The difficulties with modeling and the controversies over modeling have been so severe that in the 1977 Amendments to the Clean Air Act, the EPA is specifically directed by Congress to hold conferences on modeling at least every three years in an effort to find a common ground for modeling decisions (Clean Air Act, 1977). However, based on current modeling calculations, decisions will have to be made as to whether or not such plants will be in compliance with the law and can be built. There seems no instant remedy to this problem, and all those involved in future tar sand development environmental planning must recognize that this is a permanent or seemingly permanent constraint on our ability to determine the environmental requirements.

2-A-3. Emission Standards

Emission standards are direct regulations of the amount of various pollutants which can be emitted by specific sources. There is a large variety of types of emission standards, but most of the modern ones are based on simple weight of emissions. For example, it is illegal for new, coal-fired electric power plants in the United States to emit more than 1/10 of a pound of total suspended particulates per million Btu's of fuel burned. This is a "weight-rate" emission standard. Currently in the United States there are 22 such national industrial standards in force. These are referred to as the New Source Performance Standards (NSPS) (High, 1976). These all apply to new installations in existing industries. There is no one of them which applies specifically and directly to a tar sand processing industry. The ones which would be applicable to a tar sand industry are those which deal with the petroleum refining parts of the tar sand industry; specifically, these are the ones referring to emissions from petroleum storage and emissions from refinery waste gas combustion. The petroleum storage and waste gas processing in the existing tar sand projects is quite similar to that used in petroleum refining,

and the same should be true for future projects. Thus, there seems no reason to believe that these will pose a more severe limitation upon the tar sand projects than they place on currently existing oil refinery projects. In general, it does not appear that any of the Federal New Source Performance Standards will pose as severe emissions restrictions upon tar sand processing as the non-deterioration regulations described below.

Although the states can enact emissions or ambient air quality regulations in addition to the federal ones described above, to our knowledge no state has enacted one for tar sand development. Colorado enacted a specific standard which is in effect an emission standard for oil shale (Colorado Air Quality, 1977); and such a standard could be enacted by any other state for a nascent tar sand industry. This has not happened to date, nor does such an action appear imminent.

2 -A-4. Prevention of Significant Deterioration (PSD)

A particular problem for any future US tar sand industry is the prevention-of-significant-deterioration (PSD) doctrine which is currently part of the United States air pollution law. This doctrine was not explicitly stated in the Clean Air Act of 1970, but the courts have found that it was implied and compelled the Environmental Protection Agency to promulgate and enforce regulations concerning it. The Clean Air Amendments of 1976 specifically included this doctrine and provided regulations for it. These regulations were sufficiently repugnant to the two senators from Utah that they filibustered the Clean Air Amendments Act of 1976 to death over this specific issue. The amendments of 1977 which have become law specifically write this doctrine into the law and provide very detailed regulations concerning it.

This doctrine holds that those areas where the air is cleaner than the previously mentioned ambient air quality standards should not have their air polluted up to those standards. The 1977 Clean Air Amendments, which follow closely on the basic format outlined in EPA's regulations on

the same subject, require that all areas which have air cleaner than the national ambient air quality standards should be subdivided into three categories normally listed as Classes I, II, and III. Class I represents those areas where the highest possible air quality should be preserved. The Clean Air Amendments of 1977 specifically require that large national parks and wilderness areas be Class I. Class II represents those areas where some additional air pollution would be permitted, but pollution up to the levels of the ambient air quality standards would not be permitted. Class III represent areas which presently have clean air, but in which major industrial development is foreseen and contamination of the air up to the level of the secondary standards would be permitted.

In its original regulations (and seconded by the Congressional Clean Air Act of 1977) EPA announced that all areas of the United States which had air cleaner than the national ambient air quality standards would be initially designated Class II. Congress subsequently gave large national parks and wilderness areas a Class I designation. Subsequent to this initial designation there would be hearings and public procedures for determining which areas would be reclassified as Classes I and III. Therefore, at present, subject to future revision, the potential tar sand areas are classified as Class II.

Table 2-2 presents the current non-deterioration regulations in the Clean Air Act of 1977. The major tar sand deposits of the US (See Figure 1-3) are located adjacent to several national parks (Canyonlands, Arches, Capitol Reef). These areas are Class I; developments outside them which would cause the Class I increments to be violated within them are forbidden by the PSD regulations. These will probably be the strictest formal environmental regulations with which future US tar sand developments must comply.

TABLE 2-2

FEDERAL SIGNIFICANT DETERIORATION LIMITATIONS⁽¹⁾Permitted Increases Over Baseline⁽²⁾
(micrograms/m³)

	Class I	Class II	Class IIa	Class IIb	Class IIc	Class III
<u>Particulates</u>						
annual avg ⁽³⁾	5	19	Same as Class II →			37
24 hr. max ⁽⁴⁾	10	37				75
<u>Sulfur dioxide</u>						
annual avg.	2	20				40
24 hr. max.	8	29	29	36	37	182
3 hr. max.	25	512	325	130	75	700

Areas designated as

Class I	Large National parks, national wilderness areas No. Cheyenne Indian Reservation
Class II	Rest of U.S.A.
Class III	None

Notes to Table 2-2

1. Based on the "Clean Air Amendments of 1977."
2. Here "baseline" means the existing air quality at the time the regulations took effect, which is generally 1975. However, under no circumstances may this increment be allowed if it would cause a primary or secondary federal ambient air quality standard to be exceeded.
3. The annual averages are geometric mean for particulates and arithmetic mean for sulfur dioxide.
4. All the short-term increments in this table (i.e., less than annual average) are "not to be exceeded more than once per calendar year."
5. Class II-a (unofficial name, not so designated in the regulations) applies to facilities which will exceed the increments in a Class I area, but will "have no adverse impact on air quality related values of such lands (including visibility). . ."
6. Class II-b (unofficial name, not so designated in the regulations) applies to facilities to be constructed in or near Class I areas which ". . . will not adversely affect the air quality related values of the area (including visibility). . ." but will on up to 18 days a year cause increments higher than the Class I. These are for SO₂ only. Class II-b applies to low terrain areas and Class II-c applies to high terrain areas.

2 -B. Water Pollution

Water pollution regulations and policies are generally established to remedy existing conditions rather than to deal with new situations. The entire water pollution abatement effort is also in the process of changing from effluent to receiving water regulation criteria. This means that it is not very clear exactly which water pollution regulations a new tar sand industry will have to comply with nor what constraints will be imposed. An example is the question of what stipulations will be put on subsurface recharging of wastewaters.

In general, it may be said that the spirit of the new antidegradation policies (see Section 2-B-3) will apply with discharge permits (see Section 2 -B-2) required for "point" discharges. Specifically, the water quality and quantity limitations for tar sand developments depend on water quality and dilution water availability as well as state and local governmental water-use priorities. In Utah, for example, it may be necessary to buy water rights from already established users (usually agricultural ones) to obtain water.

2 -B-1. Water Pollution Policies and Programs

The water pollution regulations applicable to tar sand development are administered by the Environmental Protection Agency (EPA) and the U. S. Public Health Service (USPHS) at the federal level. At the state level, the regulations are usually enforced and administered by state and county health departments and by state water pollution committees. In many instances, laws and regulations go unenforced due to lack of mandate, lack of qualified manpower, unrealistic regulations, or local opposition.

A sweeping federal-state program against water pollution was launched in late 1972 when Congress enacted the Federal Water Pollution Control Act Amendments. Congress intended the Act to achieve two major goals:

- 1) To achieve, wherever possible, by 1983, water which is clean enough for swimming and other recreational uses and clean enough for the propagation of fish, shellfish, and wildlife.
- 2) By 1985, to have no discharges of pollutants into the nation's waters ("zero discharge" goal).

In 1976, the National Commission on Water Quality (NCWQ) presented an assessment of the experience garnered with the 1972 amendments to the Federal Water Pollution Control Act. Briefly, the midcourse corrections recommended were:

- That present requirements for uniform adoption of further pollution abatement beyond that required for 1977 be postponed for 5 to 10 years pending further assessment of progress.
- That achieving the "fishable and swimmable" goal by applying the 1977 requirement of use of best practicable technology to all dischargers. This presumably includes some sources previously considered nonpoint sources by EPA.
- That the ultimate goal of "zero discharge" be changed to one "stressing conservation and reuse of resources."
- That immediate attention be directed to elimination of the discharge of toxic pollutants in toxic amounts and to universal application of new source performance standards to all new point source discharges.

All of the discharge limitations discussed up to this point affect the content and volume of what is dumped into waterways. Eventually, however, the purity of the receiving waters will serve as a standard for controlling pollution.

The Water Pollution Control Act clearly notes that the states have the primary responsibility for controlling water pollution. In some cases, the states apply more stringent controls to regulate pollutants than does the federal government.

To make sure that all effluent limitations and other requirements are met, EPA and the states issue discharge permits to all specific "point" sources of pollution. The 1972 Act makes it illegal to discharge any pollutant without a permit and sets up a systematic time schedule that a plant must follow in reducing the pollution it produces. In effect, a permit is an agreement between a discharger and the government that sets specific limits on the content, volume, and temperature of what may be discharged into the water, generally based on the best available technology, economically achievable for pollution control facilities by 1983.

The River Basin Plan is one basic EPA planning process mechanism. It is prepared under Section 303 of the Act and pertains primarily to a river basin, which is the area drained by a river and its tributaries. The 303 Plan identifies and measures the pollutant found in waters within the basin and sets limits on what can be dumped into those waters. It also develops a basic implementation plan for water pollution control in the river basin.

The Areawide Waste Treatment Management Plan (Section 208) deals with the serious water pollution problems that often plague built-up or highly industrialized areas. These are usually urban areas where water quality problems are so serious that special management and control techniques are needed. Areawide planning considers a great deal more than just the technology of waste treatment--it is also concerned with such related issues as land use, zoning, development, transportation strategies, air quality, and solid waste management. It also deals specifically with the problem of "nonpoint" sources of water pollution, such as urban run-off and erosion at construction sites.

It is EPA's intent to have state water quality standards established to meet minimum federally instituted criteria and further to have state planning/management programs (303) with similar consistency. Local

decision-making is featured in the areawide (208) programs, but again the minimum federal/state standards concept and a minimum cost effectiveness is maintained.

2 -B-2. The Discharge Permit Program

The permits now issued under the National Pollutant Discharge Elimination System (NPDES) regulate discharges into navigable waters from all point sources of pollution, including industries, municipal treatment plants, large agricultural feedlots, and return irrigation flows. The permits, which are valid for up to five years, can include abatement measures required to meet the effluent limitations for 1977 and 1983, the new source standards, toxic effluent standards, and any more stringent limitations based upon water quality standards. The core of the permit is a specific "schedule of compliance," which prescribes an enforceable sequence of actions or operations leading to compliance with an effluent limitation, other limitation, prohibition, or standard. For example, such a schedule might set dates for design, engineering, construction, or process changes. These dates--no more than nine months apart--become checkpoints for measuring progress toward compliance with the effluent limitations. Failure to meet any requirement cited in the permit document--including any compliance schedule--constitutes a violation of the permit and a violation of the Act.

Responsibility for administering the permit program rests jointly with EPA and the states. EPA has established limitations on which the permits are based. The permits may be issued by either EPA or the states under one of two programs:

- 1) The federal permit program, under which EPA issues permits after certification from the state.
- 2) A state permit program, under which the state issues the permit following approval of the state program by EPA. In this

EPA retains veto power over the issuance of individual permits and monitors the adequacy of the overall state program.

EPA can delegate to the state its authority to issue NPDES permits if the proposed state program meets stringent federal requirements. In general to satisfy the NPDES requirements, a state must promulgate formal regulations so that the permit agency has authority to:

- 1) Issue permits which comply with all requirements of the Act
- 2) Modify or revoke permits if there is a violation of the law
- 3) Control disposal of pollutants into wells
- 4) Inspect, monitor, and enter the premises of all dischargers
- 5) Require reports from all permit holders and industrial or municipal treatment works
- 6) Insure that all interested or potentially interested parties have an opportunity to comment on an application prior to issuance of a permit
- 7) Abate violations of permits through civil and criminal penalties
- 8) Insure that industrial users of treatment works comply with pretreatment standards, user charges, and inspection and monitoring provision required under the Act.

The state must also have an approved "continuing planning process" and an enforceable law prohibiting any discharge of pollutants not authorized by the permit.

2 -B-3. Water Quality Criteria and Standards

The Federal Water Pollution Control Act Amendments of 1972 mandated that the EPA publish water quality criteria, accurately reflecting the latest scientific knowledge and the kind and extent of all identifiable effects on health and welfare which may be expected from the presence of pollutants in any body of water. In July, 1976, EPA published a final draft

of a report entitled "Quality Criteria for Water" (EPA, 1976). As pointed out by EPA in the report, the included water quality criteria do not have a direct regulatory impact (at this point in time); they form the basis for judgment in several EPA programs that are derived from water-quality considerations. For example, water quality standards developed by the states under Section 303 of the Act and approved by EPA are to be based on the water quality criteria, appropriately modified to take account of local conditions.

Criteria are presented for those substances that may occur in water where data indicate the potential for harm to aquatic life or to water users or to consumers of the water or the aquatic life (see Table 2-3). Unfortunately, present criteria do not represent an all-inclusive list of constituent contaminants. Thus, although the introductory portions of the report refer to the importance of toxicity considerations relative to the protection of aquatic life, there are no specific guidelines relative to establishing safe or acceptable discharge conditions, when a combination of common toxic materials or exotic toxic materials may appear in effluent discharge to a surface water.

Since most U.S. tar sand deposits are in Utah, it is appropriate to examine its water pollution standards and policies. The Utah Committee on Water Pollution consists of eight members, appointed by the Governor to staggered four-year terms, with the Director of Health as an ex-officio member. The Committee sets the Utah State water quality standards and cooperates with EPA and the Utah Division of Health in administering the state and federal water standards, permits, and programs (Utah Div. of Health, 1978). In 1976, the Utah Committee on Water Pollution adopted the following anti-degradation policy with regard to water quality in the state of Utah.

Numerical Standards for Protection of Beneficial Uses of Water

Constituent	CLASSES											
	1A	1B	1C	2A	2B	3A	3B	3C	3D	4	5	6
Bacteriological (No./100 ml)												
(30-day Geometric Mean)												
Maximum Total Coliforms	1	50	5,000	1,000	5,000	*	*		*	*		
Maximum Fecal Coliforms	*	*	2,000	200	2,000	*	*		*	*		
Physical												
Total Dissolved Gases	*	*	*	*	*	(d)	(d)		*	*		
Minimum DO (mg/l) (e)	*	*	5.5	5.5	5.5	6.0	5.5		5.5	*		
Maximum Temperature	*	*	*	*	*	20°C	27°C		*	*		
Maximum Temp. Change	*	*	*	*	*	2°C	4°C		*	*		
pH	6.5-9.0	6.5-9.0	6.5-9.0	6.5-9.0	6.5-9.0	6.5-9.0	6.5-9.0		6.5-9.0	*		
Chemical (Maximum mg/l)												
Arsenic, dissolved	.05	.05	.05	*	*	*	*		*	.1		
Barium, dissolved	1	1	1	*	*	*	*		*	*		
Cadmium, dissolved	.010	.010	.010	*	*	.0004(a)	.004(a)		*	.01		
Chromium, dissolved	.05	.05	.05	*	*	.10	.10		.10	.10		
Copper, dissolved	*	*	*	*	*	.01	.01		*	.2		
Cyanide	*	*	*	*	*	.005	.005		*	*		
Iron, dissolved	*	*	*	*	*	1.0	1.0		1.0	*		
Lead, dissolved	.05	.05	.05	*	*	.05	.05		*	.1		
Mercury, total	.002	.002	.002	*	*	.00005	.00005		.00005	*		
Phenol	*	*	*	*	*	.01	.01		*	*		
Selenium, dissolved	.01	.01	.01	*	*	.05	.05		*	.05		
Silver, dissolved	.05	.05	.05	*	*	.01	.01		*	*		
Zinc, dissolved	*	*	*	*	*	.05	.05		*	*		
NH ₃ as N (un-ionized)	*	*	*	*	*	.02	.02		*	*		
Chlorine	*	*	*	*	*	.002	.01		*	*		
Fluoride, dissolved (b)	1.4-2.4	1.4-2.4	1.4-2.4	*	*	*	*		*	*		
NO ₃ as N	10	10	10	*	*	*	*		*	*		
Boron, dissolved	*	*	*	*	*	*	*		*	.75		
H ₂ S	*	*	*	*	*	.002	.002		*	*		
TDS	*	*	*	*	*	*	*		*	2500		
Radiological (Maximum pCi/l)												
Gross Alpha	15	15	15	*	*	15(c)	15(c)		15(c)	15(c)		
Radium 226, 228 combined	5	5	5	*	*	*	*		*	*		
Strontium 90	8	8	8	*	*	*	*		*	*		
Tritium	20,000	20,000	20,000	*	*	*	*		*	*		
Pesticides (Maximum ug/l)												
Endrin	.2	.2	.2	*	*	.004	.004		.004	*		
Lindane	4	4	4	*	*	.01	.01		.01	*		
Methoxychlor	100	100	100	*	*	.03	.03		.03	*		
Toxaphene	5	5	5	*	*	.005	.005		.005	*		
2, 4-D	100	100	100	*	*	*	*		*	*		
2, 4, 5-TP	10	10	10	*	*	*	*		*	*		
Pollution Indicators (c)												
Gross Beta (pCi/l)	50	50	50	*	*	50	50		50	50		
BOD (mg/l)	*	*	5	5	5	5	5		5	5		
NO ₃ as N (mg/l)	*	*	*	4	4	4	4		*	*		
PO ₄ as P (mg/l) (f)	*	*	*	.05	.05	.05	.05		*	*		

STANDARDS WILL BE DETERMINED ON A CASE-BY-CASE BASIS (SEE APPENDIX D)

STANDARDS WILL BE DETERMINED ON A CASE-BY-CASE BASIS

STANDARDS WILL BE DETERMINED ON A CASE-BY-CASE BASIS

- * Insufficient evidence to warrant the establishment of numerical standard. Limits assigned on case-by-case basis.
- (a) Limit shall be increased threefold if CaCO₃ hardness in water exceeds 150 mg/l.
- (b) Maximum concentration varies according to the daily maximum mean air temperature (see Table at right).
- (c) Investigations should be conducted to develop more information where these pollution indicator levels are exceeded.
- (d) Not to exceed 110% of saturation.
- (e) These limits are not applicable to lower water levels in deep impoundments.
- (f) PO₄ as P (mg/l) limit for lakes and reservoirs shall be .025.

(b) Temp.	°C	mg/l
	12.0 and below	2.4
	12.1 to 14.6	2.2
	14.7 to 17.6	2.0
	17.7 to 21.4	1.8
	21.5 to 26.2	1.6
	26.3 to 32.5	1.4

Waters whose existing quality is better than the established standards will be maintained at high quality unless it has been affirmatively demonstrated to the State that a change is justifiable as a result of necessary economic or social development and will not preclude present and anticipated use of such waters. Any industrial, public, or private project or development which would constitute a new source of controllable pollution or an increased source of controllable pollution to high quality waters will be required to provide waste treatment to maintain high water quality to the extent that such treatment is practicable.

Specifically, the Utah antidegradation policy has three parts:

- 1) restoring water quality to those waters that have already been degraded,
- 2) maintaining the protection of high quality waters from new degradation,
- 3) specifying where the policy is attainable and applicable.

The maintenance policy statement in Utah reads as follows:

It is the State policy wherever attainable to: 1) maintain the chemical, physical, and biological integrity of Utah's waters, 2) protect and maintain the existing and potential beneficial uses and 3) prevent initial or further degradation of the existing water quality whether it be pristine quality, high quality, restored quality, or low quality.

In the context of the antidegradation policy, "integrity" refers to the completeness, unimpaired wholeness, and stability of aquatic ecosystems. The integrity of a water, or aquatic ecosystem, is characterized by its structure (chemical and physical constituents and plant and animal populations) and its functions.

Natural ecosystems perform functions that are a direct benefit to man. Some typical examples of such beneficial functions are:

- Recycling wastes, such as nutrients, rather than letting wastes accumulate,
- Reducing runoff and flood levels,
- Increasing groundwater recharge,
- Purifying water for human use and consumption,
- Providing fish and wildlife habitat, and
- Providing opportunities for recreation and enjoyment of aesthetic values.

It is the intent of Utah's antidegradation policy to restore and maintain functions such as these, which are intrinsic to the integrity of aquatic ecosystems.

The Utah antidegradation policy further states:

The restoration and maintenance policy statements shall be considered attainable, unless such attainability is precluded by one or more of the following conditions:

1. Where it is affirmatively demonstrated to the Water Pollution Committee, after full satisfaction of the inter-governmental coordination and public participation provisions of the State's continuing planning process, that degradation of existing water quality which is better than the established standards: a) is justifiable as a result of necessary social and economic development, and b) will not result in water quality standards violations, and c) will not interfere with or become injurious to present and anticipated beneficial water uses: the Committee may approve such degradation.

2. Where it is affirmatively demonstrated to the Water Pollution Committee, after full satisfaction of the inter-governmental coordination and public participation provisions of the State's continuing planning process, that modifications to best available technology economically achievable will a) represent the maximum use of technology within the economic capability of the owner or operator, and b) result in reasonable further progress toward the elimination of the discharge of pollutants; the Committee may approve such modifications.

3. Where a person affected by water quality related effluent limitations demonstrates at a public hearing that: a) there is no reasonable relationship between the economic and social costs and benefits to be obtained by achieving these effluent limitations or b) compliance with such limitations would result in substantial and widespread adverse economic and social impact; the Water Pollution Committee may approve adjustments to such limitation as it applies to such person.

4. Where best management practices are not practicable, the Water Pollution Committee may approve modifications to such practices.

5. Where the owner or operator of a point source, after opportunity for public hearing, demonstrates to the satisfaction of the Water Pollution Committee that a thermal effluent limitation is more stringent than necessary to assure the protection and propagation of a balanced indigenous population of fish and wildlife, the Committee may impose a modified thermal effluent limitation that will assure the protection and propagation of a balanced indigenous population of fish and wildlife.

6. Where the Water Pollution Committee demonstrates that:

- i) An existing designated use is not attainable because of natural background;
- ii) An existing designated use is not attainable because of irretrievable man-induced conditions;
- iii) Application of effluent limitations for existing sources more stringent than state and federal requirements to maintain the existing designated use would result in substantial and widespread adverse economic and social impact;

the Committee may designate less restrictive beneficial water uses.

Social and economic growth and development can be accomplished within the framework of the antidegradation policy. The total amount of pollution loading to waters of the state can be kept from increasing year after year by reducing present pollution loads and minimizing the pollution loads from new sources. This can be accomplished by a combination of the following:

- 1. Developing wasteload allocations to accommodate new source loadings via reductions in current pollution loadings,
- 2. Implementing new source performance standards to minimize the loading from new sources,
- 3. Promoting the growth and development of clean industries,
- 4. Adopting a no-mixing-zone requirement where necessary to meet water quality standards,
- 5. Designing closed loop, total containment, and waste recycling systems (e.g., land disposal systems and evaporation ponds),
- 6. Locating new industries so as to minimize water pollution concentrations,
- 7. Implementing best management practices for nonpoint sources, and
- 8. Implementing more stringent point source controls as improved technology becomes available.

To enforce the antidegradation policy, the state of Utah has assigned beneficial water-use classes with specific water quality criteria (see Table 2-3).

The promulgated Utah Water Quality Standards are in close agreement with federal standards. In Utah the rivers and tributaries in the tar sands areas have been assigned beneficial-use classes by the Utah Committee on Water Pollution. Essentially all of the rivers carry an "Agriculture" classification.

Certain criteria apply to all waters of the State of Utah regardless of their designated uses. These are intended to protect all waters from the illegal discharge of wastes or other substances, as follows:

Materials that will settle to form objectionable deposits;
Floating debris, oil, scum, and other matter to form nuisances;

Substances producing objectionable color, odor, taste, or turbidity or detectable sheen;

Materials, including radionuclides, in concentrations or combinations which are toxic or which produce undesirable physiological responses to human, resident fish, and other animal or plant life;

Substances and conditions or combinations thereof which produce undesirable aquatic life or tastes in fish and other animal or plant life;

Any constituents which will interfere with the designated beneficial uses.

Seasonal criteria may be required for segments that are dewatered, have significant diversions, or for other reasons may have periodic seasonal, or intermittent periods of flow. These waters shall be protected against discharge of wastes or other substances that may result in a threat to public health or substances which interfere with current or potential downstream beneficial uses. These situations may create the need for polished secondary treatment for any other significant discharges into the segments.

The Utah Committee on Water Pollution has generally taken the position that the Utah Water Pollution Act applies to all of the State's waters including groundwaters, underground contamination, aquifer disturbances, etc. This stand has sometimes brought the Committee into conflict with the Oil, Gas, and Mining Division of the Utah Department of Natural Resources.

The seven States of the Colorado River Basin have developed water quality standards for salinity in the Colorado River System (Seven States of the Colorado River Basin, 1975a, 1975b). These salinity standards were incorporated by reference into the Utah Water Quality Standards as of October 18, 1975, by action of the Utah Water Pollution Committee and the Utah State Board of Health.

Due to the concern over salinity in the Colorado River, it is unlikely that tar sand projects will be approved which may significantly increase the salinity of surface or groundwater runoff.

Fines are produced when the tar sand is washed. In the GCOS operation in Canada, the fines produce a gel-like substance (active clay particles) which is difficult to treat by ordinary sedimentation (Allen and Sanford, 1973). Since the U.S. tar sands have a larger matrix, this is not anticipated to be as much of a problem. Nevertheless, treatment of the wash water will be necessary to conserve water and to minimize the discharge of suspended sediments.

The water rights process in Utah follows the "doctrine of prior appropriation" which gives the water rights to the claimer with the highest priority of use but which, in practice, has given the water as well as the water right to the first and earliest filer. Since most of the water available in the Colorado River Basin has been filed on, this means that the tar sand industry will have to purchase water rights from local users (mainly irrigation rights) or otherwise negotiate for their water. Water rights in Utah are generally regarded as heirlooms, and their availability does not follow usual free marketplace principles. This may prove a constraint depending on the particular location and the quantity of water needed.

2-B-4. Summary of Water Pollution Constraints

Although an extensive discussion of the basic pollution sources has not been presented in this report, it should be emphasized that water pollution mechanisms are well understood. The pollutant-generating phenomena have been extensively investigated, both from fundamental scientific and routine engineering points of view. The results of these investigations and research projects have demonstrated that control of water pollution to virtually any desired level can be realized.

In real world situations, two qualitative factors enter; namely, "what is the environmental attitude of the industry?" and second "who controls and how stringently?" In many cases, the second factor depends on the first. Personalities and attitudes may also be problem constraints. Grey areas of water quality standards ("best practicable technology") and difficult enforcement areas (aquifer disturbances, groundwater contamination) are typical fields where semantics and personal interpretations enter.

Water quality effluent standards and their degrees of enforcement have generally become more stringent over the last few decades. In practice this may appear as though the rules of the game are being changed during the game. A significant trend in this respect is the ongoing transfer of authority and responsibility from the federal level to state and county agencies. The EPA 208 area-wide water quality management planning program which vests a large degree of specific planning in state and local governments is an example of this.

This transfer of authority and responsibility should lead to better cooperation and understanding between industry and regulatory officials. The local input and know-how is urgently needed in many cases where the imposing of national standards may have been inappropriate and unrealistic.

In conclusion, it can be stated that since water pollution abatement is a relatively young field, it should be expected that technology, regulations, and enforcement will not remain the same but change subject to sociological developments and public reactions.

2.-C. Solid Waste Disposal

The constraints on air and water pollution, which are discussed in the preceding sections are aimed at prevention of direct contamination of air and water, generally with materials believed to be directly harmful to

human health and the health of plants, animals, etc. The situation with processed tar sands disposal and the disposal of other solid wastes is more indirect. Solid wastes piles do not constitute immediate threats to health and welfare as do direct emissions of toxic materials into the air and water. They can, however, pose indirect threats because the material itself or some of its contents can become air and/or water pollutants, and the pile itself may move suddenly.

2-C-1. Environmental Threats

The specific threats are:

1. Air pollution due to wind erosion of the surfaces of storage and disposal piles (Pfeffer et al., 1974).
2. Pollution of local surface waters as the result of
(a) the leaching of salts or other materials from processing wastes and (b) the pickup of silt or sediment by erosion of the surface of disposal piles.
Transfer of possible hazardous organics or trace elements to the biosphere, including the poisoning of plant life.
Transfer of toxic substances from the wastes to the covering vegetation (EPA, 1975).
3. Mass movement of material due to collapse or slumping of unstable disposal piles.
4. Visual pollution by scarring the earth and disruption of the natural scenic values of the area and the inherent economic devaluation of surrounding property (Bullock et al., 1975).

2-C-2. Wastes to be Dealt With

The solid wastes to be dealt with in a major tar sands operation are:

1. Top soil stripped from affected lands (presumably stockpiled for later use in rehabilitation programs).
2. Overburden (if open pit mining is used).
3. Ore of too low a quality to be economically processed.
4. Processed sands
5. Dusts and fines created during ore transportation and crushing operations.

2-C-3. Lease Stipulation Constraints

Most of the tar sands resource is on federal lands. There will probably be lease stipulations on their exploitation. These stipulations will presumably be similar to those for oil shale. The oil shale stipulations presented here may serve as a guide to the future.

The oil shale operations being developed on public lands are controlled by lease agreements entered into between the developer (lessor) and the Bureau of Land Management of the U. S. Department of the Interior (BLM, 1974). The typical BLM oil shale lease agreement requires (1) that the lessee file and obtain approval of a detailed development plan before any work other than exploratory be performed, and (2) that operations conducted under the lease be "in compliance with all applicable federal, state, and local water pollution control, water quality, air pollution control, air quality, noise control, and land reclamation statutes, regulations, and standards." In addition, such leases include specific environmental stipulations which require that the lessee avoid removing or damaging objects of historical or scientific value; minimize damage to fish and wildlife habitat; incorporate the means to insure the health and safety of their workers and personnel; minimize air, water, and noise pollution; and preserve the scenic and functional aspects of the land both during and on completion of the operation.

In the area of land rehabilitation, the lease requires that all lands disturbed by the development be returned "to a usable and productive condition consistent with or equal to pre-existing land uses in the area and compatible with existing adjacent undisturbed natural areas." The latter requires that disturbed land masses and waste dumps be stabilized, contoured, and protected against wind and water erosion.

2 -C-4. Federal Laws and Regulations

Federal laws and regulations relating to surface mining and the surface disposal of mine wastes and refuse include:

1. The Surface Mining Control and Reclamation Act of 1977
2. Mandatory safety standards for surface coal mines, surface work areas of underground coal mines, refuse piles, and impounding structures (30 CFR 77).
3. The Resource Recovery and Conservation Act of 1976.

Although the first two of these statutes specifically refer to coal mining, this is probably because coal mining activities are considered the most pressing current problem. However, it is likely that tar sands operations will be ruled within the intent of the laws or the scope of the laws; and they will be expanded to include tar sands operations.

The environmental protection performance standards of the Surface Mining Control and Reclamation Act of 1977 require that surface mining operations be conducted in a manner (1) to maximize the utilization and conservation of the full resource being recovered; and (2) to allow restoration of affected lands, including surface disposal of mine wastes, tailings, coal processing wastes, etc., "to a condition capable of supporting the uses which it was capable of supporting prior to any mining or higher or better uses of which there is reasonable likelihood." This will require the separate

removal and segregated storage of top soil; stabilization and protection of all affected surface areas, backfilling, compaction and grading to restore the approximate contour of the original land, replacement of removed top soil, re-establishment of a diverse, effective, and permanent vegetative cover, and the long-term assumption of responsibility for successful revegetation. There are special provisions for prime farm lands, but they are not relevant to the lands of significance to tar sands operations. It is further required that mining and associated operations be conducted in a safe manner, with a minimum disturbance to the prevailing hydrologic balance, minimum chance of land slide or damage, etc.

The mine safety standards of interest to tar sands operations are those dealing with (1) the required character and construction of refuse piles and (2) water, sediment or slurry impoundments, and impounding structures. Although designed for coal mine refuse piles, they are directly applicable to the piles to be used for the surface disposal of processed tar sands. The regulations were prepared and promulgated as a direct result of the failure of the Buffalo Creek coal mine refuse embankment on 26 February 1972 (Schlick et al., 1977). The regulations were designed to protect miners who were employed on the mine property and were promulgated under the Federal Coal Mine Health and Safety Act of 1969. Some provisions of these regulations are summarized below:

1. Refuse Piles: Construction Requirements (30 CFR Section 77)
 - a. Refuse deposited on a pile shall be spread in layers and compacted in such a manner so as to minimize the flow of air through the pile.
 - b. Refuse shall not be deposited on a burning pile except for the purpose of controlling or extinguishing a fire.
 - c. Clay or other sealants shall be used to seal the surface

of any refuse pile in which a spontaneous ignition has occurred.

- d. Surface seals shall be kept intact and protected from erosion by drainage facilities.
 - e. Refuse piles shall not be constructed so as to impede drainage or impound water.
 - f. Refuse piles shall be constructed in such a manner as to prevent accidental sliding and shifting of materials.
 - g. No extraneous combustible material shall be deposited on refuse piles.
 - h. New refuse piles and additions to existing refuse piles shall be constructed in compacted layers not exceeding two feet in thickness and shall not have a slope exceeding 27 degrees except where a minimum safety factor of 1.5 can be demonstrated and appropriate approval obtained.
 - i. Foundations of refuse piles shall be cleared of all vegetation and undesirable material that would adversely affect the stability of the refuse pile.
 - j. All fires in refuse piles shall be extinguished by an approved method.
2. Water Sediment or Slurry Impoundments and Impounding Structures: General (30 CFR Section 77)
- a. Plans shall be required for the design, construction, and maintenance of structures which impound water, sediment, or slurry if the structure can (1) impound water, sediment, or slurry to an elevation of five feet or more above the upstream toe of the structure and can have a storage volume of 20 acre-feet or more; or (2) impound water, sediment, or slurry to an elevation of 20 feet or more above the

upstream toe of the structure; or (3) is determined to be a hazard to personnel in the area.

- b. Plans for impoundments and impounding structures will have to be approved prior to the beginning of work on the construction of the impounding structure.

In addition, water, sediment, or slurry impoundments and impounding structures will have to be properly identified, periodically inspected, the condition of the structure periodically reported upon, and must satisfy certain requirements before the impoundment or impounding structure is abandoned.

The Resource Conservation and Recovery Act of 1976 could apply to waste disposal from tar sand operations. However, this is far from certain. The act requires the Environmental Protection Agency to determine which wastes are to be classified as "hazardous wastes." Those wastes are subject to provisions of the act; other wastes are, in general, not.

The Environmental Protection Agency issued proposed guidelines for identifying hazardous wastes in December of 1978 (EPA, 1978, 1978a). Public hearings were held upon these guidelines; the agency is now preparing final regulations. At the public hearings most of the representatives of the mining industry argued strongly that the solid wastes which are regularly disposed of by the mining industry should not be treated as hazardous wastes and hence should not fall under the regulations of the Resource Conservation and Recovery Act of 1976.

EPA's proposed guidelines make clear that, in the ordinary sense of the words, the waste from mining operations is not hazardous waste. However, they believe that because of the large volume of some of these mining wastes, these wastes may have to be considered as hazardous wastes. The pertinent section of the EPA proposed guidelines is quoted below.

Special Waste Standards

In the course of preparing Subtitle C regulations under RCRA, the Agency realized that some portions of certain very large volume wastes will be hazardous under Subpart A standards and thus will come within the purview of the Subtitle C regulatory scheme. These wastes are cement kiln dust, utility waste (fly ash, bottom ash, and scrubber sludge), phosphate mining and processing waste, uranium and other mining waste and gas and oil drilling muds and oil production brines.

The Agency has very little information on the composition, characteristics, and the degree of hazard posed by these wastes, nor does the Agency yet have data on the effectiveness of current or potential waste management technologies or the technical or economic practicability of imposing the Subpart D standards on facilities managing such waste.

The limited information the Agency does have indicates that such waste occurs in very large volumes, that the potential hazards posed by the waste are relatively low, and that the waste generally is not amendable to the control techniques developed in Subpart D. The Agency is calling such high-volume hazardous waste "special waste" and is proposing to regulate it with special standards.

The following table provides some information about those wastes which, when hazardous, the Agency proposes to regulate with special standards. With two exceptions, EPA does not know how much of the total amount of waste generated in these categories is, in fact, hazardous and thus subject to Subtitle C regulations. Only waste which is hazardous under Subpart A standards, however, is "special waste" under this Subpart. Any portion of the waste on the following table which is not hazardous under Subpart A standards is not regulated at all under Subtitle C and thus is not "special waste".

Special Waste

[Metric tons/yr]

Waste	Quantity	Possible Hazard
Cement Kiln Dust.....	12 million*	Alkalinity and heavy metals
Utility Waste (fly, ash, bottom ash,... scrubber sludge)	66 million*	Heavy metals (trace)
Phosphate Mining, Beneficiation, and Processing Waste	400 million...	Radioactivity (low levels)
Uranium Mining.....	150 million...	Radioactivity
Other Mining Waste.....	~2 billion*	Heavy metals, acidity
Gas and Oil Drilling Muds and Oil..... Production Brines	5 million....	Alkalinity, heavy metals, toxic organics, salinity

Note.--It is not yet known how much of the total quantity of waste marked with an asterisk (*) is, in fact, hazardous waste.

A proposed rulemaking will be published at a later date regarding the treatment, storage, and disposal of special waste. The Agency will be developing additional information in order to write substantive standards for special waste, and hereby solicits information and comment from the public which may assist the Agency in developing its proposals. For the time being, all facilities which handle special waste will be exempted from the storage standards (§ 250.44) and the treatment and disposal standards (§ 250.45). In order to provide some protection from special waste and to collect additional information on special waste streams, EPA has prepared special standards for each type of special waste. Many of the general facility standards in § 250.43 are prescribed for special waste. In addition, some special waste must meet standards which are designed to control potential problems unique to that waste.

From these proposed guidelines it is not at all clear that the solid waste from a tar sands mining operation would be considered "hazardous waste" or "special waste".

If, however, it were determined that the waste from tar sand operations were covered by the Resource Conservation and Recovery Act of 1976 this would mean that the operators of future tar sand mining projects would be required to obey the waste storage requirements of the future EPA guidelines concerning hazardous wastes. The most significant of these and those most applicable to a tar sand operation would be the reporting, monitoring, and closure and post-

closure monitoring requirement and the requirements for ground water and leachate monitoring. The experience in Canada indicates that the fine clay-like material present in the waste from the tar sands operation acts as a very effective sealant in the waste ponds. (See Section 4-F-7 of this report.) The Utah tar sand deposits are believed to contain smaller amounts of fine materials and therefore it is not as certain that the ponds will be self-sealing. Nonetheless it seems clear that one of the natural requirements of any major large-scale waste storage project will be the protection of adjacent surface streams and groundwater from infiltration of leachates from the storage. Thus it is unlikely that the requirements of the RCRA will be more burdensome than those of other existing rules and regulations. The significant increase in cost and difficulty for future tar sand operations, if they do fall under the purview of RCRA, will be increased record keeping and reporting.

