
Volume 1: Main Report

**Western Oil Shale
Development:
A Technology Assessment**

November 1981

**Prepared for the
U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and Emergency
preparedness
under Contract DE-AC06-76RLO 1830**

DOE Project Manager: G. J. Rotariu

**Pacific Northwest Laboratory
Operated for the U.S. Department of Energy
by Battelle Memorial Institute**



NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the 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.

The views, opinions and conclusions contained in this report are those of the contractor and do not necessarily represent those of the United States Government or the United States Department of Energy.

PACIFIC NORTHWEST LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
Under Contract DE-AC06-76RLO 1830

Printed in the United States of America
Available from
National Technical Information Service
United States Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22151

Price: Printed Copy \$_____*; Microfiche \$3.00

*Pages	NTIS
	Selling Price
001-025	\$4.00
026-050	\$4.50
051-075	\$5.25
076-100	\$6.00
101-125	\$6.50
126-150	\$7.25
151-175	\$8.00
176-200	\$9.00
201-225	\$9.25
226-250	\$9.50
251-275	\$10.75
276-300	\$11.00

Volume 1: Main Report

WESTERN OIL SHALE DEVELOPMENT:
A TECHNOLOGY ASSESSMENT

November 1981

Prepared for
the U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and Emergency Preparedness
under Contract DE-AC06-76RLO 1830

DOE Project Manager: G. J. Rotariu

Pacific Northwest Laboratory
Richland, Washington 99352

FOREWORD

The U.S. Department of Energy (DOE), Office of the Assistant Secretary for Environmental Protection, Safety, and Emergency Preparedness (EP), Office of Environmental Assessments, has been conducting technology assessments of the evolving energy technologies. The purpose of these is to evaluate in as quantitative a manner as possible the potential environmental, health, and socioeconomic impacts of each technology as it moves towards commercialization. The assessments identify where further information is needed, provide an analysis of potential environmental, health, and socioeconomic consequences of each technology, and define research and development (R&D) needed to ensure environmentally acceptable commercialization.

This is the final report of the Western Oil Shale Development Technology Assessment. We would like to express our appreciation to Drs. Darryl Hessel and Ira Levy of the Pacific Northwest Laboratory for their efforts in coordinating the work, to Dr. Hessel and Mr. Gabor Strasser for preparing this report, and to the entire team of participants listed in the Appendix for conducting and reporting the major technical studies.

Dr. George J. Rotariu
Oil Shale Technology Assessment Project Manager
Technology Assessments Division

CONTENTS

FOREWORD	iii
1.0 INTRODUCTION	1.1
1.1 STUDY CONTEXT	1.1
1.2 OBJECTIVES	1.2
1.3 JUSTIFICATION	1.2
1.4 BACKGROUND	1.3
1.5 RATIONALE	1.5
1.6 APPROACH	1.6
1.7 REPORT ORGANIZATION	1.8
1.8 REFERENCES FOR CHAPTER 1	1.9
2.0 SUMMARY OF ISSUES AND FINDINGS	2.1
2.1 PRACTICAL RATES OF RECOVERY	2.2
2.2 TECHNOLOGICAL ASPECTS	2.2
2.3 AVAILABILITY OF NATURAL AND ECONOMIC RESOURCES	2.3
2.3.1 Oil Shale	2.3
2.3.2 Water	2.4
2.3.3 Other Resources	2.4
2.4 ENVIRONMENTAL ACCEPTABILITY	2.5
2.4.1 Air Quality	2.5
2.4.2 Solid Waste	2.7
2.4.3 Ground Water	2.8
2.4.4 Surface Water Quality	2.10
2.4.5 Ecology and Agriculture	2.13
2.4.6 Health and Safety	2.15

2.4.7	Socioeconomics	.	.	.	.	.	.	.	.	2.16
3.0	TECHNOLOGICAL STATE-OF-THE-ART	.	.	.	.	.	.	.	.	3.1
3.1	SHALE PREPARATION	.	.	.	.	.	.	.	.	3.2
3.1.1	Mining	.	.	.	.	.	.	.	.	3.2
3.1.2	Crushing and Storage	.	.	.	.	.	.	.	.	3.5
3.2	ABOVEGROUND RETORTING	.	.	.	.	.	.	.	.	3.7
3.2.1	Process A	.	.	.	.	.	.	.	.	3.7
3.2.2	Process B	.	.	.	.	.	.	.	.	3.14
3.2.3	Process C	.	.	.	.	.	.	.	.	3.15
3.2.4	Process D	.	.	.	.	.	.	.	.	3.17
3.2.5	Process E	.	.	.	.	.	.	.	.	3.21
3.3	PROCESS F: MODIFIED IN-SITU RETORTING	.	.	.	.	.	.	.	.	3.24
3.4	PROCESS G: TRUE IN-SITU RETORTING	.	.	.	.	.	.	.	.	3.26
3.5	PRODUCTION SCENARIOS AND SITE LOCATIONS	.	.	.	.	.	.	.	.	3.27
3.6	TRANSPORTATION	.	.	.	.	.	.	.	.	3.30
3.7	REFERENCES FOR CHAPTER 3	.	.	.	.	.	.	.	.	3.37
4.0	AVAILABILITY OF NATURAL AND ECONOMIC RESOURCES	.	.	.	.	.	.	.	.	4.1
4.1	OIL SHALE	.	.	.	.	.	.	.	.	4.1
4.2	WATER AVAILABILITY	.	.	.	.	.	.	.	.	4.10
4.2.1	Water Needs	.	.	.	.	.	.	.	.	4.10
4.2.2	Surface Water Sources	.	.	.	.	.	.	.	.	4.11
4.2.3	Ground-Water Sources	.	.	.	.	.	.	.	.	4.14
4.3	OTHER RESOURCES	.	.	.	.	.	.	.	.	4.15
4.3.1	Labor	.	.	.	.	.	.	.	.	4.16

4.3.2	Transportation	4.19
4.3.3	Equipment and Materials	4.20
4.3.4	Financing	4.20
4.4	REFERENCES FOR CHAPTER 4	4.22
5.0	AIR QUALITY	5.1
5.1	AIR QUALITY STANDARDS	5.2
5.2	EXISTING AIR QUALITY CONDITIONS IN THE OIL SHALE REGION	5.6
5.3	PROJECTED AIR QUALITY IN THE PICEANCE CREEK BASIN	5.8
5.3.1	Approach	5.8
5.3.2	Sources of Present Meteorological and Air Quality Data	5.9
5.3.3	Projection of Air Quality	5.10
5.3.4	Suggested Air Quality Impacts	5.16
5.4	PROJECTED AIR QUALITY CONSTRAINTS FROM POTENTIAL IMPACTS OUTSIDE OF THE PICEANCE CREEK BASIN	5.21
5.5	CARBON DIOXIDE	5.27
5.6	REFERENCES FOR CHAPTER 5	5.28
6.0	SOLID WASTE FROM MINING AND SURFACE RETORTS	6.1
6.1	CHARACTERIZATION OF RAW OIL SHALE	6.2
6.1.1	Organic Materials	6.2
6.1.2	Chemical Composition	6.2
6.2	CHARACTERIZATION OF SURFACE RETORTED OIL SHALE	6.2
6.2.1	Mineralogy	6.4
6.2.2	General Physical and Chemical Characteristics	6.6
6.2.3	Organic Materials	6.8
6.3	LEACHING OF RAW AND RETORTED SHALE	6.10
6.3.1	Laboratory Studies	6.10

6.3.2	Field Studies	6.12
6.4	LAWS AND REGULATIONS AFFECTING SOLID WASTE DISPOSAL	6.14
6.5	DISPOSAL PROCEDURES	6.16
6.5.1	Retorted Shale Piles	6.16
6.5.2	Stabilization and Revegetation	6.17
6.5.3	Evaluation of Disposal Plans	6.19
6.6	POTENTIAL IMPACTS TO WATER QUALITY	6.20
6.7	RESEARCH NEEDS	6.22
6.8	REFERENCES FOR CHAPTER 6	6.24
7.0	GROUND-WATER IMPACTS	7.1
7.1	INTRODUCTION	7.1
7.2	LAWS AND REGULATIONS	7.5
7.3	IMPACTS ON GROUND-WATER QUANTITY	7.6
7.3.1	General Observations	7.7
7.3.2	Detailed Analysis of Dewatering on Tracts C-a and C-b	7.8
7.3.3	Reinvasion of Ground Water into the Dewatered Retort Areas	7.27
7.4	IMPACTS ON GROUND-WATER QUALITY	7.29
7.4.1	Impacts from Disposal Piles	7.29
7.4.2	Impacts from Underground Operations	7.30
7.5	POTENTIAL ENVIRONMENTAL CONTROL STRATEGIES FOR MIS OPERATIONS	7.37
7.5.1	Site Selection	7.37
7.5.2	Grouting	7.37
7.5.3	In-Place Precipitation of Calcite to Seal Pores	7.39
7.5.4	Grout Curtain	7.39
7.5.5	Design Retorts with Hydraulic Bypass	7.40

7.5.6	Cap Rock in Place	7.41
7.5.7	Recover and Treat Leachate	7.42
7.5.8	Treat Leachate In-Situ by Adsorption and Ion Exchange	7.42
7.5.9	Modification of Retort Operating Conditions . .	7.43
7.5.10	Self Treatment	7.44
7.6	REFERENCES FOR CHAPTER 7	7.44
8.0	SURFACE WATER IMPACTS	8.1
8.1	DESCRIPTION OF SURFACE WATER RESOURCES	8.2
8.1.1	Colorado River Basin Overview	8.2
8.1.2	Streams in the Oil Shale Region	8.8
8.2	WATER QUALITY LAWS, STANDARDS, AND REGULATIONS	8.12
8.1.2	Federal Water Pollution Control Act	8.12
8.3	WATER QUANTITY CONCERNS	8.20
8.3.1	Effects of Consumption of Surface Water	8.21
8.3.2	Effects of Ground-Water Removal	8.26
8.4	WATER QUALITY CONCERNS	8.27
8.4.1	Current Surface Water Quality	8.28
8.4.2	Salinity Effects of Dewatering	8.30
8.4.3	Process Effluents	8.38
8.4.4	Surface Runoff	8.45
8.4.5	Potential Impacts on Surface Waters from Aquifer Contamination	8.46
8.5	REFERENCES FOR CHAPTER 8	8.52
9.0	ECOLOGICAL SYSTEMS LEVEL RESPONSES TO SHALE OIL DEVELOPMENT . .	9.1
9.1	INTRODUCTION	9.2
9.2	PROJECTIONS OF FUTURE CONDITIONS WITH SHALE OIL DEVELOPMENT .	9.3

9.2.1	Soils	.	.	.	.	.	.	.	.	9.3
9.2.2	Water Resources	.	.	.	.	.	.	.	.	9.4
9.2.3	Vegetation	.	.	.	.	.	.	.	.	9.4
9.2.4	Fauna	.	.	.	.	.	.	.	.	9.25
9.2.5	Wildlife	.	.	.	.	.	.	.	.	9.29
9.2.6	Mule Deer Harvest	.	.	.	.	.	.	.	.	9.31
9.2.7	Agriculture	.	.	.	.	.	.	.	.	9.32
9.3	REFERENCES FOR CHAPTER 9	.	.	.	.	.	.	.	.	9.32
10.0	HEALTH AND SAFETY	.	.	.	.	.	.	.	.	10.1
10.1	DIRECT TOXICITY	.	.	.	.	.	.	.	.	10.1
10.2	SKIN DISEASES	.	.	.	.	.	.	.	.	10.2
10.3	RESPIRATORY ILLNESS	.	.	.	.	.	.	.	.	10.5
10.4	EXPOSURE ROUTES FOR GENERAL TOXICITY	.	.	.	.	.	.	.	.	10.6
10.5	REFERENCES FOR CHAPTER 10	.	.	.	.	.	.	.	.	10.7
11.0	SOCIOECONOMIC ACCEPTABILITY	.	.	.	.	.	.	.	.	11.1
11.1	THE STUDY REGION	.	.	.	.	.	.	.	.	11.1
11.2	THE DOE OIL SHALE SCENARIO	.	.	.	.	.	.	.	.	11.6
11.3	POPULATION	.	.	.	.	.	.	.	.	11.8
11.3.1	Geographic Distribution	.	.	.	.	.	.	.	.	11.9
11.3.2	Indirect Employment	.	.	.	.	.	.	.	.	11.11
11.4	PUBLIC FACILITIES AND SERVICES	.	.	.	.	.	.	.	.	11.17
11.5	HOUSING	.	.	.	.	.	.	.	.	11.24
11.6	SOCIAL IMPACTS	.	.	.	.	.	.	.	.	11.27
11.7	PLANNING AND NEEDS ASSESSMENT	.	.	.	.	.	.	.	.	11.30
11.8	REFERENCES FOR CHAPTER 11	.	.	.	.	.	.	.	.	11.32
APPENDIX A--	STUDY PARTICIPANTS	.	.	.	.	.	.	.	.	A.1

FIGURES

3.1	Room and Pillar Mining Concept	3.3
3.2	Pyrolysis and Oil Recovery Unit, Process A	3.8
3.3	Process C, Upflow Retort	3.18
3.4	Process E Diagram	3.23
3.5	Process F: Modified In-Situ Retorting of Oil Shale, Diagram	3.25
3.6	Location of Proposed Oil Shale Projects	3.28
3.7	Energy Related Vehicles per Day, 1979 and 1990	3.35
3.8	Loaded Energy Trucks per Day, 1985 and 1990	3.36
4.1	Oil Shale Deposits of the Green River Formation	4.3
4.2	Privately Owned Tracts in the Piceance Basin	4.7
4.3	Thickness of the Oil Shale Deposits in the Piceance Basin That Yield at Least 25 gal/ton of Shale Oil	4.8
5.1	The Mandatory Class I Federal Areas in the Neighborhood of the Colorado Oil Shale Formation	5.5
5.2	The 6 Mile-Mesh, Township Grid Used for Air Quality Studies Over the Piceance Basin	5.14
6.1	Observed Concentration Ranges in ppm and Probable Average Values for Minor Elements in Green River Oil Shales from the Piceance Creek, Uinta, and Green River Basins	6.4
7.1	Vertical Cross Section of Piceance Creek Basin	7.2
7.2	Schematic Representation of Water Pollution from Modified In-Situ Oil shale Retorting	7.4
7.3	Location of the Piceance Basin and Prototype Oil Shale Lease Tracts C-a and C-b	7.9
7.4	North-South Geohydrologic Section Through the Piceance Basin	7.10
7.5	West-East Geohydrologic Section Through the Piceance Basin	7.11
7.6	Stratigraphy of the C-a Tract and Location of the Mining Zone	7.16

7.7	Stratigraphy of the C-b Tract and Location of the Mining Zone	7.17
7.8	Rate of Expansion of Retorted Area with Time in the C-b Tract	7.20
7.9	Rate of Expansion of the Retorted Area with Time in the C-a Tract	7.21
7.10	The 60-Year Simulation of Dewatering for the C-b Tract	7.22
7.11	The Position of the Phreatic Surface for Dewatering the C-b Tract in an Expanding Retort Scenario	7.23
7.12	Drawdown of the Phreatic Surface for the 50-Year Simulation of Dewatering at a Radial Distance of 3.5 km from the Center of the C-b Tract	7.24
7.13	Variations of Inflow Rates with Time Over the C-a Tract for Two Permeabilities for the Lower Aquifer	7.25
7.14	Water Table Fluctuations at a Radial Distance of 5 km from the Center of the C-a Tract	7.26
7.15	The Profile of Phreatic Surface After 200 Years of Reinvasion in the C-b Tract	7.28
8.1	The Upper and Lower Colorado River Basins	8.3
8.2	Seasonal Variation in Discharge for the Colorado River at Lees Ferry, Arizona	8.5
8.3	Drainage Pattern for Piceance and Yellow Creeks	8.9
8.4	Seasonal Variation in Discharge for the Green River at Green River, Utah	8.10
8.5	White River Basin Schematic of Assumed Reservoir and Diversion Facilities	8.25
9.1	Measures of Sensitive Plant Responses to Relatively Long-Term SO ₂ Exposure	9.14
9.2	Various Plant Responses to Long-Term Ethylene Exposure	9.23
11.1	Oil Shale Country, Northwest Colorado	11.2
11.2	Relative Population Impacts by 1990 for Selected Colorado Communities	11.17
11.3	Projection of Fiscal Capacity of Rifle	11.21
11.4	Projection of Fiscal Capacity of Meeker	11.21

11.5	Projection of Fiscal Capacity of Rangely		11.22
11.6	Projection of Fiscal Capacity of Grand Junction		11.22
11.7	Projection of Fiscal Capacity of Craig		11.23
11.8	Projection of Fiscal Capacity of Glenwood Springs		11.23

TABLES

3.1	Net Emissions from Oil Shale Mining		3.5
3.2	Net Particulate, Emissions from Shale Crushing and Storage		3.6
3.3	Net Emissions from Process A		3.11
3.4	Pre-Refining and Upgrading Facility Input: 52,000 BPSD Major Solid Wastes/Catalyst Replacement		3.12
3.5	Chemical Components of Process Water from Process A		3.13
3.6	Net Emissions from Process B		3.15
3.7	Net Emissions from Process C		3.19
3.8	Air Emissions During Project Operation of Process D		3.20
3.9	Volume of Solid Waste Generated by the Process D Project and Disposal Area Requirements		3.21
3.10	Air Quality Standards and Projected Ambient Levels of Pollutants at the Site for Process D		3.22
3.11	Estimated Air Emissions from Commercial Scale MIS Development		3.25
3.12	Low Scenario of Shale Oil Production		3.29
3.13	Medium Scenario of Shale Oil Production		3.31
3.14	High Scenario of Shale Oil Production		3.32
3.15	Vehicle Miles per Day Traveled on Tract Access Roads		3.34
4.1	Potential Shale Oil in Place in the Green River Formation: Colorado, Utah, and Wyoming		4.2
4.2	Ownership of Western Oil Shale Lands		4.9

4.3	Privately Held Blocks Capable of Supporting 50,000 Barrels per Day Production for 30 Years	4.9
4.4	Labor Requirements of Oil Shale Facilities	4.16
4.5	DOE Scenario of Oil Shale Work Force	4.17
4.6	1979 Population of Colorado Oil Shale Counties	4.18
4.7	Materials and Equipment Required for Oil Shale Development	4.21
5.1	The Federal and State Ambient Air Quality Standards	5.3
5.2	PSD--Ambient Air Increments: Maximum Allowable Increase	5.4
5.3	Existing Air Quality Data Summary for Federal Oil Shale Lease Tracts	5.7
5.4	Pollutant Source Strengths for the High Scenario of Oil Shale Production	5.12
5.5	Preliminary Results from the Simple Plume Model	5.17
5.6	The Estimated Annual PSD Increment Used Up by a 300,000 bpd Industry Over Class II Areas in the Piceance Basin	5.21
6.1	Concentration of Selected Elements and Their Probable Mineral Residences in Raw Shale from the Piceance Creek and Uinta Basins	6.3
6.2	Retorting Processes	6.5
6.3	Select Elemental Concentrations in Raw and Retorted Paraho and TOSCO Oil Shales	6.8
6.4	Chemical Properties of Union Oil Retorted Shale	6.9
6.5	Concentrations in the First Column Volume of Leachate from Mahogany Zone Raw and Retorted Shales	6.11
6.6	Composition of Water Samples and Leachates from the Anvil Points Experimental Site at the DOE Rifle Oilshale Facility	6.13
6.7	Averaged Values of Constituents Found in Soil Leachates and Surface and Ground Waters	6.21
7.1	Colorado Ground-Water Laws	7.6
7.2	Estimated Composition of Leachate Exiting an In-Situ Retort Located on Lease Tracts C-a and C-b	7.33

7.3	Comparison of Predevelopment and Postdevelopment Ground-Water Quality with Water Levels Not to be Exceeded in Main Water Mass	7.36
7.4	Candidate Control Strategies for MIS Retorts	7.38
8.1	Reservoirs in the Upper Colorado River Basin as of 1965	8.6
8.2	Historical Annual Flowrates for Five Sample Stations in the Piceance Basin	8.10
8.3	Major Reservoirs Developed Since 1960 in the Green River Subregion	8.10
8.4	Average TDS Concentration at Various Points Along the Green River	8.11
8.5	Effluent Limitations for Petroleum Refineries	8.13
8.6	Proposed Water Quality Criteria for Designated Uses	8.15
8.7	Colorado Water Quality Standards for Selected Uses and Parameters	8.16
8.8	Utah Water Quality Standards for Selected Uses and Parameters	8.17
8.9	Primary Drinking Water Standards	8.19
8.10	Salinity Criteria for Colorado River	8.20
8.11	Approximate Size and Distribution of Shale Oil Industry in Upper Colorado River Basin 13 Assessment	8.21
8.12	Year 2000 Water Depletions for Synfuels Scenarios, Upper Colorado River Basin 13 Assessment	8.23
8.13	Suspended Sediment Concentrations of the Upper Colorado River Basin	8.28
8.14	Contributions of TDS by Natural and Man-Made Sources in the Upper Colorado River Basin in 1965	8.29
8.15	Quality of Some Surface Streams in the Oil Shale Region	8.31
8.16	Ground-Water Quality for Constituents Included in Dewatering Discharge Analysis	8.34
8.17	Annual Mean Flowrates and concentrations of Constituents Included in Dewatering Discharge Analysis: White River	8.34

8.18 Annual Mean Flowrates and Concentrations of Constituents Included in Dewatering Discharge Analysis: Colorado River	8.35
8.19 Resulting Concentrations in Stream Quality from Aquifer Pumping	8.36
8.20 Composition of Retort Water, Gas Condensate, and Mine Water	8.41
8.21 Treatment Requirements for Reuse and Disposal	8.42
8.22 Summary of Process Specific Research on Retort Water, Gas Conden- sate, and Mine Waters	8.43
8.23 Relative Rankings of the Water Treatment Methods	8.45
8.24 Summary of Content of Leachates in Spent Shale from Above-Ground Retorting Processes	8.48
8.25 Comparison of Predevelopment and Post Development Ground-Water Quality	8.51
9.1 Types of Chronic Low-Level Plant Effects and Probable Mechanisms Involved	9.6
9.2 Percent of the Total Leaf Area Injured by Different Concentra- tions of SO ₂ in Two-Hour Field Fumigation Studies	9.8
9.3 Summary of Toxicological Experiments with Sulfur Dioxide	9.26
9.4 Summary of Toxicological Experiments with Sulfur Dioxide	9.27
11.1 Personal Income by Selected Major Sources, 1978	11.3
11.2 Population Changes, 1970-1979	11.5
11.3 DOE Scenario of Oil Shale Work Force	11.7
11.4 Geographic Distribution of Work Force	11.12
11.5 Geographic Distribution of Nonbasic Work Force Comparison of Los Alamos and COG Methods	11.13
11.6 Family Size Multipliers	11.14
11.7 Scenario-Induced Population--Los Alamos Method	11.15
11.8 Projected Total Population Growth of Selected Communities	11.16
11.9 Estimates of Public Expenditures	11.19

1.0 INTRODUCTION

During the past decade the United States and the world in general have experienced rapidly increasing prices for petroleum fuels. There have also been periods during which normal supplies were not adequate. As the United States has searched for solutions to this problem, synthetic liquid fuels have become a matter of intense interest. Fuels from oil shale have emerged as a domestic source of substantial potential importance. The assessment presented in this report has been conducted to improve the nation's understanding of the potential contribution from this source and the environmental, health, safety, and socioeconomic consequences of developing that contribution.

1.1 STUDY CONTEXT

Much has been written on the subject of shale oil production, as attested to by the lists of references which are part of this document. Understandably, these referenced reports cover a wide spectrum, since their authors represent differing values and interests. Some place major emphasis on oil shale potential (in light of our vast deposits) and take optimistic positions on most issues of feasibility and environmental degradation. Others focus more on the potential dangers than on the benefits.

Experience with and understanding of shale oil extraction and processing are still very limited. The many impacts on the environment that might result from oil shale extraction and processing are perhaps even less understood. This lack of experience and understanding gives rise to a multitude of uncertainties about the following three crucial aspects of oil shale development: 1) the details of the feasible/desirable technological processes, 2) qualitative and quantitative environmental impacts, and 3) the economic viability of such processes.

Because of these uncertainties, the question of "what should be done about oil shale?" still cannot be answered to the satisfaction of policy and decision makers. However, it should be possible to separate the known from the uncertain. This report presents a synthesis of what is known now; no attempt was made to generate new knowledge.

1.2 OBJECTIVES

The general goal of this study is to present the prospects of shale oil within the context of 1) environmental constraints, 2) available natural and economic resources, and 3) the characteristics of existing and emerging technology.

The objectives are:

1. to review shale oil technologies objectively as a means of supplying domestically produced fuels within environmental, social, economic, and legal/institutional constraints;
2. using available data, analyses, and experienced judgment, to examine the major points of uncertainty regarding potential impacts of oil shale development;
3. to resolve issues where data and analyses are compelling or where conclusions can be reached on judgmental grounds;
4. to specify issues which cannot be resolved on the bases of the data, analyses, and experienced judgment currently available; and
5. when appropriate and feasible, to suggest ways for the removal of existing uncertainties that stand in the way of resolving outstanding issues.

1.3 JUSTIFICATION

Oil shale development has been pursued by the Department of Energy (DOE) under its original broad charter to identify and develop energy production technologies in the United States.

Under this broad charter, the Office of the Assistant Secretary for Environmental Protection, Safety, and Emergency Preparedness in the DOE has been responsible for identifying and evaluating the effects of energy technologies on the natural environment and on human health and safety. This assessment was originally undertaken to help the Assistant Secretary discharge this responsibility relative to oil shale development.

This assessment report should provide relevant inputs to both government and industry concerning decisions about the development of oil shale as a source of domestic liquid fuel.

1.4 BACKGROUND

This brief section is included at the outset of the report for the benefit of those readers who are not familiar with the evolution of oil shale development.

Oil shale has held a certain fascination for people through the years. There is evidence that in earliest times Indians burned shale rock containing rich kerogen deposits. Shale oil was first produced in the United States in the mid-1850s, but was abandoned as a fuel source in 1860 when petroleum was discovered in Pennsylvania. It was pursued actively again from 1912 to 1922 and from 1948 to 1955.

The impetus for these early explorations was the possibility of extracting valuable fuel from shale. The deterrents were technical and economic. As long as enough liquid petroleum, vis-a-vis demands, was found in the United States, or could be imported at reasonable costs, both the required technology and economics favored petroleum. Hence, oil shale exploration and commercialization were repeatedly abandoned.

Today's interest in oil shale development can be traced primarily to the rapid rise in petroleum prices and the uncertain availability and cost of foreign crude imports that now represent about half of the total U.S. oil supply. Today the technology is much improved, though not commercially perfected. The expected economics of an oil shale industry, could turn out to be competitive under certain conditions.

In light of the recurring disruptions in liquid fuel supplies, the re-emerging interest in oil shale development is not surprising. Oil shale deposits are immense. In addition to industry, both the executive and legislative branches of government have shown varying degrees of interest from time to time. Many agencies and private organizations concerned with the protection of

the environment have opposed oil shale, because its development could affect pervasively the physical and social environments of northwestern Colorado and neighboring states.

Most of the latest surface technologies that have been proposed were either developed in the 1950s and early 1960s or are offshoots of processes developed at that time. In-situ technologies were initiated in the late 1960s. No retorting process, however, has been operated in the United States at a scale larger than 1,000 barrels per day. The characteristics of commercial-sized plants, therefore, remain uncertain since they cannot be extrapolated from pilot scale plants. These uncertainties include technical feasibility and economic viability as well as the severity of environmental impacts.

The Federal government made extensive efforts during the late 1970s to develop oil shale resources. They included various DOE activities and numerous Congressional activities represented by publications such as Senator Hart's Synthetic Fuels Report, September 27, 1979,⁽¹⁾ and the Office of Technology Assessment (OTA) publication: An Assessment of Oil Shale Technologies, June 1980.⁽²⁾

During 1980 the Synthetic Fuels Corporation was established through the Synthetic Fuels Corporation Act of 1980. The corporation was authorized under the law to spend up to \$88 billion during its 12-year life time. It was mandated to foster, by financial assistance, commercial production by private industry of synthetic fuels, including oil shale.⁽³⁾

Utah, Wyoming, and Colorado have significant oil shale deposits. The Colorado sites seem most appropriate for initial commercial oil shale development. Industry and state government in Colorado have shown interest in oil shale since long before the 1973 Arab oil embargo. The richest deposits in the western oil shale region are concentrated in Colorado.

1.5 RATIONALE

This technology assessment was initiated and the original rationale for it was conceived in the summer of 1979 under the authority of the U.S. Department of Energy (DOE), Office of the Assistant Secretary for Environmental Protection, Safety, and Emergency Preparedness (EP), Office of Environmental Assessments.

The project was undertaken to examine shale oil as a prospective domestic energy source, within the context of environmental constraints, available natural and economic resources, and the characteristics of existing and emerging technology. During the course of this study, energy policy has evolved from an active Federal role in fostering commercialization of synthetic fuels technology to a Federal role which fosters supply-side economics and permits free market forces to dictate the pace and type of energy technologies that need to be developed. Under either policy, intense interest in oil shale is determined by the following facts:

1. Oil shale is one of our most abundant potential sources of liquid fuel. The U.S. has immense deposits of oil shale, equivalent to over two trillion barrels of oil, of which about 400 billion barrels derive from high-grade deposits (30+ gallons of oil per ton) in the West that are viewed as recoverable. At a use rate of 17 million barrels of oil per day, 400 billion barrels of oil are equivalent to over 40 years of U.S. liquid fuel consumption, even with a 50% recovery loss adjustment.
2. Oil exploration and development are proceeding actively with private industrial or combined government and private support.
3. The technical feasibility, economic viability, and environmental acceptability of commercial shale oil production are poorly understood.

This technology assessment integrates and synthesizes the relevant data concerning the issues in Item (3), particularly the environmental aspects.

1.6 APPROACH

Oil shale development is fraught with uncertainties. At this early stage of technological development, data on technical performance and environmental emissions are scarce and generally believed by scientists and governmental officials to be unreliable. Under these circumstances, it is not surprising that interested industrial participants, public officials, and representatives of various interest groups have expressed a wide range of opinions on the prospects for and consequences of shale oil production.

In light of these circumstances, this assessment has proceeded through several stages: issues have been identified and described; tentative conclusions have been drawn and examined; and results have been reported. These stages have involved a small group of investigators who have functioned principally as integrators of information; two panels composed of representatives of private and governmental organizations interested in oil shale development; and a group of scientists and consultants endeavoring to conduct a series of technical supporting studies focused on quantitative, critical studies of the technological state-of-the-art and a broad range of environmental factors.

The panel members (identified in the Appendix) were selected for their scientific expertise, experience with oil shale, and/or interest in eventual decisions on commercial application of shale oil production processes. Included were a Technology Panel of five individuals involved in developing and applying processes for producing shale oil, and an Impact Panel of seven individuals concerned with potential environmental, health and safety, social, economic, legal, or institutional constraints and impacts of shale oil production. These panels clarified issues and developed information supporting their respective positions. The panel members applied their experience and judgment, developed through involvement with the fledgling oil shale industry, to some of those issues that at the time of the meetings could not be resolved through technical analyses alone. The panels contributed to the assessment mainly at the initial stage of issue identification and description.

The technical supporting studies were designed to assemble and examine systematically the available field and laboratory data. As a common frame of

reference for these studies a variety of above-ground (AG) and modified in-situ (MIS) retorting processes were incorporated into a hypothetical, but realistic, technological mix. This mix was designed so that it would produce 300,000 barrels per day at a time assumed to be about 1990 or 1995.

Three scenarios were developed for illustrative purposes; the technical studies were conducted only on the highest production combination. The low production scenario is an example of slow development. Production is projected to reach 41,050 barrels per day by 1990. Only three plants are included. Additional production capacity will require a reduction of uncertainties either through commercial operating experience or through government incentives, such as price supports. The medium- and high-production scenarios assume that the technologies will be successfully demonstrated and that the government will provide necessary financial incentives. Production is then projected to reach, respectively, 188,950 or almost 300,000 barrels per day by 1990, depending on the extent to which the technologies are proven and on the incentives offered. This is still relatively low compared to the stated expectations of some firms who project millions of barrels per day from oil shale.

An attempt was made to rigorously consider the shale oil production technologies as described in the high scenario. This effort was expected to lead to recognition of most of the potentially significant impacts of a mature shale oil production industry. Impacts on media (air, surface water, ground water, and land), ecological systems and agriculture, human (primarily occupational) health and safety, social and economic systems, and legal/institutional systems were considered.

As the study progressed, it became apparent that the conduct of a rigorous, quantitative, systematic analysis was constrained by the absence of adequate data on existing conditions, by the state of development of shale oil production technologies, and by the absence of quantitative analytical models appropriate for application under the conditions in the oil shale region. For example, existing data on gaseous emissions, solid waste, and liquid effluents generated from pilot-scale shale oil families were not highly reliable and were not collected in ways that would make them comparable. Furthermore, extrapolation of these data to the much larger anticipated commercial scales was

considered by the scientists in the study to be unlikely to produce results representative of actual performance of projected commercial facilities. Data on meteorological and existing air quality conditions in and around the Pieceance Creek Basin were especially inadequate. Air quality simulation models developed and available at the time of the study were not appropriate to the high elevations and rough topography of the oil shale region. Therefore useful projections would not have been possible even if good data had existed.

Credible projections of impacts from solid waste disposal were precluded by inadequate information of the physical and chemical character of spent shale to be produced by commercial shale oil plants and by lack of experience with the mechanical and hydrological properties of large spent shale piles. For in-situ retorts, projection of impacts from spent shale was further complicated by the state of knowledge of geochemical and hydrological characteristics of aquifers and by lack of information on long-term (hundreds of years) chemical and physical interactions between chemical components in leachates and ground water and between these components and the rock composing the aquifers.

For these reasons, most of the results of this study comprise an overview of existing knowledge rather than a quantitative analysis of projected conditions from a shale oil industry. The study investigators and the participants in the technical supporting studies were forced by these circumstances to rely heavily upon other relevant studies and ongoing events for information useful in assessing oil shale development. Nevertheless, where it was possible to develop appropriate analytical techniques or models and where useful projections of impacts could be made, these steps were taken. Such efforts were based on the 300,000 bpd scenario. The findings in this report are derived from the combined results of the panel meetings of May 1979, the technical supporting studies, and the continuing review of other related studies and events.

1.7 REPORT ORGANIZATION

The organization of this report reflects the needs of staff in the DOE Office of Environmental Protection, Safety, and Emergency Preparedness, for whom the report was primarily generated. Accordingly, the report is not encyclopedic but, rather, focuses on those aspects of oil shale development and

operation which are likely of greatest importance to the Office. The report emphasizes impacts and constraints associated with the natural environment, human health and safety, and socioeconomic systems. Uncertainties are highlighted, whether due to limitations in existing data or analytical techniques.

Chapter 2 presents issues and tentative findings under the following five categories: 1) Practical Rates of Recovery, 2) Technological Aspects, 3) Availability of Natural and Economic Resources, 4) Environmental Acceptability, and 5) General Economic Viability.

Chapters 3 through 11 provide a digest of current relevant information in the following areas: Chapter 3--oil shale technology, Chapter 4--availability of natural and economic resources, and Chapters 5 through 11--environmental acceptability.

An appendix which identifies the participants in the study is provided after Chapter 11.

Other volumes of this report present supporting studies conducted as parts of this assessment. They deal with the following topics:

- Volume 2. Technology Characterization and Production Scenarios
- Volume 3. Air Quality
- Volume 4. Solid Waste
- Volume 5. Ground Water
- Volume 6. Surface Water
- Volume 7. Ecology and Agriculture
- Volume 8. Health and Safety
- Volume 9. Socioeconomics.

1.8 REFERENCES FOR CHAPTER 1

1. U.S. Senate, Subcommittee on Synthetic Fuels of the Committee on the Budget. 1979. Synthetic Fuels. 96th Congress, 1st Session. U.S. Government Printing Office, Washintgon, D.C.
2. U.S. Congress, Office of Technology Assessment. 1980. An Assessment of Oil Shale Technologies. U.S. Government Printing Office, Washington, D.C.

3. Energy Security Act. Public Law 96-294, signed by President Carter, June 30, 1980.
4. "Exxon Sees 15 Million B/D Synfuels Demand in 2000." June 17, 1980. The Energy Daily, p. 3.

2.0 SUMMARY OF ISSUES AND FINDINGS

This chapter is intended to provide a brief overview of the results of the assessment which is the subject of this report. There is no attempt here to be exhaustive in covering the content of the study. Instead, the chapter is selective, focusing upon results of interest to a broad audience. More thorough discussions appear in the other chapters of the report, and even more can be found in the supporting volumes.

References have been omitted from this chapter. Succeeding chapters provide complete documentation of all material used.

There are three major arguments supporting the explanation and possible development of a commercial oil shale industry in the United States.

1. Liquid Fuels Availability--There is a global liquid fuels problem, notwithstanding fluctuations such as the oil glut of 1981.
2. Immense Shale Deposits--There are immense oil shale deposits in the U.S. which have the potential of supplying all our needs for liquid fuels at the current rate of consumption for a time period approaching one-half century.
3. Recoverability Demonstrated--It has been demonstrated that oil shale can be retrieved from the ground, retorted, and refined to required specifications. Modified in-situ (MIS) retorting techniques have also been demonstrated, although they have not yet been shown to be efficient in recovering kerogen.

While the above arguments appear persuasive by themselves, numerous problems temper their promising message. These include recovery rates, technical feasibilities, economic viabilities, and environmental acceptabilities. Many of these are identified in this chapter, and they are discussed more fully in chapters 3.0 through 11.0. The Table of Contents of these succeeding chapters serves as a ready means for cross referencing.

2.1 PRACTICAL RATES OF RECOVERY

Based on existing and projected technologies (without major new developments) maximum production rates are not likely to exceed one million barrels per day. Principal constraints are effects on air quality, especially violation of current prevention of significant deterioration (PSD) limits and readily available surface water supplies.

This rate of recovery represents only about 5% of our needs for liquid fuels. Although much higher rates of recovery have been discussed lately, these have not yet been analyzed in terms of the actual working technologies and processes, nor in terms of their potential environmental economic, social, and political consequences.

2.2 TECHNOLOGICAL ASPECTS

Over the last forty years, industry has developed a range of oil shale retorting technologies. Important among the surface retorting technologies are TOSCO II, Lurgi, Paraho, Union B, and Superior. Occidental Oil Shale, Incorporated, has developed a modified in-situ process with some success. The Rio Blanco Oil Shale Company has also been experimenting with an MIS process. In general, the above ground retorting technologies are much closer to commercial readiness than are the MIS processes. However, most of the information about all of these technologies is based on bench- or pilot-scale operating experience, not commercial operating experience. Until full-scale modules (approximately 5,000 to 10,000 barrels per day) are built and are in operation, many uncertainties will remain. Uncertainties about the technical feasibility of a profitable and environmentally acceptable industry are likely to slow development.

In addition to the technologies already mentioned, the following backup or emerging technologies also exist: Illinois Institute of Technology Institute's Radio-Frequency; Raytheon's Radio-Frequency; Chevron's Fluidized-Bed; Equity's Pure In-Situ; Union's Solid Gas Retort (SGR); Institute of Gas Technology's Hytort; Multi-Mineral's Integrated In-Situ; Marathon's Steam Retort; and Horizontal Technology's Recycling Chemical Solvent Process. These technologies are

less well known than the earlier technologies, but some could ultimately become widely used if they are more fully developed and successfully demonstrated.

The oil shale industry, as it emerges, will employ a variety of technologies adapted to the specific characteristics of the shale deposits in different geographic locations. This report uses a mix of processes for its 300,000 barrels per day scenario. In reality, the industry in the 1990s may use fewer technologies, and plants may be larger than those shown. The processes actually used will almost certainly differ somewhat from those discussed, and they may even include processes that have not yet emerged or that are hybrids of other processes. The technologies presented are nevertheless representative of the shale oil technologies likely to comprise an industry in the near future.

2.3 AVAILABILITY OF NATURAL AND ECONOMIC RESOURCES

2.3.1 Oil Shale

U.S. reserves of oil shale are immense. Estimates of the total size of deposits vary with the oil shale yield considered economically recoverable, which in turn is a function of the price of competitive energy sources. This reserve is in any case far larger than U.S. reserves of oil and gas. Most experts estimate that over 400 billion barrels are economically recoverable. Eighty percent of this lies in northwestern Colorado.

Development of this resource may be limited by environmental standards. Lengthy permitting processes could delay start-up of commercial facilities on Federal land by almost 10 years, and on private land, by 7 years.

Land ownership patterns are another substantial barrier to development. First, about 85% of all oil shale reserves are on Federal land. The title to much of this land is questionable due to unpatented mining claims made under the Mining Act of 1872. Leasing by industry is limited to tracts of no more than 5,120 acres each by the 1920 Mineral Leasing Act. This is only enough for one commercial-scale plant, so developers cannot benefit from their experiences in further developments on the same tracts. Privately owned tracts of oil shale land are often small and non-contiguous, and they may have lower grade

shale than the Federal tracts. There are twenty-eight private blocks of land that are considered capable of supporting a 50,000 barrel per day plant.

2.3.2 Water

Surface water supplies in the Upper Colorado River Basin appear to be adequate to support a 500,000 to 1,000,000 barrel per day oil shale industry. This water would come from the White River, the Upper Colorado River Main Stem, and tributaries local to the Piceance Creek Basin; it might be supplemented by water from underground aquifers.

