COO/4043-1

ANALYSIS OF THE ENVIRONMENTAL CONTROL
TECHNOLOGY FOR OIL SHALE DEVELOPMENT

By
Noel de Nevers
David Eckhoff
Stephen Swanson
Bard Glenne
Fred Wagner

February 1978

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

College of Engineering
University of Utah
Salt Lake City, Utah

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

TECHNICAL INFORMATION CENTER
UNITED STATES 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.

NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Department of Energy, nor any of their employees, nor any of their contractors, subcontractors, or 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.

This report has been reproduced directly from the best available copy.

Available from the National Technical Information Service, U. S. Department of Commerce, Springfield, Virginia 22161.

Price: Paper Copy \$11.75
Microfiche \$3.00

ANALYSIS OF THE ENVIRONMENTAL CONTROL TECHNOLOGY
FOR OIL SHALE DEVELOPMENT

Noel de Mevers, Professor of Chemical Engineering
David Eckhoff, Associate Professor of Civil Engineering
Stephen Swanson, Research Associate Professor of Mechanical
and Industrial Engineering
Bard Glenne, Associate Professor of Civil Engineering
Fred Wagner, Associate Professor of Mechanical and Industrial
Engineering

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

NOTICE
This report was prepared as an account of work
sponsored by the United States Government. Neither the
United States nor the United States Department of
Energy, nor any of their employees, nor any of their
contractors, subcontractors, or 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.

February 1978

Prepared for
The U. S. Department of Energy
Under Contract No. EY-76-S-02-4043

ed
DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

TABLE OF CONTENTS

	Page
SUMMARY	1
 I. INTRODUCTION	 3
I-A. The Oil Shale Resource and Its Potential Exploitation	 3
I-B. Some History of Oil Shale Exploitation, and A Description of the Projects Currently in Progress	 4
I-C. Environmental Constraints	17
I-C-1. The Scope and Goals of this Study	18
I-C-2. General Kinds of Environmental Problems	22
I-D. Proposed Environmental Control Strategies	25
I-D-1. Air Pollution	25
I-D-2. Water Pollution	26
I-D-3. Processed Shale Disposal	26
I-E. Environmental Control Difficulties and Questions	27
II. ENVIRONMENTAL CONSTRAINTS	29
II-A. Air Pollution	30
II-A-1. Air Quality Standards	32
II-A-2. The Role of Modeling	36
II-A-3. Emissions Standards	39
II-A-4. Non-Deterioration	40
II-B. Water Pollution	45
II-B-1. Regulatory and Statutory Factors-- Water Pollution	 45
II-B-1-a. EPA's Strategy	46
II-B-1-b. Water Planning Programs	49

II-B-1-c. The Discharge Permit Program	50
II-B-1-d. Water Quality Criteria and Standards	51
II-B-2. Utah Regulations	53
II-B-3. Colorado Regulations	56
II-B-3-a. Colorado Water Control Act	56
II-B-3-b. Colorado Water Quality Control Commission	56
II-B-4. Other Water Constraints	56
II-B-5. Summary of Water Pollution Constraints	59
II-C. Solid Waste Disposal	61
II-C-1. Environmental Threats	62
II-C-2. Wastes to be Dealt With	63
II-C-3. Lease Stipulation Constraints	64
II-C-4. Federal Laws and Regulations	65
II-C-5. Utah Regulations	69
II-C-6. Colorado Regulations	70
II-C-7. Summary of Solid Waste Disposal Regulations	72
II-D. Other Environmental Constraints	73
III. PROPOSED ENVIRONMENTAL CONTROL TECHNOLOGIES	75
III-A. Overall Process Scheme — Surface Retorting	76
III-B. Overall Process Scheme — In-Situ Retorting	81
III-C. Technology Transfer	84
III-D. Air Pollution Control Technology	88
III-D-1. Control of Particulates	96
III-D-2. Reactions and Compounds of Sulfur and Nitrogen	98
III-D-3. Control of Sulfur Oxides	102

III-D-4.	Control of Nitrogen Oxides	109
III-D-5.	The Chemistry and Control of Hydrocarbons and Carbon Monoxide	112
III-E.	Water Pollution Control Technology	113
III-E-1.	Overview of Water Control Technology	113
III-E-2.	Water Use and Quality	114
III-E-3.	Aquifer ReInjection	116
III-E-4.	Surface Runoff Diversion	120
III-E-5.	Wetting of Spent Oil Shale	121
III-E-6.	Containment and Evaporation (Zero Release Concept)	123
III-F.	Solid Waste Disposal and Management	128
III-F-1.	Disposal Site Selection and Preparation	129
III-F-2.	Transport of Wastes to Disposal Facility	133
III-F-3.	Construction of Disposal Pile	133
III-F-4.	Control of Surface Erosion	140
III-F-5.	Rehabilitation of the Disposal Facility	141
III-F-6.	Recycling and Reuse of Waste Oil Shale	142
III-F-7.	Underground Storage of Processed Shale	144
III-G.	Other Environmental Control Technologies	145
IV.	POTENTIAL PROBLEMS AND DIFFICULTIES WITH PROPOSED ENVIRONMENTAL CONTROL TECHNOLOGIES	147
IV-A.	Comparison of In-Situ and Surface Processing From an Environmental Viewpoint	147
IV-A-1.	Air Pollution	147
IV-A-2.	Water Quality	148
IV-A-3.	Surface Disposal of Waste	149
IV-B.	Proprietary Information	150
IV-C.	Potential Air Pollution Difficulties	151
IV-C-1.	Polynuclear Aromatics	152

IV-D.	Water Pollution	153
IV-D-1.	Aquifer ReInjection	154
IV-D-2.	Dam Safety	154
IV-D-3.	Evaporation Ponds	155
IV-D-4.	Burnt-Out In-Situ Retorts	156
IV-D-5.	Spent Shale Piles	158
V.	THE COST OF ENVIRONMENTAL CONTROL	160
V-A.	The Colony Cost Breakdown	160
V-B.	Mixed Costs	163
V-C.	Fraction of Plant Cost for Environmental Control.	164
VI.	RESEARCH NEEDS AND POLICY QUESTIONS CONCERNING THE ENVIRONMENTAL CONTROL TECHNOLOGY FOR OIL SHALE DEVELOPMENT.	167
V-A.	Research Problem; Utilization of Burnt In-Situ Retorts	169
V-B.	Removal of Hydrogen Sulfide From Gas Streams Containing Large Amounts of Carbon Dioxide	171
V-C.	Policy Questions Concerning Utilization of Crude Shale Oil	172
V-D.	Oil Retention by Processed Shale	174
V-E.	Cooperation Between Projects	175
V-F.	Extrapolation to a Mature Industry	178
	BIBLIOGRAPHY	180
APPENDIX I.	Oil Shale	A-I-1
APPENDIX II.	Oil-Shale Retorting Technology	A-II-1
APPENDIX III.	Particulate Control Technology	A-III-1
APPENDIX IV.	Removal of H ₂ S from Gases	A-IV-1
APPENDIX V.	Conversion of H ₂ S to Sulfur	A-V-1
APPENDIX VI.	Separation of H ₂ S and Ammonia	A-VI-1
APPENDIX VII.	The Non-deterioration Doctrine	A-VII-1
APPENDIX VIII.	Hydrology of Oil Shale Regions	A-VIII-1

TABLES

TABLE 1:	Results of Federal Prototype Lease Program Bidding	8
TABLE 2:	Status of Oil Shale Projects as of February, 1978.	14
TABLE 3:	Federal Ambient Air Quality Standards.	34-35
TABLE 4:	Significant Deterioration Limitations.	42-44
TABLE 5:	Raw Surface Water Criteria	57
TABLE 6:	Colorado Water Quality Standards Summary	58
TABLE 7:	Recommended Maximum Water Quality Constituent Concentrations	60
TABLE 8:	Particulate Control Technologies for Various Oil Shale Projects	89-90
TABLE 9:	Sulfur Control Technologies for the Various Oil Shale Projects	91-92
TABLE 10:	Nitrogen Control Technologies for the Various Oil Shale Projects	93
TABLE 11:	Hydrocarbon Control Technologies for the Various Oil Shale Projects	94
TABLE 12:	Carbon Monoxide Control Technologies for the Various Oil Shale Projects	95
TABLE 13:	Summary of Unit Process in Refinery Fuel-Gas Desulfurizing.	104-105
TABLE 14:	Greatest Observed Rainfalls, Grand Junction, Colo.	122
TABLE 15:	Mean Monthly Precipitation - Evaporation Data.	126
TABLE 16:	Characteristics of Processed Oil Shale	138
TABLE 17:	Breakdown of Investments for the Colony Project.	161
TABLE 18:	Breakdown of Operating Costs for the Colony Project.	162
TABLE I-1:	Minerals Analysis of Raw Shale	A-I-2,3
TABLE II-1:	Some Comparisons of Various Retorting Technologies	A-II-18
TABLE IV-1:	Estimated Gas Compositions for Various Retorting Schemes.	A-IV-8
TABLE V-1:	Design Data of Stretford Plant	A-V-21

FIGURES

FIGURE 1:	Location of Federal Prototype Lease Tracts	7
FIGURE 2:	Capital Cost Index for the Period 1967-77	9
FIGURE 3:	A Chronology of the Participants in the Colony Project and the Closely Related C-b Federal Prototype Lease	12
FIGURE 4:	Schematic View of the Air Pollution Problem	31
FIGURE 5:	Illustration of Two Different Approaches to Estimating the Ground Level (hillside) Concentration of Pollutant from a point source.	38
FIGURE 6:	Schematic View of an Oil Shale Operation Using Surface Retorting	77
FIGURE 7:	Schematic View of an In-situ Oil Shale Operation.	82
FIGURE 8:	The Oxidation and Reduction of Nitrogen and Sulfur.	100
FIGURE 9:	Sulfur Control Schematic.	107
FIGURE 10:	Water Flow in Oil Shale Projects.	115
FIGURE 11:	Schematic of Water Flow in Aquifer ReInjection.	119
FIGURE 12:	Types of Embankments to be Used for Processed Shale and Other Solid Waste Disposal.	130
FIGURE 13:	Schematic Illustration of the Phases in the Construction of a Waste Disposal Embankment	131
FIGURE 14:	Schematic of Processed Shale Disposal Pile Prior to Rehabilitation	132
FIGURE 15:	Three Modes of Embankment Failure	134
FIGURE I-1:	Extent of the Green River Formation in Colorado Utah and Wyoming.	A-I-4
FIGURE II-1:	Flow Diagram of TOSCO II Process.	A-II-4
FIGURE II-2:	Flow Diagram of Paraho Direct Process	A-II-6
FIGURE II-3:	Flow Diagram of Paraho Indirect Process	A-II-7
FIGURE II-4:	Flow Diagram of Union Type A Retort	A-II-9
FIGURE II-5:	Flow Diagram of Union Type B Retort	A-II-10

FIGURE II-6:	Detailed Diagram of Union Type B Retort	A-II-12
FIGURE II-7:	Flow Diagram of Superior's Multi-Mineral Process	A-II-14
FIGURE II-8:	Artist's Conception of Superior's Circular Grate Retort.	A-II-16
FIGURE II-9:	Cross Section of Superior's Circular Grate Retort.	A-II-17
FIGURE III-1:	Typical Commercial Cyclones	A-III-3
FIGURE III-2:	Typical Commercial Baghouse	A-III-4
FIGURE III-3:	Venturi Scrubber, Wet-approach Type	A-III-7
FIGURE III-4:	Typical Electrostatic Precipitator.	A-III-9
FIGURE IV-1:	Typical Flow Diagram for an Amine Scrubber Removing H_2S from "Sour Fuel Gases"	A-IV-3
FIGURE IV-2:	Typical Integration of Amine Treating Into an Oil-shale Processing Plant	A-IV-6
FIGURE V-1:	Theoretical Equilibrium Conversion of Hydrogen Sulfide to Sulfur Vapor	A-V-5
FIGURE V-2:	Schematic Flow Diagram of a Claus Plant	A-V-6
FIGURE V-3:	Effect of Vanadate Concentration on rate of Reaction	A-V-14
FIGURE V-4:	Rate of Reaction Versus pH for Conversion of Hydrosulfide to Sulfur.	A-V-15
FIGURE V-5:	Time of Reaction Versus Percent Conversion for Conversion of Hydrosulfide to Sulfur.	A-V-15
FIGURE V-6:	Effect of Temperature on Thiosulfate Formation	A-V-17
FIGURE V-7:	Effect of pH on Thiosulfate Formation	A-V-17
FIGURE V-8:	Typical Flow Diagram of Stretford Process	A-V-19
FIGURE VI-1:	Typical Flow Diagram of Waste Water Treatment (WWT) Process (84).	A-VI-3
FIGURE VII-1:	A Major Controversy in the Modeling	A-VII-9
FIGURE VII-2:	Light Scattering Effects of the Navajo Plume.	A-VII-11
FIGURE VII-3:	Cooling Tower Water Vapor Intersecting Inversion Plume	A-VII-12

FIGURE VII-4: The Public Controversy over the Kaiparowits Project	A-VII-18
FIGURE VII-5: Location of Oil Shale Deposits in Relation to Colorado and Dinosaur National Monuments.	A-VII-19
FIGURE VII-6: Upper Portion of Parachute Creek Canyon	A-VII-27
FIGURE VIII-1: Piceance Creek Hydrologic Basin	A-VIII-2
FIGURE VIII-2: Concentration of Dissolved-Solids in the Upper Aquifer	A-VIII-4
FIGURE VIII-3: Dissolved-solids Concentration in the Alluvial Aquifer	A-VIII-5
FIGURE VIII-4: Concentration of Dissolved-Solids in the Lower Aquifer	A-VIII-6

SUMMARY

This report examines the environmental control technology proposed in the various oil shale projects which are under development. The technologies for control of air pollution, water pollution, and for the disposal, stabilization, and vegetation of the processed shale 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 processed shale. However, based on the goal of producing an environmentally and aesthetically acceptable finished processed shale pile, it seems probable that this can be accomplished.

We conclude that the environmental control technology is available to meet all current legal requirements. This was not the case before Colorado changed their applicable Air Pollution regulations in August of 1977; the previous ones for the oil shale region were sufficiently stringent to have caused a problem for the current stage of oil shale development. Similarly, the federal air-quality, non-deterioration regulations could be interpreted in the future in ways which would be difficult for the oil shale industry to comply with. The Utah water-quality, non-deterioration regulations could also be a problem. Thus, the only specific regulations which may be a problem are the non-deterioration parts of air and water quality regulations.

However, the proposed projects are of minimal commercial size and if all of them were to proceed, the total production would be of the order of 200,000 barrels per day of petroleum, which is of the order of one percent of the current U. S. national petroleum consumption. Although with available

air pollution control equipment it will be possible to meet the non-deterioration regulations at this level of production, it seems doubtful that the industry could be expanded by an order of magnitude and still meet these regulations. Thus, a decision to expand to a full-scale industry (e.g., one million barrels/day) would require a regulatory or legislative decision to reclassify the oil shale region to a less-stringent non-deterioration classification.

During the period 1976-77 the proposed technology for oil shale development has switched strongly from surface processing to in-situ processing. The in-situ retorts may lead to problems of unwanted flow between aquifers and thus to ground-water contamination. The proponents believe that problem can be averted, but large scale demonstration has not taken place. Although in-situ processing has this potential problem, it eliminates the surface processed shale pile, minimizes the surface disturbance, and seems to have a simpler air pollution control problem than surface mining. Thus, on balance, it seems to be likely to have less environmental impact than surface retorting (or to be able to meet environmental regulations at lesser cost).

The unresolved areas of environmental concern with oil shale processing are mostly for the problems not covered by existing environmental law, e.g., trace metals, polynuclear organics, ground water-quality changes, etc. These may be problems, but no evidence is yet available that these problems will prevent the successful commercialization of oil shale production.

I. INTRODUCTION

1-A. The Oil Shale Resource and Its Potential Exploitation

The oil shale resource which is contained in the Green River Formation in western Colorado, eastern Utah, and southern Wyoming represents a potential liquid hydrocarbon source far larger than the known petroleum reserves of the United States. However, at no time in the past has this resource been commercially exploitable. In recent years the United States has recognized that it has a hydrocarbon supply shortage which is currently met by large-scale oil imports with consequent foreign-exchange and national-security difficulties. For this reason there has been renewed interest in the exploitation of the oil shales contained in the Green River Formation.

An oil shale is neither oil nor shale; it is rather a marlstone, which is a complex mixture of carbonates and silicates which contains within it a rubbery, organic material called "kerogen," which upon heating to about 900°F decomposes to form gas, oil, and a carbonaceous residue. The richest oil shales contain up to 35 or 40 gallons per ton of recoverable liquid hydrocarbons; the quality of the shale is variable with that containing less than ten gallons per ton currently being considered uneconomical to ever recover. There exists a substantial literature on the oil shale resource and its exploitation (1, 2, 3, 4, 5); it is assumed that most readers of this report have some knowledge of the oil shale potential or will look through that literature to gain further background. Appendix I gives a brief summary of background information.

The oil shale literature generally does not address the question of why it is economical (or thought to be economical) to produce liquid fuels from oil shale, which is a very dilute organic material source (typically less than 12 percent organic), instead of using abundant coal (which is typically up to 90 percent organic). The answer is that the hydrogen content of the crude "shale oil" is much higher (typically 10 percent by weight) than the hydrogen content of the organic material in coal (typically 4 percent by weight).

In order to produce liquid fuels which flow easily and behave properly in internal combustion engines, it is necessary to chemically bind enough hydrogen into the fuel to approximate the properties of the liquid hydrocarbons found in conventional petroleum. The oil fraction recovered from oil shale is already hydrogenated to nearly this composition. In order to achieve a comparable degree of hydrogenation starting with coal, one must practice heroic chemical engineering on a gigantic scale. This involves hydrogenation over catalysts at high temperatures and high pressures. It can obviously be done, but not inexpensively. Most groups which have studied the question conclude that, at least for now, it will be cheaper to start with the dilute organic material in shale, separate that organic material from the mineral residue, and go through mild processing steps to obtain liquid fuels than to start with the more concentrated organic material in coal and go through extreme and difficult processing steps in order to produce liquid fuels.

I-B. Some History of Oil Shale Exploitation, and A Description of the Projects Currently in Progress

We have known of the existence of the oil shale resource in the western U.S. since before the turn of the century. In 1930 the entire area was closed to oil shale mineral claims by executive order because it seemed clear that

everyone knew that the resource was there, and no true "discovery" in the sense of mineral-leasing law was possible. Since that time there has been continued controversy over ownership of the resource. Approximately 23 percent is in private hands where it occurs in areas where there were farms which were homesteaded or where mineral claims were prosecuted successfully before the federal closure. The remainder is in federal or state hands. Most of the best resource (in the sense of highest quality, greatest depth of resource, etc.) is in federally owned lands.

Several times in the past the federal government has initiated efforts to develop such oil shale for a national energy reserve; this occurred during both world wars and to some extent after the second one. There were strong feelings that this resource ought to be held for federal use as are, for example, the Naval Oil Reserves. Until the late 1960's, there was some pressure from industry to lease the existing federally owned land without any particular promise by the industry that they would exploit the resource promptly. The critics of the oil industry asserted that the oil industry was merely trying to control future resources and had no intention of current exploitation. The fact that the oil companies did acquire the privately owned oil shale reserves and did not exploit them lends some credence to this view. On the other hand, the oil companies took or asserted the view that since most of the resource belongs to the federal government, it was unreasonable to expect the oil companies to work out the technology which would then increase the value of the federally owned resource and make it more expensive for them to obtain later. This impasse was finally broken in the early 1970's when the program was initiated within the Department of the Interior to issue federal prototype leases. Those leases were to be large enough to support an operation which would demonstrate the technology on a commercial scale. Prompt exploitation was required. Six lease areas

were put up for competitive bidding, two each in the states of Colorado, Utah and Wyoming. The areas are shown on Figure 1 where they are labeled C-a, C-b, U-a, U-b, W-a, W-b, standing for Colorado, Wyoming, and Utah tracts a and b respectively. These were selected to represent a variety of types of deposit in which a variety of types of mining and processing would be feasible.

Although the process of preparing for the lease bidding was begun much earlier, the actual date of bidding was the spring of 1974 shortly after the Arab oil embargo and during the period of greatest excitement over the prospects of future oil embargoes. As a result, very large sums of money were bid for the tracts; the results of that bidding are shown in Table 1. As that table shows, no bids were received for the two Wyoming tracts. The first reason for this is that the bidding was sequential, with Colorado first, Utah second, Wyoming third; the companies most interested in acquiring reserves did so in the first two states. The second is that the companies believed that technologically the Wyoming tracts were more difficult and less promising than those in Utah and Colorado. The bonus bids listed in Table 1 were to be paid in five equal annual installments beginning with the first one upon receipt of the contract in the spring of 1974.

Since the bidding took place, the companies which won the contracts have all had bitter second thoughts about the projects. During the period between the acquisition of the contracts with the federal government and the time construction was to begin, the most rapid capital-cost inflation ever experienced in the U.S. occurred (Figure 2). This resulted in the projected prices of the processing plants doubling, and in some cases tripling, within a period of one to two years. The resulting values of the estimated facility costs were so high that all of the projects found it financially impossible to continue.

FIGURE 1. Location of Federal Prototype Lease Tracts (17)

TABLE 1

RESULTS OF FEDERAL PROTOTYPE LEASE PROGRAM BIDDING

Tract	Estimated recoverable reserves, billions of barrels	Winning bonus bid, millions of dollars	Successful bidders
C-a	1.32	210.3	Gulf, Std. Oil Ind.
C-b	1.72	117.8	Arco, TOSCO, Ashland, Shell
U-a	0.24	75.0	Sun, Phillips
U-b	0.27	45.1	Std. Oil Ohio, Sun, Phillips
W-a	0.25	--	--
W-b	0.25	--	--

FIGURE 2. Capital cost index for the period 1967-77, showing the rapid rise in the period 1973-1975 (112)

One may see how this increase in capital costs affects such a project by noting that some current estimates of the entire costs of such a project are approximately \$20,000 per barrel per day of installed capacity; e.g., a 50,000-barrel per day project would cost about a billion dollars. 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 of $(\$4000 \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 looks highly uneconomical. If the capital charge were only one-third as much, as it appeared to be at the time the lease bidding took place, then the capital charge would have been a much more manageable fraction of the world price of the product.

As permitted by the federal leases, all of the leaseholders have requested and received delays in the leases which allow them to delay the fourth payment and to delay work on the project. The delays granted have all been for one year ending September 1977; further extensions may occur.

Currently, some of the oil industry groups involved in the oil shale venture have taken the view that they will proceed with the projects only if they receive federal financial assistance. The type of assistance requested varies from company to company. Some request direct federal subsidies; others request fixed federal minimum shale oil prices above the world oil price; others request federal loan guarantees which will make it possible for them to acquire construction capital at a lower interest rate than they would have to pay for a speculative project of this type if it were not guaranteed by the federal government (6, 7). Two projects, however, (C-a and C-b) currently intent to proceed without such federal financial aid.

Oil shale projects have been hard on their sponsors. Generally, they are too large (typically requiring capital investments in the order of a billion dollars) for one company to fund them, so partnerships are formed. As the economic winds change and cost projections change, partners drop out and new ones are found. This is illustrated in Figure 3, which gives some of the history of the Colony Project and the project to exploit the C-b Federal Prototype Lease.

The Colony Project began in 1964 with TOSCO (The Oil Shale Company), a technology developer, Cleveland Cliffs Iron, a mining company, and Standard Oil of Ohio forming a joint venture for oil shale work and acquiring suitable privately owned rich oil shale lands. In 1969 ARCO (The Atlantic Richfield Company) joined the group. By the early 1970's they had decided to use a large, company-owned tract of rich oil shale land (the Dow West property) and were preparing detailed engineering designs for a 50,000-barrel per day project. At that point, the Federal Prototype Lease program was announced. TOSCO and ARCO were adequately satisfied with the economic prospects of both the Dow West property and of the C-b project to bid on the C-b with Ashland and Shell as additional partners. By this time, Cleveland Cliffs and Standard of Ohio had withdrawn from the Colony Project.

The ARCO-TOSCO-Shell-Ashland joint venture was the successful bidder for the C-b tract; at that point, Ashland and Shell were included (via buy-in options) into the Colony Project, making the participants in both projects the same. Then the giant upsurge in capital costs occurred, and the economics of the projects became less and less attractive. The federal prototype lease required annual payments of 23.6 million dollars. ARCO and TOSCO decided to cut their losses on C-b and to concentrate on the Dow West (Colony) property which they considered a better economic prospect, so they dropped out of C-b

FIGURE 3. A Chronology of the Participants in the Colony Project and the Closely Related C-b Federal Prototype Lease.

at the end of 1975. By the end of November, 1976, Shell decided to withdraw entirely from the oil shale business, letting its option on the Colony project expire and withdrawing from the C-b project. Ashland let its option on Colony expire to concentrate on finding a partner to continue with C-b.

They found one in Occidental, who had been one of the low bidders on C-b in the spring of 1974 (\$16 million vs. the winning bid of \$210 million). Occidental had been a major proponent of in-situ* processing and had conducted extensive pilot tests of its version of this process on privately owned land. They had been seeking partners with large, high-grade reserves for a commercial venture, so when Shell withdrew from C-b, Occidental joined with Ashland and converted the project to an in-situ one using their technology.

Thus, seven companies have been involved, of which four remain. The Colony project is dormant, and only two of the seven (Ashland and Occidental) now publicly state their intention to go ahead on a commercial project under current economic conditions.

Table 2 summarizes the status of the three Federal Prototype Leases, as well as the private projects which have been adequately discussed to report upon. The only one on the list whose sponsors currently (Winter 1978) say that they are planning rapid commercialization is the C-b project, which Occidental and Ashland are busily converting from an underground mining and surface retorting project to an in-situ project (8), which is scheduled for commercial scale production (57,000 B/D) by September 1983.

Rio Blanco (C-a) is moving fairly rapidly on a conversion of their original project from open-pit-mine and surface retort to in-situ with some

* The distinction between "conventional", "in-situ" and "modified in-situ" will be discussed in section III-A.

TABLE 2

STATUS OF OIL SHALE PROJECTS AS OF FEB. 1978

Name	Type	Participants	Status
C-b	Federal Prototype Tract C-b	Ashland-Occidental	Converting from above-ground to in-situ. Optimistic about prompt commercialization with private funds. (But lease payments are suspended).
Rio Blanco	Federal Prototype Tract C-a	Gulf, Std. Oil Ind.	Lease payments suspended, switching to in-situ plus surface retorting. Revised DDP submitted.
White River	Federal Prototype Tracts U-a, U-b	Sun, Phillips, Std. Oil Ohio	Dormant, lease payments suspended, in litigation over title to leases
Colony	Private	Arco, TOSCO	Dormant
Union	Private	Union Oil of California	Dormant
Superior	Private, seeking public support. Involves other minerals.	Superior Oil	Dormant - seeking federal land exchange.
Occidental Logan Wash	Private	Occidental	This was a testing program which is continuing to gather data while Occidental-Ashland gear up for C-b. Presumably it will shut down when that becomes commercial.
Geokinetics	ERDA technology demonstration.	Geokinetics-Aminoil ERDA	Active, on a small scale.

surface retorting. Their plan calls for test in-situ work to begin in the fall of 1977, and steady progress toward commercial operation (79,000 B/D) in the late 1980's.

White River (D-a, D-b) is currently in total suspension waiting for the outcome of some legal challenges to the federal government's title to the land in the lease tract (9).

Union Oil of California did a large-scale pilot operation on its process (which has since been modified) in the 1960's and has been interested in a commercial venture,(10) but there has been no concrete announcement of their intention to begin one.

Superior Oil is actively soliciting government cooperation (in the form of a land exchange) for a venture which will involve not only oil shale, but two other minerals (11). In the north end of the Piceance Basin, the lower parts of the oil shale deposit also contain Nahcolite (crude NaHCO_3) and Dawsonite ($\text{NaAl}(\text{OH})_2\text{CO}_3$). In some places, large, separately mineable veins of these minerals appear. In others these minerals are well mixed with the shale. Superior proposes to mine this mixed shale and process it to recover the shale oil, a crude nahcolite, soda ash and aluminum oxide. At present this is in the negotiating stage, but no firm commitments to proceed have been made by Superior.

Geokinetics and ERDA have signed a contract for a joint venture to develop Geokinetics' version of in-situ retorting, which is only applicable to shallow oil shale deposits (12). Field tests are proceeding in eastern Utah to demonstrate the commercial prospects of this process.

In parallel with the above projects and the Federal Prototype Leasing Project, there is a proposal in Congress (S 419, 95th Congress) which is being actively debated to have the federal government fund a prototype surface retort operation. This has received the active support of Union Oil Company and Paraho. Its purpose would be to erect one full-commercial-size retort or possibly several of different types and have their operations funded by the federal government.

The most significant change in the oil shale outlook in the past year and one-half, has been the switch in emphasis from mining and surface retorting to in-situ retorting. As the prototype lease program was originally conceived, all of the lease tracts were to have been for deep or strip mining and surface retorting. After the leases were let, a request was made and acted upon to begin a second lease offering with tracts specifically suitable for in-situ operation. A team was assembled to prepare the environmental impact statement for such a development; the environmental impact statement proceeded as far as a first draft. Then, as discussed above, the rapid increase in the cost of surface-processing facilities made the economics of surface processing much less attractive, which resulted in two of the three demonstration projects being converted from surface processing to in-situ (or in-situ combined with some surface processing). The basic reason for this conversion is that the in-situ processes, as currently envisaged, are much less capital intensive than processes involving mining and surface retorting.

With the conversion of two of the three surface-mining federal demonstration leases to in-situ projects, the interest in a subsequent lease offering for in-situ projects has greatly diminished, and that project within the Department of the Interior is currently dormant.

It should also be noted that all of the proposed projects now in planning call for gradual commercialization with some additional demonstration work to be done before the final overwhelming commitment of capital is made. Occidental and Ashland plan to have several test retorts burned before they make the final decision to go into commercial operation. Rio Blanco plans almost ten years of modular development before they will commit to full-scale production. Both Paraho and Union Oil call for the erection of one full-scale retort and its testing before a commercial operation takes place. Superior also indicates

its desire to begin a one-retort module, obtain all the necessary information, and then expand to full-scale production.

I-C. Environmental Constraints

These projects will all be large-scale mining, chemical processing, and waste disposal projects. In-situ projects involve less mining, surface retorting and waste disposal per unit of production than "conventional" projects. But even so they will mine and dispose of significant amounts of waste, and hence face the same constraints on a reduced scale. Most are located on federal land, and all would require the use of federally-owned land for pipeline, access corridor, etc. For this reason the three on federal land and the Colony project are required by the National Environmental Policy Act to complete extensive environmental impact studies. These have been completed at least as far as draft form; therefore, we can evaluate what they propose to do.

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

For air quality there exists a very detailed set of regulations describing what conditions these projects must meet. These are spelled out in Section II-A below. Similarly for water quality, there exist reasonably detailed constraints which are spelled out in Section II-B below. For the processed shale disposal and treatment (Section II-C below), which will be one of the most complex, difficult, and uncertain parts of the environmental constraints, there does not appear to be as clear, concrete, and straightforward a set of guidelines. The additional 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.

In addition to federal and state law, the oil shale projects which are proceeding in the federal prototype program will be obliged to meet the environmental constraints which are written into the federal prototype project lease agreements. In general, these restate the condition that the projects must meet federal and state air and water pollution law and in addition provide some constraints about processed shale revegetation, etc. These may prove to be more detailed guidelines for what must be accomplished than the ad hoc views discussed previously.

I-C-1. The Scope and Goals of this Study

The purpose of this study is to review in a comprehensive way the proposed environmental control technology for the three federal prototype projects (as well as the two others, where including them seems appropriate). The principal attention will be devoted to those technologies which are specifically intended for control of air pollutant emissions, water pollutant emissions, and for the containment, stabilization, and final disposal of the processed shale and raw shale mined for in-situ preparation.

An obvious problem facing the authors of this study is to make adequate use of the many, many previous studies on the same topic and still provide some original and useful results. Technically-trained readers of this report who would like to read a thorough, heavily documented summary of the whole environmental problem set associated with the nascent oil shale industry, should consult "A Preliminary Assessment of Environmental Impacts from Oil Shale Developments" prepared by TRW for the Industrial Environmental Research Laboratory of EPA (13). Although there are other good studies on the same topic (14, 15) this one is current and thoroughly reviews most of the others. If one wishes even more detail, one can consult the Detailed Development Plans (8, 16, 17, 18, 19) submitted by the proposed developers to the Department of the Interior, and the Final Colony Environmental Impact Statement (19).

Thus, one can easily bury himself in detailed statements of environmental impact and environmental control plans.

In this report we have assumed that the audience we are addressing is technically trained in some aspect of the oil shale environmental problem, but not in all aspects of it. (Each of the authors is technically trained in some aspect of it; none of us are experts in all aspects.) Our goal is to show such an audience the whole view of the projects, their probable impacts, what control technology is envisaged by the oil shale 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 control technology. The other materials presented are background, intended to make clear what the problem is and what legal constraints the control technology must operate against.

In developing the oil shale projects, the companies involved will cause a major change in the region in which the projects will take place. That area is currently very sparsely inhabited and has few signs of human activity. The projects would each employ several thousand people at the peak of construction and up to a thousand each at the time of full commercial operation. These people 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 project, it is proposed that none of this type of off-site pollution shall be considered in the question of control technology for oil shale development. None of the problems of the type discussed above are significantly different from those faced by any new or growing city in an

arid 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 oil shale area (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 oil shale industry.

In addition, the shale oil, 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 (21). 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 shale oil in our study.

At the oil refinery the shale oil will replace an equivalent amount of conventional oil. (This assumes that the demand for petroleum products at the time these projects come on line will not be significantly influenced by these project. Hence, if they do not come on line, that demand will be met from other sources; their arrival simply displaces these other sources.) Some Detailed Development Plans indicate that the shale oil will be processed on-site to a condition in which it is readily substitutable for ordinary oil in refinery operations. There is no indication that the oil companies intend to significantly modify their processing technology when shale oil 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 shale oil.

Other Detailed Development Plans indicate that the shale oil may be given only a minimal upgrading at the oil shale site and then be transported to a remote refinery for further processing. The control technology which would be used at the oil shale site would thereby be transferred to the distant refinery. But the technology would be substantially the same. Thus, the technology will be examined independent of whether it would be used to upgrade the shale oil to semi-finished products at the site or at the input end of a remote oil refinery.

The 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 the United States at the same time. We will not investigate these control technologies nor include them in this study.

These projects will be consumptive water users in the sense that they will draw water from the Colorado River or its tributaries and not return it. (Some projects indicate that the water removed to dewater mines will be more than that needed for processing, so that there will be no net withdrawal from surface flows. However, even in this case there will be net evaporation which decreases the total flow in the dewatered aquifers, so that the aquifer outflow in springs and seeps will be decreased in the long term resulting in a diminution of the water flow into the Colorado River and its tributaries). The Colorado River currently has a salinity problem which has led to conflict with Mexico and for which expensive correction projects are underway. By removing fresh water from the Colorado River or its tributaries, the oil shale projects will 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 oil shale 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 oil shale industry.

In summary, for this study we intend to draw a boundary around the actual plant sites of the oil shale projects and study the technology for controlling on-site air pollutant emissions, on-site water pollutant emissions, on-site processed shale 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-C-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 human fecal matter 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 Minamata 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

wastes 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 (22). Nonetheless, one 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 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 oil shale development? The oil shale developers believe that first-order environmental problems are extremely unlikely to occur in oil shale development. Most of the possible first-order environmental problems which could occur in an oil shale development are covered by specific environmental law, e.g., the Clean Air Act of 1970 (23), the Federal Water Quality Act of 1972 (24), the Toxic Substances Control Act (25), etc. The developers in their Detailed Development Plans have stated explicitly that they intend to comply with these laws and have shown in some detail how they intend to do it. 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 the oil shale development area.

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

What is the likelihood that the proposed oil shale developers are right in their view that they can prevent first-order environmental problems from occurring and that they can meet applicable federal laws? Most of the developers are oil companies or are groups which include oil companies in their make-up. In the past 25 years, the oil companies have made big political and economic errors but few very big technical ones. The only obvious example of serious technical errors in the oil industry have 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. It seems clear that on a steady-state basis with all their environmental control equipment functioning properly, the oil shale 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 like a retention dam rupture which would lead to a temporary first-order or possibly second-order environmental problem.