2-C-5. Utah Regulations

In the Utah Mined Land Reclamation Act of 1975, the Utah Legislature indicated that whereas mining is essential to the economic and physical well-being of the state of Utah and the nation, when mining operations require that the surface of the earth be altered, such alterations "should be done in such a way as to minimize undesirable effects on the surroundings." The act further holds that "mined land should be reclaimed so as to prevent conditions detrimental to the safety and welfare of the citizens of the state and to provide for the subsequent use of the lands affected." This legislation gives the jurisdiction and authority for administering the provisions of the act to the Utah Board of Oil, Gas and Mining, and placed upon that board the responsibility to adopt general rules and regulations under which the mining industry shall operate with respect to mined land reclamation.

The rules and regulations for implementing the provisions of the Utah Mined Land Reclamation Act of 1975 have been promulgated and were formally adopted on 22 October 1975. These rules require that each time a new mining operation is commenced, a separate notice of intention be filed with the State Division of Oil, Gas and Mining. This notice must include a reclamation plan and a map of the area affected. The reclamation plan shall include:

1. A statement of known prior and current uses to which the land was put including estimates of current surface resources and its capabilities to support a variety of uses or potential uses.
2. The possible uses for the land following termination of mining operations.
3. The manner in which the overburden, topsoil, tailings, waste or rejected materials will be deposited, including:
 - a. the manner in which plant supporting material will be conserved and restored, and
 - b. an explanation of how toxic or otherwise undesirable materials will be segregated and disposed of.
4. The extent of grading, backfilling, compaction, etc. of the soil; of fill which will be required and the manner in which such operations will be accomplished.
5. A plan to revegetate or otherwise minimize or control erosion or siltation of the disturbed surface. Priority shall be given to providing a quick, permanent, protective cover of non-noxious plants which will enrich the soil.

6. A timetable for the accomplishment of each major step
in the reclamation plan.

The map submitted with the notice of intention to commence mining operations should include all topographical and hydrographic features of the area as well as the location of all developments, the storage area for topsoil and the disposal areas for overburden, waste, tailings, or rejected materials and water.

2 -C-6. Summary of Solid Waste Disposal Regulations

It is clear from the above that the solid waste regulations are not in the form of numerical standards (either emission or concentration) as are the air and water regulations. Rather they are in the form of requirements for presenting plans to be studied by the land reclamation agencies and approved if they appear to meet the objectives prescribed.

3. ENVIRONMENTAL CONSTRAINTS - CANADA

Our reason for being interested in Canadian environmental law is to help us understand how that law has influenced the two existing tar sand recovery projects in Alberta and how it will influence future tar sand projects in Alberta. The authors have searched for a comprehensive document which compares Canadian and U.S. environmental law without finding such a comparison. The authors are not lawyers; we present this comparison as the best which we can make from the reading of the pertinent Canadian laws and our knowledge of U.S. laws plus discussions with knowledgeable Canadian officials. It is certainly not offered as a complete examination of the details of legal structures of the two countries.

Although there are significant differences in the fundamental legal structure of the two countries, it is our observation that the final result of environmental control law in Canada is not drastically different than it would be for a similar facility in the United States. Thus it appears to the authors that if the existing tar sand plants in Alberta and those which are envisioned for the near future had been subject to U.S. environmental regulations (instead of Canadian) as they existed at the time of the construction or will exist in the future, the plants would have been (or would be) substantially the same as they are now.

The principal differences between U.S. and Canadian environmental law are 1) Canada does not have a written formal constitution which stands above the acts of Parliament as the United States Constitution stands above the acts of Congress or the state legislature. Thus it is not possible, for example, for a parliamentary law in Canada to be declared unconstitutional as it is possible for a law passed by the Congress of the United States or by a state legislature.

2) It appears that English common law, which the United States shares with Canada, plays a more significant role in the adjudication of environmental disputes in Canada than it does in the United States.

3) In both Canada and in the United States there is a division of responsibility between the Federal Government and the governments of the states (U.S.A.) or provinces (Canada). However, in this division of responsibility, the relative role of the Federal Government is much stronger in the United States than in Canada. The two existing tar sand developments are both strongly governed by the environmental regulations of the province of Alberta and only slightly influenced by federal regulations. If the same facilities had been located in the United States, they would be much more strongly governed by the federal regulations than by the regulations of the state in which they were located.

4) In the United States much environmental regulation has been written with force of law with specific numerical emission or ambient values which must be met by emitters or which must be met in the ambient environment. In contrast, Canadian law is much more strongly based on consultation and negotiation. Where United States law would typically say, "A new plant must not emit more than x," Canadian law would typically say that the owners of the new plant must submit a set of plans and specifications which must be approved by the appropriate authorities who will then grant a license to operate according to that set of plans and specifications. The degree of emission control required of the plant is much more likely to be arrived at by negotiation between the plant operator and the regulatory authorities in Canada than it would be in the United States.

5) Regulations and policies in Canada seem to lag the corresponding ones in the United States by several years. For example, environmental impact assessment and ambient air quality regulations entered Canadian law several years after they entered U.S. law. (Their forms were also modified, but the essential ideas were the same.)

Considering now the similarities between the U.S. and Canadian law, we see that because many industries operate in both countries and because the countries have continual communications with one another and because professionals in the environmental areas in both countries pay attention to what occurs in the other, the prevailing ideas of what can be practically accomplished by any given environmental control activity are more or less the same in both countries. For this reason, what is considered "best available technology" in Canada is strongly influenced by what is deemed to be best available technology across the border in the United States. It would be unlikely that the Canadians would permit the installation of a new facility in Canada which could not meet the environmental regulations in the United States. The Canadians are extremely familiar with U.S. regulations. Similarly, U.S. environmental specialists are familiar with Canadian regulations. Thus although the details of the standard-setting process may be quite different because of the different legal and historical situation in Canada, the practical consequences of environmental regulations in Canada and Alberta are quite similar to those in the United States.

3-A. Air Pollution Regulations

United States air quality standards are discussed in Section 2-A-1. The Canadian Federal equivalents are called Ambient Air Quality Objectives (Savage, 1977). These are compared to U.S. Ambient Air Quality Standards in Table 3-1. The corresponding Alberta regulations are called maximum levels; these are also shown in Table 3-1.

From Table 3-1 we can see that the "acceptable" and "desirable" levels in Canadian Federal regulation correspond somewhat with the primary and secondary standards and U.S. regulations. We also see that Alberta does not have the double set of regulations as does the U.S. or the Canadian Federal.

TABLE 3-1

Comparison of U. S. Federal, Canadian Federal, and Alberta
Ambient Air Quality Standards and Goals

Quality Standards and Goals

Pollutant	Averaging Time	Standard/Goal in Microgram/m ³ (except mg/m ³ for CO)				
		U.S. Federal		Canadian Federal		Alberta
		Primary	Secondary	Acceptable	Desirable	
Photochemical Oxidant (ozone)	annual average	-	-	30	20	-
	24 hour	-	-	50	30	30
	1 hour	240	-	160	100	100
Carbon Monoxide	8 hour	10	-	15	6	6
	1 hour	40	-	35	15	15
Nitrogen Dioxide	annual average	100	-	100	60	60
	24 hour	-	-	200	-	200
	1 hour	-	-	400	-	400
Sulfur Dioxide	annual average	80	-	60	30	30
	24 hour	365	-	300	150	150
	3 hour	-	1300	-	-	-
	1 hour	-	-	900	450	450
	0.5 hour	-	-	-	-	525
Total Suspended Particulates	annual average	75	60	70	-	60
	24 hour	260	150	120	-	100
Hydrocarbons	3 hour (6-9 a.m.)	160	-	-	-	
Hydrogen Sulfide	24 hour	-	-	-	-	4
	1 hour	-	-	-	-	14
	0.5 hour	-	-	-	-	17

Again from Table 3-1 comparing the numerical values, we see that in all cases the Alberta regulation is the same or more stringent than the Canadian "acceptable." In many cases the Alberta regulations are the same as the Canadian Federal "desirable" regulations.

We also see in Table 3-1 that Alberta has a regulation for hydrogen sulfide. Similar regulations do not exist in the United States nor in Canadian Federal regulations. The reason for this is that Alberta is a major producer of sour natural gas which contains large quantities of hydrogen sulfide. There are many plants in Alberta which process this sour gas to remove the hydrogen sulfide. Although they in general work satisfactorily, there is always the possibility that some amount of hydrogen sulfide may escape from the wells, gathering lines, processing plants, etc. Hence the greater interest in ambient hydrogen sulfide in Alberta than in other parts of Canada or in most of the U.S. (which has no major deposits of natural gas with as high a hydrogen sulfide content as those normally found in Alberta).

Comparing the Canadian acceptable standard to the U.S. Federal primary standards, we see that where there are comparable values, the Canadian values are in general the same as or somewhat lower than the U.S. values. In addition, we see that the Canadians have promulgated a wider range of short-term standards than has the U.S.

The Canadian Federal and Alberta standards shown in Table 3-1 do not play as significant a role in Canadian air pollution law as the corresponding U.S. primary and secondary standards play in U.S. air pollution law. It does not appear that Canada or Alberta has undertaken a major effort to reach the acceptable (or Alberta maximum permissible) concentration by a fixed deadline corresponding to the major effort being made in the U.S.

to reach the primary standards everywhere in the country by fixed deadline (originally 1975, now extended to 1987). Rather the Canadian Federal and Alberta ambient regulations are used as guidelines for the evaluation of

new facilities. New facilities will be required to use the best available control technology but in addition will be required to demonstrate by modeling that their emissions will not cause these ambient air standards to be violated.

The role of emissions standards in U.S. air pollution law is discussed in Section 2-A-3. Both Federal Canada and Alberta have corresponding emission regulations (Savage, 1977). To date the list of such emission standards in Canada is much shorter than the corresponding list for the United States. A 1977 compilation of regulations shows that the industries covered in Canadian Federal law were portland cement, asphalt paving, metallurgical coke manufacture, and secondary lead smelters.

The Alberta regulations for the same date covers only particulate emissions but does cover a wider list of sources. Of these the only one involved in the tar sands exploitation is "the processing of hydrocarbons and petroleum products" where the standard of 0.2 lbs per thousand pounds of effluent is not particularly restrictive for modern processing plants. However, GCOS is in violation of these regulations in its power plant and is taking corrective action.

As discussed previously, these numerical regulations do not play as significant a role in Canada as they do in the United States. In contrast, the binding environmental control regulations for a tar sand plant or any other major new facility are made when the developer of the facility submits a set of plans and specifications which are reviewed by the provincial environmental control agency. If they do indeed correspond to what is deemed to be best practical technology, they will be approved. Since the technology has improved steadily over the past few years, the permissible emissions rates (in tons of pollutants per ton of tar sand processed) have moved steadily downward. Syncrude will emit significantly less than GCOS; Cold Lake will emit significantly less than Syncrude (on a ton of pollutant

per ton of bitumen basis). The provincial and federal government agencies regularly attempt to determine what constitutes current best available control technology and to thereby lower the permitted emission level as much as is deemed practical (Albera Environment, 1978a). This progression is illustrated in Table 3-2.

3-B. Water Pollution Regulations

The United States water pollution regulations are discussed in Section 2-B of this report. The federal Canadian water pollution policy (Canada Water Act) is essentially enabling legislation specifying the steps the federal government (Governor in Council) may take to rectify or prevent pollution (Savage, 1977). The actual designation of water quality standards, treatment requirements, or wastewater disposal permits is left to the individual provinces or to an incorporated "Water Quality Management Agency" should the Governor in Council deem its establishment necessary.

The Canada Water Act contains a water anti-degradation clause (Par. 17) which refers specifically to interference with or alteration of the nutrient balance in waters so as to render the waters less useful to animal, fish, plant, or man. To apply this antidegradation clause uniformly has been difficult, and some large bodies of Canadian waters have deteriorated (i.e., Okanagan Lake System) in spite of the Act and established agencies. Similar difficulties regarding application and enforcement of antidegradation policies have been experienced in the U.S.

Aside from the general Water Act, the Canadian federal water pollution regulations contain the following specific acts which may affect tar sand operations:

- Fisheries Act
- Migratory Birds Convention Act
- Navigable Waters Protection Act
- Oil and Gas Production and Conservation Act

TABLE 3-2

Progressive Improvement in Sulfur Recovery for Alberta Tar
Sand Projects

<u>Project</u>	<u>Year Completed</u>	<u>Sulfur Dioxide Emission Rate (tons SO₂/1000 bbl) Synthetic Crude Produced)</u>	<u>Data Source</u>
GCOS	1967	5.0	Alberta Environment (1973)
Syncrude	1978	2.3	Goforth (1977)
Cold Lake	1985(?)	0.6	Imperial Oil (1978a)
Alsands	1986(?)	0.7	Alsands (1979)

The Fisheries Act contains regulations regarding "Petroleum Refinery Liquid Effluents." These regulations pertain to the following deleterious substances: a) oil and grease, b) phenols, c) sulfide, d) ammonia nitrogen, e) total suspended matter, f) any substance capable of altering the pH of liquid effluent or once-through cooling water. Table 3-3 gives an overview of the amounts of these substances which may be discharged by a petroleum refinery.

The Migratory Birds Regulation and the Navigable Waters Protection Act state merely that nothing may be discharged into waters which may interfere with migratory birds frequenting the waters or navigating in the waters.

The Oil and Gas Production and Conservation Act enables the Governor in Council through the Minister to regulate oil and gas production on land belonging to the Federal Canadian Government (including Yukon and the Northwest Territories), as well as submarine coastal areas. The Act also pertains to recharging or injection of underground formations, but contains no specific numerical regulations.

The Canadian provincial water pollution regulations are not uniform and depend, as in the USA, on the particular waterbody and its use. The Alberta Surface Water Quality Objectives (Alberta Water Quality Branch, 1977) states that "no action can or should be permitted which endangers legitimate uses or causes the overall aquatic environment of an area to deteriorate." Clearly, this is a statement akin to an antidegradation policy. The particular surface water quality objectives for Alberta are listed in Table 3-4. The Alberta Clean Water Act (Savage, 1977) does not differentiate as to the various possible water uses (as do the Utah standards), but the Alberta surface water quality criteria do contain numerical standards for suspended solids concentrations--a significant water quality parameter in tar sands operations.

The general implication of the Alberta Surface Water Quality Objectives is to leave the details, such as specific discharge permits, to negotiations

TABLE 3-3

Canadian Petroleum Refinery Liquid Effluents Regulations
(Savage, 1977). (Not directly applicable to tar sands upgrading plants).

AMOUNTS TO BE USED IN CALCULATING AUTHORIZED DEPOSITS
OF DELETERIOUS SUBSTANCES

Name of Deleterious Substance	Monthly amount in pounds per 1,000 barrels of crude oil	One day amount in pounds per 1,000 barrels of crude oil	Maximum daily amount in pounds per 1,000 barrels of crude oil
1. Oil and Grease	3.0	5.5	7.5
2. Phenols	0.3	0.55	0.75
3. Sulfide	0.1	0.3	0.5
4. Ammonia Nitrogen	3.6	5.7	7.2
5. Total Suspended Matter	7.2	12.0	15.0

AMOUNTS TO BE USED IN CALCULATING ADDITIONAL AUTHORIZED DEPOSITS
OF DELETERIOUS SUBSTANCES WHEN STORM WATER IS BEING DISCHARGED
AND LIMITS OF DEPOSITS AUTHORIZED

Name of Deleterious Substance	Pounds per 10,000 Canadian Gallons of Storm Water	Pounds per month per 1,000 barrels of crude oil per day
1. Oil and Grease	1.0	25.0
2. Phenols	0.1	2.5
3. Total Suspended Matter	3.0	75.0

TABLE 3-4

Alberta Surface Water Quality Objectives. (Alberta Water Quality Branch, 1977)

1. Bacteriology (Coliform Group)

- (a) In waters to be withdrawn for treatment and distribution as a potable supply or used for outdoor recreation other than direct contact, at least 90 per cent of the samples (not less than five samples in any consecutive 30-day period) should have a total coliform density of less than 5,000 per 100 ml and a fecal coliform density of less than 1,000 per 100 ml.

- (b) In waters used for direct contact recreation or vegetable crop irrigation the geometric mean of not less than five samples taken over not more than a 30-day period should not exceed 1,000 per 100 ml total coliforms, nor 200 per 100 ml fecal coliforms, nor exceed these numbers in more than 20 per cent of the samples examined during any month, nor exceed 2,400 per 100 ml total coliforms on any day.

2. Dissolved Oxygen

A minimum of five mg/l at any time.

3. Biochemical Oxygen Demand

Dependent on the assimilative capacity of the receiving water, the BOD must not exceed a limit which would create a dissolved oxygen content of less than five mg/l.

4. Suspended Solids

Not to be increased by more than 10 mg/l over background value.

5. pH

To be in the range of 6.5 to 8.5 pH units but not altered by more than 0.5 pH units from background value.

6. Temperature

Not to be increased by more than 3°C above ambient water temperature.

7. Odour

The cold (20°C) threshold odour number not to exceed eight.

8. Colour

Not to be increased more than 30 colour units above natural value.

9. Turbidity

Not to exceed more than 25 Jackson units over natural turbidity.

10. Organic Chemicals

Constituent	Maximum Concentration (mg/l)
Carbon Chloroform Extract (CCE) (includes Carbon Alcohol Extract)	0.2
Methyl Mercaptan	0.05
Methylene Blue Active Substances	0.5
Oil and Grease	substantially absent, no iridescent sheen
Phenolics	0.005
Resin Acids	0.1

11. Pesticides

To provide reasonably safe concentrations of these materials in receiving waters an application shall not exceed 1/100 of the 48-hour TL₅₀. No pesticides can be used in Alberta unless they have been registered under the Pest Control Products Act. Any pesticides used on, in, or near water (within 100 linear feet) must be approved by a Department of Environment permit issued under The Agricultural Chemicals Act.

12. Toxic Chemicals

Constituent	Maximum Concentration (mg/l)
Arsenic	0.01
Barium	1.0
Cadmium	0.01
Chromium	0.05
Cyanide	0.01
Lead	0.05
Mercury	0.0001
Selenium	0.01
Silver	0.05

13. Radioactivity

Gross Beta not to exceed 1,000 pCi/l.
Radium 226 not to exceed three pCi/l.
Strontium 90 not to exceed 10 pCi/l.

14. Inorganic Chemicals

Constituent	Maximum Concentration (mg/l)
Boron	0.5
Copper	0.02
Fluoride	1.5
Iron	0.3
Manganese	0.05
Nitrogen (Total Inorganic and Organic)	1.0
Phosphorus as PO ₄ (Total Inorganic and Organic) ...	0.15
Sodium (as percent of cations)	between 30 & 75
Sulphide	0.05
Zinc	0.05

NOTE: The predominant cations of SODIUM, CALCIUM and MAGNESIUM and anions of SULPHATE, CHLORIDE and BICARBONATE are too variable in the natural water quality state to attempt to define limits. Nevertheless, in order to prevent impairment of water quality, where effluents containing these ions are discharged to a water body the permissible concentration will be determined by the administrative authority in accordance with existing quality and use.

15. Unspecified Substances

Substances not specified herein should not exceed values which are considered to be deleterious for the most critical use as established by the administrative authority.

between the provincial regulatory agency and the industry. It should be kept in mind here that the Canadian tar sands operations are located in sparsely populated areas with fairly large surface streams. In other words, dilution water is readily available and short-range water pollution impacts are not keenly felt. In the USA this is not so since the water quantity and quality of the Colorado River is very crucial to downstream agricultural water users.

For purposes of conserving the environment, the province of Alberta also has an Environment Conservation Act (Savage, 1977). An Environment Conservation Authority has been established under this Act for purposes of reporting to the Minister any matters which may adversely affect, destroy, disturb, alter, or pollute the "natural resources," meaning land, plant life, animal life, water, and air. Basically this authority is analogous to the environmental impact statement (EIS) requirement established by most states in the USA.

Specifically, the province of Alberta has also established guidelines for the effluents from coal mining (Alberta Water Quality Branch, 1973) and from petroleum refineries (Alberta Water Quality Branch, 1976). The quality of the coal mining effluent is referenced with regard to total suspended solids, total iron, pH, and turbidity. Ponds for retaining storm water refer to 10-year frequency storms with 24-hour duration.

The guidelines for petroleum refinery effluent refer to best practicable technology including two-stage oil removal (API separators and dissolved air flotation), sour water stripping for sulfide and ammonia removal, biological treatment of all process water, storm-water treatment, and waste flow equalization. Both guidelines are quite specific in their requirements and demand considerable pollution-abatement engineering before waste discharge permits are granted. Only some of these requirements are applicable to tar sand operations, particularly surface mining operations.

For the new operations of the Syncrude type, the requirements add up to zero discharge and maximum recycle achievable utilizing tailings ponds.

For the Cold Lake in-situ type operation, the requirements will likely be considerably more stringent than those of the Refinery Liquid Effluent Regulations or Alberta Guidelines.

In general it may be said that although the natural environment in the areas of tar sands deposit in Canada is quite different from that in Utah, the water pollution regulations are quite similar. In the USA, the federal government plays a dominant role while in Canada the provinces take the initiative. In Alberta quite specific guidelines have been developed for the discharge of industrial effluents, including those from coal mining and petroleum refining. The specifics of these guidelines as they may apply to tar sands operations will be discussed in Section 4-E of this report.

3-C. Solid Waste Disposal Regulations

The Canadian Mines Regulation Act of 1975 describes the requirements for surface mining by stating objectives to be met without numerical specifications (Savage, 1977).

U. S. Standards are similar but do contain a specific limitation of a maximum slope of 3/1 on the steepness of slopes on waste piles.

The Canadian regulations are geared to a concern for a solution of the problem as to how to control the reclamation of the surface and describes duty and procedure as illustrated by the following excerpt:

It is the duty of every owner, agent, or manager of a mine to institute and carry out a programme for the protection and reclamation of the surface of the land and watercourses effected thereby and, on the discontinuance or abandonment of a mine, to undertake and complete the programme to leave the land and watercourses in a condition satisfactory to the Minister; and such a programme shall be submitted to and approved by the minister as hereinafter provided. Before commencing preparatory work for publication from a mine, the owner, agent, or manager of the mine shall file with the Minister a report in such form and containing such information as the Minister may prescribe. (Savage, 1977)

This procedure provides for an approval system for a proposed operation program

which can cause the operation to conform to the best available changing technology.

The Alberta Coal Mining Waste Water Effluent Guidelines of 1978 influence solid waste management by limiting the location of ponds;

A retention pond should preferably be located out of a stream bed unless the upstream watershed is to be seriously disturbed.

The following excerpts from these guidelines influence some decisions to be made in the design of the solid waste disposal system:

The plant and any tailings ponds shall be operated on a closed water circuit. There shall be no discharge of process waste water and plant site surface runoff to natural drainage except as a result of minor natural seepage.

Details as to how this specification influences design will be addressed in Section 4.

The size of settling ponds is influence by the requirement:

The settling characteristics of the suspended solids on which the design of the settling pond is based should be obtained by conducting tests on actual waste waters approximating those expected and not on artificial materials.

The design of the dike retaining the tailings is influenced by the requirement:

When the waste waters to be treated consistently require only the removal of suspended solids, the use of a leaky dam or rock-bench-type structure may be suitable. The filter principle may, in some cases, be further extended to gravel-based ponds where water dissipates by seepage.

The specifications for preparation of the sites require:

Site preparation for retention ponds shall include clearing of all bushes, trees, stumps, roots, and other material and the salvaging of available soil and/or regrowth material for reclamation.

These excerpts illustrate the need for concern about requirements from one agency while designing an item apparently controlled by another. In these requirements the following item appears:

All impoundments shall meet the requirements of the Water Resources Act.

We acknowledge the assistance of Mr. R. E. Beaty, Scientific Officer of the Air Quality Branch of Alberta Environment, who - together with some of his colleagues from the water quality branch - reviewed a draft of this chapter, and made helpful suggestions and comments.

4. PROPOSED ENVIRONMENTAL CONTROL TECHNOLOGIES

In choosing an emission control technology or a more general environmental control technology, one has two options; one option is to modify the project in such a way as to eliminate the source of contamination or emissions. The second alternative is to put some form of treatment device (sometimes called "tailpipe treatment device") on the outlet from the process to prevent the emission of the harmful material generated within the process. A clear example of these two options exists in the automotive industry where some manufacturers have modified the design and function of their combustion chamber (for example, through "stratified-charge" engines) to minimize or eliminate the formation of harmful pollutants, while others have elected to allow the pollutants to be formed in the engine and then to treat them external to the engine in catalytic converters.

In the tar sand industry, the original designs of the Canadian projects mostly envisaged processes which maximized the economic efficiency of the recovery of the bitumen from the tar sand and its upgrading to syncrude and then used tailpipe devices to minimize the emissions of harmful materials. This was, to some extent, conditioned by the history of these projects, in which most of the fundamental design and development work was done at a time when environmental control regulations were much less stringent than they are now. As the environmental control regulations became more stringent, the companies designed add-on devices to control emissions.

4-A Tar Sand Variables Which Influence The Choice of Processing Technology

Because it is apparently impractical to mine soft tar sand (or any other large, soft deposit) by underground mining techniques, each tar sand deposit must be considered as either shallow and accessible to open-pit

mining or deep and unmineable. For these deep, unmineable deposits, the only recovery technique which appears practical is some sort of in-situ processing. This situation is in sharp contrast to the situation for deep oil shales, which are quite amenable to underground mining. Two of the federal prototype oil shale leases were originally designed for underground mining and are now converting to in-situ processing. This change is occurring primarily for economic reasons but will have environmental advantages as well. However, because a soft friable material is very difficult to underground mine, this option is not available for most deep tar sands.

In addition to the distinction between deep and shallow deposits, which each require entirely different recovery technologies, there is a second property which may govern recovery technologies; namely, whether the sands are wet or dry. Microscopic examination of the Athabasca deposits (Camp, 1970) indicates that most of the sand grains have a film of water between the sand grain and the bitumen. The presence of this water film makes the separation of the bitumen from the sand grains by water displacement very easy. The displacing water merely swells this water film and floats away the bitumen, which was never in real contact with the sand grains. This is the process used in Athabasca by the commercial tar sand ventures (GCOS and Syncrude). On the other hand, the Utah deposits mostly do not have this water between grain and bitumen film but rather have bitumen adhering directly to the sand grains. This makes the removal of the bitumen from the Utah deposits by water-washing significantly more difficult than from the Athabasca deposits. It can be accomplished, but not as easily.

A third variable which causes various tar sand deposits to differ in the required processing technology is the sulfur content of the bitumen. The Athabasca bitumen is typically 5 percent sulfur while much of the Utah bitumen is less than 0.5 percent sulfur. The removal of sulfur from the bitumen in preparing the synthetic crude is a major constraint on the

processing technology for the Athabasca tar sands. Sulfur removal would not be nearly as serious a constraint on some of the Utah tar sands, and therefore the processing of the bitumen after its removal of the sands could be significantly different for the low-sulfur bitumens from Utah.

The next parameter which leads to variety in processing technique is the viscosity and viscosity-temperature relationship. Figure 4-1 shows estimated temperature-viscosity relationships for several tar sand bitumens. Note the extreme compression on the left-hand scale; that scale is the logarithm of the logarithm of the viscosity. This type of plot (Lee and Booser, 1967) is widely used for estimating the temperature-viscosity relationship of petroleum products and crude oils. For most petroleum products, the viscosity-temperature relation is approximately a straight line on this type of plot; thus on this coordinate system, measurement of the viscosity at two temperatures suffices to estimate it over a wide range of temperatures.

As a point of reference, typical motor oil used in the United States has a viscosity of approximately 100 centistokes at 70°F. We see from the plot that at temperatures in the range 200 to 260°F, most of the Athabasca bitumens have a comparable viscosity. In contrast, at 50°F their viscosity is 500 to 10,000 times as high. We also see that the Sunnyside and Asphalt Ridge bitumens from Utah both have significantly higher viscosity than most of the Athabasca deposits. Finally, we see that the Cold Lake bitumen, which is soon likely to be processed by in-situ means, has a viscosity roughly one tenth that of the Athabasca bitumens.

For almost any kind of recovery operation which one can envisage, a lower viscosity is more desirable than a high viscosity. Thus the higher the line representing the bitumen lies on Figure 4-1, the more difficult it will be to separate this bitumen from the sand or rock which contains it.

FIGURE 4-1. Viscosity-Temperature Relationships for Some Tar Sand Bitumens
Athabasca and Cold Lake Data from Simmer (1976). Sunnyside and
Asphalt Ridge Data from Kayser (1966)

The final parameter which leads to variety in processing techniques is the size of the sand grains. The Athabasca deposit contains mostly sand grains in the size range 0.1 mm to 0.5 mm. But there is a significant fraction of small sand grains or of silt or clay (Camp, 1970). These fine materials have made the processing in Athabasca much more difficult than it would be if they were not present. They tend to form an emulsion with the bitumen in water. This emulsion requires an additional separation step, (which would not be necessary if the fine materials were not present.) Furthermore, the separation of water from this fine material is quite difficult and has proven to be one of the most intractable environmental problems in the GCOS operation (Schulz and Morrison, 1973, 1974). In contrast, most of the Utah deposits contain very little of this fine material and hence will be spared this difficulty in processing and environmental control.

Oblad et. al (1976) have produced sieve analysis curves for Athabasca (Alberta) and Asphalt Ridge (Utah) tar sands. The mass median sizes are reported as about 100 and 200 microns respectively. These particle diameters correspond to settling velocities of about 1 and 2 cm/sec respectively. Roughly speaking this indicates that settling ponds in Utah need be about half the size of those in Athabasca. However, the larger fines (clay) content of the Athabasca tar sands and its propensities for forming colloidal sludges probably mean that the required settling pond sizes in Utah can be even further reduced.

There appears to be no uniformly agreed-upon criterion for deciding which deposits are economically recoverable by mining and which are not. Outtrim and Evans (1977) show that the two parameters which enter into the calculation are the ratio of total waste thickness (T_w) to the oil sand thickness (T_o) and the bitumen saturation in the oil sands in weight percent (S_b). Figure 4-2 shows the Alberta Energy Resources Conservation Board 1974 criterion for oil

FIGURE 4-2. Alberta Energy Resources Conservation Board
Estimate of the criteria for separating mineable from
unmineable tar sands (Outtrim and Evans, 1975)

sands economically recoverable by mining. It indicates that no deposit less than 5 weight percent is economically mineable and that as the concentration increases, so also does the permissible ratio of overburden or waste to oil sand. Figure 4-3 shows an expansion of this idea in which the same kind of drawing is made with values of a parameter called the "surface mineability factor" drawn on as an additional parameter. This surface mineability factor is defined as

$$\left[\text{Surface Mineability Factor} = \frac{S_b}{1 + 0.9 \frac{T_w}{T_o}} \right]$$

Figure 4-3 shows that the criterion used by the Alberta Energy Resources Conservation Board is equivalent to a surface mineability factor of five. It also shows the relation of the surface mineability factor to the bitumen saturation and ratio of (total waste thickness/oil sand thickness). If, for example, the price of oil increased more rapidly than the cost of mining, then presumably the minimum economical surface mineability factor would decrease from five to perhaps four. If the prices moved in the opposite direction, the factor would increase to perhaps six. From Figure 4-3 we can see how this would influence the economic ratio of waste thickness to tar sand thickness as a function of saturation. Outtrim and Evans used the Board's criterion of a surface mining factor greater than five being necessary to have economical surface mining to estimate the recoverable fraction of the bitumen from the Athabasca deposit. They concluded that 40 billion barrels of bitumen could be mined and approximately 27 billion barrels of syncrude produced from it. This is approximately 5 percent of the total bitumen in place in the Athabasca deposits and indicates that only a small fraction of the total Athabasca deposit is accessible for surface mining at current economics.

Figure 4-4 shows a similar estimating procedure for the Utah tar sand deposits developed by Kuuskraa et al. (1978). It has the same axes as Figures 4-2 and 4-3 but indicates a slightly higher required bitumen content and a somewhat different shape than the estimates in Figures 4-2 and 4-3. The

FIGURE 4-3. Expanded version of Figure 4-2, showing the surface mineability factor.

The Alberta Energy Resources Conservation Board currently estimates a factor of 5 is the break-even between recoverable and unrecoverable. Changes in product prices or other costs could move the break-even point to higher or lower values of the surface mineability factor. (Outtrim and Evans, 1975)

FIGURE 4-4. Estimate of criteria for mineability of Utah Tar Sand Deposit by Kuuskraa et. al. (1978). (Here "net pay" is petroleum jargon for the thickness of the oil-bearing formation).

interesting difference in Figure 4-4 is that it considers two kinds of overburden. The overburden above the Athabasca deposit is mostly soft and unconsolidated. This can be removed by simple mining techniques not requiring drilling and blasting. On the other hand, much of the Utah tar sand deposit is located beneath formations which are consolidated. These formations could not be removed by simple ripping and loading but would require drilling and blasting. As Figure 4-4 shows, the maximum ratio of overburden to tar sand would be significantly lower for those deposits which require drilling and blasting than for those where the overburden could be stripped away using simple techniques as are used at Athabasca. Using the criterion for economic feasibility shown in Figure 4-4, Kuuskraa et al. concluded that less than 1 percent on the Utah tar sands deposit was accessible to economical surface mining. (Although this is a small percentage of the total, the amount of oil recoverable in this they estimated to be 100 to 200 million barrels; thus the potential for synthetic crude oil from surface-mined Utah tar sand is comparable to the potential from a moderate-sized oil field but not comparable to the potential from a giant or super-giant oil field.)

Thus we have the anomalous situation in which there is a well-established technology for surface mining and the recovery and processing of bitumen which is currently making a significant contribution to oil production in Alberta and which could possibly be applied in Utah but which cannot be expected to be applicable to the vast majority of the resource either in Canada or in the United States. We can analyze its environmental control technology very readily because the plants exist. On the other hand, the vast bulk of the resource, if it is to be processed at all, must be processed by some form of in-situ technology. Although we have considerable information about in-situ technology, there is no existing commercial-scale in-situ project which we can examine for environmental control technology. Furthermore, the existing technology is not sufficiently successful that we can count on its being applied commercially in its present

form. Thus our analysis must concern itself with estimated future technologies.

4-B. Overall Process Scheme-Surface Processing

The environmental control technologies currently used for tar sand surface mining and processing and proposed for future surface mining and processing ventures are best considered against the background of process technology which is being used and presumably will be used in the future to produce liquid fuels from tar sands. This section discusses technology for mining and surface processing; the next section discusses the technology for in-situ processing.

The overall processing scheme used by GCOS and Syncrude is illustrated in block-diagram form in Figure 4-5. The figure is conveniently divided into two sections referred to as "recovery" and "processing." Starting at the upper left (No. 1 on the figure), one must mine the tar sands. In the two Canadian operations, this is done in open-pit mines using very large mining equipment. No. 2 on the figure indicates that the mined tar sand must be transported to the plant. This is normally done in conveyor belts with a working pile stored at the plant to even out the surges in the mining operation. No. 3 indicates the washing of the bitumen off the sand. In both plants this is accomplished at temperatures of approximately 200°F, with a large amount of hot water. Some sodium hydroxide is added to the water. This improves the recovery; the improvement is believed to be due to the reaction of the sodium hydroxide with the carboxylic acids in the bitumen to form detergents which improve the separation. In the washing operation, the large sand grains are easily separated and come off as a clean shiny sand which (shown as No. 4 on the figure) is returned to the mine or to some other storage area. In addition to this coarse sand stream, there is a fine sand or clay stream which is partly returned from one step in the processing and which cannot be easily separated from its contained water. As shown in No. 5, this is placed in a long-term storage pond where it is expected that over many years of storage there will be eventually adequate settling of the fine clays to allow them

FIGURE 4-5. Overall Flow Diagram of Surface Mining and Processing of Tar Sands as Now Used in Alberta

to be permanently vegetated. Finally (No. 6 on the figure), the mined-out areas which have been refilled with waste must be prepared for abandonment. This means that they must be graded to have a satisfactory contour, covered with some sort of suitable soil (presumably soil scraped off in the opening of the mine) and adequately revegetated so that the vegetative cover will be self-sustaining.

Turning now to the processing on the figure, the first step is a bitumen cleanup step (No. 7 on the figure) in which the concentration of water and fines in the bitumen is greatly reduced. The water and fines are returned to No. 5 on the figure. In both of the Canadian plants, this is accomplished by froth flotation, followed by dilution of the bitumen with an organic solvent and centrifuging. The organic solvent is then removed by distillation and recycled.

The cleaned bitumen then goes to the coker (No. 8 on the figure). The coker is a destructive distillation device in which the bitumen is heated to a temperature at which it will decompose and held at that temperature until decomposition is complete. The coker produces a gaseous product, a liquid product, and a solid coke (No. 15 on the figure). No. 9 on the figure shows that the liquid product is hydrotreated to remove sulfur and improve its characteristics. Although No. 9 is shown as one box, it is actually carried out in three separate hydrotreaters which treat three different boiling ranges of liquid products, naphtha, kerosene, and gas oil. This segregation by boiling point is done because the conditions for optimum hydrotreating are different for the different boiling ranges of the liquid produced. After hydrotreating, the liquids are blended to make the synthetic crude oil (No. 10 on the figure) which is the finished market product. Makeup hydrogen is required for the hydrotreater; this is supplied by the hydrogen plant (No. 16 on the figure) which must have a gas or liquid input of some kind (shown as No. 17 on the figure).

In addition to the upgraded liquid, the hydrotreaters produce a gaseous waste stream which is combined with the gas from the coker and sent to

an amine treater (No. 11 on the figure). It removes the hydrogen sulfide which is treated in a Claus plant (No. 12) for conversion to elemental sulfur, which is a waste product, and is stored at the site. The clean fuel gas (No. 14) from the treater is used for plant fuel or as feed to the hydrogen plant.

Figure 4-5 is an overall schematic which describes both Alberta plants. The substantial differences between the two plants are the mechanical technology used in mining (bucket wheel excavator for GCOS, draglines for Syncrude), different coker types (delayed coking at GCOS, fluid bed coking at Syncrude), some details of the water washing and removal, and the ultimate disposition of the coke.

Both plants have large electric power production and heating plant auxiliaries to supply their own power and to supply the heat needed for the hot-water washing and other heat-consuming processes. The GCOS plant uses the coke (No. 15 on the figure) as fuel for these plants. The Syncrude plant, on the other hand, was constructed at the time of more stringent environmental regulations and was unable to burn such a high-sulfur fuel in a new installation without flue gas desulfurization. For that reason, they are burning natural gas in their power plant for heat generation and stockpiling the coke as a waste product.