The availability of an adequate water supply is linked to several factors. First, although a large part of the water in the Upper Colorado is not currently used, if all decrees (claims made under water rights laws but not consummated) were actually used, there would be a major water shortage. Second, competition from other future users, such as agriculture and other energy activities, will limit the amount of water allocated to oil shale. Third, water shortages in the Lower Colorado Basin may force amendments to the law allocating water between the Upper and Lower Colorado Basin. Use of ground water may be limited by ground-water allocation laws, ground-water quality, and possible impacts on surface water. Most authorities on the subject conclude that while water is physically available to support an industry even much larger than 1,000,000 barrels per day, competition will become a significant factor about the year 2000, on a scale of about 1,000,000 barrels per day.

2.3.3 Other Resources

The availability of labor, transportation, equipment and materials, and financing could inhibit oil shale development. A moderate rate of development, for example the scenario created for the Department of energy for reference in this study, 300,000 barrels per day by 1990, would place heavy demands on all four of these resources.

The DOE oil shale scenario would require a work force in the state of Colorado of 7,540 in 1985 and 10,250 in 1990. The population of the four-county oil shale region in 1979 was only 109,729 people, so it is unlikely that a sufficient work force could be hired locally. Local labor would be taken away from other economic activities of regional importance, especially

agriculture. However, a sufficient work force could be brought into the region. While skilled and semi-skilled labor can be obtained, professional employees will be at a premium. Engineering firms capable of building an oil shale plant may be overtaxed.

Energy development has already had a significant impact on the transportation system of the oil shale region. Further development is likely to exacerbate the problem. Increased truck traffic could cause severely congested roads. Impacts could be mitigated by building pipelines to transport the product.

Certain pieces of equipment required for oil shale development--compressors, heaters, boilers, shell and tube exchangers, pumps, and draglines--may be in short supply. This could limit the rate of oil shale development and increase the cost.

Developing an oil shale industry will require very large capital investments. Since the technologies have not been commercially demonstrated, will require long construction times, and will produce little fuel relative to their cost, industry and the financial community may be reluctant to make the large expenditures required. Decontrol of oil prices can be expected to make synthetic fuels production less attractive to U.S. oil companies.

2.4 ENVIRONMENTAL ACCEPTABILITY

2.4.1 Air Quality

Air quality is generally considered to be that aspect of the environment most likely to constrain oil shale development. Potentially significant air quality problems include:

- impacts of toxic substances, especially polycyclic organic compounds and trace metals, on human health.
- effect of photochemical oxidants on human health, vegetation, and atmospheric visibility.

- inadvertent weather changes
- degradation of regional visibility due to particulate emissions and the production of secondary aerosols.

Air quality in the oil shale region is at present excellent. However, occasionally, ambient air concentrations of nonmethane hydrocarbons and particulates exceed standards. These problems appear to have natural causes, and EPA has indicated that they will not preclude oil shale development, provided that oil shale facilities meet emission and PSD standards.

Prevention of Significant Deterioration (PSD) regulations are most likely to constrain development. A study conducted for EPA estimates that the PSD limit for the Class I Flat Tops Wilderness Area may place an upper bound of 400,000 barrels per day on the oil shale industry. A 300,000 barrel per day industry might also use an estimated 20% to 38% of the PSD Class II SO₂ allowance and 28% to 54% of the particulate allowance for the Piceance Creek Basin, based on preliminary calculations. Estimates of these limits and impacts are highly uncertain, however, due to shortages of data on existing conditions, inadequate atmospheric models, lack of experience with commercial-scale shale oil production processes and current efforts to change the Federal air quality laws.

An oil shale industry will add to the carbon dioxide (CO₂) concentration in the world's atmosphere since the gas is released during both fuel production and fuel use. CO₂ concentrations have already been increasing for some time due to the use of fossil fuels. It has been estimated that the overall effect of this increase will be a global warming of the earth's surface during the first half of the 21st century by between 2° and 3.5°C. However, the impact of oil shale's contribution will be trivial, at the 300,000 bpd level.

While current air quality regulations may hamper extensive oil shale development, industry is exerting considerable pressure on Congress, EPA, and the State of Colorado to relax regulations. Recent elections have seen the defeat of many members of congress who helped to enact the current more restrictive air quality legislation. Industry and advisors to the Reagan administration are recommending relaxation of standards, and Congressional

action has been initiated. The revision of these regulations is likely. This could enhance the development of the oil shale industry by increasing the maximum projected production capacity based on air quality limitations.

2.4.2 Solid Waste

Shale oil development will produce large quantities of spent shale, approximately 1 ton for each barrel of shale oil. In-situ processes will leave this spent shale underground. However, surface retorting may produce large volumes of spent shale requiring disposal. A 300,000 barrel per day industry, including 165,000 barrels produced by surface retorting, will require the surface disposal of 120,000 metric tons of spent shale each day, assuming that 60% of the spent shale is returned to the mines. This shale would cover a football field to a depth of 22 m.

In addition to the physical and economic problems associated with disposal of such large volumes of waste, spent shale can cause fugitive dust emissions and potentially cause degradation of surface and ground water. Specific impacts are related to the composition of the retorted shale. This is variable and a function of the composition of the raw shale, the size of the particles, and the retorting process used. Although spent shales from several experimental facilities have been studied in some detail, further study using materials representative of commercial scale operations is required before the impacts of an oil shale industry can be completely assessed.

Water soluble salts, organic materials, and trace elements in spent shale could impact both surface and ground water quality through the uncontrolled release of leachates. In sufficient concentrations, some of these components would be toxic to wildlife, domestic livestock, and human health. Since the Colorado River is used for both drinking and irrigation in seven states and Mexico, potential toxic contamination and increased salinity are matters of concern.

Studies of leachates from spent shale show increased concentrations of a variety of substances, including organic carbon, SO_4 , S_2O_3 , Cl, Na, K, B, Mo, F, and Li. However, many of these compounds and elements are removed in the initial leachates. As the shale weathers, significant changes in the

composition of the leachates occur. After one year, the pH and levels of reduced sulfur species decrease in the leachates; however, arsenic, molybdenum, boron, and fluoride continue to leach. Even following significant weathering lithium, sodium, potassium, calcium, and strontium are released in higher concentrations from spent shale than from soil.

Potential water contamination from spent shale may be prevented or substantially reduced by properly engineered disposal. A maximum of 60% of the shale may be returned to underground mines. The remainder must be disposed on the ground surface, in canyons, hollows, or mesa top landfill sites. Careful construction of these piles, with impermeable liners and retaining dams, is expected to be effective. The piles could be stabilized in the short run by compaction with water and over the long run by a combination of engineering methods and revegetation.

One major factor affecting the ability to predict potential impacts of solid waste disposal is the general lack of commercial experience with shale retorting. Actual operating experience is needed to evaluate long-term impacts associated with the physical and chemical stability of spent shale piles and the internal hydrologic regime affecting leachate production and movement. Field experience will allow us to test the effectiveness of proposed solid waste management methods in physically stabilizing the piles and in reducing leaching.

An additional source of uncertainty is future environmental regulation of spent shale. At present, spent shale disposal procedures are regulated by state laws and by stipulations in lease agreements between the U.S. Geological Survey and the holders of oil shale leases on Federal lands. Future Federal laws for oil shale may be similar to regulations governing coal mining. If oil shale were to be placed under the hazardous waste provisions of the Federal Resource Conservation and Recovery Act, disposal costs would increase by 35 to 100 percent.

2.4.3 Ground Water

Potential damage to ground-water systems, and directly or indirectly to surface-water systems, is one of the most significant environmental issues

associated with a prospective oil shale industry. Surface retorting may cause damage if leachates from raw and spent shale piles reach ground-water aquifers or if retention dams overflow (due to a low-probability flood) discharging leachate into surface waters. Leaching of spent shale disposed of in underground mines could affect ground-water quality. In-situ retorting will have a larger impact on ground-water quality than will surface retorting. Dewatering of retorts can create many problems, and subsequent reinvasion of abandoned MIS retorts may lead to contamination of ground-water supplies.

The severity of impacts to ground water is at present unknown. The natural conditions which will affect the type and extent of the potential contamination are not well known or understood. A greater knowledge of geohydrological conditions in the Piceance Creek Basin and adequate field data are particularly needed.

Since the oil shale formations serve as aquifers in most locations where MIS retorts are anticipated, extensive dewatering of the aquifers will be necessary. This will result in drawdown of the water table and will produce large volumes of saline water which must be disposed of. After completion of MIS retorting, reinvasion of the area by ground water may not occur fully for hundreds of years. This is likely to reduce dramatically the flows in local surface streams, and it may delay field verification of controls for and impacts from abandoned MIS retorts. Extensive dewatering will also alter the quality of local ground water and reduce the flow of fresh water in wells, even though the water withdrawn in dewatering is the saline water from the deeper formations.

Over long time periods, the water in aquifers receiving leachate from numerous MIS retorts would approach the chemical composition of the leachates themselves. There is evidence that oil shale formations on the periphery of the Basin may be naturally dry, and thus require no dewatering. Flooding and leaching of abandoned retorts would, therefore, not occur in these formations. Dry formations are relatively unlikely in the Piceance Creek Basin which is at the center of the structural basin. Water quality studies suggest that the flow in some surface streams may be either entirely or partially dependent on ground-water conditions in the bedrock aquifers, those most affected by MIS

retorting. Thus, ground-water contamination could lead to surface-water degradation. Alluvial aquifers, a major source of the area's water supply, may be much less affected by oil shale development than the deep aquifers, unless dewatering eliminates or reduces base flow in these formations. The degree to which surface flows and alluvial waters are affected by the deeper aquifers is not clear.

Innovative environmental control technologies may also limit the negative impacts of oil shale development although none of these technologies has been tested or proven to be technically or economically feasible. Damages from dewatering activities may be mitigated by reinjection of the withdrawn waters downflow from the mining and retorting locations. Backflooding and leaching of abandoned, burned out MIS retorts may be avoided by preventing the entrance of water by grouting the retorts, by constructing grout curtains to divert ground water around the retorts, or by other techniques. Another alternative is to remove the potentially leachable chemical species from the retorts by intentional leaching followed by treatment of the leachates. It is also possible that otherwise leachable materials might be isolated permanently in an unleachable form through control of retorting conditions. Contamination of alluvial ground water through leaching from surface piles of spent or raw shale may be prevented through the use of impermeable liners under the piles and through other techniques of pile construction.

2.4.4 Surface Water Quality

Potential changes in the quality of surface water resulting from oil shale development are matters of great importance. The streams local to the Piceance Creek Basin are only of limited value for fishing, but they are used extensively for irrigation of crops. The Colorado River and its major tributaries, the White and Green Rivers, into which water from the oil shale region drains, are depended upon as the major source of water for all uses in a large arid area covering several western states and Mexico.

The major existing problems in the Colorado River Basin are general shortage of water (Lower Basin, especially) and salinity. The virgin flow is highly seasonal, peaking from April through July due to snowmelt. At other times, the

natural flow is largely from ground-water sources. The basin is, therefore, highly regulated with many reservoirs to store peak flows. Salinity is a natural condition due to the nature of rocks in some of the stream beds and ground-water aquifers. It is also the result of extensive irrigation of croplands.

Since reductions in stream flow tend to cause quality changes by reducing the amount of water available to dilute pollutants, flow changes are important factors in this water quality analysis.

The 300,000 barrel per day scenario discussed in this assessment would require about 26% of the average annual virgin flow of the White River Basin. An industry of 1.3 million barrels per day, by comparison, would require about 60% of the natural flow. In either case most of this water would have to be stored from the peak flows of the spring months. Demands on the Upper Main Stem of the Colorado River would be trivial as compared to the natural flow and other uses.

Ground water may be used by a shale oil industry. It exists in plentiful supply, but its use is constrained by natural quality problems and by institutional issues. Any use of ground water will reduce demands on surface water.

Ground water will be pumped from aquifers to facilitate mining and modified in-situ (MIS) retorting, irrespective of decisions made on water supply. If this "dewatering" water is discharged into Piceance and Yellow Creeks, and if the flow in alluvial aquifers and surface streams is not greatly affected by dewatering of the deep aquifers, then the discharges will swell flows in these creeks from an estimated 2 times natural annual flows in Piceance Creek to 18 to 24 times in Yellow Creek. An analysis of the quality impacts of discharging untreated dewatering water into Piceance and Yellow Creeks indicates that major increases could occur in the concentrations of sodium, boron, and fluoride. Total dissolved solids in the White River near the mouth of Yellow Creek would increase by up to 123 mg/l, bringing the concentration to 591 mg/l.

Dewatering would likely reduce or eliminate the base flow of Piceance and Yellow Creeks. One possible solution might be to reinject the water into the aquifers downflow from the mining activity. Another might be to augment stream flows by discharging the treated or untreated dewatering flow directly into the

surface streams. There is some evidence that dewatering the deep aquifers, thus reducing saline ground-water flows into Piceance and Yellow Creeks, would result in quality improvements in the White River.

A variety of waste waters would be created by a shale oil industry. However, since the oil shale region is an area that is typically water short, energy development, agricultural use, and other demands will make water increasingly difficult to obtain. Accordingly, it will be beneficial to the shale oil industry to conserve water, treating and reusing it wherever possible. Additionally, extensive treatment would be required before waste waters could be discharged to surface streams, the cost of treating them to a quality adequate for reuse will be less than the cost of discharging them.

The most difficult waste water to treat is "retort" water, which forms in the retort during pyrolysis of the shale. It contains a complex mixture of trace elements and organic substances, and adequate treatment techniques have not been developed to date. Almost no treatment research has been conducted on surface retort waters, because it was previously anticipated that these waters would not require treatment; they are produced in small volumes and were slated for hot spent shale moisturization. However, a recent ruling by the State of Colorado will require the removal of organics from these waters, and recent concern about the escape of gases, including NH_3 , may require the removal of dissolved gases. Recent indications are that distillation may be required for treatment of retort water, even though it is a very expensive process.

Surface runoff may be a problem for the industry. The most serious concerns relate to runoff from surface piles of spent or raw shale and from the plant area.

Pile designs proposed by the industry incorporate dikes, drainage channels, and retention dams to prevent runoff from surrounding areas from entering piles and to preclude runoff from spent or raw shale piles from reaching natural surface waters. They also incorporate pile linings, possibly compacted spent shale, to retard or eliminate percolation of leachates into ground-water aquifers. With revegetation, there is expectation that no leachates will reach

the bottom of the piles and that any surface runoff will approach the characteristics of runoff from natural land surfaces. For these reasons, most studies assume that surface piles will not result in contamination of surface waters.

There is, of course, the possibility of accidental spills of chemicals, shale oil, or waste fluids at production sites or in transportation corridors. The Federal Water Pollution Control Act requires each person storing minimum quantities of oil or hazardous substances to prepare and maintain a spill prevention control and countermeasure plan. This plan must describe the facility's strategy for preventing oil or hazardous substance spills from reaching navigable waters.

Contamination of ground-water aquifers is a matter of serious concern. It might occur from leachates from surface spent and raw shale piles, but more likely it would occur from ground-water reinvasion of abandoned modified in-situ (MIS) retorts. While it might take hundreds or even thousands of years, eventual contamination would reach surface waters fed by the aquifers. In addition to concerns about salinity from leaching of in-situ retorts are concerns about pH and certain chemical species. Of particular importance are toxic trace elements, such as arsenic, selenium, boron, fluorine, molybdenum, and vanadium, that have been observed in spent shale leachates.

Clearly, accurate predictions of effects of MIS retort leaching are beyond the limits of current knowledge. However, the work done to date makes it apparent that some contamination of surface streams would be likely if effective preventative measures are not developed and implemented. Several approaches to prevention have been suggested, but none have been tested nor shown to be technically or financially feasible.

2.4.5 Ecology

One of the most adverse environmental impacts on land features would occur during the construction phase of an oil shale industry. Erosion, already common to the area because of the weather extremes, including thunderstorms, would be aggravated during construction. However, revegetation of the disturbed areas is an important method for reducing the impacts.

Air pollution emissions of hydrocarbons, SO_2 , NO_2 and particulates are of potential concern regarding impacts to vegetation. Other compounds which are considered possible pollutants are ammonia, chlorine, volatile trace metals, phenols and other organic compounds. Secondary photochemical reactions may further result in production of plant toxicants. However, the dosages of the pollutants necessary to induce acute, short-term, vegetation injury are rather high and the projected range of average daily pollutant levels in the basin are rather low. Hence the probability of acute injury is minimal. However, the chronic injury resulting from long-term, low-level exposure may be significant. On the other hand, some field studies have shown that low-levels of SO_2 in the atmosphere can be one way of removing a sulfur deficiency and thereby enhancing plant growth.

Most of the area affected by shale oil mining has a unique combination of natural and cultural conditions that promote good upland habitat, which is ecologically fragile. The desert flora is particularly susceptible to man-induced changes in available water and run-off patterns and this in turn impacts animal life. It is generally conceded that mule deer, elk, pronghorn antelope, and sage grouse would decline in numbers as a result of an oil shale industry and the resulting increased human population.

The greatest impacts will occur at the local level of influence. The major factors here will be the operating procedures, disposal of residues, and the actual mine sites. Nearly all species of wildlife are expected to decline because of loss of habitat and from all forms of human activity. Many mammals and bird species are expected to be reduced by 25% to 50% within 3 to 10 years. These reduced populations include mountain lions, bobcats, elk, black bear, skunks, porcupines, coyotes, weasels, badgers, mule deer, wild horses, golden eagles, bald eagles, sage grouse, mourning doves, owls, woodpeckers, turkey vultures, nighthawks, and hummingbirds.

Intermediate impacts will be caused primarily by downstream water pollution. Species inhabiting riparian communities will consequently be most affected. Mammal species, such as muskrats and raccoons, and waterfowl and

shorebirds will undergo moderate to high declines. Maintenance of riparian habitats might mitigate the above declines as would development of compensatory tracts of lands.

The extended impacts will come primarily from the expected influx of residents due to the available job market. Mammal and avian species will undergo moderate to high declines as a result. New (human) community developments are expected to cause major problems for waterfowl, great blue heron, chukar, and beaver.

A mature, producing oil shale industry could also be detrimental to the local livestock industry because of reduced water supplies for cattle. However, this livestock reduction, if followed by reduced predator control, might help increase the populations of coyote, bobcat, black bear, mountain lion, and golden eagle.

In all, it seems likely that beaver, mountain lion, elk, and sage grouse will be eliminated from the shale oil region by a mature shale oil industry. It is likely that only beaver and elk would be reestablished after operations cease.

2.4.6 Health and Safety

There is little available data on the potential health effects of a U.S. oil shale industry. Evidence drawn largely from foreign oil shale experience indicates several possible health effects from occupational exposures. Further study should be performed before the industry is allowed to develop fully.

In general, synthetic oils appear to have a carcinogenic potential. Studies of oil shale workers in Scotland have shown evidence of an increased incidence of skin cancer. However, while shale oil is more potent than most natural petroleums, it appears to be less so than many coal-derived liquid fuels. Hydrotreating appears to lower the hazard of crude shale oil. Middle distillate shale oils, however, appear to be less carcinogenic than either the crude or the hydrotreated crude shale oils, even though the middle distillates appear to exhibit more systemic toxicity. Both the observational and experimental data on skin tumors have flaws. Experimental studies should determine

which components of shale oil are active. Observational data stem from a period when industrial and personal hygiene were less sophisticated than today.

Historical evidence indicates that the incidence of respiratory illness in oil shale workers is greater than that in the general population, although still relatively low. Shale mining, crushing, and disposal create dust particles of a size known to be deposited and retained in the lungs for long periods of time. Studies of Estonian oil shale workers have shown an excess of chronic bronchitis, mild pneumoconiosis, emphysema, and upper respiratory illness. However, raw and spent shale dusts in lungs have not been shown to be carcinogenic. Questions related to fibrogenic or obstructive lung disease require further study. Experiments in which animals have been exposed to highly concentrated aerosols have produced evidence of fibrotic changes. MIS retorting, where workers will be preparing some retorts while others are burning, may present an inhalation hazard that will need to be more fully defined, since workers may be exposed simultaneously to shale dust, diesel exhaust, and retorting offgases.

Neither the exact nature nor the pervasiveness of the relevant, applicable occupational hazards can be ascertained, based on our very limited experience. Application of available industrial hygiene procedures and equipment and of existing environmental controls may provide adequate protection. Actual commercial-scale experience is necessary before this problem can be understood adequately.

Shale oil production could possibly expose the general public to toxic or genetic effects through contamination of water and air. Ground- or surface-water contamination by biologically active materials is probable, and strong control technology efforts will be required. However, existing water clean-up techniques may be sufficient to avoid contamination of water supplies. This can only be determined as industry scales up.

2.4.7 Socioeconomics

Historically, energy development in the sparsely populated areas of the west has caused severe socioeconomic impacts due to the influx of large numbers of newcomers. The development of oil shale will generate large and rapid

population growth. The projected growth may be as severe as that which produced the widely documented boom towns of the 1970s. Accommodating this large population growth will present enormous challenges to existing communities.

Impacts due to oil shale development, however, may be partially reduced by the fact that a very large operating work force as well as construction work force will be required. There will be only a small decline in the total number of oil shale employees after the construction phase ends. Thus, the oil shale region will not experience the "bust" that usually follows a "boom."

The construction and operation work force requirements of a 300,000 barrel per day oil shale industry nearly equal the total existing labor force in Rio Blanco and Garfield Counties. There are no large urban areas in the region in which the existing infrastructure and support systems could readily absorb the anticipated population impact. The largest community, Grand Junction, already suffers from growth rates that strain existing support systems.

The worst impacts include the inadequacy or lack of public facilities and services, housing, and integration of immigrants into the community; the disruption and destruction of existing social and political structure; the degradation of the quality of life of both the indigenous population and the immigrant population; and severe inflation, especially affecting the cost of land and housing.

Most of these impacts can be mitigated by careful planning for community growth. Measures for mitigation must take into consideration such factors as administrative capacity of local governments, local and state statutory requirements, and the political climate. Implementing plans for mitigation may be difficult because there is no mechanism to coordinate such a program among Federal, state and local governments, industry, and private agencies. Local government officials, in particular, aggressively assert the need to include local governments in the planning and management of the multi-state resource development.

The inadequacy of public facilities and services may be alleviated by external financial assistance. Many communities in northwestern Colorado have already expanded public facilities, specifically water treatment plants, sewer

systems, and schools through state and Federal financial assistance. Excess capacity in these facilities is expected to reduce disruption of services and to alleviate the immediate impacts of rapid population growth. A major issue is the question of who should pay for additional municipal facilities. Community residents have expressed the belief that they should not have to pay for the facilities and services required by the immigrant population; industry officials have maintained that the government should pay for the roads leading to oil shale sites; and the state government has expressed the concern that the Federal government should provide assistance for impact mitigation of oil shale development because that development serves a national need.

This issue is further complicated by the fact that the tax base created by an oil shale industry may not coincide with political jurisdictions where socioeconomic impacts are severe. For example, Mesa county officials are concerned that although no oil shale facilities will be built in Mesa County, severe secondary impacts will be felt in Grand Junction.

In order to be successful, programs designed to mitigate social impacts must begin soon--before development occurs and newcomers arrive. This implies that communities must fund new facilities before their tax base has increased. Even if this were financially feasible, the uncertainties regarding the future of the oil shale industry make prior planning seem less urgent and more difficult.

3.0 TECHNOLOGICAL ASPECTS AND SCENARIO

This chapter deals with the technological state-of-the-art of a production scenario of 300,000 barrels per day (bpd) of production, postulated for purposes of reference in this study to occur about the year 1990. It is based on Volume 2 of this assessment report, entitled Technology Characterization and Production Scenarios.⁽¹⁾ The chapter is based on existing processes and known sites of potential commercial development. The production scenario of 300,000 bpd is derived on the basis of known or projected development plans of potential shale oil producers during the late-1979 and early-1980 time frame, and it reflects an assessment of their combined capability to respond to a production requirement of 300,000 bpd. This is a reasonable scenario given what we know about sites, processes, constraints, and possible incentives. Prospective shale oil producers have changed and developed their plans further since this scenario was created. The results of analyses based on the scenario should indicate the implications of a 300,000-bpd shale oil industry, even though some of the quantitative aspects of the findings would likely turn out to be different in light of more current assumptions about the technologies, constraints, and government actions.

In this chapter, shale mining, crushing and storage are discussed first. Next, five aboveground (AG) processes and one modified-in-situ (MIS) process are described. The aboveground technologies are based on experience with processes such as those commonly referred to as: (A) TOSCO II, (B) Paraho, (C) Union B, (D) Superior Oil and (E) Lurgi. The MIS process (F) is based on the experience of the Occidental Oil Shale Company.

Those processes are treated as "generic" processes A, B, etc., as opposed to describing them by name, such as TOSCO II, or Paraho, etc. This is done since the processes, as described here, are not identical to the processes bearing these names or company associations today.

While a very minor contribution from a true in situ (TIS) process is included in the scenario, no specific process is described in depth in this chapter. Instead, there are included here some general comments about TIS

processes. Because of the small contribution from TIS processes in the scenario, this lack of specificity will not affect the results of the assessment.

In Section 3.5, Production Scenarios and Site Locations, the aggregate 300,000-barrel-per-day production is developed showing sites, processes, and resulting emissions. Also discussed briefly are the conditions, e.g., incentives, that would make this production feasible. Some of these conditions are already being met through new legislation and government programs, although their future is uncertain.

The chapter concludes with a brief discussion of concomitant transportation requirements.

3.1 SHALE PREPARATION

Shale to be retorted above ground must be mined, crushed to retort process specifications, and brought to the surface. In MIS retorting, some shale must be removed; the remainder must be broken into proper sized pieces, or "rubbled." This section describes these important steps.

3.1.1 Mining

Although there are several methods of underground mining amenable to oil shale production, the mining method proposed for subsurface extraction of shale is the room and pillar mining system (Figure 3.1). Room and pillar mining uses the conventional cycle of drilling, charging, blasting, wetting the broken material, loading, hauling, scaling, and roof bolting. Data for oil shale mining are available from mines at the Colony and Union projects in the Parachute Creek area near Grand Valley, Colorado and the DOE site, formerly operated by the U.S. Bureau of Mines, at Anvil Points near Rifle, Colorado.

As envisioned in several potential projects, room and pillar mining can be conducted on two different levels, or benches. At each level, rooms of approximately 60 ft wide by 60 to 90 ft high are excavated, leaving pillars of approximately 60 ft by 60 to 80 ft to support the roof. The benches are each 30 to 45 ft deep. Specific pillar and room sizes depend on location, strength of the material, and mine depth.

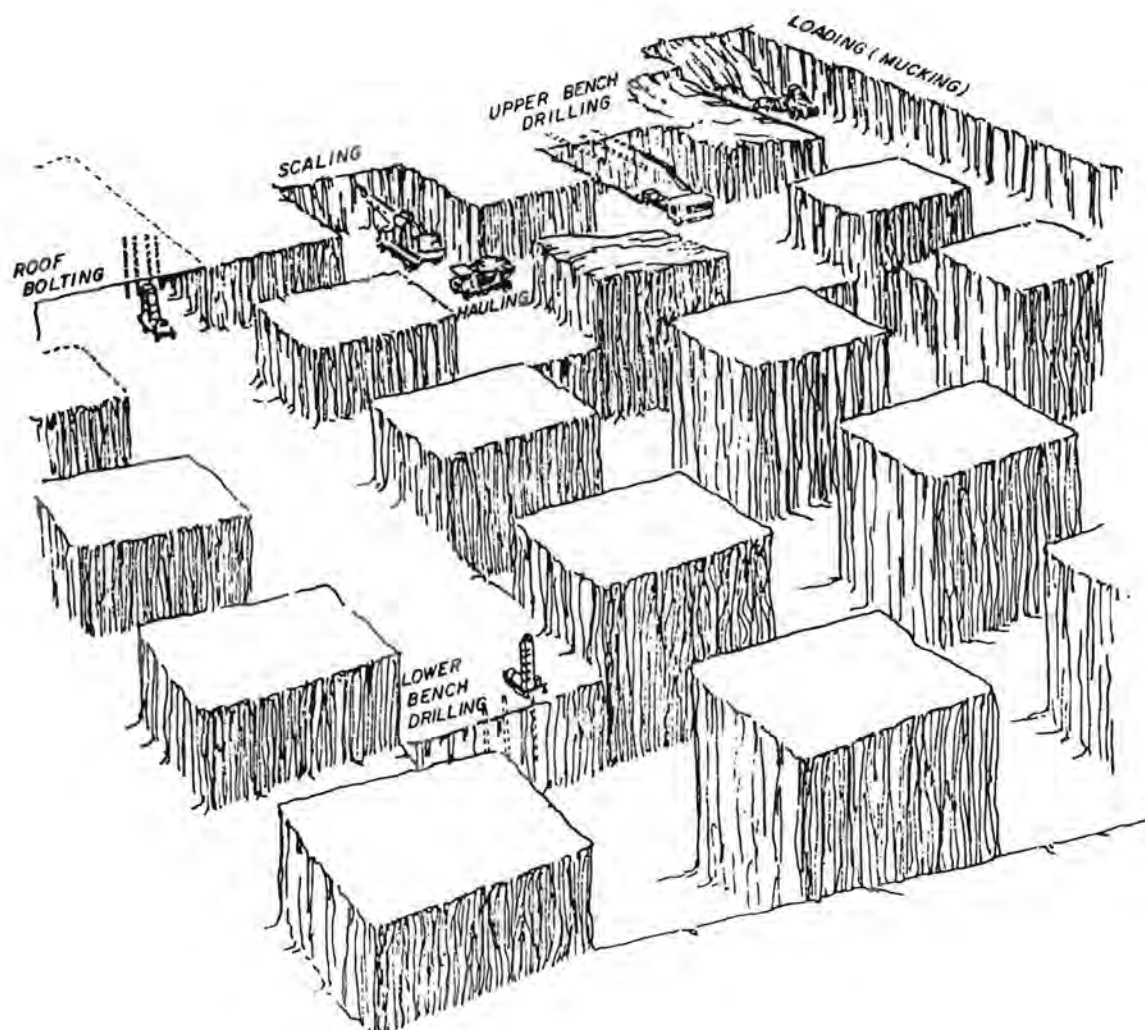


FIGURE 3.1. Room and Pillar Mining Concept(4)

The upper level drilling is horizontal, using drill jumbos that are designed to place a network of holes, several inches in diameter and perhaps 30 ft deep, into the mine heading. Lower bench drilling is vertical with a network of holes placed into the underlying bed of oil shale. The shale is then blasted, and the broken material wetted for dust suppression. The material is then loaded into dump trucks for transportation to the primary crushing stage. Up to 75% of the ore can be recovered in a shallow room and pillar mine with an optimal design.

Modified-in-situ (MIS) retorting requires the extractive mining of 20% to 40% of the shale in the preparation of the retort. A number of shafts are required for ventilation and service lines, hoisting of mined shale, placement of mining equipment, retorting, and removal of gas and oil products. Several levels are used in the development of MIS retorts; a separate level is used for the gas-way to the gas exhaust shaft.

The levels are mined by a modified room and pillar system. However, instead of pillars, continuous walls are left to form links within the retorts. Permanent bulkheads are constructed to isolate the gas level from the rest of the mine. The retorts are rubble by blasting into the retorts from the intermediate levels, allowing the broken shale to drop into cavities mined below these levels. Final connections are made to the production (gas) levels. The mined shale is hoisted to the surface for storage and later processed through surface retorting techniques.

Both conventional and modified-in-situ mines include ventilation systems, maintenance and warehousing, underground electric power distribution, compressed air generation, raw and potable water distribution and communication systems. The size of the mine operation dictates the size of the equipment maintenance facility as well as the location and size of miner accommodations for eating, changing, first aid, etc.

Emissions

Several air emissions are produced in the underground mining cycle. The array of these pollutants is the same for both the room and pillar and MIS mining operations. There are two categories of pollutants: those produced from the shale, for example particulates, and those produced from mining operations, for example CO, HC, SO₂, and NO_x. Emissions from the mining necessary to support various retorting processes are shown in Table 3.1. Note that the emissions are given as "pounds per ton" and are not the total figures for a 300,000-bpd operation.

Inputs

Underground mining requires labor, water, and other utilities. The primary use of water in the mine is to control particulate emissions. Other uses

TABLE 3.1. Net Emissions from Oil Shale Mining⁽⁵⁻⁷⁾ (pounds per ton)

<u>Process</u>	<u>Capacity</u>	<u>Particulates</u>	<u>SO₂</u>	<u>HC</u>	<u>NO_x</u>	<u>CO</u>
Process A	66,000TPD	0.00942	(a)	0.0181	0.0909	0.1597
Process B	8,400TPD	0.00424	0.005573	0.005033	0.077802	0.027583
Process C	15,156TPD	0.014416	0.005278	0.001313	0.093686	0.017614
Process D	26,175TPD	0.007181	0.005777	0.001229	0.079924	0.013853
Process E ^(b)						

(a) None reported.

(b) Similar to Process A.

are fire and safety, potable water for personnel and equipment. Approximately 6 to 10 gallons of water are used per ton of shale mined.^(3,4)

Manpower projections range from approximately 1,050 people for the White River Shale Project of 160,000-tons-per-day capacity down to 61 people for the Paraho Module Project of 8,400-tons-per-day capacity.^(3,5)

The MIS system requires approximately 500 mining personnel for a plant that is projected to produce approximately 50,000 BPSD of oil subsurface and 25,000 BPSD of oil by surface methods.

Utilities required range from 0.19 kW per ton mined for the White River Shale Project⁽⁶⁾ to 0.15 kW per ton mined for the MIS mining scheme. Diesel fuel consumption for the Paraho module project is estimated at 0.2 gallons per ton of shale mined.⁽⁵⁾

3.1.2 Crushing and Storage

Mined oil shale must be crushed, screened and stored before being used for surface retorting. There can be several crushing stages: primary, secondary and tertiary, depending upon the degree of crushing or fineness required. Primary crushers are located either in the mine or just outside of it. The crushers may be single roll, double roll, jaw, cone, or gyratory units, depending upon retorting process requirements. The primary stage generally reduces the mined shale to 10- to 12-in. particles, which may then be transported by

conveyor to a secondary crushing complex. Some retorting plants may also require tertiary crushing. Both the secondary and tertiary crushers usually are located near the retorts.

Mined shale may be stored between the mine and primary crusher, between intermediate crushers, or between intermediate crushers and the retorts. Storage should have a sufficient capacity to support a retort for at least several days.

Emissions

Particulate matter is the major pollutant produced by shale crushing and storage. Table 3.2 shows net emissions from four retorting processes. Processes A, B, C, and D are similar to the Colony,⁽⁴⁾ Paraho,⁽⁵⁾ Union,⁽⁶⁾ and Superior⁽⁹⁾ projects, respectively. All systems are assumed to use baghouses to control particulates during crushing and storage.

Major differences among processes are caused by the location of the crushers. Primary crushers for Processes B, C, and D are located inside the mine and, therefore, benefit from additional particulate control through wet suppression and baffled settling. Process A's primary crusher is located outside the mine. Except for Process C, secondary crushers are located outside the mine near the plant. Particulate emissions during crushing will vary substantially, depending upon the required degree of raw shale size reduction.

Storage techniques vary among the four processes, making emission levels difficult to compare.

TABLE 3.2. Net Particulate, Emissions from Shale Crushing and Storage⁽¹⁾
(pounds per ton)

<u>Process</u>	<u>Primary Crushing</u>	<u>Secondary Crushing</u>	<u>Storage</u>
Process A	2.6×10^{-3}	1.19×10^{-2}	1.22×10^{-2}
Process B	7.5×10^{-5}	1.94×10^{-2}	3.85×10^{-3}
Process C	6.4×10^{-5}	1.37×10^{-4}	1.21×10^{-4}
Process D	3.0×10^{-5}	6.79×10^{-3}	3.30×10^{-3}

Process A could have a storage pile of primary crushed coarse ore outside the mine and a storage bin of fine ore in the plant area. There will be no storage facility for run-of-mine ore. Process B may have "live" (current inventory) storage of coarse ore in the mine and storage of retort feed material in the plant area, as well as intermediate surge and transfer bins within the processing train up to the retort. Process C may have storage within the mine of crushed retorted feed-size material and small transfer and surge capacities throughout the processing scheme up to the retort. Process D may have live storage of crushed material only in the plant area with intermediate bins and surge hoppers.

Inputs

Primary crushing will employ approximately 10 operators for a 10,000-ton-per-day facility. Maintenance may require additional personnel. Each ton crushed will consume 0.25 kW of power.

A 10,000-ton-per-day secondary crusher will employ approximately 14 operators. Power requirements will range from 0.75 to 1.0 kW per ton crushed.

Live storage piles will require some small amount of water. Up to four men plus maintenance personnel could be needed for a 10,000-ton-per-day plant. Fuel or power needs will vary with methods used.

3.2 ABOVEGROUND RETORTING

Once the shale is prepared, the next step in shale oil production is retorting. Several aboveground retorting methods have been proposed. Those included in the scenario for this assessment are described in this section.

3.2.1 Process A

Process A is similar to the TOSCO II process. The data presented in this section are based on the proposed Colony Development oil shale facility on the Dow West property. The facility has several major components: shale mining, crushing and storage, retorting, disposing of spent shale, and product shale oil pre-refining and upgrading. Figure 3.2 shows the flow of materials through the retorting units.

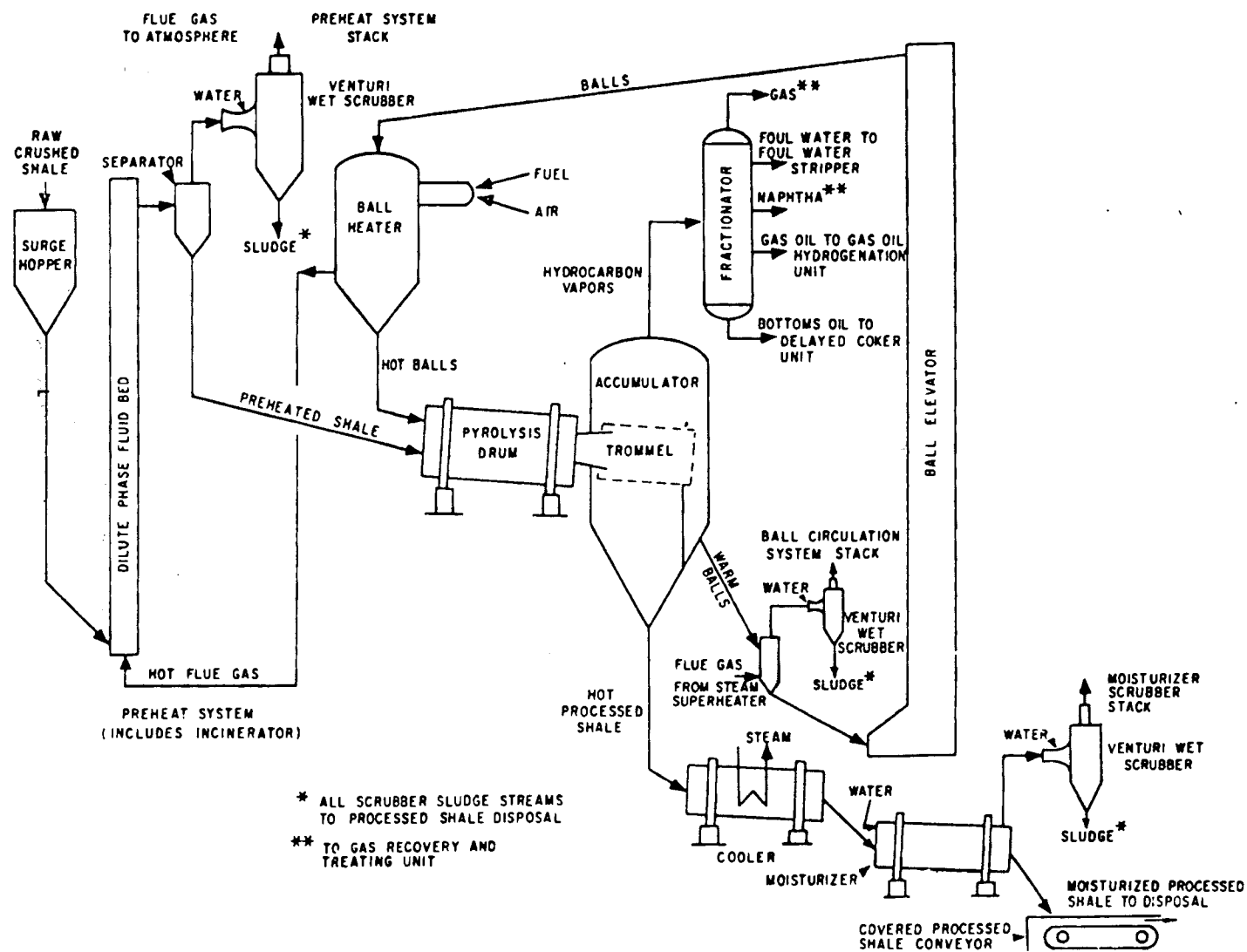


FIGURE 3.2. Pyrolysis and Oil Recovery Unit, Process A(2)

Shale mining, crushing, and storage are discussed in Sections 3.1 above. Process A will include a conventional room and pillar mine, producing approximately 66,000 tons of raw shale per day. Sixty percent of the in-place shale will be recovered. The shale contains approximately 35 gallons of oil per ton.

Process A is an indirect oil shale retorting process. Six identical retorts are proposed, each with a capacity of 11,000 tons of crushed shale per day. The process uses 1/2-in. ceramic balls as the heat transfer medium. The heated ceramic balls are mixed with a finely crushed preheated shale in a rotating-drum pyrolysis vessel. After pyrolysis is completed, the retorted shale and ceramic balls are separated in a rotating screen trommel. The retorted shale is then cooled and wetted in a moisturizing process before disposal, and the ceramic balls are recycled to a furnace for re-heating. The hydrocarbon vapors and liquids are collected in an accumulator vessel and sent to a column fractionator for separation. After separation, these raw hydrocarbon fractions are diverted to the various pre-refining and upgrading units.