I-D. Proposed Environmental Control Strategies

I-D-1. Air Pollution

The basic air-pollution-control strategy intended by the oil shale operators 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 satisfactory 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-D-2. Water Pollution

The basic water-pollution-control strategy is to prevent any surface or subsurface flow of contaminated water from leaving the shale processing site. Because the projects will be net consumers of water, they intend to reuse water so that none leaves the site (except by possible aquifer reinjection). The only liquid water leaving the plant sites will be surface water in streams outside the processing areas.

1-D-3. Processed Shale Disposal

Because the amount of shale to be processed is very large, each of these projects will have a very large processed shale disposal responsibility. Typically, a 50,000 barrel per day shale oil project would be expected to mine about 100,000 tons per day of shale and to dispose of roughly 90,000 tons per day of waste. This places them in the same size range as the largest open-pit mines in the world.

Projects using in-situ technology will have a proportionately smaller and easier waste shale disposal problem. For a simple in-situ (as proposed for C-b by Occidental and Ashland), the only rock brought to the surface will be broken shale which is mined out to produce underground cavities. This would be about 20 percent as large an amount as would be mined for a comparable-sized conventional project. Furthermore, it will be raw shale, not processed shale. Raw shale is less of a storage and environmental problem than processed

shale so that for a simple in-situ project the waste storage and disposal problem is of a smaller amount of a material easier to deal with than for a conventional project.

The Rio Blanco project (C-a) proposes to feed the shale mined out for its in-situ retorting to conventional retorts, thus having a combined project. For them (if they use this technology), the waste disposal problem will be similar to that for a conventional project, but of a reduced magnitude compared to a conventional project of the same size.

The basic processed shale strategy proposed is to select in or near each of the processing sites a low-lying land area which can be filled with the processed shale and then graded to be below or approximately the same level as the surrounding land. The processed shale will be dumped in this area in layers and compacted. When enough processed shale has been dumped so that some of it has reached its final approximate contour, the surface will be sculptured to make it not flat and monotonous. It will be covered with what available top-soil has been salvaged from other parts of the project, and it will be vegetated. The vegetation will then follow the moving top of the pile. The effort will be to establish native or other plants which are adapted to this arid environment and to get them growing well enough that they adequately retain the soil against wind and water erosion. An additional objective is that they develop root systems sufficient to feed themselves through period of drought and need no further care and attention after the project is finished.

I-E. 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 proposing to produce oil shale believe that they understand the situation well

enough that they can confidently predict the performance of the environmental control technologies which they plan to use. Many of the reviewers of their environmental statements and detailed development plans 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 processed shale disposal sections of the Detailed Development Plans 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 Detailed Development Plans, 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.

II. ENVIRONMENTAL CONSTRAINTS

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. 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, and the companies proposing to develop major oil shale projects intend to control their 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 one case of significance to the oil shale industry (air quality standards), the state of Colorado has done so.

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, the oil shale industry has been guided by the regulations of the federal and state governments with which they are expected to comply. They assert in their detailed development plans that they can, in general, meet these regulations by the application of known technology. There is, however, one exception which is the Air Quality Standard promulgated under the so-called Non-Deterioration Doctrine. In the federal prototype leasing project suspension application, the holders of these leases cite various reasons for requesting a suspension. Only one of the reasons they cite is basically an environmental one; namely, the difficulty of complying with the "non-deterioration doctrine" (26). It seems certain that they could comply with that doctrine at some cost, but they claim that the cost of so doing to be exorbitant (see section V for more on costs).

We will now examine the appropriate environmental constraints in detail.

II-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 4 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

FIGURE 4. Schematic view of the air pollution problem.

are normally referred to as "point" sources to distinguish them from the ubiquitous automobiles and house heating sources which are called "area" sources. In Figure 4 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 (27). 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. The proposed oil shale undertakings will be obliged to comply with regulations of both kinds.

II-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 five pollutants; these are total suspended particulates, sulfur dioxide, nitrogen dioxide, carbon monoxide, and photochemical oxidant.* In addition to these five 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 multiple 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 the oil shale development is expected to take place, there are very few other major sources of most of the pollutants likely to be emitted by the oil shale industry. For that reason, most of the measured concentrations of these pollutants will be easily traceable to one of the oil shale projects. Furthermore, 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 may be quite restrictive as to what type of oil shale 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 3. These 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

* An additional standard for lead is about to be issued, and may become effective during the printing period of this report.

TABLE 3

FEDERAL AMBIENT AIR QUALITY STANDARDS

Pollutant (g)	Averaging Time	National Standards (b,c)	
		Primary	Secondary (d)
Photochemical oxidants	1 hour	160 $\mu\text{g}/\text{m}^3$ (f) (0.08 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
	Annual average	80 $\mu\text{g}/\text{m}^3$ (0.03 ppm)	-
Sulfur dioxide	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 $\mu\text{g}/\text{m}^3$
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 3 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 .
- (g) A standard for lead is in the administrative processes of being promulgated; it is expected to become final in the Fall of 1977. In addition the Clean Air Amendments of 1977 prod EPA to issue a short term (e.g. 1 hour) standard for NO_2 .

any harm to human health. The secondary standards are designed to "protect human welfare." (28) 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 the currently proposed oil shale projects will have serious difficulties with the national ambient air quality standards. This statement may be challenged, because monitoring at the oil shale sites (29) 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 the oil shale industry is the non-deterioration doctrine. This is covered in Section II-A-4 and in more detail in Appendix VII.

II-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 non-deterioration standard see Section II-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 one half to 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 oil shale 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, as the various reports on the oil shale development show, the meteorology in the oil shale regions is quite complex because the topography 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 5. Both are used in modeling estimates; the resulting values can vary by a factor of 10.

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

FIGURE 5. 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. (Copied from (15) p. 6-6-45)

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. (30) 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 the oil shale environmental effort must recognize that this is a permanent or seemingly permanent constraint on our ability to determine the environmental requirements.

II-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 19 such national industrial standards in force. These are referred to as the new source performance standards (NSPS) (31). These all apply to new installations in existing industries. There is not one of them which applies specifically and directly to an oil shale processing industry. The ones which would be applicable to an oil shale industry are those which deal with the petroleum refining parts of the oil shale industry; specifically, these are the ones referring to emissions from petroleum storage and emissions from refinery waste gas combustion. Since the planned petroleum storage and waste gas processing in the oil shale projects will be quite similar to that used in petroleum refining, there seems no reason to believe that these will pose a more severe limitation upon the oil shale 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 oil shale processing as the non-deterioration regulation described below.

Although there are no federal emission standards directed specifically to oil shale production, Colorado (32) has adopted a set of sulfur oxide emission standards specifically for oil shale. They exempt production and refining operations processing less than 1000 barrels/day (which will exclude most pilot operations) but limit commercial operations to 0.3 lb SO₂/barrel of oil produced for the production operation plus an equal amount for the refining operation. If we assume typical values for the sulfur content of the shale, this indicates that about 4 percent of the sulfur may be released as SO₂ by the production facility, and another 4 percent by the refining facility. Both the Occidental and Rio Blanco revised DDP's (8,16) present engineering plans indicating that they will emit substantially less than the standard, (0.07 and 0.14 lb/bbl respectively), so that this regulation should not pose a serious problem for oil shale development.

II-4. Non-Deterioration

A particular problem for the oil shale industry is the "non-deterioration" or "non-degradation" 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 significantly 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. Subject 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 oil shale area is classified at Class II.

Table 4 presents the current non-deterioration regulations in the Clean Air Act of 1977, and also the state of Colorado clean air regulations which in some senses are more stringent. The table has nine notes indicating that in making up such a table one must often put together things which are not really the same.

TABLE 4
SIGNIFICANT DETERIORATION LIMITATIONS

	Permitted Increases over Baseline ⁽¹⁾ (micrograms/m ³)	
	Federal ⁽²⁾	Colorado ⁽³⁾⁽⁴⁾
Class I		
Particulates		
annual avg ⁽⁵⁾	5	(6)
24 hr max ⁽⁷⁾	10	
Sulfur dioxide		
annual avg	2	2
24 hr max	8	5
3 hr max	25	25
Class II		
Particulates		
annual avg	19	(6)
24 hr max	37	
Sulfur dioxide		
annual avg	20	10
24 hr max	29	50
3 hr max	512	300
Class IIa ⁽⁸⁾	(same as II except 3 hr max sulfur dioxide 325)	(6)
Class IIb ⁽⁹⁾		
Sulfur dioxide		
24 hr max	36	(6)
3 hr max	130	
Class IIc ⁽⁹⁾		
Sulfur dioxide		
24 hr max	62	(6)
3 hr max	221	

Table 4 continued

Class III

Particulates		
annual avg	37	
24 hr max	75	
Sulfur dioxide		
annual avg	40	15
24 hr max	182	100
3 hr max	700	700
Areas designated as		
Class I	Large national parks, national wilderness areas	National parks, monuments, wilderness and primitive areas, Gunnison Gorge Recreation areas
Class II	Rest of U.S.A.	Rest of state
Class III	none	none

Notes to Table 4

1. 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.
2. Based on the "Clean Air Amendments of 1977" (94).
3. Based on "Colorado Air Quality Control Regulations and Ambient Air Quality Standards" (32).
4. The State of Utah does not have a set of numerical increments separate from the federal set listed here, and which the state of Utah enforces.
5. The annual averages are geometric mean for particulates and arithmetic mean for sulfur dioxide.
6. Colorado has no sets of increments for particulates directly comparable to the other numbers in this table. However, they have ambient air quality standards more stringent than the federal, which apply everywhere outside metropolitan Denver. These are 150 micrograms/m³ 24 hr average and 45 micrograms/m³ annual average.
7. All the short-term increments in this table (i.e., less than annual

Notes to Table 4 continued

average) are "not to be exceeded more than once per calendar year".

8. 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)..."
9. 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 SO_2 only. Class II-b applies to low terrain areas and Class II-c applies to high terrain areas.

The non-deterioration regulations play such a significant role in the decision in whether an oil shale project can meet applicable environmental standards that a more complete discussion of the background and philosophy of the non-deterioration regulations is given in Appendix VIII.

II-B. Water Pollution

The water pollution regulations applicable to oil shale development are at the federal level (administered by the Environmental Protection Agency and the U. S. Public Health Service) and state level (usually administered by state and county health departments). These are also stipulations in the Federal Prototype Lease Agreements. The stipulations in the lease agreements are primarily to ensure that potential hydrologic problems are well enough understood that the federal and state regulations can be followed.

II-B-1. Regulatory and Statutory Factors--Water Pollution

A sweeping Federal-State program against water pollution was launched in late 1972 when Congress enacted the Federal Water Pollution Control Act Amendments.(24) This law updated and strengthened earlier federal water pollution legislation (33-37). Congress intended the Act to achieve two major goals:

(1) To achieve, wherever possible, by July 1, 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.

This act implicitly means a switching from effluent standards (equivalent to emission standards for air pollution described above) to receiving water standards (equivalent to air quality standards). The Environmental Protection Agency (EPA) is charged with administering the new federal water program.

II-B-1-a. EPA's Strategy

Discussed below are the elements of EPA's sequential strategy for dealing with water pollution.

The States are inventorying and assessing the present quality of their waters to define their most severe problems. This is assisting EPA and the states in deciding where to take action first. The severity of pollution in a particular body of water also dictates what method or combination of methods should be used to improve the water's quality.

EPA has established national effluent limitations on what a "point" source can discharge into the water. These have been developed for factories, power plants, sewage treatment plants, animal feedlots and other specific sources. The limitations reflect the degree of cleanup EPA expects to achieve using the latest technology for controlling wastes ("best practicable technology"). Depending on the pollutant in question, an effluent limitation may permit some discharge or no discharge at all.

Treatment plants, industries, and other "point" sources must comply with an initial set of effluent limitations by 1977. Then they must work to implement a second, even more strict set of limitations by 1983. The limitations, therefore, call on each specific source of pollutants to reduce its discharge over a period of time to meet the Act's 1983 deadline.

Consider a specific industry: EPA's guidelines on effluent limitations for the beet sugar industry call for no discharge of pollutants by July 1, 1977, provided that suitable land owned by the company is available for land disposal of waste products. If such land is not available, some discharges into the water will be allowed; but all beet sugar plants will have to meet the "no-discharge" requirement by July 1, 1985.

To make sure that all effluent limitations and other requirements are met, EPA and the states now 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. By following that schedule, the plant will cut its pollutant discharge to comply with the effluent limitations for 1977 and 1983. 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. If a power plant, factory, or treatment plant is unable to comply immediately with applicable effluent limitations, the permit sets a series of firm, intermediate targets through which the final goal can be reached by a specified date. A first round of permits is aimed at attaining a certain level of improvement by 1977; a second round will follow to insure compliance with the tighter requirements of 1983.

EPA has also established performance standards for new plants in a wide variety of industrial categories. These standards are, in effect, strict effluent limitations. They insure that new plants

have the best practicable pollution controls built in from the very beginning. In the case of the beet sugar industry, this means that all new plants must meet a "no discharge" requirement as soon as production begins.

EPA also sets standards to regulate the discharging of toxic substances, such as cadmium and mercury. The 1977 and 1983 deadlines for limiting pollutant discharges do not apply in the case of toxic substances; steps to meet these standards must be taken more quickly, since public health and welfare might otherwise be severely affected. The standards and criteria established are generally based on a study performed by the National Academy of Sciences and the National Academy of Engineering (38).

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 (39). Briefly the midcourse corrections recommended were;

1. Since the 1977 deadlines are not being met in many instances, it is recommended that extensions be granted on a case-by-case and category-by-category basis.
2. 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.
3. The NCWQ recommended retaining the substance of the 1983 goal of "fishable and swimmable" waters although it recognized that its attainment may be delayed.
4. The NCWQ recommended achieving the "fishable and swimmable" goal by applying the "1977 requirement (best practicable technology) to all dischargers." This presumably includes some sources previously considered nonpoint sources by EPA.

5. The NCWQ recommended that the ultimate goal of "zero discharge" be changed to one "stressing conservation and reuse of resources."

6. The NCWQ recommended immediate attention to elimination of the discharge of toxic pollutants in toxic amounts and universal application of new source performance standards to all new point source discharges.

In some cases, the states apply even more stringent controls to regulate pollutants. All of the discharge limitations discussed up to this point affect the content and volume of what is dumped into the waterways. Eventually, however, the purity of the receiving waters will serve as a standard for controlling pollutions. For example, the states set minimum water quality standards for each body of water. If effluent limitations are not enough to bring the quality of a particular river or stream up to meet those standards, industries and treatment plants will be compelled to comply with even tighter controls on what they discharge.

The Water Pollution Control Act clearly notes that the states have the primary responsibility for controlling water pollution. This is logical because the states--through local governments--know exactly what their specific problems are; they are also in the best position to develop and implement solutions that are tailored to local conditions.

11 B-1-b. Water Planning Programs. Several distinct planning processes have been established; each of these has its own scope and purpose and depends upon the others for its ultimate effectiveness. Here, briefly outlined, are the major planning activities associated with water pollution from oil shale operations.

The River Basin Plan (Section 303) is one basic planning mechanism. It is prepared under Section 303 of the Act and is primarily

a state effort. The plan sets up procedures to manage the water quality of a river basin, which is the area drained by a river and its tributaries. The Basin Plan identifies and measures the pollutants found in waters within the basin and sets limits on what can be dumped into those waters. It also is required to develop 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. Special Energy-Area 208 Projects have been funded and initiated in Utah, Colorado, and Wyoming. 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 "non-point" sources of water pollution, such as urban run-off and erosion at construction sites. All of these factors contribute to a comprehensive plan for managing and controlling waste quality in areas that need special attention.

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

II-B-1-c. 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 case, 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 pre-treatment standards, user charges, and inspection and monitoring provisions 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.

At this time, Utah has not established an NPDES program; and EPA is still carrying out the provisions of the Act in that state. Colorado, however, has an aggressive state permit program which reflects that state's policies as well as federal requirements.

II-B-1-d. 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. On 10 October 1975, EPA published a final draft of a report entitled, "Quality Criteria for Water" (40). 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. 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.

Many of the state regulatory programs appear to be somewhat vague because of the lack of specifications of maximum concentrations of various materials. On the other hand, these state regulations often refer to what are commonly understood to be healthy water conditions so that both management and enforcement programs may be carried out in a politically acceptable manner.

II-B-2. Utah Regulations

The original Utah Water Pollution Act was passed in 1953. The Act was administered by a nine-member Water Pollution Control Board

within the Utah State Division of Health. Board members were originally appointed to eight-year terms. The Director of Health is an ex officio member of the Board. In May 1965 the Utah Code of Waste Disposal Regulations was adopted (36). The Water Pollution Control Board has been renamed the Committee on Water Pollution and eight of its members are now appointed by the Governor to four year terms. On January 13, 1967, the Utah Water Pollution Committee adopted the following antidegradation policy with regard to water quality in the State of Utah:

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.

Furthermore, on June 23, 1972, the Utah Water Pollution Committee assigned a classification of "C" to virtually all surface waters of the State. All discharges into these waters have been given until December 31, 1983, to make sure that their discharges do not degrade receiving waters to below "C" class.

Class "C" waters are defined in the Utah State Division of Health, Code of Waste Disposal Regulations, Part 11-8, revised November 20, 1968 as follows:

Class "C" waters shall be so protected against controllable pollution, including heat, as to be suitable at all times for domestic water supplies which are treated before use by coagulation, sedimentation, filtration, and disinfection. Class "C" waters shall be suitable without treatment for aesthetics, irrigation, stock watering, propagation and perpetuation of fish, other aquatic life, and wildlife, recreation (except swimming) as a source for industrial supplies, and for other uses as may be determined by the Committee and Board.

It shall be unlawful to discharge or place any wastes or other substances in such a way as to result in:

- (a) Materials that will settle to form objectionable deposits;
- (b) Floating debris, oil, scum, or other matters;
- (c) Substances producing objectionable color, odor, taste, or turbidity;
- (d) Materials, including radionuclides, in concentrations or combinations which are toxic or which produce undesirable physiological responses in humans, fish, and other animal life and plants;
- (e) Substances and conditions or combinations thereof which produce undesirable aquatic life; or
- (f) The following specific standards being violated in any Class "C" waters:
 - 1. Chemical and radiological standards shall be as prescribed for drinking water by "Public Health Service Drinking Water Standards, 1962."
 - 2. Radioactive substances shall not exceed $1/30$ of the MPC_w values given for continuous occupational exposure in National Bureau of Standards Handbook 69 or result in accumulations of radioactivity in edible plants and animals that present a hazard to consumers.
 - 3. Hydrogen-ion concentration shall not exceed the range described by a pH of 6.5 to 8.5 nor shall it change more than 0.5 pH unit from other than natural causes.
 - 4. Monthly arithmetical mean coliform density shall not exceed 5000 per 100 milliliters, as determined by standard multiple-tube fermentation or membrane filter techniques; except that 20 percent of all samples collected in any month may exceed this standard if no more than five percent of all samples collected in the same month exceed a coliform density of 20,000 per 100 milliliters; AND, monthly arithmetical mean fecal coliform density shall not exceed 2000 per 100 milliliters.
 - 5. Monthly arithmetical mean biochemical oxygen demand (BOD) shall not exceed 5 milligrams per liter; except that 20 percent of all samples collected in any month may exceed this value if no more than five percent of all samples collected in the same month exceed a BOD of 10 milligrams per liter.

6. Dissolved oxygen shall be not less than 5.5 milligrams per liter.

Table 5 summarizes the water quality recommendations by the National Academy of Sciences and Engineering (39) and the Utah Committee on Water Pollution and compares them to existing permissive criteria for raw surface water published in the Public Health Service Drinking Water Standards.

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 state of Utah Oil, Gas and Mining Division.

II-B-3. Colorado Regulations

II-B-3-a. Colorado Water Control Act. This law establishes stream water quality standards and regulates the discharge of pollutants into waters of the state. It is administered by the Water Quality Division of the Colorado Department of Health. This division also administers the NPDES permit programs.

The water quality standards define limits as shown in Table 6.

II-B-3-b. Colorado Water Quality Control Commission. This commission and its support staff within the Colorado Department of Health administer and regulate the reinjection of water into underground disposal wells. Any disposal of water by reinjection will require public hearings and the approval of the commission.

II-B-4. Other Water Constraints

The oil shale deposits in Colorado and Utah are located in the Colorado River Basin. At the present time extensive efforts are being made to reduce the salinity of the Colorado River for purposes of complying

TABLE 5
RAW SURFACE WATER CRITERIA

Substance	U.S. Public Health Service Drinking Water Standards	"Water Quality Criteria" 1972	Utah State Class "C" Standards
Total coliforms, MPN/100 ml	5,000	20,000	5,000
Fecal coliforms, MPN/100 ml	2,000	2,000	---
Ammonia, mg/l	0.5	0.5	---
Arsenic, mg/l	0.05	0.1	0.05
Barium, mg/l	1.0	1.0	1.0
Boron, mg/l	1.0	No recommendation	---
Cadmium, mg/l	0.01	0.01	0.01
Chloride, mg/l	250	250	---
Chromium, mg/l	0.05	0.05	0.05
Copper, mg/l	1.0	1.0	---
Cyanide, mg/l	0.2	1.0	0.2
Dissolved oxygen	4	No recommendation	---
Iron, mg/l	0.3	0.3	---
Lead, mg/l	0.05	0.05	0.05
Manganese, mg/l	0.05	0.05	---
Mercury, mg/l	---	0.002	---
Nitrate-Nitrogen, mg/l	10	10	---
Nitrite-Nitrogen, mg/l	---	1	---
Oil and grease	Virtually absent	Virtually absent	---
Organics-Carbon Absorbable:	---	0.3	---
CCE, mg/l	---	1.5	---
CAE, mg/l	---	---	---
Pesticides:			
Aldrin, mg/l	---	0.001	---
Chlordane, mg/l	0.003	0.003	---
DDT, mg/l	0.042	0.05	---
Dieldrin, mg/l	0.017	0.001	---
Endrin, mg/l	0.001	0.0005	---
Heptachlor, mg/l	0.018	0.0001	---
Lindane, mg/l	0.056	0.005	---
Methoxychlor, mg/l	0.035	1.0	---
Toxaphene, mg/l	0.005	0.005	---
Herbicides:			
2, 4-D, mg/l	0.1	0.02	---
2, 4, 5-T, mg/l	0.1	0.002	---
Phenols, mg/l	0.001	0.001	---
Phosphates, mg/l	---	No recommendation	---
Selenium, mg/l	0.01	0.01	0.01
Silver, mg/l	0.05	No recommendation	0.05
Sodium, mg/l	---	No recommendation	---
Sulfate, mg/l	250	250	---
Total Dissolved Solids, mg/l	500	No recommendation	---
Zinc, mg/l	5	5	---
Biochemical Oxygen Demand (BOD), mg/l	---	---	5
pH	---	---	6.5-8.5
Turbidity, Jackson Units	---	---	5
Color, Platinum- Cobalt Units	---	15	15
Odor, Threshold Number	---	3	3

TABLE 6

COLORADO WATER QUALITY STANDARDS SUMMARY

<u>Item</u>	<u>Standard</u>
1. settleable solids	free from
2. floating solids	free from
3. taste, odor, color	free from
4. toxic materials	free from
5. oil and grease	film producing
6. radioactive material	drinking water standards
7. fecal coliform bacteria	geometric mean of <1000/100 ml< from five samples in 30-day period
8. turbidity	no increase of more than 10 J.T.U.
9. dissolved oxygen	6 mg/l minimum
10. pH	6.0 - 9.0
11. temperature	maximum 68°F

with the conditions stipulated for Colorado River water as it enters Mexico (41). Although neither Utah nor Colorado have water standards which specify maximum allowable concentrations of total dissolved solids (TDS) it is unlikely that projects will be approved which may significantly increase the salinity of runoff or groundwaters (42).

Other water quality constituents which specifically may cause problems to the development of oil shale tracts are boron and fluoride. Table 7 gives maximum recommended concentrations of boron, fluoride and total dissolved solids as functions of water use.

The water rights process in Colorado and 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 oil shale industry will have to purchase water rights from local users (mainly irrigation rights) or otherwise negotiate for their water. Water rights in Colorado and Utah are generally regarded as heirlooms and their availability do not follow usual free marketplace principles. This may prove a constraint depending on the particular location and the quantity of water needed.

II-B-5. 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 all but guaranteed.

TABLE 7
RECOMMENDED MAXIMUM WATER QUALITY
CONSTITUENT CONCENTRATIONS (40)

Water Constituent	Domestic water supplies	Irrigation Water
Boron		0.75 mg/l for sensitive crops
Fluoride	1.1 mg/l -1.8 mg/l (temperature dependent)	
Total Dissolved Solids (TDS) (for chlorides and sulfates)	250 mg/l	500 mg/l - 5000 mg/l (depending on crop)

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 on-going transfer of authority and responsibility from the federal level to state and country 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.

II-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 shale disposal and the disposal of other solid wastes is more indirect. The solid wastes piled somewhere do not constitute immediate threats to health and welfare as do direct emissions of toxic materials into the air and water. However, as discussed below, they can 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.

II-C-1. Environmental Threats

The specific threats are:

1. Air pollution due to wind erosion of the surfaces of storage and disposal piles (13,43,44).
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 (13, 44).
3. Transfer of possible hazardous organics or trace elements to the biosphere, including the poisoning of plant life (13).
4. Transfer of toxic substances from the wastes to the covering vegetation (13).
5. Mass movement of material due to (a) collapse or slumping of unstable disposal piles, and (b) changes in surface topography due to subsistence of the area over underground mines (13,43, 45). This is a particularly hazardous situation where the disposal dump is also used for fine-grain refuse settlement, filtering, pollution control or storage of process

waters, i.e., an impounding dump. Impounding dumps are highly unlikely to be used in oil shale processing or waste disposal, but their potential for severe problems, as discussed below, is so great that this type of waste pile has received much attention in the environmental regulations concerning the disposal of solid waste.

6. Combustion in the dump can cause air pollution, and people are killed falling into cavities on such dumps. This is a severe problem with coal waste dumps, which normally contain considerable combustible material. As a result of this problem, many of the regulations cited later specifically address the prevention and control of such burning dumps. Some oil shale solid wastes could burn, but most evidence suggest that this will not be a likely occurrence. Nonetheless, the oil shale operators will be constrained by law to take measures to prevent it.
7. Visual pollution by scarring the earth and disruption of the natural scenic values of the area, and the inherent economic devaluation of surrounding property (44, 46).

II-C-2. Wastes to be Dealt With

The solid wastes to be dealt with in a major oil shale 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. Dusts and fines created during ore transportation and crushing operations (which can be utilized in some processing schemes but not in others).
5. Spent solid catalysts, scrubber sludges, etc.

The amount of material involved in the above is generally several orders of magnitude less than the quantity of processed shale which will have to be disposed, and thus these other waste solid disposal problems are expected to be ancillary to the processed shale disposal problem.

II-C-3. Lease Stipulation Constraints

The oil shale operations being developed on public lands (C-a, C-b, Ua-b) are controlled by lease agreements entered into between the developer (lesser) and the Bureau of Land Management of the U. S. Department of the Interior (47). The typical BLM oil 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, the oil shale lease includes 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.

II-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 (48).
2. Mandatory safety standards for surface coal mines, surface work areas of underground coal mines, refuse piles, and impounding structures (49).

Although both 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 either oil shale operations will be ruled within the intent of the laws or the scope of the laws will be expanded to include oil shale 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 oil shale 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 oil shale operations are those dealing with (1) the required character and construction of refuse piles (50), and (2) water, sediment or slurry impoundments and impounding structures (51). Although designed for coal mine refuse piles they are directly applicable to the piles to be used for the surface disposal of processed oil shale. 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 (45). 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. The provisions of these regulations are summarized below:

1. Refuse Piles General (50).

- a. Refuse piles shall be located in areas which are a safe distance from all underground mine airshafts, preparation plants, tipples, or other surface installations and such piles shall not be located over abandoned openings or steamlines.
- b. Where new refuse piles are constructed over exposed coalbeds, the exposed coal shall be covered with clay and other inert material as the piles are constructed.
- c. A fireproof barrier of clay or inert material shall be constructed between old and new refuse piles.

- d. Roadways to refuse piles shall be fenced or otherwise guarded to restrict the entrance of unauthorized persons.
2. Refuse Piles: Construction Requirements (50).
- 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.
3. Water Sediment, or Slurry Impoundments and Impounding Structures: General (51)
- 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.

II-C-5. Utah Regulations

In the Utah Mined Land Reclamation Act of 1975 (52), 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.

II-C-6. Colorado Regulations

The rules and regulations governing the reclamation of surface mined lands and waste piles in the state of Colorado are contained in or promulgated by authority of the Colorado Mined Land Reclamation Act of 1976. This act indicates that it is the policy of the state of Colorado to allow for the continued development of the mining industry in the state, while requiring those persons involved in mining operations to reclaim the land affected by such operations so that the affected land may be put to a use beneficial to the people of the state. The stated intent of the act is "to conserve natural

resources, aid in the protection of wildlife aquatic resources, and establish agricultural, recreational, residential, and industrial sites and to protect and promote the health, safety, and general welfare of the people of this state." The responsibility for administering the provisions of the Colorado act are vested with the Mined Land Reclamation Board of the Colorado State Department of Natural Resources. Any operator proposing to engage in a new mining operation must first obtain a permit from the board.

An application for a Colorado mining permit shall include (1) identification of all individuals and organizations involved; (2) legal description of the lands affected; (3) the legal basis for the right to engage in the operation; (4) type, location and description of the operation proposed; (5) a reclamation plan; (6) an accurate map of the affected land; and (7) a timetable estimating the periods of time which will be required for the various stages of the mining operation. Reclamation is required on all lands affected by the mining operation and shall include:

1. A description of the present uses of the land, i.e., rangeland, agricultural, wildlife habitat, residential, etc., and the land in the vicinity of the development.
2. A description of the types of reclamation that the operator proposes to employ, the reasons each was selected and the acreage to be accorded each technique. This shall include plans for:
 - a. topsoil segregation, preservation and replacement.
 - b. soil grading, compaction and stabilization.
 - c. revegetation plan listing the preferred species of grass, legumes, forbs, shrubs and/or trees; the method and rate of seeding; the proposed times for seeding and planting; and fertilization if required.

3. A description of how the reclamation plan will rehabilitate the affected land; including, soil, water, air, vegetation, and wildlife.
4. A timetable indicating the manner in which the reclamation plan will be implemented.
5. A map of the area affected showing the total scope of the mining operation, the expected appearance of the area of the affected land at various times during the development, and the proposed final land use for each portion of the affected lands.

The map provided with the permit application shall be an accurate map of the affected areas identifying the areas and the adjoining surface owners of record. The map shall also show:

1. The topography of the area.
2. The location and name of all creeks, rivers, roads, buildings, oil and gas wells and lines, power and communication lines within the affected area and two hundred feet of all boundaries.
3. The general type, thickness and distribution of soil over the area in question.
4. The type of vegetation now covering the affected lands.

II-C-7. 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 satisfactory. We are not yet at the stage where we can write

specific numerical regulations for solid-waste disposal as we can (or believe we can) for air and water pollution.

II-D. Other Environmental Constraints

The environmental constraints previously listed are the major ones dealing with "first order" environmental problems. In addition, there are written into the lease stipulations for the federal prototype leasing program and into other local regulations, several sets of additional regulations which the oil shale operators must comply with. Some of these are:

1. Protection of game animals — Most of the areas of potential oil shale production are now largely devoted to livestock raising and production of game animals for hunting. The lease provision requires that the damage or disturbance of big-game habitat be minimized and, if possible, alternative habitat provided off the site. The oil shale companies have indicated that they will attempt to minimize disturbance of this habitat, fence the used areas away from those areas, not in use, which can remain as big-game habitat, and attempt to improve big-game habitat off the site in order to meet this requirement.
2. Protection of archeologic sites — Specific regulations have been written indicating that if in the construction phase any archeologic site of any significance is encountered, work in that area must be halted immediately, and the area oil-shale supervisor notified so that adequate precautions and/or salvage work can be done to recover the valuable archeological materials.
3. Shutdown — When the project is completed the lease requirements of the lease document requires that all buildings

and roads be removed, concrete buildings be leveled to the ground, and the site restored to as near its original condition as possible.

The above constitutes specific environmental constraints against which the oil shale industry must operate. An additional constraint which is not stated in the law, but is still significant, is that there must be public acceptance of the oil shale industry. If there is large-scale opposition, then such an industry may be forbidden even if it can meet all existing environmental law. For example, the Kaiparowits power project in Southern Utah could apparently have met all applicable legally enforceable environmental standards. Yet it was vigorously opposed by the National Park Service(53) and EPA, who believed that even if all standards were met, such a plant should not be constructed near a national park. Eventually, it was canceled (or put on permanent inactive status) in part because of this opposition. Similarly, the IPP power plant project in Southern Utah has been denied a BLM permit to use land near a national park, without a clear showing that any applicable standard or law would have been violated. We must take these examples into account in deciding whether an oil shale project might be rejected on environmental grounds, even if it could meet all applicable standards.

III. PROPOSED ENVIRONMENTAL CONTROL TECHNOLOGIES

In considering an emission control technology or a more general environmental control technology, one has two options; one possibility 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 this type of distinction is 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 oil shale industry the original designs of the projects mostly envisaged processes which maximized the economic efficiency of the recovery of the oil from the oil shale 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 on the retorting steps 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.

In the current situation in which substantial re-evaluation of the entire prospects of the oil shale industry is going on, it seems prudent to re-examine the

production technology to see to what extent it can be modified so that the combined costs of production of the oil from the shale and the cost of treatment of the effluent streams can be minimized. To a significant extent, this is one of the advantages of the in-situ processes and has led to their current ascendancy in the oil shale industry. In them the external cleanup of waste streams is much less expensive and complex than in most surface-retorting operations. In the earlier days of the oil shale industry in which such cleanup would probably not have been required by law, the in-situ operations would not have had this advantage; now they do and this advantage may be enough to permanently shift the economics of oil shale recovery in the direction of in-situ processing.

III-A. Overall Process Scheme — Surface Retorting

The proposed environmental control technologies to be used in the oil shale ventures are best considered against the background of the process technology which will be used in producing liquid fuels from the oil shale. This section discusses such technology when mining and surface retorting is used: the next section discusses the technology when in-situ retorting is used.

Figure 6 shows, in block diagram form, the entire oil shale processing scheme. The process begins (1 on the figure) with the mining of the shale, either by underground room-and-pillar mining or by open-pit mining. This is followed by the transportation of the shale from the mine to the processing plant (2 on the figure). At the processing plant, the shale is crushed and segregated to size (3 on the figure). Some of this crushing takes place during and adjacent to the mining process, but for block-flow diagram purposes it may be considered one step. Furthermore, in the crushing and sizing operation there is intermediate-term storage of shale at various locations.

FIGURE 6. Schematic view of an oil shale operation using surface retorting. Major solids flows are shown by the heavy lines Gas and liquid flows are shown by single lines

The next step (marked 4 on the diagram) is the retorting step in which the shale is subjected to a high temperature (900°F) pyrolysis by the addition of heat derived from burning some fuel. This causes the hydrocarbon fraction of the shale to be separated from the remaining solid mineral material. The gaseous and liquid products are shown leaving this step in the arrow to the right. Step 5 shows the conditioning of the waste processed shale, which has had its hydrocarbons removed, for disposal; and Step 6 shows the disposal of the processed shale.

Steps 1 - 6 are the steps which constitute the main materials flow on a tonnage basis. The hydrocarbon content of the shale is only a few percent of the total so that although the hydrocarbons are the interesting, valuable and important part, they do not constitute the truly large-scale aspects of the process.

Considering next the products produced in the retorting operation, the first to consider is the combustion gas shown as Block 7 on the figure. This is the combustion product from whatever material was burned to produce the heat shown entering at the left in Step 4. There are several variants on how this can be done, but all of them involve the combustion of some hydrocarbon with the resulting production of a waste gas which is mostly nitrogen and carbon dioxide but contains various contaminants including dust, sulfur oxides, nitrogen oxides, etc. The figure shows in Step 8 that this waste gas is cleaned and is then vented to the atmosphere. In some versions this gas has significant heating value. The emissions from this waste gas will be among the major air pollution emissions from the entire process.