4-C. Overall Process Scheme In-Situ Recovery

If, as described previously, the vast majority of the Canadian and US tar sand deposits are too deep for economical surface recovery, then the only hope for recovering the bitumen from them is by some form of in-situ process.

Here again, it is instructive to contrast the situation for tar sand processing with that for oil shale processing. The in-situ processes used in oil shale recovery are the same in principle as the surface retorting

processes. In them, an underground cavity full of rubblized shale is created; and then it is treated with a combustion wave similar to those which are used in some form in most surface retorts. The same situation does not exist for tar sands. All of the in-situ processes envisaged for tar sands recovery are quite different from the surface hot-water washing which is currently used by GCOS and Syncrude.

What is proposed is some extension or modification of the secondary-recovery processes which are widely used in petroleum production. The following section is written on the assumption that the reader has some familiarity with the conventional and secondary recovery of petroleum. Appendix IV reviews that subject, giving adequate background to understand the following section.

Comparing the in-situ recovery of tar sand bitumen to the conventional primary and secondary recovery of ordinary hydrocarbon liquids, we find that the significant difference is that the viscosity of the tar sand bitumen is much too high for it to flow at ordinary reservoir conditions. This adds a further complication because in most cases, although the formation is adequately porous for fluid flow and would have adequate permeability for fluid flow if the bitumen were not present, at the reservoir conditions with the high viscosity bitumen present, the formation exhibits essentially zero permeability. That means that if one wishes to introduce a fluid for the purpose of changing the viscosity of the bitumen, he finds that the fluid will not move throughout the formation with an ordinary pressure gradient because the formation is completely plugged up with bitumen.

Faced with this set of problems, the tar sand developers have almost universally concluded that the first step in any in-situ processing operation is to create some permeability in the formation by some form of fracturing of the formation. Mostly this has been accomplished by subjecting the formation to a pressure greater than the overburden pressure caused by the weight of the formation and overburden thereby performing the equivalent of "hydraulic

fracturing." Some have done this with water; others with steam. In any event the objective of this fracturing is to develop fluid communication paths between injection and production wells or in other ways to open up the formation so that fluids can penetrate. Once this formation fracturing has occurred, it is then appropriate to introduce some fluid into the formation to reduce the viscosity of the hydrocarbon present.

As shown in Figure 1-5, the possible ways of reducing the viscosity of the bitumen in place are to heat the bitumen, dissolve it in a solvent, or produce an emulsion in some lower viscosity fluid (typically water). To date there seems no serious suggestion that the solvent process has any economic feasibility for use in tar sand recovery. Although such processes are eminently successful in the laboratory where the flow can be easily confined to a narrow bed of sand, in the field the confinement problem has always proven insuperable; and the solvent losses have exceeded the value of the recovered fluid.

Shell Oil Company (Farouq Ali, 1974) conducted extensive pilot testing on the emulsion procedure in which a combination on heat and chemicals would be used to produce an emulsion of bitumen in water. At one time they were quite sanguine about the prospects of this process, but in recent years they have shown less interest.

The processes of greatest interest are those which supply sufficient heat and sufficient formation pressure to cause the fluid viscosity to drop to levels at which it will flow easily and then to cause it to flow to collecting wells and be collected as hot bitumen. The possible versions of this process are summarized in Figure 4-6. The simplest of these is steam flooding in which steam is produced in surface boilers and injected into the formation. This may be in a cyclic form in which steam is injected into a well for a period of time. The well is then shut in for a period of time and then the combined water and bitumen is allowed to flow back into the well or maybe in the form of a

<u>Name</u>	<u>Source of Heat</u>	<u>Heat transfer and/or driving fluid</u>
1-Steam Flood	External combustion of some fuel	Steam
2-Fire Flood (several variations)	Internal combustion of some of the oil in the reservoir	Air/Products of combustion (mostly CO ₂ and nitrogen)
2-Combinations of above; e.g., AMOCO's Combination Forward Combustion and Water (COFCAW)	Internal combustion of some oil in the reservoir	Air/Products of combustion, plus steam formed in the reservoir, using some of the combustion heat

FIGURE 4-6. Conceptual Comparison of Various Kinds of In-Situ Tar Sand Recovery Processes

steam drive in which steam is injected into some wells and flows towards others by driving heated bitumen before it. The proposed Cold Lake project will begin as a cyclic project but may ultimately be converted to a steam drive.

The second alternative shown in Figure 4-6 is a fire flood in which air would be injected, burning some of the bitumen in place to produce the heat necessary to cause the bitumen to flow. There are several variants on this process depending on whether the flame front moves in the same direction or in the opposite direction of the flow. This process has been tested in the Athabasca deposit and in some of the Utah deposits (Farouq Ali, 1974).

The third possibility shown in Figure 4-6 is some combination of the above of which the best known is the "combination forward and water". In this process an attempt is made to combine the best features of both of the above. This process has also been pilot tested for tar sand recovery (Farouq Ali, 1974).

One limitation on the applicability of this type of in-situ process to tar sand recovery is that the depth of the formation must be great enough to contain the pressures of the injected fluid. Typically this means that the formation containing the tar must be at least 1,000 ft. deep. As a result, one can classify tar sand deposits into shallow deposits accessible for surface mining, deep deposits suitable for in-situ recovery processes, and intermediate deposits which may not be accessible to either kind of recovery.

An additional factor to be considered in any process such as steam flooding, in which a valuable fuel is burned at the surface to provide the energy for the process, is the ratio of the energy recovered in the bitumen produced to the energy input to the heating system.

Outtrim and Evans (1977) computed a "thermal ratio." This is the ratio of the energy in the recovered bitumen to the energy input for a conventional steam flood. They estimate that if this value is less than three, it will probably be uneconomical to recover bitumen using bitumen as a fuel to produce the steam. Obviously, if some much cheaper fuel were available, a lower ratio

would be acceptable. Based upon their computation of the thermal ratio for various fractions of the Athabasca tar sands deposit, they conclude that approximately 75 percent of the Athabasca deposit has a thermal ratio greater than three and hence is accessible for some kind of thermal process. Much lower fractions of the other Alberta deposits have thermal ratios greater than three.

Kuuskraa et al. (1978) present a more complex analysis of the economically feasible tar sand deposits for in-situ recovery. Although their computations cannot apparently be reduced to a simple energy ratio as discussed above, they do clearly show that the economic potential of thick, highly saturated formations is much better than that of thin, less highly saturated deposits. This must be some function of an (energy recovery/energy input) ratio, although probably not by a simple numerical value.

Summarizing this information (and the information given in Appendix IV), we may conclude that steam flooding (of the cyclic or steam-drive type) appears to be economically feasible for the Cold Lake deposit at present. It may also prove to be feasible for the Athabasca deposit. The experience gained at Cold Lake (if the Cold Lake project is completed) will certainly aid in the application of this process to the Athabasca deposit. The other processes in which air is injected into the formation for underground combustion to provide the necessary heat are not as certain of economic success at present as is straightforward steam flooding. However, by calculations of energy ratio, it appears clear that steam flooding will not be successful in deposits which are thin (e. g. 20 ft. thick) and that therefore the only likely commercially successful in-situ process for them will be some form of underground combustion process. For this reason, it is likely that when the Utah tar sand deposits are exploited, they will use some form of underground combustion process (Cupps et al, 1976).

4-D. Technology Transfer

Most of the steps shown on Figures 4-5 and 4-6 consist of technology which has been transferred from other industries and which has been tested to some extent or is merely assumed suitable for the tar sand industry. Considering in order the steps in Figure 4-5, in Step 1 the mining of tar sand is accomplished at GCOS with more or less standard bucket-wheel excavators of types used in many other areas. As discussed by Allen (1974), this technology proved very difficult to transfer from the mining of other materials to the mining of tar sands. GCOS now believes that this is successfully demonstrated technology which can be counted upon to operate reliably and economically. However, Syncrude, after reviewing GCOS's experience, elected to use draglines instead of bucket-wheel excavators for this mining step. They piloted their mining operation fairly extensively, and they believe that the transfer of dragline excavation technology from other areas will be successful in their mine in Alberta.

Step two, the transportation of the tar sand to the plant, is accomplished in both Canadian projects by conventional belt conveyors. Again Allen (1974) indicates that the original designs for these belt conveyors proved troublesome for GCOS but that these problems have been successfully solved.

The third step, washing bitumen off the sand, is a unique step for tar sand processing. To the knowledge of the authors, no comparable process is carried out at a comparable scale in any other industry. This step was developed by Dr. K. A. Clark of the Alberta Research Center and was piloted at several levels before being applied at GCOS. Originally, Syncrude intended to use a quite different variant on this (Spraggins, 1971), but they also decided ultimately on the same technology which was used by GCOS.

Step four, returning the cleaned sand to its waste disposal area, is also one which was directly transferable from other areas and which poses no particular difficulty. The coarse sand easily drains out its water and is stable, biologically inert, and apparently inoffensive.

Step five, on the other hand, has proved to be extremely difficult and has

been the most unsuccessful of any operation conducted by GCOS. It is not clear from the literature whether GCOS realized in advance how difficult it would be to make a clean separation between the water and the fine sand, clays, etc. (Schulz and Morrison, 1973, 1974; Allen, 1974).

Step six, the preparation of the mined-out areas and the waste for abandonment, is also technology which has been transferred from other areas. This is, in principle, quite similar to that which is done in any open-pit mining operation where the environmental control regulations demand that the ground be ultimately returned to a use which is as good as or better than its original condition. The significant difference between the technology from other areas and that of Athabasca is that the Athabasca land reclamation operation is taking place in a more frigid environment than most of the large-scale land reclamation operations being conducted at open-pit mines. For this reason, the vegetation chosen will generally not be the same as is chosen, for example, in open-pit coal mines in the Mid-western or Eastern United States.

On the right side of Figure 4-5, we see that step 7, the cleanup of the bitumen and the return of fines, is an integral part of the Clark process for the separation of bitumen from sand. This also is not technology which is directly transferable from other areas but rather is a technology which required specific development and extensive pilot testing before it was applied by GCOS and Syncrude.

Step 8 on Figure 4-5 (the coker) is transferred directly from the petroleum industry. The two types of cokers used in GCOS and Syncrude (delayed coking and fluid-bed coking) are both well known and widely practiced; the operation at Athabasca is probably not significantly different from that in other areas.

The hydrotreating of the liquids produced by the coker for sulfur removal and product upgrading (Step 9) is also routine petroleum refining technology which has been transferred intact from other areas. Similarly, the hydrogen generation for the hydrotreaters (Step 16) is routine petroleum technology, and the amine treating of the waste gas for sulfur removal (Step 11) and the conversion of the sulfur from

hydrogen sulfide to elemental sulfur in the Claus plant (Step 12) are routine petroleum operations which have been transferred intact (or with minor modifications) to tar sand processing.

Because the in-situ processes are largely modifications of processes used in conventional oil recovery, most of the technology for them will be transferred from conventional oil recovery technology. For example, the drilling rigs, drilling tools, well completion equipment, downhole installations, and oil-gathering systems will all be transferred virtually unchanged from those used in conventional oil fields. Similarly, if large-scale steam floods based upon surface production of steam are used, the devices from producing that steam by burning some fuels will be substantially the same as those used in other industries for the production of steam. The large-scale steam flooding operations in the heavy oil fields of California use "package boilers" of types readily available for use in other industries. Similar types would presumably be used in large-scale steam floods wherever these are undertaken for the recovery of bitumen from tar sands.

Similarly, if in-situ technology is used to recover bitumen, the processing of the bitumen after its recovery will be substantially the same as is shown on the right of Figure 4-5. The cleanup of the bitumen to remove water and fines may be somewhat different, but subsequent processing will be essentially the same.

The technologies which will be used in in-situ processing which cannot be transferred directly from conventional oil field operations are those for dealing with extremely viscous fluids in the formation. Most of the tests made to date for recovery of bitumen from tar sands by in-situ methods have concentrated on attempting to overcome the difficulties which result when conventional hydrocarbon recovery techniques are used for very viscous tar sands. One obvious manifestation of this is the much closer well spacing which will be used for in-situ processing compared to that in conventional oil fields. A typical tar sand recovery operation may have wells as densely spaced as one per acre while in a conventional oil field, one well

for every 40 to 160 acres is common. The much-closer well spacing is needed to overcome the difficult problems of getting the viscous oil to move.

In summary, the mechanical aspects and hardware aspects of in-situ processing will be transferred more or less completely from conventional petroleum technology. On the other hand, the design of the project and the procedure for mobilizing the oil will be significantly different. These are the parts which will be difficult and which will require extensive field testing.

4- E. Air Pollution Control Technology

This section reviews and discusses the air pollution technology which is used in the two existing Canadian projects and is proposed for the Cold Lake project for each of the five air pollutants for which U.S. ambient quality standards have been established. In each of the following sections, the control technology for one of the pollutants is discussed. Similarly, an attempt is made in each section to indicate what parts of the control technology can be readily transferred from the Canadian plants to the U. S. deposits and which parts will require modification.

4- E-1 Control of Particulates

Particulates are fine particles or droplets of any material which are small enough to remain suspended in the atmosphere for long periods of time. In order to remain in the atmosphere and not settle out by gravity as dust or sand would, the particulates must generally be smaller than about 10 microns. (A micron is 10^{-6} meters.) A typical human hair is approximately 50 microns in diameter so that the particulates of interest for air pollution control and regulation are generally particles or droplets whose diameter is 1/5 or less the diameter of a typical human hair. Particles larger than this are generally considered to be dust rather than particulate. Dust generated

from construction activities or industrial processes can cause local problems such as dust collecting on clothes, window sills, etc., but generally particles much larger than 10 microns will not stay in the atmosphere very long and are not the subject of air pollution control regulations. Large dust sources frequently cause a local nuisance and are regularly attacked in nuisance suits in court.

The Federal Government has established ambient air quality standards for particulates which are shown in Tables 2-1 and 2-2. There is a permanent particulate problem in most of the western United States because when strong winds follow a protracted dry period, enough fine particulates will be blown up from non-vegetated areas to cause the normal particulate sampling devices to indicate values exceeding the national short-term (24 hours) ambient air quality standards. Such readings have been taken at various locations in Utah.

The basic control technology for particulates in almost all industrial applications is based upon the fact that when fine particles are brought into close contact with one another, they agglomerate, forming larger particles which are then too large and heavy to stay in the atmosphere. Therefore, if one can cause the particles to come together and perhaps be slightly moistened, the resulting product is no longer a collection of fine particles which would be suspendable in the atmosphere but rather a collection of much coarser agglomerates which can normally be successfully placed in land fills or disposed of in other ways. Almost all commercial particulate control devices operate by attempting to force the particles into contact with one another in this way.

For a surface-mined tar sand operation, the principal potential sources of particulates are the blasting, excavation, transportation, and storage of overburden, blasting, mining, crushing, and transportation of the tar

sand and the transportation and disposal of the processed tar sand. The particles so generated are all almost entirely fine rock particles with more or less the same physical properties as the tar sand itself.

An additional and important particulate source is the fine particles produced in coke burning processes. The GCOS plant burns much of its coke to provide fuel for power generation and steam production. The coke contains some mineral matter; this produces a fine ash which must be removed from the combustion gas stream. The Syncrude plant will burn very little coke; most of its coke will be stockpiled. However, some coke is burned in a fluid-bed coker regenerator so that the combustion gas stream from this vessel contains these fine particles as well. In the proposed Cold Lake project, some coke is burned in the regeneration step in the flexicoker. Here also a fine particle stream is produced. It is possible that in the future there will be tar sand processes in which none of the coke is burned and hence this particulate stream will not exist.

In the Canadian tar sand mining operations, the material mined is generally so wet and so thoroughly saturated with bitumen and sticky that it produces virtually no dust in mining, stockpiling, transfer from belt to belt, and transfer to and from storage. Neither Syncrude nor GCOS has any kind of dust control facility on its ore production, transport, or storage facilities. Alberta Environment indicates that they see no problem with this and that the emission rates of the dust from this mining and processing operation are acceptably low with no controls of any kind. If, in the future, we have large-scale mining of Utah tar sands, this will probably not be the case. These sands are generally not as wet as the Athabasca sands, nor are they as highly saturated in hydrocarbon. Therefore, they are likely to pose more of a dust problem in handling, mining, transportation, and storage than do the Athabasca tar sands. Nonetheless, the control of dust from that sort of mining operation is a straightforward undertaking well known to those in

the mining industry. Normally, it requires that at the belt transfer points, transfer points to storage, etc., there be an enclosure with an induced draft fan sucking air through a baghouse to collect the dust produced by these operations. Presumably, that will be done in any Utah tar sand mining operation.

The Sohio Petroleum Company (1974) submitted to the Utah State Board of Oil and Gas Conservation a proposed plan for mining the bituminous sand deposits at Asphalt Ridge, Utah. In that mining plan, they discuss the problem of dust formation in mining and conclude "Dust from the mining operations will be suppressed and controlled by sprinkling water obtained from the Green River. No dust will be caused in mining the bituminous material as it is made up of oil saturated sand."

The Utah Department of Natural Resources (1974) in commenting on this application agreed that periodic watering would be a suitable dust control measure for the mining of the tar sands and overburden removal.

Hence it appears that dust production during mining will not be a major air pollution source and that good engineering practice including wetting should be suitable to control this emission source.

The fine particles produced in the combustion of the coke produced in the upgrading of the Athabasca bitumen are not significantly more difficult to collect than the fine particles produced in the burning of pulverized coal. One may look upon this coke as being an equivalent of a high-sulfur, low-ash coal. The GCOS plant which burns large amounts of this coke to produce its electric power and steam requirement uses mechanical collection devices of the type normally referred to as multiclones. These have only moderate collection efficiency, and the plant is in violation of the current emission regulation of the province of Alberta. (They were not in violation when the plant was constructed.) Under the prodding of the province of Alberta (Alberta Environment, 1973), they are installing an electrostatic precipitator

to collect these fine particles from the boiler and therefore get that boiler and power production into compliance with their regulation.

For the corresponding situation, Syncrude uses an electrostatic precipitator (Goforth, 1977). It is anticipated that its effluent gas stream will be in compliance with Alberta effluent regulations.

In the same situation, the Cold Lake project which proposes to use flexicoking indicates that they will use a Venturi scrubber, in which the scrubbing fluid is heavy gas oil, to remove fine particles from the gas stream leaving their reactor vessel. This returns the ash particles to the gasifier. They take a purge stream from the gasifier in order to prevent a build up of inorganic materials (ash) in the coker-heater system.

The particulate control technologies for existing and proposed tar sands projects are summarized in Table 4-1.

The Alberta plants do not consider control of particulates a particularly serious problem; for them the principal environmental control cost is the control of sulfur. For example, in the Syncrude license to operate (Alberta Environment, 1978b), the emission rate of sulfur oxides and nitrogen oxides are specified directly in tons per hour or tons per day. However, the particulates regulation merely requires "the plant shall be operated such that the release of particulates from the main stack does not exceed the appropriate rates specified in Part III of the Clean Air (Maximum Levels Regulation) as amended from time to time." In addition, the permit requires the collected solids to be disposed of properly and fugitive emissions to be controlled properly. Thus, based on their operating experiences with GCOS, Alberta Environment concludes that particulate emissions from this type of tar sand processing facilities are not a serious problem.

4- E-2. Reactions and Compounds of Sulfur and Nitrogen

The two following sections on the control of sulfur oxides and

TABLE 4-1

Particulate Control Technology for Existing, Proposed and Possible Tar Sand Plants

Particulate Source

	Dust from mining, Transportation, storage and handling of sand and overburden	Ash from combustion of Coke
GCOS	No Control	Inertial separators (multiclones) being replaced with an electrostatic precipitator
Syncrude	No Control	Electrostatic precipitator
Alsands	No Control	Electrostatic precipitator
Cold Lake	No mining, nor solids handling	Venturi scrubber
Future U.S. mining-type recovery	Possibly baghouses at transfer points, wetting of piles, etc.	Unknown, probably similar to above
Future U.S. in-situ recovery	No mining nor solids handling	Unknown, probably similar to above

nitrogen oxides will be more intelligible after a brief review of the chemistry of sulfur and nitrogen, which is presented here.

Both sulfur and nitrogen in the elemental state are relatively inert and harmless to man. In fact, both are needed for human metabolism; if our bodies were deprived of either, life as we know it would be impossible. However, the oxides of sulfur and nitrogen are widely recognized air pollutants; and the reduced products are, in some cases, air pollutants.

Figure 4-7 shows in parallel form the products which are formed by oxidation or reduction of nitrogen and sulfur. Consider first reduction, which means the addition of hydrogen or the removal of oxygen. If we reduce nitrogen, we produce ammonia (which logically could be called hydrogen nitride; but because it had a common name before modern chemical naming systems were devised, it goes by its common name, ammonia). Similarly, if we reduce sulfur, we produce hydrogen sulfide. Both hydrogen sulfide and ammonia are strong-smelling materials which are relatively easily liquefied at room temperature. Both are toxic in high concentrations, but neither has been shown to be toxic in the low concentrations which might exist in the atmosphere.

Considering now what happens to sulfur or nitrogen when they are oxidized, nitrogen forms nitrogen oxide (NO) and nitrogen dioxide (NO_2). Sulfur forms sulfur dioxide (SO_2) and sulfur trioxide (SO_3). Both can also form other oxides, but these are the ones of principal air pollution interest. Nitrogen dioxide, sulfur dioxide, and sulfur trioxide are widely recognized air pollutants. We have national ambient air quality standards for nitrogen dioxide and sulfur dioxide.

The atmosphere about the earth is highly oxidizing; and therefore any significant amounts of ammonia and hydrogen sulfide emitted to the atmosphere are gradually oxidized to nitrogen or sulfur or further oxidized to sulfur dioxide or nitrogen oxides. Therefore, although ammonia or hydrogen sulfide

FIGURE 4-7. The Oxidation and Reduction of Nitrogen and Sulfur.

may be local problems where they are emitted in large quantities, generally they are not considered atmospheric pollution problems on a regional scale because of their oxidation in the atmosphere to nitrogen or sulfur or sulfur dioxide and nitrogen oxides.

4- E-3. The Removal of Nitrogen and Sulfur Compounds from Gas Streams

As shown in the preceding section, by oxidation or reduction we can convert the nitrogen and sulfur in organic compounds to various forms. In this section we will discuss the technology for removing those forms from gas streams.

The "standard" method of removing one gas from a gas stream is sketched in Figure 4-8. This method can only be used if we can find a solvent in which the gaseous component we wish to remove selectively is much more soluble than the other components in the gas stream. Assuming we can find such a solvent, the procedure is quite straightforward. The feed gas enters the absorber which is a vertical column in which the gas passes upward and the liquid solvent passes downward. Normally in the interior of the column there are bubble cap or sieve trays or packing to promote good contact between the solvent and the gas. The lean solvent enters the top of the column and flows countercurrent to the gas. By the time the gas has reached the top of the column, most of the component we wish to remove has been dissolved in the solvent; the gas passes on to the atmosphere or to its further uses. The solvent, which is now loaded with gas, passes to the stripper which normally is operated at a much higher temperature than the absorber. At this higher temperature the solubility of the gas in the solvent is greatly reduced so it comes out of solution and is cooled and sent to storage or further use.

Considering now the application of the flow diagram in Figure 4-8 to removing ammonia from the gas stream, we find that this system works extremely well because ammonia is very soluble in water or in weak acids. It is

FIGURE 4-8. The Flow Diagram for the Most Common Method of Removing One Component From a Gas Stream

possible to effect practically quantitative removal of ammonia from gas streams with water or weak acids. Generally, the solubility is so high that the simplest possible forms of this arrangement are satisfactory.

Removing hydrogen sulfide from gas streams is somewhat more difficult because it is not as soluble in water as ammonia, but it is easily dissolved in any weak caustic because it forms a weak acid when dissolved in water. The caustics to be used are chosen on the basis that they have a high affinity for hydrogen sulfide at low temperatures and a low affinity at high temperatures. The most common choices are ethanolamines (monoethanol amine, di-ethanol amine, etc.) and also the sodium or potassium salts of weak acids (carbonate or phosphate). With any of these solvents, the hydrogen sulfide can easily be removed from most gas streams using the procedure shown in Figure 4-8.

To remove sulfur dioxide from gas streams by this method is also relatively easy if there are no other acid gases present. Thus, for example, a solution of 1 percent sulfur dioxide in air could be easily removed by the scheme shown in Figure 4-8 using any weak base (for example, ammonia) and the sulfur dioxide easily regenerated to produce pure sulfur dioxide.

One might think that such a scheme would easily serve to remove sulfur dioxide from combustion products produced by burning sulfur-bearing fuels; for example, stack gases of electric power plants using sulfur-bearing coal. That is not the case because in such stack gases, there is another acid gas present in a much higher concentration. Typically, in such stack gases, sulfur dioxide will be present in the concentration of 0.1 to 0.2 percent while carbon dioxide will be present to typically 12 percent. If one used, for example, sodium hydroxide or ammonium hydroxide as the caustic to collect the sulfur dioxide in the scheme shown in Figure 4-8, he would find that although the sulfur dioxide forms a somewhat stronger acid than carbon dioxide, the carbon dioxide is present in such high concentration that the bulk of the reagent would be consumed in collecting the carbon dioxide.

It is for this reason that alkali scrubbing flue gas desulfurization processes are in general more difficult and more complex than one would assume from Figure 4-8. Finally, we can consider the problem of removing NO or NO₂ from gas streams by the type of process shown in Figure 4-8. Although NO and NO₂ are acid gases in the sense that their dissolution in water produces nitric acid, their reaction rates to produce this acid are very slow. For this reason, attempting to remove them with weak bases in the scheme shown in Figure 4-8 has, in general, proved unsuccessful.

Thus, in summary we may say that the basic procedure shown in Figure 4-8 for removing one gas from a mixture of gases works very well for ammonia in almost all circumstances, hydrogen sulfide in almost all circumstances, and sulfur dioxide in gases which contain no other acid gas. But it does not work well for sulfur dioxide in combustion gases nor for nitrogen oxides.

An additional option which is available for high-concentration sulfur dioxide streams is to carry out the reaction

forming sulfur trioxide which can be dissolved in water to form sulfuric acid. This is the most common method for removing sulfur dioxide from smelter gases. This process is generally considered economical for gases containing 4 volume percent SO₂ or more. For gases containing significantly less than that, it is uneconomical.

The separation of ammonia and hydrogen sulfide from gas streams is relatively simple by the process shown in Figure 4-8. When the ammonia or hydrogen sulfide is removed from the gas stream, it goes to subsequent processing. Ammonia is itself an article of commerce which is most widely used for a fertilizer. Plants which separate large amounts of ammonia from their gas streams normally sell it for fertilizer use. Hydrogen sulfide, on the other hand, has no such market and is normally converted to elemental sulfur.

The sulfur control technology used in the existing and planned tar sand projects is simply transferred from the technology used in conventional petroleum processing. That technology is reasonably complex and has many variants. Table 4-2 is a summary of various processes used in petroleum refining for fuel-gas desulfurization. It shows that there are several types of processes for the removal of the hydrogen sulfide from the fuel gas, several types for the conversion of this hydrogen sulfide to elemental sulfur, and several for the treatment of the residual sulfur oxides or hydrogen sulfide which passes through the preceding process. This scheme is illustrated on Figure 4-9.

On that figure we see at the left that the gas containing sulfur passes to the first box, called hydrogen sulfide separation, and fuel gas, with a very low sulfur content, leaves that box, generally for use as a fuel, possibly for use as a hydrocarbon feed to a hydrogen plant. The hydrogen sulfide goes on to further treatment. The H₂S separation box corresponds to the "fuel-gas treatment" listing at the top of Table 4-2. One sees there a variety of alternative processes. All of these follow essentially the scheme shown in Figure 4-8 and described above.

Now following the hydrogen sulfide on Figure 4-9, we see that it goes to a box called sulfur production. Air also enters this box in controlled quantities. Liquid sulfur is produced. On Table 4-2 this corresponds to the processes called "acid-gas treatment." These are of two kinds: vapor-phase oxidation or liquid-phase oxidation. In each of these, the overall reaction is

Although the overall reaction appears simple, the details of carrying it out, particularly in the liquid-phase oxidation varieties, can be fairly complex. Regardless of the internal complexity, the basic idea is the same; namely,

TABLE 4-2

Summary of Unit Process in Refinery Fuel-Gas Desulfurizing*

Process	Basis	Process Temp, C	Process Pressure, atm	Regeneration	Product Form
<u>Fuel-Gas Treatment</u>		<u>Liquid Chemical Absorption</u>			
Adip Process (Shell)	Aqueous amines, di-isopropanol	30- 55	1-70	(a)	H ₂ S
Girbotol Process (Girdler)					
Monoethanolamine (MEA)	15-20% aqueous solution	30- 55	1-70	(a)	H ₂ S
Diethanolamine (DEA)	15-20% aqueous solution	30- 55	1-70	(a)	H ₂ S
Triethanolamine (TEA)	15-20% aqueous solution	30- 55	1-70	(a)	H ₂ S
Econamine Process (Fluor)	Alkanolamine (DGA)	30- 55	1-70	(a)	H ₂ S
Shell Phosphate Process (Shell)	Aqueous K ₃ PO ₄	30- 55	1-70	(a)	H ₂ S
<u>Acid-Gas Treatment</u>		<u>Vapor-Phase Oxidation</u>			
Claus Process	Gas-phase catalytic oxidation	200-260	1- 2	none	S
		<u>Liquid-Phase Oxidation</u>			
Giammarco-Vetrocoke - H ₂ S (Powergas Corp.)	Solution oxidation of H ₂ S absorbed as thioarsenite with arsenate/arsenite air regenerated redox couple as oxygen carrier	30- 55	1-70	Air blowing	S
		30- 55	1-70	Air blowing	S
Stretford	Solution oxidation of H ₂ S (absorbed as bisulfide) by two-stage redox reaction involving vanadate and anthraquinone disulfonic acid as the oxygen carriers	30- 55	1-70	Air blowing	S
		30- 55	1-70	Air blowing	S
<u>Tail-Gas Treatment</u>		<u>Liquid-Chemical Absorption</u>			
Wellman Lord	Aqueous NaSO ₃ /NaHSO ₃ absorption	45- 55	1 ^(b)	Thermal regeneration	SO ₂ ^(c)
Beavon	Cat. hydrogenation to reduce COS, SO ₂ , and CS ₂ to H ₂ S for feed to Stretford	30- 55 ^(d)	1 ^(b)	Air blowing	S
Cleanair	H ₂ S-rich tail gas water cooled to continue Claus reaction and hydrolyze COS and CS ₂ to H ₂ S; final H ₂ S sent to Stretford	45- 55	1 ^(b)	Air blowing	S
SCOT	Cat. hydrogenation to reduce COS, SO ₂ , and CS ₂ to H ₂ S for feed to an alkanolamine absorption unit	30- 55 ^(e)	1 ^(b)	(a)	H ₂ S ^(c)
IPP	Claus redox reaction in solution with or without added catalyst	125-150	1 ^(b)	none	S
Chiyoda	Absorption of SO ₂ in dilute H ₂ SO ₄ containing Fe ₂ (SO ₄) ₃ catalyst	45- 55	1 ^(b)	(f)	CaSO ₄ ·2H ₂ O
		<u>Vapor-Phase Oxidation</u>			
Sulfreen	Catalytic use of activated carbon for high-efficiency Claus redox reaction to yield sulfur	125-150	1 ^(b)	Hot nitrogen	S

*From EPA - 450/3-74-033

Notes to Table 4-2.

- (a) Regenerate rich solution in a reboiled stripper column.
- (b) Process operated near atmospheric pressure with sufficient pressure to overcome the pressure drop in the system.
- (c) Recycle off gas to the Claus process.
- (d) Beavon process has a catalytic hydrogenation (reduction step) that is operated at about 315°C .
- (e) SCOT process has a catalytic hydrogenation step is operated at about 315°C .
- (f) Sulfuric acid neutralized with limestone.

Gas, with very low sulfur
content for use as fuel
or hydrogen plant feed

FIGURE 4-9. Sulfur Control Schematic

that oxygen from the atmosphere, in appropriate quantities, is brought into contact with the hydrogen sulfide under conditions properly controlled to convert almost all of the hydrogen sulfide to elemental liquid sulfur and water. The sulfur is then separated, normally melted and placed into insulated tank cars for shipment, or allowed to solidify for storage or landfill.

Continuing on Figure 4-9, we see a "tail gas" leaving the sulfur production block. Until the recent past, this tail gas was vented to the atmosphere. However, it normally contains fairly significant quantities of sulfur dioxide or some hydrogen sulfide and some other sulfur compounds; for example, carbonyl sulfide (COS) or carbon disulfide (CS_2). With the increasing stringency of environmental control requirements, there have developed a substantial list of "tail gas clean up" processes. These are listed on the bottom of Table 4-2. All of these attempt to remove the sulfur from this tail gas before the tail gas is vented to the atmosphere. Some of these attempt to recover the tail gas as hydrogen sulfide or sulfur dioxide and return this to the sulfur production unit. Others attempt to produce elemental sulfur from it; some produce calcium sulfate.

4-E-4 Control of Sulfur Oxides

Sulfur oxides (sulfur dioxide and sulfur trioxide) are ubiquitous air pollutants and are widely believed to have harmful long-term effects on health and welfare if the concentrations in the atmosphere are significant. We currently have a national ambient air quality standard for sulfur dioxide (see Table 2-1); and there exists an ambient air standard in California for sulfates, while EPA is considering the possibility of a national ambient air quality standard for sulfates.

The principal sources of sulfur dioxide in the atmosphere are volcanoes, the smelting of sulfide ores, and the combustion of sulfur-bearing fuels. Almost all fossil fuels contain some sulfur. This sulfur generally does not derive from the bodies of the plants or animals which have been converted

to the fossil fuels, but rather from the sulfur-bearing solutions which have percolated through the decaying organic material during its reduction from its original vegetative or animal detritus state to the state of fossil fuel. The sulfur content can range from fractions of a percent to about 7 percent.

The bitumen in the Athabasca tar sand typically has approximately 5 percent sulfur by weight. The same is true of some of the Utah deposits (those located in the southeastern portion of the state). On the other hand, those deposits located in the Uinta Basin (for example, the Asphalt Ridge deposit) typically have about 1/2 percent sulfur. This section discusses the technology which the existing and proposed tar sand processes use to control the amount of sulfur which is allowed to escape to the atmosphere. As shown in Table 3-2, the stringency of sulfur control requirements has increased over time so that the Syncrude plant has a higher degree of sulfur control than the GCOS plant, and future plants will have even higher degrees of sulfur dioxide control.

Because elemental sulfur is inert and harmless and reduced sulfur in the form of hydrogen sulfide or related compounds can be easily oxidized to sulfur or sulfur oxides, the entire strategy of the petroleum industry in dealing with the sulfur in petroleum is to manage the oxidation state of the sulfur in all the processing steps so that at all times the sulfur is in the form of elemental sulfur or reduced sulfur (for example, H_2S). Once the sulfur has all been removed from the other materials and is available in the form of a concentrated stream of relatively pure hydrogen sulfide, this is then reacted with oxygen from the air in controlled amounts to oxidize it only as far as elemental sulfur, not to SO_2 . The elemental sulfur is then collected and either sold for use in production of sulfuric acid or land filled if there is no market for it in the region.

If, on the other hand, the sulfur is burned and some ordinary combustion process producing a dilute stream of SO_2 , this is much more difficult and expensive to control. In the tar sand processes now in operation, the major escape of sulfur compound to the atmosphere results from the total or partial combustion of sulfur-bearing coke. New tar sand processes will almost certainly be unable to burn this sulfur-bearing coke and will have to deal with it in a reduced state as described above. This combination of relatively easy control of reduced sulfur and extremely expensive control of oxidized sulfur in dilute form in combustion gases is illustrated by Figure 4-10 which shows the major sulfur flows through the Syncrude operation. In it we see that all of the incoming sulfur goes to the fluid coker. The operation of cokers in tar sand bitumen upgrading is sufficiently interesting that it is covered in Appendix I. Although more details are given there, one can see from Figure 4-10 that the type of coker used in Syncrude produces a solid coke, streams of fuel gas and liquid products, and an off gas. The solid coke which is 9 weight percent sulfur contains approximately 18 percent of the input sulfur. At Syncrude, this coke is being stored for possible future use or for land filling.

The coking operation itself takes place in the absence of oxygen, and the products produced from it are in the reduced state. Most of the sulfur leaving the coker in the form of liquid or gases is present as hydrogen sulfide or liquid sulfur-bearing compounds. Figure 4-10 greatly simplifies the flow of these reduced sulfur compounds; between the fluid coker and the amine plant are a series of liquid-product hydrogenation steps which remove sulfur from the liquid products. The combined sour fuel gas from the fluid coker and from the liquid product hydrogenation plants goes to the amine plant where the hydrogen sulfide is separated and thence to the sulfur plant and sulfur storage. Approximately 72 percent of the input sulfur finds its way to sulfur storage. In Alberta sulfur finds no ready market so sulfur is

FIGURE 4-10. Major Sulfur Paths and Daily Tonnages (Elemental Sulfur Basis, in Tonnes) for the Syncrude Operation. (Goforth, 1977).

being stored indefinitely. As this diagram shows, the sulfur in reduced form is relatively easy to treat. The diagram also shows that roughly 5 percent of the sulfur escapes from the sulfur plant and is ultimately vented (as SO_2) through the CO boiler.

In contrast to the reduced sulfur of which 95 percent is recovered, the oxidized sulfur which is produced by the partial combustion of the sulfur in the fluid coker regenerator leaves the regenerator as a dilute (0.2 percent) SO_2 stream which is not treated but rather burned and emitted to the atmosphere. This oxidized stream is the principal source of sulfur emissions from the Syncrude plant accounting for approximately 2/3 of the total.

Table 4-3 shows the progressive change with time in the SO_2 control technology used by the tar sand processing plants. We see that GCOS burns all of its coke, Syncrude in effect burns 29 percent of its coke to provide the heat of coking, and Cold Lake does not intend to burn any of its coke. There has been no significant change in the recovery efficiency of the Claus plants for converting hydrogen sulfide to sulfur, but the first two plants had no tail-gas-clean-up process while the Cold Lake plant will have a 75 percent efficient tail-gas-clean-up process which leads to an overall sulfur recovery efficiency of Claus plant plus clean-up plant of 99 percent.

4-E-5. Control of Nitrogen Oxides

Nitrogen oxides (NO , NO_2 , and sometimes referred to as NO_x) are widely distributed air pollutants. Nitrogen oxide (NO_2) is known to be harmful to human health in high concentrations and is believed harmful in lower concentrations. There exists a national ambient air quality standard which established permissible concentrations of this material (see Table 2-1).

NO is not known to cause human health effects. However, under many conditions it is converted in the atmosphere to NO_2 , and therefore any NO_2 control program must involve control of emissions of NO .