Each retorting train has three major parts which determine its emissions: the preheat system, the elutriator system, and the retorted shale wetting system. The preheat system heats the finely crushed shale to 500°F before the shale is mixed with the heated ceramic balls in the pyrolysis drum. The elutriator system uses warm flue gas from the steam superheater to remove residual dust from the ceramic ball recirculation system after pyrolysis. After the spent shale is cooled, it is moisturized to about 14% by weight in a moisturizing drum. It is then conveyed to the shale disposal pile.

Processed shale will be dumped into a compacted landfill with a retaining embankment. Topsoil will be removed before filling and used for eventual reclamation and revegetation of the site.

The raw whole shale oil produced by the retorts (52,000 barrels per stream day (BPSD)) will then be processed in an on-site pre-refining facility. Process A upgrades each hydrocarbon cut separately. The products are:

- 47,000 BPSD Low Sulfur Fuel Oil
- 4,300 BPSD LPG

- 135 tons per stream day (TPSD) of NH_3
- 173 TPSD Sulfur
- 896 TPSD Coke.

Vapor products from the accumulator vessel of the pyrolysis unit enter the fractionator and are separated into gas, raw naphtha, gas oil, and bottoms oil. These products are then diverted to the various units in the pre-refining system: the gas treating plant, hydrogen plant, hydrotreaters, delayed coking plant, ammonia separating unit, and sulfur recovery unit.

The gas and raw naphtha streams are sent to the gas recovery and treating unit for gas treating and naphtha stabilization. The gas treating plant removes hydrogen sulfide and carbon dioxide from the retort gases so that these gases can be consumed as an in-plant fuel in compliance with applicable emission regulations. Acid gas is removed by conventional diethanolamine absorption. Recovered acid gases are sent to the sulfur recovery plant. The gas oil is sent to the gas oil hydrogenation unit. The bottoms oil is diverted to the delayed coker unit. The foul water stripper removes absorbed ammonia and hydrogen sulfide from water condensed out of the retort gas stream. The stripped water is used for processed shale moisturizing.

Emissions

Table 3.3 lists the emissions produced by each of the major components for 66,000 TPD Process A retorting, pre-refining, and upgrading systems. For emissions from mining, crushing, and storage for Process A see Section 3.1. Table 3.4 lists major solid wastes produced during pre-refining and upgrading.

Inputs

The proposed six-train commercial Process A plant will use fuel provided by an on-site upgrading facility. However, smaller plants may use conventional fuels purchased from outside sources. The type of fuel consumed will alter emission levels. Several of the pre-refining and upgrading systems will also have furnaces and will burn treated gas.

TABLE 3.3. Net Emissions from Process A⁽¹⁾ (pounds per ton)

Component	Particulates	SO ₂	NO _x	HC	CO	Sludge
Retorts ⁽⁶⁾						
Preheaters	0.08170	0.01709	0.44163	0.09080	0.01465	0.63640
Elutriators	0.07259	0.03182	0.03804	0.00010	0.00096	0.04810
Shale Wetters	0.08170	0	0	0	0	0.03182
Pre-Refining and Upgrading						
Hydrogen Generator	0.00383	0.00921	0.02765	0.00054	0.00333	
Gas Oil Hydrotreater	0.00067	0.00158	0.00469	0.00010	0.00061	
Napththa Hydrotreater	0.00007	0.00013	0.00044	0.00004	0.00007	
Sulfur Recovery	0	0.03178	0	0	0	
Delayed Coker	0.00037	0.00094	0.00283	0.00007	0.00033	
Utility Boilers	0.00098	0.00242	0.00727	0.00013	0.00087	
Boilers, Off-Site Product Storage	0.00004	0.00015	0.00030	0	0.00004	

TABLE 3.4. Pre-Refining and Upgrading Facility Input; 52,000 BPSD
Major Solid Wastes/Catalyst Replacement⁽⁴⁾

<u>Source of Solid Waste</u>	<u>Quantity/Replacement Period--Tons/Time</u>	<u>Annual Production Tons</u>	<u>Major Constituent</u>
<u>Gas Recovery and Treating Unit</u>			
DEA Filter	8.25 T/2 weeks	214.5	
DEA Filter	8.25 T/2 weeks	214.5	
<u>Hydrogen Genera- tor Unit</u>			
Hydrodesul- furizer	55 T/3 years	18.3	Spent HDS Catalyst (cobalt molybdate)
Guard Bed Reactor	20 T/3 years	6.7	Spent ZnO Catalyst (ZnS)
Shift Conver- ter (High Temp.)	50 T/5 years	10	Spent Fe-Cr Catalyst
Shift Conver- ter (Low Temp.)	50 T/3 years	16.7	Spent Cu-Zn Catalyst
<u>Hydrotreater Units</u>			
Gas Oil	300 to 500 T/year	300 to 500	Proprietary Solid
Gas Oil	230 T/year	230	Spent HDN Catalyst
Naphtha	60 to 80 T/year	60 to 80	Proprietary Solid
Naphtha	75 T/year	75	Spent HDN Catalyst
<u>Sulfur Recovery Unit</u>			
Claus Trains (2)	160 T/2 year	80	Spent Alumina Catalyst
<u>Delayed Coker Unit</u>	800 T/day	292,000	Green Coke ^(a)

(a) May be marketable by-product.

Several of the pre-refining and upgrading systems have catalysts, which must be replaced periodically. Table 3.4 includes the amounts of each required.

In the Process A pyrolysis unit water is used to cool and wet the processed shale. Each of the six retorting trains will require 455 gpm. This water is acquired from various process units within the system. A foul water stripper removes dissolved NH_3 , H_2S and CO_2 but the water will retain some residual chemical components, listed in Table 3.5. This water will be conveyed to the disposal site along with the spent shale.

TABLE 3.5. Chemical Components of Process Water from Process A⁽⁴⁾

<u>Component</u>	<u>PPMW in Water Added to Spent Shale</u>
Ca^{+2}	280
Mg^{+2}	100
Na^{+1}	670
NH_4^{-1}	15
Zn^{+2}	5
As^{+5}	(15 to 300 ppb)
Cr^{+6}	2
CO_3^{-2}	360
HCO_3^{-1}	100
SO_4^{+2}	850
$\text{S}_2\text{O}_3^{-2}$	90
PO_4^{-3}	5
Cl^{-1}	570
CN^{-1}	5
Phenols	187
Amines	253
Organic Acids	631
Neutral Oils	525
Chelate	<u>3</u>
Totals (rounded)	4,650

3.2.2 Process B

Process B is similar to the Paraho process. While the actual Paraho development will now be in Utah, for purposes of this assessment scenario, the Process B module retort will have shale provided from a mine which is an extension of the present DOE mine at Anvil Points near Rifle, Colorado. The existing mine has been developed by room and pillar mining. Approximately 8,400 tons of shale must be mined each day to support the Process B retort. The recovery efficiency, exclusive of the barrier pillar, will be 70%. The mined shale will be crushed inside the mine and then conveyed to the secondary crushing and screening facilities. Mining and crushing are discussed in Section 3.1 above.

The Process B retort converts solid kerogen into suspended oil mist which is then carried in the exit gas stream. Carefully sized and sampled raw oil shale is charged into the top of the retort. After reaching retorting temperatures in the vertical vessel, the shale flows downward by gravity, is discharged, and is transported to a disposal area. The oil mist produced and the gas stream are drawn off the top of the vessel; the mist is collected as oil; the gas stream is compressed in a closed loop and the excess is vented to a thermal oxidizer or processed and burned in process equipment.

The retort will be approximately 42 ft in diameter. It will operate at slightly above atmospheric pressure.

Clean, sized, raw oil shale is delivered by belt conveyor to the top of the retort. A feeding device distributes the shale particles uniformly into the vessel. The discharge grate provides a uniform rock descent throughout the entire cross section of the retort. In the descent, the shale moves through four zones: oil mist formation, retorting, combustion and cooling.

Recycled gas, mixed with controlled amounts of processed air, enters the retort at several levels. The residual carbon on the retorted shale is burned to provide the required heat. The recycled gas helps control the temperatures of combustion and also conveys the oil mist upward and out of the top of the retort. The gas stream, laden with oil mist, enters the electrostatic precipitators and separator devices to recover the oil which is piped to storage

tanks. A portion of the gas is returned to retort and the remainder is treated for nitrogen and sulfur removal and then burned in a boiler or in power production equipment, and/or it is burned and vented to the atmosphere.

The retorted shale, after discharge from the bottom of the retort, will be conveyed to a surge bin and from there conveyed to the disposal areas.

Emissions

Table 3.6 shows emissions expected from the Process B pyrolysis or retorting section. Data are derived from a 8,500 TPD unit.

Inputs

Make-up water is required for cooling the air-gas distribution circuit. Other water requirements include: dust control, NH_3 removal from the excess gas, Stretford processing of the excess gas to remove sulfur compounds, and retorted shale disposal. Approximately 250 acre-ft per year are required.

The electrical requirement for the retorting plant complex, offices, facility maintenance etc., is rated at 12,000 kW. The number of plant personnel, in addition to those employed in mining and crushing-screening-storage operations, is approximately 220 people.

3.2.3 Process C

Process C is similar to the Union B process. Mining, crushing, and storage operations are similar to descriptions in Section 3.1. The Process C mine

TABLE 3.6. Net Emissions From Process B (pounds per ton of shale)

<u>Component</u>	<u>Particulates</u>	<u>SO₂</u>	<u>NO_x</u>
Retort ⁽¹⁰⁾	0.001500		
Transfer ⁽¹⁰⁾	0.001232		
Points	0.001232		
	0.001232		
Gas Turbine ⁽¹⁾			0.134561
Boiler ⁽¹⁾		0.008060	
Thermal Oxidizer ⁽¹⁾	0.015111		

will be on the north side of the East Fork of Parachute Creek. The mine will use room and pillar mining techniques and will have a net recovery of 75% of the oil shale in the mine. The mine will produce an average of 15,156 tons per day of run-of-the-mine ore. Both primary and secondary crushing, as well as live storage, will be handled underground.

The Process C retort is designed for indirect processing of the oil shale using heated recycled gas. The oil shale is elevated to temperatures sufficient for the thermal decomposition of the hydrocarbon matter (kerogen). The retort is capable of operating successfully on shale of 35 gallons per ton and higher grades. The retort uses shale particles ranging from 1/8 to 2 in. in diameter.

The unique feature of the Process C retort is a "rock pump" which forces the shale upward from the bottom to the top where the shale discharges. The heated recycle gas enters the top of the retort and flows downward countercurrent to the ascending shale. The gas stream, laden with oil mist, exits near the bottom of the retort and flows through oil separation equipment to recover the oil before the gas is compressed. After compression, the majority of gas is heated to required temperatures in indirect-fired heaters. The smaller portion of gas (flue gas) is sent to the Stretford gas treating section for sulfur compound removal and then it is burned in the heaters to supply some of the heat requirement. The heat content of the gas produced from the retort is above 800 Btu/CF. The retorted shale is quenched directly with water, then mixed with waste raw shale fines and transported to a disposal site. After leaving the quench, the retorted shale contains approximately 29% water by weight. The oil is pumped to a pre-refining step, after which the product oil is put into storage before shipping to market or for additional refining.

The pre-refining part of the plant complex includes a fractionator, fractionator reboiler, process equipment and product storage.

The fractionating section is designed to split some of the crude shale oil into gas and a final crude shale oil product. The gas, which is sent to the Stretford unit for H_2S removal, is used as plant fuel in several parts of the complex such as the recycled gas heater, steam boilers, inert gas generator and

fractionator reboiler. The bottoms, or crude shale oil, flow to the product storage tank for final shipment from the plant site.

Figure 3.3 shows the basic components of the Process C system.

Emissions

Emissions from a 10,000 TPD Process C (retort) are given in Table 3.7.

Inputs

Approximately 238 people will be employed by the Process C operation, of which 120 will support pyrolysis and 12 pre-refining.

Water will be supplied to the plant from wells. Approximately 300 acre-ft per year will be used, the major portion allocated to retorted shale disposal.

Fuel requirements for pyrolysis will be satisfied by burning approximately 9×10^6 cu ft per operating day of the gas produced from the process. The fuel requirements are approximately 12,000 standard cu ft per day (SCFD) based upon a fuel gas having a higher heater value (HHV) of 1,170 Btu/SCF.

Pyrolysis will require 6 MW of electric power to operate the rock pump and compressor motors; pre-refining will require 10 kW.

3.2.4 Process D

Process D is similar to the Superior Oil Company process. This process is consistent with operations in the multimineral co-production of shale oil, since it includes accurate control of temperatures in the retorting zone.

The principal products of a shale co-products operation are: shale oil, soda ash, nahcolite, and alumina. Surface processing facilities include the retorts, a nahcolite separation unit, and a mineral co-product (soda ash and alumina) unit. In general, the nahcolite is upgraded by crushing and photo-sorting techniques; the finished mineral products are produced by a leaching and evaporation system.

The Process D mine will be located off the Piceance Creek Road about 17 miles west of Meeker, Colorado and 38 miles east of Rangely, Colorado. Rather than mining in the Mahogany Zone region, the project proposes following the down dip of the formation below the base of fracturing to the lower zone

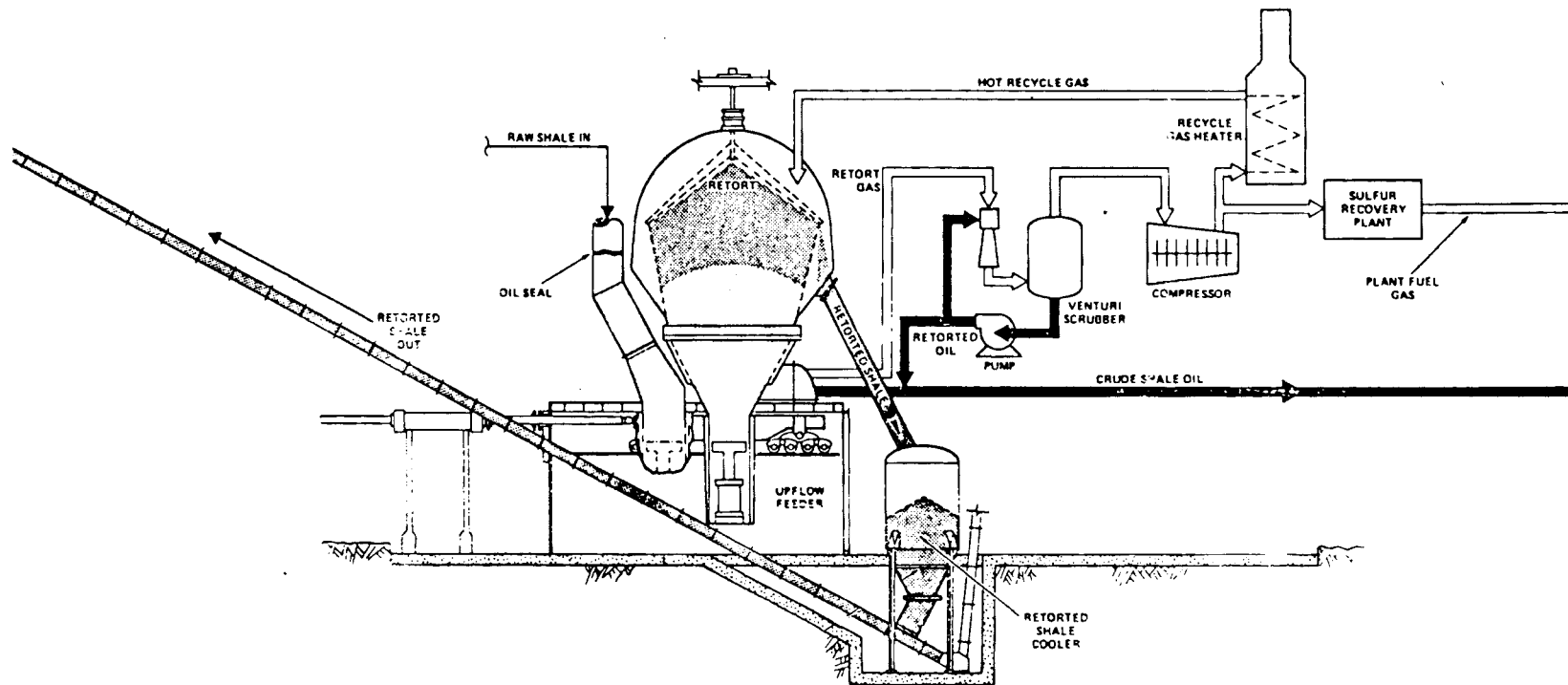


FIGURE 3.3. Process C, Upflow Retort(17)

TABLE 3.7. Net Emissions from Process C (pounds per ton of shale)⁽¹⁾

<u>Component</u>	<u>Particulates</u>	<u>SO₂</u>	<u>NO_x</u>	<u>HC</u>	<u>CO</u>
Retorting Operations					
Retort	0.001200	0.000312			
Recycle Gas Heater		0.018082	0.019507	0.003003	0.095890
Steam Boilers (2)		0.028767	0.028493	0.000444	0.025699
Flare Stack		0.000384	0.000178	0.000006	0.000178
Retort Vent		0.000384	0.000178	0.000006	0.000178
Pre-Refining Operations					
Fractionator Reboiler		0.004055	0.004521	0.000088	0.004164
Process Equipment				0.048000	
Product Storage Tank				0.009120	
Vapor Disposal Unit	0.000002		0.000714	0.000001	0.000408

where the nahcolite and dawsonite minerals are more prevalent in the shale formation. Conventional room and pillar mining will be used, with operations on three independent levels. Primary crushing (26,175 TPD) will occur in the mine with the crushed product conveyed to a secondary crusher outside the mine. Mining, crushing, and storage have been discussed in Section 3.1.

The major components of Process D are a unique retort, a gas circulating system with oil separation equipment and heaters in which circulating gases are heated to retorting temperatures. The primary difference between this and other processes is that the retort allows an integrated process technology to retort the shale not only by hot gases, but also by reacting the residual carbon in the shale, in a separate zone in the retort, with air, steam and recycled hot gases from the retorted shale cooling zone.

Emissions

The emissions from the Process D retort and from the nahcolite and mineral co-product facilities are shown in Table 3.8. Solid wastes are displayed in Table 3.9. Projected ambient levels of air pollutants have been calculated and are shown with air quality standards in Table 3.10. These tables were developed by Energy Development Consultants⁽¹⁾ and represent expected conditions.

TABLE 3.8. Air Emissions During Project Operation of Process D⁽¹⁾

Source	(average pounds per hour)				
	SO ₂	NO _x	NMHC	CO	TSP
Steam Plant	308.20	42.00	1.00	17.00	5.00
Nahcolite Kiln	4.16	12.00	0.04	0.23	3.15
Alumina Kiln	15.22	8.54	0.15	0.83	15.00
Lime Kiln	10.43	2.33	0.10	0.60	5.00
Inert Gas Genertor	0.37	0.008	0.003	0.017	0.005
Oil Storage Tanks	---	---	15.00	---	---
Diesel Exhaust (shale storage area)	1.50	17.80	1.40	4.30	1.30
Gasoline Exhaust	0.015	0.273	0.371	11.30	0.017
Product Transportation	0.70	1.33	0.71	6.73	0.32
Employee Transportation	0.05	0.47	0.45	4.20	0.11
Mine Vent					
Diesel Exhaust	6.30	87.20	1.34	1.90	6.00
Primary Crusher	---	---	---	---	2.20
Secondary Crusher	---	---	---	---	6.60
Storage Dome	---	---	---	---	2.10
Tertiary Crusher	---	---	---	---	1.47
Nahcolite Screening	---	---	---	---	2.33
Photosorters	---	---	---	---	2.33
Oil Recovery Surge Bin	---	---	---	---	4.30
Alumina/Soda Ash Crusher	---	---	---	---	5.90
Conveyor Belt, Misc. Handling, and Product Load Out	---	---	---	---	0.80
Fugitive Dust	---	---	---	---	11.17
Total	346.95	171.95	20.56	47.11	75.10

NOTE: SO₂ = Sulfur dioxide
 NMHC = Non-methane hydrocarbons
 TSP = Total suspended particulates

NO_x = Oxides of nitrogen
 CO = Carbon monoxide

TABLE 3.9. Volume of Solid Waste Generated by the Process D Project and Disposal Area Requirements⁽¹⁾

<u>Year</u>	<u>Volume (yd³)</u>	<u>Area (acres)</u>
1980	---	---
1981	---	---
1982	477	0.10
1983	748	0.15
1984	3,583	0.74
1985	1,238	0.26
1986	200	0.04
1987-2006	26,000	5.37
2007-2008	<u>280,640</u>	<u>57.98</u>
Total	312,886	64.64

Input

Inputs to Process D include water, labor, electrical power and diesel fuel.

3.2.5 Process E

Process E is similar to the Lurgi/Ruhrgas process. There is little information on mining or crushing; however, both should be similar to mining and crushing for Process A.

Process E is an integrated process using indirect heating. The heated recycled gas technology converts the hydrocarbon to oil without diluting the product gas with products of combustion.

The system uses a vessel that allows intimate contact between the raw fine-sized shale and a retorted shale medium that is heated above retorting temperatures of 900°F. The exchange of heat converts kerogen in the shale to oil and gas. The products are separated, and the retorted shale is combusted with air to burn the residual carbon, thereby supplying the heat for the process. Circulated gas is less than in most processes, and the gas has a medium Btu content. Process E is diagrammed in Figure 3.4.

TABLE 3.10. Air Quality Standards and Projected Ambient Levels of Pollutants at the Site for Process D⁽¹⁾ ($\mu\text{g}/\text{m}^3$)

Pollutant	Standards			Existing Levels at the Site
	Federal (primary)	Federal (secondary)	State	
Sulfur Oxides				
Annual	80	---	---	10
24-Hour	365	---	---	133
3-Hour	---	1,300	700	218
Nitrogen Oxides				
Annual	100	100	100	10
Non-Methane Hydrocarbons				
3-Hour (6 to 9 a.m.)	160	160	---	220
Oxidant (ozone)				
1-Hour	235	235	235	180
Carbon Monoxide				
8-Hour	10,000	10,000	10,000	4,400
1-Hour	40,000	40,000	10,000	5,300
Total Suspended Particulates				
Annual	75	60	75	11
24-Hour	260	150	260	11

NOTES: The existing level of non-methane hydrocarbons presently exceeds Federal guidelines.
The gaseous pollutant levels were projected from data taken at Oil Shale Tract, California (Gulf Oil-Standard Oil 1976).
Total Suspended Particulates levels were taken from Oil Shale Tract Cb (Ashland Oil-Occidental Oil 1977). The annual level is based on geometric means and the 24-hr level is arithmetic.

Emissions

Because of desulfurization reactions, gas leaving the separating bin contains only 20 ppm SO_2 .⁽¹²⁾ A small amount of NO_x is also produced. Other emissions have not been quantified and published in the literature.

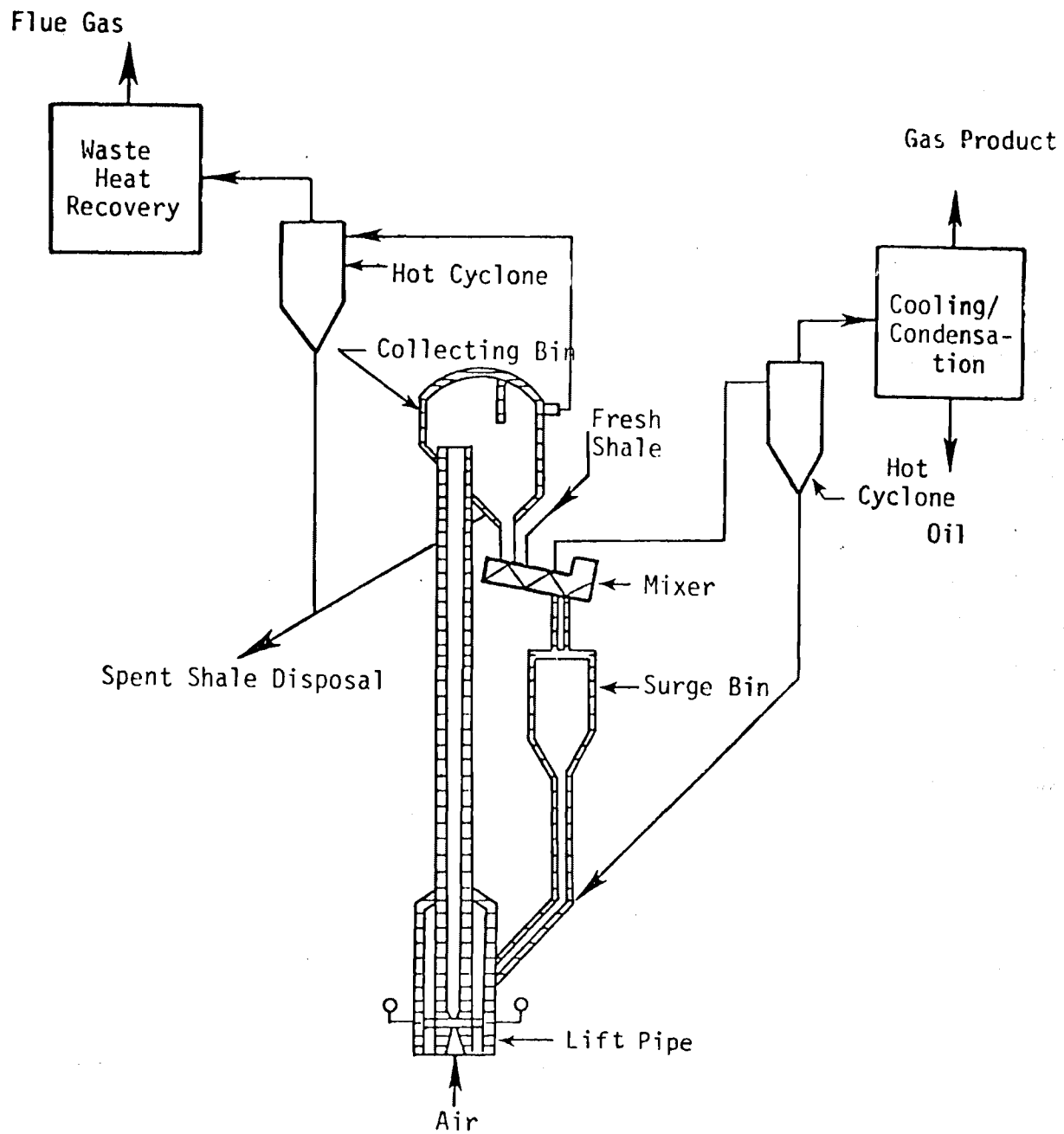


FIGURE 3.4. Process E Diagram(11)

Inputs

Data for water consumption, power, and labor are incomplete. Estimates for operating a 50,000 BPD plant are 4,900 tons of water per hour, 11,000 kW power, and 30 people working in the retort section during each shift.

3.3 PROCESS F: MODIFIED IN-SITU RETORTING

Process F is similar to Occidental's Modified In-Situ retorting process, as designed for the C-b tract. An ancillary phase of this development is providing information and experience leading up to a full-scale commercial development. The commercial facility discussed below is extrapolated from the ancillary facility. The actual commercial-scale design eventually used by Occidental is expected to deviate significantly from the design presented here.

Underground mining will be used to extract 41,000 TPD of raw shale to create a void large enough for the underground retorts. Mining is described in Section 3.1. Successive areas, called panels, will be mined. Each will contain 32 clusters of retorts; each cluster will contain eight individual retorts. The processing strategy for the clusters has not yet been determined; however, 50,000 BPD of shale oil will be produced. Figure 3.5 illustrates the configuration of the ancillary phase retort.

Surface facilities will include a gas treatment unit for the removal of sulfur compounds, gas blowers, possibly a thermal oxidizer, and steam generation facilities. Designs for these facilities are being considered. The mined-out shale will be stored for future surface retorting.

Emissions

Table 3.11 provides estimates of emissions from a commercial-scale MIS development. Available estimates for these emissions vary greatly. Accurate data will be generated only when development of the process is underway.

These estimates assume particulates from the mine are controlled by wet suppression and baffled settling. The retort off-gas is treated with a Stretford or combination oxidizer FGD process to remove sulfur compounds. Particulates generated during shale transportation and disposal will be controlled

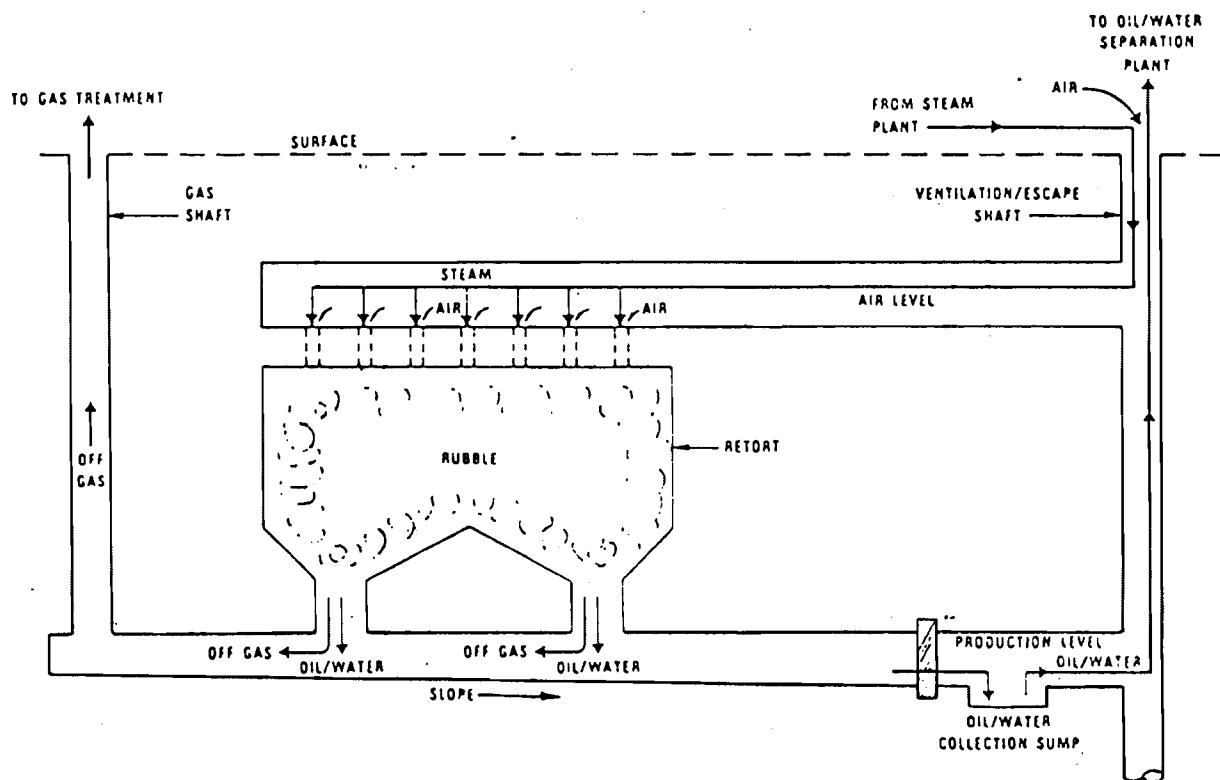


FIGURE 3.5. Process F: Modified In-Situ Retorting of Oil Shale, Diagram⁽¹³⁾

TABLE 3.11. Estimated Air Emissions from Commercial Scale (50,000 bpd) MIS Development^(1,14)

Pollutant	Source Strength (pounds/ton)
CO	2.247
Particulate Matter	0.2650
Hydrocarbons	0.0844
SO ₂	0.1978
NO _x	1.597

by venture scrubbing or baghouse. Wet suppression and chemical stabilizers will limit particulates from disposed shale.

Inputs

Mine de-watering should provide for all make-up water requirements if process water needs are not met by other sources. It is anticipated that no make-up water will be required during the early phases of tract production from surface sources.

Ground Water

Process F will be used, according to the scenario, in retorts located in the Mahogany zone of the Green River formation. The Mahogany zone separates two major aquifers; the upper aquifer consists of sandstone and fractured marlstone, the lower one of fractured and leached marlstone. The aquifer system is recharged primarily by snow melt. The Mahogany zone is impermeable and acts as an aquaclude. The potential impact of MIS retorting on the quality of ground water is an important issue affecting the viability of this technology. Chapter 7 provides a generic discussion of the impacts of oil shale retorting on ground water.

Energy Development Consultants, Inc. has discussed the structure of the aquifers at the proposed MIS site in greater detail as part of the backup documentation to this assessment of oil shale technology (Volume 2).⁽¹⁾ Additional discussion is available in Volume 5, which is focused on ground water.⁽¹⁵⁾

3.4 PROCESS G: TRUE IN-SITU RETORTING

Process G is similar to a true in-situ (TIS) process developed by Equity Oil Company and Atlantic Richfield Company. In the process, superheated steam is forced through wells into the "Leached Zone," an oil shale deposit which has been made porous through the leaching of salts by ground water. It is estimated that about 550 billion barrels of shale oil exist in such deposits in the Piceance Creek Basin.⁽¹⁶⁾

In applying Process G, the first step is to dewater the formation in order to improve its permeability and to facilitate heating. Then wells must be

drilled for steam injection and gas and oil production. When the steam is injected, it pyrolyzes the kerogen in the formation, and the pyrolysis gases and shale oil are drawn out through the production wells. The process is still in an early stage of development, with testing being conducted by Equity in a leached oil shale seam 500 ft thick underlying a surface area of 0.7 acres. If successful, a two-year test will produce some 300,000 barrels of shale oil.⁽¹⁶⁾

Information on emissions and inputs for Process G is preliminary since the process has not been tested extensively. The process is included in the scenario for this assessment (Section 3.5, below, and Volume 2)⁽¹⁾ at a very low level of production (2000 bpd). Since it is included at such a low level, errors in the estimate of emissions for purposes of this assessment will not cause major errors in the overall environmental analysis.

Other TIS methods have been tested. Most have not been successful. One which does show some promise, however, is being tested and developed by Geokinetics, Inc. The Geokinetics process is being applied to relatively shallow, thin deposits (e.g., 100 ft of overburden and 30 ft of shale). The shale seam is fractured explosively, resulting in surface uplift. The fractured seam is then ignited to burn horizontally, driving gases and oil ahead of the flame front to be collected at production wells. DOE and Geokinetics hope to develop a commercial-scale operation by 1982.⁽¹⁶⁾

3.5 PRODUCTION SCENARIOS AND SITE LOCATIONS

Projections of oil production in barrels per day have been made for three different scenarios: high, medium, and low. These scenarios are described in the following paragraphs. Figure 3.6 shows the location of possible oil shale sites.

The low scenario (Table 3.12) is a representation of what might have happened if Federal government incentives for synthetic fuels during 1979-1990 had remained as they were in 1979. No significant breakthroughs in in-situ technologies would be expected during the same period. Estimated production by 1990 in the scenario is 41,050 barrels per day. Development of oil shale in

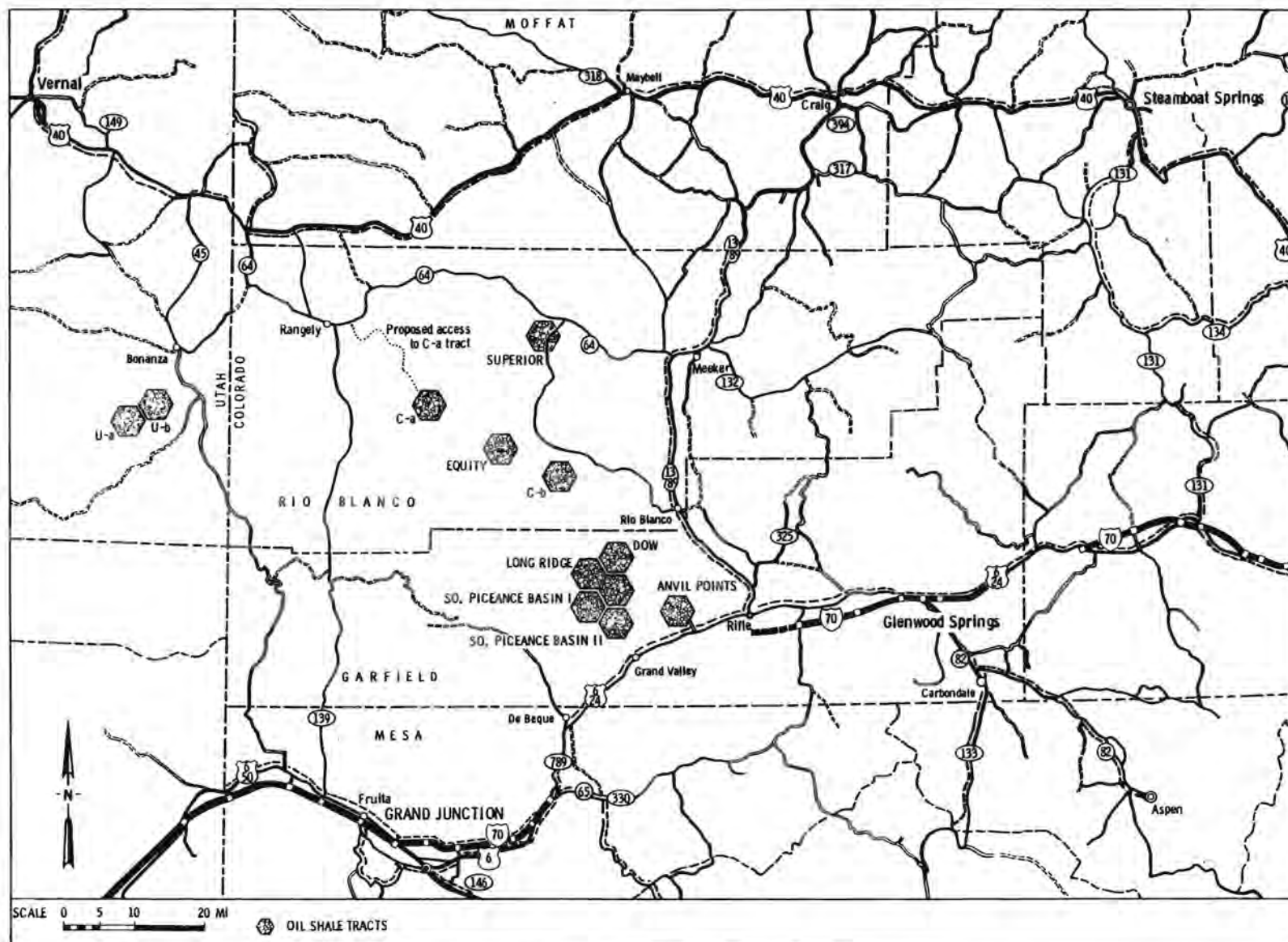


FIGURE 3.6. Location of Proposed Oil Shale Projects

TABLE 3.12. Low Scenario of Shale Oil Production (barrels per day, by year)

Key	Tract	Process	1979	1980-1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1	Long Ridge	C				8,000	8,000	8,000	8,000	12,000	17,600	17,600	17,600
2	Anvil Points	B					8,000	8,000	8,000	8,000	9,700	9,700	9,700
3	DOW	A							9,000	12,000	13,750	13,750	13,750
Total Surface Induced						8,000	16,000	16,000	25,000	32,000	41,050	41,050	41,050
Total in Situ Induced (none)													

this scenario assumes that continued inflation will increase the cost of imported oil at a faster rate than it will increase the cost of producing domestic oil from shale. This scenario would be expected to make shale oil production profitable, but it entails considerable risk for companies venturing into the industry.

The medium scenario (Table 3.13) assumes a phased rather than a crash development of oil shale. Production would total 188,950 barrels per day by 1990. This scenario assumes the establishment of financial incentives of about \$3 per barrel, for example by a tax credit, by 1980. Some grant money would spur commercial production from several different oil shale technologies. Further development of in-situ and modified in-situ technologies is also assumed.

The high scenario (Table 3.14) depicts rapid development of oil shale resources, with production reaching close to 300,000 barrels per day by 1990. In this scenario, it is assumed that MIS retorting technologies are improved so that they are a major component of the industry. It is also assumed that the government expedites licensing of facilities.

This scenario is the one considered specifically in this assessment. It assumes a broad array of Federal incentives, meeting a variety of needs experienced by possible participants in the oil shale business with their particular financial circumstances. Such incentives might include a tax credit per barrel equal to or greater than \$3, purchase guarantees, accelerated depreciation schedules, loan agreements, or joint private-Federal ownership and/or operation of facilities. The Synthetic Fuels Corporation Act provides for loans and loan guarantees up to 75% of the initial estimated cost of synthetic fuels projects. The Corporation is authorized to make price guarantees and purchase agreements for synthetic fuels. It may also enter into joint ventures for synthetic fuel project modules for commercially feasible technologies.

3.6 TRANSPORTATION

In describing the technology scenario for purposes of evaluating impacts from development of a shale oil industry, it is necessary to include some statements about transportation of raw materials, shale oil product, and people.