Returning to the diagram, we see (Step 9), and that one of the products of the retorting process is a gas. In some versions of the retorting scheme,

this is a low-Btu gas with a heating value of less than 200 Btu per cubic foot while in others it is a high-Btu gas with values similar to the 1,000 Btu per cubic foot which is typical of natural gas. In either event, this gas will be cleaned as shown in Step 10 and then will be used (Step 11) either as a fuel or heat input to the retorting process (Step 4) or as a fuel in the various auxiliary processes in the overall scheme. It is possible that in the high Btu gas cases, this gas may be a product which is exported and sold or may be used (Step 11) as an input material for the hydrogen plant. In all retorting schemes such gas is produced, and will be processed to remove sulfur and nitrogen compounds before it is burned, sold, or used internally as plant fuel.

Returning again to the stream shown leaving the retort, we see that there is a liquid product shown as Box 12. This is the principal and most valuable product from the entire operation; one retorts oil shale to make liquid products. Step 13 shows that this product must be treated to remove its nitrogen and sulfur and to lower its viscosity. This would be done in petroleum-refinery-type processes. One of the required inputs for this type of process is hydrogen; Box 14 shows a hydrogen plant which would produce the necessary hydrogen. Box 15 shows that this hydrogen must be produced by a process which consumes some gas or liquid fuel. This could be any of several hydrocarbon streams available in the entire processing complex. Finally, Box 16 shows the products which emerge from Box 13, the treatment of the liquid product. Most of the nitrogen in the liquid product emerges as liquid ammonia which is sold for use as fertilizer (the rest is in the final product fuel); most of the sulfur in the liquid product emerges as elemental sulfur which will be sold for sulfuric acid production if a market exists or otherwise disposed of as an inoffensive solid; the liquid fuels are the end product of the

entire operation. In addition, in some process variations a solid coke would be produced which may be a valuable byproduct or may end up being an inert waste product to be landfilled.

Summarizing the entire processing scheme, we see along the left side of the figure that there are six large steps which involve the handling of vast quantities of solid material. To the right of them are a large number of processing steps, most of which involve only liquids and gases and whose total mass throughput is only a few percent of the mass throughput of the solid handling steps shown on the left.

Figure 6 shows the flow diagram for a self-contained oil shale venture which produces as its finished products ammonia, sulfur, and liquid fuels ready to be used as produced or with minor additional processing. An alternative procedure is proposed by RBOSP (C-a) and Occidental-Ashland (C-b). In it the liquid product from retorting operation would not be treated to remove nitrogen and sulfur or to lower viscosities (13 on Figure 6), but rather would be treated very mildly to lower its pour point and placed in an interstate pipeline for transportation to a remote oil refinery (Chicago? Salt Lake City?) At the oil refinery the removal of nitrogen and sulfur would take place in the processing to form finished petroleum products. The technology to be used for environmental control at the remote oil refinery would not be substantially different than that which will be used in a self-contained oil shale production retorting and refining operation.

The advantages cited for this latter procedure are that processing is transferred to an existing refinery, thereby taking advantage of existing facilities and minimizing an increase in population and environmental impact which would occur at the oil shale site. The decision as to whether to upgrade the oil at the site or at a remote refinery will most likely be made on economic rather than environmental grounds.

This alternative fits into Figure 6 if we understand that the pipeline between Boxes 12 and 13 on that figure is a long distance pipeline rather than a few hundred feet and that Boxes 13 through 16 are located at an oil refinery many miles distant from the oil shale region.

III-B. Overall Process Scheme-In-Situ Retorting

In-situ retorting means carrying out the retorting process in place without bringing the oil shale to the surface. Currently, some companies make the distinction between "in-situ" and "modified in-situ." The former means an in-situ operation which is conducted entirely from the surface with no entry of workers into the oil shale bearing formation. Modified in-situ means a process where some mining is done in order to prepare a section of oil shale for in-situ retorting. Since the in-situ without such manned entry currently appears much less promising than modified in-situ, it seems plausible to expect that over the years the term "modified" will be dropped, and what is now called modified in-situ will be called simply in-situ. That terminology is used here.

Figure 7 shows the entire oil shale operation for an in-situ project. It is easiest to consider it in comparison with Figure 6 for a surface retorting operation. The first step of an in-situ project (marked 1 on Figure 7) is to mine out a certain fraction of the shale area to be treated. This varies from 15 to 30 volume percent, depending upon whose estimates one takes. The purpose of this mining is to provide void volume so that in Step 2 when the remaining shale is converted to rubble there will be adequate void spaces for it. The shale removed in Step 1 is placed on the surface or possibly stockpiled for use as feed to a surface retorting operation. In Step 2 the remaining shale is converted to rubble by explosive fracturing. Numerous variants on the explosive fracturing technique have been proposed and at least two will be tried. Regardless of which is tried the consequence is to produce

Step 1 is only large scale solids handling step.

FIGURE 7. Schematic view of an in-situ oil shale operation. Major solid flows are shown by the heavy lines Gas and liquid flows are shown by single lines

a vertical room filled with rubblized oil shale. In Step 3 the rubblized oil shale is retorted by passing air through it from above. To start the operation some external fuel must be added to ignite the oil shale from the top of the rubble pile. After ignition, a combustion wave passes down through the oil shale rubble pile with the heat flowing forward from the combustion zone retorting the shale. Most operators express their intention of adding steam or inert gas to the air passing through the oil shale to lower peak temperatures in the retorting zone, thereby improving the performance of the process. The individual retorts will be quite large, probably on the order of 100 x 100 ft. in plan view and 300 to 700 ft. vertical dimension. The burning of a retort will take approximately two months; a combined project will consist of four to ten retorts burning at one time. After the retort has been burned, it will be sealed off from the surrounding area if needed in order to prevent the flow of liquids through it which would possibly damage aquifers.

Turning now to the right side of Figure 7, we see that high-Btu gas stream shown on Figure 6 does not occur on this figure because the gas coming from an in-situ retort is much more like the combustion gas shown in the upper line of Figure 6. This gas will normally contain enough carbon monoxide and hydrogen to be a valuable fuel and after all hydrocarbons and sulfur have been removed it will be used as a fuel. The liquid product shown in Box 7 is the desirable product; this then passes to a processing scheme in the lower right-hand corner which is in no significant way different from the processing scheme which would be used for an above-ground retort.

The current modified detailed development plan for the Rio Blanco oil shale projects indicates that they intend to combine in-situ and surface processing by using the shale mined out in Step 1 of Figure 7 as the mined shale in Step 1 of Figure 6. In that case both processes will operate in parallel

with their connection being that the annual rate of production of mined shale for the in-situ operation would have to be equal to the rate of feed of shale to the surface retorts.

III-C. Technology Transfer

Most of the steps shown on Figure 6 and 7 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 oil shale industry. Considering the steps in Figure 6, in order and their transfer nature:

Step 1 . The mining of the shale will use conventional room-and-pillar mining or open-pit mining. These types of mining are well known for other materials. The oil shale has certain characteristics as a rock which are different from other ores. However, the room-and-pillar mining technique has been thoroughly piloted by the Bureau of Mines (1, 2, 4) and is unlikely to contain any significant surprises. Similarly, the open-pit mining technology should not be significantly different from the open-pit mining of many other kinds of ores.

Step 2 . The transportation of the shale to the plant is basic conveyor and material handling technology. If anything, the oil shale should be easier to transport than many others because it tends to be less of a dust producer than many other ores.

Step 3 . The crushing and sizing of the shale is again technology borrowed from other mineral-processing industries. Because the oil shale is somewhat different than other rock, this poses some minor problems; but this has been piloted on a large scale and does not seem to be a particularly difficult process.

Step 4 . The retorting of the shale is the truly unique aspect of the entire oil shale operation. Although many parts of this borrow from other industries, we have no knowledge of another industry which does a

truly comparable step. The requirements of this step are to heat the shale to the temperature at which the organic material decomposes (900°F), separate that organic material from the inorganic residue, remove the inorganic residue from the processing system, and accomplish the entire results with a maximum energy efficiency and a minimum loss of valuable organic material. There are numerous processes which have been tried for doing this. The three most currently prominent are the TOSCO process, the Paraho direct process, and the Union model B. These differ principally in the way in which the heat is brought to the shale. (Appendix II gives some details on them.)

Step 5 . The conditioning of the processed shale for disposal is not fundamentally different from similar steps in other industries. It consists of cooling and adding moisture to the material so that it will not pose a severe dust problem.

Step 6 represents one of the major technical challenges of the entire operation. In many other industries, waste material of similar kinds has regularly been disposed of by placing it on open waste dumps. However, this industry will be processing extremely large amounts of waste which will make their waste dumps orders of magnitude larger than those common in typical metal mining, coal processing, etc.. Furthermore, the environmental requirements of our current society are much more stringent than those which were imposed upon previous metal mining operations, etc., so that it appears by universal consensus to be the case that the disposed-of waste must be left in a condition far superior to that of the many existing waste dumps which dot the western states. The final requirement seems to be that the waste dump be adequately vegetated so that it has a self-sustaining, viable vegetative cover; that the material be adequate compacted and shaped so that

it has no reasonable prospect of moving by slumping, landslides, etc.; and that it be adequately protected against leaching of salts or other materials from it. Considerable research has been done on the properties of the waste material and the steps which must be taken to reach these objectives. Since the stabilization and vegetation of the processed shale has not been accomplished on a large-scale basis anywhere, we must consider this as a new technology now under development.

Turning now to the steps on the right of Figure 6, we see the treatment of the exhaust gas from the combustion step. This will require removal of particulates and possibly removal of sulfur oxides. However, most of the planned processes will attempt to remove the sulfur down to acceptable limits before combustion because that is more economical than post-combustion sulfur removal. Thus, the only cleaning step required will be particulate removal which is a technology transferrable from other processes in which combustion gases are treated to remove particulates. To our knowledge, no pilot plant testing or development of particulate removal technology specifically for oil shale processing has been carried out nor is currently intended because the shale processors believe the technology is transferrable. Considering next the gas (Box 9), it is shown being treated in Step 10. The objective of this treatment is principally to remove hydrogen sulfide. The removal of hydrogen sulfide from gas streams is an extremely well-known technology which is practiced in the natural gas and petroleum refining industries (See Appendix IV). The groups developing the oil shale projects have assumed that this technology can be transferred directly. To the knowledge of the authors, no specific piloting or research has been conducted toward developing new types of hydrogen sulfide removal technology for the oil shale industry. The use of the cleaned gas as fuel or hydrogen source should pose no unusual problems.

The treatment of the liquid product to remove nitrogen and sulfur (Step 13 on the diagram) is in many ways similar to the same processes as carried out in oil refining. The fundamental technology is the same and is assumed transferrable. The oil companies have done considerable pilot plant testing of this technology and have no doubt found that some changes and modifications of the oil refining technology are needed, but they are confident that the fundamental schemes for other oils will work for oil shale and do not consider this an unusual problem.

The production of hydrogen for the treatment of the shale oil is a conventional technology. All modern oil refineries use large quantities of hydrogen which are normally produced by steam reforming of methane or some other light hydrocarbon. The light hydrocarbons produced as byproducts in oil shale retorting (for example, the gas) can apparently serve as feedstock for the hydrogen plant without difficulty (according to the DDP's). This is a mature technology which can be transferred intact from other areas.

A similar analysis of the in-situ processing scheme shown in Figure 7 indicates that Step 1, the mining out of 15 to 30 percent of the shale in order to provide void volume for subsequent operations, is a completely well-known mining operation no different than Step 1 of Figure 6. Step 2 on this figure, however, the conversion of the remaining shale to rubble by explosive fracturing, is a novel technology because the size of the blocks to be fractured is much larger than in conventional mining. The basic techniques are not substantially different, but the companies proposing to undertake the oil shale ventures believe it necessary to carry out pilot programs to guarantee the transferrability of this technology.

Step 3 on the left, the burning of the rubblized shale in place, is also a technology which is unique to the oil shale industry. The basic flow

arrangement to be used in in-situ processing (down-flow of air, down-passage of the combustion wave through rubblized shale) is basically the same as was used in the N-T-U type of surface retort (2). That idea has been known for many years. The novel thing here is carrying it out in place with rock which has not been carefully crushed to a uniform size, but rather, is merely the unsorted result of blasting and caving. In principle, this must work and pilot tests by Occidental at a fairly large scale have indicated that it does indeed work, so that this is a technology which is unique to the oil shale industry but which has been piloted. Step 4, the sealing of the burned retorts, if needed, to protect aquifers, is not directly transferrable to our knowledge. The provision of impermeable layers underground through cementing, grout curtains, etc., is a well-known technology, but whether it can be easily transferred to burned out oil shale retorts is unknown (it is also unknown whether it will be necessary).

All of the processing steps shown on the right of Figure 7 are the same as those shown in Figure 6 and have been previously discussed.

Summarizing the entire processing scheme, we see that most of it consists of technologies well known in other areas. The parts which are unique to the oil shale industry and for which we do not have large-scale demonstrations are the retorting of the ore (Step 4), the disposal of the processed shale (Step 6), and the treatment of the liquid products to remove nitrogen and sulfur and to lower the product viscosity (Step 13), and the large-scale underground blasting, retorting and sealing in the in-situ version. These are the steps in which unexpected difficulties could occur.

III-D. Air Pollution Control Technology

Tables 8, 9, 10, 11, and 12 show the various technologies which will be employed in the different projects to control each of the five air pollutants for which federal ambient air quality standards have been established. In

TABLE 8

PARTICULATE CONTROL TECHNOLOGIES FOR VARIOUS OIL SHALE PROJECTS

Uses in Various Projects

Technology	Rio Blanco (Commercial operation as a combined in-situ and surface retorting operation, as de- scribed in the modi- fied DDP)	Rio Blanco (Based on full-scale operation as a strip mine and surface op- eration, as de- scribed in the orig- inal DDP)	White River (Based on full-scale operation listed as Phase IV in the DDP)	C-b (Commercial operation as an in-situ project, as described in the revised DDP)	C-b, Colony (Based on original deep mining alterna- tive, discussed in the original DDP and the Colony EIS)
Wetting	Roads, construction sites, ore housing, stockpiles	Mine dust control, primary ore stock- pile and reclaim, traffic dust	Mine dust control, processed shale transfer, traffic dust	The revised DDP says very little about particulate control. It does say that the statements in the ori- ginal DDP applying to pollution will gener- ally apply.	C-b DDP does not give details of particu- late control technol- ogies. However, they planned to use under- ground mining similar to Rio Blanco and Tosco II retorts similar to Rio Blanco so their entry should be similar to Rio Blanco's with the GCR retort entries deleted.
Baffled settling chambers			Mine dust control		
Wet scrubbers	In-situ gas	Tosco preheaters, Tosco spent shale moisturizers, Tosco steam superheaters GCR moisturizer	Primary crusher ore transfers, secondary crushers, vertical retort feeder, spent shale moisturizer	The mining particulate control should be the same as in other mining projects.	
Cyclones		GCR retort overhead	Secondary crushers, fines-type retort ball elutriators, fines-type retort shale preheaters	The DDP implies that the retort off gas will not require par- ticulate control to meet applicable stan- dards.	
Bag filters	All crushers, ore transfer pts., bins, etc.	All crushers, fine ore storage	Processed shale trans- fer		
Electrostatic precipitators		GCR retort overhead	Vertical retort oil mist gas separation ⁽²⁾		

Notes to Table 8

1. Although Colony could be considered a separate project for the purposes of this table, the entries would be so similar to the entries for project C-b as to make them repetitious. One may verify this by comparing the diagrams presented for the various process units in the Colony Environmental Impact Analysis and the C-b Detailed Development Plan. For example, comparing Figure 25 of the Colony EIA and Figure IV-18 of the C-b DDP, we see that the only difference is that the latter had deleted the word "special" from the "LPG special product to storage" line at the upper right hand corner. This deletion was considered so minor that the draftsman did not bother closing up the space, but left it reading "LPG product to storage". Similarly, Figure IV-20 of the C-b DDP was made from Figure 27 of the Colony EIA. The minor letter changes on the revised figure are in a lighter shade than the original, e.g., the addition of the words (H_2S and CO_2) in the upper right hand corner.
2. In vertical retorts, e.g., Paraho Direct type, an electrostatic precipitator is used to remove oil mist from the gas. This also removes particles. This upflow gas combustion is shown here as a pollution control device, although the DDP does not list it.
3. Union and Superior are not included in this table, nor in the subsequent ones listing control technology for other pollutants, because they have not published descriptions of their proposed projects in detail comparable to that the DDP's cited above, or the Colony EIS. However, we may safely speculate that since they both envisage deep mining, their air pollution control technology for deep mining will be similar to that shown for the projects on this table. Their surface retorting will be technically quite different than Tosco II or Paraho, but the gas streams produced will be similar, and will presumably be treated similarly.

TABLE 9
SULFUR CONTROL TECHNOLOGIES FOR THE VARIOUS OIL SHALE PROJECTS
Uses in Various Projects

Technology	Rio Blanco (Commercial operation as a combined in-situ and surface retorting operation, as described in the modified DDP)	Rio Blanco (Based on full-scale operation as a strip mine and surface operation, as described in the original DDP)	White River (Based on full-scale operation listed as Phase IV in the DDP)	C-b (Commercial operation as an in-situ project, as described in the revised DDP)	C-b, Colony (Based on original deep mining alternative, discussed in the original DDP and the Colony EIS)
Amine scrubbing		High Btu gas	High Btu gas		High Btu gas (in this case there is no low Btu gas, so this is all gases) Hydrogen plant feed
Stretford scrubbing	Retort offgas		Low Btu gas	Retort offgas	
Claus conversion to sulfur	All acid gases	All acid gases	All acid gases		All acid gases
Sour Water Stripping	All sour waters	All sour waters	All sour waters		All sour waters
Beavon tail-gas cleanup	Claus tail gas	Claus tail gas			
Oil Hydrotreating		All liquid products	All liquid products		All liquid products
Water Wash	Retort offgas	Low Btu gas			Hydrotreater offgas
Rectisol scrubbers		Hydrogen plant			

(Continued on the next page)

TABLE 9 continued

Davy Powergas			Claus tail gas		Claus tail gas
Sulfinol scrubbing	High Btu gas				

TABLE 10

NITROGEN CONTROL TECHNOLOGIES FOR THE VARIOUS OIL SHALE PROJECTS

Technology	Uses in Various Projects				
	Rio Blanco (Commercial operation as a combined in-situ and surface retorting operation, as de- scribed in the modi- fied DDP)	Rio Blanco (Based on full-scale operation as a strip mine and surface op- eration, as de- scribed in the orig- inal DDP)	White River (Based on full-scale operation listed as Phase IV in the DDP)	C-b (Commercial operation as an in-situ project, as described in the revised DDP)	C-b, Colony (Based on original deep mining alterna- tive, discussed in the original DDP and the Colony EIS)
Oil hydrotreating		All liquid products	All liquid products	Not discussed at all in revised DDP	All liquid products
Waste Water Treating	All wash waters	All wash waters	All sour waters		All sour waters
Ammonia Extrac- tion (ammonex)		All ammonia-con- taining gases and liquids			
Rectisol Absorp- tion		Hydrogen plant			
Water wash		Low Btu gas	Low Btu gas		Low Btu gas Hydrotreater off gas
Ammonia conden- sation (WWT)			Hydrotreater water		
Ammonia conden- sation					Ammonia from sour waters (detailed purification scheme not revealed)
Oxidation to nitrogen in Claus Furnace	Ammonia from sour water stripper				

TABLE 11

HYDROCARBON CONTROL TECHNOLOGIES FOR THE VARIOUS OIL SHALE PROJECTS

Technology	Uses in Various Projects				
	Rio Blanco (Commercial operation as a combined in-situ and surface retorting operation, as described in the modified DDP)	Rio Blanco (Based on full-scale operation as a strip mine and surface operation, as described in the original DDP)	White River (Based on full-scale operation listed as Phase IV in the DDP)	C-b (Commercial operation as an in-situ project, as described in the revised DDP)	C-b, Colony (Based on original deep mining alternative, discussed in the original DDP and the Colony EIS)
Incineration or Thermal oxidizer	Tosco raw shale preheat stacks, retort gases	Tosco raw shale preheat stacks	Tosco raw shale preheat stacks	All retort gas	Tosco raw shale preheat stacks
Floating Roof Tanks	Naphtha storage	Naphtha, diesel, raw shale oil storage	Naphtha storage		Hydrotreater feed storage, Naphtha storage

TABLE 12

CARBON MONOXIDE CONTROL TECHNOLOGIES FOR THE VARIOUS OIL SHALE PROJECTS

Technology	Uses in Various Projects				
	Rio Blanco (Commercial operation as a combined in-situ and surface retorting operation, as described in the modified DDP)	Rio Blanco (Based on full-scale operation as a strip mine and surface operation, as described in the original DDP)	White River (Based on full-scale operation listed as Phase IV in the DDP)	C-b (Commercial operation as an in-situ project, as described in the revised DDP)	C-b, Colony (Based on original deep mining alternative, discussed in the original DDP and the Colony EIS)
Incineration or Thermal oxidizer	Tosco raw shale preheat, all retort gases	Tosco raw shale preheat	Tosco raw shale preheat	All retort gases	Tosco raw shale preheat

each of the following sections, we will review the control technology for one of these pollutants, referring regularly to the appropriate table.

In making up these tables, we have included not only the current (1978) versions of the Rio Blanco and C-b projects, but also the original versions shown in the Detailed Development Plans submitted in the Spring of 1976.

Our reason for so doing is that the developers put considerable efforts into preparing those detailed development plans and that, hence, their work should be recognized and examined, and secondly, that by thus expanding the table, we can show a wider range of possibilities of how environmental control technology would work for all of the ways now under active consideration for producing shale oil from shale.

III-D-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 ten 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 3 and 4. 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 in Rangely, Grand Junction, and Rifle, Colorado, and regularly at various locations in Utah.

For an oil shale operation, the principal sources of particulates are the blasting, mining, crushing, and transporting of the shale, the retorting operation in which the shale is processed, and the transport and disposal of the processed shale. The particles so generated are almost entirely fine-rock particles with more or less the same chemical and physical properties as the oil shale itself. The fine particles coming out of a retort would be similar chemically and physically to the processed shale.

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.

Table 8 shows the proposed particulate control technologies to be used in the oil shale development projects for which we have detailed development plans (and the colony EIS).

The various technologies to be used are listed on the left of Table 8 and they consist of wetting, baffled settling chambers, wet scrubbers, cyclones, bag filters, and electrostatic precipitators. This is practically a complete list of the types of particulate control technologies which are used in the entire range of industrial applications. It seems clear that in each case, the engineers preparing the detailed development plans have examined the particular dust or particulate source and attempted to select the most economical of the range of existing, off-the-shelf technologies to be applied to each one.

In selecting a particulate control device, the designer needs to know the weight flow rate of air or gas to be treated, the properties of the gas, the kind of particle to be removed, and its particle size distribution. The particle size distribution is a critical item because some kinds of particulate control devices work well for one particle size range and poorly for another. For example, cyclone separators are widely used to collect large particles but are generally ineffective for particles below about 5 microns in diameter. On the other hand, high energy scrubbers are very efficient for small particles (1 micron or lower) but are seldom applied for larger particles because they are too expensive to deal with a particle stream which can be handled by a much cheaper cyclone separator.

Appendix III reviews the entire field of particle control technology and discusses its application to the particular streams described in Table 8.

III-D-2. Reactions and Compounds of Sulfur and Nitrogen

The two following sections on the control of sulfur oxides and 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; and 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 8 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 may be local problems where they are emitted in large quantities,

FIGURE 8. The oxidation and reduction of nitrogen and sulfur.

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.

Considering now the sulfur and nitrogen which are present in the oil shale, this sulfur and nitrogen are normally present in the organic compounds which form the "kerogen." The sulfur and nitrogen are directly attached to carbon atoms by sulfur-carbon bonds or nitrogen-carbon bonds. If one simply burns the kerogen, which means oxidizing it, almost all of this sulfur and nitrogen would be oxidized to sulfur or nitrogen oxides. In general, this is environmentally unacceptable and would also prove unacceptable for many combustion uses because the resulting highly acidic gases are harmful to engines, etc. Therefore, the procedure which the oil shale developers propose to use, which is quite analogous to the procedure which the petroleum industry uses in dealing with oils which contain nitrogen and sulfur, is to break the sulfur-to-carbon and nitrogen-to-carbon bonds by hydrogenation. This is shown as reduction on Figure 8. By passing the hydrocarbon (in this case crude shale oil) with hydrogen at high pressure and temperature over a suitable catalyst, the hydrogen can be made to take the place of the sulfur or the nitrogen in the oil; and the sulfur and the nitrogen will be liberated from the oil in the form of ammonia and hydrogen sulfide. This then requires that the ammonia and hydrogen sulfide be separated from the oil product and processed in some other way. This is proposed in the original oil shale development plans, the liquid shale oil produced would be subjected to a catalytic hydrogenation, which would separate the vast majority of the nitrogen and sulfur from the oil product.

In the original Detailed Development Plans which envisaged significant oil shale upgrading at the oil shale sites, the hydrogenation of the oil shale shown in Figure 6 would have occurred at the oil shale site. This would simultaneously convert most of the sulfur in the shale oil to hydrogen sulfide and most of the nitrogen in the oil shale to ammonia.

In the two revised Detailed Development Plans for in-situ processing, the hydrogenation of the shale oil is not envisaged at the oil shale site, but rather at a remote oil shale refinery. However, the processing technology is substantially the same whether the processing takes place at the oil shale site or at the refinery. Either way, when the hydrogenation takes place the gas stream going from gas separation to sulfur production will contain both hydrogen sulfide and ammonia.

An alternative not shown on Figure 6 or 7 is to avoid this severe hydrogenation entirely, by using the crude shale oil directly as a boiler fuel in one of the many West-coast power plans which cannot be easily converted to coal. In this way the shale oil would replace conventional heavy fuel oil which might be easier to process directly to motor fuels than the shale oil. In this case, the crude shale oil might be burned directly as produced, or might undergo a very mild hydrogenation to lower the sulfur content to meet air pollution standards. The fate of the nitrogen is uncertain. There are published reports (49) that with proper burner adjustments, crude shale oil can be burned in utility boilers without exceeding the stack gas nitrogen oxide standards (NSPS). This must mean that the oxygen content in the combustion zone is low enough that most of the fuel nitrogen is converted to diatomic nitrogen rather than nitrogen oxides. If this is indeed the case, this may be the most economical way of all of dealing with the high nitrogen content of crude shale oils.

III-D-3. 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 3); 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 principle 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. Typical oil shale has an organic material called "kerogen" in it which typically has a sulfur content of about 1 percent. This section discusses the technology which the oil shale industry proposes to use to prevent the escape of more than trace amounts of this sulfur to the atmosphere.

Because 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.

In designing the oil shale processing schemes, the companies so doing have assumed complete transferrability of the sulfur-control technology which has been very thoroughly worked out for the oil refining industry. That technology is reasonably complex and has many variants. Table 13 is a summary of various processes used in petroleum refining fuel gas desulfurization. It shows that

TABLE 13

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 (OGA)	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	200-250	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

- (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 that is operated at about 315+ °C.
- (f) Sulfuric acid neutralized with limestone.

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 proceeding process. This scheme is illustrated on Figure 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, possible for use as a hydrocarbon feed to the hydrogen plant. The hydrogen sulfide goes on to further treatment. The H_2S separation box corresponds to the "fuel-gas treatment" listing at the top of Table 13. One sees there a variety of alternative processes. All of these follow essentially the following scheme. The sulfur-bearing gas is washed with an aqueous solution of some type of weak caustic. Because hydrogen sulfide is a weak acid in solution, it dissolves in the water and reacts with the weak caustic, forming a weak acid-caustic salt in solution. This removes the hydrogen sulfide from the gas. The solution from this washing process is taken to a separate piece of equipment, called a stripper, in which the temperature is raised enough so that the above-mentioned weak acid-base salt decomposes and relatively pure hydrogen sulfide is removed from the solution. This also regenerates the weak caustic solution which is then returned to the scrubbing unit for capture of more hydrogen sulfide. Now following the hydrogen sulfide on Figure 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 13 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

FIGURE 9. Sulfur control schematic.

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, 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 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 13. 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.

Almost all of the processes listed in Table 13 are functioning commercial operations which are available from chemical industry suppliers and which can be erected and operated with performance guarantees by anyone who will pay for them. The oil shale industry has taken the view that hydrogen sulfide produced from oil shale is no different than hydrogen sulfide produced from other hydrocarbons and that, therefore, these processes which work successfully everywhere else in the world on petroleum-generated hydrogen sulfide will work adequately on hydrogen sulfide produced from oil shale.

The scheme shown in Figure 9 is almost invariably used on gas streams which contain relatively little nitrogen, e.g., the high-Btu gas from Tosco II retorts. However, for gases which contain a great deal of nitrogen (e.g., off gas from in-situ retorts) the most economical process seems to be one in which all three boxes on Figure 9 are combined into one, and that one is a liquid-phase oxidation process. This process (most often the Stretford Process) is described in some detail in Appendix V.

Further details on these processes are given in Appendices IV, V, VI, and VII.

III-D-4. 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 3). 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 .

World-wide a major source of NO and NO_2 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 combines to form NO which in turn reacts to form NO_2 . 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 in in lightning strokes. 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 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 like power plants and process heaters.

The oil shale operations will involve large-scale combustion sources for the retorting of the shale, for process heat, and for electrical power generation. It appears from the detailed development plans that the oil shale companies intend to use the same general procedures used by other combustion sources to minimize the formation of nitrogen oxides in their combustion sources and do not intend to propose novel technology for this purpose. 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 an oil shale processing furnace or a petroleum refinery furnace.

An additional and interesting problem for the oil shale industry is the removal of the nitrogen which is part of the organic content of the oil shale. A typical "kerogen" contains approximately 2 1/2 weight percent nitrogen. This is much higher than is found in typical petroleum products and crude oils. In general, such high contents of nitrogen are unacceptable in finished petroleum products because their combustion would lead to the formation of corrosive products in the engine, leading to rapid engine wear and deterioration. For this reason, this nitrogen must be removed from the products.

In comparing the projects originally shown in the Detailed Development Plans to in-situ projects which are now envisaged, we see that there has been a significant reduction in the amount of on-site processing planned to be carried out at the oil shale site. In the Detailed Development Plans originally presented, most of the operators contemplated processing the oil shale on site to remove most of the nitrogen and sulfur and prepare products which were very close to conventional crude oil for further processing. The two currently planned projects both envisage only minimal treatment of the shale oil in order to prepare a material which is of low enough viscosity and low enough pour point to be shipped in interstate pipelines. The further removal of sulfur and nitrogen from this oil would be carried out at some remote refinery. Thus, the problem of the removal of nitrogen and sulfur from the oil and the containment of that nitrogen and sulfur during the removal steps is transferred from the oil shale site to a remote site, probably a major refinery in the Midwest.

There is little published data on the ammonia content of the off gases from in-situ retorts. The Revised Detailed Development Plan for the C-b Tract does not indicate that any steps are necessary to deal with the ammonia in the off gas. The Revised Detailed Development Plan for the Rio Blanco Project indicates that some ammonia may be present and that this will be collected in the wash water which scrubs the entire in-situ retort off gas and then removed with the hydrogen sulfide from this water in the foul-water stripper and sent to the Claus Plant. Presumably in the Claus Plant the oxidation will proceed only as far as nitrogen; not to nitric oxide, i.e.,

and not

III-D-5. 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. It is expected to be a minor constituent of retort off-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 the oil shale 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 that for carbon monoxide; namely, reacting them with oxygen to produce carbon dioxide and water. That is the principal control technology which will be used in the oil shale 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 oil shale operations 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.

Table 17 lists the hydrocarbon control technologies for the various oil shale products. There we see that one of the technologies is incineration.

The gas coming off of the raw shale preheater in the TOSCO process contains some hydrocarbon. This is burned (in a heat-recovery furnace) to oxidize this to carbon dioxide and water. In addition, there exists the possibility of the emission of hydrocarbons from the storage of oil shale products. There exists a substantial set of regulations in state and federal law concerning the storage of hydrocarbons and what technologies should be used to minimize the emissions from storage. Generally, for liquid hydrocarbons this consists of the use of floating roof tanks; and these are shown in Table 11 and in the detailed development plans to be used for all hydrocarbons whose vapor pressures are high enough to require them.

Table 12 shows the carbon monoxide control technologies indicated in the detailed development plans. The significant carbon monoxide sources in any of the proposed technologies are the TOSCO shale preheater and the in-situ gases. The incinerator which destroys the hydrocarbons in that stream will also destroy the carbon monoxide.

III-E. Water Pollution Control Technology

III-E-1. Overview of water control technology

Techniques used to abate water pollution generally depend on the type of water pollution encountered which again vary with the water source or process utilized. The basic sources of water pollution connected with oil shale development are:

- a. Mine Dewatering (drain water and seepage)
- b. Aquifer Disturbance (seepage due to increased permeability)
- c. Process water (oil shale processing, environmental pollution controls, waste-water)
- d. Surface Runoff (leaching from processed oil shale, storm runoff)

The first two sources produce water of groundwater quality. Process water usually is more contaminated and may require thorough treatment (containment and/or evaporation). Surface runoff quality varies depending on erosion, leaching

and drainage system. Figure 10 gives a pictorial overview of water sources, water uses, and water control technology in oil shale projects.

The basic methods for dealing with polluted water resulting from oil shale developments are:

- a. Aquifer ReInjection. Usually applied to excess water of high quality or similar quality to that of the groundwater. The water source is usually mine dewatering.
- b. Surface Runoff Diversion. Surface runoff entering plant site is diverted around plant site or processed oil shale site. The purpose is to prevent surface-stream contamination by soil and leached oil shale.
- c. Wetting of Spent Shale. To stabilize the processed oil shale and to revegetate the oil shale piles, considerable water is needed. This furnishes a disposal method for water of irrigation quality.
- d. Containment and Evaporation (zero release concept), consist of evaporating water from cooling and evaporation towers as well as from containment and evaporation ponds. It is a last resort for water which may not be reused or injected into aquifers.

Ideally the quantity of water obtained from mine dewatering would equal the amount of water needed for oil shale processing and processed oil shale wetting. 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 retorting process.

III-E-2. Water Use and Quality

It has been estimated that 1.0-5.4 cubic meter of water is required for oil shale development per cubic meter of oil produced (13). The low figure is

FIGURE 10. Water Flow in Oil Shale Projects.

for the Occidental in-situ process while the high figure is for the White River Shale Project. More than 20 percent of the water demand is attributed to processing of the oil shale with 45 to 50 percent consumed in moisturizing processed shale (13). Revegetation and dust control may take 10 to 15 percent of the water demand. A proposed total shale oil production rate of 207,500 bbls/day at tracts C-a, C-b, and U-a/U-b in Utah and Colorado is supposed to use about 33,400 AF/Yr of water (13).

Wastewater produced in connection with oil shale production comes specifically from the following sources:

- a. mine dewatering
- b. retorting operations
- c. oil shale upgrading operations
- d. environmental controls (air and gas)
- e. cooling water and boiler blowdowns
- f. sanitary facilities
- g. storm runoff

The Union Oil Retort B process has estimated a wastewater production of about $0.2 \text{ m}^3/\text{m}^3$ of oil produced not including mine dewatering and storm runoff (13). The quality of the wastewater produced depends on the predominant source. Wastewater from oil shale processing is expected to have high concentrations of organic amines, organic acids, ammonia, carbonates and bicarbonates. Biochemical and chemical oxygen demand (BOD, COD) are also high (5,000 to 20,000 mg/l). The quality of the water obtained from mine dewatering is approximately that of the groundwater while the quality of the storm runoff is highly dependent on location, drainage system and construction practices.

III-E-3. Aquifer ReInjection

As the name implies, aquifer reinjection is a method of disposing of withdrawn groundwater. On oil shale projects the groundwater is usually obtained

from mine dewatering operations. Mine dewatering may involve water seeping into mines and/or water pumped from wells drilled for purposes of dewatering shafts and rooms.

The amounts of water expected from oil shale mine dewatering operations vary from location to location. 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 (see Appendix VIII). Aquifer permeability is also an important factor.

The Rio Blanco Oil Shale project is estimating about 5 m³ of water from mine dewatering and seepage per m³ of oil produced for its C-a tract (13). Part of this water will be reinjected into groundwater aquifers (16). The Colony development on the Dow West property expect no or little mine dewatering (20). The reason for the difference is that the Rio Blanco tract is located at the center of the hydrologic basin, where there will be considerable hydrostatic pressure, while the Colony tract is located at the edge of the basin adjacent to deep canyons and cliff faces, where the hydrostatic pressure should be negligible. This illustrates the fact that 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.