TABLE 4-3

Comparison of Sulfur Control Technologies for Various Tar Sand Projects

Project	Date Completed	% of Coke Sulfur Released as SO ₂	% Recovery Efficiency of Claus Plant	Recovery efficiency (%) of Tail-Gas Cleanup Process
GCOS	1967	100%	96%	none
Syncrude	1968	29%	95%	none
Cold Lake	1985 (?)	none	96%	75% (of 4% passing claus plant)
Alsands	1986 (?)	38%	96%	97.5% (of 4% passing claus plant)

Worldwide, a major source of NO and NO₂ in the atmosphere is the production from the air by lightning strikes. Whenever air is heated to a very high temperature, the nitrogen and oxygen in the atmosphere combine to form NO which in turn reacts to form NO₂. This naturally formed NO is a natural fertilizer and contributes to the world's soil fertility.

However, in heavily populated industrial areas, the principal source of nitrogen oxides in the atmosphere is fuel combustion. An additional source is chemical processing, mostly involving the production and use of nitric acid; but on a tonnage basis, the principal source is combustion.

Whenever high-temperature combustion occurs, NO is formed by the same process which it is formed by in lightning strokes, viz.

In a typical coal-fired power plant, the exhaust gas contains approximately 300 ppm of nitrogen oxides. The various approaches which have been taken to limit this nitrogen oxide emission have been lowering of the peak flame temperatures, modifying the combustion gas properties so that the peak temperatures are reached under conditions where there is an oxygen deficiency and variants of these schemes. There does not now exist a commercially proven add-on technology for treating large volumes of gas for the removal of nitrogen oxides. The auto industry is developing catalytic methods for treating the nitrogen oxides from automobile exhausts, but it seems very unlikely that these will be suitable for large-scale combustion applications such as power plants and process heaters.

Existing and planned tar sand recovery operations involve large-scale combustion sources for process heat and for electrical power generation. The tar sand companies use the same general procedures used by other combustion sources to minimize the formation of nitrogen oxides in their combustion sources. They take the view that the burning of a certain amount of fuel in

a certain type of furnace will be treated no differently if this is a tar sand processing furnace or a petroleum refinery furnace.

Another potential source of nitrogen oxide pollution is the combination of nitrogen from the bitumen with oxygen during processing or combustion. Athabasca bitumen is typically 0.4 to 0.5 weight percent nitrogen (Hendrickson, 1975). This is similar to the nitrogen content found in typical petroleums. Its removal is not considered a major problem by the tar sands processors. This is in marked contrast to oil shale production. The organic matter in oil shale typically contains approximately 2 1/2 percent nitrogen; the removal of this nitrogen is one of the major expenses in oil shale processing.

Most of the nitrogen originally present in the tar sand bitumen is liberated in the hydrogenation processes which are used to upgrade the naphtha, kerosene, and gas oil which is produced in the coker. This hydrogenation converts the nitrogen in the bitumen to ammonia which is removed in the gas washing process and subsequently separated from the water in the sour water stripper.

If the quantity of ammonia were large enough for economical recovery and sale, this ammonia would be so recovered. Current operations at GCOS and Syncrude involved ducting the ammonia to one of the incinerators which burns it producing mostly elemental nitrogen but some oxides of nitrogen. The amount of oxides of nitrogen so produced is evidently sufficiently small that the topic of nitrogen oxide contamination is rarely discussed at all in the documents describing the environmental control technology for the existing and planned facilities in Alberta.

The Alberta Environment operating license for Syncrude (1978b) requires that the oxides of nitrogen content of the main stack shall not exceed a 1/2-hour average level of 700 parts per million. The same permit permits the emission rate of nitrogen oxides from the main stack to 70 tons per day or 2 tons per any 1/2-hour period.

There is no indication in any of the Syncrude literature that any control technology is required in order to meet these emissions limitations. Ordinary combustion and incineration of the ammonia from the gas washing process apparently produces a waste stream which is in compliance with these regulations.

4-E-6. The Chemistry and Control of Hydrocarbons and Carbon Monoxide

In contrast to sulfur and nitrogen which form harmful air pollutants when oxidized, carbon monoxide and hydrocarbons generally form innocuous materials upon oxidation. Carbon monoxide is a toxic gas which is formed mostly by incomplete or partial combustion and is normally mostly formed in internal combustion engines. It is also found in some concentrations in almost all industrial combustion gases.

When carbon monoxide reacts with oxygen, it forms carbon dioxide, which is a significant constituent of the atmosphere and is chemically quite inert. Therefore, the strategy in dealing with carbon monoxide industrially and in tar sand projects is to incinerate the gases containing it; i.e., react them with oxygen at high temperatures to convert the carbon monoxide to carbon dioxide.

Hydrocarbons are compounds of hydrogen and carbon. If they contained no other elements, the control technology for them would be equally simple with the technology for carbon monoxide; namely, reacting them with oxygen to produce carbon dioxide and water. That is the principal control technology which is used in the tar sand industry. However, although simple hydrocarbons frequently contain only hydrogen and carbon, the more complex ones generally contain some nitrogen, oxygen, and sulfur. As described previously, all of the existing and planned tar sand operations use (or will use) catalytic hydrogenation to reduce the amount of nitrogen and sulfur in the finished hydrocarbon products to low levels. However, the resulting hydrocarbon streams

which are subsequently burned will contain some small amounts of nitrogen and some sulfur which will be emitted to the atmosphere as the oxides of these materials.

Although carbon monoxide and hydrocarbons pose very significant problems in many of the urban areas of the United States and possibly in Canada, they are not believed to cause significant problems in the area of the Athabasca tar sand deposit. The principal source of carbon monoxide in most of the large cities of the world is from incomplete combustion in automobile engines. The license to operate for Great Canadian Oil Sands (Alberta Environment, 1973) places no restrictions whatever on the emission of carbon monoxide. This reflects the fact that ordinary efficient combustion at the major process sources in the operating plant is adequate to prevent the emission of any significant amount of carbon monoxide. Thus, for GCOS the control technology for carbon monoxide is simply the operation and maintenance of all furnaces and boilers at proper fuel-air ratios.

Syncrude, on the other hand, produces a significant amount of carbon monoxide in the coker regenerator. As is customary in the regenerators of fluid cokers and fluid bed crackers, the off-gas stream is sent to a CO boiler where it is burned, producing steam and converting the CO to CO₂. This is the only significant CO control technology in the Syncrude plant. Proper operations of the various furnaces and boilers is also required to guarantee that the CO emissions are small.

The operating license for Syncrude (Alberta Environment, 1978b) makes no mention of carbon monoxide emissions. As in the case of GCOS, they assume that proper boiler operation including proper operation of the carbon monoxide boiler will be adequate to reduce the emission of carbon monoxide to negligible levels.

The operating permit for GCOS (Alberta Environment, 1973) makes the following statement concerning releases of hydrocarbons, "Section 2.5.

The operation of the plant shall be such that a minimum of unburned hydrocarbons are released into the atmosphere." This reflects the view held by GCOS and by Alberta Environment that in any petroleum processing operation, there are certain inevitable escapes of hydrocarbon vapors to the atmosphere. These occur from storage and transfer of liquid hydrocarbons, from leaks from pump glands and seals, leaks from valves and fittings, etc. In refineries located in areas which do not have stringent hydrocarbon control requirements, these can be fairly significant emission sources. In areas such as Los Angeles where the hydrocarbon emission regulations are apparently the strictest in the country, all of these minor sources are controlled as much as possible; and the emissions are significantly lower than in other areas. The clear intent of the statement quoted above is that the tar sand operators shall use good housekeeping and maintenance procedures to minimize the emissions of hydrocarbons. From the various environmental documents concerning GCOS, Syncrude, and Cold Lake, it appears that the operators use (and intend to use) standard petroleum refinery technology for the handling, transportation, and storage of hydrocarbons. As a result, the emissions of hydrocarbons from their processes will be the same as would occur in a conventional oil refinery handling a comparable amount of material.

The Syncrude operating license (Alberta Environment, 1978b) requires that all hydrocarbons storage tanks above a minimum size and containing hydrocarbons with significant vapor pressure shall be of the floating-roof type or shall be closed vessels or pressure spheres. This is a typical control requirement for hydrocarbons which is now applied in all major jurisdictions of the United States.

Table 4-4 shows estimated air pollutant emissions for 1977 from the entire U.S. oil refining industry. From this table we may draw several interesting conclusions. First, we see that approximately one half of the total hydrocarbon emissions come from leaks. These are leaks from pumps,

TABLE 4- 4

Estimated Air Pollutant Emissions From Total U.S. Oil Refining
Industry (Kemp and Dykema, 1978)

Estimated Air Pollutant Emissions for 1977 from Entire U.S. Oil Refining Industry, In Millions Of Tons/yr.				
	NO _x	HC	CO	Particulates
Process Heaters	0.435	0.049	0.036	0.090
Catalytic Crackers	0.053	0.174	14.859	0.161
Leaks	Neg.	0.198	Neg.	Neg.
Fluid Coking	Neg.	Neg.	Neg.	0.028
Total	0.488	0.421	14.895	0.279

valves, safety blowdown systems, etc. It is clear that this is a significant source which is difficult to control.

The second interesting conclusion is that catalytic cracking is the principal source of carbon monoxide and particulate emissions from oil refineries.

The two existing tar sand processing plants do not have catalytic crackers. However, the gas-oil fraction of the synthetic crude oil which they produce most likely eventually goes to a catalytic cracker in some other refinery. Thus, although they do not have that emission on their site, those emissions are produced somewhere. The tar sand processing plants are in many ways like oil refineries. Most likely they also will have significant emissions of hydrocarbons from miscellaneous leaks in pumps, valves, etc. In addition, they must emit some hydrocarbon from the settling pond where the reject sand and clay are separated from water. Although the fraction of the hydrocarbon going to that pond is small, the overall quantity is significant. Much of that hydrocarbon is of a high molecular weight which will not readily evaporate; some of it does evaporate.

4 - F Water Pollution Control Technology

4 - F-1. Overview of Water Control Technology

Techniques used to abate water pollution generally depend on the type of water pollution encountered which again varies with the type of water source and process utilized. The basic sources of polluted water connected with tar sands development are:

- a. Process water (tar sand processing, environmental pollution controls, waste water)
- b. Surface runoff (leaching from processed tar sands, storm runoff)
- c. Aquifer disturbance (seepage due to increased permeability)
- d. Mine dewatering (drain water and seepage).

Process water usually is heavily contaminated and requires extensive treatment. After treatment, some of it may be recirculated. Surface runoff quality varies depending on erosion, leaching, and drainage system. The last two sources produce water of groundwater quality. Figure 4-11 gives a pictorial overview of water sources, water uses, and water control technology in tar sands projects.

The basic methods for dealing with polluted water resulting from tar sand projects are:

- a. Waste-water treatment. Usually this is applied to process water which may undergo oil separation (two stage) followed by coagulation and sedimentation. Settling ponds where separation of fines takes place cover extensive areas in Canadian tar sand projects. Biological treatment (also called secondary) may be applied for further reduction of organic material and suspended solids. In Canada settling pond effluents are largely recycled back through the primary extraction process.
- b. Surface runoff diversion. Surface runoff entering the plant site is diverted around plant site and/or processed tar sand site. The purpose is to prevent surface-stream contamination by sediments and leached tar sand constituents.
- c. Aquifer reinjection. Excess water of high quality or similar quality to that of the groundwater may be injected into an aquifer if mine dewatering is necessary and restrictions exist on surface discharges.
- d. Containment and evaporation (zero-release concept). Evaporating water from cooling towers as well as from containment and evaporation ponds disposes of waste water. It is a last resort for water which may not be reused or disposed of by aquifer reinjection or be discharged.

FIGURE 4-11. Water Flow in Tar Sand Projects

- e. Wetting of spent sands. To stabilize the processed sands and to revegetate the sand piles, considerable water is needed. This furnishes a disposal method for water of irrigation quality. This water disposal method is not practiced in Canada due to high rainfalls but may be necessary in Utah.

Ideally, the quantity of water obtained from mine dewatering would equal the amount of water needed for tar sand processing and sand stabilization. Unfortunately, this supply and demand will rarely be in perfect balance so extra water may be needed; or excess water may have to be disposed of, depending mainly on the mine dewatering quantity and bitumen recovery process (in-situ or conventional). Tar sand projects in Canada are net surface water consumers (not counting bog draining), and tar sand projects in Utah must be expected to use considerably more water than they will find.

4- F-2. Water Use and Quality

The existing tar sands developments are located in areas (Northern Alberta in Canada) where water is fairly readily available. Therefore, relatively little information is accessible as to actual water use and consumption except for the Cold Lake Project (Imperial Oil) and the Alsands Project Group where applications to the Alberta Energy Resources Conservation Board contain the information (Imperial Oil Ltd., 1978b, Alsands Project Group, 1978).

The Cold Lake in-situ project estimates to need 1.11 m^3 of water per barrel of upgraded crude with a recycle ratio of about 0.55. The water make-up would be about $0.72 \text{ m}^3/\text{bbl}$. For a 50,000 bbl/day operation, this means a net water use of about 10,800 acre-feet per year.

Figure 4-12 shows the detailed water balance for the Alsands Project. The 28 million cubic meters/yr withdrawn from the Athabasca river corresponds to a make-up requirement of $0.56 \text{ m}^3/\text{bbl}$ of syncrude (@ 140,000 B/D). The total water useage is $1.82 \text{ m}^3/\text{bbl}$ of syncrude, with a recycle ratio of 2.3. For

Figure 4-12. Overall water balance for the Alsands Project (Alsands, 1978)

the first three years of the project there will be no water recycle from the pond; after that time a clear water layer adequate for use as plant water will form on the pond.

The reports on the quantity of water used in the GCOS project vary. Speight and Moschepedis (1977) show a total steam and water use of about 112,000 tons/day for a 65,000 bbl/day plant ($1.7 \text{ m}^3/\text{bbl}$). The same report shows 117,500 tons/day of water disposed of along with 108,184 tons/day of tailings. The major share of the water use and disposal is to and from the primary extraction process.

Oliver (1976) states that GCOS's cooling water (9-10 MGD) is taken from and returned to the Athabasca River while process water for extraction is recycled from the tailings pond with make-up water coming from the Athabasca River.

Lang (1977) states that GCOS uses about 4 MGD in the extraction process with 80 percent coming from the sludge settling ponds and 20 percent from the Athabasca River. This means that about $0.33 \text{ m}^3/\text{bbl}$ of water is required in the extraction process at GCOS with about $0.07 \text{ m}^3/\text{bbl}$ being the net intake (recirculation ratio of 0.80). These numbers seem low when compared to those of Speight and Moschepedis (1977).

To resolve this disparity, a call was placed to Mr. William Cary, Environmental Coordinator, Great Canadian Oil Sands Ltd., who reported a net water use at GCOS of about 35 gal (Imp) per ton of sand mined. This translates to a net water use of about $0.33 \text{ m}^3/\text{bbl}$, a figure which coincides with that reported by Speight and Moschepedis (1977) using 20 percent make-up water. Mr. William Cary also stated that the solids content of the tailings material is about 45 percent and that the surface area of the tailings pond is 1978) some 620 acres with a depth of about 284 feet (volume of approximately 147,000 acre-feet).

At Syncrude, Mr. Stuart Elliott, Environmental Coordinator, reported

that the gross water use is about 250,000 m³/d with a recirculation ratio of about 0.50. This means a net water use of about 0.96 m³/bbl. The ultimate size of the Syncrude tailings pond is set at 10 mi² (6400 acres) surface area with an average depth of about 40 feet (volume of approximately 250,000 acre-feet). The source of the make-up water at Syncrude is the Athabasca River.

The general flow scheme for the proposed Shell facility (McConville, 1975) indicates a net water use of 0.42 m³/bbl for a 100,000 bbl/day of crude oil production. Recirculation of tailings pond water is contemplated.

The conclusion that may be drawn from the operating and proposed tar sands operations in Canada is that a 50,000 bbl/day operation requires 5,000-11,000 acre-feet/yr of water depending on mining method and recirculation ratio. By far the largest portion of the water is utilized in the primary extraction process.

The Athabasca tar sands contain a large amount of fines which do not readily settle out in the tailings pond. These fines increase the size of the tailings pond and reduce the recirculation ratio thereby increasing the need for make-up water. The criterion used for recycle water in the GCOS operation (Allen and Sanford, 1975) is that water having 5 percent or less of less than 2-micron-size material may be used on a basis of 2 gallons of recycle water for 1 gallon of make-up water (recirculation ratio of 2).

In Utah, due to lower percentages of fines present than in the Canadian tar sands, the required size of tailings ponds may be smaller and recirculation ratios of water higher. If the water requirement of the primary extraction process to be used in Utah is the same as that used in Canada, the net water requirement in Utah would therefore most likely be less than that in Canada.

Another factor which will tend to limit the net water use for tar sand operations in Utah is the relatively poor availability and high cost of

water. The Central Utah Project, for example, is proposing to transfer about 200,000 acre-feet/yr of water from the Colorado Basin where most of the tar sand deposits are located and to the Great Basin (drainage to Great Salt Lake).

4- F-3. Waste-Water Treatment

The mixture of tailings and water from the primary extraction process (solids content of 0.45) is usually taken directly to the tailings pond where settling separates the water from the sand and fines. The problem in Canada has been a large share of fines which settle very slowly and form a gelatin-like sludge. The slow settling velocities of the fines have resulted in large tailing ponds and considerations of coagulant agents and possible filtration schemes. In Utah, the presence of a much smaller percentage of fines in the tar sands is expected to alleviate the need for such large tailings ponds.

The mechanics of settling ponds may be described by the following expression:

$$V_0 = \frac{Q}{A}$$

where,

V_0 = surface loading rate (overflow rate)

Q = average daily flow

A = surface area of pond.

In the GCOS operation, it appears that the surface loading rate is about 0.05 m/day. This means that those particles which have settling velocities larger than 0.05 m/day in general will be removed in the settling pond. As a comparison, it may be mentioned that silica particles with a diameter of 2 microns have a settling velocity in water at 10°C of about 0.24 m/day.

The average detention time by the water particles in a settling pond may be calculated from the expression:

$$T = \frac{V}{Q}$$

where,

T = detention time in days

V = volume of pond

Q = average daily flow.

In the GCOS operation, the average detention time in the settling pond appears to be about 1500 days.

The process water from the final extraction and coking usually needs to undergo oil separation (two-stage) and coagulation before it may enter the settling pond or evaporation pond. From the settling pond, the effluent has been recycled to the primary extraction process along with the necessary make-up water.

Unless waste-water may be discharged to streams (unlikely in Utah), a certain amount may be exported to containment and evaporation ponds or eliminated through sludge disposal. However, for proper sludge disposal and stabilization, it is usually necessary to dewater the sludge thoroughly. Particular in the winter this may be a problem.

4- F-4. Surface Runoff Diversion

In arid climates a large part of the land runoff is conveyed underground in alluvial and bedrock aquifers. However, during spring snowmelt and intense rainstorms, considerable overland flow and surface stream flow will take place. These intermittent flows tend to move large sediment loads and cause considerable erosion. The landscape in the tar sand development region is a manifestation to the influence of such water erosion.

Since uncontrolled erosion of processed tar sand may carry sand, salts, and other constituents into surface streams, it is important to prevent or control the erosion of processed tar sand. The steps needed to prevent erosion may involve:

- a. Preventing runoff from the upstream drainage area from entering the disposal site by diverting it around the disposal site.
- b. Collecting erosion from disposal site by building a check dam downstream from the disposal site.
- c. Irrigating and revegetating the finished tar sand piles.

To minimize the amount of diversion structures needed, it is helpful to choose a disposal site with a small upstream drainage area. The method normally used to estimate storm runoff from small drainage areas (less than one square mile) is the "rational formula":

$$Q = ciA$$

where,

Q = peak runoff in cubic feet per second

c = coefficient depending on surface imperviousness

i = rainfall intensity in inches per hour for the rainfall duration

A = drainage area in acres.

Commonly used values for the coefficient, C, in the above formula may be found in most hydrology books such as *Hydrology for Engineers* by Linsley, Kohler, and Paulus, 1975. Typical values for rainfall intensities for the region are not available; however, rainfall data have been measured by the U.S. Weather Bureau office in Grand Junction, Colorado; they are shown in Table 4-5.

The rainfall duration used in estimating the peak runoff should correspond to the minimum time required for the entire drainage area to contribute water to the runoff. To estimate storm runoff for larger drainage areas (larger than one square mile), the hydrograph method should be used. This method is described in most books dealing with hydrology.

4- F-5. Aquifer ReInjection

As the name implies, aquifer reinjection is a method of disposing of withdrawn groundwater. On tar sand projects the groundwater may be obtained

TABLE 4-5

Greatest Observed Rainfalls, Grand Junction, Colorado

Rainfall Duration	Total Rainfall	Period of Record	Date of Occurrence
5 minutes	0.44 in.	1899-1977	July, 1974
10 minutes	0.66 in.	1899-1977	" "
15 minutes	0.96 in.	1899-1977	" "
30 minutes	1.08 in.	1899-1977	" "
1 hour	1.37 in.	1899-1977	" "
2 hours	1.38 in.	1899-1977	" "
24 hours	2.50 in.	1892-1977	October 17, 1908
1 month	3.78 in.	1892-1977	September, 1896

from pit or mine dewatering operations. In Utah, mine dewatering is not anticipated to be a problem, at least not for surface mining operations.

Water bearing aquifers are termed "alluvial" when they consist of unconsolidated soil, sand, gravel and rock usually deposited by streams and found near the land surface, and "bedrock" if they consist of fractured or porous rock. Aquifers may be confined between impervious strata and exhibit pressures higher than that expected from hydrostatic considerations (artesian aquifers).

Flow through aquifers is normally determined from Darcy's equation:

$$V = kS$$

in which;

V = superficial water velocity

S = slope of pressure gradient (energy grade line)

k = material permeability which is a function of porosity, water temperature and particle size and shape.

Locations near the discharge areas of groundwater aquifers can be expected to give the smallest yields while locations distant from these areas may give larger mine dewatering quantities. Aquifer permeability is also an important factor. The amount of mine dewatering required, even for mines in the same stratigraphic interval, can be different by orders of magnitude, depending on their location within the hydrologic basin.

Aquifer reinjection involves the sinking of several shafts or wells into an aquifer chosen for reinjection, lining the shafts and pumping the excess water into the shafts. The city of Los Angeles disposes of large quantities of treated wastewater in this manner. To inject water into an aquifer, it is necessary to have adequate aquifer permeability and storage capacity. Even with rather large distances separating dewatering and reinjection operations it is possible to create a recirculation system. Alluvial aquifers usually

have the best permeability for reinjection except during times of heavy snowmelt.

State regulatory agencies are taking the view that discharges into alluvial aquifers should meet the same standards of water quality as discharges to streams, because alluvial aquifers frequently feed springs, streams, etc. For tar sand projects, the mine dewatering water will probably be too saline for such surface injection, and will have to be reinjected into the saline aquifers from which it came.

4 - F-6. Containment and Evaporation (Zero Release Concept)

Wastewater disposal using evaporative cooling towers has been extensively practiced by the electric power industry. The proposed coal burning 3000MW plant at Kaiparowits, Utah, proposed to evaporate as much as 45,000 acre-feet of water per year, (U. S. Department of Interior, 1976).

The purpose of this evaporation is not to dispose of wastewater, but to supply the cooling water needed for the power plant's condensers. This is not a total disposal method, because as the water evaporates it leaves behind most of its dissolved solids content, and the remaining water becomes more and more loaded with dissolved solids. Eventually, a concentration would be reached at which the solids in the water deposited in pumps, lines, etc., and prevented system operation. To prevent this, most evaporative cooling towers steadily remove some water (called "blowdown", because the comparable stream from a steam boiler is called "blowdown") from the system, thereby removing dissolved solids and controlling the solids content. For a typical arid West application (BLM, 1977), the permitted solids concentration is 15 times that of the makeup water, so that one would expect that about 1/15 of the makeup water would be taken as blowdown. However, some small amount of water is also lost as droplets, so the blowdown is about 1/16 of the feed water. This blowdown water may be used for moisturizing waste solids. Any surplus is disposed of by evaporation

to dryness in evaporation ponds or for irrigation if possible.

Domestic wastewater disposal by evaporation ponds, or more commonly called lagoons or stabilization ponds, has been practiced by communities where land is relatively inexpensive. The city of Logan in Utah, with a population of about 25,000, relies on stabilization ponds for treatment of its domestic wastes. The ponds occupy 450 acres and inflow is 10 to 24 cubic feet/sec with complete containment in winter, but spilling during the summer months and using the effluent for irrigation (Jones, 1977).

The containment and evaporation ponds are also used by the electric power generating industry for disposing of blowdown wastes from cooling towers and by the coal industry for disposing of coal slurries (U. S. Department of Interior, 1975). Utah Power and Light uses a containment and evaporation pond with some spilling going to irrigation at its new 860 MW coal-burning power plant at Huntington, Utah. The plant elevation is about 6400 feet above sea level and the pond covers 10 acres with an inflow of 0.5 to 1.0 cfs (Grey, 1977).

The Navajo Generating Station at Page, Arizona, (elevation 4300 feet) has 190 acres of evaporation ponds with some spilling of water for road dust control and irrigation. Pond inflow is 4 to 5 cfs and annual net evaporation is thought to be about 6 feet with little seepage loss.

For tar sand projects, the containment and evaporation pond technique of disposing of wastewater is a last resort after the water has been reused (from final extraction, upgrading, etc.) since the method is not effecient when dealing with large quantities of water.

Basically, the containment and evaporation process depends on settling and biological decomposition for removal of solids and suspended matter and on evaporation for removal of water. The process may be aerobic (water essentially saturated with dissolved oxygen) or anaerobic (water essentially void of dissolved oxygen) depending on pond depth, reaeration, and type of

waste (microbial action). The amount of chemical or biochemical oxygen demand (COD or BOD).

In most of the Western U. S. the net annual evaporation loss (evaporation minus precipitation) is 3 to 6 feet depending mainly on latitude and altitude. Table 4-6 contains data on representative values for the expected net evaporation rates for western Colorado and eastern Utah for an altitude for about 5000 feet above sea level (NOAA, 1976). Tar sand containment-evaporation ponds may be located at 6000 to 7000 feet elevation and lower net evaporation can be expected. To convert from fresh-water pan evaporation data (Class A U. S. Weather Bureau pan) to actual pond evaporation a pan coefficient of 0.70 was used. This coefficient accounts for the larger volume of the pond, but not for higher total dissolved solids concentrations. TDS concentrations of more than 10,000 mg/l may further reduce the evaporation (by about 5 percent for a TDS concentration of 80,000 mg/l) (Steed and Glenne, 1972).

It can be seen that no, or negative evaporation (precipitation), must be anticipated during four winter month (December to March). This, of course, is due to low temperatures and possible ice cover. A net annual evaporation of 25 to 45 inches, depending on location and elevation can probably be expected with a maximum net evaporation of about 10 inches/month during June to July. A location with warm winds will greatly enhance the evaporation.

The percolation from the containment and evaporation pond depends on the permeability of the underlying soil or rock. Since the ponds may be located in gulleys and canyons, it is very likely that the underlying formation will be an alluvium with relatively high permeability.

A study of small stabilization ponds in California showed percolation rates from 36 inches/year in clay soils to 500 inches/year in a soil with gravel and silt (McGawney, 1968).

All in all, it is likely that unless a impermeable clay blanket is used

TABLE 4-6

Mean Monthly Precipitation - Evaporation Data

Fort Duchesne, Utah (Elev. 4990) (NOAA, 1976)

	Pan Evaporation (in.)	Pond Evaporation (in.)	Precipitation (in.)	Net Pond Evap- oration (in.)
Jan.	—	—	0.47	-0.47
Feb.	—	—	0.36	-0.36
Mar.	—	—	0.43	-0.43
Apr.	3.00*	2.10*	0.61	1.49*
May	7.36	5.15	0.68	4.47
June	8.00	5.60	0.86	4.74
July	8.59	6.01	0.46	5.55
Aug.	7.25	5.08	0.72	4.36
Sept.	5.72	4.00	0.63	3.37
Oct.	3.13	2.19	0.89	1.30
Nov.	—	—	0.51	-0.51
Dec.	—	—	0.61	-0.61
Annual	43.05	30.13	7.23	22.90

* estimated values

Mean Monthly Precipitation - Evaporation Data

Grand Junction, Colorado (Elev. 4800) (NOAA, 1976)

	Pan Evaporation (in.)	Pond Evaporation (in.)	Precipitation (in.)	Net Pond Evap- oration (in.)
Jan.	—	—	0.64	-0.64
Feb.	—	—	0.61	-0.61
Mar.	—	—	0.75	-0.75
Apr.	4.00*	2.80*	0.79	2.01*
May	12.87	9.01	0.63	8.38
June	17.31	12.12	0.55	11.57
July	17.43	12.20	0.46	11.74
Aug.	14.64	10.25	1.05	9.20
Sept.	11.56	8.09	0.84	7.25
Oct.	7.11	4.98	0.93	4.05
Nov.	3.00*	2.10*	0.61	1.49*
Dec.	—	—	0.55	-0.55
Annual	87.92	61.54	8.41	53.13

*estimated values

to line a pond, at least during the early stages, considerable water may be drained from the pond by seeping into an underlying alluvial aquifer.

4 - F-7. Leachate Production

The reviewers of a draft of this report expressed considerable concern with the possibility that leachate from stored waste solid material would pose a serious water pollution problem. An examination of the literature concerning the Alberta Tar Sand Projects reveals almost no description of leachate problems. Discussion with the environmental control officers for the two existing and one of the proposed Canadian tar sand operations revealed that to the best of their knowledge there is no leachate from the stored waste solids. The reason for this is that as described elsewhere, the Athabasca Tar Sands contain a significant fines (clay) fraction. This fraction is hard to settle but similarly it is hard to filter through. That part of the fines fraction which does seep into any porous section of the base and the sides of the containing pond or waste storage pond plugs it very effectively.

There has been a seepage problem at Great Canadian Oil Sands. There the containment dike is built by hydraulic filling from the waste pond. The water which is carried onto the dike during the filling operation percolates out of the dike; that which is added on the side away from the pond percolates out that side. In the original design of the project a drainage ditch was cut at the toe of the dike to capture this water and discharge it to the Athabasca River.

Subsequently it was discovered that this water is toxic to fish. Currently it is not known which ingredient in the water is the cause of the fish toxicity; it is believed that it is an organic acid but that is not certain. As a result of the observed fish toxicity Great Canadian Oil Sands has been obliged to capture this water and pump it into its storage pond.

Currently, neither of the two Canadian projects monitors the aquifers below their storage ponds for leachate infiltration. Both are planning to

begin such monitoring, prodded to do so by the Canadian Environmental Control Regulatory bodies. The Alsands Environmental Impact Assessment (Alsands 1978(a), p5) indicates:

"There is a limited potential for escape of contaminants to surface waters around storage areas and emergency ponds, and also for leaching of heavy metals, sulphur or other compounds from storage piles. All storage areas containing potentially toxic materials will be dyked and surface runoff waters will impounded on site.

During early years of development, minor seepage is anticipated from the tailings pond. This seepage will originate from stored sludge and water inside the dykes. Within three years the pond is expected to generally seal from the inside as fine materials settle from the tailings. As a control measure, the pond will be surrounded by an outer ditch excavated to impervious layers and the collected water pumped back into the tailings pond as required. The quality of water in the surrounding shallow aquifer will be monitored.

The two responses of Alsand to queries by Alberta Environment and the Alberta Energy Resources Conservation Board (Alsands 1979, 1979(a)) reveal that neither of these bodies questioned Alsands about leachate. They apparently agree with the above statement that it is simply not a problem.

As mentioned previously, one of the advantages of the Utah tar sand deposits over those at Athabasca is that they contain few if any fine (clay) materials. This should make the processing much simpler than it has been at Athabasca. Correspondingly this means that the waste material will not be as good at self-sealing of waste containment ponds against leachate as the Athabasca waste is. In other waste containment activities it is widely known that an impervious layer of clay can be placed at the bottom of a waste storage pit thereby preventing any infiltration. It is common practice to place such clay layers in the center of earth-filled dams to prevent seepage. As with any other technology this can be done improperly, with disastrous results, as occurred in the Teton Dam failure in 1976. However, if it is done properly, there is no significant percolation; this

is the case in most of the earth-filled dams in the world. If it does appear upon further testing that the waste waters and waste solids from future Utah tar sand operations do not contain enough fine materials to self-seal the waste ponds then it will be necessary to line such ponds with impervious materials, for examples clays.

4 - G Solid Waste Disposal and Management

4 - G-1. General Premise

The basic premise governing the design of the waste products disposal phase of the tar sands operation is that plant and tailings ponds shall be operated on a closed water circuit. There is to be no discharge of process waste water or plant and tailings site runoff, to natural drainage, except as a result of minor natural seepage.

To implement this concept it will be necessary to bypass the elements of the operation with a drainage channel to carry the upstream run-off past the operation and trap contain the leachate generated by run-off from the plant site and waste disposal area as illustrated in Figure 4-13.

4 - G-2. Description of Solid Wastes

Waste materials from a typical open pit tar sands mining and processing operation may be classified according as follows:

<u>TYPE OF MATERIAL</u>	<u>DESCRIPTION OF WASTE MATERIAL AND DISPOSAL SITE LOCATION</u>
1. Topsoil	Soil and rock stripped from the surface and stored for use at a later time. Stockpile to be convenient to the loading and hauling process during the revegetation effort.
2. Overburden	<p>Soil and rock not to be used in the plant operation. Stored in one of two areas shown in Figure 4-13.</p> <p>Initial stage. Material stripped from its location over the ore and deposited outside the mine area so as to not interfere with the mining operation.</p> <p>Second stage. Material stripped from its location over the ore and deposited in the adjacent mined out area of the mine without interfering with the current mining operation.</p>

FIGURE 4-13. Schematic Layout for a Typical Tar Sands Operation

3. Tailings Processed tar sands pumped in slurry form to the tailings pond and stored for dewatering and revegetation. (Continuing during time required for activities outlined above.)

4-G-3. Disposal Technology

The technology required for the surface disposal and management of solid wastes from the tar sands operation is that which is required to (1) Prepare the disposal site, (2) Transport the wastes to the disposal site, (3) Construct a stable pile of dry wastes, (4) Construct a stable dike to contain the tailings, (5) Protect the surface of each against erosion and (6) Rehabilitate the disposal facility to a state consistent with pre-existing land form and a usage compatible with existing adjacent undisturbed terrain.

These operations will not require the development of new technology since the required technology is, in the most part, adaptable from the technology already developed in connection with the construction of earthen dams, highway construction and disposal of wastes associated with coal mining operations.

Due to the unique characteristics of the tar sand tailings and dry climate as found in Utah, the preparation of the sand surfaces for revegetation will probably require the modification of present technology as developed in Canada.

4-G-4. Disposal Site Selection & Preparation

The optimized solution for this problem will include minimum costs incurred while meeting the following needs:

1. The site available for development must be large enough to accommodate the volume of wastes to be generated during the life of the project.
2. The distance between the plant site and the disposal area should be the minimum practical.

3. Impact on such factors as the amount of surface water drainage into and ground water seepage from the proposed disposal site should be minimized. This drainage complicates the problem of construction or stability of the disposal piles as well as causing water pollution problems.

The general terrain in the tar sands area in Canada is flatter and a more uniformly sloping terrain than the potential development areas in Utah. In Canada this suggested large single areas with reasonable height dikes. The areas in Utah are better characterized by rolling hills with flat-topped ridges and rounded canyon walls dropping into flat bottom canyons. This condition may require the utilization of dikes located closer together; the interruption of multiple drainage lines adds to the problem.

Embankments for the disposition of overburden will be the side-hill non-impounding type which may develop into a valley fill variety.

Preparation of the disposal site will consist of the construction of access roads, and the removal of debris and large rocks which may hamper the operation of machinery on the site. Soil stripped from the surface of the dump site will be stockpiled in a separate area to be later rehabilitation efforts. Larger pieces of rock may also be kept for placement on the final surface of the disposal pile. This would enhance the aesthetics of the area by breaking up straight lines and smooth surfaces, as well as aiding the control of surface erosion.

4- G-5. Transport of Wastes to the Disposal Facility

Processed tar sands will be pumped to the tailings pond while dry wastes will be trucked to the appropriate site.

4- G-6. Construction of Disposal Piles

Design Considerations

The failure of a refuse embankment for a coal mine on Buffalo Creek in

West Virginia in 1972, killing 125 persons, dramatically demonstrated the need for adequate consideration to be given to the design and construction of such dikes and dams. (Schlick, 1977).

Although the failure of a processed tar sand disposal embankment would not cause the same disastrous consequences, it would cause the leachate to overflow the retention dam, thus polluting the drainage pattern in the area. It would probable affect the usefulness of the land after the completion of the project and it could be dangerous to workers in the area.

There are basically three modes in which an embankment may fail. These failure modes are illustrated in Figure 4-14. First, the entire embankment may slide down the slope upon which it was constructed. Secondly, material may break away and slide down the sloped surface. Finally, a large portion of the pile may break away and slide down the sloped surface. In all these modes of failure the cause of the failure is shear stresses which exceed the ability of the pile to resist them. In the first mode, the critical stress is the shear stress between the pile and the surface upon which the pile is constructed. In the second and final case the cause of the failure is critical shear stresses within the pile material itself. The solution to the mode-one type of failure is to interlock the embankment with the supporting surface. If the surface of the land is not naturally rough enough to accomplish the interlocking or if the stripping of the topsoil from the site "polishes" the surface to the degree that interlocking will be insufficient to hold the embankment on the slope, it may be necessary to intentionally cut steps or other irregularities into the smooth surface before construction of the embankment is begun.

The properties of a soil or other granular material which determine its shear strength, hence its ability to be retained in a pile, are the angle of internal friction and the coefficient of cohesion. (Meyers 1976, Sokolorski

(a) slippage of pile down the slope

(b) spalling of surface

(c) instability of pile

FIGURE 4-14. Modes of Embankment Failure

1960). The angle of friction is generally not significantly affected by moisture content. At low moisture content, the water surrounds the particle and there is cohesion due to capillary forces (Meyers 1976). Contribution to the strength of the material can be lost by either drying the material or saturating it with water.

Another material property which is important in understanding the behavior of embankments is permeability. This is the measure of how rapidly water will flow through the material. The coefficient of permeability has the units of velocity, such as feet per year; this coefficient is treated as an index of comparison with no direct physical significance. The higher the value of the index, the faster water will be absorbed into the material.

If a typical material is compacted to a density of about 90 pounds per cubic foot it becomes impervious to this flow.

The process of the movement of water downward through the material is described as percolation. Examples include the absorption of moisture due to standing water on the surface of the pile. By providing sufficient slope to expand surfaces of the pile and avoiding depressions in which water may accumulate and stand, it will be possible to restrict saturation to the outer portion of the exposed surface of the pile.