TABLE 3.13. Medium Scenario of Shale Oil Production (barrels per day, by year)

Key	Tract	Process	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1	Long Ridge	C				8,000	8,000	8,000	8,000	17,600	17,600	17,600	19,400	30,000
		A												
2	Anvil Points	B					8,000	8,000	8,000	8,000	9,700	9,700	10,700	10,700
		E												
3	Superior	D									12,000	12,000	13,200	20,000
		E												
4	DOW	A								12,000	27,500	41,250	41,250	50,000
Total Surface Induced						8,000	16,000	16,000	37,600	37,600	66,800	80,550	84,550	110,700
5	Tract C-a	F										37,500	47,250	47,250
6	Tract C-b	F								10,000	10,000	10,000	20,000	30,000
7	Equity	G									1,000	1,000	1,000	1,000
Total in Situ Induced										10,000	11,000	48,500	68,250	78,250
All Production						8,000	16,000	16,000	16,000	47,600	77,800	129,050	152,800	188,950

TABLE 3.14. High Scenario of Shale Oil Production⁽¹⁾ (barrels per day, by year)

Key	Tract (county)	Process	1979	1980	1982	1983	1974	1985	1986	1987	1988	1989	1990
1	Long Ridge	C			8,000	8,800	8,800	17,600	19,400	19,400	30,000	30,000	30,000
		A				880	1,760	1,760	1,940	1,940	3,000	3,000	3,000
2	Anvil Points	B				8,000	8,000	8,800	8,800	9,700	9,700	10,700	10,000
		E					800	880	880	970	970	1,070	1,070
3	Superior	D						12,000	12,000	13,200	13,200	20,000	20,000
		E							1,200	1,320	1,320	2,000	2,000
4	Sand Wash (Utah)	A								10,000	10,000	11,000	11,000
5	DOW	A						27,500	41,250	50,000	55,000	55,000	55,000
6	Tract U-a, U-b	B								10,000	10,000	11,000	11,000
		E									1,000	1,100	1,000
7	So. Piceance Bsn.	Unknown I									10,000	10,000	10,000
8	So. Piceance Bsn.	Unknown II										10,000	10,000
Total Surface Induced					8,000	17,680	19,360	68,650	85,470	116,530	144,190	164,870	164,870
9	Tract C-a	F								37,500	47,250	57,000	57,000
		A or E								12,500	15,750	19,000	19,000
10	Tract C-b	F				10,000	20,000	30,000	50,000	50,000	50,000	50,000	50,000
11	Equity	G						1,000	1,000	1,000	2,000	2,000	2,000
12	SE Utah	Unknown III									2,000	2,000	2,000
Total in Situ Induced						10,000	30,000	31,000	51,000	101,000	117,000	130,000	130,000
All Production					8,000	27,680	39,360	99,540	136,470	217,530	261,190	294,870	294,870

This assessment uses predictions of traffic volume prepared for the Colorado West Area Council of Governments.⁽¹⁷⁾ The Colorado West study examined the impacts of energy development on Garfield, Mesa, Moffat, and Rio Blanco counties. The study made several assumptions.

- 350,000 BPD of shale oil will be produced in the region.
- Coal production will also increase 40%, leading to 10,500 people employed in energy production. About 80% of the increase is due to oil shale facilities.
- Most workers will commute by bus. Other personal transportation will depend on private automobiles.
- Shale oil will move by pipeline after the industry is established, but by truck during the earlier stages.

The total vehicle miles per day traveled on the tract access roads given in Table 3.15 are derived assuming that 80% of the transit needs are met by bus service, and 20% by private automobiles. The buses are of an assumed capacity of 60 employees each, and the automobiles are assumed to carry three people per vehicle.

Traffic volumes for the projected 350,000 bpd oil shale production scenario are shown in Figure 3.7 for the major highways in the regional transportation system. These traffic volumes include rates for both automobile and truck travel. The component of traffic volume due to loaded truck travel under the 350,000 bpd scenario is quite small compared to other modes of vehicular travel. The loaded energy truck per day traffic volume is displayed separately in Figure 3.8. The reduction in truck traffic between 1985 and 1990 occurs because shale oil is transported by pipeline instead of trucks as the pipelines are put into service.

TABLE 3.15. Vehicle Miles per Day Traveled on Tract Access Roads

Oil Shale Development Tract	Maximum Production (1990)(18)	Projected Employment (1990) (mature operation)(18)	Projected Vehicle-miles/day Highway-to-Tract Access Road(1)	Distance Highway-to-Tract Access Road
DOW	50,000 bpd	2,052 ⁽³⁾	4,800 v-m/day	16.0 mi.
Anvil Points ^(a)	10,700 bpd	550	484 v-m/day	5.5 mi. ^(b)
Long Ridge	30,000 bpd	700	1,328 v-m/day	12.0 mi.
Superior	24,000 bpd	1,300	516 v-m/day	2.5 mi.
C-b	30,000	1,200	384 v-m/day	2.0 mi.
C-a	47,250	1,500	4,320 v-m/day	18.0 mi.

(a) Note projected community of 100 homes on access road.

(b) Assuming 80% bus and 20% auto traffic.

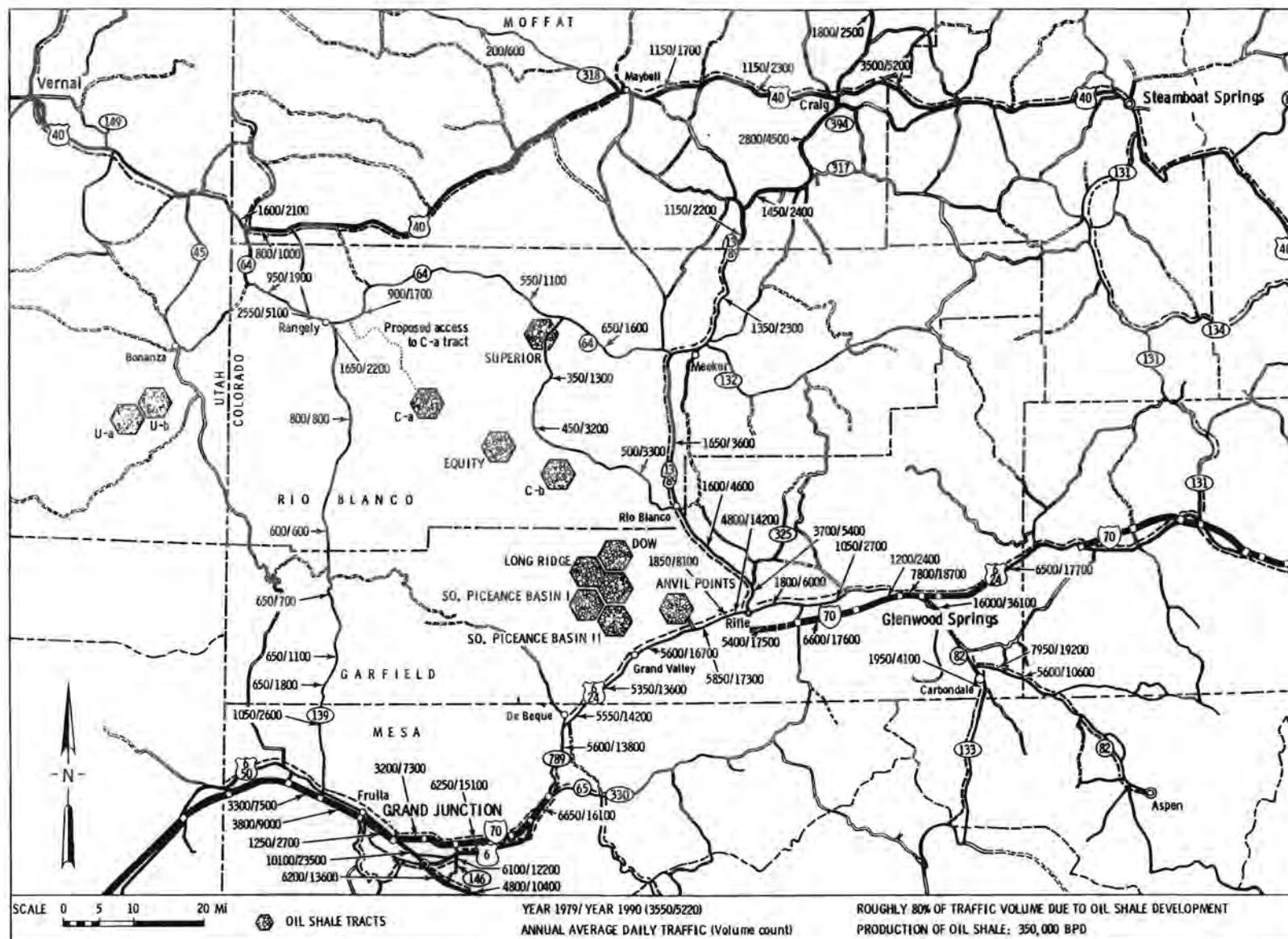


FIGURE 3.7. Energy Related Vehicles per Day, 1979 and 1990(1,17)

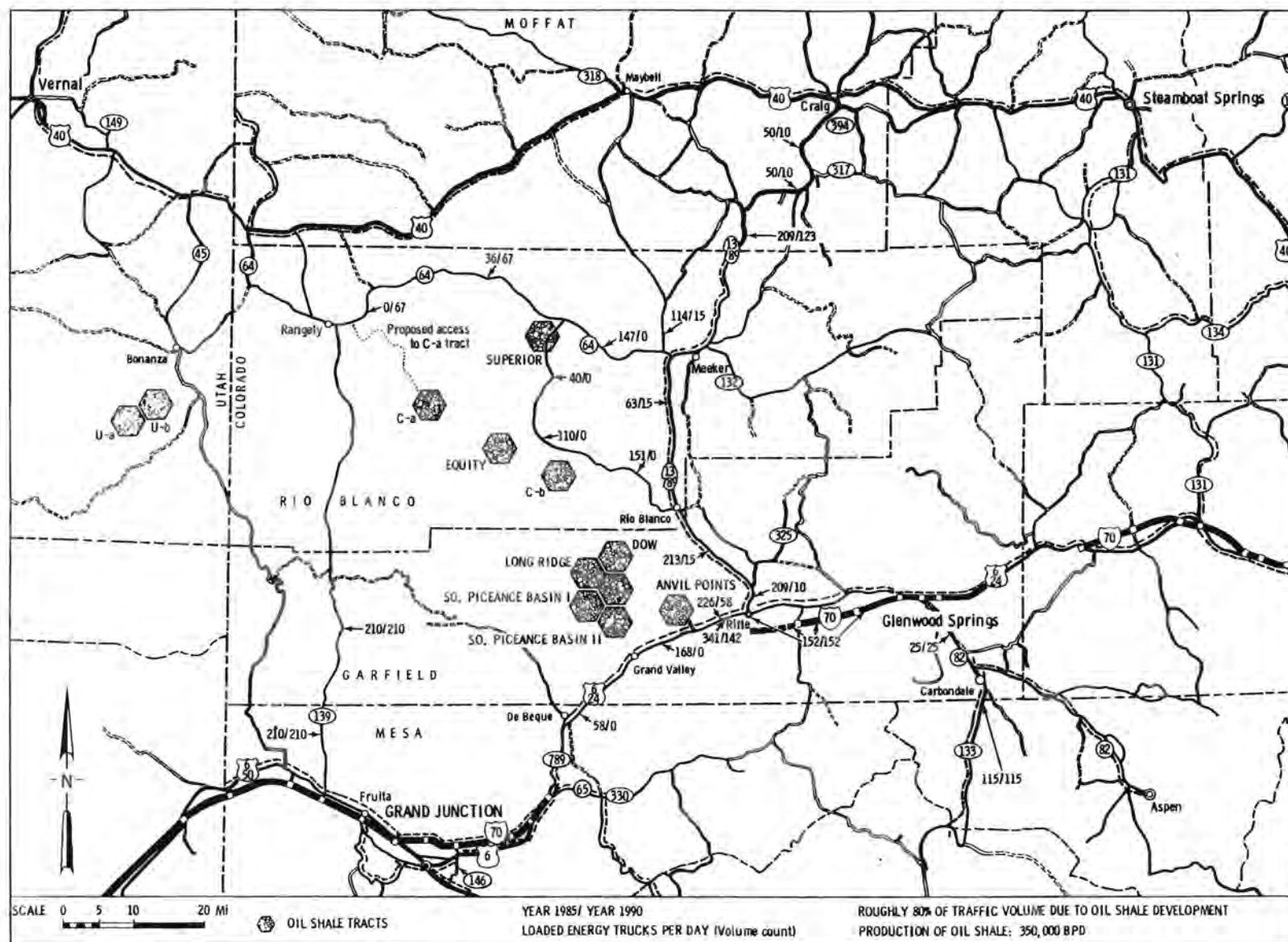


FIGURE 3.8. Loaded Energy Trucks per Day, 1985 and 1990(1,17)

3.7 REFERENCES FOR CHAPTER 3

1. Energy Development Consultants, Inc. 1981. Technology Characterization and Production Scenarios. Volume 2 in this assessment report.
2. Colony Development Corporation. 1974. An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado.
3. White River Shale Project. 1976. Detailed Development Plan.
4. Bureau of Land Management, U.S. Department of the Interior. 1975. Final Environmental Impact Statement of Proposed Development of Oil Shale Resources (Colony Development Corporation). Denver, Colorado.
5. Development Engineering, Inc. 1978. Air Emission Source Construction and Operating Permit Application. Application to U.S. Environmental Protection Agency and Colorado Department of Health.
6. Marshall, P., and J. Agapito. 1974. Plant and Mine Studies, Parachute Creek, Colorado. Colony Development Corporation (in Final Environmental Impact Statement, Appendix 14).
7. Charken, R. F., E. B. Cook, and T. C. Ruhe. 1974. Toxic Fumes from Explosives Ammonium Nitrate-Fuel Oil Mixture. Bureau of Mines RI 7867.
8. Union Oil Company of California. 1978. Emission Permit Application to the Colorado Department of Health.
9. U.S. Department of the Interior, Bureau of Land Management. 1979. Draft Environmental Statement: Proposed Superior Oil Company Land Exchange and Oil Shale Resource Development. Denver, Colorado.
10. Colorado Air Pollution Control Division. 1978. Emission Factors for Mining Operation. Denver, Colorado.
11. Colorado Air Quality Control Commission. 1980. Public Hearings to Consider Proposed Revisions to the Regulations of the Colorado Air Quality Control Commission. Meeker, Colorado, September 12, 1980.
12. Marnell, Paul, American Lurgi Corp. 1976. "Lurgi/Ruhrgas Shale Oil Process." Hydrocarbon Processing, September 1976: 269-271.
13. Courtesy of Ralph M. Parsons Company
14. Drake, R. L. 1981. Air Quality Impacts. Available as Volume 3 in this assessment report.

15. Mehran, M., T. N. Narasimhan, and J. P. Fox. 1981. An Investigation of Dewatering for the Modified In-Situ Retorting Process, Piceance Creek Basin, Colorado. Available as Volume 5 in this assessment report.
16. U.S. Department of Energy. 1979. Oil Shale RD&D--Program Management Plan (draft). U.S. Department of Energy, Washington, D.C.
17. TDA, Inc. 1979. Colorado West Transportation Plan. Draft, prepared for the Colorado West Area Council of Governments. Rifle, Colorado.
18. Department of Natural Resources, State of Colorado. 1979. Colorado Oil Shale: The Current Status. Colorado Geological Survey, Denver, Colorado.
19. Courtesy of Union Oil Company of California.

4.0 AVAILABILITY OF NATURAL AND ECONOMIC RESOURCES

The potential for shale oil to become a significant component of the U.S. energy supply is dependent not only on the development of adequate production technology, but also upon the availability of raw materials and other critical resources. In this chapter attention is focused on the availability of oil shale and water supplies. The availability of labor, transportation facilities, equipment and materials, and training is touched upon but not considered in depth since the principal emphasis of this assessment is not on economic feasibility.

4.1 OIL SHALE

Oil shale is a resource of great potential significance to the United States. The deposits are classified according to yield and location. Two trillion barrels of shale oil are estimated to exist in deposits of oil shale in the United States. The estimate for the highest shale oil yield, above 30 gallons per ton, is placed at about 400 billion barrels. The lower yield deposits are far greater but will be more difficult to recover. The Geological Survey considered in 1973 about 400 billion barrels to border on being economically producible. Others believe that over 600 billion barrels may be recoverable. The portion of this that could be recovered using current technologies is highly dependent upon the cost of competitive energy sources; it is larger than U.S. reserves of oil and natural gas.⁽¹⁾ One U.S. Department of Energy report notes that even assuming a 10% recovery rate, the energy potential of the Green River Formation is six times greater than present estimates of domestic petroleum reserve.⁽²⁾

Oil shale deposits exist in several locations in the United States. While the deposits in the central and eastern United States cover a very large area, they are different in kind and have a far lower potential yield according to the Fischer assay, than western deposits. The U.S. Department of Energy is currently sponsoring research and development to extract natural gas trapped within these shale formations,⁽³⁾ and experimental work by the Institute of Gas Technology to produce shale oil with their "Hytort" process has been

encouraging.^(4,5) The western deposits, however are considered to be of far greater national importance and are the major subject of this technology assessment. Table 4.1 shows the potential shale oil in place in the Green River Formation.

The shale of the Green River Formation of Colorado, Wyoming, and Utah contains an estimated equivalent of 1.8 trillion barrels of oil. About 85% of the U.S. oil shale reserves are found in this formation. (A reserve is a deposit from which the resource can be taken and processed at a profit.) Similarly, about 85% of the rich, recoverable shale oil is located in northwestern Colorado (see Table 4.1).

Figure 4.1 shows the location of the western oil shale deposits. These deposits underlie some 11 million acres. Because they have been extensively explored, the geological structure of the deposits is fairly well known.⁽³⁾

Many of the Green River deposits have little commercial value since they are low grade. About 400 billion barrels of shale oil, however, are found in deposits that are at least 100 ft thick, with yields of at least 30 gallons per ton. Another 1.4 trillion barrels are contained in deposits at least 15 ft thick and yielding at least 15 gallons per ton.⁽³⁾ This totals 1.8 trillion barrels. By comparison, the U.S. domestic petroleum reserves were estimated in January 1978 at about 30 billion barrels, or about one-twentieth that of oil shale. Four hundred billion barrels, recovered with an efficiency of about 50%, are equivalent to about 40 years of total U.S. petroleum demand, at the current rate of 17 million barrels per day.

TABLE 4.1. Potential Shale Oil in Place in the Green River Formation: Colorado, Utah, and Wyoming⁽⁶⁾

Nature of the Deposit	(billions of barrels)			
	Colorado	Utah	Wyoming	Total
At least 100 ft thick with oil yields averaging at least 30 gal/ton	355	50	13	418
At least 15 ft thick with oil yields averaging at least 15 gal/ton, excluding the deposits shown above	<u>840</u>	<u>270</u>	<u>290</u>	<u>1,400</u>
Totals (rounded)	1,200	320	300	1,820

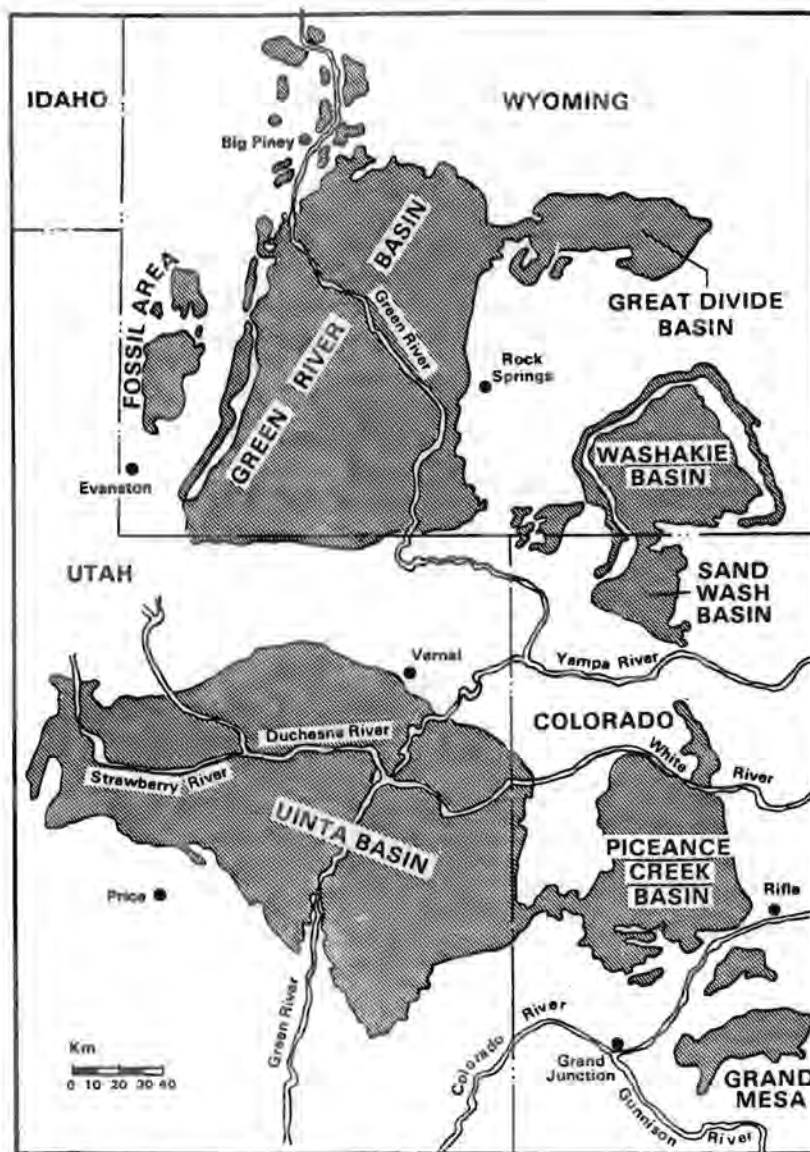


FIGURE 4.1. Oil Shale Deposits of the Green River Formation(3,7)

These numbers are clearly significant, and were it not for some serious constraints, shale oil could emerge as the cure-all to our energy problems. The constraints do exist, however, and they include physical limitations on the rate of production (probably not much more than one million barrels per day without major environmental and socioeconomic intrusions); long lead times (probably 10 years even for a modest industry); uncertain capital and operating costs (probably "high"); and environmental impacts (which are still insufficiently understood).

The Carter administration set goals for synfuels production; for shale oil, they were 400,000 barrels per day (bpd) for 1990.⁽⁸⁾ Forecasts abound. A recent study prepared for the Environmental Protection Agency (EPA) by TRW, Inc., projected 200,000 bpd by 1990 and 500,000 bpd by 2000.⁽⁹⁾ Another recent estimate prepared for EPA by Hagler, Bailly, and Company, calls for 40,000 bpd to 50,000 bpd by 1985, 100,000 bpd to 275,000 bpd by 1990, 425,000 bpd to 600,000 bpd by 1995, and 700,000 bpd to 1,400,000 bpd by 2000.⁽⁹⁾ The Office of Technology Assessment tends to favor 400,000 bpd by 1990.⁽³⁾ Exxon, by contrast, discussed synfuels production levels of 15 million bpd by the Year 2000, 8 million bpd of which would come from oil shale.⁽¹¹⁾ A poll of industry representatives conducted by the U.S. Department of Energy (DOE) in 1979 resulted in estimates of 0 to 230,000 bpd by 1985, 150,000 to 450,000 bpd by 1990, and 500,000 to 1,000,000 bpd by 2000, assuming removal of several legal and economic hurdles in 1980. The authors of that study estimate 300,000 bpd by 1990.⁽¹²⁾

Environmental quality standards, especially air quality standards, may constrain the development of a shale oil industry to less than 1,000,000 bpd, especially in light of anticipated development of coal-derived synthetic fuels in the same general geographic area. Safe operation of an oil shale industry within Prevention of Significant Deterioration (PSD) limits for the Class I air quality designated area, Flat-Tops Wilderness Area, has been predicted only as high as 800,000 bpd⁽¹³⁾ or 900,000 bpd.⁽¹⁴⁾ One official from the U.S. Environmental Protection Agency (EPA), who has been closely involved with oil shale development, has stated that he believes 400,000 bpd is close to the limit.⁽¹⁵⁾ Relaxation of the air quality constraints is being sought actively by some major oil shale companies (e.g., Exxon)⁽¹⁶⁾ and may be obtained in light of recent changes in the membership of the U.S. Congress.⁽¹⁷⁾

Acquiring environmental permits is likely to cause delays in the rate of development of an oil shale industry. While efforts are being made to simplify EPA permitting procedures, any shale oil production facility will require numerous Federal, state, and local approvals. L. W. Harrington reviewed the "Regulatory Obstacles to the Oil Shale Industry"⁽¹⁸⁾ which is based on two studies conducted by Systems Applications, Incorporated (SAI).^(19,20) As noted

by Harrington, SAI⁽²⁰⁾ concluded that permitting problems could delay by almost 10 years the start-up of a commercial shale oil facility on Federal land, resulting in a lead time of between 14 and 24 years. On privately owned land, the delays were estimated to be 7 years, resulting in a lead time of 8 to 15 years. SAI noted that even if the probability of obtaining each individual permit without delay were as high as 95%, the chances of obtaining all of them without serious delay would be only about 10%.

About 85% of all oil shale reserves are located on Federal land. This has proved to be a substantial barrier to development. First, the title to much of this land is uncertain, based on unpatented mining claims. Prior to 1920, oil shale was a "locatable" mineral under the Mining Act of 1872. In 1920, with the passage of the Mineral Leasing Act, it became a "leasable" mineral, subject to a savings clause which preserved the rights of claims filed prior to 1920. In 1964 the Federal government challenged these claims, leading to litigation in Shell Oil versus Andrus (which proved that oil shale is a valuable mineral under the law) and Tosco versus Andrus, which is still unsettled.⁽²¹⁾ In 1973 roughly 85% of the Federal land titles were questionable, including 95% of Colorado's high-yield Piceance Basin.⁽¹⁾

In addition, the 1920 Mineral Leasing Act allows developers to acquire only 5,120 acres of Federal land. While the U.S. House of Representatives and the Energy Committee of the Senate approved in September and November, 1980, respectively, a bill to give the Interior Department authority to lease additional land for off-site disposal of wastes and for other surface uses, the bill failed to become law. New bills concerning this constraint are being prepared in the new Congress.^(22,23) Unless a bill is enacted quickly, however, the measure may become entangled in a comprehensive oil shale leasing bill proposed by the Administration.⁽²³⁾ Therefore, the 5120-acre limit still applies. This is enough for only one commercial-scale plant. Developers are reluctant to use their limited acreage until the technology is proven.

In the early 1970s the Department of Interior leased four 5,000-acre tracts on Federal land, two in Colorado and two in Utah. Although development is proceeding on the two Colorado tracts by Occidental-Tenneco and by Rio

Blanco (Gulf and Standard of Indiana), the two Utah leases are presently suspended because of suits over land ownership.

Privately held reserves, except for the Colony and Union tracts, are of a lesser grade than Federal lands.⁽¹³⁾ Those claims filed under the 1872 law were based on observations of the outcrop of oil shale formations, especially the Mahogany zone. These outcrops are at the edge of the Piceance Creek Basin. Figure 4.2 shows the location of the privately owned lands; Figure 4.3 superimposes information about the thickness of the shale. Due to the slope of the ancient lake bed on which the sediment forming the organic material in the shale collected, the shale is much thicker in the center of the Basin. Furthermore, the richness and homogeneity of the shale on the edges of the Basin are much poorer than in the center because of the effects of advancing and receding water at the edges of the lake over the ages when the shale was being deposited.⁽³⁾ As Table 4.2 shows, private lands are often held as a series of non-contiguous tracts. This makes development considerably more difficult. For example, Exxon's 10,500 acres of oil shale land are spread out over 30 tracts. Even though Federal law provides for the blocking up of lands by exchanges, the Department of Interior has discouraged the exchange of private for public lands, making it difficult for industry to acquire contiguous blocks of land.⁽²¹⁾

Many of the privately held blocks are too small to support commercial development. Twenty-eight private blocks are considered capable of supporting for 30 years a plant of 50,000 barrels or more per day, as shown in Table 4.3. Twenty-four of these blocks are in Colorado. Since in-situ or modified in-situ processing can be used with lower yield shale (only 15 gallons per ton), using this method of processing would result in the development of the largest number of blocks.⁽⁸⁾

Some improvements in private holdings are being achieved through agreements among firms to combine or exchange land parcels. For instance, the Cleveland-Cliffs Iron Company, Standard Oil of Ohio, and Superior Oil Company have agreed to pool their interests in two oil shale tracts north of Grand Junction, Colorado, totalling some 20,000 acres.⁽²⁴⁾ Also, some state lands are being made available by Wyoming⁽²⁵⁾ and Utah.⁽²⁶⁾

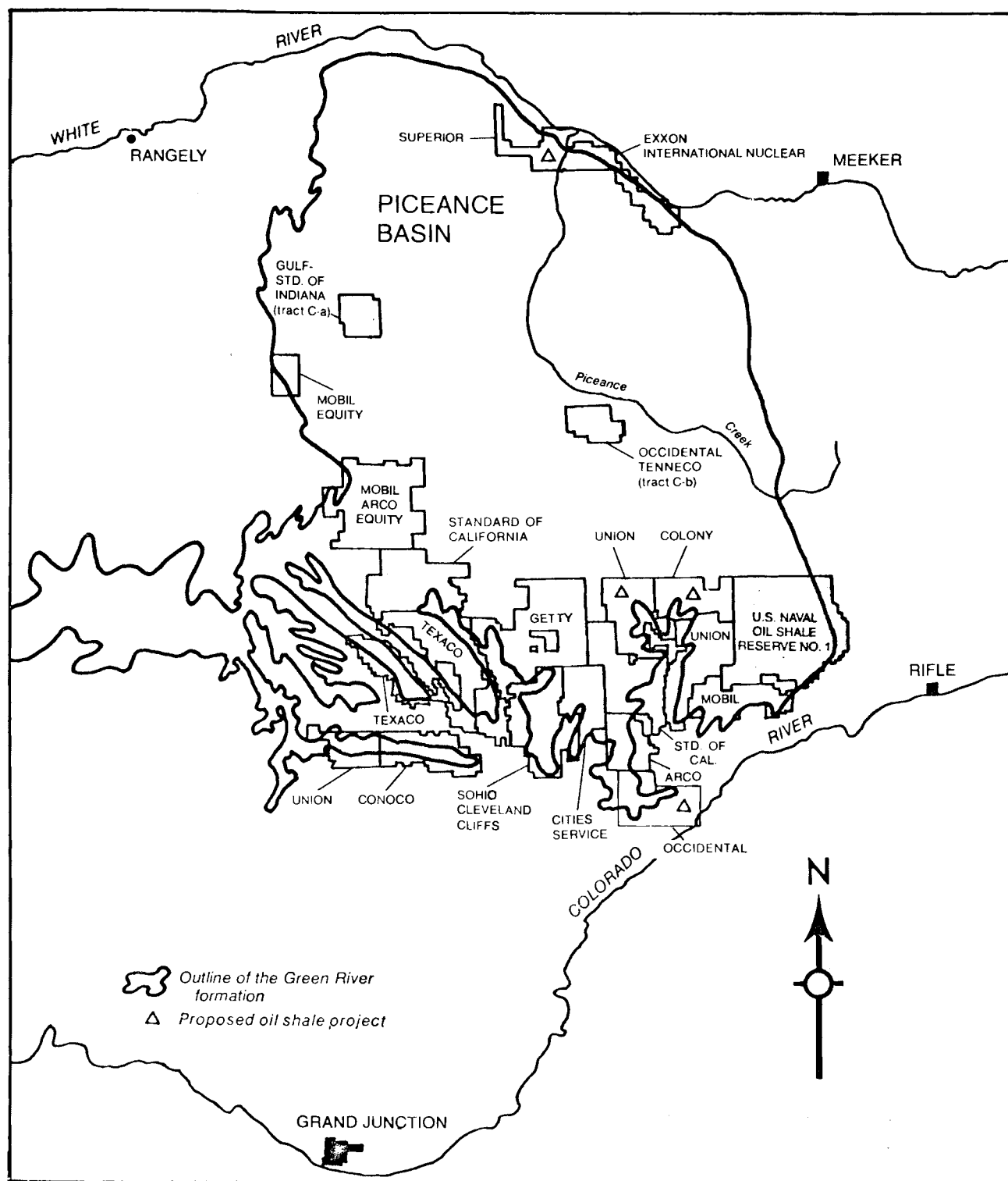


FIGURE 4.2. Privately Owned Tracts in the Piceance Basin(3,7)

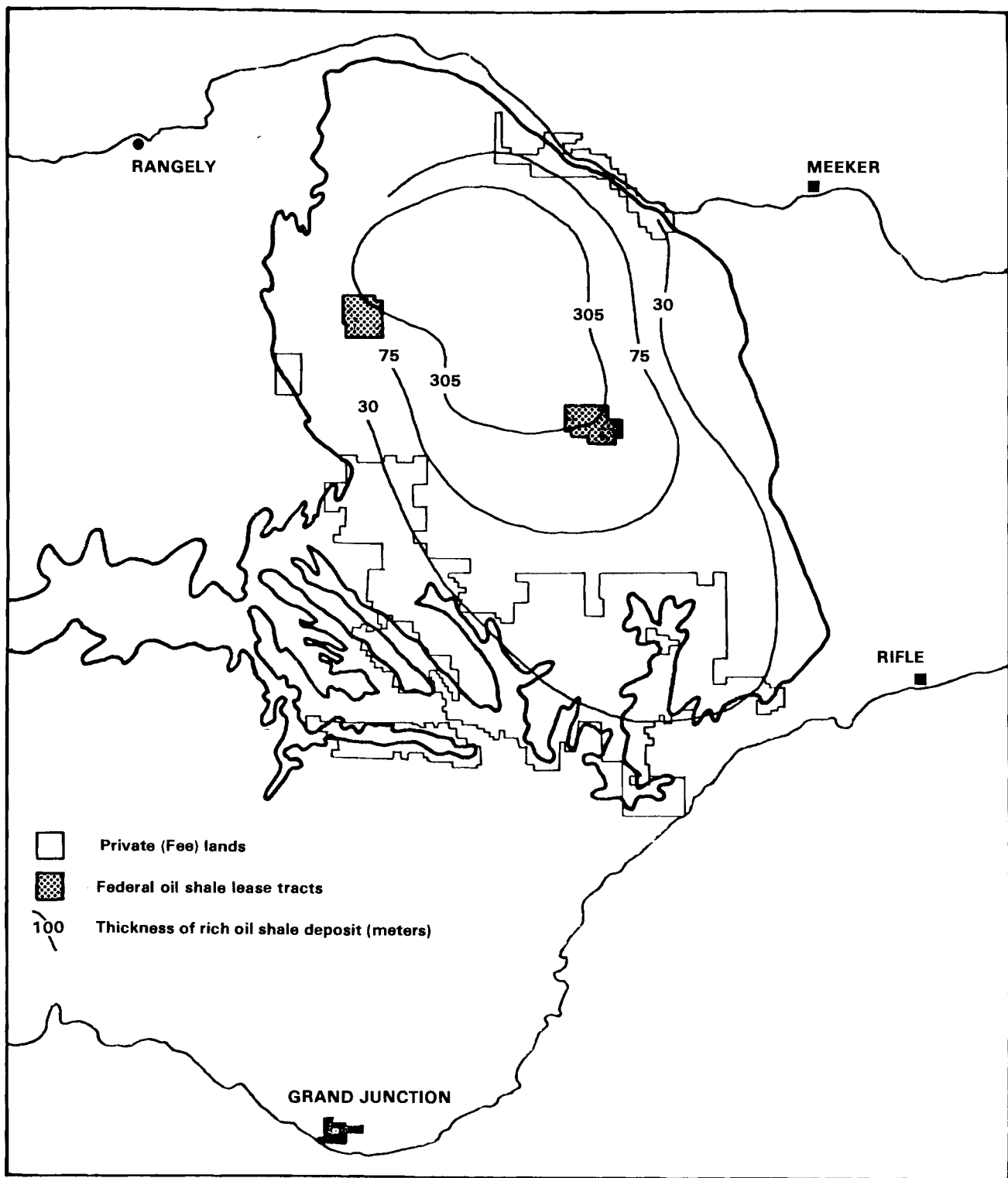


FIGURE 4.3. Thickness of the Oil Shale Deposits in the Piceance Basin(3)
That Yield at Least 25 gal/ton of Shale Oil

TABLE 4.2. Ownership of Western Oil Shale Lands⁽¹⁾

	Colorado		Utah	
	Acres	Tracts	Acres	Tracts
Federal Government (clear title)	320,000		780,000	
Federal Government (clouded title)	1,100,000		3,000,000	
Standard of California	40,950	4	0	0
Union Oil	29,630	3	0	0
Texaco	19,070	3	8,300	1
Getty	24,300	1	0	0
Atlantic Richfield	19,730	13	2,570	1
Mobil	19,280	2	0	0
Sohio	9,620	12	8,970	5
Other	217,000		1,100,000	

TABLE 4.3. Privately Held Blocks Capable of Supporting
50,000 Barrels Per Day Production for 30 Years

Method	Assumptions	Number of Contiguous Blocks
Underground Mining with Surface Retorting	Requires an in-place resource base of 30 GPT oil shale of at least 1.1 billion barrels (50% recovery)	10
Surface Mining with Surface Retorting	Requires an in-place resource base of 25 GPT oil shale of at least 650 million barrels, with a ratio of overburden to oil shale of 1 to 1 (85% recovery)	1
Modified In Situ and True In Situ	Requires an in-place resource base of 15 GPT oil shale of at least 1.8 billion barrels (30% recovery)	17

4.2 WATER AVAILABILITY

Questions about the availability of water to support an oil shale industry in the west have been the focus of many analyses and testimonies during the past ten years. Examples of the record on this point include the Final Impact Statement for the Prototype Oil Shale Leasing Program,⁽²⁷⁾ "Hearings before the House Subcommittee on Mines and Mining" concerning "Information on Oil shale Development,"⁽²⁸⁾ "Hearings before the Subcommittee on Energy Production and Supply" concerning "Oversight--Availability of Water Supplies,"⁽²⁹⁾ and "Upper Colorado River Basin 13(a) Assessment: The Availability of Water for Oil Shale and Coal Gasification Development in the Upper Colorado River Basin."⁽³⁰⁾

While the questions are complex, especially in light of the concurrently developing demands for water to support coal gasification and other energy development in the area, all of these analyses tend to lead to a common conclusion. They conclude that adequate surface water is available, or can be made available, for development of an oil shale industry of 500,000 to 1,000,000 barrels per day, or even more, between now and the Year 2000. Numerous circumstances, however, affect the availability of this water. Some of these are explored in this section.

4.2.1 Water Needs

In developing and operating an oil shale industry in the west, water is needed for a variety of purposes. These include mining and handling of ore, power generation, retorting and upgrading of raw shale oil, disposal and revegetation of spent shale, and municipal use. After studying information on a variety of emerging shale oil production technologies, the Office of Technology Assessment⁽³⁾ found that the average net need for all purposes together, which turns out to be similar for both above-ground and modified in situ processes, is likely to be about 5,800 acre-ft per year for a 50,000 barrel-per-day facility. If one assumes 6000 acre-ft per year for a 50,000 barrels-per-day facility, then requirements for a 300,000 barrels per day industry would be about 36,000 acre-ft per year. For purposes of comparison, an industry of 1,000,000 barrels per day would then need about 120,000 acre-ft per year.

4.2.2 Surface Water Sources

Surface waters readily available to an oil shale industry would come from the Upper Colorado River and its tributaries, principally the Green River and the White River. Estimates of the dependable average flow of the Colorado River at Lees Ferry, located at the bottom of the Upper Colorado River Basin, vary from 18.0 million acre-ft per year, the basis of the Colorado River Basin Compact of 1922, to 13.4 million acre-ft per year by the U.S. Water Resources Council.⁽³¹⁾ A flow of 13.8 million acre-ft per year, the average for the years 1922-1970, is widely used as a working figure.

One interesting calculation in 1978 indicated that under average operating conditions (i.e. 13.8 million acre-ft per year at Lees Ferry) and fulfilling all legal responsibilities under the Colorado River Basin Compact, there is a net remaining margin of water available in the Upper Colorado River Basin for consumptive use within the state of Colorado of 873,000 acre-ft per year.⁽³²⁾ This would be enough for a seven million barrel per day oil shale industry if it were all made available for that purpose.

Another source of water potentially available to oil shale development in Colorado is augmentation from Bureau of Reclamation Reservoirs. Specifically, the Colorado Department of Natural Resources⁽³³⁾ notes that 90,000 acre-ft per year might be available from Green Mountain Reservoir and that 48,000 acre-ft could be made available from the Ruedi Reservoir.

In light of the surface water sources considered to be applicable to an oil shale industry, the State of Colorado has concluded that a 500,000 barrels per day industry could be supported without having to forego other projected consumptive uses of water.⁽³³⁾ A supporting study by the Colorado Department of Natural Resources⁽³⁰⁾ concluded that an "emerging energy technology (EET)" industry including 1.3 million barrels per day of shale oil and 2 billion standard cubic feet per day from high Btu gasification of coal, could be supported without having to reduce significantly other projected consumptive uses in the Upper Colorado River Basin. This higher estimate was based upon four critical qualifications:

1. Water not currently under contract can be purchased from existing U.S. Bureau of Reclamation reservoirs; and/or new reservoir, pipeline, and pumping facilities are constructed in order to capture, store, and transport water.
2. The estimate takes into account only consumptive uses. Instream uses, therefore, such as fisheries and recreational activities, might be reduced.
3. The estimate does not allow for potential future constraints resulting from such institutional factors as Federal environmental regulatory laws and programs.
4. This estimate includes potential energy developments in all of the Upper Colorado River Basin, which includes Colorado, New Mexico, Utah, Wyoming, and a very small part of Arizona. Some constraints could be applied to the industry if the development in any one state exceeded the limits of that particular state's allocation under the Upper Colorado River Basin Compact of 1948.