Figure 11 shows schematically the use of aquifer reinjection to dispose of mine dewatering water. A single mine shaft and mine cavity are shown, although operating mines will have several shafts and many cavities. At the bottom of the cavity is a sump where mine drainage collects. This water is pumped to the surface through pipes in the shaft, and then disposed of by pumping down wells into one of three aquifers. The uppermost aquifer, called "alluvial aquifer" is the layer of soil, sand, gravel and loose rock near the surface. This is the cheapest place to dispose of the water (if permitted) because it requires only shallow disposal wells and this aquifer generally can easily accept more water than the others.

The other two aquifers shown are labelled "bedrock aquifers" because they consist of solid but porous rock, not like the loose material in the alluvial aquifers. If there is an aquifer above the one which drains into the mine, it will generally be cheaper to dispose of the water into that aquifer. If not (or if disposal into it is not permitted), then the water must be reinjected into the same aquifer which is draining into the mine. It might appear that this is a self-defeating process in which one simply pumps the water around forever. However, the rate at which water will flow around this cycle is governed by the permeability of the rock which is generally low enough that the flows are manageable. In this case, if the amount removed is the same as the amount reinjected, then once the initial dewatering has taken place there will indeed be a closed-loop flow with little change in water quality or pressure outside the ring of injection wells.

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 most oil shale projects, the mine dewatering water will be much too saline for such surface injection, and will have to be reinjected into the saline

FIGURE 11. Schematic of water flow in aquifer reinjection of dewatering water.

aquifers from which it originally came. The Rio Blanco Revised DDP (16) indicates that they intend to dewater the two aquifers on the tract separately and reinject separately. This is logical because the upper aquifer in that region has better quality water than the lower. Their policy is one of putting the water back into the ground at a place where the quality of the water in place is comparable to that which they are injecting.

III-E-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 oil shale development region is a manifestation to the influence of such water erosion.

Since uncontrolled erosion of processed oil shale may carry shale, salts and other constituent into surface streams, it is important to prevent or control the erosion of processed oil shale. Since most proposals for disposal of processed oil shale entail disposal in canyons or gulleys, 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. Moisturizing the processed oil shale to allow optimum compaction.
- d. Irrigating and revegetating the finished oil shale pile.

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 (55). 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 14.

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 hydrology books (55).

III-E-5. Wetting of Spent Oil Shale

Moisturizing the processed oil shale may be desirable for at least four reasons:

- a. To prevent excessive dusting.
- b. To obtain optimum compaction which will stabilize the pile and prevent erosion.
- c. To irrigate the pile and aid in revegetating the spent shale.
- d. To get rid of excess water from oil shale processing and mine dewatering.

TABLE 14
GREATEST OBSERVED RAINFALLS, GRAND JUNCTION, COLO.

Rainfall Duration	Total Rainfall	Period of Record	Date of Occurrence
5 min.	0.44 in.	1899 - 1977	July 1974
10 min.	0.66 in.	1899 - 1977	"
15 min.	0.96 in.	1899 - 1977	"
30 min.	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	Oct. 17, 1908
1 month	3.78 in.	1892 - 1977	Sept. 1896

The spent shale should be wetted to contain up to about 15 percent moisture (by weight) to make it coherent and to prevent dusting. This means that for each cubic meter of processed shale up to 210 kg or 7.4 cubic feet of water will be needed. For a 50,000 barrel of oil per day operation, with a processed oil shale production of about 90,000 tons per day, this means a water use of up to 3600 acre-feet per year for the initial oil shale moisturization. Another way of stating this is that up to 1.55 m^3 of water is needed for the initial oil shale moisturization for each m^3 of oil produced.

The ultimate fate of most of the water used for spent shale moisturizing is evaporation. At 15 percent by weight moisture, the water is not mobile for ground water flow and will not move as groundwater in the spent shale pile. Much of it will be evaporated in the period between the time the piece of shale containing it is put on the pile and the next piece is put over it.

III-E-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 5000 MW plant at Kaiparowits, Utah, proposed to evaporate as much as 45,000 acre-feet of water per year (56).

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 (57), 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 (ash in power plants, processed shale in oil shale projects). 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 (58).

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 (59). 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 Canyon, 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 (60).

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 oil shale projects, the containment and evaporation pond technique of disposing of wastewater is a last resort after the water has been reused since the method is not efficient 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 biological decomposition which will take place in the waste is normally measured by its ability to withdraw oxygen from water, commonly called 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 15 contains data on representative values for the expected net evaporation rates for western Colorado and eastern Utah for an altitude of about 5000 feet above sea level (61). Oil shale containment-evaporation ponds are planned 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) (62).

It can be seen that no, or negative evaporation (precipitation), must be anticipated during four winter months (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.

TABLE 15

MEAN MONTHLY PRECIPITATION - EVAPORATION DATA
FORT DUCHESNE, UTAH (ELEV. 4990) (61)

	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) (61)

	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

The percolation from the containment and evaporation pond depends on the permeability of the underlying soil or rock. Since the ponds are planned for 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 (63). Since average net evaporation rates are about 36 inches/year more water may be lost through percolation than evaporation.

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

III-F Solid Waste Disposal and Management

The technology required for the surface disposal and management of solid wastes from oil shale operations is that required to (1) prepare the disposal site, (2) transport the refuse to the disposal site, (3) construct a stable pile of the refuse, (4) protect the pile surface against erosion by wind or water, and (5) rehabilitate the disposal facility to a state consistent with the pre-existing land uses in the area and compatible with existing adjacent undisturbed natural areas. The latter is complicated by the arid nature of the climate in the area of oil shale projects.

This solid waste disposal and management will not necessitate the development of new technology since the required technology is, in the most part, adaptable from the technology already developed in connection with:

- (1) Disposal of wastes from coal mining and tailings from coal processing operations (45,64).
- (2) Treatment and disposal of fly ash from coal-fired power plants (65).
- (3) Construction of earthen dams and roadway land fills (66).
- (4) Rehabilitation of strip-mined lands and coal mine refuse disposal facilities (67,68,69,70).

Due to the salinity of processed oil shale and the alkalinity of soil in the area, the preparation of dump surfaces for revegetation will probably be the only area where new technology may be required.

III-F-1. Disposal Site Selection and Preparation

The first step in the development of the waste disposal facility is the selection of the site for the facility. Basic requirements are that the facility be large enough to accommodate the volume of wastes anticipated

during the duration of the project and that the disposal site be close to the processing operations. In addition, it is desirable to minimize other factors, such as, amount of surface water drainage into and ground water seepage from the surface of the proposed disposal site, which might complicate the construction or stability of the disposal pile.

The landscape in the area of current and potential oil shale developments is characterized by rolling hills with flat-topped ridges and rounded canyon walls dropping steeply 100 to 300 feet into narrow, flat-bottomed canyons. In all projects, canyon-type disposal sites are planned.

Embankments will be of the side-hill, non-impounding variety (Figure 12) (59). Initially they will be side-hill embankments, but they may develop into the valley-fill variety. If necessary to accommodate the amount of waste generated, the pile may also be extended above the elevation of the present ridge line (Figure 13). A drainage ditch will be required to collect runoff from flowing into the disposal pile (Figure 14). Runoff from the pile itself will be collected in a leachate ditch and routed to a catch basin behind a retention dam which will prevent the leachate from entering and polluting nearby streams and waterways.

Rio Blanco had planned to use a flat disposal site off the tract (84 Mesa) but apparently could not obtain the necessary permits and/or approvals, and is now planning their disposal facility alongside of Rinky Dink Gulch in the southeast corner of the tract (71).

Preparation of the disposal site will consist of the construction of access roads, the removal of debris and large rocks which might hamper the operation of machinery on the site, and probably stripping of the surface and other soil from the site. Soil stripped from the surface of the dump would be stockpiled in a separate area so that it could be used in later rehabilitation efforts. Larger pieces of rock may also be kept for later 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. It would also aid in controlling surface erosion.

(a) side hill, non-impounding embankment

(b) valley-fill, non-impounding embankment

FIGURE 12. Types of Embankments to be used for Processed Shale and other Solid Waste Disposal

FIGURE 13. Schematic Illustration of the Phases in the Construction of a Waste Disposal Embankment

FIGURE 14. Schematic of Processed Shale Disposal Pile prior to Rehabilitation

III-1-2. Transport of Wastes to Disposal Facility

Processed shale will be transported to the disposal site by belt conveyors while other wastes will be hauled to the site in trucks. At the disposal site, the processed shale will be deposited in temporary storage and truck-loading hoppers from which the shale will be loaded into trucks for placement on the disposal pile. Moisture added to the shale to cool it after it is removed from the retorts will raise the moisture content of the the processed shale to about 14 percent by weight. This should be adequate to control fugitive dusts and to assist in the construction of a stable disposal pile.

III-F-3. Construction of Disposal Pile

Design Considerations: Until about five years ago, little or no serious consideration was given to the design and construction of the refuse embankments for mining or process operations. The folly of this was dramatically demonstrated in 1972 by the failure of the refuse embankment for a coal mine on Buffalo Creek near Saunders, West Virginia. One hundred and twenty-five persons lost their lives in this tragedy and nearly 4,000 were left homeless (45,64). Although the failure of a processed shale disposal embankment would probably not have the disastrous consequences of the Buffalo Creek failure, it could cause the leachate to overflow the retention dam, thus polluting streams in the area. It would probably significantly 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 15. First, the entire embankment may slide down the slope upon which it was constructed. Secondly, material may spill from the sloped portion of the embankment. Finally, a large section of the pile might break away and slide down the sloped surface. The latter is termed an instability failure. In all these modes of failure,

FIGURE 15. Three modes of embankment 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 other two cases, 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 surface. If the surface of the land is not naturally rough enough to accomplish the interlocking, or if the stripping of top soil from the site "polishes" the surface to the point that the interlocking will be insufficient to hold the embankment on the slope, it may be necessary to intentionally cut steps or other irregularities into the stripped 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 (65,66). The angle of friction is generally not significantly affected by moisture content. On the other hand, cohesion is strongly dependent upon moisture content. At low moisture content, the water surrounds the particles and there is a cohesion due to capillary forces (65). The contribution to the strength of the material can be lost by either drying the material or saturating it with water. In tests using wetted but unsaturated shale processed using the TOSCO II technique, the cohesion was measured to be 1000 pounds per square foot (psf), but when this same material was saturated, the cohesion dropped to 400 psf or 40 percent of the unsaturated value (71). This helps explain why embankment failures of all modes are generally associated with the presence of water. The absorption of water by the embankment not only decreases the shear strength of the material but also

increases the magnitude of the stresses imposed on the body by increasing the weight of the upper portions of the structure.

Another material property which is important in understanding the behavior of processed shale embankments is permeability. Permeability is a measure of how rapidly water will flow through the material. The coefficient of permeability has the units of velocity, such as feet per year, but has no direct physical significance. It should be treated as an index of comparison with no convenient physical significance. The higher the value of the index, the faster water will be absorbed into the material. In tests on a sample of a mixture of TOSCO II processed shale (65%) and Paraho processed shale (35%), the behavior was classified as semi-pervious. If this material is compacted to a density of about 90 pounds per cubic foot, the behavior becomes impervious. In a test designed to simulate burial at 90 feet, the measured permeability varied from 0.3 to 0.6 feet per year (71). This means that water will not readily be absorbed into a properly compacted processed shale pile. The shale can become saturated by the process known as percolation, the absorption of moisture due to the protracted contact of water with the material. Examples include the absorption of moisture due to a standing pool of water on the surface of the pile and the absorption of moisture due to a cover of a melting snow-pack (43). By providing sufficient slope to exposed surfaces of the pile and avoiding depressions in which water may accumulate and stand, it should be possible to restrict saturation to the extreme outer portions of the exposed surfaces of the pile.

Characteristics of Processed Shale: Shale retorted by the TOSCO II process is crystalline and bulky with a large proportion of fine material. It is a reasonably good material for the construction of embankments. Tests

conducted on this processed shale indicate that the angle of repose, i.e., the angle of the sides of the pile produced by dropping the material onto a level surface, is 35 degrees under dry conditions and 20 degrees under saturated conditions (71). This means that under saturated conditions TOSCO II processed shale would be capable of maintaining a slope slightly steeper than 3:1, i.e., one foot drop in three feet of horizontal distance. With the shallow slope of 4:1 which is planned for the sides of processed shale embankments, it has been estimated that the safety factor for an infinitely high pile will be 1.5 with the outer two feet of the pile saturated. Although there is always uncertainty in this type of analysis, a safety factor of 1.5 is higher than that normally associated with soil embankments and is considered very good.

Shale retorted by the Paraho direct mode process is soft and friable. It contains 2 to 3 percent organic "carbon" residue by weight, and has somewhat larger particles than the TOSCO II processed shale (see Table 16). It is possible to further pyrolyse this matter to produce additional process heat and create a carbon-free ash in which the dolomite and calcite in the original oil shale rock is decomposed and calcium silicate formed. This ash has a composition similar to Portland cement and will create additional cohesive forces when moisturized (10 percent is optimal) and allowed to cure. The result is a solid substance which is much stronger than the ash and which is impervious to the flow of water. The cured material achieves approximately 90 percent of its strength in the first sixteen days of storage. The strength of the final structure can be increased further by grinding the ash into a smaller particle size before it is moisturized and placed into the pile.

Other Failure Modes: Another type of soil failure is liquefaction.

TABLE 16

CHARACTERISTICS OF PROCESSED OIL SHALE⁽¹³⁾

	Retorting Method	
	Paraho Direct Mode	TOSCO II or Paraho Indirect Mode
Geometric mean size, μ	0.205	0.007
Bulk density, g/cm^3	1.44	1.30
Solids density, g/cm^3	2.46	2.49
Porosity	0.41	0.47
Permeability, cm^2	3.46×10^{-9}	2.5×10^{-10}

In this type of failure, which is commonly confused with the mode 3 or instability 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. The material then simply falls away and flows down the slope of the embankment in the same manner as a fluid. Such failures may also be triggered by the earth movement during an earthquake (shock or seismically-induced liquification). The important thing to remember here is that liquification is associated with material that is saturated with water. In the case of the processed shale pile, saturation is expected to be restricted to the outer portion of the exposed surfaces. Under these conditions, even seismically-induced liquification would probably only result in minor slumpages or bulges.

Construction Techniques: The steps in the construction of the processed shale disposal pile are (1) distribution of shale to the pile, (2) compaction of the pile to a sufficiently high density that it will be impervious to the flow of water, and (3) grading the pile to desired slopes. The shale temporarily stored in the hoppers will be loaded into bottom-dump trucks in which it will be transported to and placed upon the disposal pile. The shale will be deposited in windrows which will be spread into 2-foot lifts by a grader. The shale will be compacted to a density of about 85 pounds per cubic foot (pcf) by the action of the trucks and graders moving across the pile. This will be adequate for the interior 80 percent of the pile. The exterior 20 percent of the pile will be compacted to about 90 pcf using mechanical compactors. This will further decrease the permeability of the surface layers.

III-F-4. Control of Surface Erosion.

The disturbance of existing land surfaces and the creation of new surfaces significantly increases the rate at which surfaces may be eroded by wind and water. Since processed oil shale is an easily erodible material, it is planned to have available a variety of suitable surface treatments to control this mechanism while revegetation is underway. Eventually rehabilitation requirement will make it necessary that all dump surfaces and affected lands be revegetated. In the meantime, measures will have to be taken to control the surface erosion pollution mechanism.

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 drianpipes, down drains, 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 fibers, emulsions, chemical binders, jute netting and mats , and plastic matting and nets.

III-F-5. 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. The pre-existing uses of the land involved in oil shale development are grazing lands for domestic livestock and wildlife. Wildlife noted on these lands include mule deer, wild horses, birds, small herbivores, and predators (71). 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 of 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 processed shale piles, namely, try to establish vegetation directly upon the processed shale itself or provide a cover of fertile soil suitably isolated from the processed shale and in which seeds will germinate and grow. Properties of processed shale which limit the ability to establish plant life directly upon processed shale are (1) the high soluble salt content of the shale, (2) the alkalinity of processed shale, (3) the lack of nutrients needed to foster plant life, and (4) the dark color and texture which cause it to be a good absorber of solar radiation. It has been shown that the germination and growth of most plants is adversely affected when the conductivity of the soil (directly related to the soluble salt content) exceeds 4 mmhos/cm or the soil has a high pH factor (related to alkalinity) (13). In addition, the nitrogen and phosphorus content of processed shale is insufficient to support plant life, and when subjected to direct sunlight the processed shale surface can reach temperatures of 65°C (150°F) which is too high for the germination and growth of plant life.

To successfully establish plant cover directly upon a processed shale pile will require that the surface of the pile be leached to reduce its salinity and alkalinity, plant nutrients be supplied in the form of a

fertilizer and/or mulch, and the surface be covered with low absorptivity material, such as straw, to keep the surface temperature low enough that it does not interfere with seed germination and plant growth. In arid climates typical of most oil shale developments, it may also be necessary to irrigate the newly planted areas to increase the rate of rehabilitation. A major difficulty with this technique is that it will be impossible to assure that the entire surface is leached uniformly and there will probably be pockets where leaching was inadequate and plants will not grow. In addition, since the processed shale is so fine, it is possible that capillary movement of salts within the pile might resalinify the surface and prove toxic to plant life.

The second technique for vegetating the waste pile utilizes the top soil stripped from the ground before construction of the pile to create a fertile layer of soil over the completed dump. To keep the soil from being contaminated by the capillary movement of salts upward, a barrier of crushed rock and gravel will be placed on the surface of the processed shale pile before the cover of soil is applied. A five-foot layer of coarse rock and gravel is planned to be followed by 12 inches of soil. This depth of coarse material should be enough to stop the upward flow of salt by capillary action.

III-F-6. Recycling and Reuse of Waste Oil Shale

Studies have shown that fly ash (65) as well as other mining and metallurgical wastes can be successfully utilized as construction materials (72). It has been further demonstrated that processed oil shale can be utilized with asphalt to produce a medium-wear pavement material (73). It is therefore conceivable that processed oil shale could be utilized to help construct roadways and other structures on or near the oil shale

development. In general, other material such as the overburden removed in sinking shafts, tunnels, etc., will be a superior construction material and will be given preference in construction of needed facilities. In addition, the cost of transporting bulk construction materials to the construction site is usually a major cost so unless there is a major construction project in the immediate vicinity of the oil shale project, it is unlikely that much of the processed oil shale will find usage in any area other than those directly associated with the oil shale operation itself (74).

III-F-7. Underground Storage of Processed Shale

One possibility which is given some consideration in the revised Rio Blanco Detailed Development Plan (16) is that the processed shale from their TOSCO II Retorts could be slurried with water and pumped back into the void space in burned-out in-situ retorts. This would have several advantages: first, it reduces the volume of spent shale which must be stored at the surface, second, it may be possible to fill the in-situ retorts full of solid, thereby making them much less permeable to water, third, if it is possible to complete the filling operation so that the roof of the retorts is supported, the chance of eventual collapse of the retorts and resulting surface subsidence will be minimized.

At present, this is a speculative technology which may be used. Rio Blanco has expressed its intention to test it; they have made no commitment to use it on a commercial scale until they see the results of those tests.

As discussed briefly in the introductory part of this report, in some parts of the oil shale deposit there exists, mixed with the oil-bearing shale, deposits of nahcolite and dawsonite. The Superior Oil Company has

developed technology for separating the nahcolite from the shale before the shale passes through the retorts for the recovery of oil. They have also developed technology for treating the retorted shale to recover the aluminum content of the dawsonite as an alumina which can be processed to make commercial alumina suitable for the production of aluminum and to also recover soda ash. In this case, they propose that the processing will remove sufficient material from the spent shale that the spent shale can all be replaced in the mined-out area whence the shale was removed. This process has not advanced technically as far as the others and thus we are not nearly as certain how it will function. But since it is their intention to replace the solid waste product all in the ground, it seems clear that it will, to this extent, but somewhat more environmentally benign than those processes which deposit waste on the surface.

III-G. Other Environmental Control Technologies

Some processing which is done for internal reasons also functions as an environmental control technology. For example, the Colony EIA (75) indicates that they will have to remove arsenic from the streams which are hydrotreated, because arsenic is harmful to the hydrotreating catalyst. They do not give a figure for the arsenic content of their raw shale oil, but from the figures they do give, one may estimate it at about 35 ppm. Similarly, Union (10) reports that the crude shale oil from their Type B retorts "... contains 50 ppm of chemically combined arsenic, which will be reduced to about 2 ppm in a proprietary Union Oil process. It is reacted with an absorbent which picks up arsenic to about 80 percent of its weight...". However, Rio Blanco (76) presents data from which one can infer that the arsenic content of the raw shale oil produced from its tract is about 8 ppm.

These differences may result from local difference in arsenic content of the shale, or differences in the type of retort used; all three of the above results are from different retorting procedures. Workers at the Laramie Energy Research Center of ERDA have surveyed the trace element content of oil shales, shale oils and retort waters (77). They found less than 10 ppm of arsenic in most samples, but did find one with 53 ppm. They also found this variation puzzling, and suggested that it may be due to the presence or absence of water in the retorting process. If the shale oil is not treated to remove this arsenic it will presumably end up as fly ash or furnace ash where the oil is burned. Although there is no national air pollution regulations for arsenic, it is known to be poisonous in large doses, and also to be a carcinogen (78). Thus arsenic removal for internal catalyst protection will also serve an environmental purpose.

IV. POTENTIAL PROBLEMS AND DIFFICULTIES WITH PROPOSED ENVIRONMENTAL CONTROL TECHNOLOGIES

IV-A. Comparison of In-situ and Surface Processing From an Environmental Viewpoint

The large shift in emphasis from surface retorting to in-situ retorting which has occurred in the past year was driven largely by economics; in-situ is much less capital intensive than surface retorting. In addition, its promoters have asserted that it is environmentally superior (i.e., has less environmental impact). Is this claim justified? To answer this question fairly we should compare the in-situ operations to surface operations which only proceeded as far as the crude pipelineable shale oil which is the intended product of projects C-a and C-b.

IV-A-1. Air Pollution

The air pollution consequences of in-situ retorting should, in principle, be roughly the same as the air pollution consequences of retorting a comparable amount of material in a surface retort of the type envisaged by Paraho or the older Bureau of Mines retorts. Technically, the retorting process in those retorts is very similar to the retorting process which goes on in the in-situ operation, and therefore, we would expect the gas coming off of that operation to be very similar to that from the in-situ operation. One significant difference is that the amount of crushing, transporting, and storage of crushed shale at the surface would be fairly significant for the surface retorting operation and much smaller for the in-situ operation and there is no processed shale to handle in an in-situ operation, so that the fugitive dust loading from the in-situ

operation should be significantly smaller.

An additional factor in favor of the in-situ operation, which it is not possible to quantify from published data, is that the in-situ gases pass over fairly substantial amounts of unprocessed shale before reaching the gas collection ducts and therefore have some of their particles removed by contact and may have some of the sulfur compounds removed by contact with the shale which is itself a weak sulfur-compound absorber. A variant on the in-situ process which has been discussed, but to the knowledge of the authors, not presented in technical terms is to use the calcium and magnesium oxides in a burned-out retort as sulfur-removal devices. To do so, one would route the retort off gas, after separation from oil and water, through one of the burned-out retorts before bringing it to the surface. It is possible that in this way one could remove enough of the sulfur from the gas so that surface sulfur removal would not be needed. To the knowledge of the authors, this is currently a speculative process which has not received any significant amount of testing.

IV-A-2. Water Quality

In most parts of the rich oil shale deposits, it will be necessary to dewater the mines which produce the shale whether the mine is an open-pit mine, or an in-situ mine. The amount of water so produced depends upon the amount of intersection of the aquifers and the hydrostatic pressure in the aquifers, but the quality of the water so produced should be more or less identical regardless of which mining procedure is used. Similarly, the water produced during retorting should be more or less the same whether the retorting is in-situ or a surface retorting scheme like Paraho direct which is chemically analogous.

The significant differences in terms of water quality between in-

situ processes and mining processes with surface retorting are that in the mining processes with surface retorting there is a potential water problem from the processed shale stored at the surface (which problem the oil shale operators believe can be totally controlled) whereas this problem does not exist with in-situ which would have no processed shale at the surface, and that in the in-situ process when the process is totally complete the burned-out retorts will present potential pathways for the travel of water from one aquifer to another. In most of the mining versions considered (e.g., the original detailed development plant for Tract C-b) the vertical height of the mined-out sections would normally be about 60 feet. In contrast, the vertical height of the in-situ retorts will normally be on the order of 300 to 700 feet. Thus, the burned-out retorts, filled with processed shale, represent potentially greater routes of communication between the two major aquifers in the region than the mines themselves would. When we know more about it, we may conclude that it is a simple matter to seal these retorts so that there are no modes of communication between the two aquifers, but for the moment this must be considered a potential problem.

IV-A-3. Surface Disposal of Waste

Here the in-situ has a very clear environmental advantage since much less waste will be disposed of at the surface per unit of oil produced, and that waste will be mostly unprocessed oil shale which is a highly resistant rock which does not leach or decompose easily under the ambient conditions which exist in Western Colorado or Eastern Utah.

Thus, it appears that in going from surface processing to in-situ the industry has probably reduced its environmental problems and environmental control costs and certainly reduced its surface impact. If it does

turn out that the processed retorts do not represent significant means of communication between the aquifers or can be easily sealed to prevent that, then the overall environmental impact of the in-situ retorting will be much less than that of surface retorting, as in-situ's proponents claim.

IV-B. Proprietary Information

One of the problems facing anyone who tries to assess the potential environmental control difficulties to be encountered in oil-shale 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. Hence, these organizations do not wish to reveal to the public information which they intend to sell to potential licensors.

A particular example of this type concerns Occidental's in-situ work. They apparently have more operating experience in in-situ retorts than anyone else. They have published very little of a substantial nature describing the engineering aspects of their retorts. One should not fault them for this, they did all that work with their own funds and expect others to pay them to find out what they have already paid to find out. But, as a result, there is, to our knowledge, no published analysis of their waste gas stream, nor published analysis of the composition of the crude shale oil produced, etc.

The other firms in similar positions normally have published somewhat more, because of different contractual histories. For example, the Detailed Development Plans contain estimated off-gas analyses for the TOSCO and Paraho retorts. Nonetheless, there does not appear to be any published information on the particle loading or the particle size distribution and their off-gases, etc.

In this situation, we are faced with the developers' assertion that the control devices that they intend to use are adequate to meet environmental control standards and we are not directly able to check these statements. Presumably, the air pollution control agencies in the states where the facilities will be located will be able to gain access to the missing information and to check the calculations to assure themselves that there is no significant likelihood of a violation of the applicable standards. Most states have laws protecting the confidentiality of such information so that even after state review of plans is completed we may not have access to a detailed description of the off-gas flows from various processes.

IV-C. Potential Air Pollution Difficulties

Based on all the preceeding discussion, it seems clear to the authors that most likely the oil-shale industry at the level of several projects in the 50,000 to 100,000 barrel-a-day range can be established without violation of any applicable air pollution control standard with the possible exception of the Colorado Class I nondeterioration regulation. 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 oil shale facility haul road would almost certainly show an ambient air quality standard violation.

IV-C-1. Polynuclear Aromatics

Some concern has been expressed about the presence in shale oil and processed shale of polynuclear aromatics (sometimes referred to as polynuclear organic materials (POM's))(79). Some of these are known to be carcinogens in animals and potentially so in man. The example compound which is frequently used as an indicator of the presence of this large family, and as a test carcinogen by skin application to mice, is benz-a-pyrene (BAP).

Tests have shown that fairly significant amounts of benz-a-pyrene are present in raw oil shale, and in the retorted waste shale. Benz-a-pyrene is a normal constituent of the products of combustion of almost any type of fossil fuel.

The environmental question is - will the large amounts of benz-a-pyrene which will be in the processed shale piles ever find their way into the ambient air or water, and if so will they then prove harmful to plants, animals, or humans? It is certainly the intent of the oil-shale operators to prevent any processed shale from becoming part of the atmosphere or the aqueous environment. If their processed shale storage plans work as they intend, then these materials will be permanently immobilized and permanently

isolated from the environment. The processed shale from in-situ retorts will be contained underground and hence should be permanently immobilized.

However, even if these materials do become part of the atmospheric or aqueous environment there is still serious question whether they will be harmful. It has been shown (80) that in the case of some organic residues which contain a benz-a-pyrene, the residue itself is not carcinogenic when applied as a surface patch to mice, while its benzene extract is carcinogenic. This implies that the solid which contains the benz-a-pyrene ties up the benz-a-pyrene in such a way that it is not biologically active, while the benzene extract liberates it in such a way that it is biologically active and causes skin cancer in mice. The oil shale companies have conducted toxicological tests both addressed at the question of whether the benz-a-pyrene in processed oil shale, and in the intermediate streams in the oil shale industry, will be an environmental hazard, and at the question of whether it is an occupational hazard for the workers in the oil shale industry. These tests are continuing, but the results reported so far (80) support the contention of the oil shale industry that, although large amounts of benz-a-pyrene and other polynuclear aromatics will be present in the processed shale, and to some extent in the crude shale oil, they will not be present in a form which will pose an environmental health hazard.

IV-D. Water Pollution

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

IV-D-1. Aquifer Reinjection

If aquifer reinjection of water is necessary this normally means that sizeable 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 rise 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.

IV-D-2. Dam Safety

The oil shale projects envisage using catchment or 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 (1976) and the Buffalo Creek

failure in West Virginia (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 Bureau of Reclamation (81). 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 (59, 81).

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.

IV-D-3. Evaporation Ponds

Although evaporation ponds will not be used as extensively in the planned oil shale operations as they are in power plants in the arid southwest, they will be used to some extent. The problems which can occur with evaporation ponds are:

- (1) Dam (or embankment) failure, discussed above,
- (2) Climate (i.e., precipitation)
- (3) Hydrology (stream inflow, flooding, percolation)
- (4) Land availability
- (5) Odors
- (6) Birds

the problem 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 15).

Containment and evaporation ponds are generally planned between the depositional area for processed oil shale and a downstream check dam. The check dam will be built to secure the processed oil shale pile as well as to pond wastewater for evaporation.

Land suitable for containment 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 water supply of culinary water. Land which bears signs of torrents, flash floods, avalanches or landslides, or geologic faults should naturally be avoided. Containment and evaporation ponds should also be so located that possible noxious odors from biological decomposition or anaerobic processes do not reach or bother surrounding settlements.

Since it is impossible to cover containment and evaporation ponds (nothing would evaporate) sea gulls and other birds can feed on the ponds. To avoid possible contamination from being carried by these birds to other sources of culinary water, neighboring reservoirs of culinary water should be covered and/or the water should be disinfected.

IV-D-4. Burnt-Out In-situ Retorts

The first of the novel water pollution control problems to be considered is the existence of the burnt-out in-situ retorts at the end of an oil shale project. These retorts, at the end of their commercial life, will be large chamber (typically 100 x 100 feet x 300 to 700 feet

high) filled with large-size retorted oil shale. Generally they will be located in the zones between the upper and lower aquifers in the Piceance Basin.

At this time we do not know for certain what the hydrologic effect of these will be. It is possible that the spent shale produced in in-situ operations will be inert because its surface has been somewhat melted, or it may be that this material will leach well. It is possible that there may be no ground water flow through these or it is possible that significant flow will occur.

The largest scale tests of this kind of operation were made by Occidental Petroleum Company in the D-A property which is located at the edge of the basin and does not have hydrologic properties comparable to those which will be encountered in the middle of the basin. Therefore, although we have many ideas and studies on what the long-term effect of these holes will be, we cannot say that we know for certain, based on experience, what they will be.

The worst imaginable outcome would be that they form a path for flow from the lower aquifer to the upper aquifer and thence out into streams and springs. The lower aquifer water is generally of poorer quality than the surface water, since it contains large amounts of dissolved solids. In order to know for certain whether this is likely to occur, we would have to know what the hydrologic conditions between these two aquifers are. To our knowledge, no comprehensive examination of this problem has appeared in public.

The in-situ developers are aware that this is a potential problem, and indicate that they plan to test various ways of dealing with it. It seems likely that a satisfactory solution can be found; but it is not abso-

lutely certain that one can (at an acceptable price).

IV-D-5. Spent Shale Piles

The spent shale piles which will be produced by any surface re-torting operation will be unique in the world in the magnitude of processed solid material which will be brought to the surface and stored there. The detailed development plans for those projects which intended (and/or intend) to use surface retorts have devoted considerable attention to the design and operation of these piles with the objective of guaranteeing that they are stable and there will be no percolation of water through them with the resultant leaching of salts and other materials from the piles into the surface waters. In general it seems clear that much thought and effort has gone into this. Similarly, medium-sized tests of the behavior of this material in the Colorado environment have been made. Based on all of these, it appears that the situation should be manageable. However, this is one of the areas where we are going up many orders of magnitude in size from anything really comparable which has been tried before. In any such scale-up which involves many orders of magnitude, there is always the risk that some unforeseen situation will occur which will be troublesome.

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.

Even after the pile has been completed and fully vegetated it will be desirable to monitor plant life to assure that the plant life is not becoming threatened by resalinification of the surface or that trace elements from the pile which would be toxic to grazing animals is not being transferred into the plant life. One study has shown that the zinc and molybdenum levels in vegetation grown on processed oil shale exceeds the maximum amount recommended for forage to be consumed by cattle.

V. 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 an oil shale project is due to environmental control technology. This is not surprising because these projects are to date still paper-and-pencil projects; none has been constructed. Furthermore, the projects which are in the furthest advanced states of development are being pursued by companies which are actively attempting to license their competitors to use their technology. Hence they are unwilling to reveal to the public that cost information which they tend to include as part of their license packages.

V-A. The Colony Cost Breakdown

The most detailed set of cost estimates which we have been able to find we presented by Whitcombe et al. of The Oil Shale Corporation (115). These are for the Colony Project and are believed to be accurate as of the end of 1975. They are based on detailed estimates prepared by C. F. Braun and Company for a complete oil shale project to be carried out by Colony in Colorado. These are summarized in Tables 17 and 18. These are based upon a projection rate of 43,200 barrels per calendar day of 40° API sulfur-free synthetic crude.

From these tables, we may draw the following conclusions: 1) These projects are very capital-intensive. The projected investment is slightly over \$22,000 per barrel/calendar day. As shown in Section I-B, for such a capital investment at normal interest rates, one would expect the capital charge to be of

TABLE 17

BREAKDOWN OF INVESTMENTS ⁽¹¹⁵⁾
FOR THE COLONY PROJECT
 (Basis - September 1975 Dollars)

<u>Description</u>	<u>Capital Investment</u> <u>\$ Million</u>
<u>CONTRACTOR ESTIMATES</u>	
Mining, Crushing and Spent Shale Disposal	100
Pyrolysis and Oil Recovery	244
Oil Upgrading and Hydrogen Plant	103
By-Product Recovery	54
Utilities and General Facilities	<u>159</u>
Subtotal	660 (1)
<u>RESERVE COSTS</u>	131
<u>OTHER COSTS</u>	
Mine and Spent Shale Disposal Mobile Equipment	18
Catalysts and Chemicals	12
Spare Parts	3
Project Management and Plant Staffing	25
Taxes and Insurance During Construction	6
Community Assistance Costs	28
Pre-Committment Costs	10
Mine Predevelopment Costs	9
Prepaid Process Licenses	1
Miscellaneous Other Costs	9
Working Capital	18
Plant Fixit and Startup Allowance	<u>30</u>
GRAND TOTAL INVESTMENT	960

- (1) The subtotal of \$660 million is as estimated by the engineering contractors. Allocation of costs to the individual units is by TOSCO after analysis of the detailed contractor estimates.