Another type of soil failure occurs at a condition called liquefaction. In this type of failure the application of both saturation and vibration to a normally well behaved soil will cause its behavior to change from solid-like to liquid-like. A material under this condition may fall away and flow down the embankment. Such failures may be triggered by the earth movement during an earthquake (shock or seismically-induced liquefaction).

The solution to the problems outlined requires the designer to understand the materials to be utilized for his project. Some important factors are;

- (1) The engineering characteristics of the soil particles including size, shape and gradation.

- (2) The chemical composition of the water and other materials contained in the pores.
- (3) The water present and its movement through the soil.
- (4) The nature of the foundation upon which the structure is to be built.

The information presented here is not intended to provide any basis for an individual to attempt to design but rather to provide an insight into a complex problem that requires the services of a qualified geotechnical specialist. This type of an operation includes solving problems related to both dry embankments as well as hydraulic fills.

This history of slope selection to provide a stable design in the mining industry has some interesting application. When Kennecott Copper Company began their operation of the hydraulic fill of the copper operation tailings in Utah they searched for a precedent to the problem of slope of the dike surface. They found one in Egypt at a slope of 3:1 and used that slope for many years. This selection proved adequate until concentrations of water at specific locations adjacent to the dike perimeter contributed to a failure of the dikes. The solution to the problem included flattening the slope to 5:1 and discharging the tailings around the perimeter of the dike thus controlling the concentration of water. (Ensign 1978).

The reader is directed to Appendix 5 which describes the language of slope expressions as well as common engineering application of those slopes. This is prepared to assist readers as they encounter slopes expressed several forms such as %, angle and in ratio.

In Appendix 6 the authors have compiled some excerpts from a paper describing the specific solution to the problems described here at the Athabasca operation. This is provided as a natural follow up to this reading for the convenience of the reader.

4-G-7. Construction Technique

The transportation of dry wastes from the mine to its disposal site will

be carried out using conventional equipment available in the heavy construction industry. Compaction of such dry materials will be accomplished with standard wheel and drum compactors as well as that effort accomplished by the passage of vehicles over the material to be compacted. Compaction of the coarse sand deposited by the hydraulic process will require experimentation in order to optimize the equipment selection being considered.

4-G-8 Control of Surface Erosion

The disturbance of existing land surfaces and the creation of new surfaces significantly increase the rate at which surfaces may be eroded by wind and water. Eventually the rehabilitation effort will make it necessary that all dump surfaces and affected lands be revegetated. Some measures may be required to control surface wind erosion until that effort can be accomplished.

For the "dry" waste materials planned techniques for providing control of surface erosion are primarily designed to control water erosion but will also be effective against wind erosion. The techniques include contouring of slopes, roughening of surfaces, providing an erosion-resistant drainage system, and providing temporary surface cover. Treatments may be required on both finished and unfinished surfaces. The basic stratagem of slope contouring and surface roughening is to decrease the amount of runoff as well as slow the water movement. Although long slopes tend to collect more runoff than short ones, the size and speed of the resulting stream will increase the likelihood of erosion. Thus long slopes will be constructed to function as a series of short slopes by providing such diversion features as benches, terraces, ditches and dikes. Benches can be carried laterally to a point where the drainage can be emptied into a riprapped channel, which will carry the water off the slope. In addition, the surface will be roughened by scarification, bulldozer "tracking", and/or furrowing slopes along contours. Selective spreading of individual large rocks on the surface may also be used

to provide an energy dissipation mechanism. These techniques will also contribute to the development of plant life on the surface.

If necessary, special, erosion-resistant drainage facilities can be incorporated into the disposal facility. This may be necessary to handle the water and sediments which occur as the result of unusually heavy downpours on loose soil surfaces. Such drainage systems could include drainpipes, down drain, chutes and flumes. Such a system could be designed for temporary or permanent use.

There are a variety of temporary covers which have been successfully applied to surfaces where grading has been done but revegetation has not yet been established. These covers include straw, cellulose fiber, emulsions, chemical binders, jute netting and mats, and plastic matting and nets.

For the tailings surface in the tailings ponds the problem of surface erosion will be quite different, mostly dust problems, until after the vegetation is established.

4-G-9. Rehabilitation of the Disposal Facility

Once the disposal facility has been constructed to its maximum depth (or height), the surface of the pile must be rehabilitated to a state consistent with the pre-existing uses of the land and compatible with existing, adjacent undisturbed natural areas. Pre-existing uses for some of the land which may be involved in tar sands are grazing lands for livestock and wildlife. Rehabilitation of the waste disposal pile will require two processes, namely (1) shaping the pile to reduce its visual impact, and (2) revegetating the surface in a manner which will visually blend with the vegetation on adjacent undisturbed lands and will provide a suitable feed for animals which will eventually be grazing on the rehabilitated land. In shaping the pile, the edges and toes of slopes will be rounded to blend man-made slopes into natural ground shape, benches and terraces will be created to break up long slopes and

natural-looking ridges and valleys will be constructed in large disposal piles. Large rocks may also be placed upon slopes to produce natural-looking discontinuities.

The ultimate success in minimizing the visual impact of waste disposal facilities and restoring the area to its pre-existing uses, depends upon the ability to establish natural vegetation on the surfaces on the pile. A cover of vegetation is also the ultimate technique for stabilizing the surface of the pile against wind and water erosion. There are basically two techniques proposed for the vegetation of waste sand piles, namely, try to establish vegetation directly upon the processed sand itself or provide a cover of fertile soil suitably isolated from the site prior to the beginning of operations.

Great Canadian Oil Sands implemented a rehabilitation plan which included sloping the dike walls, establishing grasses and shrubs, and then entered the experimental stages of tree growth. Research efforts were conducted to define the chemical, physical, mineralogical and microbiological properties of their tailings deposits. Field studies were conducted to determine how tailings can be treated to improve leaching experiments, the use of synthetic fibers, muskeg, and manure, etc. The quality of supernatant water is being scrutinized to determine its effect on migratory birds, (Allen 1974).

The major difference between that problem in Alberta and Utah is that the Utah tar sands are located in arid areas. This lack of moisture may require a markedly different approach from that taken in Canada. The volumes of waste materials involved are great enough that the individual solutions will be required and must be found.

4-H Environmental Control Technology for in-situ Combustion

The environmental control technologies discussed in the previous part of this chapter apply mostly to the two existing plants in Canada. Both of these use surface mining of the tar sand plus the Clark hot-water process for removing

the bitumen from the sand and bitumen coking followed by hydrotreating to produce the finished crude oil. Because these are existing operations whose technology is quite well known, there is little uncertainty about their environmental control technology.

This chapter has also discussed the proposed Cold Lake project. This project is less well known because it exists only in the application stage. However, all of its parts have been subject to large-scale pilot testing; therefore its environment control technology is also reasonably well understood.

Neither of these two processes is likely to be transferred to the Utah deposit without substantial modification because of the differences between the Utah deposit and the Alberta deposit. Therefore, it seems appropriate to consider what the environmental control technology might be for other possible recovery methods. These other methods are not as well known or understood as those which have been discussed previously. Therefore this discussion is obviously somewhat speculative.

The most thoroughly studied alternative recovery method is some form of in-situ combustion with or without the addition of water. Various forms of this process have been pilot tested in Canada and in Utah (Farouq Ali, 1974). Its obvious economic advantage is that it does not require external fuel for heating the bitumen in place as does the steam process proposed at Cold Lake. Its disadvantages are that it requires large, expensive, energy-consuming air compressors to drive air into the formation for burning and secondly that the control of the flow underground is more difficult in this process than is the steam flood as proposed in Cold Lake.

The environmental differences between this process and the Cold Lake process should be:

- 1) In this process there would be significant cracking of the bitumen in the ground so that the recovered hydrocarbon would not require as substantial

a cracking on the surface. It is possible that the recovered hydrocarbons would have a sufficiently low molecular weight that they could be transported from the plant site to an existing oil refinery and treated there as a conventional petroleum without having a coker at the plant site.

2) There will be a very large combustion gas stream to be disposed of at the plant site. All of the air which is injected into the formation and used to burn the residual hydrocarbon to produce the heat for the process is eventually returned to the surface (as combustion products) through producing wells. This air will presumably contain significant amounts of sulfur. Depending upon the operating conditions, this may be in the form of hydrogen sulfide or in the form of sulfur dioxide. In either case, it will be in dilute form in a gas stream containing substantial amounts of nitrogen. However, there seems no reason to believe that it cannot be adequately treated to meet reasonable emission standards. This treatment will be more expensive than the treatment of ordinary flue gases from combustion sources like power plants, but it should be technically feasible.

Two other technologies which may be applied some time in the future are thermal and solvent bitumen recovery processes. These are much further from commercialization than the in-situ combustion described here. These two processes and their environmental control technologies are described in Appendix II.

5. ENVIRONMENTAL CONFLICT WITH UTAH NATIONAL PARKS

Figure 1-3 shows the location of the major tar sand deposits in the United States, which are all in the state of Utah. Figure 5-1 shows those same tar sand deposits and also shows the national parks, national monuments, and the Glen Canyon Recreation Area which are all located in Utah. Two of the large tar sand deposits exist in whole or in part in national parks and in the national recreation area. Others exist in close proximity to national parks or national recreation areas. This proximity or overlap between the resources and the national parks and recreation areas has been a cause of controversy in the past and may be in the future. For example, current U. S. law is moving strongly in the direction to totally forbidding mining in national parks (National Park, 1976). There are some existing mining claims in national parks and monuments. The Park Service is attempting to have all of those terminated and to prevent any further mining in the national parks. Thus it seems safe to assume that, without a special act of congress, it will be impossible to mine any of the tar sand deposits in the national parks.

In addition, the national parks in Utah are all large enough to be classified as mandatory Class 1 prevention of significant deterioration areas for air quality (see section 2-A-4). This means that only very minor emissions to the atmosphere can be permitted in their proximity. The two national monuments shown have not been reclassified from Class 2 to Class 1 but may be so reclassified in the future. If the Dinosaur National Monument were so reclassified, it would also place severe air quality restraints on what could be emitted to the atmosphere at Asphalt Ridge.

On the other hand, some of the deposits are reasonably remote from the nearest national park or monument, for example, the Sunnyside deposit.

Two recent environmental conflicts in Utah illustrate that large scale industrial development in the scenic area of Southern and Eastern Utah has vigorous opposition. The first of these examples is the Kaiparowits project.

FIGURE 5-1. Map of Utah showing National Parks, National Monuments, and National Recreation Areas, and also tar sand deposits.

This was an effort by a consortium of power companies to construct a large, coal-fired power plant on top of the Kaiparowits Plateau. This would have been approximately 50 miles southeast of Bryce Canyon National Park and close to the boundaries of the Glen Canyon National Recreation Area. Although other factors were involved, the environmental opposition to the project and the threat of unending litigation on that issue was one of the major factors which caused the sponsors of the project to cancel it in the Spring of 1976. (New York Times, 1976).

Intermountain Power Project (IPP), and equally large coal-fired power plant, was proposed for a site approximately eight miles from the boundary of Capitol Reef National Park. Under considerable pressure from the environmental community, Secretary of the Interior Andrus denied IPP's sponsors a permit to build such a project in the near vicinity of Capitol Reef National Park, (Salt Lake Tribune, 1977). At that time the construction group indicated its willingness to move the project approximately 30 miles to the east, thereby moving it further from the national park boundaries. This site also was rejected by Secretary Andrus. The project is now considering a site in Western Utah at least 100 miles from any national park or monument.

In neither the Kaiparowits case nor the IPP case was there any showing made that any applicable environmental standard would have been violated. A special section was written into the Clean Air Act of 1977 specifically to resolve the conflict between IPP and the Class 1 PSD increment in Capitol Reef National Park (New York Times, 1977). However, the visibility section of that act might have been difficult for IPP to meet, even with the above special section of the Clean Air Act. Similarly, if the Kaiparowits project were reanalyzed in the light of the current Clean Air Act, it might have been found in conflict with it. But at the time projects were cancelled or moved, there was no such showing. Thus they were cancelled or moved, not because of explicit conflict with environmental regulations, but because there was a strong belief on the part of the environmental movement, (which in the case of the IPP project was translated into official policy of the U. S. Department of the Interior,) that large, coal-burning power

plants should not be located in Southeastern Utah. The Clean Air Act of 1977 Amendments strengthen that view by including a very strong visibility protection section (section 169A).

As a consequence of this history, it seems clear that any large source of air pollution, though it be controlled to the highest degree now technologically feasible, would still be unacceptable in the areas surrounding the national parks in Southeastern Utah. As an additional factor in the decision of whether or not to approve such plants in that area, one must consider the impact of the influx of a large number of workers. Southeastern Utah is very sparsely populated. The environmental groups which argued against the Kaiparowits and IPP project stated that the influx of construction workers, miners, and operating workers required for those projects would have a severe and detrimental effect on that area. They argue that the area's highest and best use is for scenic enjoyment and recreation and that the population growth associated with such a project should not be allowed to conflict with this use. The recent IPP decision by the Secretary of the Interior appears to have been influenced at least in part by this argument.

It is difficult to predict the future policy of the Department of Interior regarding large-scale industrial developments in Southern Utah. However, from the history presented here, it is clear that any major exploitation of the tar sand deposits which are closest to the national parks will receive very stringent scrutiny. Mere compliance with the existing formal environmental regulations (e. g. the Clean Air Act) may not be enough to guarantee that the necessary permits from the Department of the Interior will be forthcoming.

6. THE COST OF ENVIRONMENTAL CONTROL

After all this discussion of the environmental control constraints, technologies, and proposed applications, it seems appropriate to inquire, "What is the cost of environmental control?" In attempting to answer this question, we quickly discovered that very little has been published which would allow a direct calculation of what fraction of the cost of a tar sand project is due to environmental control technology.

This is not surprising because the two existing projects are built by companies who are actively attempting to license their competitors to use their technology. As discussed above, they are unwilling to reveal to the public the cost information which they intend include as part of their license packages. In addition, the in-situ projects are still paper-and-pencil projects; none has been constructed. Thus their costs are all estimates rather than actual known costs.

6-A. Cost Estimates for a Syncrude-type Plant

Egglestone and Wise (1976) present cost estimates for a new plant of the same type as Syncrude with the capacity of 100,000 barrels per day; these estimates are summarized in Table 6-1 and 6-2. From the first of these, we see that the estimated capital cost is \$2.5 billion. The two largest contributors to capital cost are the mine and the upgrading facilities (coker and hydro-treaters). The "off sites" is not described in detail in their paper but presumably includes such things as road construction, pipeline connections, electric power connections, utility and maintenance buildings, etc.

Table 6-2 makes clear that the capital costs are the principal costs in a tar sand operation. Note that this table does not include any interest on borrowed capital or return on equity. If we assume that borrowed capital has a charge of 10 percent, then that would add approximately another \$7 per

TABLE 6-1

CAPITAL COST ESTIMATES FOR 100,000 B/D (OF PRODUCT) TAR SAND PROJECT, USING
SYNCRUDE TECHNOLOGY. (EGGLESTONE AND WISE, 1976)

TYPICAL CAPITAL COST BREAKDOWN⁽¹⁾
OIL SANDS PLANT - CURRENT TECHNOLOGY

<u>Plant Area</u>	<u>MM\$ (1978)</u>	<u>% Of Total</u>
Mine	700	28
Bitumen Recovery	300	12
Upgrading	700	28
Offsites	400	16
Power Plant	400	16
	<hr/> 2,500	<hr/> 100

(1) Includes indirect construction costs plus interest during construction, working capital, and preproduction costs.

TABLE 6-2

OPERATING COST BREAKDOWN FOR 100,000 B/D (OF PRODUCT) TAR SAND PROJECT,
USING SYNCRUDE TECHNOLOGY (EGGLESTONE AND WISE, 1976)

<u>Item</u>	<u>Basis</u>	<u>\$/BBL. (1978)</u>	<u>% of Total</u>
Energy Import	Gas at \$1.50/MCF	0.7	7
Capital Related			
Maintenance	4%/Yr.	2.7	29
Depreciation	5%/Yr.	3.4	37
Taxes & Insurance	1.5%/Yr.	1.0	11
Total Capital Related		7.1	77
Other			
Admin/Tech. & Operating Staff	1500 personnel (all fringes)	1.0	11
Misc. (Catalyst, Chemicals, etc.)		0.5	5
Total Other		1.5	16
Total		9.3	100

(As discussed in the text, this is an OPERATING cost summary. If we assume an interest charge of 10%/year on invested capital, that would add approximately \$7/bbl to the total cost, making the cost -before profit- in 1976 dollars approximately \$16/bbl).

barrel to the cost of the product. We see that the entire payroll for the operation adds only approximately \$1 per barrel to the cost which (if we include interest on the borrowed capital) would be roughly 1/16 of the total cost of the product.

To determine the cost of environmental control, we must estimate what fraction of these costs are environmental control costs. On Table 6-2, the only direct environmental cost is the cost of natural gas which is shown to add \$0.7/bbl to the cost. This is an environmental control cost, at least at Syncrude, because they have an available alternative fuel (the coke from their coker) which cannot be burned without flue gas desulfurization. They concluded that it was cheaper to purchase natural gas and stockpile the coke than to burn the coke with flue gas desulfurization.

Other than this natural gas cost, the other non-capital costs of environmental control are very minor. Certainly some of the 1500 personnel listed on Table 5-2 are operators of plants used for environmental control, and some of the miscellaneous catalysts and chemicals, etc., are also part of the environmental control operations; but as Table 6-2 shows, the capital-related costs are the overwhelming majority of the total. We make only negligible error if we consider only capital-related costs in determining the cost of environmental control.

There are some parts of the process which are strictly environmental control technology and which would not be used if there were no environmental control regulations. These include the Claus plant for the conversion of hydrogen sulfide to elemental sulfur, the particle precipitator on the carbon monoxide boiler, the tall stack for dispersing effluents, and the use of floating-roof tanks for liquid-product storage for liquids with significant vapor pressures. In addition, the plants presumably contain the wastewater treating facilities which would not be needed except for environmental control.

There are some capital costs which cannot be simply stated as environmental or not. For example, the sulfur removal plant which takes hydrogen sulfide out of the coke gas stream before the gas stream is sent to the hydrogen plant is for the most part not an environmental control plant. The reason is that even if there were no environmental control regulations, it would be necessary to remove most of the sulfur from that stream in order to use it to produce a satisfactory grade of hydrogen. However, its design and operating specifications are influenced by the environmental control regulations; it would probably not operate to as strict a sulfur specification if there were no environmental regulations than it does given environmental regulations.

In an earlier age, when our environmental consciousness and environmental regulations were not as strict as they are now, no effort would have been made to return the waste sand from the project to the mined-out areas or to diked storage ponds. Rather, it would simply have been discharged to the nearest large body of water. In this case, that would have been the Athabasca River whose flow would probably be adequate to carry the solids to Lake Athabasca. Examples of this type of solid waste disposal are the placer mining in California which largely filled in San Pablo Bay and more recently the Taconite processing operation on the shore of Lake Superior which deposits its tailings in the lake and has been the subject of recent environmental litigation. Thus one should probably conclude that the entire solid waste disposal facilities for such a project were environmental control facilities.

6-B. Cost of Environmental Control

Table 6-3 shows our estimates of the capital cost of environmental control for a 1000,000 B/D Syncrude-type project. From it, we see that the estimated environmental control capital costs are about \$96 million. This is only 4 percent of the estimated total capital cost shown in Table 6-1. The details of these cost estimates are shown in Appendix VII.

TABLE 6-3
ESTIMATES OF THE CAPITAL COST INVESTMENT FOR ENVIRONMENTAL CONTROL FOR A
100,000 B/D SYNCRUDE-TYPE PLANT

Facility	% of capital cost which is for environmental control	Estimated Capital Cost (X\$10 ⁻⁶)	
		Total	Environmental
CO Boiler Electrostatic Precipitator	100%	2.1	2.1
Claus Plant & Tail Gas Cleanup	100%	20.0	20.0
Tall Stack	75%	4.0	3.0
Amine Scrubbers	25%	17.0	4.2
Waste Water Treatment	100%	4.2	4.2
Waste Sand Disposal	100%	63.0	<u>63.0</u>
Total			96.5

See appendix VII for details of these estimates.

In a previous report on oil shale development (de Nevers et al., 1978), we reported that the proponents of oil shale development believed that 10 to 20 percent of their total capital cost was for environmental control equipment. In comparison, this 4 percent estimate appears low. Is it right or plausible? That is hard to say. None of the tar sand developers have shown detailed cost estimates which would allow a check. The previously cited estimates were obtained only on a "not for attribution" basis, and it is hard to know what all they considered as environmental control costs.

It is clear from Table 6-3 that the major environmental control costs are the Claus plant with its accessories and the waste sand retention pile. It seems unlikely that the estimates presented here are wrong by a factor of more than 2. Hence it is probable that the environmental control investment for a project such as Syncrude is less than 10 percent of the total investment.

After this report was submitted in semi-final form to DOE for review, Alsands published a set of cost estimates for their project (Alsand, 1979 (a)). That report is somewhat more detailed than the cost breakdown of Egglestone and Wise, and not as detailed on environmental costs as the values presented here (Appendix VII). The Alsand values agree fairly well with those presented here. The Alsand cost breakdown is included as Appendix VIII; to our knowledge it is the most detailed published tar sand cost estimate.

7. POTENTIAL PROBLEMS AND DIFFICULTIES WITH PROPOSED ENVIRONMENTAL CONTROL TECHNOLOGIES

7-A. Comparison of In-situ and Surface Processing from an Environmental Viewpoint

The two existing tar sand recovery projects are both surface processing projects. The one major proposed projects now under government review in Canada (Cold Lake) is an in-situ project. As discussed in the text, is is likely in the long-term that most tar sand projects will be in-situ projects because the majority of the resource is only accessible to in-situ processing.

7-A-1. Air Pollution

The air pollution consequences of in-situ recovery should, in principle, be slightly less than the air pollution consequences of recovering and processing a comparable amount of bitumen in a surface process. The processing steps which occur after a stream of clean bitumen has been produced should be virtually identical for in-situ and surface-processed bitumen. Therefore, there should be no significant difference in the air pollution emissions from processing bitumen after it is recovered.

However, in the surface mining process, significant amounts of tar sand are exposed at the surface; and significant amounts of tar sand are exposed in the mining, transportation, and storage of the sand for this process. Although the volatile hydrocarbon content of this tar sand is quite small, it is not zero; and therefore, there should be some emission of volatile hydrocarbons from this exposed tar sand. In addition, the cleaned sand which is sent to waste disposal contains some very small fraction of volatile hydrocarbons, and these also will be emitted to the atmosphere. Finally, some small fraction of the diluent stream (normally a naphtha), which is used to reduce the hydrocarbon viscosity at some point in the

separations scheme, is lost to the waste pile or the atmosphere. Thus from all of these sources, we may infer that there is an emission of hydrocarbons to the atmosphere as a result of all of these processes which will not occur in an in-situ operation. To date we have found no published estimates of the magnitude of this hydrocarbon emission; it is not considered a serious problem by the environmental control agency in Alberta.

In addition, we may infer that because there is more movement of solid material in the overburden stripping, mining, and solid waste disposal of a surface mining project than there is solid movement in the road development, drilling site development, and drilling of the multiple wells required for an in-situ project, the construction-related dust emissions will presumably be larger for a surface mine and processing plant than for an in-situ project. In Alberta, where the moisture content of the soil is generally high, this has not been a significant problem. In Utah, where the tar sand deposits occur in a very arid environment, it could be a more significant problem.

In conclusion, it appears that the hydrocarbon and the particulate emissions from an in-situ tar sand operation will be less than from a correspondingly sized surface mining and recovery operation. These two types of emissions are not considered major air pollution problems in Alberta and are presumably minor contributors to the overall air pollution contribution of a tar sands processing plant.

7-A-2. Water Pollution

Table 7-1 gives an overview of the water use for the existing (GCOS and Syncrude) and proposed Canadian tar sands operations. As can be seen, the gross water requirement of $1.11 \text{ m}^3/\text{bbl}$ estimated for the in-situ operation (Cold Lake, Imperial Oil, Ltd.) is somewhat smaller than for the surface mining processes (GCOS and Syncrude) while the net water use of $0.72 \text{ m}^3/\text{bbl}$ is quite similar.

TABLE 7-1
WATER USE FOR TAR SANDS OPERATIONS

Plant	Type Mining	Crude Oil Output (bbl/day)	Gross Water Requirement (m ³ /bbl)	Net Water Use (m ³ /bbl)	Water Recirculation Ratio	Major Water Requirement
GCOS	Surface	65,000	1.73	0.33	0.80	Primary Extraction (94%)
Syncrude	Surface	120,000	1.91	0.96	0.50	Primary Extraction
Shell	Surface	100,000		0.42		Primary Extraction
Cold Lake	In-Situ	125,000	1.11	0.72	0.55	Injection Steam (46%)
Alsand	Surface	140,000	1.82	0.56	0.69	Primary Extraction

Table 7-2 gives a breakdown of the specific water requirements for the GCOS and Cold Lake operations. The major water use in the GOCS operation is for primary extraction while in the Cold Lake in-situ operation, it is for steam injection. In the in-situ operation, the water used for steam injection is mostly consumed by displacing bitumen in the ground.

The steam used for injection becomes polluted with oil, ammonia, salts, and metals in the displacement process. Care must be taken that this water is held in place or pumped out and not allowed to pollute useful groundwater aquifers.

At the Cold Lake in-situ operation, wastewaters will be partially disposed of by deep-well injection. The remainder will be treated to required standards and disposed of into surface streams; e.g., the Beaver River (Imperial Oil, Ltd., 1978b). The waste water problem created by upgrading, coking, treatment backwash, surface runoff, utilities, etc., can be expected to be similar for in-situ and surface mining.

A big advantage of the in-situ process is the absence of the large settling ponds necessary for separation of tailings and water with surface mining. Another advantage is the absence of the tailings sludge deposited in the settling ponds.

7-A-3. Surface Disposal of Waste

In-situ processes will require virtually no surface disposal of solid waste. In a properly functioning in-situ operation, none of the sand will be brought to the surface. In contrast, all mining and surface processing operations require very significant solid waste disposal. However, for an in-situ operation, normally a greater number of surface acres will be disturbed by the construction of roads, drill sites, corridors, etc., than are disturbed in an open-pit mine. However, the nature of the disturbance will be much less severe; and in a moist climate, it is reasonable to assume

TABLE 7-2
WATER REQUIREMENTS FOR TAR SANDS OPERATIONS
Speight & Moschepedes (1977) and Imperial Oil Ltd. (1978b)

GCOS Water Requirements (surface mining):

Primary Extraction	1.62 m ³ /bbl
Final Extraction	0.19 m ³ /bbl
Coking	0.02 m ³ /bbl
	<hr/>
Total:	1.83 m ³ /bbl

Cold Lake Water Requirements (In-situ process):

Injection Steam	0.51 m ³ /bbl
Process Water	0.14 m ³ /bbl
Cooling Tower	0.20 m ³ /bbl
Treatment Backwash	0.12 m ³ /bbl
Utility Water	0.10 m ³ /bbl
Potable Water	0.03 m ³ /bbl
	<hr/>
Total:	1.11 m ³ /bbl

that once the project is completed, the land can be quickly restored to more or less its original state. The same is not true of arid areas where revegetation of roads, etc., is an extremely slow process.

In summary, it appears that in-situ processing will involve slightly less air pollution problems, easier water pollution control problems--but not necessarily complete elimination of these--and a much smaller area of significantly disturbed landscape to be returned to an acceptable condition. Overall we must conclude that the environmental impact of in-situ processing will be generally less visible and probably less significant than that of open-pit mining and surface processing.

7-B. Proprietary Information

One of the problems facing anyone who tries to assess the environmental control difficulties which have been encountered by the existing tar sand projects or which are likely to be encountered in future tar sand projects is that much of the technology of these projects is proprietary technology which has been developed by organizations which intend to offer it for use for a fee. For example, GCOS has indicated their willingness to sell a complete technology package on their type of operation to other potential tar sand operators. Hence they do not wish to reveal to the public information which they intend to sell to potential licensors.

For this reason, there do not appear to be in the literature detailed flow diagrams on either the GCOS or Syncrude processing operations nor detailed cost breakdowns on the various parts of the processing scheme. There has been ample discussion of the difficulties which GCOS has had with their mining equipment and with the processing of the waste waters which contain fine materials which gel. But difficulties in the processing and environmental control have not been discussed in much detail in the literature, presumably because the companies consider this proprietary information.

7-C. Potential Air Pollution Difficulties

Based on all the preceding discussion, it seems clear to the authors that most likely the tar sand industry at the level of several projects in the 50,000- to 100,000-barrel-a-day range can be established in Utah without violation of any applicable air pollution control standard. Thus, it seems clear that the likelihood of "first-order" problems is remote.

What is the likelihood that "second-order" difficulties will be encountered? The most probable second-order difficulty is the occasional high ambient air concentration which is caused by an occasional breakdown or malfunction of emission control equipment. Most regulations permit a certain number of these to occur without penalty because they appear to be inevitable.

The second most likely difficulty is probably some problem with "dust control measure." In the arid West, wind-blown dust is a permanent air pollution problem, and any entry of large-scale mechanized equipment into these sites will produce local dust problems. This has been a permanent problem to EPA in trying to establish some sensible particulate control regulations because it is clear that an ambient air quality monitor located adjacent to a heavily used dirt road will record regular violations of the particulate ambient air quality standards in dry weather. Such a monitor at the edge of an unpaved tar sand facility haul road would almost certainly show an ambient air quality standard violation.

7-D. Potential Water Pollution Difficulties

Some of the potential problems with water pollution control technology are of a routine sort which are known elsewhere; others are unique to the tar sand industry. Considering the routine ones first:

7-D-1. Dam Safety

Tar sand projects use settling ponds and retention dams to prevent contaminated surface waters from leaving their sites. The possible tragedy

associated with dam failure is fresh in everyone's mind due to the Teton Dam catastrophe in Idaho in 1976 and the Buffalo Creek failure in West Virginia in 1972. To avoid downstream flooding, dams must be properly designed and constructed. Proper materials for impervious cores and/or blankets and for the supporting fill must be located prior to design. For the design of dams, the reader is referred to "Design of Small Dams," published by the U. S. Department of Interior (1973).

Close supervision and monitoring of dam construction is necessary to ascertain that proper materials, material sizes, material distributions, moisture contents, compaction, etc., are used. Where dangers of overtopping a dam by inadvertently overfilling the pond exist, provisions should be made for a spillway section in the dam since embankments are usually quite vulnerable to erosion and serious damage if overtopped (U. S. Department of Interior, 1975).

Regardless of how well we design them, we must always recognize that a dam and its associated reservoir represent a vast amount of gravitational potential energy which, if released suddenly, can cause catastrophic effects. The safety record of dams is generally good, but it is far from perfect.

7-D-2. Settling and Evaporation Ponds

Settling ponds are used by the tar sand industry to separate process water from the tailings. The coarse fraction of the tailings sand is used to build the retaining dikes, while the sludge fraction flows into the center of the pond. Evaporation ponds may be used to store and dispose of process water which may not be recirculated through the process. The problems which may occur with settling and evaporation ponds are:

- 1) dam (or embankment) failure, discussed above
- 2) climate (i.e., precipitation, freezing, evaporation)
- 3) hydrology (stream inflow, flooding, percolation)
- 4) sludge dewatering and tailing disposal
- 5) land availability

6) odors

7) birds

The problems of climate mean that a careful assessment must be made of precipitation, temperature, and evaporation records in the area where the pond is contemplated (see Table 4-5).

Settling and evaporation ponds are generally planned between the depositional area for processed tar sand and a downstream check dam. The check dam may be built to secure the processed tar sands as well as to pond wastewater for evaporation. Obviously, the sheer size of the settling ponds (10 sq. mile surface area at Syncrude, Alberta) presents a location problem in hilly terrain (i.e., Utah).

The settling pond will be situated where the tailing are desposited as the tailings contain considerable amounts of water (about 50% for Athabasca conditions). (About 98-99% of the tailings and 88% of the water come from the primary extraction process at the GCOS operation.) For the first few years, the settling pond will be away from the actual mining site (until space is available for redeposition). Dewatering of the tailings is accomplished by careful consideration of depositional patterns, hydraulic sluicing, and withdrawal locations of recirculated water.

The problems of hydraulic movements of tailings (sediment transport) may be such that considerable effort and money may be spent diking and sluicing the ubiquitous mass. Certainly the volumes are such as to have an extensive visual impact.

The wastewater from the coker and hydrotreater may be sour, containing H_2S and NH_3 in addition to phenols and perhaps cyanides. Normally this wastewater is mostly recirculated internally. The wastewater from the final extraction process and upgrading may also contain oil and require special water treatment (oil separation, biological treatment).

Sludges from settling ponds and evaporation ponds are likely to have high concentrations of sulfur, oil, salinity, nitrogen (ammonia), manganese, nickel, zinc, and other metals. Care must be taken that they do not flow, leach, or percolate into watercourses.

Dewatering of sludges and redeposition of sludges settling out in the evaporation pond may be necessary and accomplished by removing the sludges by bulldozer and transporting them to the tailings pile. These sludges may have value as a fertilizer for revegetation purposes.

Care must be taken that settling and evaporation ponds do not overflow due to precipitation, snowmelt, and stream inflows. Percolation to ground-water aquifers may also be a problem until sealing by sludge deposits occurs.

Land suitable for settling and evaporation ponds needs to be relatively flat without large streams or springs and should not be located on top of an alluvial aquifer which is a supply of culinary water. Land which bears signs of torrents, flash floods, avalanches or landslides, or geologic faults should naturally be avoided. Evaporation ponds should also be so located that possible noxious odors from biological decomposition or anaerobic processes do not reach or bother surrounding settlements.

Sea gulls and other birds usually feed on the ponds. Neighboring reservoirs of culinary water should be covered and/or the water should be disinfected to avoid possible contamination from being carried by these birds to sources of culinary water.

7-D-3. Aquifer ReInjection

If aquifer reinjection of water is necessary, this normally means that sizable quantities of water have been obtained from mine dewatering operations. This means that the aquifers in the area probably have high permeability, a condition which is necessary for aquifer reinjection. In other words, if the water is produced by mine dewatering, it is probably possible to get rid of it by aquifer reinjection.

Problems may arise in connection with water quality and interpretation of water quality discharge regulations. It may, for example, not be possible to take water which comes from a bedrock aquifer with relatively high total dissolved solids concentration and reinject it into an alluvial aquifer with water of relatively low total dissolved solids concentration.

It should also be kept in mind that alluvial and bedrock aquifers may be very efficient in removing certain water impurities (e.g., suspended solids, bacteria, virus, organic matter, etc.) but rather inefficient in removing others (e.g., nitrates, dissolved solids).

The entire aquifer reinjection operation depends on the interpretations of local, state, and federal officials of state and federal water discharge regulations. Under a strict interpretation of the "zero release concept," aquifer reinjection may not be feasible; however, in practice it seems that aquifer reinjection will be allowed so long as it does not significantly pollute or degrade the water quality of an aquifer.

7-D-4. Potential Difficulties with Tailings Piles

In Canada (GCOS) swell factors of 7 percent have been observed for the overburden and 35 percent for the tailings. This has resulted in "reclaimed land surfaces" more than 100 feet higher than the original surface (depending on the amount of overburden) (Allen and Sanford, 1973).

Aside from the visual impacts of the tailings piles, this means that attention must be paid to design and operation of these piles with regard to compaction, erosion, and water pollution. Percolation of water may take place with resulting leaching of salts and other materials from the piles.

Because of this uncertainty, it seems prudent to monitor the materials being placed into the piles, the care utilized in constructing the piles, and the conditions of the piles themselves.

Tests should be conducted to verify the properties of the materials being deposited on the pile and the level of compaction which has been achieved. Pore pressures should be measured at various levels to see if the pile has, in fact, been made impervious to the flow of ground water. Surface contours should be measured periodically to detect mass movement of the pile before a catastrophic failure can occur.

EPA (1976) reported sulfur contents of Utah tar sands ranging from 0.14 percent to 6.27 percent. An average of 0.4 percent of sulfur is quoted for the tar sands in the Uinta Basin (80 samples). Average metal concentrations of Utah tar sands are listed as:

Chromium	103	parts	per	million
Cobalt	103	"	"	"
Copper	110	"	"	"
Manganese	547	"	"	"
Nickel	203	"	"	"
Zinc	212	"	"	"

Leachates from tailings piles need to be analyzed for oil, salinity, nitrogen, and metal concentrations and appropriate disposal measures developed.

Revegetation of tailings piles has been achieved in Canada on test sites (Takyi, et al., 1977, Rowell, 1977). Takyi, et al. list the following main conclusions:

- 1) To vegetate areas where heavy oil sand may be present, it is recommended that the oil sand-bearing materials be mixed with fertilizer and a good soil material and left for a growing season before seeding, at which time fertilizers should again be applied.
- 2) In areas where salinity levels are extreme, normal chemical means of reclaiming saline soils before sowing may be the only solution to this problem. Where salinity is low to moderate, tolerant plant species could be seeded without chemical reclamation.
- 3) In areas of high pH (about 10), it is recommended that acidification and correction of salinity problems where they may also exist be carried out before seeding.

4) To ensure balanced stands of legumes and grasses it is recommended that seeding mixtures consist of species of grasses and legumes which would compete on an equal basis or to use a larger percentage of legume seeds in the seeding mixture and to ensure soil conditions favoring legumes in competition with grasses.

5) One fertilizer application per growing season may be all the fertilizer that would be required in a vegetation program. Initial fertilizer rates should not be less than 80 lb N, 40 lb P, and 80 lb K per acre per year after the establishment of vegetation. Liming would be necessary if the soil became more acid, as from fertilization and sulfur dioxide emissions from the processing plant.

6) A seedbed allowing for deeper root penetration is of high priority in establishing greater slope stability.

Root penetration of the dike was restricted almost exclusively to the surface peat layer. Although this was enough to maintain slope stability with normal surface run-off, serious erosion and washouts occurred with heavy surface run-off due to average rainfalls.

7) The capacity of soils to withstand acidification will be an important consideration in revegetation in the area. Tailings sand, lean and heavy oil sands were extremely poorly buffered against acidity. Under the conditions likely to prevail near an extraction plant they could be expected to be acidified to levels at which plant growth would be eliminated with ten years exposure. When mixed with peat and overburden materials the buffering capacity of tailings sand could be improved to acceptable levels.

8) The study of general microbial populations, specific types of organisms and enzyme activities provided a baseline of biological information and enabled no assessment of the potential of mine materials to cycle nutrients. No material was devoid of microbial activity. The high input of sulfur into the soils resulted in low aryl sulfatase activities and high populations of sulfate reducing organisms. Low phosphatase and protease enzyme activities linked with low levels of organic nitrogen indicated a limited ability of the tailings materials and overburdens to supply available nitrogen and phosphorous to plants. Natural levels of atmospheric nitrogen fixation by free-living micro-organisms was extremely low.