These four qualifiers to the estimate of the higher Colorado Department of Natural Resources reveal the sensitivity of the prospective water supply to a variety of uncertainties. Two authors from the U.S. Department of Energy have aptly observed that "water availability (for an oil shale industry) is more a legal and political problem than a physical problem."⁽³⁴⁾ For instance, the calculation noted above that indicated a net water availability of 873,000 acre-ft per year in the Upper Colorado River Basin also showed that if decrees (claims made under water rights laws but not consumated) currently entered were actually used, there would be no surplus water available, and in fact, in an average year there would be a net shortage of 416,000 acre-ft.⁽³²⁾ Colorado Governor Lamm has observed that "Over 500,000 barrels (of shale oil) per day, our studies indicate an increasingly tight situation which may cause shifts in historic allocations and priorities."⁽³³⁾ Governor Lamm has been very clear about the state's high interest in maintaining a balanced economy, including substantial agriculture which could not compete economically with the energy industry for water.⁽³³⁾

Developing the surface water for a synfuels industry may be difficult in light of the stress it would place on the White River. One industrial lawyer has observed that "lack of an interstate compact governing allocations of water from the White River may yet prove to be the 'Achilles tendon' of the oil shale industry."⁽³⁵⁾ There is also evidence that building a critical White River Dam in Utah may be delayed or even prevented by problems with the habitat of endangered fish species.⁽³⁶⁾

Water rights laws in Colorado, Utah, and Wyoming are based upon the doctrine of prior appropriation. Under these laws, a potential user of water obtains a conditional water right by filing a conditional "decree." This decree establishes the place of that potential user in the seniority system, determining the rights of that user relative to other users or potential users in the same class of the "preference" system. With this system, a potential industrial water user is placed in the seniority system with other industrial water users, and the oldest claim has first rights. A newer claim by a municipal water system, however, commands a higher preference and will be served before all industrial users when the water supply is short. Since seniority is established by the date of the decree, an active user of water may be denied water if someone with an older, inactive decree chooses to use the water he has claimed. Water rights may be traded or bought and sold independent of land ownership, with the approval of the relevant states. While some prospective shale oil production firms have established decrees--829,029 acre-ft per year had been awarded to companies for oil shale development in Colorado by 1974⁽³⁷⁾--any claims by new oil companies will have to purchase existing rights or will have to settle for rights very junior in the seniority system with little guarantee of dependable water supplies.

Another legal-institutional question concerns the allocation to an energy industry of water from existing Bureau of Reclamation reservoirs. Under present law, it is required that such reservoirs be used primarily (70%) to supply needs present at the time of the decision to build the projects.⁽³⁷⁾

One consideration of enormous potential significance is the water situation in the Lower Colorado River Basin. In 1978, the Assistant Secretary for Land and Water Resources, U.S. Department of the Interior, stated that "...with

an inflow of 10 (billion) gallons per day (or 11.2 million acre-ft per year), the Lower Colorado is just meeting the treaty requirements to Mexico....It is able to do so now only because of heavy ground-water mining. During drought conditions, or if ground water is depleted beyond reach, meeting the requirements of the Lower Colorado Basin will not be possible."⁽³⁸⁾

Since under the Colorado River Basin Compact the Upper Basin is committed to passing only 8.5 million acre-ft per year into the Lower Basin, it is clear that the Upper Basin has been subsidizing the Lower Basin water use to a substantial extent, some 2.7 million acre-ft per year. Thus, while water is legally available to the Upper Basin states, there is reason to question whether its consumption would stand the test of a challenge because such consumption would result in severe shortages in the Lower Basin. This situation will be made worse if massive unadjudicated claims by Indian tribes are charged against the Lower Basin states under a 1968 act.⁽³⁵⁾

4.2.3 Ground-Water Sources

The Piceance Creek Basin includes two major bedrock aquifers containing up to 25 million acre-ft of water.^(39,40) While the actual ground-water system has been found to be more complicated than described by Weeks et al.⁽⁴¹⁾ the simplified description which follows may be helpful. The upper aquifer is separated through most of the basin from the lower aquifer by a layer of rich oil shale up to 200 ft thick. Since both aquifers are fed from snowmelt at about the 7000 ft level in surrounding mountains, they are both under hydrostatic pressure so that water from them will flow upward to the surface where access is possible. Accordingly, some of the surface streams are fed by ground water from those aquifers and from the alluvial aquifers which occur under and adjacent to some creek beds. The bedrock aquifers are fed at the rate of about 26,000 acre-ft per year, and the water flows toward the central portion of the basin from the edges. Ultimately the water from the aquifers flows into the Piceance and Yellow Creeks, which are tributary to the Upper Colorado River by way of the White and the Green Rivers.⁽³⁹⁾

Water could be produced from the bedrock aquifers to support a substantial oil shale industry. The water in the aquifers tends to contain high

concentrations of dissolved solids and fluorides, making most of it unfit for human consumption, but some of the water is acceptable for livestock watering. The upper aquifer water generally contains less than 2000 mg/l of dissolved solids; the lower aquifer varies from 1,000 to 63,000 mg/l. Fluorides range from about 10 to 70 mg/l in both aquifers.⁽³⁾ If ground water were used as the sole water source for an above-ground oil shale retorting plant of 50,000 barrels per day capacity, two to four wells would be required. If aquifers were mined to an extreme, they could support a one million barrels per day industry for 200 to 500 years.⁽³⁾ However, under current Colorado law, such mining is prohibited.⁽⁴⁷⁾

Use of the ground water for shale oil production, or even the dewatering of the aquifers in the areas of shale mines or modified in-situ retorts, implies several complications. In both Utah and Colorado, for instance, ground-water use is controlled by permits. In Colorado, any ground water which feeds surface streams is also subject to prior appropriation doctrine, just as surface waters are.⁽³⁾

In both dewatering and direct use of ground water, the quality of the water will present problems. For dewatering, the problem is how to dispose of large volumes of water which contain contaminants greatly in excess of acceptable limits for discharges to streams; for direct use, the contaminants may limit applications in shale processing or in land reclamation. Finally, substantial use of ground water--in excess of the recharge rate for a local area or for the aquifers as a whole--will likely reduce or eliminate the flow of water in surrounding wells and in some surface streams. The extent of these effects, however, is still highly uncertain.⁽⁴¹⁾

4.3 OTHER RESOURCES

Availability of oil shale and water is clearly of critical importance to the development of a shale oil industry. Many other commodities are also of great significance. While these commodities are not the focus of this assessment, this section considers them briefly.

4.3.1 Labor

A typical (e.g., 150,000 bpd) oil shale plant will require about 3,000 peak construction employees and, later, 1,100 permanent operating personnel.⁽⁸⁾ These labor requirements will vary somewhat with the size and type of processing plant and mine. Table 4.4 gives a range of figures.

The development scenario used in this report assumes most oil shale will be produced in Colorado and Utah. Development in Wyoming will be very limited. Table 4.5 gives construction and operation work forces estimates supplied by the Technology Characterization task of this DOE Oil Shale Technology Assessment. The table includes 11 facilities, with a total capacity of 280,000 barrels per day, or 94% of the projected 1990 shale oil production. These projections are based on estimates of possible shale oil production levels for each company, characterization of extraction technology, and estimates of facility expansion plans beyond the time period of this assessment.

The existing population of the region is sparse. Much of this work force, therefore, will have to be brought into the region. The magnitude of such an influx of personnel is increased by the fact that three to four times as many

TABLE 4.4. Labor requirements of Oil Shale Facilities⁽¹⁾

<u>Plant</u>	<u>Operating Personnel</u>	<u>Peak Construction</u>
Underground Mine (66,000 Tons Per Day)	743	
Surface Mine (66,000 Tons Per Day)	410	
Mine for Modified In-Situ (MIS) (41,000 Tons Per Day)	1,039	
Surface Retorting (50,000 Barrels Per Day)	429	3,300
MIS Plant (57,000 Barrels Per Day)	561	2,900
MIS and Surface Plant (76,000 Barrels Per Day)	1,000	2,500

TABLE 4.5. DOE Scenario of Oil Shale Work Force⁽⁴⁶⁾

	<u>1980</u>	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>	<u>1986</u>	<u>1987</u>	<u>1988</u>	<u>1989</u>	<u>1990</u>
<u>Colorado</u>											
Garfield County:											
Union (Construction)	300	800	700	700	800	700	200	0	0	0	0
(Operations)	100	250	400	400	400	400	550	700	700	700	700
Anvil Points (Construction)	0	300	500	200	250	400	200	100	0	0	0
(Operations)	80	200	300	300	300	300	300	450	450	550	550
Colony (Construction)	400	600	1,000	1,500	2,000	2,000	2,000	2,000	2,000	1,500	1,000
(Operations)	150	300	500	800	800	800	800	1,200	1,500	1,800	2,000
Chevron/Mobil (Construction)	0	0	0	0	100	300	500	500	600	600	200
(Operations)	0	0	0	0	100	100	200	300	300	500	500
Rio Blanco County:											
Superior (Construction)	0	0	150	275	450	800	710	100	400	600	100
(Operations)	20	50	110	185	405	540	600	920	920	1,200	1,200
C-a (Construction)	0	0	0	100	300	300	500	1,000	1,500	800	500
(Operations)	0	250	350	300	300	300	300	600	1,000	1,200	1,500
C-b (Construction)	0	0	0	100	300	300	500	1,000	1,500	800	500
(Operations)	0	250	350	300	300	300	300	600	1,000	1,200	1,500
<u>Utah</u>											
Uintah County:											
Sand Wash (Construction)	0	0	0	100	300	500	500	500	100	100	100
(Operations)	0	0	0	100	100	200	300	300	300	350	350
U-a, U-b (Construction)	0	0	0	100	300	500	500	200	100	0	0
(Operations)	0	0	0	100	200	300	300	300	400	400	400
TOTAL	1,050	3,000	4,360	5,060	7,705	9,040	9,160	10,770	12,770	12,300	11,100

new people will be required in western communities to provide services to the plant personnel.⁽⁸⁾ Only a handful of communities have more than a few thousand people. The population of these communities has been fairly stable throughout the past decade. Table 4.6 shows the populations of the four Colorado counties which will be most affected by oil shale development.

TABLE 4.6. 1979 Population Estimates of Colorado
Oil Shale Counties⁽⁴³⁾

<u>Garfield County:</u> Total	20,251
Carbondale	2,282
Glenwood Springs	3,604
Parachute	442
New Castle	483
Rifle	2,320
Silt	1,147
All Unincorporated	9,973
<u>Mesa County:</u> Total	72,263
Collbran	370
DeBeque	303
Fruita	2,526
Grand Junction	24,423
Palisade	1,146
All Unincorporated	43,494
<u>Moffat County:</u> Total	12,151
Craig	7,446
Dinosaur	388
All Unincorporated	4,317
<u>Rio Blanco County:</u> Total	5,064
Meeker	1,840
Rangely	1,982
All Unincorporated	1,242

The type of personnel required for large-scale oil shale development may be difficult to obtain. While requirements for construction workers are low relative to the size of the national labor force, professional employees are at a premium. The thirty-five 57,000 barrels per day synfuel plants required to implement former President Carter's energy plan would need 24,000 professionals: managers, engineers, draftsmen, and others. Only 45,000 were employed by related industry (process industry, petroleum, petrochemicals, chemicals, minerals beneficiation) in 1978.⁽⁸⁾ About 20 firms in the United States have the technical capability of designing and constructing an oil shale plant. Building enough plants to produce 400,000 barrels per day by 1990 would take about 12% of their capacity. This could compete with other industrial expansion.⁽⁴²⁾

4.3.2 Transportation

Initially, shale oil will probably be transported by truck to existing pipelines or railheads. As plants exceed 15,000 barrels per day, pipelines will be used to ship the product. Energy development has already had a significant impact on the transportation system of the oil shale region. Further development is likely to exacerbate the problem.

The State of Colorado has estimated that rapid oil shale development could increase truck traffic by 1,142 trips by 1985. If pipelines are not built, by 1990 there could be 5,142 extra truck trips, virtually closing the highways to other traffic. Even lesser increases in traffic will require road improvements: widening parts of existing roads, resurfacing roads, completing existing roads. Road construction could cost more than \$100 million to support a 400,000 barrels per day oil shale industry.

A shale oil pipeline is already planned to carry shale oil from the colony project to Casper, Wyoming. The 40-cm diameter pipeline will cost over \$100 million to build, and will carry 50,000 barrels of oil each day. The pipeline should be completed by 1985. A second, smaller, pipeline is planned to run to Rangely, Colorado.⁽⁴⁴⁾

4.3.3 Equipment and Materials

Oil shale development will require a variety of equipment and materials. Table 4.7 provides a list of sample items associated with various oil shale processes. Certain of these items, for example thick-walled pressure vessels, pumps, valves, compressors, alloy materials, major mining equipment, and oxygen plants are in very short supply. Building a production capacity of 400,000 barrels per day will require from 6% to 12% of our production of valves, compressors, heat exchangers, and pressure vessels. The Fluor Corporation estimates that, to build a 1.5 million barrel per day synthetic fuel industry by 1990, about 40% of our capacity for compressors and more than 30% of our capacity for fired heaters, boilers, shell and tube heat exchangers, and pumps, will be required.⁽⁴⁵⁾

The short supply of these critical items may mean that long lead times will be necessary to obtain them, constraining development of shale resources.⁽⁸⁾ Shortages of these items could also increase construction costs.⁽⁴²⁾

4.3.4 Financing

Developing a large-scale synthetic fuels industry will require very large capital investments. A Pace manager estimates that outlays of about \$7 billion per year will be required for a 1.5 million barrel per day industry by 1995. In 1978, a total of \$27.2 billion was invested in the U.S. construction industry.⁽⁴⁵⁾

The very large capital costs of synthetic fuels, including shale oil, may hinder development of the industry. The Bankers Trust Co. of New York expects less than one-third of the 1.75 million barrels per day synthetic fuels industry envisioned by the Carter administration for 1990 to actually be in place by that year. Synthetic fuels technologies, for the most part, have not been properly demonstrated, will require a long time to build (implying long-term capital burdens), and will be very expensive relative to the amount of fuel produced. At present the energy industry is 35% externally financed. New capital expenditures could increase this ratio substantially. Tax incentives could provide industry with the impetus to invest their profits in oil shale

TABLE 4.7. Materials and Equipment Required For Oil Shale Development(1)

<u>Process</u>	<u>Equipment</u>	<u>Materials</u>
Exploration	Vehicles Drilling Rigs Well Logging	
Underground Mine (66,000 tons per day Oil Shale)	9 Jumbo Drills 5 Powder Trucks 5 Scaling & Roof Bolting Rigs 7 Front-end Loaders 20 Haulage Trucks 10 Bulldozers	7300 Tons Steel
Surface Mine (66,000 tons per day Oil Shale)	4 Loading Shovels 12 Trucks 4 Drills 3 Bulldozers 2 Front-End Loaders 1 Explosives Truck	7400 Tons Steel
Mine for MIS Devel- opment (41,000 tons per day Oil Shale)	6 Jumbo Drills 4 Powder Trucks 4 Scaling & Roof Bolting Rigs 4 Front-End Loaders 12 Haulage Trucks 4 Bulldozers	
Surface Retorting/ (50,000 Barrel per day Shale Oil)	Pyrolysis & Oil Recovery Units Gas Recovery & Treating Units Hydrogen Production Units Gas-Oil and Naptha Hydro- genation Units Ammonia Separation & Sulfur Recovery Units Delayed Coker Foul Water Stripping Units	900 Tons Cement 6000 Tons Structural Steel 2000 Tons Reinforc- ing Bars & Piping 2000 Valves
MIS Processing (57,000 Barrels per day Shale Oil)	Gas and Water Treatment Units Oil/Water Separators Product Gas Boilers	
MIS and Surface (76,000 Barrels per day Shale Oil)	TOSCO II Retorts Oil & Oil-Gas Recovery Units Gas Purification & Sulfur Recovery Units Foul Water Stripper Oil Fractionation & High Btu Gas Units Oil Upgrading & Blending Units	

plants instead of other, non-energy projects. Recent deregulation of oil prices, however, may make conventional fuels more attractive to oil companies, reducing the incentive for synfuels investment.

4.4 REFERENCES FOR CHAPTER 4

1. Science and Public Policy Program, University of Oklahoma. 1979. Energy from the West: Energy Resource Development Systems Report: Volume III, Oil Shale. Prepared for Environmental Protection Agency, EPA-600/7-79-060c. U.S. Department of Commerce, National Technical Information Service, Springfield, Virginia.
2. U.S. Department of Energy. 1979. Oil Shale RD&D: Program Management Plan (Draft). U.S. Department of Energy, Washington, D.C.
3. U.S. Congress, Office of Technology Assessment. 1980. An Assessment of Oil Shale Technologies. U.S. Government Printing Office, Washington, D.C.
4. Feldkirchner, H. L., and J. C. Janka. 1979. "The Hytort Process." Presented at the Symposium on Synthetic Fuels from Oil Shale, Atlanta, Georgia, December 1979.
5. "With Help, Eastern Shale Competitive." Synfuels Week. October 13, 1980, p. 5.
6. Culbertson, W. C., and J. K. Pitman. 1973. "Oil Shale," in United States Mineral Resources, U.S. Geological Survey Professional Paper 820, pp. 497-503.
7. Duncan, D. C., and V. E. Swanson. 1965. Organic-Rich Shales of the United States and World Land Areas. U.S. Geological Survey Circular 523.
8. U.S. Congress, Senate, Subcommittee on Synthetic Fuels of the Committee on the Budget. 1979. Report: Synthetic Fuels. 96th Congress, First Session. U.S. Government Printing Office, Washington, D.C.
9. "EPA Study Sees Slower Synfuels Growth." Synfuels Week. October 6, 1980, p. 3.
10. "EPA Consultants Project Synfuels Future." Synfuels Week. October 27, 1980, p. 4.
11. "Exxon Sees 15 Million B/D Synfuels Demand in 2000." The Energy Daily. June 17, 1980, p. 3.

12. U.S. Department of Energy, Assistant Secretary for Policy and Evaluation. 1979. Energy Supply Strategy: Getting Technology Commercialized--Shale Oil; Enhanced Oil Recovery, DOE/PE/4973. Washington, D.C.
13. "EPA Doubles Feasible Shale Projection." June 30, 1980. Synfuels Week, p. 3.
14. "Air Commission Estimates Shale Potential." Synfuels Week. November 24, 1980, p. 4.
15. "EPA Retreats on Shale Production." December 8, 1980. Synfuels Week, p. 4.
16. Exxon Official Urges clean Air Act Changes." Synfuels Week. November 24, 1980, p. 2.
17. "Clean Air Congressmen Purged." Synfuels Week. November 10, 1980, p. 8.
18. Harrington, Larry W. 1980. "Regulatory Obstacles to the Oil Shale Industry." Presented at Oil Shale: The Environmental Challenges, Vale, Colorado, August 11-14, 1980, sponsored by the Oil Shale Task Force and the U.S. Department of Energy.
19. Science Applications, Inc. 1979. Development and Application of a Permit Information System for Shale Oil, DOE/ET/93764-1 and DOE/ET/83764-1 (App.). NTIS, U.S. Department of Commerce, Springfield, Virginia.
20. Science Applicatons, Inc. 1979. "Impact of the Regulatory Structure on Accelerated Commercialization of Oil Shale."
21. Spence, H. M. 1980. "Oil Shale and the Environment." Presented at The Outlook for Oil Shale Conference, Denver, Colorado, June 19, 1980, Sponsored by Synfuels Week.
22. "Rio Blanco Will Appeal to Congress in 1981." Synfuels Week. December 22, 1980, p. 4.
23. "Off-Tract Bill Introduced." Synfuels Week. February 2, 1981, p. 5.
24. "Three Firms Swap Oil Shale Tracts." Synfuels Week. November 17, 1980, p. 3.
25. "Wyoming Shale Tests Approved by State." Synfuels Week. November 17, 1980, p. 3.
26. "Utah State Leases to be Developed." Synfuels Week. November 17, 1980, p. 5.

27. U.S. Department of the Interior. 1973. Final Impact Statement for the Prototype Oil Shale Leasing Program. U.S. Government Printing Office, Washington, D.C.
28. U.S. House of Representatives, Subcommittee on Mines and Mining of the Committee on Interior and Insular Affairs. 1974. Hearings: Information on Oil Shale Development. 93rd Congress, First Session. U.S. Government Printing Office, Washington, D.C.
29. U.S. Senate, Subcommittee on Energy Production and Supply of the Committee on Energy and Natural Resources. 1978. Hearings: Water Availability for Energy Development in the West. 93rd Congress, Second Session. U.S. Government Printing Office, Washington, D.C.
30. Colorado Department of Natural Resources. October 1979. Upper Colorado River Basin 13(a) Assessment: The Availability of Water for Oil Shale and Coal Gasification Development in the Upper Colorado River Basin: Summary Report, a Report to the U.S. Water Resources Council, Public Review Draft. Denver, Colorado.
31. U.S. Water Resources Council. 1978. The Nation's Water Resources: The Second National Water Assessment, Part V, "Regional Assessment Summaries," Review Draft. Washington, D.C.
32. U.S. Senate, Subcommittee on Energy Production and Supply of the Committee on Energy and Natural Resources. 1978. Hearings: Water Availability for Energy Development in the West. Testimony by Roland Fischer, Secretary-Engineer, Colorado River Water Conservation District, Glenwood Springs, Colorado. 95th Congress, Second Session. U.S. Government Printing Office, Washington, D.C.
33. Colorado Department of Natural Resources. 1979. Colorado Oil Shale: The Current Status. Prepared under U.S. Department of Energy Contract #DE-FG48-79R800212.001. Colorado Geological Survey, Denver, Colorado.
34. Zukor, S. H., and P. A. Petzrick. 1980. "Oil Shale Technologies Ready Now for Commercialization." Paper presented at the 7th Energy Technology Conference and Exposition, sponsored by American Gas Association, Electric Power Research Institute, Gas Research Institute, and National Coal Association, March 24-26, 1980, Washington, D.C.
35. "Water Interstate Compact Necessary." Synfuels Week. February 2, 1981, p. 4.
36. "BLM Sees Potential White River Dam Problem." Synfuels Week. December 15, 1980, p. 1.
37. U.S. Code Title 43, Section 360(B).

38. U.S. Senate, Subcommittee on Energy Production and Supply of the Committee on Energy and Natural Resources. 1978. Hearings: Water Availability for Energy Development in the West. Testimony by Hon. Guy R. Martin, Assistant Secretary for Land and Water Resources, U.S. Department of the Interior. 95th Congress, Second Session, U.S. Government Printing Office, Washington, D.C.
39. Weeks, J. B., G. H. Leavesley, F. A. Weider, and G. J. Saulnier, Jr. 1974. "Simulated Effects of Oil Shale Development on the Hydrology of the Piceance Basin, Colorado." U.S. Geological Survey Professional Paper 908, U.S. Government Printing Office, Washington, D.C.
40. Price, D., and T. Arnow. 1974. "Summary Appraisals of the Nation's Ground Water Resources--Upper Colorado Region." U.S. Geological Survey Professional Paper 813-C, U.S. Government Printing Office, Washington, D.C.
41. Fox, J. P., P. Persoff, P. Wagner, and E. J. Peterson. 1980. "Retort Abandonment--Issues and Research Needs." Paper presented at Oil Shale, The Environmental Challenges, sponsored by the Oil Shale Task Force and the U.S. Department of Energy, August 11-14, 1980, Vail, Colorado.
42. Sladek, T. A., P. L. Poulton, W. E. Davis, and P. A. Robinson. 1980. "A Technology Assessment of Oil Shale Development." Presented at the 13th Oil Shale Symposium, Golden, Colorado, April 16, 1980.
43. Colorado Demographer's Office. 1980. Population Estimates.
44. "Exxon Applies for Shale Pipeline Permit." Synfuels Week. January 12, 1981, pp. 3-4.
45. "Pace Analyzes Synfuels Investment." Synfuels Week. July 14, 1980, p. 2.
46. Mangeng, C. 1981. Socioeconomic Impacts of Oil Shale Development. Available as Volume 9 of this assessment report.
47. The John Muir Institute, Inc. 1980. Institutinal Constraints on Alternative Water for Energy: A Guidebook for Regional Assessments. Prepared for U.S. Department of Energy under contract to Los Alamos Scientific Laboratory. DOE/EV/10180-01. Washington, D.C.

5.0 AIR QUALITY

Colorado, Utah, and Wyoming are states which have enjoyed a wealth of natural beauty. The mountains in the western part of Colorado, for instance, have supported a billion-dollar tourist industry because of their natural beauty and the opportunities they provide for hiking, camping, hunting, and skiing. Colorado alone has more than 50 peaks of greater than 14,000 ft (4267 m) elevation offering spectacular views even from places accessible by automobile. Population in these states is generally sparse. No large communities are found near the oil shale region. It is no surprise that many people and organizations in these states, especially in Colorado, express strong concerns about the prospect of a large shale oil industry with its threat of impacts on the natural environment and on life styles in small communities.

The impacts on the environment must be considered in the decisions to be made on development of a shale oil industry. Questions of environmental acceptability are raised both by residents of the region (as noted above) and by the existence of state and Federal environmental quality laws and regulations.

Air quality is viewed by many authorities as that aspect of the environment most likely to prove limiting to a shale oil industry. Air quality at the present time in the oil shale region tends to be excellent. It is considered to be vital to the well-being of people in the region. Participants in a workshop on "Health and Environmental Effects of Oil Shale Technology" noted the importance of four potentially significant air quality problems:⁽¹⁾

- increased environmental concentrations of toxic materials, particularly the polycyclic organic materials and trace metals and their impacts on human health and welfare
- increased production of photochemical oxidants in the atmosphere which will adversely affect human health as well as produce vegetation stress and contribute to visibility degradation
- inadvertent weather modifications, currently not well defined, associated with the emissions from all cycle components of shale oil development

- degradation of regional visibility from the increased atmospheric loading of primary particulate matter and the production of secondary aerosols.

Little has been written about the first and third problems in this list but the other two have been the focus of much concern and study in evaluations of the prospects for a major shale oil industry. This chapter concentrates primarily on the second and fourth problems in the list.

Much of the information presented in this section is drawn directly from a study in support of this assessment conducted by Drake and Huang⁽²⁾ at the Pacific Northwest Laboratory (PNL).

5.1 AIR QUALITY STANDARDS

Environmental law focusing on air quality, as embodied in the Clean Air Act and its amendments, and the Code of Federal Regulations, requires government to:⁽³⁾

- protect the public health by establishing, implementing, and enforcing primary ambient air quality standards
- protect the public welfare by establishing, implementing, and enforcing secondary ambient air quality standards
- prevent significant deterioration
- protect and enhance visibility.

The highest priority is to protect the public health by attaining and maintaining primary ambient air quality standards. However, the 1977 Amendments have strongly stressed the Prevention of Significant Deterioration (PSD) and the protection and enhancement of visibility in pristine areas.

Table 5.1 gives the primary and secondary National Ambient Air Quality Standards, (NAAQS)⁽⁴⁾ and state standards,⁽⁵⁾ while Table 5.2 gives the maximum allowable increases for PSD ambient air increments over Class I, II, and III areas.⁽⁶⁾ Class I areas are those for which the least amount of additional pollutants will be allowed; Class III will allow the largest increments of pollutants. Mandatory Class I areas include: existing national parks,

TABLE 5.1. The Federal and State Ambient air Quality Standards(4-7)

Pollutant	Ambient Air Quality Standards (concentrations in micrograms per m ³)				
	Federal (primary) Human Health	Federal (secondary) Public Welfare	Wyoming ^(a)	Colorado ^(a)	Utah
SO ₂					
Annual Arithmetic Mean	80	NONE	<u>60</u>	80	80
24-hr Maximum	365	NONE	<u>260</u>	365	365
3-hr Maximum	NONE	1,300	1,300	<u>700</u>	NONE
Particulates					
Annual Geometric Mean	75	60	<u>60</u>	75	75
24-hr Maximum	260	150	<u>150</u>	260	260
NO ₂ Annual Arithmetic Mean	100	100	100	100	100
O ₃ 1 hour	235	235	<u>160</u>	<u>160</u>	240
CO					
8-hr Maximum	10,000	10,000	10,000	10,000	10,000
1-hr Maximum	40,000	40,000	40,000	40,000	40,000
Nonmethane Hydrocarbons					
3-hr maximum (6-9 am). . .	160 ^(b)	160 ^(b)	160 ^(b)	160 ^(b)	160 ^(b)

(a) Where state standards are more restrictive (underscored) than Federal standards, the state standards are controlling.

(b) A nonhealth related guide for ozone control.

TABLE 5.2. PSD--Ambient air Increments: Maximum Allowable Increase(a)

Class I

<u>Pollutant</u>	<u>Concentration in g/m³</u>
Particulate Matter:	
Annual Geometric Mean	5
24-hour Maximum	10
Sulfur Dioxide:	
Annual Arithmetic Mean	2
24-hour Maximum	5
3-hour Maximum	25

Class II

Particulate Matter:	
Annual Geometric Mean	19
24-hour Maximum	37
Sulfur Dioxide:	
Annual Arithmetic Mean	20
24-hour Maximum	91
3-hour Maximum	512

Class III

Particulate Matter:	
Annual Geometric Mean	37
24-hour Maximum	75
Sulfur Dioxide:	
Annual Arithmetic Mean	40
24-hour Maximum	182
3-hour Maximum	700

(a) Under no circumstances may this increment be allowed if it would cause a primary or secondary Federal ambient air quality standard to be exceeded.

national wilderness areas and national memorial parks exceeding 5000 acres in size, national parks exceeding 6000 acres in size, and all areas that have been redesignated Class I under the previous EPA regulations prior to the enactment of the 1977 Amendments. All other applicable areas start off as Class II unless redesignated. The maximum allowable increases listed in Table 5.2 generally cannot be exceeded more than once a year unless a special variance for a limited extension of 18 days per year is obtained.

The mandatory Class I Federal areas in the neighborhood of the Piceance Creek Basin are shown in Figure 5.1. The Flat Tops Wilderness Area is the closest downwind Class I area to the Colorado oil shale formations. Dinosaur National Monument, to the northwest of the Piceance Basin, is currently not a Class I area, but it is being considered for that type of designation. Other

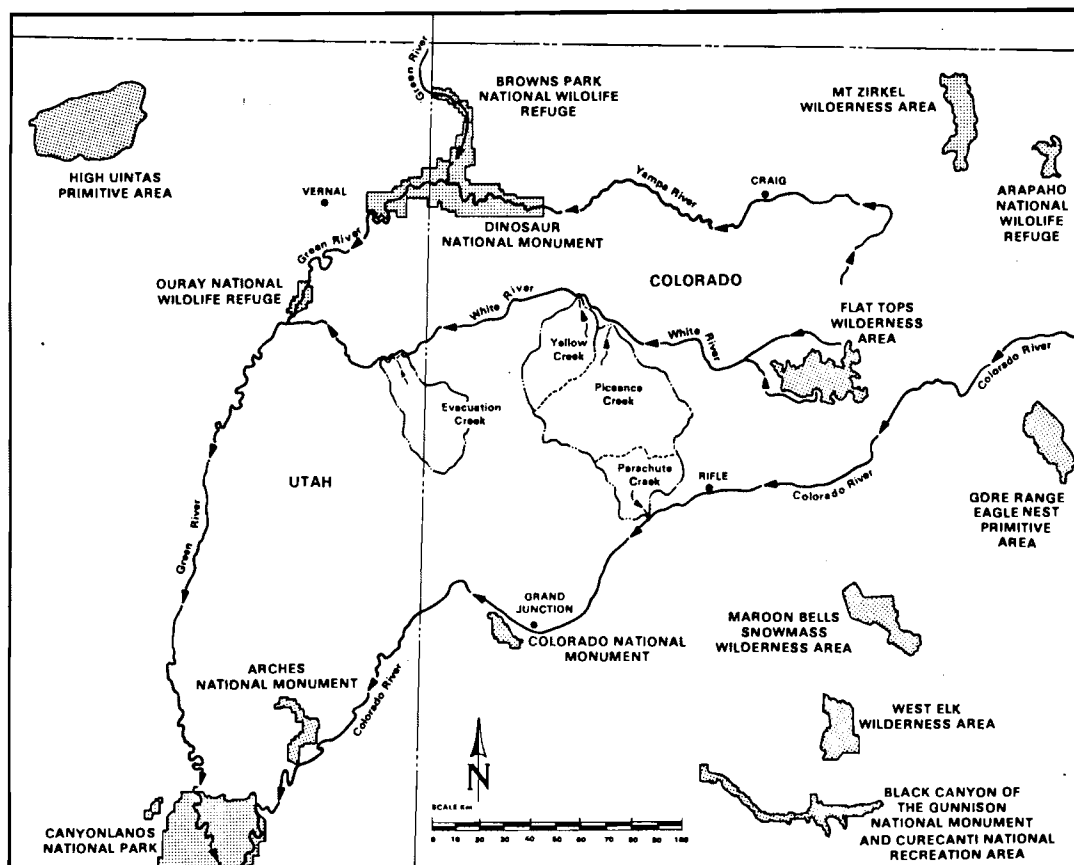


FIGURE 5.1. The Mandatory Class I Federal Areas in the Neighborhood of the Colorado Oil Shale Formation

Class I areas shown in Figure 5.1 are somewhat protected from a mature oil shale industry due to local terrain and prevailing winds and temperature fields.

Some Colorado Ambient Air Standards are currently being brought into conformity with the Federal regulations, while other standards (i.e., sulfur dioxide and oxidants) are more restrictive than the EPA primary and secondary standards. Standards that are common to Colorado and the Federal government include:

- The Colorado standards for total suspended particulates, which conform to existing Federal Ambient Air Quality Standards
- The Colorado regulations for a) the methods for measurements of ambient concentrations of sulfur dioxide and b) the manner in which these concentrations are reported, which conform to the Federal regulations.
- The Colorado regulations for Prevention of Significant Deterioration, which are consistent with Federal PSD requirements.

Standards for the state of Wyoming are more restrictive than Federal standards for SO₂, particulates, and oxidants. Utah standards are identical to Federal standards in all cases.

5.2 EXISTING AIR QUALITY CONDITIONS IN THE OIL SHALE REGION

Air quality in the oil shale region is typically excellent due to the absence of major industrial plants and large communities. Nevertheless, ambient levels of some air pollutants exceed some state and Federal standards. In particular, nonmethane hydrocarbons sometimes exceed NAAQS limits in the Utah lease tracts U-a and U-b. Similarly, particulates and nonmethane hydrocarbons exceed NAAQS limits at the Colorado lease tracts C-a and C-b.⁽⁸⁾ One set of data showing this is presented in Table 5.3. A visible haze has been observed in the Parachute Creek Basin.⁽⁸⁾ Most of these situations are thought to result from natural causes,⁽⁸⁾ although some of them may be consequences of long-range transport of air pollution.

TABLE 5.3. Existing Air Quality Data Summary for Federal Oil Shale Lease Tracts(8,9)

<u>Criteria Pollutant</u>	<u>Primary National Standard</u>	<u>Tract C-a</u>	<u>Tract C-b</u>	<u>Tracts Ua-Ub</u>
Particulate				
Maximum 24 hr ($\mu\text{g}/\text{m}^3$)	260	469	178	127
Annual Mean ($\mu\text{g}/\text{m}^3$)	75	18	11	22
No. Occurrences Exceeding NAAQS ^(a)		5	4	
SO₂				
Maximum 3 hr ($\mu\text{g}/\text{m}^3$)	1,300	345	88	40
Maximum 24 hr ($\mu\text{g}/\text{m}^3$)	365	82	43	25
Annual Mean ($\mu\text{g}/\text{m}^3$)	80	19	1	10
NO_x				
Annual Mean ($\mu\text{g}/\text{m}^3$)	100 ^(b)	4	10	10
CO				
Maximum 1 hr ($\mu\text{g}/\text{m}^3$)	40,000	6,823	2,841	5,200
Maximum 8 hr ($\mu\text{g}/\text{m}^3$)	10,000	4,824	1,659	3,900
NMHC^(c)				
Maximum 3 hr ($\mu\text{g}/\text{m}^3$)	160	505	2,316	1,970
No. Occurrences Exceeding NAAQS ^(a)		94		138
Oxidant				
Maximum 1 hr ($\mu\text{g}/\text{m}^3$)	235	177	160	190
No. Occurrences Exceeding NAAQS ^(a)		5		42

(a) National Ambient Air Quality Standards.

(b) Standard applies to NO₂.

(c) Nonmethane hydrocarbons.

The high natural concentrations of some pollutants in the oil shale regions have implied a constraint on the development of any shale oil industry. However, the Environmental Protection Agency (EPA) ruled in 1977 that air quality problems arising from natural sources would not preclude oil shale development, provided that facility complied with emission and PSD standards.⁽⁷⁾

5.3. PROJECTED AIR QUALITY IN THE PICEANCE CREEK BASIN

This section focuses on air quality impacts to be expected in the Piceance Creek Basin from a shale oil industry. Air quality analytical efforts in this assessment were addressed specifically to this problem. Section 5.4 considers impacts and constraints associated with air quality outside of the Basin.

5.3.1 Approach

Air Quality impacts from a shale oil industry would result from process emissions and the effects on these emissions of a variety of meteorologic conditions. Both of these factors were studied in this assessment.

In the work done at the Pacific Northwest Laboratory (PNL) for this assessment, a simple, multiple-source plume model was used to evaluate likely air quality impacts in the Piceance Creek Basin from the 300,000 barrels per day industry posed in the assessment scenario (see Section 3.5).⁽²⁾ Simple plume models for uniform wind and thermal conditions possess the following properties:

- concentrations from a continuous steady source vary in direct proportion to the source strength or rate of emission
- concentrations vary inversely with the mean wind speed at the source
- distance from the source to the receptor and intensity of atmospheric turbulence determine the height and width of a plume at the receptor
- concentrations may decrease because of chemical reactions, radioactive decay, and removal
- practical time scales are 1 to 2 hr; space scales 10 to 20 km

- extra provisions are made to account for calm winds, complex terrain and low inversion levels.

Other models, more appropriate to the topography and to the nature of the sources in a shale oil industry, could have been used in the PNL study, but the benefits of using them would have been lost due to the absence of the dense data base needed by them. Brief descriptions of "box models" and "puff models," for instance, are provided by Drake and Huang.⁽²⁾ A more extensive and generalized discussion of dispersion modeling applicable to the oil shale region is provided by the Office of Technology Assessment (OTA).⁽⁷⁾

5.3.2 Sources of Present Meteorological and Air Quality Data

The best source of meteorological data for the oil shale region is the National Climatic Center (NCC) at Ashville, North Carolina. At NCC, the data that are routinely collected at the National Weather Stations (NWS) are archived; these data include wind speed and direction, temperature, humidity, and precipitation. Upper air NWS's obtain vertical profiles of meteorological data twice daily; these data are very important for defining upper level flows and temperature and humidity fields over the oil shale areas. However, the density of both surface and upper air NWS's is not sufficient to define properly the meteorology and climate over the Piceance Creek Basin.

The scarcity of meteorological data in this region can be partially overcome through the use of the following data sets or sources of information:

- NASA, NOAA and Department of Defense satellite data on surface temperatures; daily layer average profiles of temperature and humidity, and fog and cloud cover
- DOE wind energy surveys for Idaho, Wyoming, Utah and Colorado
- USGS data from various field experiments
- cooperative surface stations supplying temperature and precipitation data to NCC
- various special field programs in the mountains and valleys of Idaho, Utah, and Colorado, including the baseline data collected over the oil shale tracts of Utah (U-a and U-b) and Colorado (C-a and C-b)

(the C-a tract lies in the Yellow Creek watershed, the C-b tract in the Piceance Creek watershed, and the U-a and U-b tracts near the mouth of Evacuation Creek, Figure 5.1, above).

The work for this assessment done by PNL relies principally upon the data obtained from the lease tract measurements for characterization of the air quality conditions in the Piceance Creek Basin. The data were obtained on magnetic tapes from the Environmental Protection Agency (EPA). They included:

- Meteorology--Wind speed and direction at one or more levels; temperature at one or more levels; solar radiation, relative humidity, and precipitation
- Air Quality--Air concentrations of NO_x , NO , SO_2 , H_2S , total hydrocarbons, methane, nonmethane hydrocarbons, CO , and ozone.

The major problems with these data were the short period of record and the lack of spatial representativeness of the data for the Piceance Basin at large. The stations in and around Tract C-b were close enough to one another to represent only a short segment of the Piceance Creek (in a SE to NW direction) and a NE facing slope along the creek. The stations in and around Tract C-a were representative of only a short segment of the Yellow Creek and one of its tributaries (in a SW to NE direction).

Similar conclusions about the tract data were given in a recent report by Wolf.⁽¹⁰⁾ The objective of Wolf's study was to assess the regional representativeness of the tract data from the Federally leased oil shale tracts C-a, C-b, and the combined tracts U-a and U-b. However, in general, the data did not allow such a regional synthesis. For example, he found that continuity of air-flow between the tracts appears to exist only in the afternoon during the warmer months when the upper level flow is strong enough to dominate the region. At other times, local conditions dominate the air flows.

5.3.3 Projection of Air Quality

Major sources of emissions of air pollutants from a shale oil industry might include:⁽¹¹⁾

- SO₂ (sulfur dioxide)--Fuel combustion from process heaters, construction and mining machinery, transportation vehicles, and tail gases of sulfur recovery operations
- NO_x (nitrogen oxides)--Fuel combustion from process heaters, construction and mining machinery, transportation vehicles, and explosives
- CO (carbon monoxide)--Fuel combustion from process heaters, construction and mining machinery, transportation vehicles, and explosives
- HC (hydrocarbons)--Combustion emissions and product storage tank vapors
- Particulate matter--Blasting, handling, and disposal of raw and spent shale; raw and spent shale dust in process gas streams, fuel combustion, and site activities which generate fugitive dust.
- Potentially hazardous substances:
 - Silica (quartz) may be present in oil shale dust and associated fugitive dust
 - Polycyclic organic material (POM), and certain trace metals from fuel combustion and fugitive dust from spent shale handling and disposal may be present.
 - Gaseous Ammonia, hydrogen sulfide, and volatile organics may be released during moisturizing and subsequent cooling of retorted shale.