TABLE 18

BREAKDOWN OF OPERATING COSTS (115)
FOR THE COLONY PROJECT
 (Basis - September 1975 Dollars)

<u>COST CENTER</u>	<u>\$ Million/Yr</u>	<u>\$/Bbl⁽¹⁾</u>
Mining, Crushing and SS Disposal	30,000	1.91
Plant Operating Labor	1,700	0.11
Plant Maintenance (Excluding Mining)	11,000	0.70
Electrical Power Costs (Ex. Mining)	8,800	0.56
Catalysts and Chemicals	6,200	0.39
Administrative	2,200	0.14
Taxes and Insurance	7,000	0.45
Miscellaneous Other	1,100	0.06
License Fee	3,600	0.23
Contingency	<u>3,400</u>	<u>0.22</u>
 TOTAL OPERATING COSTS	 75,000	 4.77
 <u>BY-PRODUCT CREDITS</u>		
Ammonia	6,300	0.40
Sulfur	900	0.06
Coke	<u>2,400</u>	<u>0.15</u>
 TOTAL CREDITS	 9,600	 0.61

(1) Based on Total Plant Products

the order of \$11 per barrel of product. 2) The operating costs are much less than the capital costs. As shown in Table 18, the projected operating costs are of the order of \$5 a barrel; and if one subtracts the by-product credit, they are of the order of \$4 a barrel. Thus, it seems clear that an oil shale venture is a highly capital-intensive undertaking in which the principal cost of producing finished shale oil is that of paying off the large capital cost. 3) If we examine the capital cost breakdown, we see that the large individual items are, in order of importance, the pyrolysis and oil recovery section, the utilities and general facilities, the reserve costs (i.e., the cost of acquiring the mineral rights to the oil shale land which the TOSCO estimates have placed at 25 cents per contained barrel), the upgrading and hydrogen plant, and the cost of establishing the mining, crushing, and spent-shale disposal. 4) On the other hand, the largest single operating cost, as shown in Table 18, is the mining cost which accounts for more than a third of the total.

V-B. Mixed Costs

When one attempts to sort out environmental control cost from other types of costs, he quickly finds that there are some costs which can be simply put down as environmental and others which cannot. For example, the sulfur removal plant which takes hydrogen sulfide out of the 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. On the other hand, the Claus plant, which converts the hydrogen sulfide so removed to elemental sulfur, is almost entirely an environmental-control plant. In the early days of the natural gas business, the hydrogen sulfide removed from the gas was simply wasted to the atmosphere. Claus plants have been installed to convert this hydrogen sulfide to sulfur, not in order to make a profit on the sulfur but in order to meet environmental regulations.

Another example is the incinerator on the kiln waste gas in the TOSCO process. This incinerator is needed to meet environmental control regulations, but it also recovers the energy in the hydrocarbons and uses it to produce steam. At the outlet of this incinerator is a set of cyclones and a bag house. The cyclones would be needed whether there were environmental requirements or not because they recover a valuable product. The bag house is required for environmental regulations entirely. However, the design of the cyclones is influenced by the environmental control regulations because if there were none, they would presumably be designed for a different control efficiency level than they are now.

In summary, there are some parts of the plant which are clearly environmental control, some which are clearly in no way related to environmental control, and quite a few which are mixed.

V-C. Fraction of Plant Cost for Environmental Control

Although none of the companies involved in these projects have published (to our knowledge) the fraction of their plant cost which is attributable to environmental control, several of them were willing to tell us their estimate of what fraction that is. They all did so on a "not to be quoted by name"

basis so that these values must be regarded as estimates which cannot be directly checked nor attributed to their sources. These estimates were generally prepared internally for the benefit of management decision making and because in some states; e.g., Utah, environmental control equipment can be purchased with tax-exempt bonds.

The representatives of the oil shale companies who gave us these estimates pointed out the problem of mixed use of facilities described in Section V-B above and indicated that these mixed use facilities were the greatest cause of uncertainty in their estimates. With all these restrictions, they were then willing to say that the environmental control cost was somewhere in the neighborhood of 10 to 20 percent of the capital cost of the project. Here environmental control costs could be defined as those cost reductions which would occur if by government fiat the oil shale industry were exempted from all environmental control regulations. In terms of fraction of expense, most of the companies indicated that the largest amount of this 10 to 20 percent was in air pollution control equipment including the sulfur and nitrogen recovery equipment and particulate control equipment. The other parts including water pollution control and revegetation equipment for the spent shale were not considered as expensive as the air pollution control equipment. If we adopt the maximum value of 20 percent of the capital investment, we could then go back to Table 17 and note that this most likely applies not to the entire project cost but rather to the contract estimates which are roughly two-thirds of the total so that, for example, in Table 7, the environmental control equipment costs would be 20 percent of \$660 million or \$132 million. This is of the order of \$3,000 per barrel per calendar day, which, by the simple economics shown in Section I-B would translate to a per

barrel cost of \$1.64. If we add an operating cost of perhaps 10 percent of total operating cost, this would come out to about a total of \$2 per barrel as environmental control cost. This compares with an estimated total cost of \$15 to \$20 per barrel.

Again, let us emphasize that the environmental control costs estimated here should only be considered as a rough estimate.

VI. RESEARCH NEEDS AND POLICY QUESTIONS CONCERNING THE ENVIRONMENTAL CONTROL TECHNOLOGY FOR OIL SHALE DEVELOPMENT

Could environmental technology problems significantly influence the "yes-or-no" decision whether we will have a commercial scale oil shale industry? 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. Oil shale 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. When the holders of the Federal Prototype leases requested suspensions in the Spring and Summer of 1976, some of them cited environmental reasons, but in our opinion, these were merely added to buttress their position, which was that the current economic prospects were unsatisfactory.

If any single formal environmental regulation is going to significantly delay or hinder the development of oil shale, it will be the non-deterioration 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 oil shale industry in western Colorado, eastern Utah, and/or southern Wyoming, then those areas, which are currently very sparsely inhabited, will have large numbers of new inhabitants and will change significantly in character. The non-deterioration 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 population of the people of Colorado and/or Wyoming and/or 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 oil shale development.

Will the costs of environmental technology be so high as to make otherwise financially viable oil shale 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 oil, ancillary facilities, etc. It seems clear that none of the environmental control technologies which are summarized in this report and which have been proposed by the various developers, 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 spent shale piles, process exhaust gases for control of sulfur dioxide and particulates, etc. But as shown in Section V 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 oil shale industry at prices which are not so high as to seriously jeopardize the economics of viable oil shale 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 the oil shale industry, but rather, ones which bear on questions of change of direction, size, or economics of the oil shale industry. We believe that most of the problems or policy questions suggested here are ones which are deserving of attention, because the cost of investigating them is significantly smaller than the

potential benefits from resolving them in a satisfactory way.

VI-A. Research Problem; Utilization of Burnt In-situ Retorts

In the previous history of the oil shale industry, and in the first set of detailed development plans presented, the waste oil shale, after processing, was considered to be simply an unpleasant waste disposal problem.

Those proposing the new in-situ technology have taken pretty much the same view. However, the retorted residue which they will produce is in several significant ways different than the retorted residue produced by surface retorting, and for this reason presents some interesting opportunities and challenges. The significant differences are: 1) It is entirely contained within a closed chamber with suitable access available to the top and the bottom of the chamber, so that one could flow liquids or gases through the bed of processed shale, in either the upflow or downflow direction with relatively little additional expense for setting-up to do so; 2) In general, the rock size will be much larger than the rock size for any surface retorting operation, because the blasting procedure used to prepare in-situ retorts does not crush the shale nearly as fine as is required for all known retorting operations in surface retorts; 3) The spent shale in these retorts has been retorted much more slowly than the spent shale produced from surface retorting operations. The typical advance rate of the flame front in in-situ retorting will normally be of the order of 10 to 15 feet per day. The advance rates are much higher for surface retorts. This slow advance rate is made necessary by the large particle size described above.

What are the possible uses one could make of these beds of spent

shale enclosed within their cavities? If the retorting is carried out at a high enough temperature to cause the carbonates in the mineral to decompose, then the resulting spent shale will contain fairly large amounts of calcium and magnesium oxides. These materials are mild caustics and will be present in finely divided form in a porous material. They could be used for absorption and chemical sequestering of materials like sulfur dioxide. Thus, one could conceivably use a burned-out retort as a sulfur dioxide scrubber making such processing at the surface unnecessary. There is obviously an economic question here as to whether it would be more economical to pay the extra cost of moving the gas around and back down into the retort rather than doing surface processing, but it is possible that it will be economical. Secondly, in those areas of the oil shale deposits where there exists significant deposits of dawsonite and nahcolite, the most economical way of recovering those might be to do an in-situ processing which is controlled in such a way as to maximize the solubility of these two minerals and produce them by leaching of the spent shale. Third, all processing schemes leave some carbon in the form of residual coke on the spent shale. It might prove economical in in-situ operations to conduct the operation as a two-stage operation in which only enough carbon was burned in the initial pass to recover most of the liquid hydrocarbon that could be recovered. Then a second pass would be made in which the objective was either to recover a hot air stream, to be used to drive gas turbines for power, or the carbon could be used in a hydrogasification reaction (water-gas reaction) to produce carbon monoxide for use as fuel.

None of the above operations seems feasible for a surface shale pile because every effort will be made to prevent the flow of fluids through such piles and the piles will be compacted for stability. However, with the

underground burned-out shale pile, these are distinct possibilities and this suggests that we should consider the burned-out shale retorts as a potential resource. A modest exploratory research program seems justified, to examine these in detail and conduct small-scale laboratory work on them.

VI-B. Removal of Hydrogen Sulfide From Gas Streams Containing Large Amounts of Carbon Dioxide

A unique aspect of the oil-shale retorting process is that a waste gas is produced that contains some significant amounts of hydrogen sulfide, which must be removed from the waste gas, and also contains large amounts of carbon dioxide. The hydrogen sulfide is produced by reduction and liberation of the sulfur content of the "kerogen". The carbon dioxide is produced by calcination of the calcium and magnesium carbonates in the base rock.

It is in the best interest of the oil shale operators to get as much of the sulfur in the kerogen out into this gas stream as possible, because it thereby lowers the sulfur content of their crude shale oil. It is in their best interest to produce no carbon dioxide at all. This production of carbon dioxide by calcination is an energy consumer which produces nothing of value for them. Therefore, they attempt to manage their processes in such a way as to minimize the calcining of calcium and magnesium carbonates.

One consequence of this is that the off-gas stream, which must be treated for H_2S removal, contains significant amounts of carbon dioxide. Most of the processes for treating gases to remove hydrogen sulfide, which are in common use in the United States, are intended to remove it

from natural gas or hydrocarbon gases which contain little or no carbon dioxide. They work on the fact that hydrogen sulfide, when dissolved in water, is a weak acid, and hence they capture it in weak caustic solutions. If the same technology were applied directly to oil shale off-gases, very large amounts of carbon dioxide would also be removed. This would increase the required sizing of the off-gas scrubbing unit, and would result in the hydrogen sulfide thus produced being contaminated with large amounts of carbon dioxide. It is possible to treat such gases in subsequent steps for sulfur production, but at a cost of reduced efficiency.

Faced with this problem, the oil shale developers have mostly indicated that they intend not to use the conventional amine type scrubbing, but rather to use a liquid-phase oxidation process, normally the Stretford process, to remove the hydrogen sulfide. Although this process is apparently quite suitable for treating such gases, it is questionable whether it is the most economical. Industry sources indicate that serious work is going on to try to develop amine type or weak-base-type scrubbing systems which will remove small amounts of hydrogen sulfide in the presence of large amounts of carbon dioxide. If such processes can be worked out, and demonstrated, they will probably be more economical than the readily available Stretford process.

This is not an example of an environmental threat; the Stretford process will work. Rather, it is an example of the need to develop more economical technology for the peculiar situation which exists in oil shale retort off-gases.

VI-C. Policy Question Concerning Utilization of Crude Shale Oil

The two groups which are currently actively pursuing in-situ

projects (C-a, C-b) have both indicated their interest in having the crude shale oil processed on-site only far enough to make it pipelineable (i.e., not too viscous nor too high a freezing temperature) and then shipping it to remote markets. Part of their intention appears to be to have the crude shale oil used as a boiler fuel in power plants or other large boilers. As described previously, this has the advantage that this shale oil can apparently be burned in these boilers without violating the sulfur or nitrogen standards normally enforced for exhausts from oil-fired power plants. If this is the case, this saves them the high cost of removing the chemically bound nitrogen from the shale oil.

There is an energy policy question with a related environmental question involved here. It is the general policy of the Federal Government to encourage existing power plants to convert from oil to coal. However, currently there are a large number of power plants which burn oil and which may find it difficult to convert to coal within their remaining useful lifetimes. Giving them shale oil as a fuel reduces their demand for conventional heavy oils or makes those oils available for refining. Most likely, the actual amount of nitrogen oxide emitted when shale oils are burned in these plants can be reduced to meet the standards but probably cannot be reduced to as low a level as would be obtained burning the other kinds of oil.

Thus, it appears that a thorough study should be made of whether using shale oil to back out conventional residual oil, or other heavy oils from electric power plants as a way of avoiding the costly denitrification of the shale oil is indeed in the national interest.

VI-D. Oil Retention by Processed Shale

All three of the original Detailed Development Plans indicate that the developers plan to subject all oil spills, waste water, oily water and other chemical-or-oil-contaminated water to the standard waste-water treatments which are conventionally used in oil refineries. After the water has been so processed, it is intended to use it for wetting the spent shale to prevent dust emissions from the shale pile.

It is not obvious that it makes sense to go to that expense in cleaning up that water if it is to be used on spent shale. The spent shale will be able to retain some finite fraction of its own weight in oil in a capillary manner. Furthermore, the spent shale will be rich in calcium and magnesium oxides which will readily react with phenols and other organic acids. Therefore, it is reasonably likely that if the oily water or chemically contaminated water which is occasionally discharged from parts of the processing plant or in other ways generated were used to moisten the spent shale without any treatment to remove oils, phenols, and/or organic acids, etc., the oil and other materials would be permanently immobilized in the spent shale and never again appear in ground or surface waters. If this is the case, then very substantial savings could be made in the plant design by eliminating those waste-water treatment facilities.

This suggests that an appropriate research topic would be the measurement of the oil-retaining properties of spent shale, as well as a measurement of the ability of the spent shale to tie up and immobilize the other contaminants which are regularly found in petroleum-refinery waste waters. The logical way to proceed on this would be to obtain an adequate sample of spent shale and adequate samples and/or appropriate chemical analyses of the types of waste waters expected or normally generated in

petroleum refineries and run breakthrough tests of the kind conventionally done in petroleum secondary-recovery research. There it is normally observed that most porous rocks will retain up to 30% of their pore volume of organic liquids and that this retained organic liquid cannot be removed by infinite flushing with water. If a similar observation is made in laboratory tests with spent oil shale and synthetic oily and/or acidic waste water, then it would be prudent to suggest that the demonstration projects which will produce processed shale should go ahead without oily water treatment in reasonable confidence that if they use oily waters to moisturize spent shale there will be no discharge of oil or the other chemicals found in such waste water streams to either ground or surface waters.

VI-E. Cooperation Between Projects

Each of the original Detailed Development Plans and each of the modified DDP's is based on the assumption that the others will not proceed and, therefore, each project must proceed independently. If, however, more than one of them, or perhaps all three of them, proceed simultaneously, then it would be prudent to inquire whether there would be savings, both environmental and financial, in the pooling of some expenses. For example, all three of the demonstration projects are located roughly in a line 50 miles long. Therefore, if, instead of each one erecting its own construction camp or workers' residential city, a general construction camp or workers' city for all three was located somewhere near the middle of that 50-mile line, the result would be that there was one large construction camp or workers' city instead of three small ones. This would probably result in economies of scale in the development of a new city

and would minimize the likelihood of spreading the workers widely in areas where their effect on the environment could not be controlled. An obvious difficulty with this suggestion is that if there is only one new city and it is only in one state, then the other state involved might feel that it was deprived of the employment opportunities, tax revenue, etc., involved in constructing a new city or expanding an existing city in it. It seems plausible that the states involved could work out some joint arrangement so that there would be one city that served all three projects, possibly Rangely or an expanded version of Rangely, and that tax revenues, etc., would be divided equitably.

An additional opportunity for joint effort among projects would be the development of a joint electric power supply system. In the original Detailed Development Plans, the White River Oil Shale Project contemplated burning its gas to produce electric power while the other two did not.

In the modified detailed development plans, Rio Blanco indicates that they will use all the available low-Btu gas for power generation, but that they do not believe that this power thus generated will be adequate to cover all of their internal power needs, and that hence a new power line must be strung to them from the Moon Lake Electric Power Cooperative. The C-b Revised Detailed Development Plan indicates that one of the options being considered is on-site electric power generation, but that this option is not included in the basic development plan for the present. They indicate that if they do elect to produce electric power they could satisfy all their on-tract consumption and in addition export 300 to 400 megawatts of electric power. However, for the time being, their plan considers that power will be obtained from the Colorado-Ute Electric Power Company which will have to string in new lines for them.

It is not clear from the two detailed development plans why one will have enough surplus gas to be a net power exporter, while the other, utilizing all its gas to make electric power, will be a net power importer. This should be resolved by the time the projects reach commercial size.

It is unfortunate that Tract C-a is located in the Moon Lake Electric Cooperative's service area while Tract C-b is located in the Colorado-Ute Electric Power service area, because if it is indeed required that they must each obtain their power from the power companies which serve those areas, then the total amount of new line which must be strung will be much greater than if they could both obtain their electric power from the same source. It would seem to be in the interest of maximum use of resources, and minimizing economic waste, to make some arrangement whereby both could have a common supply source and to the extent feasible could cooperate on electric power matters. Furthermore, if additional projects come in as these ones prove economically viable, it would be intelligent to have a cooperative electric power arrangement for the whole oil shale area; this would probably be both environmentally and financially superior to a fragmented arrangement.

Similarly, the revised Rio Blanco project DDP indicates that they contemplate constructing a rail siding for their own use in Rifle for delivery of equipment. Presumably, the same rail siding could serve for delivery of equipment to the C-b Project. This is cited as a minor example of and opportunity for the projects to cooperate in developing their support and infra-structure facilities to minimize cost and environmental disturbance. Similar opportunities must exist in the area of product oil pipelines, roads, communications systems, etc.

VI-F. Extrapolation to a Mature Industry

An additional policy issue which should be faced is the relationship between the environmental impact of the prototype projects and the environmental impact of a mature oil-shale industry in the same general area. The three original prototype projects together at their maximum stage of development would produce approximately 300,000 bbls per day of shale oil. The two now under active consideration would produce 136,000 bbls per day. The total U.S. consumption of liquid hydrocarbons is currently of the order of 20,000,000 bbls per day; there are hopes that the shale oil industry could produce up to several million barrels per day. This represents a one-order-of-magnitude increase in scale. What would be considered acceptable for the demonstration projects may not be acceptable for the full-scale projects. For example, the emissions of particulates and sulfur oxides from the individual projects can presumably be controlled to levels which will not violate ambient air quality standards nor non-deterioration regulations. But that assumes that the emissions from each plant are sufficiently remote from that of any other plant that the effects are not cumulative. If, on the other hand, we have a high concentration of such plants in one region, then the effects will be cumulative and we must reexamine what the permitted emission rates will be.

One may speculate that if it proves economically feasible to produce large quantities of liquid fuels from oil shale, it will be a national decision, presumably initiated or ratified by the Congress, that the oil shale development area will be something corresponding to the Class III non-deterioration regulations of the EPA where the air may be polluted up to the secondary standards. If that is the case, then a much larger

industry would be permitted than if it is not the case. This is clearly an issue which must be examined and on which a decision will have to be made at some point.

Similarly, a ten-fold increase in production rate over that foreseen for the prototype projects would require ten times as much water and would result in much more disruption of existing aquifers.

BIBLIOGRAPHY

1. East, J. H. Jr., and E. D. Gardner, "Oil Shale Mining Rifle, Colorado 1944-46, *Bureau of Mines Bulletin* 611, (1964).
2. Thorne, H. M., K. E. Stanfield, G. U. Dinneen, and W. I. R. Murphy, "Oil Shale Technology: A Review," *Bureau of Mines Information Circular*, 8216 (1964).
3. "Proceedings of the ___ Oil Shale Symposium," annually in the fourth quarterly edition of the *Quarterly of the Colorado School of Mines*. e.g., the 9th Symposium Proceedings is Vol. 71, No. 4, Edited by James H. Gary.
4. _____, "Oil Shale Mining, Processing, Uses and Environmental Impacts- Citations from the Engineering Index Data Base," NTIS/PS-76/0320.
5. _____, "Oil Shale Mining, Processing, Uses and Environmental Impacts- Citations from the NTIS Data Base," NTIS/PS-76/0319.
6. Abel, J. M. (Union Oil Co. of California), "Statement before a hearing of The Subcommittee on Energy Research and Water Resources of the Committee on Energy and Natural Resources of the United States Senate," Denver, Colorado, March 11, 1977.
7. U. S. Dept. of Interior, "Application for Suspension of Operations and Production under Oil Shale Lease Serial U-25918," Submitted to Area Oil Shale Supervisor's Office by Sun Oil Co. and Phillips Petroleum Co. 7-19-76, Appendix A.
8. *Oil Shale Tract C-b Modifications to Detailed Development Plan*, Submitted by Ashland Oil Co. and Occidental Oil Shale Inc., Feb. 1977.
9. *Salt Lake Tribune*, May 20, 1977.
10. Hopkins, J. M., H. C. Huffman, Arnold Kelly and J. R. Pownall, "Development of Union Oil Company Upflow Retorting Technology," Presented at the 81st National Meeting of the AIChE, April 11, 1976, Kansas City, MO.
11. Weichman, B. E., "Multi-mineral Oil Shale Commercialization," Presented at the 81st National Meeting of the AIChE, April 11, 1976, Kansas City, MO.
12. Jones, J. B. Jr., "The Paraho Oil Shale Retort," Presented at the 9th Oil Shale Symposium, Colorado School of Mines, April, 1976.
13. Environmental Protection Agency, "A Preliminary Assessment of Environmental Impacts from Oil Shale Development," Contract 68-02-1881, (Pre-publication Copy).
14. "Oil Shale Air Pollution Control," EPA-600/2-75-009, May 1975, prepared by Stanford Research Inst. for EPA.
15. *Summary of Industry Oil Shale Environmental Studies and Selected Bibliography of Oil Shale Environmental References*, Rocky Mountain Oil and Gas Association, Oil Shale Committee, March 1975.

16. Rio Blanco Oil Shale Project, *Revised Detailed Development Plan-Tract C-a*, Submitted to the Area Oil Shale Supervisor, May 1977 (3 volumes).
17. White River Oil Shale Project, *Detailed Development Plan*, Submitted to the Area Oil Shale Supervisor's Office, Spring 1976 (2 volumes).
18. Oil Shale Tract C-b, *Detailed Development Plan and Related Materials*, Submitted to the Area Oil Shale Supervisor, Spring 1977 (2 volumes).
19. Rio Blanco Oil Shale Project, *Detailed Development Plan - Tract C-a*, Submitted to the Area Oil Shale Supervisor, Spring 1976 (4 volumes).
20. BLM, *Final EIS Proposed Development of Oil Shale Resources by Colony Development Operation in Colorado*, (2 volumes).
21. Klipp, J. E., *An Oil Spill Contingency and Response Plan for a Proposed Pipeline System*, U. S. Dept. of the Interior, BLM, December 1973.
22. Rosenbaum, J. B., et al., "Sulfur Dioxide Emission Control in Japanese Copper Smelters," *USBM Information Circular*, 8701 (1976).
23. _____, "The Clean Air Act," 42 U. S. C. 1857 et seq., EPA, Washington, D. C., (December, 1970).
24. *Federal Water Pollution Control Act Amendments of 1972*.
25. *Toxic Substances Control Act*, Public Law 94-469.
26. Letter from W. T. Herget, President, Rio Blanco Oil Shale Project to Peter A. Rutledge, AOSS, Dated July 2, 1976.
27. de Nevers, Noel H., "Air Pollution Control Philosophies," *JAPCA*, 27, 197 (March 1977).
28. EPA, "National Primary and Secondary Ambient Air Quality Standards," *Federal Register*, 36, 8186 (April 30, 1971).
29. White River Oil Shale Project, *First Year Environmental Baseline Report*, p. III-41 (May 1976).
30. *Clean Air Amendments of 1977*, Section 310.
31. High M. D., "Status Report on Federal Regulations for New Source Performance Standards," *JAPCA*, 26, 471 (May 1976).
32. "Colorado Air Quality Control Regulations and Ambient Air Quality Standards," Colorado Air Pollution Control Commission. Amendments to Regulation No. 1, Adopted August 11, 1977.
33. *Federal Water Pollution Control Act*, of 1956.
34. *Ibid.*, Amendment (1961).
35. *Ibid.*, Amendment (1965).
36. *Ibid.*, Amendment (1966).

37. *Water Quality Improvement Act, of 1970.*
38. *Water Quality Criteria, 1972, EPA-R-73-033, March 1973.*
39. National Commission on Water Quality, "Staff Draft Report," Washington, D. C., 1975. National Commission on Water Quality, "Draft Recommendations to the Commissioners," Washington D. C., 1976.
40. *Quality Criteria for Water, EPA, Washington, D. C., 20460 (Pre-Publication Copy).*
41. EPA "Colorado River System Salinity Control Policy," Title 40, Chap. I, Part 120.
42. Colorado River Basin Salinity Control Forum, "Proposed Water Quality Standard for Salinity including Numeric Criteria and Plan of Implementation for Salinity Control," June 1975.
43. Pfeffer, Fred M., and Robert S. Kerr, "Pollutional Problems and Research Needs for an Oil Shale Industry," National Environmental Research Center Office of Research and Development, U. S. Environmental Protection Agency, Corvallis, Oregon, Report No. EPA-660/2-74-067 (June 1974).
44. Bullock, W. D., et al., "Environmental Aspects of the North American Mining Industry," *Minerals and the Environment*, Edited by Jones, M. J., pp. 27-43. The Institution of Mining and Metallurgy, London, England, 1975.
45. Schlick, D. P., and W. A. Wahler, "Mine Refuse Impounding in the United States," Mining Enforcement and Safety Administration, U. S. Dept. of the Interior, Information Report 1028 (Revised January 1977).
46. Fortune, Michael, "Environmental Consequences of Extracting Coal," *Energy and Human Welfare - A Critical Analysis, 1: The Social Cost of Power Production*, Edited by Commoner, Barry, et al, pp. 40-66. Macmillian Information, New York, 1975.
47. Oil Shale Lease, Tract U-a, Entered into on May 1, 1974 by the United States of America, acting through the Bureau of Land Management of the Department of the Interior, Phillips Petroleum Co, Bartlesville, OK, 74004 and Sun Oil Co., Dallas, TX 75221.
48. *The Surface Mining Control and Reclamation Act of 1977 (Public Law 95-87).*
49. *30 CFR Part 77.*
50. *30 CFR Sections 77.214 and 77.215.*
51. *30 CFR Section 77.216*
52. *Utah Mined Land Reclamation Act of 1975 (Title 40-8, Utah Code).*
53. _____, "Analysis of Kaiparowits Powerplant Impacts on National Recreation Resources," Dept of the Interior National Park Service, March 1967.

54. Herget, W. T., President, Rio Blanco Oil Shale Project, quoted in *Oil and Gas Journal*, 75, 25, January 17, 1977.
55. Linsley, R. K., M. A. Kohler, and J. L. H. Paulhus, *Hydrology for Engineers*, 2nd Edition, McGraw-Hill Book Company, 1975.
56. U. S. Department of the Interior, *Environmental Impact Statement, Final-Kulpavovits*, Bureau of Land Management, March 3, 1976.
57. *Final Environmental Statement - Emery Power Plant*, BLM, Dept. of the Interior, p. 1-34, March 1977.
58. Personal Communication with Professor Norm Jones, Dept. of Civil Engineering, Utah State University, Logan, UT, August 1977.
59. U. S. Dept. of the Interior, *Engineering and Design Manual, Coal Refuse Disposal Facilities*, Mining Enforcement and Safety Administration, U. S. Government Printing Office: 1975 O-579-1601.
60. Personal Communications with Mr. Don Grey, Utah Power and Light Co, Salt Lake City, UT, August 1977.
61. National Oceanic and Atmospheric Administration, *Climatological Data, Annual Summary*, Utah and Colorado, National Climatic Center, Asheville, NC 1976.
62. Steed, J. N. and B. Glennie, "Water Budget of the Great Salt Lake," *Proc. Am. Water Resources Assoc. Cont.*, Salt Lake City, UT, Nov., 1972.
63. McGauhey, D. H., *Engineering Management of Water Quality*, McGraw-Hill Book Co., NY, 1968.
64. D'Appolonia, E. Consulting Engineers, Inc., *Engineering and Design Manual: Coal Refuse Disposal Facilities*, Mining Enforcement and Safety Administration, U. S. Dept. of the Interior (1975).
65. Meyers, James F., et al., "Fly-Ash Embankments," *Fly Ash a Highway Construction Material*, pp. 122-153. Federal Highway Administration, U. S. Dept. of Transportation, Report No. FHWA-IP-76-16, June 1976.
66. Sokolorshi, V. V., *Statics of Solid Media*, (Translated from Russian by D. H. Jones and A. H. Schofield), Butterworth Scientific Publications, London, 1960.
67. "Restoration after Opencast Mining and Quarrying," *Mine and Quarry*, 15-16, 19 (April 1977).
68. Ward, J. E., et al., "Water Pollution Potential of Rainfall on Spent Shale Residues," Colorado State University, Fort Collins, CO (EPA Grant No. 14030 EDB) (December 1971).
69. Jeffrey, D. W., et al., "Ecological Approach to Mining Waste Revegetation," *Minerals and the Environment*, Edited by Jones, M. J., pp. 371-385. The Institution of Mining and Metallurgy, London, England, 1975.
70. May, Morton, et al., "Reclamation of Strip Mine Spoil Banks in Wyoming," *Energy and Human Welfare - A Critical Analysis*, Vol. 1: *The Social Costs of Power Production*, Edited by Commoner, Barry, et al., pp. 67-80. Macmillan Information, NY, 1975.

71. See Reference No. 16, Vol 3.
72. Emery, J. J., "Use of Mining and Metallurgical Wastes in Construction," *Minerals and the Environment*, Edited by Jones, M. J., pp. 261-272. The Institution of Mining and Metallurgy, London, England, 1975.
73. Gromko, Gerald J., "A Preliminary Investigation of the Feasibility of Spent Oil Shale as Road Construction Material," *Transportation Research Board, Transportation Research Record*, No. 549 (1975).
74. Earnest, H. W., et al., "Underground Disposal of Retorted Oil Shale," Tenth Oil Shale Symposium Proceedings, *Quarterly of the Colorado School of Mines*, Vol. 63, No. 4. Edited by Reuheus, J. B., pp. 213-222, Colorado School of Mines Press, Golden, CO, 1977.
75. "An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado," Part I, Plant Complex and Service Corridor, Colony Development Operation, p. 223, (1974).
76. See Reference No. 16, p. 3-2-14.
77. Poulsen, R. E., et al., "Minor Elements in Oil Shale and Oil Shale Products," Laramie Energy Research Center Publication LERC/RI-77/1 (January 1977).
78. Sax, N. I., *Dangerous Properties of Industrial Materials*, 4th Ed. Van Nostrand Reinhold, NY, p. 419 (1975).
79. Schmidt-Collerus, J. J., F. Bonomo, Kishor Gala and LaRose Leffler, "Polycondensed Aromatic Compounds (PCA) and Carcinogens in the Shale Ash of Carbonaceous Spent Shale from Retorting of Oil Shale," *Science and Technology of Oil Shale*, T. F. Yen Ed., Ann Arbor Science, Ann Arbor, Michigan (1976).
80. Coomes, R. M., "Health Effects of Oil Shale Processing," Proceedings of the 9th Oil Shale Symposium, *Quarterly of the Colorado School of Mines*, Vol. 71, No. 4 (October 1976).
81. U. S. Dept. of the Interior, Bureau of Reclamation, *Design of Small Dams*, 2nd Edition 1973. U. S. Gov't. Printing Office, 2403-0078, Washington, (1973).
82. Shreve, R. H., *Chemical Process Industries*, 3rd Edition, McGraw-Hill NY, p. 176 (1967).
83. Danneberg, R. O., and A. Matzick, "Bureau of Mines Gas-Combustion Retort for Oil Shale, A study of the Effects of Process Variables," *USBM Rept. of Investigations* 5545, 1960.
84. Riesenfeld, F. C. and A. L. Kohl, *Gas Purification*, 2nd Edition, Gulf Publishing Co, Houston, TX, 1974.
85. Weast, R. C. (editor), *Handbook of Chemistry and Physics*, 47th Edition . Chem Rubber Co., Cleveland, OH, p. D-80, 1957.
86. Grekel, H., L. V. Kunkel and R. McGalliard, "Package Plants for Sulfur Recovery," *Chemical Engineering Progress*, 61, p. 70 (1965).

87. Lewis, Bernard and G. Von Elbe, *Combustion, Flames and Explosions of Gases*, 2nd Edition, Academic Press, NY, p. 693 (1961).
88. Genco, J. M., and S. S. Tam, "Characterization of Sulfur Recovery from Refinery Fuel Gas," EPA-450/3-74-055. Prepared by Battelle-Columbus Laboratories for EPA, June 1974.
89. *New York Times*, October 2, 1976, p. 7.
90. EPA, "Requirements for Preparation, Adoption, and Submittal of Implementation Plans," *Federal Register*, 36, p. 8186 (April, 1971).
91. Stokinger, H. E., "Concepts of Thresholds in Standard Setting," *Arch. Env. Health*, 25, pp. 153-157 (September, 1972).
92. Wilson, W. E., "Selected Information on Air Pollution Visibility," Appendix F to Appendix C to the *Southwest Energy Study*, Dept. of the Interior (November 1972).
93. EPA, "Prevention of Significant Air Quality Deterioration," *Federal Register*, 39, p. 42510, December 5, 1974.
94. *Clean Air Amendments of 1977*, (August 1977), (Comments based on the Conference Report 95-564 which was the only text available at the time of writing).
95. 40 CFR 5201 (f), "Approval and Promulgation of Implementation Plans."
96. Turner, D. B., "Workbook of Atmospheric Dispersion Estimates," EPA Publication No. AP-26 (1970).
97. Start, G. E., C. E. Dickson and L. L. Wendell, "Diffusion in a Canyon Within Rough Mountainous Terrain," NOAA Technical Memorandum ERL ARL-38, Idaho Falls, ID, August 1973.
98. White, W. H., et al., "Formation and Transport of Secondary Air Pollutants: Ozone and Aerosols in the St. Louis Urban Plume," *Science*, 194, (187-189), Oct. 8, 1976.
99. *Salt Lake Tribune*, April 27, 1973, p. B3, See also April 7 and March 13 editions of the same paper.
100. *New York Times*, April 15, 1976 p. 21.
101. Colorado Air Pollution Control Commission, Colorado Dept. of Health, "Colorado Air Quality Control Regulations and Ambient Air Quality Standards," p. AAS-2.1, 1976.
102. Herget, W. T., President, Rio Blanco Oil Shale Project, letter of July 2, 1977 to Peter A. Rutledge, Area Oil Shale Supervisor, Dept. of the Interior formally requesting suspension of lease provisions on Tract C-a.
103. See Reference 17, p. 3-17-1.
104. *Salt Lake Tribune*, April 19, 1976 p. 21.
105. *Salt Lake Tribune*, November 6, 1974, p. 1.

106. U. S. Geological Survey, "Water Resources Data for Utah," "Water Resources Data for Colorado," Annual Publication. National Tech. Inform. Serv., Springfield, VA 22161.
107. Weeks, John B., et al., "Simulated Effects of Oil-Shale Development in the Hydrology Piceance Basin, Colorado," Professional Paper 908, 1974.
108. U. S. Dept. of Interior, *Final Environmental Statement for the Prototype Oil Shale Leasing Program*, (1973).
109. Weichman, B. E., "Depositional History and Hydrology of the Green River Oil Shale, Piceance Creek Basin, Rio Blanco, County, Colorado," *Proceedings of the 102nd Annual Mtg. of AIME* (1973).
110. Whitcomb, J. A. and R. G. Vawter, "The TOSCO-II Oil Shale Process," Presented at AIChE National Meeting, March 1975.
111. White River DDP (op cit) page 3.7-10.
112. Sitter, C. R., "Dynamics in the Gasoline Supply Outlook," Presented at the Automotive News World Congress, July 11, 1977, Detroit.
113. *Chemical Engineers' Handbook*, R. H. Peery and C. H. Chilton, eds, 5th Edition, McGraw-Hill, NY 1973.
114. Oglesby, Sabert and G. B. Nichols, "A Manual of Electrostatic Precipitator Technology - Part I Fundamentals," Southern Research Institute, Birmingham, AL, 1970.
115. Whitcomb, J. A., R. G. Vawter and J. F. Nutter, "Shale Oil Production Costs and the Need for Incentives for Pioneer Plant Construction," Presented at the ACS Div. of Ind. and Eng. Chemistry Symp. on the Commercialization of Synthetic Fuels, Feb. 1-3, 1976, Colorado Springs, Colo.