In Athabasca, Canada, the average precipitation ranges from 14 to 20 inches annually, averaging 9 inches of rain. The average frost-free period is approximately 90 days. The climate in Utah (at an elevation of 6000-7000 feet) is not very different, although the native vegetation is considerably

different. In Utah the growing period is drier and day temperatures somewhat higher meaning that irrigation is probably necessary for revegetation of tailings piles to succeed.

Availability of irrigation water may be a problem in some areas of Utah. For a 50,000-B/D plant, approximately 100 acres of land will have to be cleared per year. At an irrigation use of 5 acre-feet/acre-year, this means a use of about 500 acre-feet/year of irrigation water for revegetation.

The following is a list of vegetation native to the Uinta Basin in Utah and suitable for revegetation:

crested wheat grass, Russian wild rye, yellow sweet clover, gray rabbit bush, black sage, and winged salt bush.

7-E. Underground Fluid Management

The pumping of water from or into groundwater aquifers can, under special conditions, give unexpected and undesired results. Some of the undesired effects may be:

- a. subsidence of land surface
- b. lateral movement (soil masses)
- c. opening of earth fissures
- d. hydrocompaction.

Subsidence of land surface due to groundwater withdrawal has been observed in many places. Some of the most famous cases are Venice in Italy, Mexico City, Tokyo, Osaka, Taipei, and San Joaquin Valley in California. In Mexico City and the San Joaquin Valley, total subsidences of as much as 8 meters have been observed (Bouwer, 1978). The common cause of land subsidence is an increase in the intergranular soil pressure due to a decrease in hydraulic pressure, by loading a granular material, or by increased water movement (quick condition).

In Wilmington, California, withdrawals of oil have caused subsidence of as much as 9 meters and horizontal displacements of as much as 3.7 meters.

The opening of fissures or faults is sometimes caused by changes in the groundwater situation. Groundwater withdrawal may cause compression of fine-textured layers with the result that overlaying blocks may rotate and open up surface fissures (usually parallel to surface contours). Water from groundwater recharging operations may, under special conditions, serve as lubricants in causing differential land movements; e.g., Rocky Mountain Arsenal, Denver, and Tejon Ranch, California (Sylvester, 1970).

Some loose, dry soils (usually alluvial or aeolian) may collapse upon wetting. This phenomenon, called hydrocompaction, sometimes occurs in dry climates if water is added to loose soil (which may support large loads when dry). The foreign water causes collapse of the soil structure itself, and a compaction (25 percent is not unusual) occurs (Bouwer, 1978).

8. POLICY QUESTIONS CONCERNING THE ENVIRONMENTAL CONTROL TECHNOLOGY FOR TAR SAND DEVELOPMENT

Could environmental technology problems significantly influence the "yes-or-no" decision whether we will have a commercial-scale tar sand industry in the U. S. A? That is, perhaps, the most important question which this report should address. Based on all the foregoing analysis, the authors conclude that the answer is no. Tar sand industries have been started and stopped and at the point of becoming commercial ventures and then postponed largely for economic, and to some extent, political reasons; but, to our knowledge, no project has been stopped for reasons which are basically environmental.

If any single formal environmental regulation is going to significantly delay or hinder the development of U. S. tar sand deposits, it will be the prevention of significant deterioration (PSD) doctrine, which, in effect, is a land-use planning doctrine, which requires us to make conscious decisions when we wish to change any area from non-industrial to industrial. If we are to have a large-scale tar sand industry in eastern or southeastern Utah, then those areas, which are currently very sparsely inhabited, will have large numbers of new inhabitants and will change significantly in character. The PSD policy of the Clean Air Act of 1970, as amended in 1977, requires considerable public hearing and regulation work before such a change can occur. If a significant fraction of the people of Utah make the decision that they wish those areas to remain sparsely settled and non-industrial, they can use this doctrine to block such development. The authors consider that highly unlikely, but it appears to be the only way in which current environmental law could pose genuinely insuperable barriers to tar sand development.

Will the costs of environmental technology be so high as to make otherwise financially viable tar sand projects financially non-viable? Again, we believe the answer is no. All indications are that the projects' economics are largely controlled by the costs of mining, processing of the bitumen, ancillary facilities, etc. It seems clear that none of the environmental control technologies which are summarized in this report and which have been used in Alberta or proposed for use in the U. S. A. pose overwhelming financial burdens compared to the other costs of the projects. Clearly, the projects could proceed at lower cost if there were no requirements to treat surface waters, revegetate solid waste piles, process exhaust gases for control of sulfur dioxide and particulates, etc. But as shown in Section 6, these costs are not major costs compared to the other costs in the projects.

Thus, it seems reasonable to assert that environmental technology, adequate to meet existing standards, is available for the tar sand industry at prices which are not so high as to seriously jeopardize the economics of viable tar sand projects. The research problems and policy problems which are discussed in the rest of this section are not ones which are likely to be matters of life-or-death importance for a future U. S. tar sand industry, but rather ones which bear on questions of change of direction, size, or economics of a future U. S. tar sand industry.

8-A. Interaction with Oil Shale Development

The major tar sand deposits of the United States, in eastern and southeastern Utah, are in close physical proximity to the major oil shale deposits of the United States which are in the Uinta Basin, Piceance Basin, and Washakie Basin of Utah, Colorado, and Wyoming. If both tar sands and oil shales are commercially exploited at the same time, there is bound to be some interaction between the two types of exploitation.

Oil shale and tar sand projects, if exploited simultaneously, will compete for water, air quality (PSD) increments, and land. All foreseeable

oil shale and tar sand exploitation projects will require some water input. In Alberta there are large unappropriated rivers flowing through the areas with the greatest tar sand deposits. In contrast, in Utah the only surface waters in the area are part of the Colorado River drainage system. (The tar sand deposits are mostly located in the drainages of the Green, White, Price, Fremont, and Escalante rivers, all of which drain ultimately into the Colorado.) The waters of the Colorado River are divided among the various states by the Colorado River Compact. Because most of the tar sand deposits are in Utah, water for tar sand projects would have to come from Utah's share of the Colorado River water. Similarly, water to exploit Utah oil shales would come from Utah's allocation from the Colorado River water. Currently Utah has some of that water unallocated, but numerous claims are being made against it. Therefore, if both tar sands and oil shales are to be exploited, some decisions must be made by the Utah State Engineer who allocates water in Utah as to how much water is available for each of the two kinds of exploitation.

Similarly, tar sand and oil shale projects, even using the best available control technology, will emit some air pollutants. The areas in which they are to be located generally are covered by the prevention of significant deterioration doctrine in the U. S. air pollution law. This doctrine limits the maximum incremental concentration increases which can be permitted by all sources in a given area. Generally, if the first new source to locate in an area after the effective date of the regulations uses up the entire increment, then no additional new source can be permitted in the area. Under these circumstances, the regulatory agencies might compel the first source to reduce its emissions so that additional sources will be permitted. Under these circumstances, oil shale and tar sand development will compete for these increments; and presumably the first project into commercial operation will tend to block other projects by using up the available air pollution increment.

In some places tar sands and oil shales occur in the same geographical location. This is particularly true in the case of the P. R. Springs deposit where the oil-impregnated sandstone lies directly beneath the richest oil shale interval (Marchant, Johnson, and Cupps, 1974). Thus the exploitation of one of these mineral resources in that area could conflict with the exploitation of the other.

The above section lists potential conflicts between oil shale and tar sand projects. In addition to such conflicts, there exists the possibility of cooperation. A significant part of the cost of any such venture is that of providing the infrastructure needed to support it. If we simultaneously exploit oil shales and tar sands in the same general area, it may be possible that they could share infrastructure. In particular, the costs of providing electric power, water, pipeline for products, road and railroad connections, etc., could presumably be shared between projects of various kinds. In this sense the prior or simultaneous development of oil shale resources could provide financial support for tar sand exploitation.

Finally, there is the question of minimum economic sizes for oil shale and tar sands projects. The two tar sands projects now operating in Canada are roughly 50,000- and 100,000-barrel-a-day projects. Most of the planned or widely discussed oil shale projects suggest that 50,000 barrels a day is the economic minimum. The proposed Cold Lake in-situ tar sand project in Canada is designed for 160,000 barrels per day. Because of the economies of scale, it seems doubtful that surface mining tar sand recovery projects smaller than about 50,000 barrels a day would be economical. Thus surface-mined tar sand and oil shale both have the disadvantage that they cannot come into production economically on a gradual basis but rather either come on full scale (50,000 barrels a day or more) or not at all.

The same is not true for in-situ tar sand recovery projects. It is entirely possible that a 5,000- or 10,000-barrel-per-day in-situ tar sand

recovery project could be economical. The economies of scale do not appear to operate as strongly for in-situ projects as they do for surface-mining projects. The same is apparently not true for in-situ recovery of oil shale; because of the large-scale mining required there, the minimum economic size is apparently in the order of 50,000 barrels per day. Therefore, it appears that small-scale and gradual introduction of in-situ tar sand is possible but that any other kind of tar sand or oil shale exploitation must come in at a large scale.

The policy question to be considered here is whether the government should be involved at all in helping decide which of these two resources should be exploited first. Secondly, if the government is to be involved, to which should it give favored treatment regarding allocation of water rights, air quality increments, etc.? One obvious policy possibility would be for the government to take no position on this and let the market decide. Under these circumstances, market forces would control which of either of the resources is exploited first. However, the government is involved in the prototype oil shale leasing program; and there are regularly offered bills in Congress to have the government sponsor and provide part of the cost of modular demonstration plants for various oil shale processing technologies. To date none of these bills have passed both houses of Congress.

If the government is to make a commitment of some significant amount of federal funds to the development of processes for oil shale or tar sand and the total funds available for both kinds of processes is limited, it would seem that exploitation of oil shales should probably be preferred. The reason for this recommendation is that the size of the potential resource in oil shale is 20 to 30 times as large as the size of the potential tar sand resource. Therefore, the potential payout to the government in making either or both of these resources economically accessible is greater in the oil shale case.

BIBLIOGRAPHY

- Alberta Environment, *License to Operate or Use No. 73-A1-114*, Great Canadian Oil Sands, Edmonton, Alberta (1973).
- Alberta Environment, *Report on Syncrude Canada Limited, March, 1978* (prepared by the Federal-Provincial Air/Atmosphere Committee), Edmonton, Alberta, 1978a.
- Alberta Environment, *License to Operate or Use No. 78-AL-210*, Syncrude Canada Limited, Edmonton, Alberta, August 24, 1978b.
- Alberta Water Quality Branch, Standards and Approvals Division, Environmental Protection Service, *Waste Water Effluent Guidelines for Alberta Petroleum Refineries*, Edmonton, Alberta, August 16, 1976.
- Alberta Water Quality Branch, Standards and Approvals Division, Environmental Protection Service, *Alberta Surface Water Quality Objectives*, Edmonton, Alberta, January, 1977.
- Alberta Water Quality Branch, Standards and Approvals Division, Environmental Protection Service, *Alberta Coal Mining Waste Water Effluent Guidelines*, Edmonton, Alberta, January, 1978.
- Allen, A. R., "The Mining and Extraction of Bitumen from the Athabasca Tar Sands," *CIM Bulletin*, 67 (746), 97-108 (June, 1974).
- Allen, A. R., and E. R. Sanford, "The Great Canadian Oil Sands Operation" in *Guide to the Athabasca Oil Sands Area*, M. A. Carrigy and J. W. Kramers, Eds., Alberta Research Council, Edmonton, Alberta, 1973.
- Alsands Project Group, "Application to the Alberta Energy Resources Conservation Board for an Oil Sands Mining Project," Submitted by Alsands Project Group, Box 2606, Station M, Calgary, Alberta, December, 1978.
- Alsands Project Group, "Environmental Impact Assessment presented to Alberta Environment in Support of an Oil Sands Mining Project," Submitted by Alsands Project Group, Box 2606, Station M, Calgary, Alberta, December, 1978(a).
- Alsands Project Group, "Regional Socio-Economic Impact Assessment - in Support of an Oil Sands Mining Project." Two volumes prepared by Hobart, Walsh, and Associate Consultants, Ltd., and Quest Consultants, Limited, Alsands Project Group, Box 2606, Station M, Calgary, Alberta, December, 1978(b).
- Alsands Project Group, "Social Impact-Benefit/Cost Analysis presented to the Alberta Energy Resources Conservation Board in Support of an Oil Sands Mining Project." Prepared by Hu Harries and Associates, Ltd., and Hobart, Walsh, and Associate Consultants, Ltd., Alsands Project Group, Box 2606, Station M, Calgary, Alberta, December, 1978(c).

Alsands Project Group, "Environmental Impact Assessment - Oil Sands Mining Project - Supplemental Information Requested by Alberta Environment," Alsands Project Group, Box 2606, Station M, Calgary, Alberta, April, 1979.

Alsands Project Group, "Application No.'s 780724 and 790191 - Oil Sands Mining Project - Supplemental Information Requested by the Alberta Energy Resources Conservation Board," Alsands Project Group, Box 2606, Station M, Calgary, Alberta, April, 1979(a).

Alsands Project Group, "Application to the Alberta Energy Resources Conservation Board for a Power Plant in Conjunction with an Oil Sands Mining Project," Alsands Project Group, Box 2606, Station M, Calgary, Alberta, April, 1979(b).

Bachman, A. W., and D. H. Stormont, "Plant Starts, Athabasca Now Yielding Its Hydrocarbons," *Oil Gas Journal*, 65 (43) (October 23, 1967), p. 69-88.

Ball, M. W., "Development of the Athabasca Oil Sands," *Trans Can Inst of Mining and Met*, 44, 58-91 (1941).

Berlie, E. M., D. G. Cooley, G. Earl, R. K. Kerr, D. M. Leahey, and S. V. Noble, *Evolution of Pollution Abatement Technology as Applied to the Alberta Oil Sands*, report prepared for Alberta Environment by Western Research and Development Ltd., Calgary, Alberta, 1976.

BLM, Department of the Interior, *Final Environmental Statement Emery Power-plant*, p. 1-34, March, 1977.

BLM, Department of the Interior, *Draft E.I.S., Proposed Development of Oil Shale Resources by Colony Development in Colorado*, 1975.

Booz Allen, *Evaluation of Techniques to Remove and Recover Sulfur Present in Fuel Gases Produced in Heavy Fossil Fuel Conversion Plants*, Report No. 9075-051, Contract No. 68-02-1358, prepared by Booz Allen Applied Research, Bethesda, MD, for EPA (1975).

Bouwer, H., *Groundwater Hydrology*, McGraw-Hill Book Co., New York, 1978.

Bullock, W. D., et al., "Environmental Aspects of the North American Mining Industry" in *Minerals and the Environment*, M. J. Jones, Ed., The Institution of Mining and Metallurgy, London, England, 1975.

Camp, F. W., *The Tar Sands of Alberta, Canada*, Cameron Engineers, Denver, Colorado, 1970.

Carrigy, M. A., "Historical Highlights" in *Guide to the Athabasca Oil Sands Area*, M. A. Carrigy and J. W. Kramers, Eds., Alberta Research Council, Edmonton, Alberta, 1973.

Clark, K. A., "The Athabasca Tar Sands," *Sci Amer*, 180 (5), 52 (May, 1949).

"The Clean Air Act as Amended August, 1977," 42 USC 1857, et seq.

Colony Development Operation, *An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado - Part I, Plant Complex and Service Corridor*, p. 223 (1974).

Colorado Air Quality Commission, "Colorado Air Quality Control Regulations and Ambient Air Quality Standards," *Amendments to Regulation No. 1*, Adopted August 11, 1977.

Cottrell, J. H., "Development of an Anhydrous Process for Oil Sand Extraction, p. 193-206 of *Athabasca Oil Sands: A Collection of Papers Presented to K. A. Clark on the 75th Anniversary of his Birthday*, M. A. Carrigy, Ed., Research Council of Alberta, Edmonton, Alberta, 1963.

Cupps, C. Q., C. S. Land, and L. C. Marchant, "Field Experiment of In-Situ Oil Recovery from a Utah Tar Sand by Reverse Combustion" in "Oil Shale and Tar Sands," J. W. Smith and M. T. Atwood, Eds., *AIChE Symposium Series 155* (Volume 72), 1976.

Demaison, G. J., "Tar Sands and Supergiant Oil Fields" in *The Oil Sands of Canada-Venezuela 1977*, D. A. Redford and A. G. Winestock, Eds., Canadian Inst. of Mining and Metallurgy, 1977.

de Nevers, Noel, David Eckhoff, Stephen Swanson, Bard Glenne, and Fred Wagner, "Analysis of the Environmental Control Technology for Oil Shale Development," Report COO-4043-1 for the Department of Energy, 1978.

de Nevers, Noel, "Air Pollution Control Philosophies," *JAPCA*, 27, 197 (March, 1977).

Deroo, G., B. Tissot, R. G. McCrossan, and F. Der, "Geochemistry of the Heavy Oils of Alberta" in *Oil Sands: Fuel for the Future*, L. V. Hills, Ed., Canadian Society of Petroleum Geologists, Calgary, 1974. See also the comment on this paper by D. S. Montgomery and the authors' reply, all in the same volume.

Dorrence, S. M., "Status of Tar Sands Conversion Process Technology and Residuals Management" in *Proceedings of the First Symposium on Management of Residuals from Synthetic Fuels Production*, May, 1976.

Ebanks, W. J., Jr., G. W. James, and N. D. Livingston, *Evaluation of Heavy Oil and Tar Sand in Bourbon, Crawford and Cherokee Counties, Kansas-Final Report*, U. S. Department of Energy Report No. BERC/RI-77/20, Bartlesville, OK, 1977.

Egglestone, A. E., and T. H. Wise, "Athabasca Oil Sands - Developments in Extraction and Upgrading" in *Proc 26th Canadian Chemical Engineering Conf*, (Symposium on Tar Sands), Canadian Society of Chemical Engineering, Ottawa (1976).

Ensign, H., Personal communication with H. Ensign, Staff Engineer, Kennecott Copper Corp., November, 1978.

EPA, "National Primary and Secondary Ambient Air Quality Standards," *Federal Register* 36, 8186 (April 30, 1970).

EPA, "Colorado River System Salinity Control Policy," *Title 40, Chapter I, Part 120*, 1975.

- EPA, *Quality Criteria for Water* (Pre-publication copy), Washington, D.C., 1976.
- EPA, *Production and Processing of U. S. Tar Sands: An Environmental Assessment*, EPA-600/7-76-035, December, 1976.
- Farouq Ali, S. M., "Application of In Situ Methods of Oil Recovery to Tar Sands" in *Oil Sands: Fuel of the Future*, L. V. Hills, Ed., Canadian Society of Petroleum Geologists, Calgary, Alberta, 1974.
- Foster Research, *Cost Benefit Analysis of the Cold Lake Oil Sands Project*, prepared for Imperial Oil Co., Calgary, Alberta, 1978.
- Frazier, N. A., D. W. Hisson, W. E. Ballantyre, and E. J. Mazey, "Production and Processing of U. S. Tar Sands; an Environmental Assessment," prepared for EPA by Battelle Columbus Laboratories, EPA Report No. EPA-600/7-76-035, December, 1976.
- Glassett, J. M., and J. A. Glassett, *The Production of Oil from Intermountain West Tar Sands Deposits*, final report to USBM on Contract No. S0241129, Eyring Research Inst, Provo, UT 84601, March 1976.
- Goforth, R. R., "Application of Best Practicable Technology in Air Pollution Control for the Syncrude Project," *Proceedings 2nd Pacific Chemical Eng. Congress* (PACHEC '77), Denver, Colorado, August 28-31, 1977, p. 1287.
- Gray, G. R., *The Syncrude Project: An Engineering Challenge*, presented at 24th Canadian Chemical Engineering Conference, Ottawa, Ontario, October, 1974.
- Grey, Don, Utah Power and Light Co., Salt Lake City, Utah, personal communications, August, 1977.
- Hardy, R. M., *Tailings Dams*, Engineering Institute of Canada Tar Sands Conference, Edmonton, Alberta, April, 1974.
- Hendrickson, T. A., *Synthetic Fuels Data Handbook*, Cameron Engineers, Inc., Denver, Colorado, 1975.
- High, M. D., "Status Report on Federal Regulations for New Source Performance Standards," *JAPCA* 26, 471 (May, 1976).
- Imperial Oil Limited, *The Cold Lake Project: A Report to the Energy Resources Conservation Board*, Calgary, Alberta, May, 1978a.
- Imperial Oil Limited, *Preliminary Environmental Impact Assessment for Imperial Oil Limited Cold Lake Project*, AERCB Application No. 770866, Calgary, Alberta, February 20, 1978b.
- Jones, Norm, Department of Civil Engineering, Utah State University, Logan, Utah, personal communications, August, 1977.
- Kayser, R. B., "Bituminous Sandstone Deposits, Asphalt Ridge," Special Studies #19, *Utah Geological and Minearological Survey*, p. 34, 1966.
- Kemp, V. E., and O. W. Dykema, "Inventory of Combustion Related Emissions from Stationary Sources (Second Update)," EPA-600/7-78-100, U. S. EPA, ORD,

- Klipp, J. E., *An Oil Spill Contingency and Response Plan for a Proposed Pipeline System*, BLM, Department of the Interior, 1973.
- Kuuskraa, V. A., Sandra Chalton, and T. M. Doscher, *The Economic Potential of Domestic Tar Sands* prepared for U. S. Department of Energy, Div. of Oil, Gas, and Shale Technology by Lewin and Associates and the University of Southern California, HCP/T9014-01, UC-91, January, 1978.
- Lang, D. D., "The Environmental Impact of Oil Sands Processing on Land Reclamation" in *Proc Second Pacific Chem Eng Congress*, Denver, 1977, Amer Inst of Chem Eng, p. 1284.
- Lee, R. E., Jr., and E. R. Booser, "Lubrication and Lubricants" in *Encyclopedia of Chemical Technology*, Second Edition, Vol. 12, p. 557, Interscience Publishers, New York, 1967.
- Lijmach, G. W. M., "On the Origin of Petroleum," *Ninth World Petroleum Congress Proceedings*, Applied Science Publishers, London, 1975, Vol. 2, p. 357.
- Lowe, R. M., "The Asphalt Ridge Tar-Sand Deposits" in "Oil Shales and Tar Sands," J. W. Smith and M. T. Atwood, Eds., *AIChE Symposium Series 155* (Volume 72), 1976.
- Marchant, L. C., L. A. Johnson, and C. Q. Cupps, "Properties of Utah Tar Sands--Three-mile Canyon Area, P. R. Spring Deposit," *U. S. Bureau of Mines Report of Investigations 7923* (1974).
- Marchant, L. C., and L. A. Johnson, "U. S. Energy Research and Development Administration Tar Sand Research--Update" in *The Oil Sands of Canada-Venezuela 1977*, D. A. Redfore and A. G. Winestock, Eds., Canadian Institute of Mining and Metallurgy, 1977.
- Martin, S. W., and L. E. Wills, "Coking Petroleum Residues," *Adv. in Petroleum Chem. and Refining 2* (K. A. Kobe and J. J. McKetta, Eds.), Interscience, New York, 1959.
- Maxwell, Judith, "Developing New Energy Sources; The Syncrude Case," *C. D. Howe Research Institute Observations No. 10*, Howe Research Institute, 2064 Sun Life Bldg, Montreal, Quebec, November, 1975.
- McGauhey, D. H., *Engineering Management of Water Quality*, McGraw-Hill Book Co., New York, 1968.
- Meyers, J. F., et al., "Fly Ash Embankments," *Fly Ash, a Highway Construction Material*, FHWA, U. S. Department of Energy Report FHWA-IP-76-16 (June, 1976).
- National Oceanic and Atmospheric Administration, *Climatological Data, Annual Summary, Utah and Colorado*, National Climatic Center, Asheville, NC, 1976.
- National Park System Mining Regulation Act, *USC 1901-1912, PL 94-492*, September 28, 1976, *90 Stat 1342*.

- Nemerow, N. L., *Industrial Water Pollution; Origins, Characteristics, and Treatment*, Addison-Wesley Pub. Co., Reading, MA, 1978.
- Neveril, R. B., J. U. Price, and K. L. Engdahl, "Capital and Operating Costs of Selected Air Pollution Control Systems," *JAPCA* 28, 829 (August, 1978).
New York Times, The, April 15, 1976, p. 21.
New York Times, The, August 4, 1977, p. 1, col. 1.
- Oblad, A. G., J. D. Seader, J. D. Miller, and J. W. Bunger, "Recovery of Bitumen from Oil-Impregnated Sandstone Deposits of Utah" in "Oil Shale and Tar Sands," J. W. Smith and M. T. Atwood, Eds., *AIChE Symposium Series 155* (Volume 72), 1976.
- Oliver, W. L., "Fuels from Tar Sands," *Proc 26th Canadian Chemical Engineering Conf* (Symposium on Tar Sands), Canadian Society of Chemical Engineering, Ottawa, Ontario, 1976.
- Outtrim, C. P., and R. G. Evans, "Alberta's Oil Sand Reserves and Their Evaluation," *Heavy Oil Symposium 28th Annual Technical Meeting of the Petroleum Society of CIM*, May, 1977.
- Peterson, W. S., and P. E. Gishler, "The Fluidized Solids Technique Applied to Alberta Oil Sands Problem" in *Proceedings of the First Athabasca Oil Sands Conference*, Edmonton, Alberta, September, 1951, p. 207-236.
- Pfeffer, F. M., and R. S. Kerr, "Pollution Problems and Research Needs for an Oil Shale Industry," National Environmental Research Center Office of Research and Development, EPA, Corvallis, OR, *EPA-660/2-74-067* (June, 1974).
- Phizackerly, P. H., and L. O. Scott, "Major Tar Sand Deposits of the World," *Seventh World Petroleum Congress Proceedings*, Elsevier, London, England, 1967, Vol. 3, p. 551.
- Prats, Michael, "A Current Appraisal of Thermal Recovery," *Journal of Petroleum Technology* 30, 1129-1136 (August, 1978).
- Pratt, Larry, *The Tar Sands: Syncrude and the Politics of Oil*, Hurtig Publishers, Edmonton, Alberta, 1976.
- Resources Management Consultants (Alberta) Ltd., *Socio-Economic Overview of the Cold Lake Heavy Oil Project*, prepared for Imperial Oil Limited, Edmonton, Alberta, 1978.
- Ritzma, H. R., "Commercial Aspects of Utah's Oil-Impregnated Sandstone Deposits," *Interstate Oil Compact Commission Committee Bulletin* 15 (2), December, 1973.
- Ritzma, H. R., "Utah's Tar Sand Resource: Geology, Politics, and Economics" in "Oil Shale and Tar Sands," J. W. Smith and M. T. Atwood, Eds., *AIChE Symposium Series 155* (Volume 72), 1976.

- Rosenbaum, J. B., et al., "Sulfur Dioxide Emission Control in Japanese Copper Smelters," *USBM Information Circular 8701*, 1976.
- Rowell, M. J., "Continued Studies of Soil Improvement and Revegetation of Tailings Sand Slopes," *Env. Research Monograph 1977-4*, Syncrude, Canada.
- Salt Lake Tribune, The*, August 9, 1977, p. C5, col. 1.
- Savage, R. K., *A Digest of Environmental Protection Legislation in Canada, to January 1, 1977*, Vol. I, 6th Edition, Canadian Industries, Ltd., Montreal, Quebec, 1977.
- Schlick, D. P., and Wahler, W. A., "Mine Refuse Impounding in the United States," Mining Enforcement and Safety Administration, *U. S. Department of the Interior, Information Report 1028* (Revised January, 1977).
- Schulz, K. F., and D. N. Morrison, *Great Canadian Oil Sands Tailings Disposal Parts 1 and 2*, Alberta Research Council, 1973 and 1974, open file reports No. 1973-38 and 1974-44, Edmonton, Alberta.
- Science Policy Research Division and Foreign Affairs Division of the Congressional Research Service, Library of Congress, "Energy from U. S. and Canadian Tar Sands: Technical, Environmental, Economic, Legislative, and Policy Aspects," report prepared for the Subcommittee on Energy of the Committee on Science and Astronautics, U. S. House of Representatives, *Ninety Third Congress*, GPO, Washington, D.C., December, 1974, Document 43-005-0.
- Seader, J. D., and K. M. Jayakar, *Process and Apparatus to Produce Synthetic Crude Oil from Tar Sands*, U. S. Patent Application Serial No. 851,226, filed December 15, 1977.
- Seven States of the Colorado River Basin, *Supplement, Including Modifications to Proposed Water Quality Standards for Salinity, Including Numeric Criteria and Plan of Implementation for Salinity Control, Colorado River System*, 1975a.
- Seven States of the Colorado River Basin, *Proposed Water Quality Standards for Salinity, Including Numeric Criteria and Plan of Implementation for Salinity Control, Colorado River System*, 1975b.
- Shewchuk, P. G., *Water Considerations for Alberta Oil Sands Development*, Standards and Approvals Division, Environmental Protection Service, Department of the Environment, Edmonton, Alberta, 1975.
- Simmer, M., "Processing and Utilities in In-Situ Recovery" in *Proc 26th Canadian Chemical Engineering Conf* (Symposium on Tar Sands), Canadian Society of Chemical Engineering, Ottawa, Ontario, 1976.
- Sitter, C. R., *Dynamics in the Gasoline Supply Outlook*, presented at the Automotive News World Congress, Detroit, Michigan, July 11, 1977.
- Sohio Petroleum Company, *Proposed Plan for Mining and Processing Operations Bituminous Sands Deposits Asphalt Ridge Area, Uinta County, Utah* (with particular reference to the Environmental Effects of the Operations), presented before the Board of Oil and Gas Conservation, Department of Natural Resources, State of Utah, Vernal, Utah, August 28, 1974.

- Sokolorski, V. V., *Statics of Solid Media* (Translated from Russian by D. H. Jones and A. H. Schofield), Butterworth Scientific Publications, London, England, 1960.
- Speight, J. G., and S. E. Moschopedis, "Some Aspects of Oil Sand Processing" in *Proc 27th Canadian Chemical Engineering Conf*, Canadian Society for Chemical Engineering, Ottawa, Ontario, 1977.
- Spraggins, F. K., "A Second Generation Tar Sands Plant" in *Proceedings of the Eighth World Petroleum Congress*, Applied Science Publishers, London, England, 1971, Vol. 4, p. 35.
- Steed, J. N., and B. Glenne, "Water Budget of the Great Salt Lake," *Proc. Am. Water Resources Assoc. Conference*, Salt Lake City, UT, November, 1972.
- Stuart, Alexander, "That 'Very Interesting Dance' in the Baltimore Canyon," *Fortune* 98-5, p. 66 (September 11, 1978).
- Supple, M. A., and K. Raschid, "Reduction of Flue Gas Particulates in a Tar Sand Plant" in *Proc 27th Canadian Chemical Engineering Conf*, Canadian Society for Chemical Engineering, Ottawa, Ontario, 1977.
- Sylvester, A. G., "Fluid Pressure Variations and Prediction of Shallow Earthquakes," *Science* 169, pp. 1231-1232, 1970.
- Takvi, S. K., M. H. Rowell, W. B. McGill, and M. Nyborg, "Reclamation and Vegetation of Surface Mined Areas in the Athabasca Tar Sands," *Env. Research Monograph*, 1977-1, Syncrude, Canada.
- U. S. Department of the Interior, "Design of Small Dams," Bureau of Reclamation, 2nd Edition, GPO, 2403-0078, 1973.
- U. S. Department of the Interior, "Engineering and Design Manual, Coal Refuse Disposal Facilities," Mining Enforcement and Safety Administration, GPO, 0-579-1601, 1975.
- U. S. Department of the Interior, *Env. Impact Statement, Final Statement, Kaiparowits*, BLM, March, 1976.
- Utah Department of Natural Resources, Division of Oil and Gas Conservation, *Preliminary Environmental Impact Analysis A Proposed Oil Extraction and Strip-Mining Project*, August 23, 1974.
- Utah Division of Health, *Draft Utah Water Quality Standards*, Salt Lake City, Utah, June, 1978.
- White River Oil Shale Project, *First Year Environmental Baseline Report*, p. III-41 (May, 1976).

Appendix I - Coking

Both existing tar sand projects in Canada and the proposed Cold Lake project use some form of coking as the first step in the upgrading of the bitumen to produce liquid fuel. The environmental control technology used on these projects is influenced by the decision to use coking (as opposed to other alternatives) and by the decision as to which kind of coking process will be used. This appendix reviews the purposes and the technology for coking as a background to the understanding of the environmental control technology in tar sand development.

The purpose of coking is to convert high molecular-weight, high carbon-to-hydrogen ratio liquids and solids into lower molecular-weight, lower carbon-to-hydrogen ratio liquids which are suitable for use as liquid fuels. Normally additional processing steps follow coking in the preparation of liquid fuels. The secondary purpose of the coking operation is to transform the sulfur content of the high molecular-weight material into a more manageable form.

The basic chemistry of a coking operation is shown in the following equation:

This equation shows a feed material in which the number of carbon atoms is typically 20 to 40 being heated and decomposing to form other materials in which the number of carbon atoms is generally less. If the hydrogen were equally distributed between the two products shown on the right then the only effect would be to lower the molecular weight. However, if the conditions are selected correctly, the first product shown will have most of the hydrogen (d/c greater than b/a) while the second product will have almost no hydrogen (f approximately equal to 0). Thus, if the first product on the right is

the desired liquid product and the second product on the right is almost pure carbon (of approximately 0), then this could be considered as a simple carbon removal operation. Normally in the decomposition, the average molecular weight is significantly lowered so that c is significantly smaller than a . This frequently results in the formation of several new molecules for each original molecule.

Figure I-1 shows how the distribution of products is influenced by the "severity," which is a function of reaction time and the temperature at which coking takes place. At low temperatures, very little solid is formed; and we merely have the separation of larger molecules from smaller ones. Temperatures of 900 to 1200°F represent the range of greatest interest for petroleum processing; this range is normally used on tar sand bitumen. The principal products generated by this process are gasoline, gas oil, and petroleum coke. At much higher temperatures, the principal products are hydrogen gas and carbon black. This is a highly undesirable result. Thus, Figure I-1 shows that there is an optimum range of temperatures which maximizes the amount of the original hydrogen in the feed which is retained in liquid products which are in the boiling range suitable for use as liquid fuels.

In dealing with a material such as tar sand bitumen which has too high a ratio of carbon to hydrogen to be suitable for liquid fuels, one has two alternatives--remove carbon or add hydrogen. Coking is a carbon-removal process. The alternative is to add hydrogen by catalytic hydrogenation. This alternative has been seriously considered. The Cold Lake application (Imperial Oil, 1978a) discusses several alternative hydrogenation schemes and indicates that although they are technically feasible, they are less attractive economically than coking as a carbon-removal scheme. Shell Oil Company in its earlier proposals (Hendrickson, 1975) intended to use a different carbon-removal scheme called solvent de-asphalting. Since no current tar sand project indicates its intention to use solvent de-asphalting,

Figure I-1. Effect of Temperature (and Also Reaction Time) on Product Distributions in Pyrolysis of Hydrocarbons (Martin and Wills, 1959)

it will not be discussed at great length here. In general, it accomplishes the same kinds of results as shown in Equation I-1 above but by a different mechanism.

The oldest coking process and the one in which there is the greatest wealth of industrial experience is delayed coking, which is shown in Figure I-2. This is the process which is used at GCOS and which is used in numerous refineries throughout the world. In it we see that the feed ("residuum," in petroleum refinery terminology, which would be the crude bitumen in a tar sand operation) is fed to the product fractionator where it combines with unreacted feed. It is then pumped through a coking furnace which raises its temperature to approximately 900°F and passes into one of the two coke drums shown at the left of the figure. In the coke drums, the temperature is kept high enough and pressure high enough so that most of the feed material does not vaporize. The chemical reaction shown in Equation I-1 proceeds with the formation of products which are liquid at ordinary temperatures but which are gaseous at this high temperature. These pass overhead from the coke drum to the product fractionator where they are separated and sent on for further treatment. Some of the original feed passes over as well; it is separated in the product fractionator and recycled to the coking furnace. The percent recycle is one of the important operating parameters of the delayed coker; typically 10 to 30 percent of the feed to the coker is recycled with the remainder being fresh charge.

The coke drums are typically steel vessels lined with refractory, up to 10 ft in diameter and perhaps 100 ft tall. When the level of solid coke has built up to within about 10 ft of the top of the drum, the feed is switched to the other drum. Steam is then introduced into the drum to sweep all of the volatile hydrocarbons out of the drum to the blow-down gas scrubber. When no more hydrocarbons appear in the coke drum vapors, the drum is depressurized and the solid coke removed. Normally this is done by a hydraulic jet reamer which passes into the drum from above. Normally each coke drum has a large

Figure I-2. Simplified Flow Diagram of Delayed Coking (Imperial Oil, 1978b).

tower-like structure above it which serves as support for the hydraulic reamer. The coke plus water passes to the coke pit. From here it is picked up (normally in front-end loaders or clam-shell cranes), drained, and stored.

The advantages of this process are that it is extremely well known and extremely flexible. By varying the temperature, pressure, and percent recycle in the feed, one can handle a wide range of feed materials and have considerable control over the ratio of coker naptha to gas oil and the product quality.

The disadvantages of this process are:

1. It is discontinuous, requiring a switch from one coke drum to the other when one drum is full (roughly once every 8 hours).
2. It is a high-labor process requiring more operators to manage the coke than other processes.
3. It produces a high-sulfur coke which was an acceptable fuel in earlier times when sulfur-content-of-fuel regulations were less stringent, but which is generally not acceptable now.

This is the process used at GCOS. All of the coke is burned as fuel in their power plant and steam generation facilities. Fuel of that high a sulfur content could not be burned in any plant built according to current environmental regulations in the United States or Canada without flue gas desulfurization. Because it is an existing plant, operating under an existing permit, GCOS can continue to burn that fuel in Alberta. However, if they wish to expand their operation, they will not be allowed to burn that coke without flue gas desulfurization.

The second coking procedure, which is the one used at Syncrude, is fluid bed coking which is shown in Figure I-3. The chemical reaction carried out in fluid coking are the same as in delayed coking, but the manner of carrying them out is different. Starting at the left, we see that the

Figure I-3. Simplified Flow Diagram of Fluid Bed Coking (Imperial Oil 1978b)

residuum feed (bitumen feed in the case of a tar sand operation) enters a reactor. In this reactor is a fluidized bed of hot coke particles at a temperature of perhaps 1150°F. The bed is fluidized by steam. When the bitumen contacts the hot coke particles, it coats the particles; and the sensible heat from the particles provides the necessary heat to heat the bitumen to coking temperature and to provide the heat of coking. The reaction shown in Equation I-1 proceeds, and the coke particles grow as the residual coke is deposited on them. The products are scrubbed by heavy gas oil and then flow to the primary fractionator and to subsequent processing, which is in no significant way different from that of delayed coking.