The source emissions that were used for the air quality studies were based on the "high scenario" oil shale production schedule, described in Section 3.5. The high scenario assumes a mature oil shale industry producing about 300,000 bpd of shale oil.

Table 5.4 lists the tracts, retorting processes, and levels of production involved in this production scenario. The source strengths for CO, particulate matter, hydrocarbons, SO₂, and NO_x from each of the sources are also shown in Table 5.4. They were calculated in units of kg/hr using the data from the

TABLE 5.4. Pollutant Source Strengths for the High Scenario of Oil Shale Production(2)

Key	Tract (company)	Process ^(a)	BPD Production	Source Strengths in kg/hr ^(b)				
				CO	Particulate Matter	Hydrocarbons	SO ₂	NO _x
1	Long Ridge	C	30,000	(c)				
		A	3,000	155.1	69.8	70.4	66.4	210.1
2	Anvil Points	B	10,700					
		E	1,070	15.5	95.1	5.7	8.6	93.9
3	Superior	D	20,000					
		E	2,000	185.0	116.4	36.7	43.8	263.6
4	Sand Wash, Utah	A	11,000	63.1	103.5	41.0	41.1	225.0
5	DOW	A	55,000	315.3	517.5	204.8	205.5	1124.2
6	Tract U-a, U-b	B	11,000					
		E	1,100	56.9	25.7	25.8	24.4	77.1
7	South Piceance Basin	Unknown I	10,000	84.1	52.9	16.7	19.9	119.8
8	South Piceance Basin	Unknown II	10,000	84.1	52.9	16.7	19.9	119.8
9	Tract C-a	F	57,000					
		A or E	19,000	1388.7	329.6	118.8	183.1	1297.9
10	Tract C-b	F	50,000	1123.6	132.5	42.2	98.4	798.3
11	Equity	G	2,000	16.8	10.6	3.3	4.0	24.0
12	SE Utah	Unknown III	2,000	16.8	10.6	3.3	4.0	24.0

(a) See Chapter 3 for Description of Retorting Processes.

(b) For each process all of the emissions from the various sources have been lumped together, i.e., particulate matter, hydrocarbons, carbon monoxide, oxides of nitrogen and oxides of sulfur.

(c) Blank spaces indicate the information was not obtained or estimated.

scenario and technology characterization study done for this assessment.⁽¹²⁾ Because of the lack of proper data and the unknown characteristics of some of the processes, the values shown in Table 5.4 are the combined emissions for the processes of mining, crushing and storing shale, retorting, disposing of spent shale, pre-refining and upgrading, and storing the product. In addition, a constant "stack height" for all sources and emissions was assumed.

In deriving these source strengths, it was assumed that maximum feasible air pollution control technologies were being applied. Details about the control technologies assumed are provided in Chapter 3 of this report and in the supporting study by Energy Development Consultants (EDC).⁽¹²⁾ A broad discussion of technologies applicable to oil shale facilities and processes is available in the oil shale assessment report by the Office of Technology Assessment.⁽⁷⁾ For Sources 2, 7, 11, and 12 in Table 5.4, PNL used a weighted average of the emissions from the Paraho Direct, TOSCO II, Union B and Occidental processes, as presented in the EDC report. For all of the sources, it was assumed that the grade of oil shale was 25 gallons (95 liters) of oil per ton of shale.

The approximate location of the Colorado tracts, or sources of pollutants, are shown in Figure 5.2. The locations of the Utah sources are along the White River near the mouth of Evacuation Creek (See Figure 5.1, above). The grid shown in Figure 5.2 was used in the PNL analysis.⁽²⁾ This grid is patterned after the common township grid shown on USGS topographical maps; thus, the mesh size is 9.65 kilometers, or 6 miles.

In order to simulate 20 years of air quality data for the grid shown in Figure 5.2, PNL considered a simple, multi-point source, Gaussian plume model. The form of the governing equation is:

$$C_{ij} = \sum_i \frac{Q_i}{U} \phi_{ij} \text{ (source location, wind direction, receptor location),}$$

where Q_i are the source strengths given in Table 5.4, U is the uniform wind velocity over the Piceance Basin, C_{ij} is the concentration at the receptor

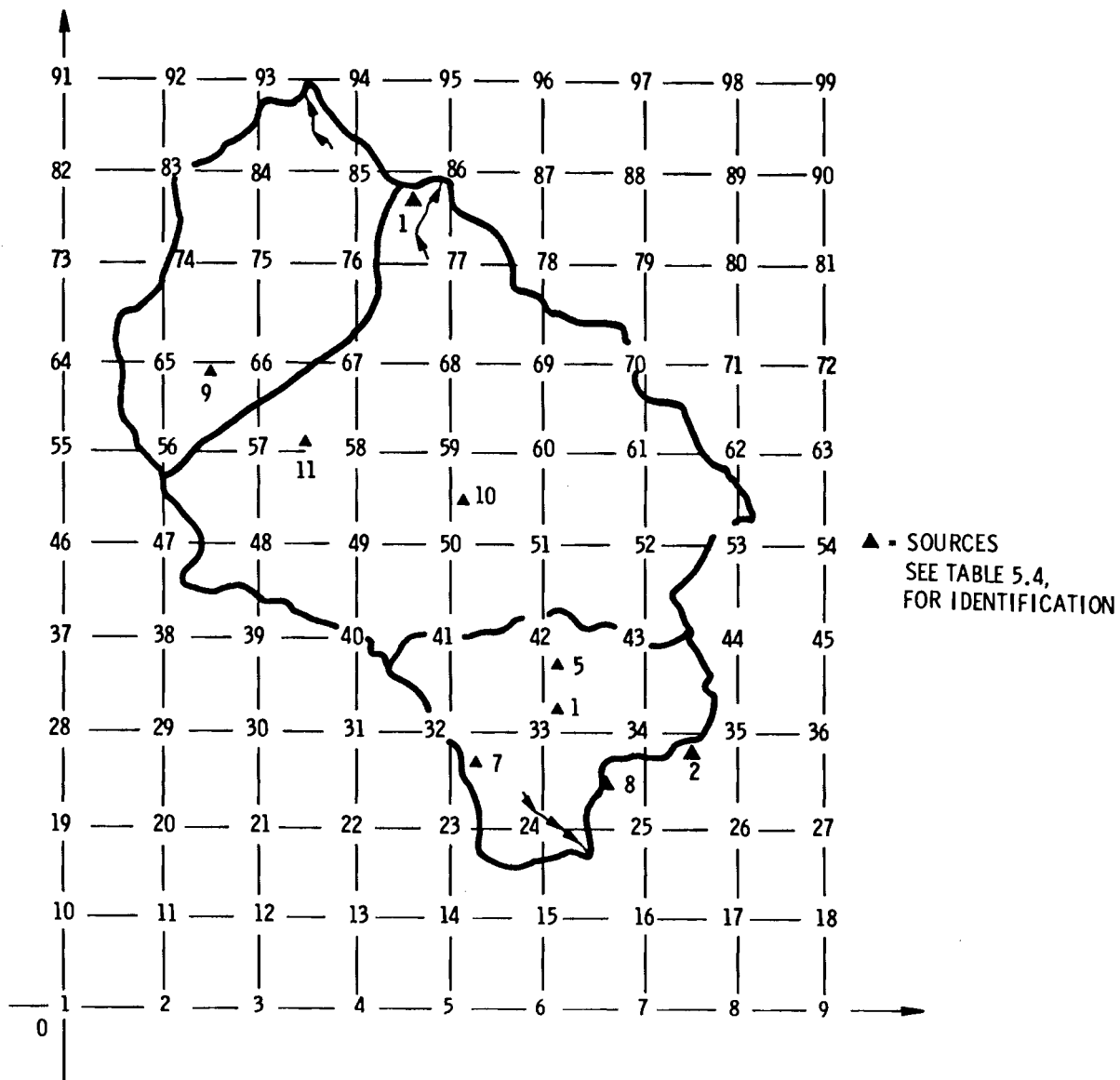


FIGURE 5.2. The 9.65 Kilometer (6 Mile)-Mesh, Township Grid Used for Air Quality Studies Over the Piceance Basin.(2)

locations (the 99 grid points in Figure 5.2), ϕ_{ij} is the usual Gaussian function which depends on the effective stack heights (H) and diffusion coefficients (σ_y and σ_z), and "i" is the source index for the sources given in Table 5.4. The diffusion coefficients used in σ_i are given by:

$$\sigma_y = a_y x (1 + 0.004x)^{-1/2}$$

$$\sigma_z = a_z x^b$$

where x is the downwind distance from the source, a_y , a_z , and b are coefficients that depend on atmospheric stability. The required input data for the models are the source parameters of location, stack height and emission rate; the meteorological parameters of wind speed, wind direction, and atmospheric stability class; and the receptor parameter of location. The output data are average concentrations of the pollutants at each receptor location (the grid points shown in Figure 5.2).

The air quality estimates resulting from the PNL analysis were based on the following assumptions and parameters:

- Monthly averaged air concentrations of particulate matter, hydrocarbons, SO_2 and NO_x were given for the 99 grid points over a 20-year simulation.
- The three Utah sources were assumed to be negligible over the Piceance Creek Basin.
- The effective stack height for all sources and emissions was assumed to be 50 m.
- Sixteen wind directions and three stability classes were used. The uniform wind field over the Piceance Creek Basin was taken from data generated over Tract C-b.
- The Gaussian plume model was used to generate daily mean concentrations, using actual Tract C-b data, for a period of one year.
- From the year's worth of data, monthly means and standard deviations were derived.
- The 20 years of concentration data were generated using the computed means and standard deviations in a random number generator.

Table 5.5 gives the results of monthly means of ground-level air concentrations of SO_2 and particulate matter obtained from the simple plume model. The grid-point numbers in the table refer to the grid shown in Figure 5.2, above.

5.3.4. Suggested Air Quality Impacts

Only a few definitive statements concerning violations of air quality standards can be made from the results of the PNL modeling activities. The reasons for this are twofold: the coarse-screening characteristics of the modeling technique used to generate the 20 years of air quality data limit the model use for these purposes; and worst-case conditions were not considered by the modeling technique. Both of these constraints are due to the lack of adequate meteorological and climate data to drive more sophisticated models.

Table 5.6 shows the annual PSD increments that may be used up by a 300,000 bpd industry over Class II areas in the Piceance Basin. These annual estimates for SO_2 and particulate matter were obtained from the data given in a 12-month version of Table 5.5.⁽²⁾ In applying the information in Tables 5.5 and 5.6, the simplistic nature of the modeling effort should be taken into account. Without further and extensive analysis of these results, it is not possible to evaluate their accuracy as forecasts of air quality conditions which would result from the 300,000 bpd industry.

TABLE 5.5. Preliminary Results from the Simple Plume Model(2)

<u>Month</u>	<u>Grid Point Number</u>	<u>Location</u>	<u>Monthly Mean SO₂ Air Concentration₃ in µg per m³</u>	<u>Monthly Mean Particulate Air Concentration₃ in µg per m³</u>
January	25 }	Near mouth of Parachute Creek	0.85	2.18
	49 }	Piceance Creek Basin	2.99	4.44
	50 }		5.78	8.49
	51 }		3.60	5.94
	52 }		1.43	3.39
	58 }	Piceance Creek Basin	5.81	7.94
	59 }		11.30	15.20
	60 }		6.85	10.70
	61 }		2.43	6.10
	65 }	Yellow Creek Basin	0.97	1.92
	66 }		1.48	2.73
	67 }	Piceance Creek Basin	4.10	6.20
	68 }		6.72	9.66
	69 }		3.97	6.37
	70 }		1.22	3.07
	74 }	Yellow Creek Basin	1.33	2.43
	75 }		2.63	4.81
	76 }		2.40	4.45
	77 }	Piceance Creek Basin	2.17	4.09
	84 }	Yellow Creek Basin	1.63	3.22
	85 }		1.40	2.72
	93 }		0.64	1.63

TABLE 5.5. (contd)

<u>Month</u>	<u>Grid Point Number</u>	<u>Location</u>	<u>Monthly Mean SO₂ Air Concentration₃ in µg per m³</u>	<u>Monthly Mean Particulate Air Concentration₃ in µg per m³</u>
April	25 }	Near mouth of Parachute Creek	0.67	1.76
	49 }		0.90	1.48
	50 }	Piceance Creek	1.74	2.83
	51 }	Basin	1.72	3.48
	52 }		1.69	4.14
	58 }		1.71	2.37
	59 }	Piceance Creek	3.32	4.54
	60 }	Basin	3.23	6.21
	61 }		3.13	7.88
	65 }	Yellow Creek	0.72	1.41
	66 }	Basin	1.14	2.07
	67 }		1.60	2.55
	68 }	Piceance Creek	2.07	3.04
	69 }	Basin	1.82	3.49
	70 }		1.57	3.95
	74 }	Yellow Creek	1.09	1.98
	75 }	Basin	2.18	3.95
	76 }		1.49	2.74
	77 }	Piceance Creek Basin	0.81	1.53
	84 }	Yellow Creek	1.20	2.27
	85 }	Basin	0.83	1.57
	93 }		0.23	0.59

TABLE 5.5. (contd)

Month	Grid Point Number	Location	Monthly Mean SO ₂ Air Concentration ₃ in µg per m ³	Monthly Mean Particulate Air Concentration ₃ in µg per m ³
July	25 }	Near mouth of Parachute Creek	0.34	0.88
	49 }		2.19	3.47
	50 }	Piceance Creek	4.24	6.65
	51 }	Basin	3.73	7.32
	52 }		3.23	7.98
	58 }		4.20	5.68
	59 }	Piceance Creek	8.19	10.90
	60 }	Basin	7.19	13.30
	61 }		6.20	15.60
	65 }	Yellow Creek	1.37	2.72
	66 }	Basin	2.07	3.77
	67 }		3.48	5.35
	68 }	Piceance Creek	4.90	6.94
	69 }	Basin	4.00	7.37
	70 }		3.10	7.81
	74 }	Yellow Creek	1.98	3.58
	75 }	Basin	3.93	7.13
	76 }		2.77	5.03
	77 }	Piceance Creek Basin	1.60	2.92
	84 }	Yellow Creek	2.47	4.90
	85 }	Basin	1.67	3.26
	93 }		1.01	2.66

TABLE 5.5. (contd)

<u>Month</u>	<u>Grid Point Number</u>	<u>Location</u>	<u>Monthly Mean SO₂ Air Concentration₃ in µg per m³</u>	<u>Monthly Mean Particulate Air Concentration₃ in µg per m³</u>
October	25 }	Near mouth of Parachute Creek	1.18	3.03
	49 }	Piceance Creek Basin	2.18	3.64
	50 }		4.15	6.83
	51 }		3.67	7.35
	52 }		3.19	7.87
	58 }	Piceance Creek Basin	4.15	5.72
	59 }		7.93	10.70
	60 }		7.01	13.00
	61 }		6.08	15.40
	65 }	Yellow Creek Basin	1.59	3.19
	66 }		2.37	4.34
	67 }	Piceance Creek Basin	3.76	5.99
	68 }		5.15	7.64
	69 }		4.10	7.66
	70 }		3.04	7.68
	74 }	Yellow Creek Basin	2.20	4.00
	75 }		4.38	7.98
	76 }		3.38	6.27
	77 }	Piceance Creek Basin	2.38	4.55
	84 }	Yellow Creek Basin	2.53	4.88
	85 }		1.90	3.67
	93 }		0.68	1.77

TABLE 5.6. The Estimated Annual PSD Increment Used Up by a 300,000 bpd Industry Over Class II Areas in the Piceance Basin⁽²⁾

<u>Grid Point Number</u>	<u>Estimated Annual SO₂ Air Concentration₃ in µg per m³</u>	<u>Percentage of Class II PSD Increment</u>	<u>Estimated Annual Particulate Air Concentration₃ in µg per m³</u>	<u>Percentage of Class II PSD Increment</u>
50	3.95	20	6.10	32
58	3.94	20	5.38	28
59	7.63	38	10.27	54
60	5.81	29	10.17	54
61	4.00	20	10.07	53
68	4.43	22	6.32	33

5.4. PROJECTED AIR QUALITY CONSTRAINTS FROM POTENTIAL IMPACTS OUTSIDE OF THE PICEANCE CREEK BASIN

Development and operation of a shale oil industry will be subject to constraint by a variety of air quality regulations. The most significant are the following:⁽¹¹⁾

- New Source Review Procedures (NSRP) and New Source Performance Standards (NSPS) of the EPA
- Air quality maintenance planning, currently involving Federal, state, and local agencies under the State Implementation Plans (SIP)
- Prevention of Significant Deterioration (PSD) regulations adopted by the EPA
- Federal and state permit application regulations for constructing and operating new sources
- New source review procedures adopted by local pollution control districts
- Emission limits and controls required by local pollution control districts.

Few scientists or government officials believe that a shale oil industry in Colorado, Utah, and Wyoming will be allowed to create gross

air pollution problems. In commenting on the prospect of a very large industry (e.g., 8 million barrels per day), one EPA official predicted that "air pollution in the Piceance Basin would be 'twice as bad as the New York-New Jersey area,'" and said that "ozone pollution could be 10 times worse than the current level in Denver."⁽¹⁵⁾ Short of this sort of large scale situation, it is generally conceded that the size of an oil shale industry will be limited by air quality Class I increments at the Flat Tops Wilderness Area.^(13,14)

The EPA has been working for several years to develop a reliable estimate of what size shale oil industry could be operated in the Piceance Creek Basin without violating PSD Class I limits at Flat Tops. Early estimates were as low as 200,000 bpd. In-house studies in EPA have indicated that 400,000 bpd of shale oil could be produced in the Basin without violating these limits.⁽¹⁶⁾ An EPA official stated in June 1980, that it appeared, on the basis of an unpublished study for EPA that 800,000 bpd might be possible.⁽¹⁷⁾ In November 1980, the director of the National Commission on Air Quality, an agency created to advise Congress, indicated that the figure might be as high as 900,000 bpd.⁽¹⁸⁾ In December 1980, the EPA official stated publically that the assumptions and methodology of the contracted study did not hold up under critical examination. With that explanation, he retreated to the 400,000 bpd estimate.⁽¹⁹⁾

If the PSD limit for Flat Tops allows a large industry (e.g., 800,000 bpd), it may be that the deterioration in the Class II areas in and around the Piceance Creek Basin will be exceeded before the Class I limits are reached. This view has been presented by Drake and Huang⁽²⁾ and by EPA,⁽¹⁷⁾ who point out that the Class II limits would affect the clustering and spacing of plants. This constraint on location of facilities would reduce the efficiency of resource use as well as the scale of the potential industry.

One message made obvious by the uncertainties about air quality impacts is the need for improving regional air quality modeling capability and improving data on current meteorological and air quality conditions in the oil shale resource areas, especially in the Piceance Creek Basin. These needs have been emphasized by EPA,⁽²⁰⁾ OTA,⁽⁷⁾ PNL,⁽²⁾ and others.⁽¹⁾ One participant in the developing shale oil industry notes, "Due to the small magnitude of PSD

increments, one should be wary of the small margin for error in computing PSD increments in order to satisfy industry and regulatory agencies.⁽¹¹⁾

The Federal law does not provide a means for allocating available PSD increments among developing industrial plants, except on a first come, first served basis. This practice may very well result in the inability of many prospective shale oil producers to obtain permits. Where older industrial facilities exist in an area, the law allows newer facilities to be added so long as emissions from existing plants are reduced by a like amount. This provision is inapplicable in the oil shale region and probably will continue to be so because all of the plants will be new and will be applying state-of-the-art emission controls. A subsequent developer would have to apply even better measures which might be outside the limits of technological or economic feasibility.⁽⁷⁾

With the obvious benefits to oil companies and to the nation as a whole of a substantial shale oil industry, it is not surprising that there are efforts to bring about some relaxation of current air quality laws, especially as they affect the PSD regulations. While environmental advocates will work to prevent this, it is likely that some regulations will be relaxed. Advisors to the Reagan Administration are making strong recommendations for such changes,⁽²¹⁾ and recent congressional elections resulted in the defeat of many congressmen who played key roles in the 1975-1977 clean air debates and the resulting restrictive legislation.⁽²²⁾

The National Commission on Air Quality has tried to determine how much additional shale oil production could be achieved, beyond the limits of PSD Class I, if the only air quality constraints were the less-strict secondary ambient air standards for sulfur dioxide and particulate matter.⁽¹⁸⁾ In its report of March 1, 1980, the Commission recommended to Congress the following actions:⁽²³⁾

- Eliminate the increment requirements in Class III and most Class II clean-air zones

- Limit Class II to those areas that current law says may not be made into Class III, including large national parks, national primitive areas, national wildlife refuges, and some other areas
- Allow states and Indian tribes to designate Class II zones
- Require that air permits be processed within a year for large polluting sources (emitting more than 500 tons of a pollutant per year), with a six-month deadline for smaller sources
- Eliminate the law's current one-year preconstruction monitoring requirement in clean-air zones, but allow permitting authorities to fix both preconstruction and postconstruction monitoring requirements
- Give states more authority over air quality improvement plans and require quicker review of suggested changes
- Grant new plants a 10-year grace period before requiring any retrofits, unless EPA designates specific new pollutants of concern
- Set uniform emission control criteria for plants locating in clean-air or dirty-air regions. Preconstruction review would be limited to new plants or modifications causing more than 100 tons of emissions per year. Plants emitting less than 500 tons/yr would have to use only new source performance standards. Plants emitting 500 to 1000 tons/yr would have to use stricter "best available control technology" (BACT), while even larger plants would have to adopt stricter controls
- Eliminate fixed deadlines for achieving national air quality standards in highly polluted areas, but continue emission offsets for most areas
- Replace the law's current system of severe sanctions for areas without acceptable air quality improvement plans with a graduated system of sanctions
- Eliminate all Class III strict visibility and other protection for Class I Federal zones.⁽²⁴⁾

The Heritage Foundation, advising President Reagan during the transition between administrations, advocated strongly that PSD Class II and III constraints be eliminated. They would require only that new plants meet relevant new source standards. Current increments for pristine Class I zones would be relaxed and met only on an annual basis.⁽²¹⁾

An Exxon official has noted that the "short-term increments for sulfur dioxide and particulate matter in Class II and more restrictive Class I lands could present 'major' development barriers." He called for the law to be changed to require "only 'best available' technology controls unless health-based ambient air quality standards were threatened."⁽²⁵⁾

The Rio Blanco Oil Shale Company is challenging a recent change in PSD rules which specifies that fugitive dust emissions from synfuels facilities must be counted along with process emissions when plants calculate their total pollution. Since Rio Blanco wants to construct an open pit mine, which would generate substantial dust, the company is afraid that application of the rule will prevent them from taking what they consider to be an essential step in their production of shale oil. A critical question, as yet unanswered, is where the emissions are to be measured relative to the location of the mine.⁽²⁶⁾

One hot debate has concerned the EPA's new visibility standards. Comments from DOE⁽²⁷⁾ and the White House^(27,28) on the proposed standards issued by EPA in May 1980 attacked the rules on many fronts. Of particular concern were measures controlling cumulative impacts in the form of regional haze, or "plume blight," resulting from many plants and the concept of "integral vistas"--scenic views, as determined by Federal land managers, that can be seen from within a Class I area. While DOE claimed that the proposals could "strangle the shale industry and inhibit other synfuels production," the Department of the Interior asserted that the regulations would have minimal impact on synfuels development.⁽²⁹⁾

After some hurried efforts to respond to hundreds of comments, EPA promulgated its regulations on visibility on November 21 in compliance with a court order from a settlement between EPA and Friends of the Earth. As promulgated,

the regulations narrowed but did not remove the "integral vista" provisions, and they clarified the provision that final permitting decisions will be left to the states with the approval of the EPA state implementation plan.⁽³⁰⁾ The states are allowed to consider cost and energy factors in deciding whether to grant permits to plants whose operations could affect integral vistas.⁽³¹⁾

The changes made by EPA have not quieted the objections to the visibility regulations. Industry groups have filed suits. The rules allowed suits to be filed until early February.⁽³²⁾ With all of the controversy, the U.S. Forest Service has decided against recommending creation of any "integral vistas" near pristine wilderness areas.⁽³³⁾ There is speculation that EPA will withdraw the rules.⁽³⁴⁾

One major attack on air quality laws and regulations was focussed on the Colorado state emission limits for SO₂. The Cathedral Bluffs Shale Oil Company (Occidental and Tenneco), holder of the lease on Colorado tract C-b, asked the Colorado Air Pollution Control Commission to change the state limit on SO₂ from shale oil facilities, set in 1977 at 0.3 pounds per barrel. They asked that the limit be set aside in favor of a "best available control technology" (BACT) rule to be applied to individual plants on case-by-case basis.⁽³⁵⁾ Cathedral Bluffs stated that it could achieve an emission rate of only 0.58 pounds per barrel from the Occidental MIS process and 0.41 pounds per barrel using a combined MIS and Lurgi surface retort complex.⁽³⁵⁾ Later, the company indicated that it might be able to hold combined emissions to 0.3 pounds per barrel.⁽¹²⁾ The Rio Blanco Oil Shale Company and the Multi-Mineral Corporation also asked the Commission for this change, while the Union Oil Company, having received a permit under the current rule, objected to the proposal.⁽³⁶⁾ Opposition by Union and by Senator Gary Hart (D-Colorado) was based on the argument that changing the limits would result in exceeding the Class I PSD constraint at Flat Tops Wilderness Area with a smaller industry than otherwise possible. It would, consequently, preclude some prospective shale oil producers from entering the industry. On February 5, 1981, the state agreed to a compromise allowing the Cathedral Bluffs Oil Shale Company to obtain a state air quality permit so long as the firm agrees to an interim production limit and certain other requirements.⁽³⁷⁾

As industrial firms and environmental advocates look at the future, they see uncertainty regarding potential Federal air quality laws and regulations. EPA has been studying, for instance, the possibility of establishing short-term (e.g., 1-hour or 3-hour) standards for SO_2 , which is already controlled to 24-hour periods,^(38,39) because scientific evidence does not preclude the possibility that significant health effects may occur from short exposures to high concentrations of this gas. Short-term limits have also been discussed for NO_2 using similar rationale.^(40,41) Short-term limits would be much more difficult for a shale oil production process to satisfy than would current limits.

EPA has stated that it is most likely that environmental controls required to be applicable to first generation shale oil plants will be set as parts of the terms and conditions of individual permits. The agency has noted that rigid control requirements now might dampen innovation in the synfuels industry.⁽⁴²⁾ Although the case-by-case approach, as argued here, would tend to ease the constraints on industry, policy statements from the Region VIII (Denver) office of EPA have suggested that the agency will push for application of "better than best available" air pollution controls.⁽⁴³⁾

5.5. CARBON DIOXIDE

Carbon dioxide (CO_2) concentrations in the atmosphere of the world have been increasing for some time. In July 1979, the National Research Council of the National Academy of Sciences convened a study group to assess the scientific basis for projection of possible future climatic changes resulting from man-made releases of carbon dioxide into the atmosphere. The report on that study noted:⁽⁴⁴⁾

We now have incontrovertible evidence that the atmosphere is indeed changing and that we ourselves contribute to that change. Atmospheric concentrations of carbon dioxide are steadily increasing, and these changes are linked with man's use of fossil fuels and exploitation of the land. Since carbon dioxide plays a significant role in the heat budget of the atmosphere, it is reasonable to suppose that continued increases would affect the climate.

It is generally anticipated that the concentration of CO_2 in the atmosphere will double from the current (1979) level of about 334 ppm by sometime in

the first half of the twenty-first century, possibly about 2035, resulting in a global surface warming of between 2°C and 3.5°C.^(44,45)

Concern about the CO₂ problem has led to debate about the increased concentrations which might result from synfuels production. Accurate predictions are beyond the current state-of-the-art. They are complicated by the large number of variables which affect the rate of concentration change, lack of information on these variables, limitations of models to accommodate all of these variables, and knowledge of coefficients describing relationships among the variables.⁽⁴⁴⁾ Some authors have warned that, depending largely upon the temperature of the retorting processes applied, production and use of shale oil could release one and one-half (lower temperatures) to five times (higher temperatures) more CO₂ than burning of conventional oil to obtain the same amount of energy.⁽⁴⁶⁾ Predictions for coal-derived synfuels are higher.⁽⁴⁷⁾

Estimates are that global synthetic fuels production of 5 to 6 million barrels per day oil equivalent over the next 20 years could add 2 to 3 ppm CO₂ to the atmosphere by the year 2000.⁽⁴⁸⁾ Over 50 years this might produce an increase of 20 ppm from synthetic fuels production.⁽⁴⁵⁾

The general conclusion of most of the studies conducted in the past few years is that a synfuels industry will add to the CO₂ increase in the atmosphere. However, most sources^(44,49) seem to agree that:

A six million barrel per day additional synfuel capacity will have a trivial effect on the CO₂ concentrations when added to the present world mix of fossil fuels. There should be no detectable difference in the climate from these additions.⁽⁵⁰⁾

5.6 REFERENCES FOR CHAPTER 5

1. MITRE Corporation, METREK Division. 1979. Health and Environmental Effects of Oil Shale Technology: A Workshop Summary and Panel Reports for the Federal Interagency Committee on the Health and Environmental Effects of Energy Technologies. PB-297096, National Technical Information Service, Springfield, Virginia.
2. Drake, R. L., and C. H. Huang. 1981. Air Quality Impacts. Pacific Northwest Laboratory, Richland, Washington. See Volume 3 of this assessment report.

3. Beery, W. T. 1978. "Report on the Sixth APCA Government Affairs Seminar: The New Clean Air Act, Its Impact on Energy and Growth." J. APCA, 28, pp. 573-583.
4. Council on Environmental Quality. 1980. Environmental Quality-1979: The Tenth Annual Report of the Council on Environmental Quality. Document No. 041-011-00047-5, U.S. Government Printing Office, Washington, D.C.
5. Bureau of National Affairs, Inc. Current. Environment Reporter: State Air Laws. Bureau of National Affairs, Inc., Washington, D.C.
6. Denham, R. S. 1978. "Impact of the 1977 Clean Air Act Amendments and EPA Regulations on Power Plant Siting." APCA Paper No. 78-3.4, presented at the 71st Annual Meeting of the Air Pollution Control Association, Houston, Texas.
7. U.S. Congress, Office of Technology Assessment. 1980. An Assessment of Oil Shale Technologies. U.S. Government Printing Office, Washington, D.C.
8. Crawford, K. W., C. H. Prien, L. B. Baboolal, C. C. Shih, and A. A. Lee. 1977. A Preliminary Assessment of the Environmental Impacts from Oil Shale Developments. Report by TRW Environmental Engineering Division and Denver Research Institute to U.S. Environmental Protection Agency, Contract 68-02-1881. EPA 600/7-77-069. U.S. Environmental Protection Agency, Cincinnati, Ohio.
9. Bureau of National Affairs, Inc. Current. Environment Reporter: Federal Regulations. Bureau of National Affairs, Inc., Washington, D.C.
10. Wolf, M. A. 1980. An Analysis of Baseline Data from Federally Leased Oil Shale Tracts in Colorado and Utah. RLO-227-T-31-5, Air Resources Center, Corvallis, Oregon.
11. Ertugrul, A. M., R. F. Sober, S. Wiedenbaum, and J. E. West. 1979. "An Introduction to Environmental Considerations of Commercial Oil Shale Development, with Reference to Air Quality Concerns." Paper presented at Symposium on Synthetic Fuels from Oil Shale, Atlanta, Georgia, December 1979.
12. Energy Development Consultants, Inc. 1981. Technology Characterization and Production Scenarios. Golden, Colorado. See Volume 2 of this assessment report.
13. Thoem, T. L. 1980. "EPA and Oil Shale." Paper presented at the Outlook for Oil Shale Conference, Denver, Colorado, June 19 and 20, 1980.
14. Werbe, N. 1980. Minutes of Air Quality Research Meeting. The Oil Shale Task Force of DOE, Denver, Colorado, October 6, 1980.
15. "Exxon Projections Criticized." July 28, 1980. Synfuels Week, p. 8.

16. "EPA Finishing Shale/Air Study." June 2, 1980. Synfuels Week, p. 7.
17. "EPA Doubles Feasible Shale Projection." June 30, 1980. Synfuels Week, p. 3.
18. "Air Commission Estimates Shale Potential." November 24, 1980. Synfuels Week, p. 4.
19. "EPA Retreats on Shale Production." December 8, 1980. Synfuels Week, p. 4.
20. "EPA Details Oil Shale Research Needs." December 22, 1980. Synfuels Week, p. 4.
21. "Reagan Urged to Relax Air Rules." November 17, 1980. Synfuels Week, p. 4.
22. "Clean Air Congressmen Purged." November 10, 1980. Synfuels Week, p. 8.
23. "Air Commission Wants Clear Air Streamlining." February 23, 1981. Synfuels Week, pp. 2,3.
24. "NCAQ Synfuels Findings Challenged." March 9, 1981. Synfuels Week, p. 8.
25. "Exxon Official Urges Clean Air Act Changes." November 24, 1980. Synfuels Week, p. 3.
26. "PSD Rules Face Rio Blanco Test, EPA Says." October 27, 1980. Synfuels Week, p. 2.
27. "Visibility Rules May Kill Shale Industry." August 25, 1980. Synfuels Week, pp. 1-2.
28. "White House Economists Score EPA Plan." September 8, 1980. Synfuels Week, p. 6.
29. "EPA Starts Last-Minute Visibility Study." October 6, 1980. Synfuels Week, p. 3.
30. "EPA Visibility Regulations Signed; 'Integral Vistas' Protection Narrowed." November 28, 1980. Environment Reporter: Current Developments, pp. 1098-1099.
31. "Repeal of Visibility Rules Asked." December 1, 1980. Synfuels Week, pp. 1-2.
32. "EPA Sued on Visibility." December 15, 1980. Synfuels Week, p. 1.
33. "USFS Nixes Integral Vistas." February 9, 1981. Synfuels Week, p. 1.

34. "Industry Groups Sue on Visibility." February 16, 1971. Synfuels Week, p. 7.
35. "Oxy to Ask for Break on Emissions." September 8, 1980. Synfuels Week, p. 4.
36. "Union Wants Col. to Keep Shale Standard." September 22, 1980. Synfuels Week, p. 2.
37. "Colorado Eases Shale Standard for CB." February 16, 1981. Synfuels Week, p. 2.
38. "EPA Ponders Short-Term SO₂ Standard." August 18, 1980. Synfuels Week, p. 7.
39. "EPA Slates SO₂, Particulate Forums." November 17, 1980. Synfuels Week, p. 2.
40. "EPA Eyes Short-Term NO₂ Standard." November 3, 1980. Synfuels Week, p. 3.
41. "EPA Advisors Nix Short-Term NO₂ Standard." November 24, 1980. Synfuels Week, p. 8.
42. "Synfuels Developers Can Build to Meet Federal Pollution Limits, Costle Says." January 2, 1981. Environment Reporter: Current Developments, pp. 1348-1349.
43. "EPA/Denver Wants Strict Air Pollution Controls." May 12, 1980. Synfuels Week, p. 2.
44. National Research Board, National Academy of Sciences. 1979. Carbon Dioxide and Climate: A Scientific Assessment. Climate Research board, Washington, D.C.
45. "Carbon Dioxide and Synfuels." January 1980. CO₂: Status Report: Carbon Dioxide Effects Research and Assessment Program, U.S. Department of Energy, 1(2). Washington, D.C.
46. Sundquist, E. T., and G. A. Miller. May 16, 1980. "Oil Shales and Carbon Dioxide." Science, 208, 740-741.
47. Handler, Philip. July 19, 1979. Letter to Senator Abraham Ribicoff, in U.S. Senate, Committee on Governmental Affairs. 1979. A Symposium: Carbon Dioxide Accumulation in the Atmosphere, Synthetic Fuels and Energy Policy. 96th Congress, First Session. U.S. Government Printing Office, Washington, D.C.

48. "CO₂ Symposium: Findings and Recommendations," in U.S. Senate, Committee on governmental Affairs. 1979. A Symposium: Carbon Dioxide Accumulation in the Atmosphere, Synthetic Fuels and Energy Policy. 96th Congress, First Session. U.S. Government Printing Office, Washington, D.C.
49. Rotty, R. M. 1979. Uncertainties Associated with Global Effects of Atmospheric Carbon Dioxide, ORAU/IEA-79-6 (0), Institute for Energy Analysis Oak Ridge, Tennessee.
50. Elliott, W. P., and L. Machta. "Synthetic Fuels and Atmospheric CO₂," in U.S. Senate, Committee on Governmental Affairs. 1979. A Symposium: Carbon Dioxide Accumulation in the Atmosphere, Synthetic Fuels and Energy Policy. 96th Congress, First Session. U.S. Government Printing Office, Washington, D.C.

6.0 SOLID WASTE FROM MINING AND SURFACE RETORTS

All shale oil production systems will produce large quantities of spent shale. In-situ processes will abandon these materials in the retort. Management of these retorts and associated hazards are discussed in Chapter 7. Above ground processes will create large volumes of spent shale to be disposed of on the ground surface. In addition, there will be raw shale fines, spent catalysts from shale oil upgrading, and sludges from environmental control equipment. These may be disposed to the spent shale piles. If open pit mining were involved, there would also be a large volume of overburden material. This would eventually be returned to the mine.

The disposal of solid wastes has the potential to cause a variety of environmental and ecological impacts. The mere volume of wastes from above ground retorting will create major changes in landscapes and topographic features. Dust from handling the material or from wind erosion of piles may degrade air quality. Finally, the materials will contain a wide variety of soluble salts, residual organic material, and trace elements, implying potential degradation of surface and ground waters. Some of these soluble inorganic and organic components are potential threats to wildlife, domestic livestock, and human beings if the substances are allowed to enter water bodies or plants used as food. Potential water quality degradation by organics, trace elements, or increased salinity in the Colorado River or associated ground waters are of particular concern since the river is of enormous importance as a source of drinking and irrigation water for parts of seven western states and Mexico.

Much planning has occurred as prospective shale oil companies and the government have sought ways to prevent the occurrence of serious environmental or health and safety impacts from a shale oil industry. Primarily, these plans address modified in-situ (MIS) and surface facilities. They include ways to remove or stabilize soluble residuals present in the raw or spent shale, to line and construct waste shale piles so that leachates will not escape, and to revegetate these piles after they are completely constructed.

This chapter focuses first on the character of solid wastes from shale oil production processes. It then considers methods for disposing of the waste

materials, including revegetation. Much of this chapter is taken directly from the supporting study on solid waste conducted for this assessment by J. M. Zachara of the Pacific Northwest Laboratory (PNL).⁽¹⁾ It is included as Volume 4 of this report.

6.1 CHARACTERIZATION OF RAW OIL SHALE

6.1.1 Organic Materials

Organic materials present in raw oil shale from the Green River Formation exist as soluble bitumens (20%) and insoluble kerogen (~80%). The hydrocarbon portion of the soluble fraction has been characterized in some detail; however, most of the high molecular weight constituents have not been identified.

Although most of the organic carbon found in oil shale is present as insoluble kerogen, the composition of this fraction has not been fully defined. Experiments have suggested that kerogen exists as a complex polymeric assemblage composed of linear networks of cyclic rings of methylene groups with associated long chains and aromatic structures. Details are available in reviews by Robinson.⁽²⁻⁴⁾

6.1.2 Chemical Composition

The concentration and mineralogical residence of elements have been investigated in the Green River oil shales from the Piceance Creek Basin.⁽⁵⁻⁸⁾ A summary of the major elements and their probable mineralogical residences is depicted in Table 6.1. The concentration range of select minor elements in the Green River Formation generally considered of environmental concern or enriched (above that normally found in sedimentary rocks) is presented in Figure 6.1.

6.2 CHARACTERIZATION OF SURFACE RETORTED OIL SHALE

The physical and chemical characteristics of retorted shale are a function of the composition of the raw shale, the particle size of the raw shale feedstock, and the retorting process and parameters used (e.g., temperature, heating rate, gas composition, and degree of combustion). A variety of retorting processes are likely to be incorporated in a commercial shale oil industry, resulting in different kinds of spent shale. Table 6.2 summarizes those

TABLE 6.1 Concentration of Selected Elements and Their Probable Mineral Residences in Raw Shale from the Piceance Creek and Uinta Basins^(5,9)

<u>Element</u>	<u>Range in Concentration (Weight Percent as oxide)</u>	<u>Principal Minerals</u>
Silicon	25 to 41	Quartz, albite, feldspar, analcime
Aluminum	4 to 10	Albite, dawsonite, feldspar, analcime, amorphous material
Iron	2 to 4	Pyrite, dolomite, siderite
Magnesium	1 to 8	Dolomite, calcite
Calcium	3 to 4	Calcite, dolomite
Potassium	1 to 2.5	Feldspar
Sodium	1 to 2.5	Dawsonite, albite, analcime
Sulfur	0.7 to 1.2	Pyrite, kerogen
Phosphorus	0.05 to 0.8	Apatite

processes used as bases for processes incorporated in the 300,000 barrel per day industry scenario developed for this assessment.