APPENDIX I

Oil Shale

Most of the readers of this report will find that this appendix contains nothing new to them and can safely skip it. However, for the sake of completeness, this appendix contains a short description of what oil shale is, where it is, and how it would be utilized. This seems best done by an extended quotation from a Colony Environmental Impact Analysis (75), which is presented as follows:

Fifty million years ago in ancient Lake Uinta, now a part of the Colorado River Valley in the Rocky Mountains, tremendous amounts of organic material were deposited. Over the aeons, these deposits solidified into what is considered to be the richest deposits of oil shale in the world. Oil shale is not, geologically speaking, a shale and it contains virtually no oil. It is a sedimentary rock containing organic matter called kerogen which yields substantial amounts of synthetic crude and hydrocarbon gas when heated. Although oil shale had a beginning like conventional petroleum, when organic material was deposited in large, ancient lakes, these deposits were not subjected to the heat and pressure necessary to form petroleum. Instead, the organic material was transformed into a solid hydrocarbon and locked in a marlstone matrix. When the kerogen is heated to a temperature of approximately 900°F, it decomposes to yield hydrocarbon gases and liquids.

Oil shale, therefore, should be technically defined as a marlstone-type inorganic material mixed with a three dimensional organic polymer known as kerogen. The kerogen forms the continuous phase with the inorganic components buried in the kerogen. Oil shale differs from most other naturally occurring hydrocarbon sources in that it is only slightly soluble in conventional hydrocarbon solvents. Solvent extraction of oil shale under normal conditions yields only about one percent by weight soluble organic material called bitumen. A typical inorganic materials analysis and a chemical analysis of kerogen are presented in Tables I-1 and I-2, respectively.

OIL SHALE - RESERVES AND GEOGRAPHIC SETTING

Oil shale is found throughout the world, in every continent and in at least 30 states of the United States. Reserves of oil shale are expressed in terms of barrels of oil recoverable by a

TABLE I-1
MINERALS ANALYSIS OF RAW SHALE (75)

<u>Component</u>	<u>Weight Percent</u>
Dolomite	32
Calcite	16
Quartz	15
Illite	19
Albite	10
Microcline	6
Pyrite	1
Analcite	1

Trace element data are given in (77).

TABLE I-2
CHEMICAL ANALYSIS OF KEROGEN (75)

<u>Component</u>	<u>Organic Component, Weight Percent</u>
Carbon	80.52 $\pm$ 0.40
Hydrogen	10.30 $\pm$ 0.08
Nitrogen	2.39 $\pm$ 0.10
Sulfur	1.04 $\pm$ 0.08
Oxygen	5.75 $\pm$ 0.49

standard laboratory analytical technique called "The Fischer Assay." The world's largest reserves of potential value for commercial development are found in the Green River formation in Colorado, Utah, and Wyoming over an area of about 17,000 square miles. Figure I-1 outlines the Green River oil shale formation with respect to the states of Colorado, Utah, and Wyoming. The U. S. Geological Survey has estimated that the total oil shale reserve of the Green River formation in Colorado, Utah, and Wyoming is more than 600 billion barrels of oil in deposits at least 10 ft. thick averaging 25 or more gallons of oil per ton of oil shale. The U. S. Department of the Interior has also estimated that 80 billion barrels of this reserve are recoverable by modern mining methods. This latter total is approximately twice the present domestic crude oil reserves in the United States exclusive of Alaska. To put this in some perspective, the United States, since the Civil War, has produced about 100 billion barrels of petroleum.

The Piceance Creek Basin, which ranges over 1,250 square miles in Garfield and Rio Blanco Counties in western Colorado, is the richest single area of recoverable oil shale in the United States. This area is in semi-arid western Colorado, where the rugged terrain consists of plateaus cut by intermittent streams and creeks to form canyons and valleys The Streams drain north into the White River and south into the Colorado River. According to an estimate of the Department of the Interior, the Piceance Basin of Colorado, alone, contains some 480 billion barrels of shale oil in reserves more than 10 ft. thick and averaging more than 25 gallons of oil per ton of rock.

FIGURE I-1. Extent of the Green River Formation in Colorado, Utah and Wyoming (75)

APPENDIX II

Oil-Shale Retorting Technology

As discussed in the text, the most novel and unusual technology to be used in the oil-shale venture is that for retorting. Most of the other technologies can be transferred with minimal changes from other industries, but the oil-shale retorting technology is truly novel and involves processing of a type which is not practiced in the same way anywhere else. Furthermore, there are several ways of carrying out the retorting technology and, at this time, it is not clear that any one of them is economically or environmentally far superior to the others. There are several competing processes which probably will be tried.

The tasks which any retorting technology must accomplish are the following:

- (1) Heat the shale to the temperature at which the "kerogen" in the shale will decompose, forming oil and gas. Normally, this temperature is in the range of 900 to 1000°F.
- (2) Separate the oil and gas from the shale.
- (3) Cool the shale.
- (4) Minimize the conversion of the limestone and dolomite in the oil shale to the corresponding oxides. This reaction, which is unimportant at 900 F is rapid above about 1600 F (82). If it occurs it is wastefully energy consumptive, and dilutes the product gas with useless carbon dioxide.
- (5) Minimize the conversion of the processed shale into fused "clinkers" which will cause subsequent handling difficulties. This can be

done by minimizing the maximum temperature to which the shale is exposed.

- (6) Minimize energy consumption by converting as much as possible of the energy content of the raw shale to useful ends. In practice this means burning as much as practical of the carbon residue which remains on the spent shale, and utilizing the resulting heat.

Because the oil and gas constitute the order of 10 to 15% by weight of the raw shale, it is clear that the bulk of the material in the retorting process is the inert shale which passes through, and that these retorts must handle huge tonnages of material. The mechanical arrangements for so doing must be efficient, economical and durable.

At least as early as 1964, Thorne, *et al.* (2), suggested that of the approximately 2,000 oil-shale retorting schemes which had been patented, all could be divided into four major classes based upon the method by which the heat is brought to the shale. The four classes they suggest are:

- (1) Heat is transferred to the shale through a wall,
- (2) Heat is transferred to the shale by combustion of product gases and residual carbon within the retort,
- (3) Heat is transferred to the shale by passing heated gases or liquids through the shale, and
- (4) Heat is transferred to the shale by mixing it with hot solids.

Of these four categories of possible retorts, there seems to be no commercial interest in the first because its economics appear so poor; however, there are major efforts to commercialize each of the remaining three.

The retorting schemes which are currently proposed for early commercialization are the Tosco 2, Paraho Direct, Paraho Indirect, Union B

and in-situ. These will be discussed in detail here and also appear in Table II-1.

The Tosco 2 process is shown schematically in Figure II-1. It is a member of the fourth category described above in which the heat is brought to the shale by hot solids. In this case the solids are ceramic balls approximately 1/2 inch in diameter. On the figure, if we begin at the left, we see that the raw shale from the crusher is brought to a surge hopper, then through the raw shale feeder, and then to a preheat system in which it is mixed with hot flue gases and then taken to the preheat shale separator and a pyrolysis retort drum. In the pyrolysis retort drum, hot ceramic balls at a temperature of approximately 1100°F are rotated with the shale. This crushes the shale and causes the "kerogen" to be retorted. The crushed shale and balls pass to the trommel screen. This screen has holes small enough that the crushed shale falls through as spent shale while the balls continue to the end and are separated into the ball elevator. Following next the shale, it leaves the pyrolysis accumulator at 900°F and passes to the spent shale cooler and steam generator where it is cooled to approximately 300°F. It is then moisturized with water and sent to shale disposal. Meanwhile, the warm balls coming out of the pyrolysis accumulator at approximately 900°F are elevated and then sent to the ball heater where some of the gas from the pyrolysis is burned with air to raise the temperature of the balls to 1100°F. The balls are then returned to the pyrolysis drum and the hot flue gas from the ball heater is used to preheat the shale. This diagram shows several auxiliary parts, but essentially the operation is one of heating the balls, using the balls to crush and retort the shale, separating the shale from the balls, and reheating the balls.

The Tosco 2 process has been piloted at a fairly large scale, is appar-

FIGURE II-1. Flow Diagram of TOSCO II Process (110)

ently a complete commercializable technology, and has been the technology most widely cited in the original Detailed Development Plans as the technology to be used in the prototype oil shale projects. It is also cited in the Rio Blanco modified DDP.

Figure II-2 shows the Paraho Direct retort. This is a member of the second category of retorts described above in which the shale is retorted by burning, within the shale itself, some of the gas and the residual carbon in the shale. As the figure shows, the shale flows downward by gravity through a vertical, insulated vessel. A gas-air mixture is introduced at various places in the vessel and combusted therein, burning off the carbon from the spent shale and providing as much additional heat as is needed to carry out the retorting. The oil and gas mist leave the top of the retort, are separated, and sent to an oil-gas separator. This Paraho retort is the lineal descendant of the gas-combustion retorts which have been developed by the Bureau of Mines and many others. There exists a very substantial history and literature on this type of retort (83). The differences between the Paraho retort and the predecessor Bureau of Mines retort have not been made public by the Paraho Development Company nor the oil companies which are sponsoring its development work. From the information they have revealed, it is clear that in principle what they are doing is the same, but that they must have some technological wrinkles which they consider proprietary. This retort is cited as one of the retorts to be used in the White River Oil Shale Project Detailed Development Plan. Figure II-3 shows the Paraho Indirect retort. This is a member of Category 3 of the four categories of retort described above. In it there is no combustion within the retort, but some of the gas leaving the retort is heated in an external heater, which burns some kind of fuel, and then passed through the shale in order to transfer

FIGURE II-2. Flow Diagram of Paraho Direct Process (12)

FIGURE 11-3. Flow Diagram of Paraho Indirect Process (12)

the heat necessary to accomplish the retorting. This process has not been developed as extensively as the Paraho Direct retort and not a great deal is known about it.

Just as the Paraho Report comes in two versions, one of which involves internal combustion in the retort, and the other of which involves external combustion and circulation of a heated gas, so also the Union Oil retorting process comes in two such versions (10). Figure II-4 shows the earlier version, which is called Union-A. In both versions, the oil shale is fed into the retort from below and flows upward through the retort, being forced upward by a hydraulic ram. The oil leaves the bottom of the retort and the retorted shale falls out of the top. In the Union-A version, air is admitted to the top of the retort and burns off the carbon residue left on the shale as the shale flows upward. The oil drips to the bottom of the retort and is collected. It is clear that this is, in effect, the Paraho Retort turned upside down. The advantage of the inverted flow is that if the oil condenses on the rock which is flowing upward, it drips to the bottom of the vessel and can be collected. In the Paraho-type retort where the shale is flowing down by gravity, if the oil condenses on the rock and forms a liquid, it will drip back into the combustion zone and be lost. Therefore, considerable efforts must be expended to keep it in the mist or vapor form until it leaves the retort and then to collect it in an electrostatic precipitator. The apparent drawback of the Union procedure is that it involves the complicated hydraulic ram arrangement for feeding the shale. However, Union has asserted in public that although this looks difficult, it is really easy and trouble-free.

The Union-B retort is shown in Figure II-5. It is obviously analogous to the Paraho indirect retort in that instead of producing the heat in the

FIGURE 11-4. Flow diagram of Union Type A Retort (10)

FIGURE II-5. Flow diagram of Union Type B Retort (10)

vessel burning the carbon off the shale, the heat is introduced by recycling gas which is heated in an external heater. In all other respects, this appears to be basically the same kind of retort as the Union-A retort.

Figure II-6 shows a more detailed view of current version of the Union-B retort, which shows that they have somewhat modified their view of the best way to use the hydraulic rams for forcing the shale into the bottom of the vessel. In the sketches in the two previous diagrams, one ram was used which was pivoted about a bottom pivot to collect shale from the inlet chute, and then slides back to inject it into the retort. In the modified version shown in Figure II-6, two such rams are used and instead of pivoting they roll back and forth on a wheeled cart.

The Union-A retort was piloted at a large scale in Colorado in the early 1960's. The Union-B retort has been piloted at a much smaller scale. Union has indicated their desire to participate in a federal prototype module demonstration program, if one is carried out, and their interest in entering the oil shale business on a commercial scale if suitable financial arrangements can be worked out.

The in-situ process is in many ways analogous to the Union-A retort shown in Figure II-4. However, instead of bringing the shale to the surface and crushing it and having it flow upward through the retort in which the flame zone stays in one place, the shale is crushed in place in the rock by explosive means and then air is pumped in the top and flows downward through the shale, forming a combustion wave which passes downward through the shale. Rather than being a continuous process in which one retort has shale passed through it for many years, the in-situ process would consist of many separate retorts, each of which is burned once for an average burn lifetime of approximately 60 to 200 days.

FIGURE 11-6. Detailed diagram of Union Type B retort, showing modified rock pump arrangement (10)

The two oil shale projects which now appear closest to commercialization both use versions of the in-situ retorting procedure. The C-b project, whose current operators are Occidental Oil and Ashland Oil, intend to use the technology which Occidental has piloted in their program in Logan Wash, Colorado. Based on their published information, one concludes that they are practically ready for commercialization. On the other hand, the Rio Blanco project (C-a) which also plans to use an in-situ method, is not as close to commercialization and plans several years of pilot testing of their in-situ technology before making the decision to expand to a commercial scale operation. Based upon their ODP, it seems clear that in principle, their in-situ operation is the same as Occidental's, while in the details of the mining and rock fracturing there is considerable difference in technology.

While the retorting processes described above are intended for application anywhere where oil shale is found, the next one, which is proposed by the Superior Oil Company, is specifically intended for that fraction of the oil shale obtained in the Piceance Basin, which contains significant amounts of nahcolite and dawsonite. In general, this means the oil shale in the "lower zone" and mostly the oil shale toward the northern end of the basin. This is perhaps one-third of the total oil shale.

Figure II-7 shows the overall scheme they intend to use to produce four different products from this material. As the figure shows, in step one, the shale is mined underground and brought to the surface. In step two, physical means are then used to separate the nahcolite from the shale. This does not recover all the nahcolite but the nahcolite recovered this way is of high enough quality to be used for many purposes. Step 3 is the retorting of the oil shale which is carried out in a novel retort to be

FIGURE II-7. Flow Diagram of Superior's Multi-Mineral Process (11)

described later, which recovers the oil and gas and which also processes the spent shale in such a way that it can then go to step 4 where alumina and soda ash are then recovered by leaching. They intend to put all the spent shale back into the mined-out areas. This is easier for them than for others, because the large amounts of nahcolite, alumina, and soda ash removed from the shale reduced the volume of spent shale to be dealt with.

The retort they propose to use is a "moving ring grate retort" of a type which is known in several other industries, eg. lime calcination. Figure II-8 shows an artist's conception of such a circular grate retort. It is, in principle, a large doughnut-shaped tunnel through which a continuous open mesh belt of steel moves. The oil shale is deposited on the belt at the left as shown and rotates clockwise as seen from above. Hot gases are passed through the shale in various sections which are isolated from one another by dividers so that the shale is preheated, retorted, and then cooled. The gas passing through various sections of the shale is passed downward through the shale and then collected below and ducted to subsequent processing. Figure II-9 is a cross-section through the ring grate showing how the shale rests upon the moving grate while the gas passes down through it from the circular hoods above to the wind box below. This concept has been tested for oil shale only at a relatively small size and is not as near to commercialization as are the other retorts described previously which have been tested at a larger scale. However, because the basic technology involved is being borrowed from other industries where it is well-known, it seems clear that the retorting this way can be made to work, although its economics are not as obvious as those of the ones which have been more thoroughly tested.

These seven retorting processes are contrasted on Table II-1. Con-

FIGURE II-8. Artist's Conception of Superior's Circular Grate Retort (11)

FIGURE 11-9. Cross Section of Superior's Circular Grate Retort (11).

TABLE II - 1

Some Comparisons of Various Retorting Technologies

	Tosco II	Paraho D	Paraho ID	Union-A	Union-B	in-situ	Superior
BTU constant of gas	high	low	high	low	high	low	high
Coke burned off for fuel	no	yes	no	yes	no	yes	yes
Gas needed for fuel	yes	no	yes	no	yes	no	maybe (not clear from available data)
Accommodates fines	yes	no	no	no	no	no problem	not known
Ratio of solids handled to shale mass	3	1	1	1	1	≈ 0.25	1
Spent shale characteristics	fine high carbon	coarse	coarse high carbon	coarse	coarse high carbon	retained in ground	leached

sidering the first line, we see that Tosco and Paraho Indirect, Union-B and Superior processes all produce a high BTU gas because in them no combustion air is mixed with the gas product. On the other hand, the Paraho Direct, Union-A and in-situ processes, which do mix the production gas with the combustion air, produce a low BTU gas. In the second line, we see that the Tosco 2, Paraho Indirect and Union-B do not burn the coke off of the residual shale for fuel, whereas the Paraho Direct, Union-A, in-situ and Superior processes do.

We see that an economic decision must be made in selecting retorting processes between the desire to produce a high BTU gas, which it might be economical to market in pipeline quantities, and the desire to recover all the energy in the carbon which is left behind on the shale when the oil is retorted. If the carbon is recovered by burning internally, as in the Paraho Direct, Union-A and in-situ processes, the nitrogen from the combustion air is mixed with the resulting gas so that the finished gas produced is of low BTU and hence, not suitable for long distance transmission but only suitable for on-site combustion (eg. electric power production). Union Oil has indicated that they studied the question of whether it would be economical, using the Union-B retort, to recover the energy in the carbon left on the coke, and concluded that it is uneconomical and that that energy should be discarded. Superior, on the other hand, indicates that they intend to recover it by using some version of the water-gas reaction, and use it for power production or heat generation. It is possible that they feel they must recover it in order to remove it from the shale for the further processing steps which they envisage.

The next line discusses the problem of fines. In any crushing operation, some fraction of the material will be crushed to very small

sizes. The Tosco 2 retort crushes all the material to this fine size and easily accomodates it. On the other hand, most other retorts do not, in general, handle fines well. They have so far reported that it is necessary to segregate the fine material and not put it in the retort because it causes problems (mostly plugging) in them. There is no such problem in the in-situ process and they do not segregate fines at all. The next line shows the ratio of solids handled to the shale mass. As we see, the Tosco process handles approximately three times the mass of shale because roughly two tons of hot balls must be recirculated for every ton of shale. On the other hand, the other surface retorts handle only the shale and handle it only once, and the in-situ process, which involves mining out a cavity below the shale, handles approximately 25% of the weight of shale processed. Finally, considering the spent shale characteristics, the Tosco 2 process produces a relatively fine material which has a high carbon content. On the other hand, the other surface retorts produce a much coarser material referred to commonly as being about the size of a golf ball and the in-situ retains its spent shale in the ground.

Considering the differences in environmental control technology between the various retorting schemes, it seems that the biggest differences will be in the composition of the gas produced and in the properties of the spent shale. If the Tosco 2, Paraho Indirect, Union-B or Superior retort are used, then the gas produced will be low in volume, high in BTU content, and will contain substantial amounts of hydrogen sulfide which will be removed from the gas by amine scrubbing and treated by the Claus process. If, on the other hand, the Paraho Direct, Union-A or in-situ processes are used, then there will be much larger volumes of gas produced

at a lower heating value, and the gas will probably be treated for sulfur removal by the Stretford process. Considering the spent shale, it appears that the material will be finer in the Tosco process than in any of the other surface retorting processes. The external heating processes (Tosco 2, Paraho 10, Union-B) all produce a shale high in carbon (eg. 4 wt.% carbon). The shale disposal situations will be different as regards compaction, vegetation, etc.

APPENDIX III

Particulate Control Technology

Fine particles in industrial emissions cause the smoke from smoke stacks and other process vents which have attracted the attention of air-pollution control officers for the past 80 years. There exists a very wide range of technological devices for control of particulate pollutants. Many particulate pollutants are combustible fuel, particularly the pollutants which result from inefficient coal combustion. These pollutants can be treated by improving the quality of the combustion or by after-burning. However, these methods are not available for the particulate pollutants which will be generated in the oil-shale processing operations because these particulates will mostly not be combustible.

The properties of a group of particles which one should know in order to select the proper pollution control device are the particle size and the particle size distribution (range of particle size as a function of weight fraction), the stickiness of the particles, *i.e.*, their tendency to adhere to one another or to vessel walls or to adhere to water, and the electrical resistivity of the particles, which is important in deciding whether or not an electrostatic precipitator is a suitable control device.

Most particulate control devices operate by driving particles together so that they will adhere to one another and form agglomerates. Generally, the forces which are available to accomplish this are gravity, centrifugal force, inertial force, and electrostatic force.

Very large particles (large than about 50 microns) can normally be collected by gravity. The device for accomplishing this result is a settling chamber, which is just a large room through which the contaminated gas stream

slowly flows allowing the particles to settle by gravity to the bottom of the room. The room is swept or hosed down at regular intervals to remove the accumulated dust. As discussed on Table 8, the underground mining proposals include the use of some unused portions of the mine as such gravity settling chambers to minimize the amount of particles which must be dealt with by their particulate control devices on the mine ventilation air. Such devices are generally not used in modern large-scale industrial operations for fine particles because the sizes required would be too large.

For medium-sized particles (from 5 to 50 microns in diameter), the most commonly used device is a centrifugal separator. Figure III-1 shows several different types of centrifugal separators. In all of these, the gas is induced to flow in a spiral manner inside a cylindrical container. The gas velocity is quite high, normally of the order of 100 feet/sec. At this high gas velocity, the gas particles are driven by centrifugal force, which is many times the force of gravity, to the wall of the container where they agglomerate against one another and settle by gravity to the bottom of the container, while the clean gas exits at the top. As shown on Figure III-1, it is possible to arrange large numbers of small cyclone separators in parallel in order to get reasonably high efficiency for large flows. Table 8 indicates that such cyclones will be used in several applications ahead of scrubbers which will provide the final clean-up. It is quite common to use cyclones for coarse dust removal ahead of another device which makes the fine dust removal in order to minimize the load on the fine-dust removal device.

For fine particles (less than 5 microns in diameter), the three common choices of collection device are bag filters, scrubbers and electrostatic precipitators. Figure III-2 shows a sketch of an industrial bag filter. In principle, such a device is just like any other filter, *e.g.*, a coffee filter.

FIGURE III-1.

Typical commercial cyclones. (a) Duclone collector (Ducon Company). (b) Sirocco type D collector (American Blower Co.). (c) Van Tongeren cyclone (Buell Engineering Co.). (d) Multiclone collector (Western Precipitation Corp.). (e) Dustex miniature collector assembly (Dustex Corp.). (f) Cutaway of the Dustex cyclone tube (113).

FIGURE III-2.
Typical commercial baghouse (fabric filter)
for removal of particles from gas streams
(113).

The particles collect upon the surface of a filter cloth and are removed while the clean fluid passes through. Although one can show in theory that the finest particles could pass through the filter because the holes in the filter are normally bigger than the particles, the particles themselves tend to block up these holes so that, after a starting period, filters tend to be very efficient particle removing devices. In order to obtain the very large surface area for filtration which is necessary to process large gas flows, it is common to use the arrangement in figure III-2. The filter elements are cylindrical tubes. A large number of these (perhaps several hundred) are enclosed within a sheet-metal container. The dirty gas flows up into these tubes and through them outward radially. The clean gas escapes from the outside of these tubes and is ducted to a stack. At regular intervals, the filter is shut off from the clean and dirty gas ducts, and the accumulated solids are removed from the filter by shaking or by reversing the flow through the filter or by one of several other mechanisms. This causes the collected dust to drop to a dust discharge hopper at the bottom of the container. In order to have a capacity for treating a steady flow of gas it is common to subdivide large bag-filter installations into several sections so that one section may be cleaned while the others are operating. Such bag filters are widely used in industry, particularly if the dust to be collected is valuable. The widest application of them shown in the Detailed Development Plans is in processing the dust which will be generated in crushing and in the transfer of crushed ores.

The second alternative for dealing with fine particles is a scrubber. In principle, a scrubber is a device in which fine droplets of scrubbing fluid (normally water) are brought into contact with the dirty gas stream and the particles are induced to attach themselves to the droplets. The droplets

are normally much larger than the particles and can then be separated from the gas stream by a cyclone separator or by gravity. The gas stream, after having the droplets removed, is normally much cleaner of particles than when it entered the scrubber. Figure III-3 shows a typical Venturi scrubber. In the Venturi scrubber, the gas stream to be treated passes through a device in which there is a narrow neck followed by a diverging section. The gas speeds up going through the narrow neck and reaches very high velocities (normally several hundred feet per second). At the high velocities, the gas tends to shatter the liquid droplets which have been injected with it and these droplets then are very efficient scavengers of fine particles. After the gas slows down in the expanding section of the Venturi, the combined gas-liquid flow passes into a cyclone separator which is, for all practical purposes, similar to the one shown in Figure III-1. In this separator, the liquid droplets with the particles they have collected are removed from the gas stream. Figure III-3 shows the dirty liquid being recycled to collect more dust. Some fraction of the liquid is removed and either filtered to remove the solids or used for some other purpose where the solids can be accumulated. In general, scrubbers have an excellent reputation for being good fine-particle collectors which are relatively simple to operate and efficient and economical. As shown in Table 8, the Tosco process foresees using several scrubbers at various points to treat gas-stream particle removal.

Finally, the other alternative for collecting particles is an electrostatic precipitator. In an electrostatic precipitator, the individual particles are charged and then electrostatic force is used to collect them against a grounded metal plate. They are removed from the metal plate by rapping, which causes the particles to be dislodged and to fall in agglomerates to

FIGURE III-3.
Venturi scrubber, wet-approach type. (Chemical Construction Corp.)
(113).

the floor of the container. Figure III-4 shows a schematic of a typical electrostatic precipitator of the type used in the cement or electric power industries. In it the gas flows from right to left entering through the perforated plate at the right and passing through the array of charged metal plates. Between the charged metal plates are wires which have weights to hold them in place and whose polarity is opposite that of the plates. The wires are normally held at about 40,000 volts negative relative to the plates which cause them to form a corona discharge. This discharge charges the particles which then collect against the plates, and are then knocked loose by the rappers which cause the particles to fall into the hoppers at the bottom of the vessel.

Electrostatic precipitators are in general only satisfactory if the particle resistivity falls in the range of 10^7 to 2×10^{10} ohm-cm. From the fact that the Detailed Development Plans do not indicate the use of electrostatic precipitators for dust control directly at any point, it appears likely that the resistivity of the fine dusts produced in the oil shale processing do not fall in this range of resistivities. However, electrostatic precipitators will be used in the gas combustion retorts or in the Paraho retort in the indirect mode if these are used. There the function of the electrostatic precipitator is not air pollution control, but rather the removal of the fine oil mist in which oil product exits from this type of retort. The exit gas contains mostly oil in mist form and an electrostatic precipitator collects this and separates it from the gas. In so doing, the electrostatic precipitator also removes any particles which would be present in the gas stream and gets them into the oil phase where they may be removed by filtration.

FIGURE III-4.
Typical electrostatic precipitator (114).

In general, particulate control technology is a relatively mature technology with a wide range of options which are available for various particle streams. Furthermore, for any particular particulate control task, one can specify almost any collection efficiency and, if he is willing to pay the cost, he can have that collection efficiency produced by some standard particulate control device. For example, if an electrostatic precipitator collects 90 percent of the particles, and an identical one downstream from it will collect approximately 90 percent of the remaining particles, the overall collection efficiency is 99 percent. A third identical one downstream would raise the efficiency to approximately 99.9 percent and so on. This is not quite correct because all particulate control devices preferentially collect the coarse particles first so that the stream which passes through becomes progressively more difficult to collect, but it demonstrates the idea that there is no theoretical limit to the level of control of particulates which can be obtained by going to increasingly expensive and complex control devices; the limit is set by economics and "practicality" rather than by what could be accomplished if money were no object.

APPENDIX IV

Removal of H₂S from Gases

This appendix is intended to provide the technical reader with a review of published information on the removal of hydrogen sulfide from hydrocarbon-containing gases. There exists a substantial body of literature on this subject (84). This appendix mainly summarizes information from that reference with occasional comments and discussion.

The removal of hydrogen sulfide from gases is a mature technology. A most widely used current process was patented in 1930 (84). The processes for carrying out this removal are available from many engineering design firms. These firms will design, construct and guarantee the performance of such plants for almost any set of circumstances.

There are a considerable number of alternative ways of removing hydrogen sulfide from the gas stream. The choice among these is made based on economics. The most economical process is a function of the overall composition of the gas stream, hydrogen sulfide concentration, pressure, required gas purity, and other miscellaneous factors.

Most of the commonly used hydrogen sulfide removal technologies are based upon the fact that hydrogen sulfide, when dissolved in water, forms a weak acid. (This acid does not have a common name; by analogy with the halogen acids it should be called "hydrosulfuric." Some handbooks (85), in listing acids, give all others by name and list this only simply as H₂S.) This acid dissociates according to the reaction

This is a reversible reaction. Only a relatively small amount of hydrogen

sulfide can be dissolved in an aqueous solution before the vapor pressure of the hydrogen sulfide over the solution becomes equal to the partial pressure of H_2S in the gas to be cleaned. However, if the solution contains any caustic, then the hydrogen sulfide will react with that caustic according to the reaction

The $HS(Caustic)$ which is formed in this reaction is generally non-volatile and does not contribute to any vapor pressure in the solution. Thus, as long as there is a surplus of caustic in the solution, the vapor pressure of hydrogen sulfide over the solution will be very small. As long as the vapor pressure of hydrogen sulfide over the solution is small, hydrogen sulfide will be absorbed from the gas into the solution and thereby removed from the gas. For this to be a useful process, the salt which is formed must be one which can then be decomposed to give back the hydrogen sulfide and regenerate the caustic. For this reason, the caustics which are used are generally not strong caustics like sodium hydroxide, but rather very weak caustics of which the most successful commercially have been ethanolamines

$[NH_n(CH_2 - CH_2OH)_{3-n}]$ and the salts of weak acids like carbonic and phosphoric.

In its most elemental form, a basic processing scheme of all weak-caustic hydrogen sulfide removal systems is shown in Figure IV-1. Here we see, starting at the left, that the fuel gas containing several percent hydrogen sulfide passes into a scrubber tower. It flows upward through the tower and leaves the top as purified gas. In counter-current flow in the tower, an amine solution flows downward and scrubs the hydrogen sulfide out of the gas. Under most circumstances where the gas is to be used at high pressure, this is a tray tower which contains ordinary bubble caps. For a gas which is not to

FIGURE IV-1. Typical flow diagram for an amine scrubber removing H₂S from "sour fuel gases."

be used at high pressure, it is usually advantageous to use a packed tower because of the lower pressure drop. (The latter will most likely be the case for the gases in the oil shale industry.) In either case, the amine solution, which is "loaded" with hydrogen sulfide, passes out the bottom of the tower, through a heat exchanger, and to the top of the desorbing column. The desorbing column is an ordinary bubble cap or packed column with a steam reboiler. In the reboiler, a certain fraction of bottoms liquid is boiled forming steam which acts as a stripping gas and strips the hydrogen sulfide out of the amine solution. The amine solution which is thus regenerated, passes through a heat exchanger and a cooler back to the scrubber tray tower. The gas from the top of the desorption column passes to a cooler where the steam which acted as a stripping agent is condensed and, in addition, any amine which has been carried over is condensed and returned to the desorption column. The hydrogen sulfide is shown passing out the process sheet to the right.

Figure IV-1 is a greatly simplified flow diagram which leaves out all of the control devices and start-up and shut-down lines and other miscellaneous pieces of apparatus. However, it shows the essentials of the process. In the scrubber-tray tower, the temperature is low enough that the complex between hydrogen sulfide and the amine which is formed in the solution is quite stable, has a negligible vapor pressure and, as a result, the solution is a good absorbent for hydrogen sulfide. In the desorption column, the temperature is much higher and the complex formed between the amine and the hydrogen sulfide becomes quite unstable and breaks down, leaving a gaseous hydrogen sulfide which is swept out of the column and the non-volatile amine which remains in the solution and is returned to the scrubber-tray tower.

The flow diagram shown on Figure IV-1 is not specific to scrubbing systems which use amines or any one specific amine, but could be used for any system for removing a gas from a gas stream based on its acidity and using a weak caustic as the scrubber. The flow diagram of processes for removing sulfur dioxide, carbon dioxide, and numerous other processes look essentially the same as Figure IV-1. In all other such processes, the details vary somewhat but the fundamentals are the same.

As mentioned above, the most commonly used solvent for the recovery of hydrogen sulfide is diethanol amine. Other solvents which can be used are monoethanolamine, potassium carbonate, etc. Kohl and Reisenfeld (84) give an extended discussion of the choice of solvent for various applications of this type. The criteria which seem most important are the vapor pressure of the solvent and the solvent's reaction with impurities. For example, monoethanolamine is the preferred solvent if the concentration of carbonyl sulfide in the gas stream is zero. However, if there is carbonyl sulfide in the gas stream, then it will react with the monoethanolamine and form a complex which does not break down appropriately in the decomposing column. As a result, the amine is slowly destroyed by this impurity and must be regularly replaced. There are other advantages and disadvantages for the various choices of caustic, but based on consideration of all of these, most of the oil shale processors have elected to base their designs for high BTU gas from surface retorts on the use of diethanolamine.

Just as Figure IV-1 shows in schematic form the amine treating system to be used to remove hydrogen sulfide, Figure IV-2 shows how this amine treating system will be integrated into the entire gas recovery and treating operation of a proposed oil shale complex. This diagram is for the type of facility envisaged in the original Detailed Development Plans, in which the

GAS RECOVERY AND TREATING UNIT

FIGURE IV-2. Typical integration of amine treating into an oil-shale processing plant (20).

shale oil would be substantially upgraded at the oil shale site. The revised DDPs envisage only minor treatment at the site, so that much of this processing will take place at a remote refinery. However, if the shale oil is processed for motor fuels (as opposed to boiler fuels) then this treatment must occur somewhere, and this flow diagram is still of interest. In Figure IV-2, we see the amine treating system consisting of a gas treating column and amine regenerator in the upper right hand corner of the figure. The two vertical vessels shown there correspond to the two vessels shown at the left of Figure IV-1. In order to show the entire gas treating system, some of the miscellaneous parts shown on Figure IV-1 have been omitted. We also see on Figure IV-2 that one amine regenerator column is intended to process two separate gas streams. Thus there are two adsorber columns; the one in the upper middle of Figure IV-2 which processes the C_2 hydrocarbons and lighter material, and the one in the middle bottom row, which processes the C_3 and C_4 hydrocarbons. This arrangement with two columns is economically advantageous. There is no reason that one could not do it entirely in the form shown in Figure IV-1 and then separate the C_3 's and C_4 's from the C_2 's and lighter material, but that is apparently less economical.

Table IV-1 shows the estimated composition of the gases produced by various retorting schemes. Consider first the gas expected to be produced by the Tosco retorting scheme. In this scheme, the shale is decomposed by heat supplied by hot ceramic balls. There is no air present with the shale during the decomposition. We see that the product gas contains no nitrogen or oxygen, a modest amount of hydrogen, and 5 mole % of hydrogen sulfide. The conditions under which the gas is produced are sufficiently reducing that

TABLE IV-1

ESTIMATED GAS COMPOSITIONS FOR VARIOUS RETORTING SCHEMES

Gas Composition	Tosco ⁽¹¹⁰⁾ Wt. %	Paraho Indirect ⁽¹¹¹⁾ Vol %	Paraho Direct ⁽¹¹¹⁾ Vol %
N ₂	--	1.8	61.0
O ₂	--	--	0.1
H ₂	1.5	36.6	4.9
CO	3.5	7.3	2.9
CO ₂	33.1	21.2	22.8
H ₂ S	5.2	2.0	0.1
C ₁	11.9	20.5	2.1
C ₂ 's	17.1	6.5	1.1
C ₃ 's	16.5	1.2	0.6
C ₄ 's	11.2	0.6	0.3
H ₂ O	--	2.3	4.1
Total	100.0	100.0	100.0

No entries are shown for Union-A or Union-B, nor Superior, nor any version of in-situ, because to our knowledge these have not been published. However, we can speculate that Union-A will have an off gas similar to Paraho Direct, while Union-B and Superior will have one similar to Paraho Indirect. In-situ projects should have a gas similar to Paraho Direct.

any sulfur which is present in the gas will be in the form of hydrogen sulfide. The gas also contains a significant amount of carbon dioxide and some carbon monoxide. These are not produced by combustion of carbon, but rather by decomposition of some of the mineral carbonates which are present in the oil shale. All of the oxygen contained in the carbon oxides shown in this table is due to decomposed carbonates. This gas appears to be perfectly straightforward for treatment by amine scrubbing. The concentration of hydrogen sulfide is well within the range of concentrations of hydrogen sulfide routinely treated in petroleum refining, and the efficiency of sulfur capture is largely a function of the design of the amine system.