A fraction of the coke from the reactor is steadily withdrawn and taken to another vessel called the burner, which is air-fluidized. In the burner some of the coke is burned thereby liberating enough heat to raise its temperature significantly above the temperature in the reactor. Another stream of coke is then returned to the reactor. Thus the combustion in the burner is the heat source which drives the coking reaction in the reactor. Another stream of coke is steadily withdrawn from the burner so that the inventory of the coke in the burner remains constant. The flue gas from the burner contains significant amounts of carbon monoxide and is sent to a CO boiler where it is burned, producing steam and converting the carbon monoxide to carbon dioxide.

The advantages of this process over delayed coking are:

1. It is a continuous process which does not require the switching from one drum to another.
2. It requires a lower labor input than delayed coking.
3. It provides better control of the coking reaction than in delayed coking, where the reaction takes place in a large liquid pool in the coke drums.
4. It provides a very rapid reaction in which the coking takes

place, probably in a few seconds on the surface of the hot coke pellets. Generally, short-term pyrolysis of this type produce a higher liquid yield than the slower pyrolysis which occurs in the drums of a delayed coker.

4. The bitumen is not heated in any tube furnace. Generally, coking furnaces are expensive and require careful design to avoid plugging by coke formation in the furnace.

Although fluid coking has been very successful commercially and is widely applied, it has two significant drawbacks. The first is that it also produces a coke product (in this case in the form of fine particles instead of the larger particles normally found in delayed coking). This is a high-sulfur coke which cannot normally be burned in furnaces without flue gas desulfurization. The second drawback is that the heat released in the burner is produced by burning some of the coke. Therefore, some significant fraction of the sulfur in the feed appears in the flue gas entering the CO boiler. The condition in the burner is oxidizing so that this sulfur in the flue gas is in the form of sulfur dioxide. At Syncrude the concentration of sulfur dioxide in this flue gas going to the boiler is roughly 0.2 percent. This could be treated easily by flue gas desulfurization but cannot be economically treated by sulfuric acid plants or other less expensive flue gas treatment processes. At Syncrude, this is the principal source of sulfur emissions from the plant. It was considered acceptable at the time that the Syncrude design was approved, but it most likely would not be approved according to current regulations and current thinking as to what constitutes best available control technology.

The third coking process (which is the one proposed for Cold Lake), Flexicoking, is shown on Figure I-4. In it we see that the reactor is substantially the same as the reactor in fluid-bed coking as is the treatment of the liquid product produced. The significant difference is the treatment

of the coke which is removed from the reactor. It goes to a heater, as in fluid coking, but from there it goes to a gasifier. In the gasifier, steam and air are added and a reaction of the water-gas type takes place. Overall this reaction may be described as

This reaction consumes most of the coke. A small bleed stream of coke removes the ash present in the system so that it does not build up. A significant stream of coke from the gasifier is returned to the heater. There it mixes with the colder coke which is then returned with the reactor. The reason for having an intermediate heater vessel between the reactor and the gasifier is that the operating temperature of the gasifier is about 1800°F. This is well above the optimum temperature for the coke going back to the reactor, which is about 1200°F. By mixing the very hot coke from the gasifier with the cold coke from the reactor, the operator can control the temperature of the coke being returned to the reactor.

The advantages of flexicoking over fluid coking are

1. Virtually no solid coke is produced. Almost all the coke is consumed and converted into coke gas. Only a small slip-stream of coke is produced for prevention of solid buildup.
2. The coke gas which is produced in the gasifier and then passes through the heater to the waste heat boiler, etc., is produced under reducing conditions and therefore has almost all of its sulfur in the form of hydrogen sulfide. As discussed in Section 4-E-3, it is much easier to deal with hydrogen sulfide streams than sulfur dioxide streams; thus the sulfur is in a form much more economically dealt with than the corresponding sulfur in the stream leaving the heater from a fluid coker. The gas from the heater goes to a venturi scrubber and then to a stretford

plant which removes the hydrogen sulfide and produces liquid sulfur. The treated gas is a valuable fuel, normally having a heating value of 130 Btu/cubic foot. Because all tar sand operations require significant heat input, this fuel will be used in the plant for some purpose.

In summary, coking of one form or another is extremely widely used in petroleum processing and is used in all existing and proposed tar sands processing plants. Because of the increased stringency of sulfur dioxide emission regulations, it seems likely that in the future the choice will be between fluidized-bed coking with flue gas desulfurization of the heater off gas stream and flexicoking with stretford treatment of the coke gas. The Cold Lake application (Imperial Oil, 1978b) indicates their belief that flexicoking is the more economical of these two alternatives.

Appendix II--Thermal and Solvent Bitumen Recovery Processes

This appendix discusses two entirely different processing schemes from the ones described in the text. Both of them are only applicable to tar sands which have been mined and delivered to the processing plant. Neither of them has, to the knowledge of the authors, been subjected to more than modest-scale pilot-plant testing. Neither of them, to the knowledge of the authors, is near commercialization. Because they are not near commercialization (and may never be commercialized), they have been relegated to an appendix here rather than being included in the main text. The purpose of this appendix is to explain the the processes and estimate what their environmental control technologies and problems would be, relative to the better known processes previously described. The mining of the sand would presumably be the same for these processes as for water-wash processes like those used in Alberta.

The first process is the Direct Coking of Tar Sands. This process has been well described by Camp (1970). Rather than paraphrase what he says, we have included his two-page description as a direct quote.

Direct Coking of Tar Sands

Direct coking of tar sands, using a fluidized-bed technique, has been tested by the Canadian Department of Mines and Technical Surveys, Mines Branch (22). Figure 29 is a simplified flow sheet of the pilot plant. Tar sand is fed to a first vessel which is a coker or still, operating at about 900°F. In the coker, the tar sand is heated by contact with a fluidized bed of clean sand from which the coke has been removed by burning. Volatile portions of the bitumen are distilled from the sand grains. Residual portions are thermally cracked, depositing a layer of coke around each sand grain. Coked solids are withdrawn from the coker down a standpipe, fluidized with air, and transferred to a second vessel. This vessel is a burner or regenerator; it operates at about 1400°F. In the regenerator most of the coke is burned off the sand grains. The clean hot sand is withdrawn through a standpipe. Part (20-40%) is rejected, and the balance of the clean hot sand is recirculated to the coker to provide the heat for the coking reaction. Products leave the coker as a vapor, which is condensed in a product receiver. Reaction offgases from the receiver are recirculated to fluidize the clean, hot sand which is returned to the coker. Condensate from the product receiver forms a heavy synthetic crude oil, the main reaction product. Typical properties of the synthetic crude are summarized in Table 6. Operating data from a number of coking runs on tar sands at different temperatures are summarized in Table 8. The main point to note is that to raise the coker temperature, it is necessary to raise the temperature in the burner, and/or increase the recirculation rate (recycle ratio) of hot sand to the coker. At the highest recycle ratio of 5.0, the weight ratio of sand to oil in the coker is about 35. For comparison, typical catalyst/oil weight ratios in fluidized bed catalytic cracking are 8-10.

FIGURE 29

DIRECT FLUID COKING OF TAR SANDS (22)

[(22) is Peterson & Gishler (1951)]

DIRECT COKING OF ATHABASCA TAR SAND
PILOT PLANT OPERATING DATA

Source of Tar Sand

	Abasand Run No.				Bitumount Run No.			
	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)
Feed								
Composition, wt. %								
bitumen	17.0	16.4	16.4	16.4	13.5	13.5	14.5	15.8
water	0.3	0.3	0.5	0.3	0.35	0.5	nil	0.9
Rate								
lb/hr.	83	86.4	75.5	83	107	88.6	85.4	79
lb/hr. sq. ft.	434	450	394	434	560	463	445	412
lb/hr. cu. ft. bed volume	169	176	154	169	219	180	173	161
Operating Conditions								
coker Temperature, °F	925	977	1022	1067	932	950	977	1022
burner Temperature, °F	1303	1286	1373	1436	1220	1320	1265	1400
recycle ratio lb clean sand to Coker								
lb tar sand to Coker	2.9	4.4	3.8	5.0	4.4	4.7	--	3.9
Oil Product								
Yield, Vol %	84.0	83.5	75.0	73.5	85.7	86.5	86.0	82.5
Data: Reference 22								

Direct coking of tar sand using a fluidized solids technique has much to recommend it. The process is a simple, direct treatment of the tar sand. The technology involved is similar to that in fluid catalytic cracking, so that it is reasonable to expect that large units could be engineered and scaled-up reliably. This process has the particular advantage, relative to the hot water process (discussed below), that feeds of high fines content offer no particular difficulty. There are two possibly serious disadvantages to direct coking. First, large amounts of sand may prove to be abrasive, causing material handling problems. The second point is that the sand discharged from the process is hot (1400°F) and thus represents a significant heat loss. No practical way has yet been suggested for recovering the large amount of sensible heat in the reject sand from a direct coking process. To heat the sand 1400°F requires about 240 BTU per pound of tar sand. The heating value of a pound of tar sand (12 wt.% bitumen) is about 2100 BTU. Thus, the process heat loss from this one source alone represents over 10 wt. % of bitumen contained in the tar sands.

Comparing this process to what is done at Syncrude, we see that the process sketched in Camp's Fig. 29 serves the same functions as the water-washing and the fluid coker at Syncrude. The synthetic crude oil shown in Fig. 29 would

be analogous to the combined coker naptha, kerosene, and gas oil. Presumably if Syncrude had elected to use this process instead of the one they now use, they would have replaced the product receiver in Fig. 29 with a fractionator and sent those streams to hydrogenation, etc.

In principle, it would seem that the fluid-bed coker in Camp's Fig. 29 should operate approximately the same as the fluid-bed coker in the Syncrude process. The differences are that the heat is brought in by hot sand rather than by hot granular coke (which should make relatively little difference) and that because of the water present in the tar-sand feed, the coker would contain more water and finally that the ratio of hydrocarbons to solids in the coker would probably be lower in the direct coking than in the coking of bitumen.

A novel version of this process is currently being piloted in the Chemical Engineering Department at the University of Utah. In it, there is significant heat transfer between the burner and the coker by means of heat pipes which allow that heat to be transferred without the transfer of large volumes of sand (Seader and Jayakar, 1978). This process currently exists only on the scale of a very small pilot plant.

Comparing the environmental consequences of this direct-coking process to the environmental consequences of the process currently used at Syncrude, we see that the quantity of flue gas to be treated would presumably be significantly higher for this direct coking than it would for bitumen separation followed by coking. The reason is that the sand leaves the process at a high temperature; the sensible heat contained in that sand must have been produced by burning coke. As indicated in the quote from Camp, all or most of the coke produced is burned, whereas, in the Syncrude operation (as described previously) only about 30 percent of the coke is burned. Therefore, we can estimate that the quantity of flue gas (and hence the quantity of contained sulfur dioxide) would be roughly

three and one-third times as large for this process as for the Syncrude process. If a new version of Syncrude were to be built, some form of flue-gas desulfurization would almost certainly be required. This process would suffer the drawback of having a build three and one-third times as large a flue-gas desulfurizer as a Syncrude-type process requires. The advantage of this process is that for a feed like the Syncrude feed, the waste sand leaves the burner clean and dry. Presumably the fine material, which is very difficult to separate from water at GCOS and Syncrude because it forms a gel with water, would also leave with the clean sand and would not cause a disposal or separation problem.

Since the technology described by Camp was well known long before the investment decisions for Syncrude were made, we may safely conclude that, as of that time, the economics of this process did not look as attractive as the economics of the Clark hot-water process followed by fluid-bed coking. For tar sands which are not water wet, i.e. all Utah tar sands, this process may be more attractive because the Clark process in its simple form will not work nearly as well for them as for Athabasca sands. Nonetheless, to the knowledge of the authors, there is no current commercial interest applying this type of process to the Utah tar sands.

Another version of this type of process is the Lurgi-Ruhrgas sand cracking process. This process has been used since 1958 for high-temperature cracking of crude oil and naptha, etc. It has been piloted on a small scale for Athabasca tar sand. Eggleston and Wise (1976) report that there is continuing interest in the application of this technology for the Athabasca tar sand and that economic studies are being carried out to see if it would have an economic advantage over the Clark hot water process.

Another alternate method of removing the bitumen from the tar sands is by some sort of anhydrous-solvent extraction. The following quote from Camp (1970) describes pilot-plant results for an anhydrous-solvent extraction process.

Anhydrous Solvent Extraction Process

An anhydrous solvent extraction process for bitumen recovery was developed by Cities Service Athabasca Limited (13). The work was carried out on laboratory scale during 1959-61. The anhydrous process has four major steps, shown schematically in Figure 30. The solvent used in the experimental work was not specified. Presumably it was a light hydrocarbon.

In the first or mixing stage, fresh tar sand is mixed with recycle solvent which contains some bitumen and minor amounts of water and mineral. Solvent to bitumen ratio (by weight) is adjusted to about 0.5. Total mineral content of the mixer effluent is about 55 wt. %. On the lab scale, five minutes was sufficient mixing time, using a turbine type mixer, at 100°F. The drain step which is summarized by a single block in Figure 30, is actually the heart of the solvent extraction process. This step consists of a three stage counter-current wash. Settling and draining time is about 30 minutes for each stage. The Cities Service extraction process does not use conventional mixer-settler type equipment. Instead, after each extraction step, a bed of sand is formed and the extract is drained through this bed, until the interstitial pore volume of the bed is emptied. Presumably, this is to minimize losses of solvent physically entrained with the sand. In typical runs, drain rates were on the order of 10 gal/min sq. ft., and depended on the extract viscosity, sand bed depth, and applied pressure differential. Maximum pressure differential was 15" Hg. It was observed that irregularly, the bed blinded. Drainage rate was essentially zero and the particular extraction stage in which the condition occurred was totally ineffective.

The last two steps of the process are devoted to solvent recovery. Stripping of the solvent from the bitumen is straightforward. The step of solvent recovery from the solids holds the key to the economic success of an anhydrous process. A calculated material balance for the anhydrous process is summarized in Table 9. If all steps operate according to theory, 93% of the feed bitumen is recovered. Solvent loss is only 1% of circulation, but note that nearly 3.2 lb. solvent are circulated for each lb. of bitumen recovered. This solvent loss must eventually be made up from the bitumen product, probably by some process such as coking which will have less than 100 Vol.% yield. Thus a more meaningful recovery figure is that equivalent to 100% solvent recovery. This figure, assuming solvent stripping from the solids, is 89.3%. The amount of steam indicated in the material balance (Table 9) is just the theoretical amount to raise the tar sand feed from 32°F to 212°F. This amount of steam is a fair estimate of the process heat requirements, but is inadequate to accomplish much stripping of solvent from the reject solids. Referring to Table 9, however, it appears that an excellent job of stripping is expected. If no stripping of the reject solids is accomplished, bitumen recovery falls from 93% to 90%. Solvent losses increase from 1% to 18% of circulation. This is an intolerably large loss; the corresponding bitumen recovery, corrected to 100% solvent recovery is only 19%.

FIGURE 30
ANHYDROUS BITUMEN RECOVERY PROCESS

TABLE 9
CALCULATED MATERIAL BALANCE IN
ANHYDROUS BITUMEN RECOVERY PROCESS (13)

Stream	Component, lb				Total
	Bitumen	Solvent	Mineral	Water	
Mixer step					
tar sand	380.0		2639.4	234.3	3254.5
recycle solvent	761.5	860.5	29.3	18.3	1669.6
Drain step					
makeup solvent		10.4			10.4
solvent recovered					
from product		266.7			266.7
from sand	11.4	192.3			203.7
feed from mixer	1142.3	860.5	2668.7	252.6	4924.1
product	1115.6	1127.2	41.8	25.6	2310.2
solids-to-solvent					
recovery	38.1	202.8	2626.9	277.0	3094.7
Solvent recovery step					
from product					
feed to stripper	354.1	266.7	12.5	7.3	640.6
bitumen product	354.1		12.5	7.3	373.9
from solids					
steam				149.1	149.1
solids to waste	26.7	10.4	2626.9	376.1	3040.1
<hr/>					
<u>Recoveries and losses</u>		<u>With solvent recovery from solids</u>		<u>Without solvent recovery from solids</u>	
Solvent loss, % of circulation		1.0		18.0	
Bitumen recovery, % of feed bitumen		93.0		90.0	
Bitumen recovery, equivalent to 100% solvent recovery, %		89.3		19.0	

* Calculated on the basis of 1 bbl bitumen recovered.

Camp's (13) is Cottrell, 1963.

The previous quote by Camp indicates that this pilot work was done by Cities Service, which is one of the partners in Syncrude. Therefore, they must have concluded that the solvent extraction process was less attractive than the process now used at Syncrude. Currently, to the knowledge of the authors, the only companies considering this type of process are Aminoil (a subsidiary of RJR Inc.) and Sohio. Both of these firms indicated in phone conversations that they were pursuing, at the pilot- or bench-scale level, processes related to that shown in Camp's Fig. 30, but that because they were seeking patent positions, they could not reveal the details. Both of them are using tar sands from Asphalt Ridge, Utah, for their pilot-plant operations.

As Camp's article indicates, the economic key to a successful anhydrous-solvent recovery process is the removal of the solvent from the waste sand. Camp implies that the inability to do this completely was the reason why the Cities Service process was not an economic success. It may be more successful using tar sands from Utah, which contain fewer fines, than it was with the Athabasca sands. In general, it has more chance of success with large-grained, easy-draining sand than with a sand which is smaller grained, and/or contains fines.

The principal environmental control technology problem with a tar sand recovery operation of this type would be the emission of hydrocarbons from the solid-waste pile. All of the solvent which is not recovered from the solids goes to the solid-waste pile on the surfaces of the solid waste. The solvents are most likely materials with significant vapor pressures; therefore we can expect almost all of the unrecovered solvent to evaporate from the pile. This would make such a pile a very significant hydrocarbon source. It might be possible to minimize this emission by rapid covering of the waste pile.

A distinct environmental advantage of this process is that it requires little or no water and produces little or no waste water. This would be particularly advantageous for tar sand operations in Utah, where the resource is located in a very water-poor area.

A variant on the solvent processes has been tested for Utah tar sand deposits. In this variant (Lowe, 1976), both hot water and solvent are used to remove the bitumen from the sand.

The reason for this combination appears to be that for some tar sands (mostly those from Utah), the viscosity of the bitumen is too high for a satisfactory separation of the bitumen from the sand using hot water alone. It is unlikely that any hot-water-washing operation will take place at

temperatures significantly above the boiling point of water because that would require that the operation be conducted in pressurized containers instead of those open to the atmosphere. The extra cost of conducting the entire operation under pressure is probably prohibitive. If the viscosity of the bitumen at the temperature of boiling water is too high to permit satisfactory separation, the only possible alternative seems to be to add a solvent of some kind which will dissolve in the bitumen, thereby lowering its viscosity enough to permit satisfactory separation.

As described by Lowe (1976), numerous variants of this idea have been tried on the Asphalt Ridge tar sand, which are roughly an order of magnitude more viscous than the Athabasca bitumen. Comparing these processes to the Clark hot water process used at Athabasca, we see that in both cases it is necessary to add a solvent to make some part of the separation. In Athabasca it is common to make the primary separation between bitumen and sand without a solvent and then add the solvent for the final bitumen cleanup step. With Asphalt Ridge bitumen it appears that it is better to add the solvent to the primary step in order to improve the primary separation. The disadvantage of adding the solvent for the first separation step is that it is then necessary to recover solvent from the coarse sand leaving the first separation step. At Athabasca this is unnecessary so that the bulk of the sand leaves the process without the necessity of solvent stripping and without the possibility of carrying away solvent with the coarse sand. Egglestone and Wise (1976) report on several additional variations of this process which have been pilot tested or are under pilot-scale development.

The environmental control consequence of adding solvent in the first step is similar to that of the anhydrous solvent process; namely, that there is the possibility of significant solvent carryover with the waste sand, making the waste sand a potential hydrocarbon emission source.

Appendix III Utah Tar Sand Deposits

Although there is no current commercial exploitation of the tar sand deposits in Utah for fuel production, there is continuing interest in the possibility of that exploitation. Most of this report has dealt with Athabasca and Cold Lake deposits in Alberta because those are being commercially exploited or are likely to be commercially exploited long before the Utah deposits. However it seems appropriate to include in an appendix some more detailed descriptions of the Utah deposit to aid the reader in understanding how these deposits relate to the deposits in Alberta.

The information contained in this appendix is mostly derived from the work of the Utah Geological and Mineralogical Survey (UGMS). Ritzma (1976) lists seven tar sand studies by UGMS in his bibliography. UGMS has for several years had an active program of mapping and analyzing these deposits in the hope of bringing them to commercial production. In addition we have borrowed from the report by Glassett & Glassett (1976); they rely heavily upon the Utah Geological and Mineralogical Survey data but in addition make independent judgments of their own.

Table 1-1 lists the individual deposits in the United States. In it we see that there are six Utah deposits with reserves of over a billion barrels. These six are the most likely deposits for early commercialization; between them they contain 94 percent of the known U.S. tar sand deposits. These six may be logically divided into two groups--the Uintah Basin group (Asphalt Ridge, Sunnyside, Hill Creek, and P. R. Springs) and the Southeastern Utah group (Tar Sand Triangle and Circle Cliffs.) This division is not only geological but historical. According to Ritzma (1973, 1976), the Uintah Basin deposits are all low-sulfur, (less than 0.5 wt %) chemically similar, and probably deposited in lacustrine environment in the Tertiary period 40 to 70 million years ago. In contrast the two Southeastern Utah deposits are high sulfur (typically about 5 %),

and probably developed in a brackish or marine environment in the Permian and/or Triassic periods about 230 million years ago.

Although the Uintah Basin sands have a significant lower sulfur content than the Athabasca sands, they are roughly an order of magnitude more viscous. (See figure 4-1).

Typically the Utah deposits contain very little water. This is in marked contrast to the Athabasca deposits where in most of the deposit there is a film of water between the bitumen and the sand grains. The Clark hot water process for the removal of bitumen takes advantage of this film of water; for this reason the direct transfer of this process from the water-bearing Athabasca sands to the dry Utah sand is not likely to be simple (Oblad et al., 1976).

Typically the Utah sands have roughly one half of the pore volume between the sand grains filled with bitumen. In comparison, typically 70 to 90% of the corresponding pore volume is filled with bitumen in the Athabasca deposit. This may be translated to a weight percent bitumen in the sand showing that typically at Athabasca this is 12% while in the Utah deposits it is typically 7.5%

The Athabasca deposits generally consist of thicknesses of 50 and more feet of continuous, high-saturation tar sand with few intervening layers of barren material. In contrast few of the Utah deposits are more than about 20 feet thick, and they frequently contain large intervening sections of barren material.

At Athabasca there is ample surface water for processing use; the maximum conceivable use by the existing tar sand projects requires only a few percent of the flow of the Athabasca River. In contrast the areas which contains the tar sand in Utah are high desert. Rainfall averages less than 10 inches a year. In many areas there are no permanent surface streams. If water is required for processing, it must be taken from Utah's share of the Colorado

River. Utah has some unallocated part of this water; there are many conflicting claims against it.

Although some of the Utah deposits (mostly Asphalt Ridge) are relatively soft and friable, many of the Utah deposits are in hard, consolidated sandstones which cannot be easily broken apart without high explosives. In contrast all the Athabasca deposit appears to be soft and friable.

The above are the significant physical differences between the Utah tar sand deposits and the Athabasca deposit. In addition the Utah deposits are smaller. Some of them (as discussed in section V) are located in or near national parks or recreation areas. Many of them are located in extremely rough terrain where they outcrop in canyon faces and gullies to up to 1000 ft. deep.

The above may appear as a litany of problems which the Utah deposits will face in any effort at commercializing their exploitation. These problems are well known. They have been the problems which have prevented the major oil companies from making significant investments in attempting to exploit the Utah tar sands deposits.

In July of 1974 representative Mike McCormick, the Chairman of the Sub Committee on Energy of the House Committee of Science and Astronautics, sent a letter to many U.S. oil companies and other interested parties inquiring as to their view to the probable commercialization of the Utah tar sand deposits. The following excerpts (Science Policy Research, 1974) from the responses by the oil companies indicates that the above list of difficulties and problems was enough to limit their interest in investing their own capital, at present, in exploitation of these deposits.

....U.S. tar sands are not necessarily the same as Alberta tar sands where technology presently exists for its recovery. No viable technology has been demonstrated for Utah oil sands nor can be developed by 1985. Most Utah tar sands reserves are overlain by overburden too thick for open pit mining to be attractive....

John S. Hutchings
Cameron Engineers

In response to your questionnaire on development of the Utah tar sands deposits. Atlantic Richfield acquired and held U.S. Bituminous sands leases in the mid 1960's, but abandoned them to pursue coal and oil shale as more promising domestic resources for synthetic fuel production. Some considerations which led ARCO to this course of action, and retain this view as our current position, include the following:

1. Grade and Quantity of Reserves--According to the recent study by the National Petroleum Council, Utah contains all five of the domestic tar sand deposits which may be potentially large enough to support commercial exploitation. The estimated in-place resources in these five deposits is 17.7 to 27.6 billion barrels. The deposits, however, are highly dispersed. They are spread out under hundreds of square miles of arid, mountainous terrain. On the average, they are far thinner and not as rich as the Athabasca Canadian deposits. Further, the conditions of porosity and permeability vary widely from one deposit to the next, and oil saturation may range from 6 to 30 gallons per ton within one deposit. Steeply dipping beds (3 to 20 degrees) places most of the resources out of reach of strip mining operations. A U.S. Bureau of Mines Study has estimated that less than 300 million barrels of oil could be recovered from Utah oil-impregnated sands by strip mining. Nonetheless, strip mining of the material is the only remotely viable method of recovery with present technology.

2. Hardness--Much of the U.S. resource, such as the Sunnyside, Utah deposit is best described as oil impregnated rock. It must be drilled and blasted to be broken yet is a resilient material which makes it very difficult to crush. Conversely, Canadian deposits are a suspension of sand in tar. Excavation of the material requires much less energy, and separation of the sand particles is easier to accomplish.

3. Bitumen Quality--The attached table is a comparative analysis of California, Utah, and Canadian Bitumen Extracts recovered by a Hot Water Process. The U.S. extracts are more viscous and have higher ash content than the Canadian Bitumen. In general, they are more hydrogen deficient and therefore less desirable as a feedstock for further upgrading. Recovery of the U.S. Bitumen is sometimes a more complicated process, as alkaline reagents must be added to control the acidity of hydrolyzed sulfates in the pulping and flotation process.

4. Land Problems--Tar sand deposits underlie states, federal, Indian, and private lands. Assembling large, contiguous lease blocks from a variety of owners is frustrating, complex and often very expensive. The overlying land is remote, rugged, dry and accessible only by a few limited routes. Designated national parks, national monuments, primitive and wilderness areas are some of the federal land which contain a large percentage of the tar sands resources.

5. Water Problems--A tar sands plant will require considerable water for dust control, hot water extraction and upgrading. Utah oil sands deposits could get water from the Green, White and Colorado Rivers. The Upper Colorado River Basin Compact restricts Utah's utilization to 23% of the Colorado flowage. Utah has committed all but 107,000 acre-feet and will have to carefully select priorities in the ultimate use of her entitlement. An accelerated oil

shale development program alone could consume this amount of water and irrigation, power generation, and coal gasification are competitive projects with large potential needs for water. Utah water right applications for oil shale development already exceed 319,000 acre-feet.

6. Poor In Situ Prospects--The in situ prospects for domestic tar sands are not very good, even though at least 80% of the resources are potentially recoverable only if in situ is successful. The nonuniform nature of the deposits will make in-situ recovery difficult to predict and control. Core hole samples in the Three Mile Canyon, Utah, area shows a range of permeability of 30-700 millidarcies, while porosity ranges from 3-19%. Outcrop samples of the White Rim formation, Utah, near Dirty Devil River Canyon showed similar variations, with 88 to 900 millidarcies permeability and 7 to 27% porosity. Even with this variation, these areas have been designated as being most highly favorable for in situ recovery. Very few other favorable in situ sites have been located. The data on table 1 points out the second major problem of in situ recovery from U.S. Tar Sand Reserves. The bitumen is very viscous, even at 210°F. It has a softening point of 114°F. In situ recovery of this material will require heating the formation to a significantly higher temperature than counterpart recovery from the Athabasca Sands.

7. Overall Costs--It is our view that large scale plants are necessary to produce synthetic fuels from tar sands at a price competitive with conventional crude. Without economies of scale, unit production costs would soar. A large scale (100 + MB/D) Athabasca Tar Sand plant using surface mining is expected to cost about \$10,000 per daily barrel of production. A plant this size requires immediate access to 1 billion barrels of recoverable reserves to support it. Because of the geology and topography of the Utah deposits plant sizes are likely to be in a range of 1,000 to 10,000 barrels per day. Using the "6/10's scale-up factor" in reverse capital costs for plants of this size range could range from \$25-35,000 per daily barrel of production. Because of the plant size limitations, and the more difficult mining conditions synthetic fuel production costs from domestic tar sands are estimated to be at least 2 to 3 times the cost of producing the Athabasca Sands.

8. Summary--It is not likely, in our view, that any significant production from domestic bituminous sands will be developed within the next fifteen years. We hope this gives you the data you require. If we can be of other assistance please let me know.

Sincerely yours....

Phil D. Helmig
Atlantic Richfield

....The factors and constraints that will limit the rate of development of the U.S. tar sands industry are rate of technology advancement, economics, and governmental actions. Recovery technology of a first generation commercial level has been developed for the Canadian tar sand but no viable recovery process has been reported for other types of tar deposits. Since about 5% or less of the U.S. tar deposits are considered similar in nature to those of Canada, technology developments are essential for the establishment

of a sizable domestic tar sands industry. The economics of oil recovery from tar sands (sic) are considered to be marginal or submarginal so substantial incentives are believed necessary to attract the talent and capital for a sizable industry. Additionally current actions of the Federal Government are inhibiting since the majority of U.S. tar sand reserves are under Federal lands and a leasing moratorium is now in effect which must be lifted before major consideration can be given to developing this resource....

John K McKinley
Texaco, Inc.

....I would like to reply to your letter July 23 in regard to U.S. tar sands by giving you an answer which broadly applies to several of your questions. The key factor, which in our view is likely to limit development of U.S. tar sands, is that the ore bodies almost without exception are of poor quality. For example, the Athabasca tar sand ores in economically mineable areas average about 25 gallons per ton, and with present processes the lower limit on ore quality is 14 gallons per ton. The best Utah deposits, on the other hand, run about 17 gallons per ton. For this reason we do not expect mining domestic tar sands to be an important source of oil in the next 10 to 15 years. As a rough estimate it is very improbable that production would be as much as 500,000 B/D.

Capital availability may be a problem depending on the investment climate. Tar sand mining and processing plans will probably cost in the range of \$15,000 to \$20,000 per daily barrel of capacity. Because of the low quality ore and high capital and operating costs, it appears that it will be hard to find resources which will be good enough to readily attract capital. We don't know what the product price will have to be to make one of these projects go, but we suspect that shale oil will be somewhat less costly than tar sand oil.

We expect that sometime after 1980 in situ processes applicable to Canadian tar sand will be developed. We are less optimistic as to U.S. tar sands. Several tests have been run in the U.S. by various companies including Shell without too much evident encouragement.

There are, of course, technical and environmental constraints on tar sand development. However, we feel that they are less important than (sic) the basically low quality resources....

K. Doig
Shell Oil Co.

....Tar sands occur in many places in the U.S., but they are generally limited to small deposits in difficult and expensive mining situations. There are no deposits even remotely resembling the Athabasca tar sands of Canada or the U.S. oil shale and coal deposits so far as size of reserves and economic potential for a significant contribution to the energy problem are concerned. There may be opportunities for a few plants, which could individually produce up to 50,000 bbls. per day. However, potential to expand production on the scale necessary to make a major impact on the energy

problem does not seem to exist....

Frederick W. Camp
Sun Oil Co.

....Exploitation of domestic tar sand resources at this time has been confined to small scale operations for road paving materials and other local uses. Physical, technical, land use, environmental and economic factors will, in our opinion, preclude significant development in the next fifteen years.

The physical characteristics of tar sands accumulations of Utah and California, though indicated to aggregate some 30 billion barrels in place, are a primary constraint because they are erratic in occurrence and grade and are predominantly under thick overburden which precludes large scale surface mining. New technology must be developed for in-situ recovery applications....

R.F. Tucker
Mobil Oil Co.

All of these negative results do not mean that Utah tar sand cannot be exploited economically. They do mean that, by known technology with known economics and known governmental and environmental constraints, it does not appear to be economically promising to attempt to exploit this resource. Technology, economics, governmental policies, and environmental constraints can change. In the future it may be economical to exploit these deposits.

Appendix IV - Conventional and Secondary Recovery of Petroleum

If one could separate the bitumen of a tar sand deposit from the containing mineral matter by simple liquid flow into a well, then the tar sands would have long since become a major source of liquid fuels. As the previous discussion shows, that is not the case; the bitumen can be separated as a liquid from its containing solid only by methods much more complex and difficult than simply drilling a hole into the formation. All in-situ processes for attempting to recover the bitumen as a liquid, without mining the sand, are some variant on existing processes for recovering hydrocarbons from oil fields. Their technology is an extension and modification of the technology of conventional oil recovery. This appendix reviews and summarizes the fundamentals of oil recovery as a background to understanding these in-situ tar sand bitumen recovery processes.

A conventional oil field consists of a porous rock (normally sand or sandstone or fractured or vugular limestone) which contains oil within its pores and also normally contains water or gas. The formation is usually sealed from fluid upwards movement by an impermeable rock. When a well is drilled into such a formation, if the formation is under pressure, the fluid in the formation will flow by pressure gradient into the well. If the pressure is high, the fluid will flow up the well to the surface. In an uncontrolled situation, one will have a "gusher." In properly controlled situations, the oil will flow by natural pressure to oil recovery tanks. If the pressure in the formation is not high enough to overcome gravity and lift the fluid to the surface, then a pump will be used to lift the fluid to the surface.

The corresponding situation in groundwater hydrology is the artesian one, in which an aquifer is bounded above by an impermeable stratum and contains water under sufficient pressure so that if a well is sunk into it, the water will flow spontaneously to the surface. In this case, the aquifer plays the same role as the oil-bearing formation. Most aquifers do not have this artesian situation; they require pumping to lift the water to the surface.

The mechanisms which are available to cause the fluid to move from the formation into the well are the pressure gradient from the formation to the well and/or gravity. In a thin, horizontal oil reservoir, gravity would play no significant role; the pressure gradient between the high pressure away from the well and the low pressure in the well would be the only significant mechanism for moving the fluid into the well. In a very thick formation, gravity would tend to move the fluid from the top of the stratum to the bottom of the well. Some formations are not horizontal but steeply inclined; in these, a well drilled into the bottom of the formation will collect fluid which drains by gravity from the top (see Fig. IV-1).

The mechanisms which may provide a pressure gradient to move the fluids toward the wells are the pressure of dissolved gas (which comes out of the solution as the oil is produced), the existence of a gas cap above the oil in a dome-like structure, or hydrostatic pressure of water driving it at the edge of the formation. This latter situation is quite analogous to the artesian situation in ground-water hydrology, except that at some point in the aquifer/oil-bearing formation there is an oil-water interface, which is driven by the water pressure in the aquifer.

In summary, in a naturally occurring oil field, the fluid travels to the well bore due to gravity or a pressure gradient caused by one of the above mechanisms.

Figure IV-1

Simplified illustration of the conditions under which gravity will be a significant force moving fluids toward a producing well

In an ordinary oil field, when the oil-bearing formation is first penetrated by a well, there is adequate pressure gradient between the oil in the formation and the pressure in the well for the oil to flow spontaneously into the well and/or to the surface. As the oil flows out, the pressure in the formation falls. Eventually an equilibrium is reached in which the formation pressure is no longer adequate to lift the fluid to the surface. At this time the operator normally installs a pump to lift the oil to the surface and thereby decrease the pressure in the well which, in turn, allows the fluid flow into the well to resume. Eventually, the pressure in the formation falls low enough that even if the pressure in the well is reduced to zero by rapid pumping, the fluid will no longer flow into the well. Normally, at this point 5 to 50 percent of the hydrocarbon in the formation will have been recovered; a typical value is about 30 percent.

To recover more of the hydrocarbon, the various groups of processes known as "secondary recovery" are used. In using these, one wishes to accomplish one or both of the following results: first, to restore the pressure gradient between the formation and the collection well in order to mobilize the fluids, and second to change the properties of the fluids to increase the ease of movement of the fluid to the wells and to increase the fraction of the produced fluids which are hydrocarbons.

The normal way of attempting to increase the pressure gradient toward the producing wells is to segregate the field into producing wells, from which fluid is withdrawn, and injection wells, into which a "driving" fluid is pumped. The most common arrangement is the checkerboard arrangement in which the "red squares" have injection wells and the "black squares" producing wells; one may verify that in this circumstance each injection well is surrounded by four producing wells, and each producing well surrounded by four injection wells. Alternative arrangements are also used, as dictated by local circumstances.

The injection fluid is normally water or gas or occasionally steam. If by injecting some fluid, one raises the pressure at the injection wells to significantly above the pressure in the producing wells, the fluid will flow from the injection wells into the formation, and thus increase the pressure gradient enough to move fluid to the producing wells.

Simple water and gas drives in which ordinary water or natural gas are injected have been very effective secondary-recovery procedures. Simple water drive (most often called "waterflooding") is the most widely practiced secondary recovery procedure. It is now routinely used for the majority of oil fields.

In the early days of the petroleum industry, these methods were employed only after a field had stopped producing oil by its own natural reservoir pressure. Now they are frequently begun as soon as the field is placed in production. Under these circumstances, the secondary recovery operates in parallel with the primary recovery; this is sometimes referred to as "enhanced recovery."

However, even these processes do not recover all the oil. Fairly soon after injection begins, the injected fluid appears at the producing well. For example, in a water drive, one will find both oil and water in the producing well. Eventually, the ratio of oil to water falls so low that it is no longer economical to continue flushing water through the formation to recover the amount of oil which is produced. The same situation can exist if one flushes gas through the formation after spontaneous oil production ceases. After some time, the amount of oil produced is not enough to pay the cost of compressing the gas and allowing it to flow through the formation.

In both of these cases, when it is no longer economical to further flush the formation with water or gas, perhaps 30 to 50 percent of the original oil is still in the formation. The reason that this oil is not produced from the

formation by continued flushing with water or gas is that it has been trapped in place in the pores by capillary forces. As long as the oil forms a continuous phase and there is a pressure gradient, it will move toward the well. Once the oil breaks up into discontinuous, isolated patches surrounded by a continuous phase of gas or water the pressure gradient will not move oil to the well. The pressure gradient will merely cause the continuous phase (gas or water) to move without causing movement of the discontinuous oil phase. (See Fig. IV-2)

Therefore, it is frequently desirable to use some additive with the displacing fluid to maximize the amount of oil which is moved before the oil becomes discontinuous and therefore trapped by capillary forces. Additives which are used regularly are surfacants, carbon dioxide, light hydrocarbons, etc.