Few published studies, with the exceptions of Fruchter et al.⁽¹⁰⁾ and Wildeman⁽¹¹⁾ have investigated the redistribution of elements during the retorting process. Fruchter determined that approximately 1% or more of the original weight percent of organic carbon, As, Co, Hg, N, Ni, S and Se were released during the Paraho retorting process and redistributed to the shale oil product, retort water, or offgas. Of these, 50% to 60% of the Hg, N, and organic C; 20% of the S; and 5% of the As and Se were released. Most of the elements analyzed, however, were conserved in the retorted shale. Wildeman⁽¹¹⁾ investigated elemental material balances for both the TOSCO and Paraho retorts and calculated enrichment ratios for select elements in the retorted shales. He also determined that the inorganic chemical composition of the raw shale feedstocks and the retorted shales were surprisingly homogeneous over time for each of the processes.

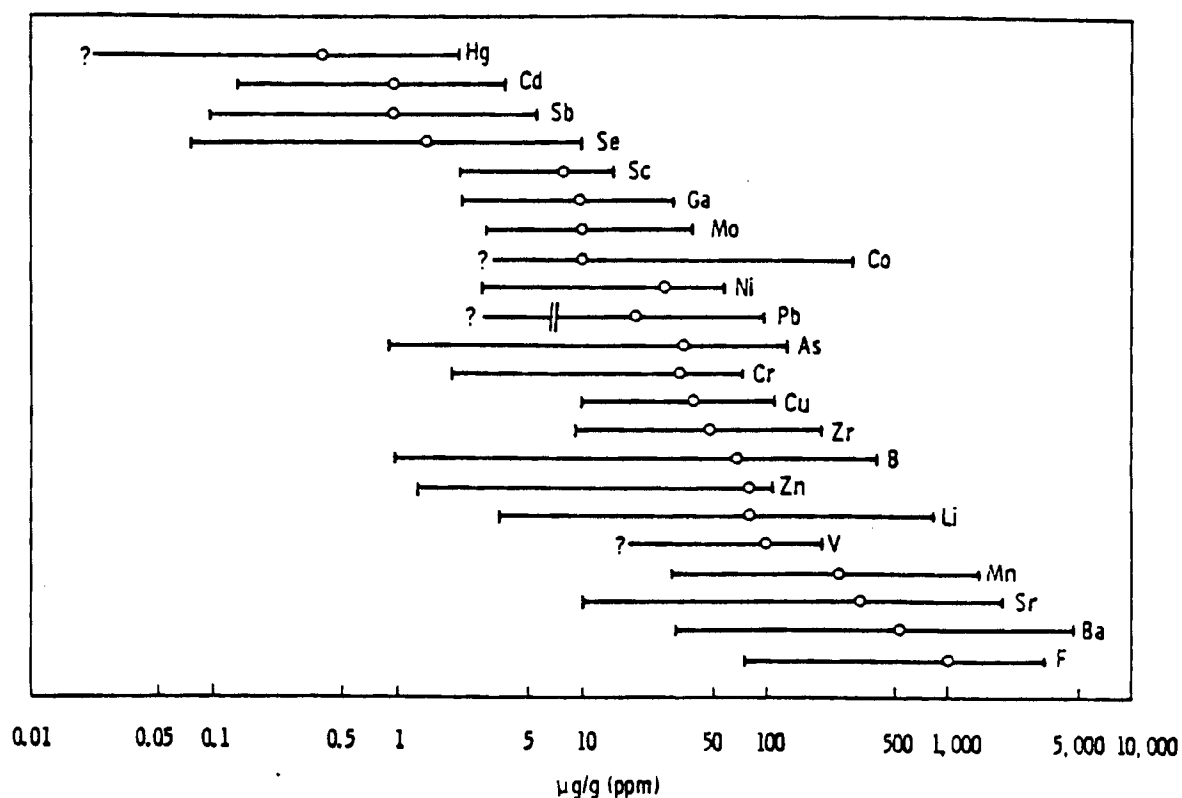


FIGURE 6.1. Observed Concentration Ranges in ppm and Probable Average Values for Minor Elements in Green River Oil Shales from the Piceance Creek, Uinta, and Green River Basins.⁽⁶⁾

6.2.1 Mineralogy

With the conservation of most of the trace elements and incomplete oxidation of organic carbon in the retorted shale, one major environmental concern has been the possible increased solubility of macro and trace elements and organic carbon resulting from mineral and kerogen decomposition reactions which have occurred during retorting.⁽¹⁴⁾ Minerals such as nahcolite, dawsonite, and analcime decompose thermally by 400°C.^(15,16) The carbonates, dolomite, ankerite and calcite, begin to decompose at 500° to 600°C.⁽¹⁷⁾ The retorting atmosphere and the mineralogical matrix can substantially alter these decomposition temperatures.^(17,18) These reactions may lead initially to the formation of water soluble amorphous oxides, and subsequently, to secondary crystalline mineral phases if requisite temperature and atmospheric conditions are reached. For example, retorting temperatures in excess of 700°C commonly instigate

TABLE 6.2. Retorting Processes(12,13)

Process	Particle Size of Raw Shale Feed (cm)	Temperature Range Retorting (C)	Heat Source	Combustion of Residual Carbon
Direct				
Paraho	0.95 to 8.89	550 to 750	Internal combustion	X
Union A		up to 1093	Preheated combustion air	X
SGR		Retort 520, gasifier 871	Synthesis gas (gasi- fied residual carbon plus steam)	X
B/SGR-3	0.32 to 5.08	Retort 480 to 540, combuster 820	Externally produced combustion gases	X
Superior	<0.25 to 7.50		Internally produced combustion gases	X
Indirect				
Union B	0.32 to 5.08	510 to 540	Hot recycle gas	
TOSCO II	1.27	480	1.27 cm ceramic balls	
Lurgi-Ruhrgas	<0.64	Retort 530, heat carrier solids 630	Small particle size heat carrier solids (pos- sibly retorted shale)	X

silication reactions, with the subsequent formation of pyroxenes.^(17,18) Quantitative studies identifying the extent of mineral decomposition reactions occurring during surface retorting processes have not been reported.

6.2.2 General Physical and Chemical Characteristics

The discussion in this chapter concerning specific retorting processes is based on those processes as presented in the literature. Since the firms working with these processes are continually improving them, comments here may not be representative of current process performance.

Published studies on surface retorted shales have dealt almost exclusively with materials generated at: 1) the Colony site by the TOSCO II process, and 2) at Anvil Points by the USBM gas combustion and the Paraho Direct Mode processes. These are semi-works scale, experimental facilities, and the products and wastes do not necessarily represent the materials which will be produced by commercial operations. They reflect a broad array of experimental process conditions manipulated by the operators to increase both product yield and the thermal efficiency of the process. Only fragmentary data could be found on the Union retorted shale,⁽¹⁹⁾ and no published information was located on Green River oil shales retorted by the Lurgi-Ruhrgas process.

The Paraho and TOSCO II retorted shales differ significantly. The TOSCO II process retorts at approximately 400°C and produces a carbonized residue containing some residual high molecular weight hydrocarbons;⁽²⁹⁾ 63% to 75% of the materials are <0.05 mm (sand) in size. Temperatures reached are probably adequate to induce the decomposition of at least a portion of the nahcolite, dawsonite, and analcime. The pH of the TOSCO retorted shale, when mixed with water (1:1), is approximately 8 to 9.⁽²⁰⁾ The Paraho process utilizes the direct, though partially anoxic, combustion of the carbonaceous residual as a heat source. As a result, it produces a retorted shale with less residual organic carbon than those produced by indirect processes.^(14,21) Merino and Crookston⁽²²⁾ and Schmidt-Collerus⁽²³⁾ report organic carbon values of up to 5% in the TOSCO retorted shale, whereas Garland et al.,⁽²⁴⁾ found approximately 2.6% organic carbon in the Paraho retorted shale. The higher retorting temperatures (600° to 750°C) reached in the Paraho process,⁽²⁵⁾ induce the

decarbonation of a portion of the carbonate minerals to their respective oxides, resulting in pH values of from 11 to 12 when contacted with H_2O .⁽²⁶⁾ Likely due to the larger minimum size required for raw shale feedstock, retorted shale produced by the Paraho process is considerably coarser than the TOSCO retorted shale. Approximately 92% of the materials are sand size (0.05 mm) or greater; 34% are greater than 8 mm.⁽²⁷⁾

In the Union A and SGR processes, the residual carbon is combusted at approximately 940°C and the resulting retorted shale has low levels of organic carbon and is nearly free of carbonate minerals, which have decomposed to oxides. Silication reactions are initiated, fusing or klinkering a portion of the retorted shale.^(13,23,28) However, a modification of the Union B process will likely be used in the initial commercial-scale retorts.⁽²⁸⁾ This indirect process produces a black carbonized retorted shale residue similar to that produced by the TOSCO II process. Refinements to the Union B process might include a secondary combustion vessel where a portion of the residual carbon is combusted as a heat source.⁽¹³⁾

The pH of saturated extracts of the Union A and SGR processes is approximately 11, while that from the Union B process is 8.5, the particle sizes are relatively coarse with 32% to 97% greater than 2 mm and 18% to 13% less than 1 mm.⁽²⁸⁾ Summaries of the chemical characteristics of the TOSCO II retorted shales can be found in a report by Wildeman⁽¹¹⁾ and an Environmental Impact Statement by the U.S. Department of the Interior (DOI).⁽²⁹⁾ Chemical characteristics of the Paraho retorted shale are discussed by Fruchter et al.,⁽¹⁰⁾ Wildeman,⁽¹¹⁾ Garland et al.⁽²⁴⁾ Most notable are the concentrations of organic carbon, N, S, F, B, V, Sr, Li, Zn. A select compilation of the elemental concentrations in retorted shales is presented for TOSCO and Paraho in Table 6.3 and for Union in Table 6.4.

The Lurgi-Ruhr gas process (indirect) will likely produce several grades of retorted shale that have been exposed to differing temperatures and degrees of combustion. This will result from the use of a hot recirculating shale residue, heated by combustion to 630°C, as the heat exchange media. In this process, raw shale is mixed with 6 to 8 times its volume of hot circulating shale residue, raising its temperature to 530°C at which point the evolution of gas,

TABLE 6.3. Select Elemental Concentrations in Raw and Retorted Paraho and TOSCO Oil Shales(10,11,22,24)

	Paraho(10)		TOSCO(11)	
	Raw	Retorted	Raw	Retorted
	Shale	Shale	Shale	Shale
	Wt.%		Wt.%	
ORG C		2.39(24)		5.5(22)
C	15.5	6.1		
H	1.50	0.17		
N	0.66	0.58		
S	0.60	0.48		
Ca	10.1	13.3	9.8	11.3
K	1.61	1.86	1.25	1.50
Mg	3.46	4.32	2.6	3.9
Na	1.69	2.19	1.43	1.74
Si	15.0	13.2	13.0	16.0
Al	3.77	4.83	3.4	4.2
Fe	2.07	2.40	1.89	2.45
	ppm		ppm	
F		1660	1020	1490
Sr	700	800	640	780
Ba	510	600	1310	1580
Mn	315	396	271	334
B	94	107	110	146
As	44	59	70	82
Cu	40	56	48	62
Cr	34	44	36	42
Pb	27	35	30	41
Ni	29	32	29	34
Zn	64	82	72	105
Mo	22	31	28	36
Se	3.1	3.3	4.1	4.9
Cd		0.57(24)	1.05	0.98
	ppb		ppb	
Hg	89	35		

shale oil vapor, and water vapor occurs.(12,30) No information is presently available on the physical or chemical characteristics of the Lurgi-retorted shales.

6.2.3 Organic Materials

Published information is scarce on the composition and identity of the residual organic fraction in surface retorted shales. No systematic studies

TABLE 6.4. Chemical Properties of Union Oil Retorted Shale(28)

Components(a) Wt%	Retort A Shale Ash	SGR Retort Decar- bonized Shale	Retort B Retorted Shale
SiO ₂	35.3	39.2	31.5
CaO	27.2	27.3	19.6
MgO	9.0	8.2	5.7
Al ₂ O ₃	8.5	8.9	6.9
Fe ₂ O ₃	7.3	3.8	2.8
Na ₂ O	5.5	3.7	2.2
K ₂ O	2.8	2.7	1.6
SO ₃	0.1	1.4	1.9
P ₂ O ₅	2.2	0.5	0.4
Mineral CO ₂	1.6	3.1	22.9
Organic C	0.5	0.3	4.3
Nitrogen, Kjeldahl			0.2
Ignition Loss @ 950°C, Wt%	2.1	3.4	26.9
Free Silica (quartz), Wt%	<2.0	2 to 5	8.0
pH of Slurry	12.5 to 13 (est)	12.5	8.7

(a) Analyses determined by heating sample to 950°C except for pH measurement. Analyses by Union Research Department.

have been reported which identified as a function of feed stock or retorting conditions both the quantity and composition of organic carbon or of water soluble, solvent extractable, or insoluble carbon residues in the retorted shale. Caolo, et al.,⁽³¹⁾ prepared both aqueous and methylene chloride extracts of TOSCO and Paraho retorted shales. Specific compounds were not identified in the aqueous extracts, however, GC and GC/MS analysis indicated that saturate normal hydrocarbons (including isoprenes, phytane, and pristane) and naphthalenes were the primary constituents extracted by methylene chloride. The percentage of the total organic carbon removed by these extraction

procedures was not presented. Schmidt-Collerus⁽²³⁾ performed aqueous and benzene extractions on various retorted shales of differing ages to identify potential carcinogens. He found that the benzene soluble fraction of carbonaceous retorted shale (up to 5% of the residual organic carbon) ranges from 0.02% to 0.20% by weight, depending on the retorting conditions and age of the retorted shale. Small quantities of polycondensed aromatic hydrocarbons and aza-azarines (AA) were identified; however, an identification of the distribution of compound classes or prominent functional groups present in the retorted shales was not attempted.

6.3 LEACHING OF RAW AND RETORTED SHALE

Laboratory leaching experiments with raw and retorted shales have been performed using batch extraction and column leaching systems. Batch extractions are used to identify the total quantity of solubles present. Column studies simulate the composition of solutions generated under natural leaching conditions, where the quantity and identity of solubles released are determined with respect to pore volumes of water passed through the material.

6.3.1 Laboratory Studies

Laboratory leachate data on raw and retorted shales have been published by several groups, including Schmehl and McCaslin,⁽³²⁾ Ward and Reinecke,⁽³³⁾ DEI,⁽²⁵⁾ the University Cooperative Studies,⁽³⁴⁾ Garland et al.,⁽²⁴⁾ Stollenwerk and Runnells,⁽²⁰⁾ and Runnells et al.⁽³⁵⁾

Most column studies have concentrated on the TOSCO II and Paraho retorted shales, and have shown that a majority of the solubles are liberated in passage of the first 1 to 2 column volumes of water. These studies have also shown that the pH of leachates from Anvil Points and Colony raw shales and from the TOSCO II retorted shales range from 7.8 to 8.4 while the pH of leachates from Paraho retorted shale ranges from 10 to 12.^(26,35) Initially, both retorted shales produce saline leachates with total dissolved solids (TDS) levels in the first column volume ranging from 8,000 to 12,000 mg/l.⁽²⁰⁾ The specific conductance of column leachates from the Paraho retorted shale dropped from 30 mmhos/cm (TDS ~18,600 mg/l) in the first column volume to approximately

2 mmhos/cm after the first 5 column volumes.⁽³⁵⁾ The initial leachates were 0.1 to 0.2 M Na₂SO₄, and the pH ranged between 11 to 12 throughout the course of the study. The TDS concentration of initial pore volumes from Colony raw shales is approximately 3700 to 4700 mg/l. The release of solubles from Anvil Points raw shales varies considerably with water retention time and ranges between 2170 to 7440 mg/l.⁽³⁵⁾ Stollenwerk and Runnells⁽²⁰⁾ determined that Mo, F and B, in addition to salts, were released from the TOSCO II shales in levels exceeding present irrigation or potable water quality standards, and a more recent publication⁽³⁵⁾ suggests that raw shales might release even greater quantities of Mo, B, and F. The release of additional trace metals from both raw and retorted shales in the absence of appreciable organic complexation is low because of probable control of hydroxide solubility. Table 6.5 summarizes the concentrations of selected solubles released from Paraho and TOSCO raw and retorted shales. A complete set of elemental concentrations, including organic carbon, has not yet been published on laboratory column leachates from the Paraho, TOSCO, or Union retorted shales.

TABLE 6.5. Concentrations in the First Column Volume of Leachate from Mahogany Zone Raw and Retorted Shales⁽³⁵⁾

	<u>TOSCO Raw</u>	<u>TOSCO II Retorted</u>	<u>Paraho Raw</u>	<u>Paraho Retorted</u>
pH	7.9	8.1	8.3	9.0
EC mmhos	6.00	15.5	3.5	12.0
TSD mg/L	3720	9600	2170	7440
Approximates				
Mo mg/L	4.2	10.0	17.5	1.0
B mg/L	13.0	6.0	26.0	0.3
F mg/L	27.0	6.3	52.5	3.5
As µg/L	18	31	100	80
Se µg/L	115	19	95	32

(a) Columns were equilibrated under saturated conditions for 10 days prior to leaching.

6.3.2 Field Studies

Reports from several field studies have defined the composition of leachates and percolates from surface retorted shales produced under natural weathering conditions. These include Ward and Reinecke,⁽³³⁾ Harbert and Berg,⁽³⁶⁾ and Garland et al.⁽²⁴⁾ All have concluded that leachates, percolates, and to some extent, surface runoff, contain elevated salinity levels when compared to local surface waters. Garland et al.⁽²⁴⁾ determined that the total concentration of major elements in the Paraho retorted shale was significantly different from a representative local soil. Although Al, Fe, K and Si are in similar concentration, the remaining major elements (Ca, Mg, Na) are elevated in the retorted shale relative to the soil. These authors systematically obtained water samples from large field lysimeters containing Paraho retorted shale and local soil materials. Select results from the study are presented in Table 6.6. The ranges presented for the retorted shale and the soil depict the elution profile, or the leaching of a pulse of solubles from these materials. High values on the left hand side of the column represent concentrations in the initial leachates, while those on the right show concentrations after one year of weathering. The soluble species most significant in leachates from the retorted shale are SO_4 , S_2O_3 , Cl, organic C, Na, K, Mo, F and Li. The presence of S_2O_3 , a reduced sulfur species that does not exist at equilibrium under aerobic conditions, reflects the reduced nature of the retorted shale. These authors suggest that the oxidation of reduced sulfur species to SO_4 is a likely mechanism accounting for changes with time in leachate pH and composition. Dissolved organic carbon values are also highest (400 ppm) initially. Dissolved organic carbon should be evaluated from the standpoint of ecological and health effects, and it could be important in the mobilization of trace metals by complexation. Unfortunately, there have been few reported studies that have identified specific organic compound classes in retorted shale leachates. In laboratory studies, Schmidt-Collerus⁽²³⁾ found that approximately 20% of the total benzene extractable carbon (≈ 0.20 wt%) from carbonaceous retorted shale was water soluble. Azarine compounds and polycyclic aromatic hydrocarbons (PAH) were identified in this fraction. After one year of field weathering, the only trace elements leaching from the retorted shale in

TABLE 6.6. Composition of Water Samples and Leachates from the Anvil Points Experimental Site at the DOE Rifle Oilshale Facility⁽²⁴⁾

	Retorted Shale (lysimeter Leachate)		Soil (lysimeter Leachate)		Irrigation Water (Colorado River)
	a	b	a	b	c
pH	11.5 to 6.9		8.5 to 7.9		8.3 to 7.7
Cond mmhos/cm	30 to 8		4.8 to 4.3		3.2 to 2.8
	-----mg/l-----				
Total C	429 to <2		320 to 48		100 to 30
Org C	400 to <2		145 to 36		32 to <2
SO ₄	20,000 to 3,000		2,050 to 1,380		1,070 to 1,400
S ₂ O ₃	2,100 to <10		<10		<10
Cl	2,200 to 70		520 to 260		140 to 130
F	13 to 3		1.4 to 0.6		0.5 to 0.2
NO ₃	6 to <0.1		41 to 2		20 to 14
Al	0.1 to 0.0005		0.5 to <0.0005		0.25 to 0.04
As	0.08 to 0.007		0.006 to 0.003		0.001
B	3 to 0.5		1.7 to 1.2		0.3 to 0.2
Ca	530 to 140		170 to 72		180 to 160
Fe	0.3 to <0.01		0.031 to <0.01		0.02 to <0.01
Mg	0.2 to 140		181 to 185		150 to 130
Mo	9.5 to 1.2		0.6 to 0.02		0.04 to 0.02
K	1,230 to 320		90 to 19		8.2 to 6.7
SiO ₂	35 to 11		34 to 20		2.6 to 2.2
Na	10,400 to 1,500		895 to 470		400 to 330
Sr	13 to 4		3 to 1.9		2.5 to 2.2
Li	20 to 5		0.09 to 0.03		0.09 to 0.04

(a) Concentrations in initial leachates.

(b) Concentrations after one year of leaching.

(c) Range in concentration of irrigation water applied.

higher concentrations than from the soils were As (x 2-10), Mo (x 5-10), B (x 0.15-15), and F (x 2-10).⁽²⁶⁾ After this same time period, the alkali and alkali earth metal elements were also being released in levels higher than soils, Li (x 200-400), Na (x 2-5), K (x 10-30), Ca (x 3-4), and Sr (x 2-3). Organic carbon levels were significantly reduced and the pH of the leachates had dropped from 11.5 to 6.9. This pH drop was observed in laboratory studies where retorted shale had been subjected to sequential wet and dry cycles.^(26,35) Detailed field studies have not been reported on shales retorted by other oil shale extraction processes.

6.4 LAWS AND REGULATIONS AFFECTING SOLID WASTE DISPOSAL

Management of solid wastes from oil shale mining and processing is not clearly prescribed by existing laws and regulations. This situation is discussed in the assessment of oil shale prepared by the Office of Technology Assessment (OTA).⁽³⁷⁾

OTA points out that each state has reclamation laws that apply to all mining operations. Under the Colorado Mined Land Reclamation Act, Colorado has set performance standards similar to, but more generalized and in some respects less restrictive than, the Federal Coal Act. The Utah Mined Land Reclamation Act establishes only general reclamation goals. It does not provide detailed environmental performance standards. In both states, the laws provide for surety (performance bonds) and enforcement, and both states call for successful revegetation.⁽³⁷⁾

Oil shale operations on Federal lands are subject to regulation by the U.S. Geological Survey (USGS). While oil shale mining is not within the purview of the Surface Mining Control and Reclamation Act, that act, which is applicable only to coal mining, provides a guide for oil shale operators. Eventual laws applicable to oil shale can be expected to have similar requirements.⁽³⁷⁾ Other applicable Federal laws, applying only to Federal lands, provide general goals and optional procedures for regulation. Consequently, the most significant regulations currently applied to oil shale lands are the prototype oil shale leases. These stipulations allow for the experimental nature of the oil shale operations by providing a period of time in which appropriate

reclamation methods are to be developed by the firms holding the leases. Firms failing to accomplish this will be required to cease operating.⁽³⁷⁾

There is some question about whether the restrictive measures of the Resource Conservation and Recovery Act (RCRA), relative to hazardous wastes, will apply to shale oil production. Some statements by EPA officials have predicted that the measures will be applied by the agency, with specific hazardous waste disposal rules being promulgated by 1983 or 1984.⁽³⁸⁾ Other officials in EPA disagree. One recently noted that in light of hazardous criteria concerning ignitability, corrosivity, reactivity, and toxicity, the most likely basis for declaring processed shale hazardous was toxicity. Since the proposed criteria have been relaxed 10-fold in this area, it is most likely that spent shale will be treated as a nonhazardous solid waste subject to 40 CFR 257 regulations.⁽³⁹⁾ Other sources indicate that oil shale wastes are unlikely to satisfy the criteria for inclusion under the law. In a recent study for the Department of Energy, a preliminary analysis of a single sample of solid waste from the Paraho process qualified for exclusion from the hazardous waste regulations.⁽⁴⁰⁾ In the report on that same study, it was estimated that application of the RCRA hazardous waste regulations would increase the operating costs for waste management by about 35% for the Paraho process, 55% for MIS, 88% for TOSCO, and 104% for the MIS/Lurgi combination.⁽⁴⁰⁾ Concern about possible application of hazardous waste regulations to spent shale may constrain shale oil producers from disposing of waste waters containing high concentrations of organics with the spent shale, as many have planned. This may be especially true of disposal of "retort water" or "retort condensate."

One fear is that spent shale will come under the hazardous waste rules because of the organic residue left on it in low temperature retorting processes. Burning the carbonaceous residue as a source of supplementary heat to generate steam and run an electric generator may alleviate this problem. An analysis of this approach applied to TOSCO spent shale indicated that it was likely that the cost of installing and operating a shale burner and small power plant would be at least a breakeven proposition economically.⁽⁴⁰⁾

There is also reason to expect that spent shale could present a fire hazard. Residual heat in the retorted shale combined with residual

carbonaceous material and unretorted raw shale in the disposal pile appears, on preliminary indications, to have the potential to initiate slow combustion by autoignition.⁽⁴¹⁾ This problem might also be prevented through burning of the carbonaceous residue.

Clarification of EPA intentions concerning the environmental requirements of shale oil production is expected through two documents. The first, entitled "Environmental Perspective on the Emerging Oil Shale Industry,"⁽⁴²⁾ discusses EPA perspective on environmental aspects. The second document, "Pollution Control Guidance for Oil Shale," is expected to be released in 1981 and will present a critical and detailed analysis of pollution control alternatives for a commercial shale oil industry.⁽³⁹⁾

Existing and prospective regulations are being used by shale oil companies as they plan for production facilities. These plans are discussed below.

6.5 DISPOSAL PROCEDURES

Most developers have anticipated the disposal of retorted shales to local canyons or land depressions near their retorting operations.^(25,28,29,43,44) If 60% of the retorted shale residue could be used as mine fill (a maximum figure),⁽⁴³⁾ 120,000 metric tons/day would still need to be disposed from the above ground production of 165,000 barrels/day oil, as considered in the 300,000 barrel/day industry scenario described in Section 3.5 of this report. Assuming an average compacted density of 1.08 kilograms per m³,⁽⁴⁵⁾ this would be a volume of about 88,000 m³ per day, or enough to cover a football field (0.40 hectares) to a height of nearly 22 m, about the height of a 6-story building. Clearly, the resulting effect on water quality will be contingent upon the properties of the retorted shale, site conditions, disposal procedures, and the efficiency of the proposed environmental controls.

6.5.1 Retorted Shale Piles

Although detailed disposal plans have not been published, general schemes have been outlined in numerous detailed development plans and impact statements.^(28,29,43,44) Generally, the development of commercial disposal sites would begin with the removal and storage of soil materials to be used in later

revegetation. In the canyon-fill type proposals (TOSCO--Davis Gulch; Paraho--Blazac Gulch; Rio Blanco--Rinky Dink Gulch), retaining dams of rock, earthen fill, concrete and/or compacted retorted shale would then be constructed to form a catchment basin. The basin would be lined, possibly with a layer of compacted retorted shale,^(25,43) and filled with processed shale, raw shale fines, additional solid wastes, and possibly retort water. Impounding dams, constructed above the disposal site would bypass seasonal stream flow under or around the fill through long conduits or paved flumes and diversion ditches.^(29,43) Drainage systems would be constructed to retain runoff or leakage from the pile and to facilitate the evaporation of these waters. Union plans to use side-valley fill along canyon walls in the East Fork of Parachute Creek.⁽²⁸⁾ Retorted shale would be laid down in windrows underlain by perhaps 3 m of highly compacted shale. Diversion ditches and flumes would be constructed to divert runoff and leachates to lined drainage ponds where evaporation of these waters would occur. Design criteria for these general plans normally incorporate cognizance of the maximum probable thunderstorm rainfall intensity, 16.5 cm of rainfall per hour.⁽²⁹⁾ Revegetation, designed to reduce wind and water erosion and to minimize potential leaching, will begin when portions of the embankments approach their final dimensions.⁽⁴⁴⁾

The success of these disposal plans is contingent upon the proper design of the retention and diversion dams, the basin lining, the stream bypass system and the runoff diversion system. The diversion dams and stream bypass systems must be able to transmit flows of flash flood magnitude. In addition, the conduit underlying the pile, possibly over 2,000 ft in length, must be maintained free from stream bedload accumulations. The compacted basin linings must minimize the leakage or release of percolates and runoff. Furthermore, proximity to the Colorado River necessitates the construction of sound, reliable dams.

6.5.2 Stabilization and Revegetation

If spent or raw shale waste piles were left exposed and unstabilized, erosion by wind and water would be likely. Contamination of streams, air quality degradation, and damage to surrounding land and ecological systems would

result. Work on stabilization and revegetation has focused mainly on spent shales. Virtually none has been conducted on raw shales or overburden materials.⁽⁴⁶⁾

Short-term stabilization (months to a few years) can be achieved with the spraying of biodegradable chemicals on the surface. Addition of emulsified asphalt or processed limestone can produce a more lasting hardened surface. Wetting and compaction of spent shales can also produce a hardened surface.⁽³⁷⁾ Revegetation is much preferred as a long-term solution since it is aesthetically more attractive, it will tend to reduce the likelihood that rain or snow melt will seep through the pile to produce leachates, and it offers the possibility for supporting wildlife or domestic livestock.

Spent shale is not a good medium for revegetation. If the color of the shale is dark, the surface will become hot during summer months. Temperatures of up to 78°C have been reported, for instance, for the TOSCO II spent shale. Together with relatively high levels of soluble salts present, these conditions hinder seed germination and subsequent plant growth.^(36,47)

Viable revegetation procedures normally include: 1) preleaching of soluble salts from the plant rooting zone, 2) fertilization with phosphorous and possibly nitrogen, and 3) surface mulching.^(28,36,47) Upward capillary migration of leached salts induced by seasonal evaporation may necessitate further irrigation or the placement of interrupting gravel layers below the rooting zone.^(14,48) Recent studies⁽³⁶⁾ have shown that covering the retorted shale with a layer of soil substantially increases the success of revegetation. The establishment of vegetation reduces, by evapotranspiration, the quantity of incoming precipitation available for pile leaching.

One concern is that plants grown on shale piles will accumulate toxic elements which will prove damaging to wildlife or domestic livestock. Molybdenum, selenium, arsenic, and fluorine, for instance, all of which are found in spent shale, can be toxic to animals even though they are not toxic to the plants which may accumulate them.⁽³⁷⁾ Some plants tend to absorb such elements selectively.

6.5.3 Evaluation of Disposal Plans

Uncertainties exist concerning 1) retorted shale physical characteristics and leachate composition with different retorting technologies and time, and 2) the design specifics, water movement, and revegetation schedules of commercial scale disposal piles. These uncertainties preclude precise estimates of: 1) maximum depth of yearly water penetration, 2) the quantities of leachates that could reach the pile bottom, 3) the ability of compacted retorted shale to act as an impervious barrier to water movement, 4) the possibility and potential quantities of leachates that could be released to surface and ground waters, 5) the probability of a retention dam failure in response to a low-recurrence precipitation event, and 6) the potential quantities of retorted shale which could be transported to surface waters by such a failure. Estimates of this type are further complicated by the climate and topography of this geographic region where precipitation ranges from 28 cm to 51 cm, the average yearly evapotranspiration is in excess of 95%,⁽⁴⁹⁾ and elevations vary from 1700 to 2700 meters. Although not yet applicable in this case, generic schemes do exist to predict qualitatively leachate generation from solid waste disposal sites.⁽⁵⁰⁾

Surface water discharge varies seasonally and is dominated by two hydrological events, the spring snowmelt and localized summer thunderstorms. Generally, the former produces the maximum yearly infiltration and the latter produces the major runoff events. Thus, sustained high streamflows occur in spring (snowmelt) while gully washers can occur during the summer months.⁽⁵¹⁾ Harbert and Berg,⁽³⁶⁾ in a study of revegetation on retorted shale plots near Anvil Points and in the Piceance Creek Basin, observed that moisture recharge occurred to depths of 90 to 140 cm each spring (1974-1976) as a result of normal to above normal precipitation events, and that soluble salts were leached to depths of 30 to 60 cm in 1975 by winter and spring precipitation. Research must be continued in this area to define adequately the movement of moisture and soluble organic and inorganic residuals in retorted shale piles that appropriately simulate commercial scale conditions.

6.6 POTENTIAL IMPACTS TO WATER QUALITY

Potential impacts arising from the storage of raw shale or disposal of retorted shales would initially be localized to surface and alluvial ground waters. Possible mechanisms of contamination might include the percolation of leachates through soil into alluvial ground waters or the direct release of pile leachates, runoff, or retorted shale materials into surface waters.

Immediate and long-term leaching behavior of the raw and retorted shales need be considered. Immediate phenomena would include the mobilization of solubles in the first several column volumes. In the case of raw shale, this leachate may contain elevated levels of boron and fluoride. Leachates from retorted shale (Table 6.7) may contain elevated levels of salts (Na, Ca, SO_4 , and Cl), monovalent cations (K, Li), reduced sulfur species (S_2O_2), mobile trace anions (B, F, Mo), and organic carbon (unknown composition). These levels are clearly in excess of those seen for comparable species in soil leachates and in Piceance and Parachute Creeks. For many soluble species, the retorted shale leachates also exceed the maximum values listed for alluvial aquifers (Table 6.7). Studies investigating the long-term effects of natural weathering reactions and microbial activity on the composition of leachates from retorted shale are in progress,^(24,55) but far from complete. Possible changes include a lowering of pH,⁽²⁴⁾ and the formation of soluble secondary organic compounds and inorganic chemical complexes, with altered solubility.⁽⁹⁾ Solubilization/insolubilization processes will likely be affected if process waters and heavy metal process related catalysts⁽¹⁴⁾ are disposed with retorted shale. Both short- and long-term leaching phenomena will likely be operative in commercial scale disposal sites where retorted shale piles will be constructed by successive additions of freshly retorted materials.

Quantitative estimates of the potential impact of commercial surface retorting facilities on local surface and alluvial ground waters cannot be undertaken presently with high precision. First, the extent of water movement in commercial or even semiworks scale retorted shale piles is unknown. This uncertainty is accentuated by the lack of published pile designs and revegetation schedules. As a result, realistic estimates of the quantities of leachates potentially released from disposal sites cannot be made. Worst case

TABLE 6.7. Averaged Values of Constituents Found in Soil Leachates and Surface and Ground Waters (24,29,52-54)

	Retorted ⁽²⁴⁾ Shale Leachate	Soil ⁽²⁴⁾ Leachate	Colorado ⁽²⁴⁾ River Water	Piceance Creek ^(52,53) U.S.G.S. Stn 103	Alluvial ^(58,59) Ground Water	Upper ⁽⁵⁴⁾ Aquifer	Lower ⁽⁵⁴⁾ Aquifer	Parachute ⁽²⁹⁾ Creek	Middle Fork of ⁽²⁹⁾ of Parachute Creek
pH	11.5 to 6.9	8.5 to 7.4	8.3 to 7.7	7.4 to 8.2				7.97	8.06
TDS (App.)				529 to 1930	6760 to 469	905	1075	791	461
	-----mg/l-----								
Org C	400 to <2	4.5 to 4.3	32 to <2		18.7	8.5	11		
SO ₄	20,000 to 3,000	320 to 48	1070 to 1400	300 to 580	1600 to 41	325	112	394	158
S ₂ O ₃ ⁻²	2,100 to <10	<10	<10						
Cl ⁻	2,200 to 70	520 to 260	140 to 130	13 to 32	9 to 270	12	22	18.4	10.6
F	13 to 3	1.4 to 0.6	0.5 to 0.2	0.6 to 1.1	33.0 to 0.40	0.41	15		
NO ₃	6 to <0.1	41 to 2	20 to 14	0.00 to 0.77	2.6 to 0.00	0.2	0.1	1.39	0.34
HCO ₃				327 to 1080	7140 to 242	482	842	363	297
CO ₃				0	401 to 0.00	0.88	69		
B	3 to 0.5	1.7 to 1.2	0.3 to 0.2		3.10 to 0.05	0.33	0.84		
Ca	530 to 140	170 to 72	130 to 160	47 to 94	120 to 6.8	35	8.9	86.3	56.4
Fe	0.3 to <0.01	0.031 to <0.01	0.02 to <0.01	0.030 to 0.160	49.0 to 0.00	5.0	0.79		
K	1230 to 320	90 to 19	8.2 to 6.7	2.6 to 4.7	6.8 to 0.9	2.2	2.6		
Li	20 to 6	0.09 to 0.03	0.09 to 0.04		0.270 to 0.00	0.13	0.13		
Mg	140 to 0.2	181 to 185	150 to 130	34 to 120	160 to 3.6	52	20	59.9	37.8
Mo	9.5 to 1.2	0.6 to 0.02	0.04 to 0.02		0.39 to 0.00	0.13	0.10		
Na	10,400 to 1,500	895 to 470	400 to 330	140 to 440	2900 to 66	212	397	142	81
Si	16 to 5	17 to 10	1.3 to 1.1	13 to 21	32 to 21	12	4.7		

scenarios based upon the failure of retaining dams in response to low probability precipitation events are not considered feasible due to the lack of hydrological information on gulches proposed for disposal. Second, the information is not available to enable the prediction of the magnitude of precipitation or sorption reactions that might occur as leachates percolate through local soils and subsoils enroute to alluvial ground waters. In addition, chemical interactions occurring during ground water transport might further attenuate, mitigate or otherwise alter the quantity and composition of oil shale related solubles eventually entering surface waters. Third, the rate and extent of water movement in alluvial aquifers near proposed disposal locations have not yet been defined. Thus, it is difficult to estimate the time required for potential contaminants to move from surface disposal locations to local surface waters and the extent of dilution. Finally, studies investigating the composition from the solubles released from retorted shales have concentrated upon materials from the TOSCO II, USBM gas combustion, and Paraho retorting processes. These materials might not necessarily represent the retorted shales produced by commercial operations. The planned incorporation of retort waters and additional process-related solid wastes into the disposal sites might further accentuate differences between the pilot or semiworks retorted shales studied and the solid wastes generated by commercial scale operations.

6.7 RESEARCH NEEDS

The published information available indicates that studies of environmental impacts of modular scale shale oil production facilities are required before useful estimates can be made of any water quality deterioration that would result from a developing surface retorting industry. Several Federal and industrial programs, designed to identify specific effects on water quality from retorted shale disposal, are presently underway. A successful, quantitative environmental assessment must await the results of these programs.

Characterization of the local soils, subsoils, surface and ground waters must continue. Questions regarding the potential effects of retorted shale disposal must be evaluated in the context of the regional climate and prominent geochemical processes. For instance, the Green River and associated Tertiary

Formations and soils formed from these geologic units represent a major natural salt loading area in the upper Colorado River Basin.⁽⁵⁶⁾ The effects of these natural processes need to be distinguished clearly from the effects of development. Research should continue on retorted shales produced by different retorting technologies and raw shales from the different development sites. These studies should focus upon the release of soluble macro and trace inorganic species, but should also identify and quantify specific organic compound classes present in retorted shale leachates. Additionally, an evaluation must also be made of the effects of long-term weathering reactions and microbiological activity on the chemical composition of soluble organic and inorganic components released from retorted shales. These studies must then be integrated with a detailed evaluation of the baseline concentrations and the mobility and persistence of these specific contaminants in local soil, subsoil, surface and alluvial ground water systems. Chemical modeling techniques which ultimately incorporate a consideration of complexation by organic ligands, should be applied to raw and retorted shale leachates, soil percolates and surface and alluvial ground waters to identify, on a theoretical basis, possible precipitation or dissolution reactions which may occur upon the mixing of these waters.

The quantities of soluble materials that may be released from a retorted shale disposal site cannot be estimated until studies are completed that define, or allow the accurate prediction of, anticipated water movement in retorted shale piles. The balance between precipitation and evapotranspiration must be evaluated, and the maximum depth of annual infiltration identified with due consideration to codisposal of retort water, configuration and chronology of pile construction, irrigation required, and revegetation. The effectiveness of the proposed design parameters must be evaluated from an engineering standpoint to determine 1) if the compacted layer can contain potentially saline runoff and leachates (if produced), and 2) whether the retaining and diversion dams can withstand high intensity, low probability precipitation events.

Site-specific hydrological investigations of specific local gulches are required for assessment of pile stability and surface water transport. Such parameters as the 1-, 10-, and 100-yr maximum discharges, sediment-load discharge relationships, and maximum stream velocities should be considered.

Alluvial ground water flow patterns and velocities must be evaluated in drainages adjacent to development sites and relationships to bedrock and surface waters must be defined. This information is essential to the identification of the residence times and dilution of potential oil shale contaminants in the alluvial ground water system.

Information generated by these programs can then be used in hydrologic transport modeling where contaminants are routed through and mixed with surface and ground waters to appraise realistically the potential effects on water quality arising from solid waste disposal.

6.8 REFERENCES FOR CHAPTER 6

1. Zachara, J. M. 1980. Assessment of Oil Shale Technology: Subtask 3.2 Solid Waste. PNL-SA-8763, Pacific Northwest Laboratory, Richland, Washington.
2. Robinson, W. E., and K. E. Stanfield. 1960. Constitution of Oil Shale Kerogen. U.S. Bureau of Mines, RI-7968. 79 p.
3. Robinson, W. E. 1969. "Kerogen of the Green River Formation." pp. 619-637. In: Organic Geochemistry--Methods and Results, E. Eglinton and M. T. J. Murphy, Ed., Springer Verlag, Berlin.
4. Robinson, W. E. 1976. "Origin and Characteristics of Green River Oil Shale." pp. 61-79. In: Oil Shale, T. F. Yen and G. V. Chilingarian, Ed., Elsevier, Amsterdam.
5. Desborough, G. A., J. K. Pitman, and C. Huffman, Jr. 1976. "Concentration and Mineralogical Residence of Elements in Rich Oil Shale of the Green River Formation, Piceance Creek Basin, Colorado, and the Uinta Basin, Utah--A Preliminary Report." Chemical Geology 17:13.
6. Dean, W. E. 1976. "Geochemistry of the Green River Oil Shale." pp. 48-56. In: Geochemical Survey of the Western Energy Regions. U.S. Geological Survey OFR-76-729.
7. Cook, E. W. 1973. "Elemental Abundances in Green River Oil Shale." Chemical Geology 11:321-324.
8. Smith, J. W., and K. E. Stanfield. 1964. "Oil Yield and Properties of Green River Oil Shale in the Uinta Basin, Utah." pp. 213-221. In: Guidebook to the Geology and Mineral Resources of the Uinta Basin. Inter-mountain Association. Petroleum Geologists Thirteenth Annual Field Conference.