Next consider the Paraho Direct Process - the rightmost column in Table IV-1. In the Paraho Direct Process, the shale is decomposed by heat generated by combustion of the carbon residue left on the shale; in contrast, this carbon residue left on the shale in the Tosco Process is not burned but is ultimately disposed of with the spent shale. Because the combustion air passes through the retort in the Paraho Direct Process, the gas leaving the retort contains 61% nitrogen as shown on Table IV-1. Very little oxygen passes through because the amount of oxygen introduced into the system is much less than that which would be required to oxidize all of the hydrocarbons present; most of the oxygen is used up. We see that this gas contains significant carbon dioxide and carbon monoxide. In this case, most of the carbon dioxide is produced by combustion of the residual carbon, and is not the result of decomposition of mineral carbonates. We see from Table IV-1 that the hydrogen sulfide concentration of this gas is quite low.

If this process is used, it may not be economical to remove this hydrogen sulfide. When this process is used, most of the organic sulfur in the shale ends up in the product shale oil. This must then be removed from the oil by

hydrotreating, which will also remove most of the nitrogen contained in the oil. Referring to Figure IV-2, we see that the gas which will normally be treated in the gas recovery system consists of the raw gas from the pyrolysis, the coker fractionators, and from the naptha and gas-oil hydrotreaters. Thus, although the gas from the Paraho Direct retort is very low in hydrogen sulfide, the hydrogen sulfide will be produced separately in the gas from the hydrotreaters. Figure IV-2 shows these two gas streams combined going to the gas treatment system. Whether the two will be combined if the Paraho process is used or will be treated separately is not known. In either event, there seems no obvious difficulty with treating the Paraho Direct gas for hydrogen sulfide removal; it contains no materials which should interfere with the amine treating process.

Finally, considering the Paraho Indirect Process, we see that its waste gas contains very little nitrogen. In the Indirect Process, the shale is heated by recirculating part of the gas stream which is externally heated in fired heaters. This gas contains a surprisingly large amount of hydrogen which is presumably produced in the system by the reduction of the contained water by organic carbon. Because this process is strongly reducing, we see that the exit gas contains 2% hydrogen sulfide which again places it in the normal range of refinery hydrogen-sulfide-bearing materials which are treated by amine scrubbing.

Table IV-3 does not contain entries for either of the Union Oil processes nor the Superior process nor in-situ. We have been unable to find any published gas compositions for the off-gas from those retorting processes.

We may, however, speculate with some confidence that the off-gases produced in the Union-A retort should be very similar to those produced in

the Paraho Direct retort, and that the off-gases produced in the Union-B retort should be very similar to those produced in the Paraho Indirect retort. Similarly, the off-gases produced in the Superior retort should be similar to those produced by Paraho Indirect while the off-gases from in-situ processing should be more like the gas produced by the Paraho Direct. These statements are based on the assumption that retorting in the presence of air, using air as the oxidizing agent to burn residual carbon for heat generation, should produce about the same gas composition independent of the details of how the gas and rock are brought together, while retorting, which is based on using a hot inert gas to transfer heat to the shale should produce about the same off-gas composition independent of the details of how the hot gas and the shale are brought together.

It is somewhat surprising that the values in Table IV-1 show so much difference between the off-gases produced by the Tosco 2 and Paraho Indirect retorts. The most striking differences are the fractions of hydrogen and of hydrogen sulfide. If one had no data to go on one would probably assume that since, in both of these retorts, the retorting takes place with no oxygen present, the retort off-gases should be substantially the same. Apparently the use of hot balls (and the more rapid heat transfer to the shale which can be produced this way) produces a different off-gas composition than is produced by the slower heating accomplished by passing hot gas through the shale. For this reason, we suggest caution in applying the foregoing estimates of the composition of gases to be expected from other retorting schemes; the differences may be great enough so that the off-gases are quite different in composition.

The removal schemes discussed here, which are based on absorbing the hydrogen sulfide in an aqueous solution of a weak caustic, will not

only recover the hydrogen sulfide, but will also recover the carbon dioxide which also forms a weak acid when dissolved in water. This need not pose a serious problem. However, in subsequent processing steps discussed in Appendix V, the process to be used depends on the concentration of hydrogen sulfide in the mixture of hydrogen sulfide and carbon dioxide. If a hydrogen sulfide content in this mixture is more than about 5 to 10%, then one technology is used; whereas, if it is substantially below about 5 to 10%, an entirely different technology is used. Both of these technologies are discussed in Appendix V. Considering now the data shown in Table IV-1, we look at the Tosco retort and see that the carbon dioxide concentration in the gas is 31.1%, while the hydrogen sulfide in the gas is 5.2%. Therefore, the hydrogen sulfide in the combination hydrogen sulfide plus carbon dioxide is $5.2\% / (31.1\% + 5.2\%) = 13.6\%$. On the other hand, for the Paraho Direct retort, the concentration of hydrogen sulfide in the mixture of hydrogen sulfide and carbon dioxide is $0.1\% / (1.1\% + 22.8\%) = 0.4\%$. These two gas streams would be treated entirely differently for sulfur removal because of the large difference in the percentage of hydrogen sulfide in the gas removed.

Most likely what will actually be done is that the gas coming from a Tosco or a Paraho Indirect retort would be processed by the technology described in this appendix and the hydrogen sulfide-carbon dioxide stream sent to a Claus plant as described in Appendix V, while the gas from a Paraho Direct retort or in-situ retort, which has a low concentration of hydrogen sulfide relative to the carbon dioxide, would not be sent to this type of plant at all but rather would be sent directly to a Stretford plant, which combines the functions of both hydrogen sulfide separation and conversion to sulfur. The Stretford process is described in the second part of Appendix V.

APPENDIX V

Conversion of H₂S to Sulfur

The process described in Appendix IV removes the hydrogen sulfide from the gas streams produced in the retorting and in the processing of the liquid products at the oil-shale site. The hydrogen sulfide thus recovered cannot be vented to the atmosphere because it is a toxic and odorous material. All of the oil-shale projects intend to convert this hydrogen sulfide to elemental sulfur. The overall reaction for this process is

Although this appears simple, there are numerous ways for carrying out the reaction depending on the properties of the gas stream and other economical variants. Kohl and Riesenfeld (84) list 26 processes for carrying out this reaction shown in Equation (V-1). However, the Detailed Development Plans and other published information on the oil-shale operations indicate that two processes are most likely to be used for almost all of the hydrogen-sulfide conversion in the oil-shale industry. These are the Claus process and the Stretford process. The Claus process will be used for hydrogen sulfide streams with a hydrogen sulfide content greater than about 5 to 10%, whereas the Stretford process will be used for streams containing a lower percentage hydrogen sulfide than this. These two processes are described in detail in Riesenfeld-Kohl's book. That book will be quoted from extensively here, with additional comments as seem appropriate by the present authors.

The Claus Process

The Claus process is not a gas-purification process in the true sense of the word, as its principal objective is recovery of sulfur from pure gaseous hydrogen sulfide or from acid gas streams containing hydrogen sulfide in high concentrations. Typical streams of this type are the acid gases stripped from

regenerable liquids, e.g., alkaline solutions or physical solvents used for the purification of sour gases. The effluent gases from the Claus plant are without value and are vented to the atmosphere, usually after incineration of residual sulfur compounds to sulfur dioxide. In view of air pollution control regulations existing in most industrialized countries which prohibit discharge of large amounts of sulfur compounds to the atmosphere, Claus plants are often mandatory adjuncts of gas-desulfurization installations, and, consequently, the Claus process is of considerable significance within the general scope of gas-purification technology. Furthermore, the Claus process yields sulfur of extremely good quality and this is a source of a valuable basic chemical. It is estimated that in 1970 approximately 9 million long tons of elemental sulfur were recovered from hydrogen sulfide bearing gases in the Western Hemisphere, Europe, the Middle East, and Japan, representing about 50 percent of the total sulfur production of that area.

Considering growing concern with air pollution, sulfur recovery in Claus type units is increasing to the point where units which normally would not be considered economical are being installed, strictly for the purpose of air pollution control. In addition, the recovery efficiency of Claus type plants is continuously improved by better design methods. Unfortunately, complete conversion of hydrogen sulfide to elemental sulfur is precluded by the equilibrium relationships of the chemical reactions upon which the process is based. As a result of this limitation, the process is, in many instances, not adequate to reduce emission of sulfur compounds to the atmosphere to the level required by air pollution control authorities and has to be supplemented with processes specifically designed to remove residual sulfur compounds from the Claus plant tail gases. Such processes are discussed elsewhere in this text.

Since the disclosure of the process by Claus in 1883, it has undergone several modifications, most of which are, however, only of historical interest. As presently used, the various processes on the market are similar in their basic concept and differ only in the design and arrangement of the equipment.

The heat of reaction for the combination of Reactions 8-2 and 8-4, i.e.,*

is 262,000 to 311,000 Btu (45), with 223,000 to 248,000 Btu for Reaction 8-2 and 38,000 to 63,000 Btu for Reaction 8-4 (45). Since Equation 8-4 represents the catalytic stage, it is seen that the temperature rise in the catalyst beds is relatively small, permitting operation at low temperatures and, consequently, the attainment of high conversion. Since the reactions are reversible and

*for internal consistency, we will retain the equation numbers and reference numbers in these extended quotes. However, figures and tables are renumbered and placed in the figure and table sections at the end of the report.

water is a reaction product, removal of water between catalytic stages would be a means to increase conversion. However, attempts to do this have so far failed, primarily because of the corrosiveness of the aqueous condensate and plugging of the equipment with solid sulfur. Thus, the presence of water vapor in the reaction gases throughout the plant imposes a definite limitation on the degree of conversion.

A further limitation on conversion is the occurrence of a number of side reactions, due to the presence of carbon dioxide and light hydrocarbons in the feed gas, resulting in the formation of carbonyl sulfide and carbon disulfide in the thermal stage of the process. These compounds are quite stable and may pass unchanged through the catalytic converters unless provisions are made for their conversion to hydrogen sulfide and carbon dioxide. Formation of carbonyl sulfide and carbon disulfide is a significant consideration in the design and operation of high-efficiency Claus plants as the sulfur associated with these compounds may amount to an appreciable percentage of the sulfur in the plant feed gas.

Various reaction mechanisms have been proposed for the formation of carbonyl sulfide and carbon disulfide (44, 45, 54, 57, 60) and for their conversion to hydrogen sulfide, elemental sulfur, and carbon dioxide. The limited plant data available indicate that carbonyl sulfide is formed primarily from hydrogen sulfide and carbon dioxide following reasonably well the equilibrium relationships prevailing at reaction furnace temperatures (see Chapter 13). However, carbon disulfide has been found in much higher concentrations than would be indicated by chemical equilibria, and an additional mechanism, probably involving hydrocarbons and sulfur vapor, is surmised. This is particularly true for the partial combustion process, where the entire feed gas is passed through the reaction furnace, and substantial amounts of sulfur are formed in the flame.

From a practical standpoint, the exact mechanism of side reaction products formation is less important than their conversion to hydrogen sulfide and sulfur to prevent emission to the atmosphere. It is generally assumed that carbonyl sulfide and carbon disulfide undergo hydrolysis (see Chapter 13) at temperatures on the order of 700°F, in the presence of an aluminum oxide type catalyst at sufficiently rapid rates to attain thermochemical equilibrium. Thus, by maintaining sufficiently high temperatures in the first

catalytic converter and by use of an active catalyst, substantial conversion of carbonyl sulfide and carbon disulfide can be obtained.

The literature describing the theoretical as well as design and operational aspects of the Claus process is quite voluminous and the reader interested in detailed information is referred to the original sources (44-59).

In view of this extensive coverage of the process in the literature, the following discussion will be directed primarily toward the design and operation of high-efficiency plants giving maximum sulfur recovery and minimum emission of sulfurous air pollutants to the atmosphere.

Basic Data

The basic chemical reactions occurring in the Claus process are represented by Equations 8-1, 8-2, and 8-4, with Reactions 8-1 and 8-2 taking place in the thermal stage (reaction furnace) and Reaction 8-4 in the catalytic stage (catalytic converters). The thermodynamics and kinetics of the reactions have been investigated by Gamson and Elkins (45), and theoretical conversion as a function of temperature and pressure was computed. These data are shown in Figure V-1. The equilibria are complicated by the presence of various species of sulfur in the sulfur vapor at different temperatures.

It can be seen from Figure V-1 that the process can be separated into two stages, i.e., a thermal stage, above about 1000°F, and a catalytic stage, usually between 700°F and a temperature somewhat above the sulfur dew point of the gas mixture. The lower this temperature, the more complete conversion can be attained. It is, therefore, advantageous to have several catalytic stages with condensation of the sulfur formed after each stage.

The catalyst used in the Claus process is either natural bauxite or alumina which may be shaped into pellets or balls. For high-efficiency plants, an alumina catalyst of high activity is usually preferred. Besides activity, resistance to attrition and to relatively high temperatures during regeneration are important catalyst properties. Furthermore, the shape of the catalyst must be such that no excessive pressure drop is incurred at space velocities ranging from 1,000 to 2,000 volumes of gas per volume of catalyst per hour.

Process Description

There are two basic forms of the process which may be termed the partial combustion and the split-stream processes. In the partial combustion process, which is shown diagrammatically in Figure V-2, the entire acid-gas stream and the stoichiometric amount of air to burn one-third of the hydrogen sulfide to sulfur dioxide is fed through a burner to the reaction furnace. At the temperatures prevailing in the furnace, typically 2000° to 3000°F, a substantial amount of elemental sulfur is formed (see Figure V-1), which is condensed after cooling the gases first in a waste heat boiler and subsequently in a sulfur condenser. While high-pressure steam can be generated in the waste heat boiler, it is preferable to produce low-pressure steam (25 psig) in the sulfur condenser in order to cool the reaction gases to obtain maximum sulfur condensation. The reaction gases leaving the sulfur condenser are reheated and flow through the first catalytic converter where additional sulfur is produced by the reaction of hydrogen sulfide with sulfur dioxide. Reheating the gas is necessary to maintain the temperature of the reaction gas above the sulfur dew point as it passes through the catalytic converter because condensation of

FIGURE V-1. Theoretical equilibrium conversion of hydrogen sulfide to sulfur vapor (84).

FIGURE V-2. Schematic flow diagram of a Claus plant (84).

sulfur leads to rapid catalyst deactivation. The gases leaving the first catalytic converter are again cooled, and sulfur is condensed. The process of reheating, catalytically reacting, and sulfur condensing may be repeated, in one, two, or even three additional catalytic stages. As conversion progresses through the catalytic stages and more and more sulfur is removed from the gas mixture, the sulfur dew point of the reaction gases is lowered, permitting operation at progressively lower temperatures, thus improving conversion (see Figure V-1). After leaving the last sulfur condenser, the exhaust gases, which still contain appreciable amounts of sulfur compounds and a small amount of sulfur vapor, are either incinerated, in order to convert all sulfur compounds to sulfur dioxide, before venting to the atmosphere, or further treated, in a separate process, for removal of residual sulfur values.

The partial combustion process is used for gas streams of high hydrogen sulfide content (above 50 percent). Depending on the hydrogen sulfide concentration in the acid gas, conversion efficiencies of 94 to 95 percent can be attained with two catalytic stages and of 96 to 97 percent with three catalytic stages. A fourth catalytic converter is normally not economical as it increases conversion by less than 1 percent. It should be noted that the conversion efficiencies indicated above do not take into account sulfur losses caused by carbonyl sulfide and carbon disulfide formation and that the overall conversions must be adjusted downward by the amount of such losses.

As stated earlier, carbonyl sulfide and carbon disulfide hydrolyze fairly readily at temperatures around 700°F in the presence of Claus catalyst. It is therefore advantageous to design the first catalytic converter for operation at such a temperature level if high conversion efficiency is required. However, this results in inefficient operation of the first converter with respect to the Claus reaction, and installation of a third converter is necessary to compensate for this loss in efficiency.

The split-stream process is used for acid-gas streams containing hydrogen sulfide in such low concentrations that stable combustion could not be sustained if the entire gas stream were fed to the reaction furnace. In this process one third of the acid gas is fed to the reaction furnace, and all the contained hydrogen sulfide is burned to sulfur dioxide with the stoichiometric amount of air. The hot gases are cooled in a waste heat boiler and then combined with the remaining two thirds of the acid gas before entering the first catalytic conversion stage. The rest of the process is identical with the partial combustion process.

Since in the split-stream process all hydrogen sulfide contained in the portion of the acid gas fed to the furnace is burned to sulfur dioxide, no carbonyl sulfide and carbon disulfide should be formed; consequently, it should not be necessary to operate the first catalytic converter at high temperatures to hydrolyze these compounds.

Combination of the partial combustion and split-stream processes may prove to be advantageous for the processing of acid-gas streams containing hydrogen sulfide concentrations on the order of 35 to 50 percent. In such cases varying amounts of acid gas may be bypassed around the furnace. Figures 8-14 and 8-15* show photographs of a large and small Claus plant.

*These photographs are not included in this report.

Design and Operation

Process design procedures have been presented by Valdes (50, 51) and by Opekar and Goar (54). Since sufficient thermodynamic and kinetic data are available in the literature, these methods are straight forward, and design optimization by the use of computer techniques is possible. One such method has been proposed by Boas and Andrade (78).

Several mechanical designs and arrangements of the major equipment have been reported in the literature. The reaction furnace normally used combines the burners, the combustion chamber, and the waste heat boiler in one integral vessel. Methods for the design of firetube reaction furnaces have been reported by Valdes (52). A different design consisting of a separate combustion furnace and waste heat boiler has been described by Sawyer, et al. (44). However, this design is not widely used in modern Claus plants.

Heating of the reaction gases may be effected by several methods (49, 50, 51, 57), i.e., bypassing of hot gases from the reaction furnace, auxiliary in-line acid-gas burners, gas-to-gas heat exchangers, and indirect fuel-gas fired heaters. The first two methods result in slightly lower conversion as some of the acid gas is bypassed around one or more catalytic converters. Gas-to-gas heat exchangers and fuel-gas fired indirect heaters are more expensive than hot gas bypasses and in-line burners, but their use may be justified if very high conversion is required. The catalyst beds may be arranged in horizontal or vertical vessels, with more than one bed located in one vessel. In very large installations, care has to be taken to assure even gas distribution and to avoid channeling.

It is customary to install mist eliminating devices after the last sulfur condenser in order to minimize entrainment of sulfur droplets into the incinerator. Installation of mist eliminators after each sulfur condenser is of value as catalyst deactivation by entrained sulfur may be a problem. Effective mist elimination devices are vessels packed with Raschig rings or wire mesh pads.

The mechanical design of small plants is often substantially different from that of large installations as small units lend themselves to compact packaging. Designs of this type of unit with capacities of less than 50 long tons of sulfur per day have been presented by Grekel, Kunkel, and McGalliard (48).

The most important variable in the operation of Claus plants is the ratio of hydrogen sulfide to sulfur dioxide in the reaction gases entering the catalytic converters. Maximum conversion requires that this ratio be maintained constant at the stoichiometric proportion of 2 moles of hydrogen sulfide to 1 mole of sulfur dioxide. Appreciable deviation from the stoichiometric ratio leads to drastic reduction in conversion efficiency (51). The proper ratio is maintained by control of the air flow to the reaction furnace which is easily done by automatic air to acid-gas ratio flow control. However, this method is only successful if the hydrogen sulfide content of the acid gas is constant, as it does not compensate for the variations in the actual amount of hydrogen sulfide flowing to the reaction furnace. Several methods based on controlling the air flow by continuous analysis of the ratio of hydrogen sulfide to sulfur dioxide in the plant tail gas have been developed. One such method has been described by Carmassi and Zwilling (61). Several analytical instruments based on vapor chromatography and ultraviolet absorption which can be used in the control circuit are commercially available.

A serious operating problem in Claus plants is deactivation of the catalyst by deposition of carbonaceous materials and, in some cases, of sulfate. Acid

gases usually contain small amounts of hydrocarbons, especially if the sour gas from which the acid gases have been removed is relatively rich in high molecular weight aliphatic and aromatic hydrocarbons which are somewhat soluble in the liquids used in the desulfurization unit. When acid gases of high hydrogen sulfide content are processed, the temperature in the reaction furnace is usually high enough to result in complete combustion of all hydrocarbons to carbon dioxide and water, and no catalyst deactivation is experienced.

However, at the low combustion temperatures occurring in plants processing gases containing less than about 40 percent hydrogen sulfide, hydrocarbons crack and the products from the incomplete combustion are carried into the catalytic reactors, gradually deteriorating the catalyst. The catalyst can be regenerated by air oxidation of the carbonaceous deposits. Care must be taken during regeneration not to exceed a temperature of about 1000°F in order to avoid changes in the catalyst structure. A good catalyst can be regenerated several times although the activity decreases somewhat with each regeneration.

Another operating problem is condensation of sulfur on the catalyst resulting in rapid deactivation. This can be avoided by maintaining the temperature in the catalytic converters above the sulfur dew point of the gas mixture. Should sulfur condense on the catalyst, raising of the gas temperature is usually sufficient to vaporize the sulfur and to reestablish catalyst activity.

The foregoing long quote from Reisenfeld and Kohl summarizes the technical details of operating Claus plants. In applying this well-known technology to the hydrogen-sulfide streams which will be generated in an oil-shale operation, we can make the following observations:

(1) The sulfur to be produced in oil-shale ventures which upgrade the shale oil on site is a fairly significant part of the total product. It will represent a significant by-product credit. For that reason, the oil-shale operators will make considerable efforts to make sure that high-quality sulfur is produced which is marketable. On the other hand, those projects which do not intend to do major shale oil upgrading on site (i.e., the two currently alive in-situ projects) will not produce nearly as much sulfur as would be produced in a project which did more refining on site. They will mostly recover sulfur in Stretford plants (next section). The

sulfur produced in this way is generally not sufficiently high purity to be marketable, and is normally land filled. The operators indicate their intention of land filling this impure sulfur when it is produced.

(2) The gas to be produced by the amine-scrubbing processes in an oil-shale venture will contain a lower percentage of hydrogen sulfide and a high percentage of carbon dioxide than is common in petroleum refining. Most of the gases which are treated in petroleum refining for hydrogen sulfide removal contain little or no carbon dioxide. However, the oil-shale gases will contain substantial amounts of carbon dioxide because carbon dioxide is generally formed by pyrolysis of the carbonates in the oil-shale during retorting. As mentioned in the previous extended quotation, the presence of carbon dioxide in the gas leads to the formation of carbonyl sulfide which must be destroyed or treated in some way. The concentration of hydrogen sulfide in the combined mixture of carbon dioxide and hydrogen sulfide is not revealed in any of the Detailed Development Plans nor in any of the technical literature we have been able to find. The operators of the projects will have some control over this by the manner in which they operate their amine-scrubbing system. However, they are limited by equilibrium considerations there and will certainly have substantial amounts of carbon dioxide in this gas stream. The previous article does not discuss the minimum concentration of hydrogen sulfide which can be processed. Other authors (86) suggest that this minimum is below 10% hydrogen sulfide but do not suggest how low it can actually go. We may infer that since the reaction in the first stage is an exothermic combustion, the lowest concentration of hydrogen sulfide which could be processed must be somewhere near the lower combustible limit. This is not exactly true because combustible limits are estimated in situations where the heat released is not stored in the reactor vessel walls. The lower combustible limit for hydrogen

sulfide is reported (87) as 4.3 mole %. Allowing for normal dilution by air to supply sufficient oxygen, one would conclude that the lowest processable hydrogen-sulfide stream would contain about 14% hydrogen sulfide; published values indicate that lower concentrations can be treated. From the Detailed Development Plans, it is clear that for all hydrogen-sulfide containing streams with 10 or more percent hydrogen-sulfide, the Claus plant is envisaged.

(3) As discussed in the previous article, a tail gas from the Claus plant will contain significant amounts of sulfur dioxide. Figure V-2 shows this as being 10,000 to 30,000 ppm. Currently, in most areas, a tail gas from Claus plants is treated by some sort of process to significantly reduce this concentration. A recent EPA report (88) lists seven such processes as being commercially operable (See Table 13). The Detailed Development Plans indicate that several of the processes so listed are under consideration for use in tail-gas cleanup. These are not discussed here because they have been adequately discussed elsewhere and are now considered to be an adequately demonstrated technology which can be purchased on an "off-the-shelf" basis by anyone building a new Claus plant.

If, as described above, the Claus plant technology is only suitable for gas streams containing from 5 to 10% or more hydrogen-sulfide, then there must be a suitable alternative for lower hydrogen-sulfide concentrations. The Detailed Development Plans indicate that of the many possible processes that could be used, the one of choice appears to be the Stretford process. That process is described in the following excerpt from Reisenfeld and Kohl. The excerpt will be followed by comments and discussion upon it and upon its applicability to the oil-shale undertakings.

The Stretford Process

The Stretford process, developed jointly by the North Western Gas Board and the Clayton Aniline Company, Ltd., was intended initially for the removal of hydrogen sulfide from coal gas. However, the process proved to be equally suitable for desulfurization of a variety of other gas streams, such as refinery gases, synthesis gas, and natural gas, as well as of hydrocarbon liquids. At present approximately 50 Stretford plants are in operation, primarily in Europe.

As originally conceived and described by Nicklin and Brunner (42), the process utilized an aqueous solution containing sodium carbonate and bicarbonate in the proportion of about 1:3 (resulting in a pH range of 8.5 to 9.5) and sodium salts of the 2,6 and 2,7 isomers of anthraquinone disulfonic acid (ADA). The postulated reaction mechanism involves five steps.

1. Absorption of hydrogen sulfide in alkali
2. Reduction of ADA by addition of hydrosulfide ion to a carbonyl group
3. Liberation of elemental sulfur from reduced ADA by interaction with oxygen dissolved in the solution
4. Reoxidation of the reduced ADA (by air)
5. Reoxygenation of the alkaline solution providing dissolved oxygen for Step 3 of the process

Although this form of the process was tested successfully in commercial installations, it was soon found that certain inherent features imposed serious limitations on its economic operation. Because the process depended on dissolved oxygen for the conversion of hydrosulfide ion to elemental sulfur, a maximum sulfide loading of only about 40 ppm could be achieved without formation of thiosulfate. This resulted in very large liquid circulation rates and considerable power consumption. Furthermore, the formation of elemental sulfur was slow, requiring large reaction tanks and large liquid inventories. Finally, in order to obtain satisfactory rates of hydrogen sulfide absorption when treating gas streams containing appreciable amounts of carbon dioxide, partial decarbonation of the solution was required before recycle to the absorber.

In order to improve the economics of the process, a number of compounds were tested as possible additives, with the principal purpose of increasing the solution capacity for hydrogen sulfide and the rate of conversion of hydrosulfide to elemental sulfur. Among the compounds tested, alkali vanadates proved to be outstanding. It was found that hydrosulfide is reduced quite rapidly by vanadate to elemental sulfur, with a simultaneous valance change of vanadium from five to four. By introducing vanadate as the oxidant, it was no longer necessary to rely on oxygen dissolved in the solution thus permitting substantially higher solution loadings. At present, sulfide loadings of 500 ppm are common, and many plants have been designed with loadings of as high as 1000 ppm (46). Because of the fast rate of reaction, it is possible to convert hydrosulfide completely to sulfur in relatively short periods of time, thus reducing the size of the reaction tanks.

Although vanadate reacts readily with hydrosulfide to produce sulfur, a solution containing vanadate alone cannot be regenerated by blowing with air. However, in the presence of ADA, complete oxidation of reduced vanadate is achieved, and the reduced ADA is readily reoxidized by contact with air. The vanadate-ADA system works at a lower pH than the original

Stretford system without loss of washing efficiency, obviating any necessity for decarbonation of the treating solution. Furthermore, the complete conversion of hydrosulfide to sulfur prior to solution regeneration and operation of the process at relatively low pH results in a minimum of thiosulfate formation.

The process, as presently practiced, has been described by Nicklin and Holland (43), Thompson and Nicklin (44), Ellwood (45), the staff of the North Western Gas Board (46), and Ludberg (47).

Basic Data

The chemistry of the process can be represented by the following idealized equations:

Equation 9-25 represents absorption of hydrogen sulfide in the solution. Although the rate of absorption is favored by high pH, the rate of conversion of the absorbed hydrogen sulfide to elemental sulfur is adversely affected by pH values above 9.5. The process is therefore best operated within a pH range of 8.5 to 9.5.

Conversion of hydrogen sulfide to elemental sulfur is represented by Equation 9-26. This reaction is quite rapid and is essentially a function of the vanadate concentration in the solution as shown in Figure V-3 (43). According to Thompson and Nicklin (44), the reaction is of second order and follows the equation:

$$t = 1/K(a - b) \times \log_e b(a - x)/a(b - x) \quad (9-29)$$

where t = time in minutes

K = reaction rate constant,

$1/[(\text{moles/l}) (\text{hr})]$

a = initial concentration of vanadium in moles/l

b = initial hydrosulfide concentration in moles/l

x = moles/l hydrosulfide reacted

Numerical values for the rate constant as a function of pH are shown in Figure V-4. A general correlation for estimating the time required for complete conversion is given in Figure V-5. The values shown in Figure V-5 are based on a reaction rate constant of 6,000 (pH about 8.5) and a vanadate concentration of 0.01 mole per liter. Such values are common in commercial use. For other values of the rate constant and molar concentrations, the reaction time is obtained by dividing the reaction time given on the graph by the value of the rate constant multiplied by the molar concentration. Equation 9-26

FIGURE V-3. Effect of vanadate concentration on rate of reaction (84).

FIGURE V-4. Rate of reaction versus pH for conversion of hydrosulfide to sulfur. (84)

FIGURE V-5. Time of reaction versus percent conversion for conversion of hydrosulfide to sulfur (84).

shows that 2 moles of vanadate are required for each mole of hydrogen sulfide. In practice an excess of vanadate is used in order to avoid overloading the solution with sulfide and subsequent formation of thiosulfate during solution regeneration.

Reduced vanadate is oxidized by ADA according to Equation 9-27. Since ADA acts as the effective oxidant for vanadate, its concentration must be sufficient to satisfy the overall equation:

Reoxidation of ADA by contact with air is fairly rapid. However, the rate of oxidation can be appreciably accelerated by the presence of small amounts of iron salts kept in solution by a chelating agent. In general, a concentration of 50 to 100 ppm of iron combined with about 2,700 ppm of ethylene diamine tetraacetic acid (EDTA) is satisfactory (44).

Besides the principal reactions, a number of side reactions occur in the process. It has been reported that it is possible under some conditions for the solution to absorb more hydrosulfide than the vanadate can oxidize, causing the vanadium to precipitate as a black complex vanadium-oxygen-sulfur compound. This compound can only be restored to a soluble vanadate by continuous air blowing over long periods of time. However, the presence of sodium tartrate in the solution largely prevents the formation of this compound (43).

The most serious side reactions are those involving hydrogen cyanide present in the feed gas and conversion of hydrosulfide to thiosulfate.

Hydrogen cyanide is absorbed by the alkaline solution and partially expelled during regeneration by air blowing. A portion of the cyanide reacts with elemental sulfur forming thiocyanate which accumulates in the solution and eventually has to be discarded. It is therefore recommended to remove hydrogen cyanide from the feed gas prior to treatment in a Stretford plant, either by a prewash or by catalytic conversion to ammonia and nitrogen.

Formation of thiosulfate is dependent on the conversion of hydrosulfide to sulfur prior to contact with oxygen, pH of the solution, and operating temperature. The effects of temperature and pH are shown in Figures V-6 and V-7, (43). It is claimed that in a properly operated plant thiosulfate formation can be controlled at less than 1 percent of the sulfur in the feed gas (46). Thiosulfate may be allowed to accumulate in the solution up to a concentration of about 20 percent by weight. When this concentration is reached, a small stream of the solution is continuously removed from the system and either discarded or treated for the recovery of contained chemicals.

Carbonyl sulfide and carbon disulfide are not absorbed by the Stretford solution to a significant degree. Methyl mercaptan is largely removed, probably by oxidation and conversion to disulfide.

Carbon dioxide is partially absorbed by the alkaline solution, resulting in the formation of bicarbonate and consequent lowering of pH. When gases containing high concentrations of carbon dioxide are treated, the absorption efficiency of the solution may be sufficiently lowered to require an appreciable increase in the absorber height (43).

FIGURE V-6. Effect of temperature on thiosulfate formation. (84)

FIGURE V-7. Effect of pH on thiosulfate formation (84).

Process Description

A schematic flow diagram of the Stretford process is shown in Figure V-8. The raw gas is contacted countercurrently with the solution in the absorber where practically all hydrogen sulfide is removed. The treated gas contains less than 1 ppm of hydrogen sulfide. The solution flows from the absorber to a reaction tank where the conversion of hydrosulfide to elemental sulfur is completed. The reaction tank may be the bottom of the absorber or a separate vessel. From the reaction tank the solution flows to the oxidizer where it is regenerated by intimate contact with air, usually in cocurrent flow. In the oxidizer sulfur is separated from the solution by flotation and removed at the top as a froth containing about 10 percent solids. The relatively sulfur free regenerated solution is recycled to the absorber.

The sulfur froth is collected in a tank and subsequently further processed in filters or centrifuges to separate the solution remaining in the froth. In general, it is necessary to wash the sulfur cake with water to recover chemicals contained in the solution and to produce relatively pure sulfur. For reasons of water balance in the system, wash water and water produced by the reaction has to be evaporated either with the gas or in evaporators, depending on the quantity of water involved.

The sulfur cake which contains about 50 to 60 percent solids may be further processed by melting in an autoclave. In this manner high grade liquid or solid sulfur is produced.

A photograph of a Stretford plant treating coke-oven gas is shown in Figure 9-17.*

Design and Operation

The absorber may be any efficient gas-liquid contacting device. Most absorbers presently in operation are packed with wood slats or with metal splash plates 2 in. wide on 6-in. centers. Large plastic rings or saddles are claimed to be equally effective. One problem which arises, especially if gases containing relatively high concentrations of hydrogen sulfide (above 1 percent) are treated, is plugging of the packing with elemental sulfur. In some installations this difficulty has been alleviated by contacting the gas first in a spray column where about 80 percent of the hydrogen sulfide is removed. Final purification is subsequently achieved in a packed column.

The reaction tank is an empty vessel sized sufficiently large to allow complete conversion of hydrosulfide to elemental sulfur (see Figure V-5). Normally a liquid residence time of 10 to 20 minutes is required.

Several types of oxidizers have been employed (44). The simplest and most commonly used form is a cylindrical vertical tank containing at the bottom a device for effective air distribution. The liquid and air flow cocurrently upward, and the sulfur froth is removed by overflowing a weir at the top of the vessel. The solution, which is essentially sulfur free, is withdrawn at a point located below the top of the oxidizer. Oxygen utilization of 15 to 20 percent is achieved.

Another type of oxidizer is similar to surface aerators used in waste-water treatment. Such machines are claimed to be particularly suitable for solutions with low sulfide loadings (44).

*Not included in this report

FIGURE V-8. Typical flow diagram of Stretford process (84).

Yet another type of oxidizer, with reportedly very high oxygen utilization (44), consists of coils through which a mixture of air (or oxygen) and solution is pumped at very high Reynolds numbers. These devices are recommended for plants operating at high pressure and particularly where oxygen is available at elevated pressures.

Stretford plants can be constructed entirely of carbon steel, with inert linings, e.g., cold cured epoxy resins, for oxidizers and sulfur froth tanks. Stainless steel linings are recommended for solution and sulfur slurry pumps. However, care should be taken to avoid sulfur deposits on unprotected metal surfaces. The Stretford process operates best within a temperature range of 70° to 110°F. There are no limitations on absorption pressure.

Operating data on several commercial units ranging in capacity from 240,000 cu ft per day to 28 million cu ft per day have been reported by Nicklin and Holland (43) and by Ludberg (47). Design characteristics of a plant treating 28 million cu ft of coke-oven gas are shown in Table V-1 (47).