One distinct problem in all such fluid-drive, secondary-recovery processes is that generally the driving fluid is less viscous than the driven fluid (the oil). Normally, water and gas are much less viscous than most oils. One can readily show in this situation that if there is any unevenness in the boundary between the driven and the driving fluids, and the driving fluid is less viscous, it will form its own channel to the producing well; this is referred to as "viscous fingering." It generally results in the driving fluid bypassing isolated sections of oil, making them discontinuous and therefore impossible to recover. The ways of curing this are to increase the viscosity of the driving fluid or decrease the viscosity of the fluid which is being driven. To increase the viscosity of the driving fluid, one can add polymers or gelling agents to water. To decrease the viscosity of the oil, one can inject solvents ahead of the driving fluid or raise the oil temperature.

The previous discussion indicated that a driving mechanism with a fluid forcing its way through the formation was the most common form of secondary-recovery operation. For extremely viscous oils, it has been found

Figure IV-2

Highly idealized representation of an oil-bearing formation in which the oil is continuous (upper figure) and therefore mobile and one in which the oil is discontinuous (lower figure) and therefore immobile. In the upper figure, both oil and water flow to the producing well. In the lower figure, only water flows to the producing well.

that an alternative which seems practical is to inject a hot fluid (almost invariably steam) into wells and thereby raise the temperature of the formation and increase its pressure. This is continued for several weeks or months. Then the well is shut in for several days or weeks, allowing the heat to spread through the formation and the pressure to rise. Finally, oil is produced back out of the same well into which the steam was injected. This cyclic technique (widely called the "huff and puff" procedure) had been extremely successful in the viscous oil fields of California and is the procedure proposed for Cold Lake. It seems clear that in this circumstance the major effects are first, to reduce the oil viscosity sufficiently so that it can move easily to the well; second, to allow the oil time to move to the well by gravity; and, third, to allow the oil to move to the well by pressure gradient, after the steam has raised the pressure of the entire formation and then the pressure is lowered at the production well by opening it and pumping out the oil. It also seems likely that in such formations when production by ordinary mechanisms has ceased, the oil most likely is discontinuous and is trapped by capillary forces. When it is steam-heated and adequate time is allowed for the discontinuous oil segments to move, they presumably move by gravity enough to reestablish contact with each other and thus to form a continuous oil phase which can then be moved to a producing well.

One of the difficulties with any procedure involving using steam to heat a formation is that of energy efficiency. Because some of this energy is left in the formation and some escapes from the formation by conduction to surrounding strata and escapes from the wellbore, the steam transmission pipes, and all of the other accessories of the project, it is possible to have situations in which more energy is input into the secondary-recovery undertaking than is recovered in the form of additional oil.

The problem of the high energy input to recovery projects which involve the production of steam at the surface and its injection into the formation has led to the development of an alternative concept in which the combustion takes place in the ground. In such a process, air is injected into the formation, and the fuel-air mixture in the formation is ignited in some way. Then part of the oil in place is burned. This produces heat which may be carried forward with the air. All of these processes are, to some extent, similar to the steam-flooding processes in that they attempt to heat the oil or bitumen to the temperature at which it will easily flow to recovery wells. The difference is that in simple steam flooding, the energy is produced by burning some concentrated fuel at the surface while in all of the underground combustion variants, the energy is produced by burning some of the hydrocarbon in the reservoir. On its face, the latter seems a much more attractive alternative because it saves the cost of burning a finished fuel at the surface and the cost of the steam generators, steam distribution facilities, etc. However, in practice this scheme is much more difficult to control. In processes where steam is produced at the surface and brought to specific locations in the reservoir, the operator has reasonably good control of the distribution of heat throughout the formation. In comparison, the operator has much poorer control where the rate of generation of heat within the formation is determined by the advance of the burning zone formed as the air passes through the formation.

Prats (1978) reviewed the status of all types of thermal recovery processes. In spite of the apparent fuel-saving advantages of underground combustion processes, he showed that both in the USA and world-wide steam processes (both cyclic - huff and puff -, and steam drive in which the steam flows steadily in one direction) have been much more widely applied than underground combustion processes. This results from the observed facts that the steam processes are simple, easily controlled, and demonstrable economic successes, while the

combustion processes have not been so far. He also shows that although waterflooding is the most common type of enhanced recovery, of all other kinds of enhanced recovery, steam flooding is the most widely used.

Appendix V--Partial Listing of Commonly Used Slope Equivalents Used to
Describe Cross-Section Slopes

In the text, the problem of disposing of waste sands from tar sand processing is discussed at length. One of the important parameters in designing the retaining structures for such disposal is the surface slope of the retaining structure. This appendix compares various ways of expressing such slopes, and gives some examples to help the reader visualize how steep various slopes are.

Description of Slope			Common Usage Situation
Degrees	Percent	Ratio H:V	
45	100	1:1	Highway cut section in rock
26 1/2	50	2:1	Steepest allowable slope in deep fills for Interstate Highway system
21 2/3	40	2 1/2:1	Athabasca tar sands project. Overburden dike to hold tailings
20	36 1/2	2 3/4:1	U.S. standard for maximum or steepest slope for solid waste stockpile. Athabasca used on outside of some dikes.
18 1/3	33 1/3	3:1	Copper ore project tailings pond dike slope. Used in Egypt. Athabasca project; selected fill forming outside of dike for tailings.
14	25	4:1	Reduced slope as required at Athabasca when 3:1 proved troublesome
11 1/3	20	5:1	Flattest slope at Kennecott Copper tailings pond dike.
4	7	14:1	Athabasca tailings discharge beach. Approximately the maximum centerline grade for Interstate Highway

Appendix VI--Tailings Dams for Tar Sand Waste

The design and construction of the tailings dams for containing solid waste at Athabasca has been one of the major engineering challenges of the entire operation. An excellent review of this subject has been prepared by Hardy (1974). The following excerpts from that review explain the problem and the steps taken so far in its solution.

The components of the tailings streams are such that, to avoid pollution of the athabasca River, its delta and even Lake Athabasca, none of them can be discharged to the river in their raw state. This means that practically the total tailings less only the fraction of the liquid component that can be recirculated must be permanently stored.

With the vast quantities of both liquid and solid tailings involved, the mined-out areas must ultimately be used for tailings storage. Storage, however, must also be provided external to the open pits for an initial period of up to 7 or 8 years before the tailings can be deposited in worked-out areas in the mine without interfering with the on-going mining operation. Even with the initial cushion of storage the volumetric materials balance is such that sufficient volume may not be available in the worked-out mining areas to take the total tailings, and therefore additional external storage space may be required.

These factors require the construction of substantial diking systems to contain the tailings, and the construction of the dikes must be a continuing operation practically for the whole life of a mine. Overburden materials from stripping operations are available for the construction of the dikes, but the economy of their construction is much more favourable if the sand fraction of the tailings can be used for fill material. The solid tailings include fine silt and clay fractions which have unfavourable stability characteristics, and which also adversely affect the volumetric materials balance between the solids in the formation and the volumes occupied after deposition as tailings.

3. Characteristics of McMurray Tar Sand Tailings

The operations at the G.C.O.S. project have shown that on the average the McMurray Formation includes about 16 percent by volume silt and clay. On a daily basis, however, the percentage silt and clay mined may vary widely. It may be as high as 30 percent and as low as 5 percent. Some of this fine fraction is scalped off as silt and clay stone lumps before it reaches the separation cells. On the average, however, about 8 percent by volume goes through the separation cells and emerges in the tailings streams.

If the discharge from the tailings lines is into a self-formed stilling basin so the velocity energy of the stream is quickly dissipated, then the sand separates out in a very low density state and a high percentage of the silt-clay fraction is trapped in the sand fabric. However, if the discharge is onto a beach the sand settles out in a running stream and is densified to a degree, while a high percentage of the silt-clay fraction remains in suspension in the liquid component and is washed into the tailings pond. With current practice most of the sand is separated out in running streams, and the tailings ponds include water, fine silt-clay in suspension, and some oil.

If it is assumed that the tailings streams as pumped from the plant have an average density of 40 percent solids by weight, (20 percent by volume), then the void ratio of the tailings streams averages 4.0. Comparing the volume of total tailings with the volume of intact tar sand in the formation having an average void ratio of 0.6, gives a bulking factor of 3.1 $((1+4.0)/(1+0.6))$. This means that if the total tailings streams must be stored, storage would be required extraneous to the mined-out pits with a volumetric capacity about double the volume of tar sand mined and processed. Such a situation would result in insurmountable difficulties for hydraulic tailings disposal systems with respect

to water supply, logistics of the disposal operation, and conservation and environmental impacts. Consistent with standard mining practice, initial planning for hydraulic tailings disposal for tar sand projects has always assumed that a much more favourable bulking factor could be achieved by recirculating water from the tailings pond back through the separation cells.

What the designer of the tailings system must be capable of estimating with a reasonable degree of accuracy is the overall bulking factor for the tailings system. It is possible to deduce the current average bulking factor for the G.C.O.S. operations from data now in the "public domain". In a submission to the Energy Resources Conservation Board of Alberta, (G.C.O.S. 1972), it was stated;

"For each ton of oil sands processed a void is created in the pit to about 16½ cubic feet. After removing the bitumen, the waste products from the extraction, the tailings, occupy about 23 cubic feet."

Within the context of the concepts discussed above these figures give an average bulking factor of 1.40. This factor is not as large as it theoretically could be, but nevertheless it does result in difficult problems in the design and operation of the hydraulic tailings disposal system.

Examination of the parameters upon which bulking factors are dependent shows that the estimated minimum average value of 1.15 for the tar sand processed will not vary significantly for practical purposes. The two most significant parameters governing the bulking factor achieved in operation are the rate of clarification of the effluent in the tailings pond and the average void ratio to which the oily, silt-clay fraction finally settles in the pond.

While the G.C.O.S. operating experience provides the most reliable data available for an average bulking factor for the tar sand mined, it must be appreciated that for another project the characteristics of the tailings streams might be different than at the G.C.O.S. project. They might be better or they might be worse. The prudent designer, therefore, will avoid locking into a disposal system based on precisely assumed bulking factors. He will to the extent practical come up with an open-ended plan that will permit modifications to suit the performance experience at the particular project.

Experience at G.C.O.S. Project

The detailed design of the G.C.O.S. operation commenced in 1964 with the plant planned to go into operation in the spring of 1967. An initial tailings disposal area was planned to be located in the Athabasca River valley immediately south of the plant. It encompassed an area in the valley known as Tar Island. By diking around the outer perimeter of the island to retain the tailings against the natural valley escarpment, a disposal area of about 1.2 square miles could be provided with a height up to the level of the top of the valley of about 220 feet. Inasmuch as the total area of G.C.O.S. lease 86 is only 6.25 square miles it was considered that the Tar Island disposal area would have ample capacity to accommodate any volume of tailings which could not be deposited in the mined-out pits. This assumed, however, that the tailings would have more or less normal characteristics

and clarified water would be available for recirculation through the separation cells. This disposal area has inherent advantages that future open pit projects in the area will never be able to match. It is close to the plant, the topography is favourable, and the volume of oil locked-in by the disposal system is minimal as is also the environmental impact.

The original designs contemplated that all tailings containing dikes would be built of waste overburden materials to be stripped from the mining area. It was considered that the Tar Island disposal area would need to accommodate the tailings during the first three years of the plant operations after which disposal would be in mined-out areas. The original design to meet this requirement provided for a dike around the outer perimeter of Tar Island only 40 feet high with tailings discharge to be from the top of the valley escarpment on the west side of the disposal area, and assuming that the sand fraction would take a slope of about 8 percent.

Construction of the dike on Tar Island to this design was commenced in 1966, but also at this time concerns were being voiced that based on the results of the pilot plant operation the solids fraction of the deposited tailings would be quite unstable because of the loose density state of the sand fraction and the large percentage of the silt-clay component trapped in the sand. They also indicated that the slope assumed by the sand fraction would be less than the 8 percent assumed in the original design, and that the clarification characteristics of the tailings pond effluent would be very poor.

Also early in 1966 the mine operating staff came on the scene. They became concerned with the shortness of the period for which the initial Tar Island storage area was to be used, the tightness of the design, and the confidence level that could be assigned to any bulking factor that might be assumed for the plant operation short of complete storage of the total tailings streams. The design of the Tar Island dike was therefore modified to provide a base width for an ultimate height of 75 feet. The redesign provided for the construction of a starter dike on this base with extension of the construction being in stages as overburden from the mine stripping operation became available, and at a rate that would keep the crest elevation ahead of the rise in tailings pond level.

The plant went into operation in the spring of 1967 and the initial operations confirmed that indeed

the sand tailings fraction did settle out to a very unstable mass. The 8 percent slope assumed for the deposited sand fraction was not achieved, and because of difficulties in arriving at an overall balanced operation tailings water was accumulating faster than the Tar Island dike could be raised to keep ahead of the water level in the pond. Moreover, the cost of building the Tar Island dike using overburden materials was turning out to be much greater than had originally been estimated, and if the full capacity of the Tar Island disposal area was to be developed the logistics of the overall mining plan were such that sufficient overburden to build the dike to the ultimate height required could not be produced.

The most attractive of the many solutions considered for these problems was one advanced by Mannix Co. Ltd., the General Contractors who had a contract for overburden stripping and construction of the Tar Island dike. With advice from an experienced dredging operator, Mr. G. E. Jones of Vancouver, they proposed to build the Tar Island dike of sand tailings by hydraulic placement followed by conventional compaction. The main barrier to this procedure was the experience that the sand tailings fraction as deposited was too unstable to work equipment on it, or for that matter to even walk on it.

A test section operation conducted in September, 1967, showed that these concepts could be met. It proved possible to work a D-6 caterpillar tractor on the sand immediately after deposition. The design of the Tar Island dike was immediately modified and construction continued using the sand tailings fraction for the dike embankment and with hydraulic placement procedure working to an ultimate design crest elevation of 1000, (maximum height of dike of 220 feet).

Inasmuch as the temperature of the tailings streams is about 140° F, it should be possible to conduct the dike building operation on a year round basis if necessary. This was successfully done during the winter of 1967-68. The main difficulty that developed with the winter operation was with dense fog at low air temperatures. This created a safety hazard. Dike building was discontinued in subsequent winters because the materials balance in the overall operation did not require winter dike construction. With current winter operations the total tailings stream is "over-boarded" directly from the dike into the tailings pond.

The design elevation of 1000 for the dike was successfully reached at the end of the 1973 construction season. During the winter of 1973-74 for the first time tailings were deposited in a worked-out area of the mine. Sludge from the Tar Island tailings pond was pumped to an area of the pit diked off with a dike built of overburden material to a maximum height of 150 feet. The mine engineering staff, not unexpectedly, would like to extend the Tar Island tailings dike to a crest elevation of 1100, giving a maximum height of 320 feet. Consideration is currently being given to this in the light of the performance of the dike to date as indicated from piezometer records, seepage flows recorded, in situ permeabilities and stability characteristics of the embankment completed to date.

The precise costs of tailings disposal with the current G.C.O.S. procedures are considered to be proprietary information. The unit cost for the structural portion of the Tar Island dike is much less than the costs for dike built of overburden. Indeed they are currently less than were included in the original cost estimates made in the planning stage. Currently the cost of tailings disposal on a ton basis for the G.C.O.S. operation is amongst the lowest of any mining operation in the western world.

Tailings Dike Designs

Turning now, at long last, to the design of the tailings dikes from the soil mechanics point of view, it will be clear from the above discussion that the designer will have several important constraints imposed on him by the logistics of the particular mining and tailings disposal operation that do not usually exist in ordinary dam design. At the G.C.O.S. project the design and construction of the dikes built of overburden materials are largely conventional. The major exceptions are that the overburden materials must be accepted as they are delivered from the stripping operations, and the designer does not have the luxury of compaction under controlled moisture contents. The overburden materials are generally highly impervious so that seepage control can be accomplished by judicious zoning of the materials as received to insure that there is a general decrease in permeability towards the downstream face.

The foundation conditions in the worked out areas of the mine are excellent. For the in-pit dikes average slopes of 2.5:1 both upstream and downstream have been used, but with some materials this has been flattened by toe berms. Slope protection where required has been lean tar sand.

The design of the Tar Island dike, however, has been somewhat more difficult. The foundation conditions are not good, and for a stretch of 2500 feet in the total length of about 12,000 feet for the dike the foundation includes a muskeg surface mantle some 10 feet thick. The conditions are such that irrespective of whether the dike is to be built of overburden materials or sand tailings, stage construction is required to accommodate the foundation conditions.

The hydraulic fill dike was built on top of the overburden dike completed as of September, 1967. The availability of sand tailings did not permit the design of a dike that would act structurally independent of the tailings in the pond. The downstream portion was therefore designed as an outer shell capable of resisting the forces tending to "burst" it out, with these forces originating as hydraulic water pressure from the tailings pond plus the earth pressure from the uncompacted sand against the upstream side of the shell. This design concept, of course, is not new. The standard practice during the period some 50 to 75 years ago when hydraulic fill dams were quite commonly built used the outer shell concept in stability considerations.

As first planned all sand downstream of a center line through the crest with an ultimate height of dike of 200 feet was to be compacted. The availability of sand required some modification of this procedure, and in fact the upper portion of the dike overlaps uncompacted sand so that a shell sloping upstream exists at the upper levels. The dike has been built to an average overall slope of 3:1 for the downstream face with horizontal berms at about 45 feet vertical intervals. In the section of muskeg foundation the dike has been built on top of the muskeg, but the downstream slope has been flattened to an average slope of 4:1. Downstream slope protection is lean tar sand up to the elevation where direct attack from the river is possible. Above this elevation seeding of the slope has been experimented with and is being successfully used.

The tailings sand, of course, is relatively pervious. The test information available at the time of the original designs was that its permeability would be of the order of one foot per day. The seepage forces in the shell, of course, are an important element in its design for stability. Two sets of conditions must be recognized. First, during the period of construction when the hydraulic placement procedure will establish a water table at the elevation of the cells being worked, and second, the ultimate condition where the phreatic line will be governed by seepage from the tailings pond.

The seepage forces originally were analysed by flow nets assuming a ratio of horizontal to vertical permeability of 4.0.

Sand embankments are relatively pervious and require downstream drainage control. The original plan was to use a downstream facing of coarse sand inside the slope protection. This was used during the first construction year, but was abandoned because of poor performance resulting from variations in grading of the sand. The design was modified to provide for internal horizontal drainage beds averaging four feet in thickness and 100 feet wide, and running the full length of the dike. Two such drainage beds have been built to-date. By coincidence it was found that the end product coke from the refinery had an ideal grading to act as a filter in contact with the sand tailings. It, therefore, has been used for the construction of both internal drainage beds. The internal drains are preferable to downstream face drainage from the stability point of view.

Crucial to the stability conditions of McMurray tar sands as deposited in disposal areas is the question of the liquefaction characteristics of the sands in the various density states at which they may exist in a compacted structural shell and below tailings ponds. The particle size band shown on Figure 1 is close to the band for fine uniform sands known to be highly susceptible to liquefaction if in a loose density state. It is beyond the scope of this review to go into the details of our studies concerning this stability factor. However in terms of relative density concepts we have estimated that the hazard of liquefaction is slight if the relative density exceeds about 30 percent. In theory this means that under ultimate density conditions in a disposal area the sand is unlikely to liquefy if its void ratio is less than about 0.79. Our field tests have shown that in the dike shell the sluicing procedure alone give a relative density of about 50 percent, and that the compaction procedures used will produce a relative density of 70 to 75 percent. On the beach above the pond level a relative density of about 40 percent is achieved by the sluicing, and only material deposited in low velocity flow below the pond level is likely to have a relative density as low as 30 percent.

Once the dike is completed to its ultimate crest level and final equilibrium pore pressures become established we consider there will be no hazard from liquefaction. The immediate hazard arises from too rapid a rate of loading where the structural shell is built on top of pond beach material. Rapid loading can generate consolidation pore pressures.

Monitoring of the sand tailings dike performance has been continuous since its construction was started in 1967. The monitoring has been by piezometers, periodic measurements of the flows from the drains, and daily density readings on the compacted shell while it was being built. A total of about 75 piezometers have been installed to date, and many hundreds of density readings have been taken.

Approval to construct the sand tailings dike was requested and given in four stages, first for a height of dike of 35 feet, and subsequently to heights of 80, 155 and 220 feet. In each case before deciding to go higher the general performance of the dike and the monitoring results were reviewed.

6. Synchrude Tailings Disposal Plans

Synchrude are planning to use hydraulic procedures for tailings disposal similar to what has been done at G.C.O.S. The conditions, however, will differ considerably from those at the G.C.O.S. project. Synchrude will be a bigger operation and approximately double the yardage of tailings will need to be handled daily as compared to the G.C.O.S. project. Similar problems with bulking as developed at G.C.O.S. will be encountered. Whether they will be more or less severe than at G.C.O.S. will not be known until operating experience is acquired.

Tailings disposal in the river valley will not be practicable at Synchrude. An initial tailings disposal area of some 9 square miles located on the

plateau adjacent to the plant and mine area is planned. This is an initial disposal area planned to take tailings for about the first 6 years of operation. Subsequently the tailings will be deposited into the worked out mine areas, but the water and sludge components will be pumped into the initial disposal area. Clarified water will be recirculated back to the plant from the initial disposal area.

Because of variation in surface relief in the initial disposal area a more complicated set of starter dikes built of overburden materials will be required than at G.C.O.S. After the plant is in operation economy of dike construction will dictate the use of tailings sand for dike construction just as at G.C.O.S.

The Syncrude mining plan involves selective mining and overburden and reject tar sand will be stacked in the bottom of mine workings continuously as the ore is being excavated. Eventually containing dikes of either tailings sand or overburden and reject materials will need to be built on this stacked material as a foundation.

The flexibility in the Syncrude plans comes from the fact that, while the ultimate crest level of the perimeter dikes for the initial disposal area will only average about 70 feet above the plateau level, the height could be increased substantially if required by unfavourable bulking factors providing it is done before deposition of tailings into the worked out mine area is commenced.

General Solution to Problems of Hydraulic Disposal

A great deal of research work has been directed to the improvement of the sludge settlement characteristics in the tailings pond. The various approaches have been outlined in (G.C.O.S. 1972a). Solutions are available but only at great cost. The capital costs of any viable solution will be in the order of hundreds of millions of dollars for a single project.

Acknowledgments

The experience and data upon which this paper is based has been acquired by the writer over the past twelve years while acting as consultant on special geo-technical problems. First to Cities Service Athabasca Inc. which subsequently became Syncrude Canada Limited, to Great Canadian Oil Sands Limited and to Canadian Bechtel Limited under their design contracts for both the G.C.O.S. and Syncrude projects. The co-operation of the managements and many individuals in these organizations is gratefully acknowledged.

References

- Allan, A.R. (1974): Coping With the Oil Sands; American Chemical Society 167 National Conference, April, 1974.
- Carrigy, M.A. and Kramers, J.W. (1974): Geology of the Alberta Oil Sands; this Conference.

- G.C.O.S. (1972): Application to Amend Approval No. 540 with Respect to Tailings Disposal; Submission to Energy Resources Conservation Board of Alberta by Great Canadian Oil Sands Limited, July 20, 1972.
- G.C.O.S. (1972a): Addendum to Application No. 6527; Submission to Energy Resources Conservation Board of Alberta by Great Canadian Oil Sands Limited, September 22, 1972.
- Hardy, R.M. and Hemstock, R.A. (1963): Shearing Strength Characteristics of Athabasca Oil Sands; Information Series No. 45, Research Council of Alberta, p 109-122.

Appendix VII. Pollution Control Cost Estimates

In Section 6 in the main body of the report, estimates are given of the cost of environmental control facilities for a hypothetical 100,000-barrel-per-day tar sand project of the Syncrude type. These are summarized in Table 6-3 of the main report. This appendix gives some details on how these estimates were prepared.

VII-1. Electrostatic Precipitator on Carbon Monoxide Boilers

Supple and Raschid (1977) present data on electrostatic precipitator tests of the fly ash from combustion of GCOS coke. From their figure No. 8, one can see that the value of the "drift velocity" (w) varies from 0.2 to 0.4 feet per second. The required efficiency for a new installation is estimated at 99 percent by weight recovery of the particles. Given these two pieces of information, one may apply the well-known Deutsch-Anderson equation and solve for the required area of collector plates per unit of gas flow rate. The result is

$$\frac{A}{Q} = \frac{-1}{w} \ln (1-\eta) = \frac{-1}{0.3 \text{ ft/sec}} \ln (0.01) = \frac{15.35 \text{ ft}^2}{\text{ft}^3/\text{sec}} = \frac{0.255 \text{ ft}^3}{\text{ft}^3/\text{min}}$$

To estimate the volumetric flow rate of gas going to the carbon monoxide boiler, we may use values from the Syncrude project which indicate that the coke production is 22 percent of the feed hydrocarbon, and approximately 29 percent of the coke is burned in the coke burner. From this we may compute:

$$\text{Feed HC} = 100,000 \frac{\text{B}}{\text{D}} \times 350 \frac{\text{lb}}{\text{B}} \times \frac{1}{0.78} = 4.48 \times 10^7 \frac{\text{lb}}{\text{D}}$$

$$\text{Coke Burned} = 4.48 \times 10^7 \frac{\text{lb}}{\text{D}} \times 0.22 \times 0.29 = 2.86 \times 10^6 \frac{\text{lb}}{\text{day}}$$

If all of this carbon burned were to leave the regenerator in the form of CO (an assumption which leads to the largest possible precipitator), the

flow rate of CO would be

$$2.86 \times 10^6 \frac{\text{lb}}{\text{day}} \times \frac{1 \text{bmols}}{12.1 \text{lb}} = 2.38 \times 10^5 \frac{\text{bmols}}{\text{day}} .$$

If all the oxygen in the regenerator air were converted to CO (i.e., none to CO₂ nor water), the percent CO in the gas leaving the regenerator would be 35 percent so that the molar flow rate to the precipitator would be

$$2.38 \times 10^5 \frac{\text{bmols}}{\text{day}} \times \frac{1}{0.35} = 6.80 \times 10^5 \frac{\text{bmols}}{\text{day}} .$$

The temperature of the gas leaving the regenerator should be the same as that of the coke leaving it; i.e., about 1000°F. Its pressure should be atmospheric so that the density of the gas should be one lbmole per 1065 ft³. Hence the flowrate to the precipitator should be

$$6.8 \times 10^5 \frac{\text{bmols}}{\text{day}} \times \frac{1065 \text{ ft}^3}{1 \text{bmol}} \times \frac{\text{day}}{1440 \text{ min}} = 5.03 \times 10^5 \frac{\text{ft}^3}{\text{min}}$$

Applying the previous result for the required area, we compute that the required area is

$$A = \frac{0.255 \text{ ft}^2}{\text{ft}^3/\text{min}} \times 5.03 \times 10^5 \frac{\text{ft}^3}{\text{min}} = 1.28 \times 10^5 \text{ ft}^2 .$$

Neveril et al. (1978) present estimating curves for the cost of a precipitator as a function of plate area. For this size precipitator (insulated), one would compute a capital cost of \$0.7 x 10⁶. Typically, installed values of precipitators are of the order of three times the purchase price; hence the cost estimate is roughly \$2.1 million for the precipitator, installed.

VII-2. Claus Plant and Tail Gas Clean Up

Goforth (1978) shows that the sulfur passing from the Claus plant of Syncrude facility to storage is approximately 945 tons per day.

Berlie et al. (1976) estimated the cost of a 1,000-ton-per-day Claus plant for use in tar sands operations at \$5 million for the basic plant,

but \$16 million if one included all of the auxiliaries including the incinerator. Furthermore, they estimated the tail gas clean-up plant at \$6 million. If one installs the tail gas clean-up facility with the Claus plant, there will be some overall savings because of commonality of facilities. Thus the estimated cost of a combined Claus plant and tail gas clean-up plant is roughly \$20 million.

VII-3. Tall Stack

The Syncrude stack is 600 feet tall. The cost of a reinforced concrete chimney with 24-ft diameter insulated steel liner was estimated from a curve supplied to the author by Milton W. Russon of the Utah Power and Light Company. This curve in turn was supplied to them by the Bechtel Corporation, based on quotes on recent years from the M. W. Kellogg Company from New York, who are the principal U. S. constructor of such stacks. For such a stack, they indicated that at the 600-ft level, the cost is roughly \$3.5 million in 1977 dollars, which has been arbitrarily scaled up to \$4 million for the estimates shown previously.

VII-4. Amine Plant Costs

Bachman and Stormont (1967) show that for the original GCOS installation, the hydrogen plant capacity was 60 million ft^3 per day and that the off-gas from the coker was 20 million ft^3 per day. They provide no estimate for the flow rate of gas from the hydrotreaters to the amine treating plant. This should be significantly less than the hydrogen plant production rate because some of the hydrogen is chemically bonded into the liquid products. Therefore, the author has arbitrarily assumed that the flow rate of gas from the hydrogenation plants to the amine treating plant is 50 percent of the feed rate to the amine treating plant. Thus the estimated combined flow rate of gases to the amine treating plant is 50 million ft^3 per day. This is for a design production capacity of 45,000 barrels per day. If

we scale this up to 100,000 barrels per day, we would estimate approximately $1.1 \times 10^8 \text{ ft}^3$ per day. However, given the roughness of the above estimating procedure, this has been rounded to 100 million ft^3 per day.

Booz Allen (1975) reported that the cost of an amine treating plant (1974 prices) was roughly $\$130/(\text{ft}^3 \text{ per day})$. If, as stated above, the flow rate of gases going to the plant is 10^8 ft^3 per day, then the investment in 1974 dollars would be \$13 million. Using the *Chemical Engineering* cost indexes for December, 1977, and for 1974, we may estimate that the cost of the amine treater would be roughly \$17 million at 1978 prices.

VII-5. Wastewater Treatment Costs

The treatment of domestic-type wastewaters is usually accomplished by primary treatment (removal of that which floats and sinks) followed by secondary treatment (biological oxidation). Approximate costs for such plants (primary and secondary) in Utah are presently;

$$\text{Cost} = \$2.4 \times 10^6 Q^{0.8}$$

in which, Q is the flow in million gallons per day. For a 50,000-barrel-per-day tar sand operation, a one-million-gallon-per-day (mgd) wastewater treatment plant (about 5000-person equivalent load) is necessary (Imperial Oil, 1978b). This translates to a capital cost of about \$4.2 million for a 100,000-barrel-per-day project.

The treatment of oil-field and refinery wastes is usually accomplished by physical methods (gravity separators, air flotation, evaporation), chemical methods (coagulation-sedimentation, chemical flotation), and biological methods (activated sludge, trickling filters, oxidation ponds) (Nemerow, 1978). This treatment is very similar to that for domestic wastewaters as detailed above.

With the addition of a two-stage API oil separator, it is therefore expected that a capital cost estimate of \$4.2 million for a 100,000 barrel-per-day project is reasonably accurate.

The costs of other possibly needed water-disposal facilities (aquifer reinjection wells, storm-water retention basins, diversion structures) would be in addition to the figures quoted.

VII-6. Waste Sand Disposal

Capital cost estimates for a tailings pond to serve the needs of a 100,000-barrel-per-day operation are defined as the construction costs for the starter dike around the perimeter of the tailings pond as described in Figure VII-6. This total dike is designed to confine the tailings to be produced during the first seven or eight years of operation.

The configuration of the pond may vary to provide the volume of storage space required. Variables include the topography of the land and the amount of land area available. The volume of storage required will depend upon the production rate of tailings as well as the characteristics of the solids in the tailings.

The land area available for the GCOS operation was limited, and the tailings pond for that project occupied one square mile with an ultimate dike height of 220'+. The Syncrude operation which more nearly fits the size of operation specified for this study selected a dike height of 75 feet and a 9-mi² area for the tailings pond.

While some details of the design of the dike for these projects were made public, construction costs were considered proprietary information.

The elements of cost for the starter dike include excavation of material, transporting the material to the site, and compacting the material into the dike according to specifications. Excavation and compacting costs are traditionally included in a bid price per cubic yard with the haul distance varying with each project.

FIGURE VII-6. Typical section through a dike. It is constructed of overburden forming a starter dike upon which hydraulic fill is placed to build the dike up to a desired total height. The magnitude of h for the starter dike is determined as a result of careful consideration of the following: the nature of the foundation beneath the starter dike, the nature of the tailings, and the management decision as to the factor of safety to be employed.

A conservative estimate of 40 feet was selected to form the basis of this estimate. It should be noted that costs per unit length of dike will vary directly with the selected value of h , and the total cost would vary directly with h and the length of the dike.

Average prices are available from the construction industry since the construction of highways and earth-filled dams utilize similar materials, methods, and equipment.

Mr. B. W. Murdock of the Design Section of the U. S. Bureau of Reclamation described current cost estimates for earthwork in earth-filled dams as \$2.13 per cubic yard. These are 1978 prices for projects with a haul distance of less than one mile.

The Utah Department of Transportation released the abstract of bids in November of 1978 for a roadway earthwork project involving 15 million cubic yards of earthwork, a quantity that is similar to that volume required for dike building. Transportation cost for this work was estimated as \$0.09 per yard mile with approximately \$0.16 per cubic yard to construct a haul road over difficult terrain.

A conservative estimate for typical earthwork for a large dike project would be \$2.13 for excavation and placing; \$0.09 per yard mile for some estimated maximum of ten miles for \$0.90 per cubic yard and \$0.16 for haul road construction for a total of \$3.19 per cubic yard placed in the dike.

Based on this unit cost estimate, the total cost for a 12-mile dike, as required to form the perimeter of a nine-square-mile tract, would be as follows:

$$\text{Section area (see Figure VII-6)} = (40 \times 120) + (20 \times 46) = 5600 \text{ ft}^2$$

$$\text{Volume per linear foot of dike} = \frac{5600 \text{ ft}^2 \times 1 \text{ ft}}{27 \text{ ft}^3/\text{yd}^3} = 207 \text{ yd}^3/\text{lin. ft.}$$

$$\text{Cost per linear foot} = \$3.19/\text{yd}^3 \times 207 \text{ yd}^3/\text{lin. ft.} = \$660/\text{lin. ft.}$$

$$\text{Cost per mile of dike} = \$660/\text{lin. ft.} \times 5280 \text{ ft/mile} = \$3.48 \text{ million.}$$

$$\text{Estimating cost figure} = \$3.5 \text{ million/mile.}$$

For a 12-mile dike serving the project as described, the estimated total cost would be 12 miles @ \$3.5 million/mile for \$42 million.

A conservative estimate attempting to account for the worst reasonable contingency due to unforeseen problems would increase this estimate by 50% for a value of \$63 million for advance planning purposes.

Appendix VIII - The Alsands Cost Estimates

As described in Section 6, Alsands published a cost breakdown for their project (Alsands 1979(a)) after this report was substantially finished. The values in it are in substantial agreement with those in this report. Their cost breakdown for a 140,000 B/D project is reproduced here.

I. SUMMARY - ESTIMATED INITIAL CAPITAL COST (\$MID-1978)

DIRECT FIELD COST

Mining	\$ 415 MM
Extraction	155
Upgrading	565
Utilities	180
Onsite-offsites	365

Indirect Field Cost, Contractor Home Office and Fee and Contingency	1,240
--	-------

TOTAL CONSTRUCTION COST	2,920
-------------------------	-------

Owner Preproduction	480
---------------------	-----

TOTAL INITIAL PROJECT CAPITAL COST	<u>\$3,400</u>
------------------------------------	----------------

Notes

1. The above does not include costs associated with the infrastructure.
2. Direct field costs include labour at base rate, material at delivered cost and subcontracts at billed cost.

3. Indirect field costs include field staff, field staff overhead, craft benefits, payroll burdens, temporary construction facilities, small tools, equipment rental, camps and preassembly yards.

II ESTIMATED POST START-UP CAPITAL (\$MID-1978)

MINING	
(Primarily Conveyors)	\$ 120 MM
UPGRADING	
(Coke Gasification)	245
	<hr/>
TOTAL POST START-UP CAPITAL COST	\$ 365 MM

Note

1. The above costs include direct labour, material and subcontracts, indirect field, contractor home office and fees and contingency.

III DETAILED DIRECT FIELD COST BREAKDOWN (\$MID-1978)

MINING		
Draglines	\$ 116.8 MM	
Reclaiming	79.6	
Material Transfer	70.6	
(conveyors and stacker)		
Mobile Equipment	26.6	
Muskeg Removal	15.3	
Dewatering	3.1	
Tailings Disposal	90.0	
Other	12.1	
(Mine Roads, Interconnecting Utilities)		
	<hr/>	
SUBTOTAL	\$ 414.2 MM	\$415 MM

EXTRACTION

Extraction Feed System	\$ 41.2	
Extraction	69.2	
Froth Treatment	44.2	
	<hr/>	
SUBTOTAL	\$ 154.6 MM	\$155 MM

UPGRADING

Diluent Recovery	\$ 35.7 MM	
Fluid Coking, Gas Recovery and Coke Handling	190.0	
Hydrotreating	144.1	
Hydrogen Synthesis (Oil Gasification)	141.9	
Gas Treating	23.2	
(Amine and Sour Water Stripper)		
Sulphur Recovery	28.8	
	<hr/>	
SUBTOTAL	\$ 563.8 MM	\$565 MM

UTILITIES

Power Generation	\$ 130.8 MM	
Water Treatment	21.5	
Cooling Water System	6.3	
Other (Fuel System including Storage, Air Systems)	21.9	
	<hr/>	
SUBTOTAL	\$ 180.5 MM	\$180 MM

ONSITE-OFFSITES

Includes relief and blowdown systems, flares, tankage, inter-connecting piping, electrical distribution facilities, raw and cooling water distribution systems, recycle water facilities, fire protection facilities, nitrogen generation, sewers, sewage treatment, ponds, separators, site preparation and roads, buildings and related facilities, ash handling facilities and miscellaneous onsite-offsites.

\$ 365 MM

TOTAL DIRECT FIELD COST

\$1680 MMIV ESTIMATED OPERATING COSTS (\$MID-1978)

Wages and Salaries

\$ 145 MM

- includes wages (\$10 per hour) and salaries of all operating, maintenance, engineering, supervision and clerical personnel at the Plant Site.
- associated burden and allowances for recruiting, training, transfers and transportation.
- turnaround costs.

Maintenance Materials and Supplies	55
Operating Materials and Supplies	18
Chemicals and Catalysts	14
Property Tax and Insurance	22
Reclamation and Revegetation	2

Corporate Overhead	19
--------------------	----

- includes salaries of all management, staff and clerical personnel not located at the Plant site.
- associated burden and allowances for recruiting, training and transfers.
- office costs

TOTAL

\$ 275 MM

Note

1. Add \$7.5 MM beginning in 1993 for the operation of coke gasification facilities.