From this discussion of the Stretford process, we see that it differs significantly from the combination of amine-scrubbing and Claus plant oxidation which was discussed previously. In the Stretford process, the hydrogen-sulfide is absorbed and oxidized in the same solution. This seems to be the process of choice when the concentration of hydrogen-sulfide is very low and the carbon dioxide concentration is high enough that if the two gases were simultaneously removed the hydrogen-sulfide would not be combustible in a Claus furnace. As discussed in the previous excerpt from Riesenfeld and Kohl, high concentrations of carbon dioxide are something of a problem in Stretford processes, but one which can be dealt with by proper design, etc. For all of these reasons, the Stretford process appears to be the process of choice for dealing with the hydrogen-sulfide content of gases like the gas which will be produced in the Paraho Direct retort, and also the gas which would be produced in in-situ retorts. Both modified DDPs indicate that they will use it on in-situ gases. There seem to be no grounds for believing that this process cannot be transferred virtually intact from its other applications and used for these gas streams.

TABLE V-1

DESIGN DATA OF STRETFORD PLANT (84)

Type of gas	Coke oven
H ₂ S in, grains/100 SCF	275
H ₂ S out, grains/100 SCF	<1
Gas volume, cu ft/day	28,000,000
Absorber (2 units in parallel),	
Height	97 ft
Diameter	12 ft
Packing type	Wooden grids
Packing height	4 layers each 11 ft, 7 in
Reaction tank	Bottom of absorber, 24 ft high
Solution pumps	3 units (one stand-by), 90,000 igph*
Oxidizer (2 units in parallel)	
Height	24 ft
Diameter	20 ft
Solution depth	20 ft
Air blower (2 units)	60,000 cu ft/hr
Filter	Rotary vacuum
* Imperial gallons per hour	

APPENDIX VI

Separation of H₂S and Ammonia

Almost all of the nitrogen in the kerogen and some of the sulfur in it will be retained in the crude shale-oil. The percentages of each vary, depending on which retorting process is used. When the crude shale-oil is upgraded to produce finished products, most of the nitrogen and sulfur must be removed from it. This will be done by hydrotreating, which converts the nitrogen to ammonia and the sulfur to hydrogen sulfide. These materials are removed from the processed products by contact with water in the hydrotreater complex. This water containing both H₂S and ammonia (Or their salt, ammonium bisulfite) must then be processed to recover each of these gases separately.

As discussed previously in the case of hydrogen sulfide removal, so also in the case of ammonia production, the amount of ammonia produced in in-situ retorting and in most surface retorting operations is very small. Most of the ammonia will be produced when the shale oil is upgraded for use as motor fuels. The original detailed development plans envisaged this upgrading taking place at the oil shale site; the revised detailed development plans envisage it either being done at a remote oil refinery or not done at all if the shale oil is used as boiler fuel. Thus, this section applied to the control of ammonia at whatever location the ammonia is produced by hydrotreating of shale oil.

The technology for this operation is described by Riesenfeld and Kohl (84).

The problem of separating H_2S and ammonia is of particular significance in the processing of aqueous condensates containing the two compounds combined as ammonium sulfide. Typical of such streams are aqueous condensates from catalytic crackers, hydrotreaters and hydrocrackers in petroleum refineries and condensates from coal, oil shale, or tar-sand hydrotreaters in synthetic fuel plants. In view of air and water pollution problems, these streams have to be freed of H_2S and ammonia prior to disposal. The conventional method is steam stripping of the condensate in a "sour water stripper," followed by further processing of the overhead vapors in a Claus-type sulfur plant. However, in certain cases this leads to serious problems in the sulfur plant, and at least partial separation of H_2S and ammonia is required. This separation can be achieved either by a process such as the Chemo-Trenn or the Ammonex process or by separate stripping of H_2S and ammonia in a system of the type described by Annesen and Gould (23). In this system which has been developed by Chevron Research Company and which is known as the Waste Water Treatment (WWT) process, streams of essentially pure H_2S and ammonia are produced.

A schematic flow diagram of this process is shown in Figure VI-1. The sour water containing typically about 3 to 5.5 weight percent ammonia and 4 to 5.5 weight percent H_2S flows first to a degassing unit to remove dissolved inert gases and from there to a surge tank. In the surge tank liquid hydrocarbons are skimmed from the water and sent to recovery facilities. The water then flows to a column operating typically at a pressure of 100 psig, where H_2S is expelled overhead while the water containing ammonia flows from the bottom of this column to a second column operating at 50 psig, for ammonia stripping. The overhead of this column is crude ammonia of about 98 percent purity which has to be further purified in a scrubbing system before being compressed and condensed as liquid ammonia. The water effluent from the bottom of the ammonia stripping tower is sufficiently pure to cause no problems in its disposal.

Processing of sour aqueous condensates from petroleum refining operations has been the subject of many studies. A particularly good treatment of the subject has been presented by Beychok (24). Design methods for sour water strippers, based on the vapor-liquid equilibrium data of Van Krevelen, Hofstijzer and Huntjens (1) are given for a variety of conditions.

The ammonia produced in this way will be sold as a byproduct of the oil shale enterprise; its most important use will be for fertilizer. The hydrogen-sulfide will join that produced in the amine treating unit, and will flow to the sulfur production plant.

From Figure VI-1 it is clear that this separation is a simple distillation process. The various suppliers are able to obtain license fees and royalties for the processes because they have proprietary know-how on the

FIGURE VI-1. Typical flow diagram of waste water treatment (WWT) process (84).

design data for the process, including the data on selection of corrosion-resistant materials. There seems no basis for believing that the sour water from a shale oil hydrotreater will be significantly different from that from conventional oil refineries. (The oil companies have run large quantities of shale oil through their pilot plant hydrotreaters, and are confident that this is correct). If this process does malfunction it will not result in direct environmental contamination, but rather will cause indirect problems. If the ammonia is not as pure as specified it may not be marketable (or may have to be sold at distressed prices to some user who can tolerate the impurities). If the hydrogen-sulfide is not adequately pure it will cause operating problems in the sulfur recovery furnaces, which might ultimately lead to increased sulfur emissions to the atmosphere.

Conventionally most of the water coming from the WWT plant in Figure VI-1 is recycled to the hydrotreater. A small bleed stream is withdrawn to prevent the buildup of minor impurities. In the oil shale use this bleed stream will most likely be used for shale moisturization, where the minor impurities will be tied up in the spent shale. If the process malfunctions, it would propagate difficulties back to the hydrotreater, possibly causing its temporary shutdown. The impurities which could get into the water going to waste moisturization are hydrogen-sulfide and ammonia, both of which are air pollutants; very large malfunctions would be needed for enough of these materials to enter the atmosphere in harmful quantities.

APPENDIX VII

The Non-deterioration Doctrine

As discussed in Section II-A, the non-deterioration regulations of the state of Colorado, and those recently enacted by the Congress pose the most difficult regulatory environmental constraint on the development of an oil-shale industry. For that reason, it seems appropriate to include a longer discussion of the doctrine on which those regulations are based. That is done in this appendix.

In the summer of 1976, a protracted debate was held in the United State Senate over the non-deterioration provisions of the proposed amendments to the Clean Air Act of 1970. It appears certain that these provisions will have sweeping effects in the currently non-industrial parts of the United States. The conference committee version of the Clean Air Amendments of 1976, which was a compromise between the bills adopted in both houses was filibustered to death in the closing days of the session, principally by the two senators from Utah. Their principal objection was the non-deterioration regulations, which they had fought unsuccessfully in the Senate debate on the bill (89). The Clean Air Amendments of 1977, which become law in August 1977, contain two section on non-deterioration which largely write EPA's previous regulations into law. The history and background of these regulations and the technical details of how they will be enforced illustrate some of the most difficult dilemmas of U.S. environmental policy.

The basic issue of this controversy is whether the very clean air areas of the country should have their very clean air preserved, or whether

they should be polluted up to the pollution levels which are considered acceptable in the industrial areas of the country. To understand the controversy, one must first understand the idea of the ambient air standards. Currents U.S. pollution law is written on the assumption that there are some concentrations of air pollutants in the atmosphere which are truly harmless to human health, to vegetation, etc. These concentrations are called "ambient air quality standards"; really they are permitted levels of air contamination. The Clean Air Act of 1970 (23) mandated that the Environmental Protection Agency (EPA) should promulgate such standards and that the states should then enact regulations to guarantee attainment and maintenance of those standards. The EPA procedural guidelines to the states (90) indicated that pollution up to the level of the "secondary standards" was permitted. (The secondary standards are designed to protect against any human welfare effect, e.g., crop or vegetation damage. They are generally more stringent than the primary, human-health related standards.) (28).

A group of environmental organizations, headed by the Sierra Club, sued the EPA to have that instruction set aside. In their suit, they quoted wording in the Clean Air Act which said that the purpose of the Act was to "protect and enhance" the quality of the nation's air, and wording in the promulgation of standards which said:

The promulgation of national primary and secondary ambient air quality standards shall not be considered in any manner to allow significant deterioration of existing air quality in any portion of any State (28).

After a protracted legal battle, the Sierra Club's position was upheld in a tie vote in the U.S. Supreme Court, and the EPA was directed to issue regulations which would have the effect of protecting the quality of the air

in those areas where the air is currently cleaner than the ambient air quality standards.

This doctrine can be considered from legal, technical, socioeconomic, or emotional viewpoints. All of these will be discussed in this appendix. The Supreme Court, naturally enough, decided the case before it on the legal basis of the wording cited above and the legislative history of the act, which indicated that this was the intention of Congress.

There are at least two technical reasons for such a policy. First, one cannot know for certain that the ambient air quality standards which are currently in force are truly protective of everyone's health against every possible effect, because these standards are based on the limited health-effects data now available to us. Second, although there is some data to support the belief that there are concentrations of pollutants in the atmosphere which are truly harmless to health (91), there is no data to support the belief that the same is true for visibility, i.e., our ability to see distant mountains and vistas (92). The ability to see such things is determined by the concentrations of fine particles in the atmosphere. The haze which regularly obscures such views in the industrial and in most of the humid parts of the world is largely made up of particles or droplets 1 micron (10^{-6} meter) or smaller in diameter. The clarity of the air is roughly proportional to the reciprocal of the concentration of such particles.

The first of these technical reasons is a thorny one. It asserts, in effect, that the whole idea of ambient air quality standards is wrong. If the ambient air quality standards truly protect against all human health, crop, livestock, property, etc., damage, then there can be no justification at all for the argument that we ought to have air cleaner than the ambient air standards in order to prevent such damage. If, on the other hand, we admit

that we don't know enough to say that with certainty, then it follows that we are deceiving the public by telling them that once we have attained the ambient air quality standards in the currently polluted areas of the country, their air is "safe to breathe". Furthermore, if there are significant health effects at concentrations below the standards, then we are hardly justified in our current delays in at least meeting the standards. There is no such technical complexity with the visibility issue; all concerned parties agree that fine particles cause visibility damage at any ambient air concentration.

Under the compulsion of the court order, EPA promulgated a set of regulations (93) in which they required that all areas of the country which currently had air cleaner than the standards should be categorized into one of three classes, which they called Categories I, II, and III. Category I would be those areas of singular scenic beauty and "pristine air quality", where almost any increase in atmospheric pollution would be unacceptable. Category II would correspond to those areas in which moderate increases in atmospheric concentration would be acceptable, but pollution up to the level of the ambient air quality standards would not. Category III was to contain those areas which now have air significantly cleaner than the standards, and in which new major industrial developments and/or population growth were welcomed. These would emit enough pollutants so that the air would be contaminated up to the level of the ambient air quality standards. EPA, in their initial promulgations, classified all areas of the country which now have air cleaner than the ambient air quality standards as Category II, and spelled out detailed descriptions as to how the states or other groups could go about attempting to have areas reclassified from II to I or to III. To date, no such reclassification has

cleared all the procedural steps to become law.

However, the Clean Air Amendments of 1977 (94) go somewhat further than the EPA in this regard. In general, they adopted the same approach as did the EPA, which is to divide the country up into categories and to legislate for each of the categories the permitted increments in air contamination. They automatically classify all national parks, international parks, and wilderness areas of more than some minimum size as Category I. The remaining parts of the country would remain as Category II.

The permitted concentration increases (Table 4) refer only to particles and sulfur dioxide. The Sierra Club has suggested that other pollutants should be included as well. EPA's rationale for selecting particles and sulfur dioxide is that these come largely from industrial sources and from well-defined point sources, whereas the other pollutants are emitted largely by automobiles and other diffuse sources which are much harder to regulate. The 1977 amendments only mandate particulate and sulfur dioxide control, but they also instruct EPA to develop regulations for other pollutants.

A new industrial facility which wishes to locate in a clean air area must obtain a permit to construct which can only be granted based upon a showing that the new facility used "best available control technology" (BACT) and that the calculated concentration increment as a result of this plant - to be measured anywhere at the ground/air interface - will not exceed the values shown in Table 4. Furthermore, since these Table 4 increments are cumulative for all industrial sources, if some industrial source had previously located in the area after the cutoff date for "existing sources" written into the act and had used up the increment, then no new source can be permitted unless the previous "new source" is forced to reduce its emission so that the cumulative effect of both will not exceed the permitted

increment. This places EPA (or the states if they accept the responsibility for enforcing the regulations) in the position of checking each new source for predicted concentrations higher than the values shown in Table 4.

There are several technological issues which have been raised as a result of EPA's regulations and Congress's enactment of them. The first is, what constitutes BACT? EPA has published its definition of best available control technology for 19 industries (95). Normally these are in terms of emission standards, i.e., permitted emission rates for specific sources. The first place at which controversy over BACT has arisen has been over attempts to locate coal-burning power plants in Rocky Mountain and High Plains states. Most of the coal which is available in the Western States is low in sulfur content (generally of the order of 0.5 to 0.7% sulfur). According to most air pollution regulations everywhere in the world, this coal could be burned without sulfur removal technology and would not violate the existing emission standards. However, it is possible to install sulfur-dioxide control devices on such power plants and thereby reduce the sulfur emissions by approximately 80 to 90%. The power companies have suggested that since their plants would meet the applicable standards which are deemed BACT for Chicago or New York, there is no reason they should be obliged to put on additional control if they are located in the plains of Wyoming or Montana. As rules are currently interpreted by EPA, and apparently seconded by Congress, that contention is acceptable and coal-fired power plants burning low sulfur coal need not necessarily use sulfur control technology. The environmental litigants are contesting this view.

Because the sulfur levels of coal vary so widely, and because the current sulfur control technology is not very advanced, it is entirely plausible that the gas coming out of a sulfur control device in an eastern

power plant would have a higher sulfur dioxide content than a gas going into the sulfur control device on a western power plant. (E.g. if the coal is 3% sulfur and the device captures 80%, then the emissions will be the same as for 0.6% sulfur coal, untreated. That is acceptable anywhere in the country. But if one requires SO_2 control anywhere, then one would put a control device on a plant burning 0.5% sulfur coal, even though the untreated stack gas was cleaner than that coming from a plant burning 3% sulfur coal, with an 80% efficient sulfur removal device.)

The second controversy is over modelling. As the above procedure is described, it is clear that one cannot build a plant and test it to see if it violates the incremental concentration standard, but rather one must have a "permit to construct" before the plant is begun. Therefore, the decision whether the plant violates the increments listed in Table 4 will not be based upon measurement of the plant's concentration downstream, but rather will be based on atmospheric dispersion models (96). There has been considerable controversy over the reliability and accuracy of such models in the past and will be more in the future. The greatest controversy will bear on the concentrations to be expected on high ground near the plant sites. In most of the scenic parts of the Western United States, the potential plant sites are generally below the highest nearby cliffs, mesas and mountaintops. Most of the pollutant dispersion experiments upon which calculation models are based were conducted in flatlands or gently rolling country like the prairies of Nebraska or the plains of Southern England. The interpretation of those data to predict whether high concentrations will be observed when the plume from an industrial source impacts upon or flows around a ground obstruction has been a matter of vigorous controversy in the past and will be in the future.

The problem is illustrated in Figure VII-1, which shows a stack from an industrial facility and a nearby mesa. If the wind blows from the stack toward the mesa, the "plume" from the stack will flow toward the mesa. If it impacts directly on it (like the jet of water from a garden hose impacting on a wall), then the concentration measured against the mesa will be equal to that in the center of the plume, which is generally quite high. This possibility is illustrated in the upper part of Figure VII-1. If, on the other hand, the main plume turns aside from the mesa wall before hitting it, then the highest measured concentration on the mesa will be much lower. There have been experimental tests (97) and modelling controversies over which of these views is the best predictor of the concentrations to be expected on the side of the mesa in Figure VII-1, or on other high ground which may be near to proposed facilities. If one adopts the modelling schemes currently used by EPA, that would make it virtually impossible to construct a new large industrial facility within 20 or 30 miles of such high ground. Because of the amount of high ground in the West, this might close very large areas to any kind of large industrial development. This high-ground problem was brought forcefully to the attention of the Congress by the controversy over the proposed IPP power plant which would have caused high concentration on some days on high ground in Capitol Reef National Park. The 1977 Clean Air Amendments have sections specifically directed to this high ground problem, allowing the Class I increments to be violated up to 18 days/yr (i.e. 5% of the time) but attaching some other restrictions. Even if it could have met these restrictions, the IPP project has been forced to move, because of the Department of the Interior decision denying them the use of public lands near the National Park.

One method of minimizing ground-level concentrations is the use of

FIGURE VII-1. A major controversy in the modeling which will be used to decide whether to permit a plant to construct and operate in a clean-air area concerns how the "plume" from such a plant will interact with nearby high ground. The top sketch shows one view, which holds that the plume will flow directly against the high ground, causing high concentrations. The second holds that it will generally divert around it, and that the measured values against the high ground will be much less than suggested in the upper sketch.

tall stacks. This has been a point of contention between the electric power industry and the EPA. Currently, the EPA has apparently been upheld in court in its view that tall stacks are only an interim measure and that emission reduction at the source will be required. However, it appears that, according to current EPA regulations and the Clean Air Act Amendments of 1977, tall stacks may be used in clean air areas to raise pollutants higher above the ground in order to have them better dispersed by the time they reach the ground and thereby avoid exceeding the numerical increments listed in Table 4. If, as suggested above, the principal real issue is visibility degradation in scenic areas, then it follows that tall stacks are a way which complies with the letter of the law, but not with the spirit of the law, because the fine particles will mostly be trapped in the atmospheric boundary layer near the ground and will have practically the same effect on long-range visibility whether the emission is from tall stacks or short ones.

Although the regulations are directly written for ambient air concentrations to be measured at ground level, if, as suggested, the real technical issue is visibility degradation, then there is an additional technical problem. Our methods of estimating the effect of a new industrial source on such visibility are crude at best. In the arid Southwest, where traditionally visibility is outstanding, there has been ample controversy over whether the currently observed days of poor visibility are due to pollutants transported long-distance from the Pacific Coast, or are due to the newly constructed coal-burning power plants in the region or some other source. As yet, we do not know enough to answer such questions with certainty.

Figures VII-2 and VII-3 illustrate some aspects of these problems. Figure VII-2 shows a layer of light-scattering haze, partially obscuring the

FIGURE VII-2. Light scattering effects of the Navajo plume obscuring visibility between Lake Powell and Navajo Mountain. (Navajo Mountain is prominent from most observation points 85± miles at Bryce Canyon National Park.)

Photo Courtesy of Dr. Michael Williams

FIGURE VII-3. Cooling tower water vapor intersecting inversion plume from the stacks of the Navajo Plant at Page, Arizona.

Photo courtesy of Dr. Michael Williams

view of Navajo Mountain. The haze in this case is mostly composed of fine particles of fly ash from the Navajo Generating Station located 40 miles west-southwest of Navajo Mountain. It is trapped in a stable layer and flowing slowly across the Utah desert. Above this stable layer, the air is clearer and normally one can see Navajo Mountain for distances of up to 100 miles. (The author personally saw it from Brian Head, 125 miles away in August 1977.)

Figure VII-3 shows the Navajo Generating Station operating during an inversion period. The large white plume at the left is a cooling tower plume, which is simply water vapor and which will evaporate leaving no visibility effecting residue. The two stacks at the right are emitting fine particles of the type which caused the haze layer in Figure VII-2. The third stack is clear because it was part of an unfinished unit of the plant at the time of the photo. Figure VII-3 also illustrates part of the high-ground problem discussed above. In the left background (just to the left of the white cooling-tower plume), is Leche-e Rock, which is 8.3 miles southeast of the plant and approximately 800 feet higher than the top of the plant's stacks. The kind of plume impingement on high ground which is shown schematically on Figure VII-1 could occur on that type of isolated mesa.

Figures VII-1, 2, and 3 do not show the harder part of the non-deterioration problem, which is the formation of the secondary particles in the atmosphere. The haze in Figures VII-2 and 3 is largely unchanged from its physical condition as emitted from the plant; it consists of very fine glassy mineral particles formed from the ash in the coal. As emitted, sulfur dioxide is transparent and has minimal light-scattering effect. However, in the atmosphere it slowly oxidizes to sulfur trioxide, which then combines with other fine particles, water, or ammonia to produce fine particles which are

powerful haze producers (98). These most likely would not be seen in clear, well-defined layers as in Figure VII-2, but more likely in a generally dispersed haze which is not easily attributable to any one source. Such general hazes have been observed in the Grand Canyon, many miles from an obvious source.

The previously-listed set of controversies were basically technical. The next set are more sociological. The first is the question of growth. The senators and representatives from Utah, which may be the state most affected by the non-deterioration doctrine, believe that if this doctrine becomes law, the industrial growth of their state will be severely curtailed. They consider it the first law of politics that they must always be in favor of industrial growth of any kind and that, therefore, any regulation which prevents new industry from locating in their state is unacceptable. A large number of industrial states, on the other hand, have joined the Sierra Club in supporting the kind of regulations shown in Table 4. Their critics claim they did so to prevent new industry from moving from their states to the clean air areas of the Rocky Mountains.

An additional social issue is the question of whether or not we should move the pollution to the people. An example of this occurred in the Salt Lake region in 1973 (99). At that time, a pipeline company was transporting crude oil from a remote area approximately 100 miles from Salt Lake City to its refinery in Salt Lake City. They wished to change the crude oil from one which would easily flow at ordinary temperatures to one which was very waxy and had a high melting point. In order to transport this new crude oil in the existing pipeline, they would have to heat the oil. They planned to do this by installing several heating stations along the route. The heating stations would burn a small fraction of the crude oil in order to heat the

remainder. Two of the proposed heating stations were located in mountain resort areas where the air was very clean. The residents of these resort areas raised the non-deterioration issue, brought the matter to hearing before the Utah State Air Conservation Committee, lost there, and began legal action to have the Federal non-deterioration doctrine used to block the construction of the heating plants. Although the oil company believed that they could ultimately win the case on its merits, they were anxious to complete the project and did not wish to suffer the legal delays involved. They worked out a compromise with the residents of the vacation areas. The oil company had an allotment of natural gas for its Salt Lake City refinery. They agreed with the gas company to transfer that allotment to the remote heating stations. They obtained the equivalent amount of heating by burning crude oil in the Salt Lake City refinery. This placated the protestors from the resort areas and allowed the project to go forward. Considering this from the non-deterioration point of view, it is clear that this switch did not in any way decrease the total amount of air pollutants to be emitted to the atmosphere. (In this case the crude oil was fairly clean burning so the amount is not very large.) But what we truly accomplished in this process was to move some pollutants from remote areas where a few people have their summer cabins to downtown Salt Lake City where large numbers of people are exposed to them. If the non-deterioration regulations operate in this way and do not operate to decrease the total amounts of pollutants emitted in the U.S., then their net consequence will be to move pollutants from areas where there are very few people to places where people generally are present in large numbers.

The conservation organizations which support the non-degradation doctrine take the view that they have in the past and will in the future oppose the construction of polluting facilities in the cities, and than hence this

argument should not be used against the non-deterioration doctrine. But in this particular case, and some others to be discussed later, the total pollutant emissions will be the same whether the new facilities are located in a remote area or in a city. In that case, the non-deterioration doctrine, if carried out, will truly "bring pollution to the people."

An additional social issue is land use planning. Many have suggested that a non-deterioration decision is a land-use-planning decision since, if we ban new industry from large areas, we have, in effect, planned the future of those areas in a non-industrial way. There has been ample controversy over land use planning in the United States in the recent past, and it appears likely there will be more in the future. Is it proper to do our land use planning through the Clean Air Act instead of doing it through a land-use-planning process which considers more issues than merely air quality?

Finally, there is the issue of aesthetics versus material wealth. It seems clear that most of the controversies involved are ones where the potential damage due to increased air pollution is primarily damage to visibility, and perhaps secondarily, damage to forests, plants, lichens, and shrubs which may be exposed to slightly higher concentrations of pollutants. As the Bible says, "man does not live by bread alone," but the opponents of this doctrine have said that we are now proposing to make enormous expenditures to protect very little. Congress, however, has specifically written visibility into the Clean Air Amendments of 1977 as an important value to be preserved.

Three examples can easily be cited where this doctrine plays a crucial role. The first is the development of the Kaiparowits project in Southern Utah. Southern Utah contains five national parks and a unique world scenic resource in its beautifully eroded desert country. It also contains large

deposits of high-quality, low-sulfur, easily minable coal. The conflict between the use of this coal and the protection of the scenic resource resulted in the eventual abandonment, or at least temporary suspension, of the Kaiparowits power project in which a consortium of power companies proposed to build a 3000-megawatt, coal-fired power plant on top of the Kaiparowits Plateau (100). This power plant in its final location would have been in direct line of sight from many of the scenic points in Bryce Canyon National Park, and its emissions would certainly have had some negative effect upon the high visibility which is requisite for the full enjoyment of the five national parks in the area. Although non-environmental issues played a significant role in the decision to suspend the applications for permits to construct this plant, the non-deterioration issue was raised and actively pursued, and the National Park Service expressed its direct opposition to the project as did the EPA (53). Figure VII-4 shows one view of this controversy.

The second example where the non-deterioration doctrine may have a significant role is the development of America's oil shale resources, which are largely concentrated in Western Colorado and Eastern Utah. This is a remote, high-air-quality area with a very small population and two large national monuments which, under the Clean Air Act Amendments of 1977 could be classified as Category I. Figure VII-5 shows the location of the major oil shale deposits in relation to these two national monuments (Dinosaur and Colorado). Figure VII-6 shows typical scenery in the oil shale area, which is wild and rugged, but generally not of national-park quality.

Currently, there are several projects in various stages of planning for building moderate size oil-shale extraction processes. These projects have all discovered that they may be in conflict with the non-deterioration

CAPITOL GAINS

FIGURE VII-4. The public controversy over the Kaiparowits project, and others which are affected by the non-deterioration doctrine, has been largely conducted in emotional terms. This cartoonist understood what the real technical issue was.

FIGURE VII-5. Location of oil shale deposits in relation to Colorado and Dinosaur National Monuments. Although the map would lead one to believe that the resource is widely distributed, the currently commercially attractive deposits are those in the Piceance Creek Basin of Colorado and those in Utah just west of Rangely, Colorado.

regulations of the Federal Government and one was in direct conflict with the more stringent non-deterioration regulations of the state of Colorado (101, 102) which have the same effect. The currently active projects have indicated that they will do only minimal processing at the oil shale site and to ship the crude shale oil by pipeline to Salt Lake City or to an interstate pipeline in Wyoming, from whence it will be shipped to a major industrial area and there further processed (103). This would be another example of the process described above whereby we would ship the potential air pollutants from the remote area where few people live to an industrial area where many people live. The amount of pollutants emitted will be roughly the same whether the shale oil is upgraded in the remote oil shale area or in an urban industrial area.

The final place where major controversy exists is in the extraction and processing of the coal deposits of the Northern Plains (Wyoming, Montana, and the Dakotas). This area contains vast reserves of high-quality coal accessible by very economical strip mining. Most energy development scenarios for the U.S. foresee that there will be much more rapid expansion of coal mining and electric power production in this area than in any other area in the country. This area is currently a very clean air area, and the expansion has been opposed by environmental groups on the grounds of violation of the non-deterioration doctrine. Additional issues of water quality, water usage, and the possibility of revegetating the strip-mined area have also been raised.

The non-deterioration controversy, as reported in the media, has been largely presented in highly emotional terms. This is illustrated by the fact that the Sierra Club and its allies refer to the doctrine as "non-degradation", while the EPA refers to it by the much milder term, "prevention of significant deterioration". The environmentalists pointed out that the Kaiparowits pro-

FIGURE VII-6. Upper portion of Parachute Creek Canyon (photo by Hubert Burke). This is typical of the scenery in the oil shale areas.

ject could not be built in Southern California (where most of the power would have gone) because of strict air-pollution regulations there. They suggested that the project would constitute "exporting pollutants from Los Angeles to Utah". Their view might be summarized as "We should not pollute one of the few remaining clean and beautiful places in the world to provide electric power for more neon signs in Los Angeles." The local chambers of commerce and county officials in the area where the plant would have been built took the view that "This new plant will mean jobs for our children, so they won't have to move to Los Angeles to earn a living. What right have a bunch of outsiders to come and tell us what is best for us? What right have they to say that this area shall be a playground for the rich, at the expense of those who live here?" When the project was finally cancelled, the local residents held a burning-in-effigy of several prominent opponents of the project (104).

What are the plausible futures of this doctrine? Although the doctrine entered air pollution law as an interpretation of what was implied in the language of the Clean Air Act of 1970 (and its legislative history) it has now been written into legislation by the Clean Air Amendments of 1977 and hence is presumably a permanent fixture of U.S. law. However, the new statute is sufficiently vague and will require sufficient administrative interpretation that it is likely to be a subject of considerable controversy and litigation for the next few years. In its present form, it seems certain to block the construction of large facilities like coal-fired power plants in the most scenic areas of the Western U.S.

Another possible future is that we will eventually decide on some land use planning scheme which will consider air quality as well as other values. This is particularly an issue in Southern Utah where the Kaiparowits project was to be located. By a referendum election in 1974 (105),

the people of the State of Utah repealed a state law which would have allowed a very mild form of state-wide land use planning. This left all land use planning in Utah in the hands of the local county commissioners. The county commissioners in the county in which the Kaiparowits project was to have been located were enthusiastic supporters of it. It would have multiplied the tax base of their county by a large factor. However, the principal landowner in Southern Utah is the Federal Government. According to Utah laws, they would have no voice whatever in land use planning in that area. In this circumstance, one can make a fair defense of using the Clean Air Act as a land use planning tool. However, in the long run, one would hope that we would plan our land use taking into account more factors than air quality.

Finally, we could attempt to discover the true effects of air pollutants at levels significantly below the ambient air quality standards, including not only visibility effects, but effects on plants, animals, livestock, and the like, and then decide on some basis how much we are willing to pay in order to limit those effects to any arbitrarily specified level. Some of the environmental groups which strongly endorse the non-deterioration concept do so on the basis that industrial growth, with its resulting air quality consequences, is irreversible; they want the present clean air areas maintained clean until we do find out enough to say for certain what such effects will be.

APPENDIX VIII

Hydrology of Oil Shale Regions

The oil shale regions marked for initial development in Western Colorado and Eastern Utah are drained by the White River and Colorado River and their tributaries, (see Figure VIII-1). Elevations in the regions are generally 5000-7000 feet above sea level and the climate is arid with an annual precipitation of 12-16 inches. The topography consists largely of plateaus, bluffs and canyons with relatively small areas of bottomland. Streams are usually intermittent (no flow during the late summer). Torrential type flows can be observed in some of the streams during times of heavy runoff (usually from spring snowmelt). Most of the prevailing streamflow is groundwater supplied by aquifers and springs.

Streamflow records can be found by consulting; "Water Resources Data for Utah" and "Water Resources Data for Colorado" published annually by U.S. Geological Survey (106). The White River near Watson, Utah (drainage area; 4020 sq. miles) has an average annual discharge of 553,500 acre-feet and a weighted average total dissolved solids concentration of 439 mg./l (106). The Colorado River near Glenwood Springs, Colorado (drainage area; 4486 sq. miles) has an average annual discharge of 1,738,000 acre-feet and a weighted total dissolved solids concentration of 270 mg./l (13).

The main tributaries to the Colorado River which drain oil shale regions are: Roan Creek and Parachute Creek. Roan Creek, near DeBeque (drainage area; 321 sq. miles) has an average annual discharge of about 29,000 acre-feet with a minimum observed flow of 3.2 cfs. Parachute Creek, near Grand Valley, (drainage area; 200 sq. miles) has an average annual discharge of about 22,000 acre-feet and is an intermittent stream (13).

FIGURE VIII-1. PICEANCE CREEK HYDROLOGIC BASIN

The main tributaries to the White River which drain oil shale regions are: Piceance Creek and Yellow Creek. Piceance Creek at White River (drainage area; 629 sq. miles) has an average annual discharge of about 12,000 acre-feet and a minimum observed flow of 0.9 cfs. The total dissolved solids content of Piceance Creek is 440-5700 mg./l with the highest concentrations downstream. Yellow Creek, near White River, (drainage area; 258 sq. miles) has an average annual discharge of about 1000 acre-feet and is an intermittent stream. Total dissolved solids concentrations in Yellow Creek are 1400-3000 mg./l (13).

Groundwater in the area is contained mainly in alluvial surface aquifers in valleys and along creeks, and in two main bedrock aquifers. Although the alluvial aquifers' permeability and specific storage capabilities may be large, their areal extents are small when compared to the bedrock aquifers. Water quality in the alluvial aquifers is similar to that of the surface streams with TDS contents of 500-8000 mg./l (13). Total dissolved solids contents of the Piceance-Yellow Creek Basin have been investigated by the U.S. Geological Survey and their findings are reproduced in Figures VIII-2-4 (107).

The upper bedrock aquifer in the oil shale deposit area overlays the Mahogany zone and consists of fractured lean oil shales, marlstones, siltstones and sandstones. Groundwater movement parallels predominant streamflows with recharge from snowmelt at higher elevations and discharge to the lower bedrock aquifer (through the Mahogany zone) and to springs along the cliffs near the top of the Mahogany zone. Total dissolved solids contents of the upper bedrock aquifer vary from about 500 mg./l near recharge areas to 1000-2000 mg./l in discharge areas (13). (See also Figure VIII-2).

The Department of Interior has estimated that the upper bedrock

**FIGURE VIII-2. CONCENTRATION OF DISSOLVED-SOLIDS IN
THE UPPER AQUIFER, MAY-SEPTEMBER 1973**

FIGURE VIII-3. Dissolved-solids concentration in the alluvial aquifer, May-September 1974.

FIGURE VIII-4. CONCENTRATION OF DISSOLVED SOLIDS IN
THE LOWER AQUIFER, MAY-SEPTEMBER 1973

aquifer in the Piceance Basin may contain as much as 25 million acre-feet of water (108).

In the Piceance Creek Basin a bedrock aquifer exists under the Mahogany zone which consists of fractured and leached oil shale. The Mahogany zone is thought to impede the flow between the upper and lower bedrock aquifers in the Piceance Creek Basin. The total dissolved solids content of the lower bedrock aquifer in the Piceance Creek Basin is 1000-80,000 mg./l and the fluoride content is nearly 10 times the recommended level for most uses (13). (See also Figure VIII-4).

The elevation of the lower bedrock aquifer relative to the alluvial aquifer or stream in nearby gulleys or bottomland is very important. If the lower bedrock aquifer is below alluvial aquifers or streams (or the peizometric pressure is insufficient to force the lower bedrock aquifer water into the alluvial aquifer) there is little danger of the saline water in the lower bedrock aquifer getting into surface streams even if the permeability between the upper and lower bedrock aquifers is increased by oil shale mining. The total dissolved solids content of springs in or near the alluvial aquifers may be a good indicator of the elevation of the lower bedrock aquifer and of possible seepage from the lower bedrock aquifer since the total dissolved solids content of the water in the lower bedrock aquifer is usually higher than that of the upper bedrock or alluvial aquifers.

Preliminary tests of aquifer transmissivity and coefficients of storage have been presented in the DDP publications for tracts C-a and C-b in the Piceance Creek Basin (16). The values are highly variable as would be expected for a reservoir dominated by fracture porosity. Accordingly, the mine dewatering predictions should be considered to be only approximate.

Weichman has estimated that the lower bedrock aquifer in the Piceance Basin may contain as much as 20 million acre-feet of water (109).