9. NAS (National Academy of Science). 1979. "Redistribution of Trace Elements from Mining and Processing of Oil Shale." Chapter 2. In: Redistribution of Accessory Elements and Compounds Associated with Mineral Resource Exploitation. Report of the Committee on Accessory Elements. National Research Council's Committee on Natural Resources, Washington, D.C.
10. Fruchter, J. S., C. L. Wilkerson, J. C. Evans, R. W. Sanders, and K. H. Abel. 1979. Source Characterization Studies at the Paraho Semi-works Oil Shale Retort. PNL-2945. Pacific Northwest Laboratory.
11. Wildeman, T. R. 1979. "Chemical Analysis of Inputs and Outputs of Oil Shale Retorts." In: Trace Elements in Oil Shale--Progress Report 1976-1979. Environmental Trace Substances Research Program, W. Chappell, Coordinator, University of Colorado, Denver, Colorado.
12. Shih, C. C., C. H. Prien, T. D. Nevens, and J. E. Potter. 1977. Technological Overview Reports for Eight Shale Oil Recovery Processes. EPA Industrial Research Laboratory, Cincinnati, Ohio.
13. Cameron Engineers. 1978. Synthetic Fuels Data Handbook. 2nd Edition. Cameron Engineers, Inc., Denver, Colorado.
14. Routson, R. C., R. E. Wildung, and R. M. Bean. 1979. "A Review of the Environmental Impact of Ground Disposal of Oil Shale Wastes." Journal on Environmental Quality 8:14-19.
15. Huggins, C. W., and T. E. Bean. 1973. "Thermal Decompositions of Dawsonite." American Mineralogist 58:548-550.
16. Johnson, D. R., N.B. Young, and W. A. Robb. 1975. "Thermal Characteristics of Analcime and Its Effect on Heat Requirements of Oil Shale Retorting." Fuel 54:249-252.
17. Kuo, M. C. T., W. C. Park, A. Lindemanis, R. E. Lumpkin, and L. E. Compton. 1979. "Inorganics Leaching of Spent Shale from Modified In Situ Processing." In: Proceedings of 12th Annual Oil Shale Symposium. Colorado School of Mines, Golden, Colorado.
18. Smith, J. W., W. A. Robb, and N. B. Young. 1978. "High Temperature Reactions of Oil Shale Minerals and Their Benefit to Oil Shale Processing." In: Proceedings of 11th Oil Shale Symposium. Colorado School of Mines, Golden Colorado.
19. Margheim, G. A. 1975. "Water Pollution from Spent Oil Shale." PhD. Thesis, Colorado State University, Fort Collins, Colorado.

20. Stollenwerk, K. G., and D. D. Runnells. 1977. "Leachability of Arsenic, Selenium, Molybdenum, Boron and Fluoride from Retorted Shale." p. 1023. In: Proceedings of Second Annual Pacific Chemical Engineering Congress. Volume II.
21. Pfeffer, F. M., and R. S. Kerr. 1974. Pollutional Problems and Research Needs for an Oil Shale Industry. EPA-660/2-74-067. National Technical Information Service, Springfield, Virginia.
22. Merino, J. M., and R. B. Crookston. 1977. "Reclamation of Spent Oil Shale." Mining Congress Journal 10:31-36.
23. Schmidt-Collerus, J. J. 1974. Polycondensed Aromatic Compounds (PCA) and Carcinogens in Carbonaceous Spent Shale from Retorting of Oil Shale of the Green River Formation. American Chemical Society, Division of Fuel Chemical Reprint 19(2):115-122.
24. Garland, T. R., R. E. Wildung, and H. P. Harbert. 1979. "Influence of Irrigation and Weathering Reactions on the Composition of Percolates from Retorted Shale in Field Lysimeters." In: Proceedings of 12th Annual Oil Shale Symposium. Colorado School of Mines, Golden, Colorado.
25. DEI (Development Engineering, Inc.), and Woodward-Clyde. 1976. Disposal of Retorted Oil Shale from the Paraho Oil Shale Project. U.S. Bureau of Mines. OFR 27-77.
26. Wildung, R. E. 1979. "Terrestrial Effects of Oil Shale Development" pp. 2.1-2.8. In: Pacific Northwest Laboratory Annual Report for 1978, PNL-2850, Pt. 2. National Technical Information Service, Springfield, Virginia.
27. Striffler, W. C., I. F. Wymore, and W. A. Berg. 1974. "Characteristics of Spent Shale which Influence Water Quality, Sedimentation and Plant Growth Medium." In: Surface Rehabilitation of Land Disturbances Resulting from Oil Shale Development--Technical Report Series No. 1, C. W. Cook, Coordinator, Colorado State University, Fort Collins.
28. Cloninger, J. S. 1978. "Revegetation of Retorted Shale." Presented at American Nuclear Society, Denver, Colorado. September 26, 1978. Union Oil Company of California, Grand Junction, Colorado.
29. DOI (U.S. Department of the Interior). 1977. Final Environmental Impact Statement: Proposed Development of the Oil Shale Resources. Colony Development Operation, Atlantic Richfield Company, Denver, Colorado.
30. Schmalfeld, P. 1975. The Use of the Lurgi-Ruhrgas Process for the Distillation of Oil Shale. Colorado School of Mines Quarterly 70(3):129-145.

31. Caolo, M., R. E. Sieviars, and J. Stanley. 1979. "Investigation of Trace Organic Compounds in Oil Shale Wastes." In: Trace Elements in Oil Shale--Progress Report 1976-1979. Environmental Trace Substances Research Program. W. Chappell, Coordinator. University of Colorado, Denver, Colorado.
32. Schmehl, W. R., and B. D. McCaslin. 1973. "Some Properties of Spent Oil Shale Significant to Plant Growth." p. 2742. In: Ecology and Reclamation of Devastated Land, Volume 1. R. J. Humik and G. Davis, Ed., Gordon and Breach, London, England.
33. Ward, J. C., and S. E. Reinecke. 1972. "Water Pollution Potential of Snowfall on Spent Oil Shale Residues." Environmental Engineering Program. Department of Civil Engineering. Colorado State University, Fort Collins, Colorado.
34. University Cooperative Studies. 1977. Trace Elements in Oil Shale--Progress Report 1976-1977. Environmental Tract Substances Research Program, University of Colorado, Colorado State University, and Colorado School of Mines.
35. Runnells, D. D., M. Glaze, O. Saether, and R. Stollenwerk. 1979. "Release, Transport and Fate of Some Potential Pollutants in Waters Associated with Oil Shale." In: Trace Elements in Oil Shale--Progress Report 1976-1979. Environmental Trace Substances Research Program. W. Chappell, Coordinator. University of Colorado, Denver, Colorado.
36. Harbert, H. P., and W. A. Berg. 1978. Vegetative Stabilization of Spent Oil Shales: Vegetation, Moisture, Salinity, and Runoff--1973-1976. EPA-600/7-78-021. Environmental Protection Agency.
37. U.S. Congress, Office of Technology Assessment. 1980. An Assessment of Oil Shale Technologies. U.S. Government Printing Office, Washington.
38. "EPA Waste Rules May Affect Synfuel Plants." May 12, 1980. Synfuels Week, pp. 1-2.
39. Theom, T. L. 1980. "EPA and Oil Shale." Presented at the Synfuels Week Conference on the Outlook for Oil Shale, Denver Colorado, June 19, 20, 1980.
40. Nevens, T. D., W. J. Culbertson, Jr., J. R. Wallace, G. C. Taylor, A. P. Jovanovich, C. H. Prien, R. E. Hicks, R. F. Probststein, and G. Domahidy. 1979. Predicted Costs of Environmental Controls for a Commercial Oil Shale Industry. COO-5107-1, Denver Research Institute, Denver, Colorado. Available as Attachment 1 in U.S. Department of Energy, 1979, Environmental Control Costs for Oil Shale Processes, DOE/EV-0055, Washington, D.C.

41. The MITRE Corporation. 1979. Environmental Control Costs for Oil Shale Processes. The MITRE Corporation, McLean, Virginia. Available as Attachment 2 in U.S. Department of Energy, 1979, Environmental Control Costs for Oil Shale Processes, DOE/EV-0055, Washington, D.C.
42. U.S. Environmental Protection Agency. 1981. Environmental Perspective on the Emerging Oil Shale Industry. U.S. EPA, Cincinnati, Ohio.
43. ERDA (U.S. Energy Research and Development Administration). 1975. Proposed Acceleration of the Paraho Oil Shale Research Project at Anvil Points, Colorado: Draft Environmental Impact Statement. Paraho Development Corporation, Anvil Points, Colorado.
44. Rio Blanco Oil Shale Project. 1977. Revised Detailed Development Plan--Tract C-a. Gulf Oil Corp., and Standard Oil Co. (Ind.), Denver, Colorado.
45. Frischknecht, N. C., and R. B. Ferguson. 1979. Revegetating Processed Oil Shale and Coal Spoils on Semi-Arid Lands: Interim Report. EPA-600/7-79-068; PB-294733, U.S. Department of Commerce, National Technical Information Service, Springfield, Virginia.
46. The MITRE Corporation. 1979. Health and Environmental Effects of Oil Shale Technology: A Workshop Summary and Panel Reports. Richard Brown, Ed. DOE/HEW/EPA 02; PB-297096, U.S. Department of Commerce, National Technical Information Service, Springfield, Virginia.
47. Cook, C. W. (Project Coordinator). 1974. Surface Rehabilitation of Land Disturbances Resulting from Oil Shale Development. Tech. Rep. Ser. No. 1 (Final Rep. Phase 1), Environmental Resource Center, Colorado State University, Fort Collins, Colorado.
48. Bloch, M. B., and P. D. Kilburn. 1973. Processed Shale Revegetation Studies, 1965-1973. Colony Development Operation, Atlantic Richfield Co., Denver, Colorado.
49. Wymore, I. F. 1974. Estimated Average Annual Water Balance for Piceance and Yellow Creek Watersheds. Technical Report Series No. 2. Environmental Resources Center, Colorado State University, Fort Collins, Colorado.
50. Fenn, D. G., K. J. Hawley, and T. V. DeGeare. 1975. Use of the Water Balance Method for Predicting Leachate Generation from Solid Waste Disposal Sites. EPA/530/SW-168.
51. Ecker, R. M., W. N. Walters, and R. L. Skaggs. 1979. Hydrologic Monitoring Program, Rifle Oil Shale Facility Site, Colorado. PNL-3220, Pacific Northwest Laboratory.
52. Weeks, J. B., and F. A. Welder. 1974. Hydrologic and Geophysical Data from the Piceance Basin, Colorado. U.S. Geological Survey, Colorado Water Resources Basic Data Release No. 35.

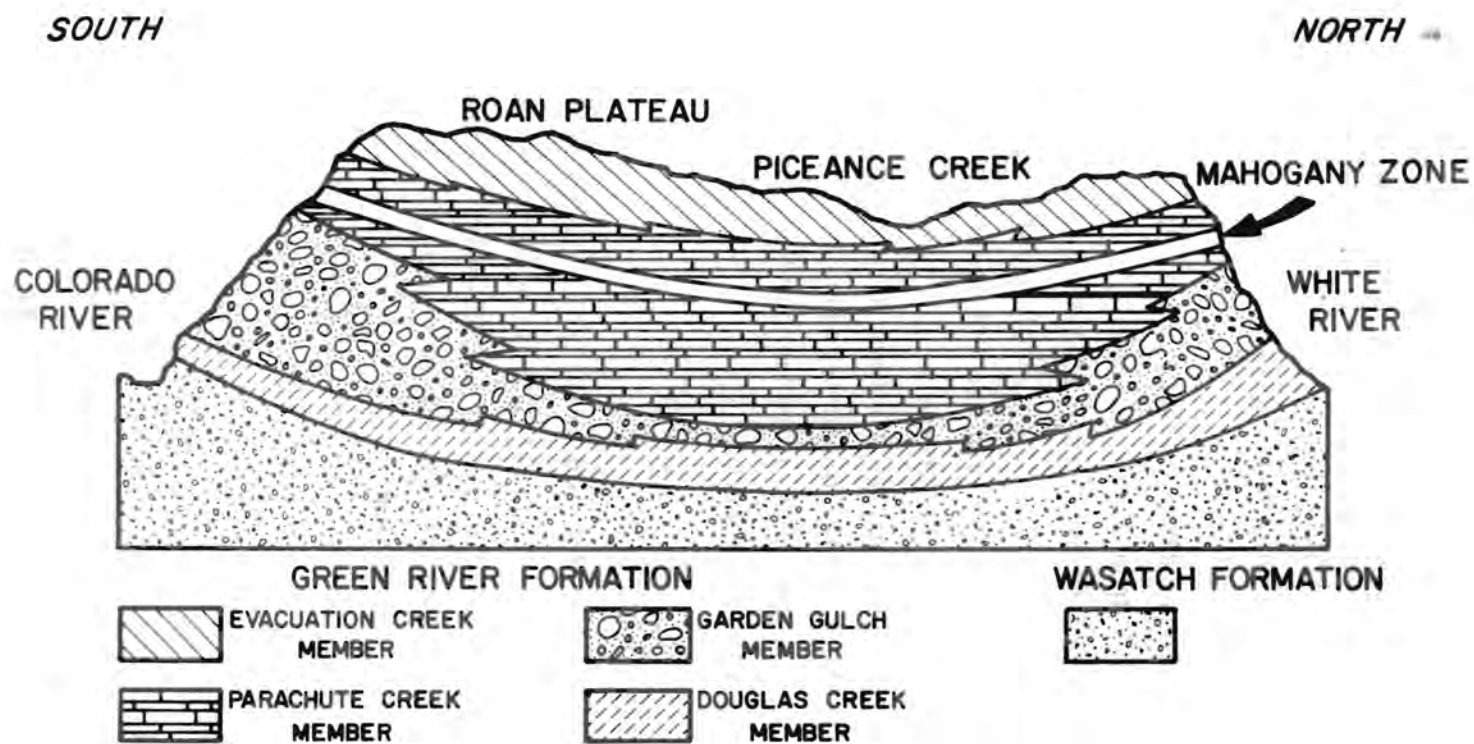
- 53. Ficke, J. F., J. B. Weeks, and F. A. Welder. 1974. Hydrologic Data from the Piceance Basin, Colorado. U.S. Geological Survey. Colorado Water Resources Basic Data Release No. 31.
- 54. Rio Blanco Oil Shale Project. 1977. Final Environmental Baseline Report for Tract C-a and Vicinity: Book 1. Gulf Oil Corp. and Standard Oil Co. (Ind.), Denver, Colorado.
- 55. Findley, J. W., M. D. Appleman, and T. F. Yen. 1974. "Degradation of Oil Shale by Sulfur-Oxidizing Bacteria." Applied Microbiology 28(3):460-464.
- 56. Iorns, W. V., H. H. Hembree, and G. L. Oakland, 1965. Water Resources of the Upper Colorado River Basin. U.S. Geological Survey Professional Paper 441. 370 p.

7.0 GROUND WATER IMPACTS

Development of an oil shale industry, especially an industry involving in-situ or modified in-situ (MIS) retorting, will result in disruption of ground-water aquifers, affecting the flow, the amount of stored water, and the quality of the water. The possible impacts of the industry on ground water and, indirectly through ground water, on surface streams are highly uncertain. The uncertainty is the result of incomplete knowledge of the geohydrology of the oil shale region, the connections between ground water aquifers and surface streams, the quality and amounts of ground water present in the region, the ground water recharge rate, the composition and leachability of contaminants in burned-out modified or true in-situ retorts, the hydrological characteristics of spent and raw shale waste piles, the composition and leachability of contaminants in such waste piles, and the effectiveness of environmental control techniques. This chapter is focused on these problems as they relate to modified in-situ retorts. Much of the material presented here has been drawn from the work prepared by Mehran, et al. for this assessment. That report is included as Volume 5 of this assessment report.

7.1 INTRODUCTION

Colorado's oil shale reserves are located primarily within the Piceance Creek structural basin. Federal tracts C-a and C-b lie within portions of this basin drained by the Yellow and Piceance Creeks, respectively. Figure 7.1 shows the generalized geohydrologic structure of this area. The Green River Formation and the Uinta Formation (not shown in the figure, but overlying the Green River Formation) contain the principal aquifers of this region. These aquifers are composed of relatively lean oil shale. They serve as ground-water aquifers because of natural porosity and because of fractures and faults developed in them. Between the two formations lies the Mahogany Zone which contains rich deposits of oil shale. The Mahogany Zone is not easily fractured because of the plastic qualities of the organic materials contained in the rock. Consequently, the zone serves as an effective barrier, or "aquatard," to flow of water between the two aquifers throughout most of the structural basin.



XBL 7812-12697A

FIGURE 7.1. Vertical Cross Section of Piceance Creek Basin^(1,2)

The total amount of ground water in these formations is unknown. The upper aquifer could contain as much as 30.5 billion m³ (25 million acre-ft) and the lower 24.4 billion m³ (20 million acre ft). These aquifers are recharged by melting of heavy snowpacks in the mountains around the edges of the basin. In the northern portion of the basin, water is discharged in the alluvium of the Piceance and Yellow Creeks; in the south it is discharged by springs.⁽³⁾

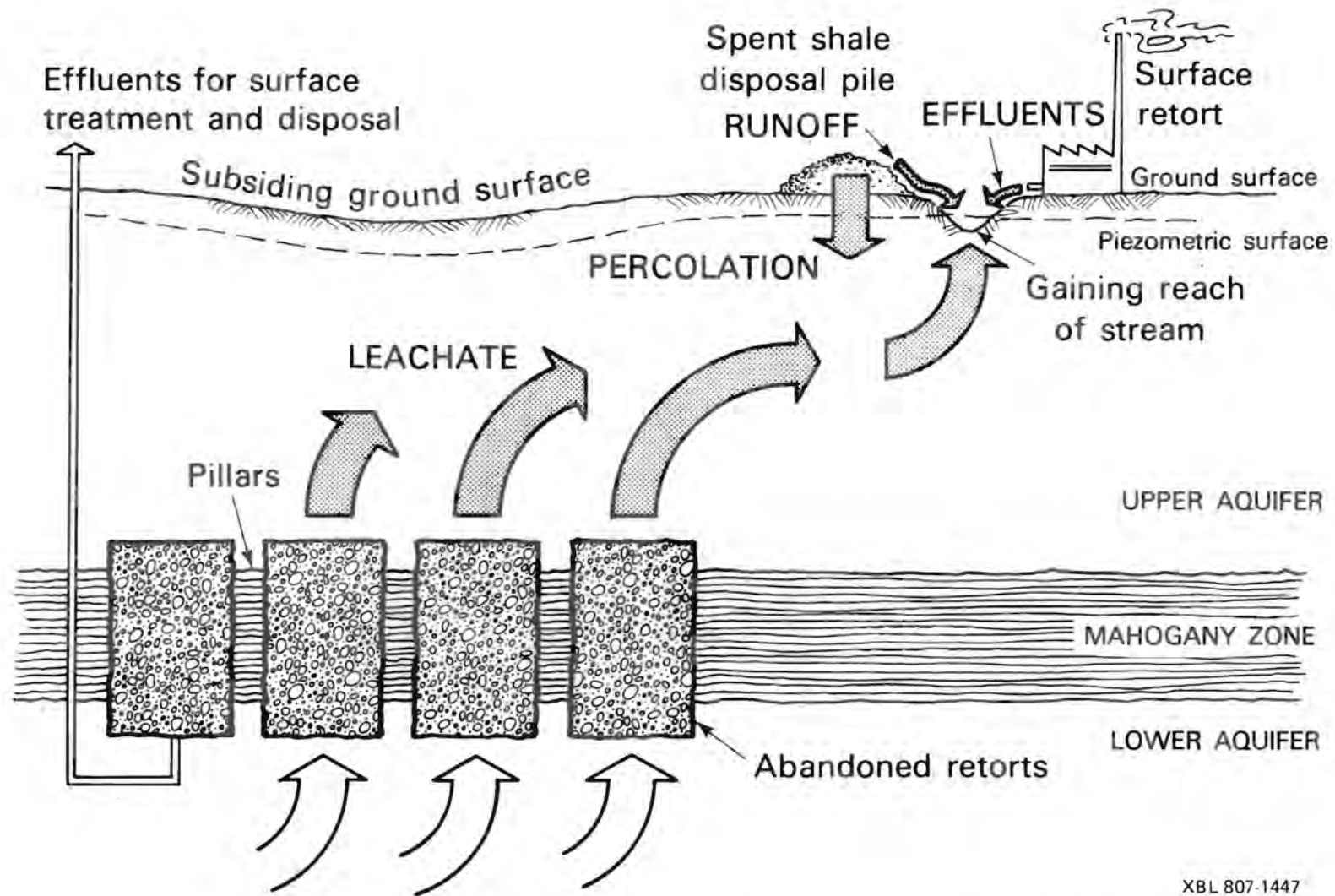
Small alluvial aquifers in the Piceance Creek Basin are partially recharged from the upper aquifer discussed above. They discharge to streams, springs, and wells.

At present, the ground water in the Uinta and Green River Formations is not widely used, but the alluvial aquifers are an important source of water within the basin. They are used mostly for residential water, stock watering, and irrigation.

Potential contamination of the alluvial ground water could result from surface water contamination caused by runoff from raw or spent shale piles, discharges of waste waters, or spills of chemicals or of shale oil. It could also occur if leachates percolate through raw or spent shale piles.

Prior to retorting with the MIS process and prior to and during open-pit or underground mining, aquifers in the area will be pumped out, or "dewatered." Contamination of these deeper aquifers could result after pumping is discontinued and ground water reinvades the affected areas. The returning waters may leach material from any spent shale in its path, contaminating both ground and surface waters. This contamination may be of direct importance if intensive industrial development requires reliance on these aquifers for domestic water supplies or irrigation. It will be doubly important if it results in eventual contamination of the alluvial aquifers, the surface streams in the Piceance Creek Basin, or the Colorado River, itself, and its major tributaries which drain the oil shale region. Figure 7.2 portrays the major contamination pathways of concern.

This chapter begins with a brief discussion of laws and regulations applicable to ground water in the oil shale region. It then proceeds to an extensive section on water quantity effects. The conduct of this assessment



XBL 807-1447

FIGURE 7.2. Schematic Representation of Water Pollution from Modified In Situ Oil Shale Retorting(1)

included a detailed analysis of the phenomena and impacts associated with necessary dewatering of the aquifers in which retorts will be constructed if a commercial MIS shale oil industry is developed.

The chapter proceeds next with a discussion of likely impacts on ground-water quality, focusing first on above ground raw and spent shale disposal piles, then on MIS retorts. The section considers both the content of leachates and their transport into and through aquifers. Finally, the chapter closes with a look at potential environmental control strategies for MIS operations.

7.2 LAWS AND REGULATIONS

Two categories of regulations involving ground water could impact oil shale development. The first category consists of those regulations which specify water quality. These regulations will determine what control technologies the industry will need, and therefore, will also influence the cost of shale oil. The second category of laws consists of rights to ground water.

Although no specific water quality standards for shale oil production have been established, several Federal and state regulations may apply. The Federal Water Pollution Control Act, the Surface Mining Control and Reclamation Act, the Resource Conservation and Recovery Act, the Safe Drinking Water Act, Colorado River Basin Salinity Control Forum Standards, and various water quality and effluent guidelines set by the states of Colorado, Utah and Wyoming all could affect oil shale development.^(1,4) These standards and regulations are presented in Section 8.2 of this report.

Western states have enacted laws governing the use of ground water. Table 7.1 summarizes those Colorado laws which could affect energy development. Utah and Wyoming have similar laws. Colorado's laws define two categories of ground water: designated ground water and ground water tributary to a stream. The first consists of all ground water inside a ground-water basin, as designated by the Colorado Ground-Water Commission, except for tributary ground water, that is, water which is hydrologically connected to a stream. The use

TABLE 7.1. Colorado Ground-Water Laws⁽⁵⁾

Ground-Water Mining	Tributary--no restrictions basins--prohibited Designated controlled depletion in non-rechargeable basins
Off site use	No exports out of state Local districts may prohibit export of ground water outside basin
Protection of Surface-Water and Land Rights	No detriment to existing uses
Protection of Ground-Water Rights	No detriment to existing uses (no unreasonable reduction in pumping pressure and levels of existing uses) No mining of rechargeable designated basins
Beneficial Uses, Preferences and Definitions	Domestic and agriculture preferred over energy and other uses
Diligence	One year to complete appropriation Liberal extensions

of designated ground water is regulated by the Colorado Ground-Water Commission. Tributary ground-water use is supervised by the State Engineer.⁽⁵⁾

The modified in-situ process planned by Occidental Oil Shale illustrates the legal constraints associated with the use of ground water in Colorado. This prototype operation would require the dewatering of portions of the aquifers surrounding the oil shale-bearing Mahogany Zone. Dewatering could reduce the volume of water in surface streams, which are already covered by water rights. Thus, Colorado's water court required Occidental to monitor water levels and to compensate any holders of water rights for water losses.⁽⁵⁾

7.3 IMPACTS ON GROUND-WATER QUANTITY

A shale oil industry would disrupt the ground-water system in the Piceance Creek Basin. The nature and extent of this disruption depends upon the

location, type of mining and retorting, size and timing of the industry, and the means of disposal of the "dewatering" water. This section examines impacts on the quantity of ground water.

7.3.1 General Observations

The richest shales under the Piceance Creek Basin are located in the Mahogany Zone, which separates the upper and lower aquifers of the ground-water system. Because of this circumstance, mining of the shale for above ground retorting and preparation of in-situ retorts will usually require extensive "dewatering" of the surrounding aquifers by pumping from wells drilled for that purpose or from sumps in the retorts, although this is not true universally. This dewatering will be especially necessary in the center of the structural basin. The geohydrology of the oil shale deposits is not well defined. Some recent work indicates that the system is a complex of permeable and impermeable layers. Smith has found that a large portion of the oil shale formation at the Naval Oil Shale Reserve is dry.⁽⁴⁾ Fox indicates that dry oil shale deposits are unlikely in the Piceance Creek Basin, but they may occur in Utah and Wyoming.⁽¹⁾

In the more usual case, dewatering will be necessary. If the waters withdrawn from the aquifers are not reinjected to the aquifers, this dewatering will interfere with flow through the aquifer system. Loss of the water will eventually reduce or eliminate supplies to wells in the affected area and to some surface streams. Natural recharging of the aquifers might not be completed until centuries after dewatering efforts cease.⁽⁶⁾

The most extensive dewatering of bed-rock aquifers will be required for the development and burning of modified in-situ (MIS) retorts. For the projected large groups of retorts, massive dewatering, requiring long-term pumping rates of 0.15 m^3 per second (3200 acre-ft per year) at tract C-a to 1.0 m^3 per second (21,600 acre-ft per year) at tract C-b may be required.⁽⁶⁾ Experience to date on tract C-a confirms that substantial dewatering will be necessary there.

Disposal of the large volumes of water pumped from aquifers will be a problem. Current laws require substantial and expensive treatment of the water

because of high concentrations of dissolved solids and particular chemical species, especially boron and fluorides. One likely solution will be to reinject the water into the same aquifer from which it came, but downflow from the retorts. This practice is legally acceptable in Colorado so long as the quality of the water is unchanged.⁽⁸⁾ After examining a number of treatment and disposal options, Sinor concluded that such reinjection would prove to be the most economical, even though it would increase the flow into a mine by, in his example, 17%.⁽⁹⁾ This approach would be expected to reduce the potential effects of aquifer dewatering.

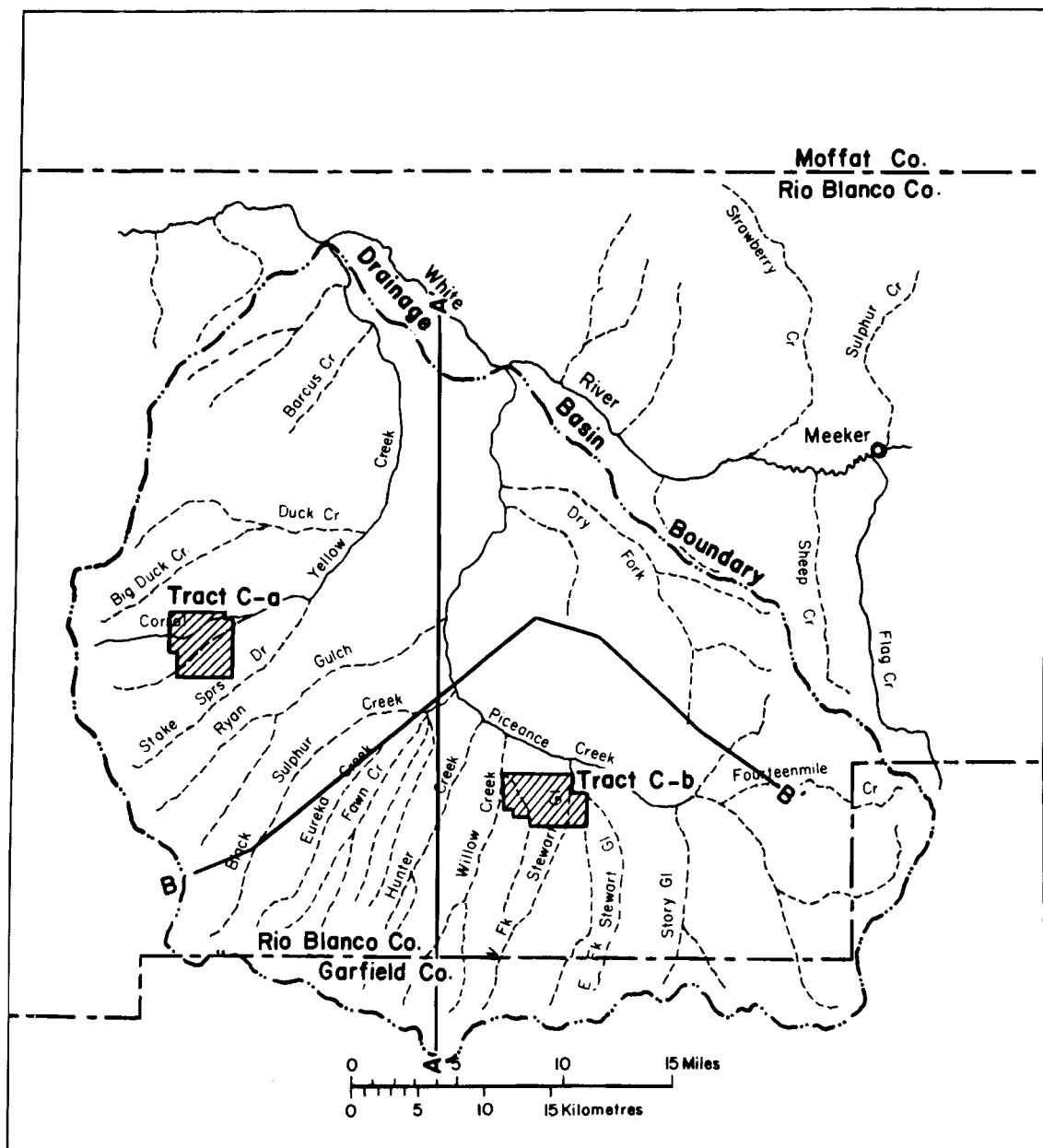
7.3.2 Detailed Analysis of Dewatering on Tracts C-a and C-b

As part of this assessment of western oil shale development, Mehran, Narasimhan, and Fox⁽⁶⁾ conducted a specific, detailed analysis of dewatering on the two Colorado Federal lease tracts necessary for application of modified in-situ (MIS) technologies. The discussion in this section is taken from their report, which is included in its entirety as Volume 5. Due to uncertainty in the field data and necessary simplifying assumptions, conclusions drawn in this report, and presented here, should be considered with caution.

The study conducted by Mehran et al. models dewatering as a saturated-unsaturated flow problem for an expanding retorted region with full interaction among the various geohydrological layers. This differs from earlier analyses which assumed saturated flow. There is a lack of field data for characterizing the geohydrological system, but the study nevertheless differentiates between the general conditions at Lease Tract C-a and those at Lease Tract C-b.

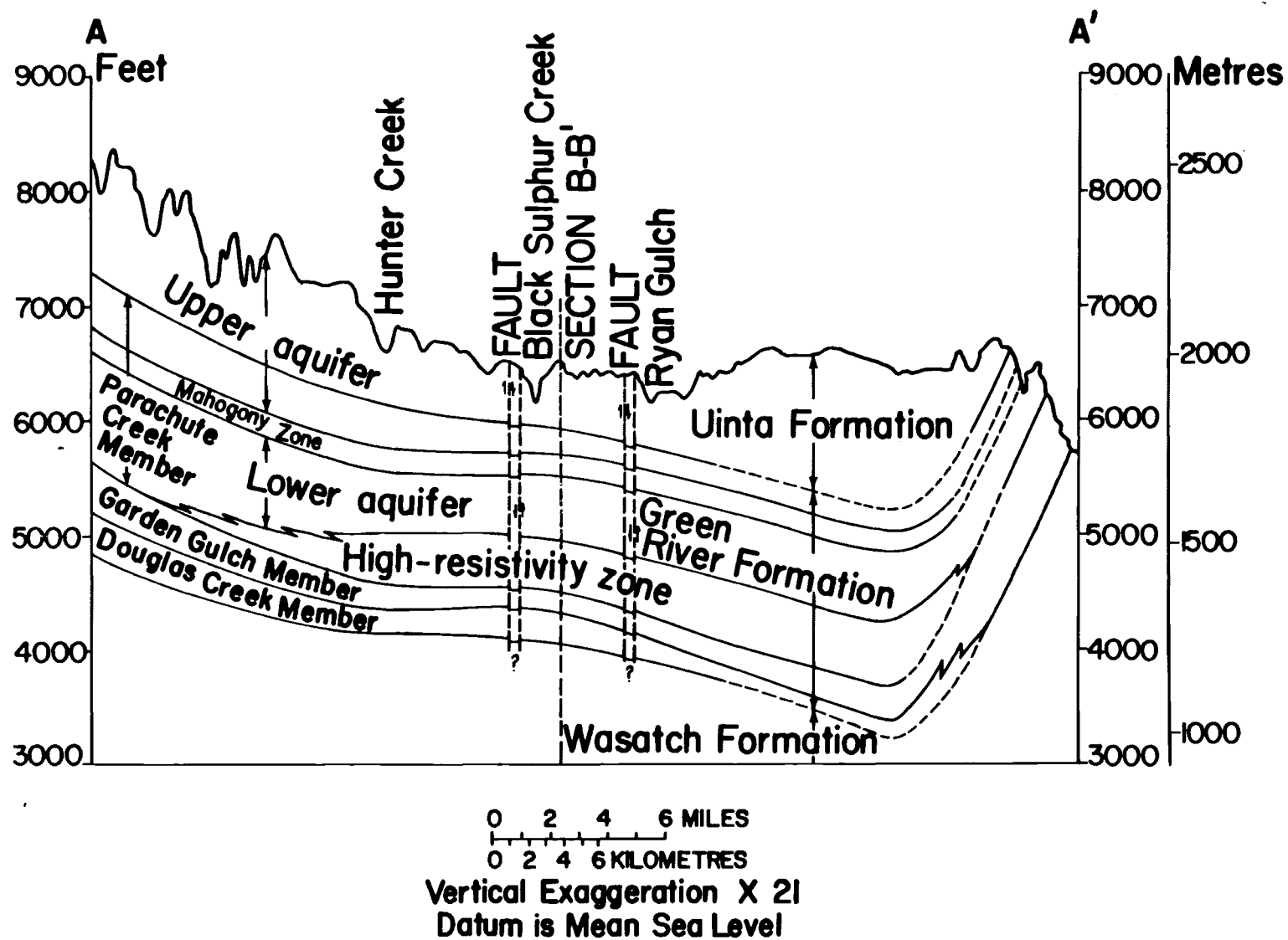
Tract C-a is located near the western extreme of the Piceance Creek Basin (Figure 7.3). Plans for the site, as studied here, call for a 10-year modular development phase (MDP) followed by a 30-year commercial industry. The commercial industry would begin with 50,000 bpd and peak at 76,000 bpd at the end of the period, using MIS technology.

Figures 7.4 and 7.5 are sections of the Piceance Creek Basin, as marked in Figure 7.3. Evident in Figure 7.5 is the difference in depth and thickness of the Mahogany Zone between Tract C-a (far left in the figure) and Tract C-b (near the center of the figure).



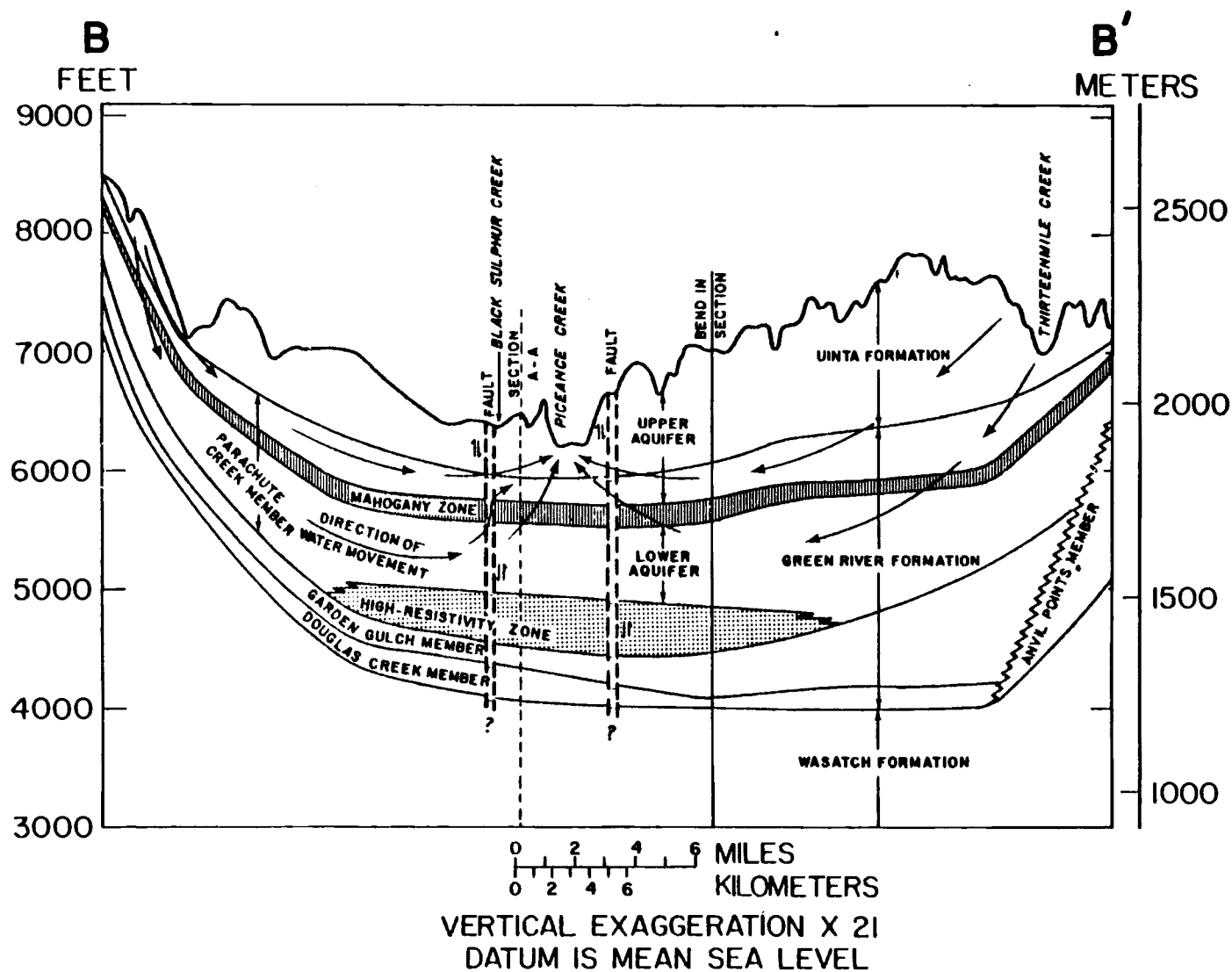
FXBL 8011-2286

FIGURE 7.3. Location of the Piceance Basin and Prototype Oil Shale Lease Tracts C-a and C-b(6,10)



FXBL 80II-23II

FIGURE 7.4. North-South Geohydrologic Section Through the Piceance Basin(6,10)
(See Figure 7.3 for location of Section A-A'.)



XBL 7812-12693

FIGURE 7.5. West-East Geohydrologic Section Through the Piceance Basin(6,10)
(See Figure 7.3 for location of Section B-B')

Hydrology

The major geohydrologic investigations are those of Coffin et al.⁽¹¹⁾ and Weeks et al.,⁽¹⁰⁾ from which most of the information presented here is extracted. Any disturbance to the hydrologic environment will affect the quantity and quality of surface and ground waters in the basin.

Surface Water. The major rivers in the area are the Colorado River and the White River. They flow westward on the western slopes of the Rocky Mountains in Colorado. A large part (2297-km^2) of the basin in the northern part is drained by the White River and its tributaries, mostly by Piceance and Yellow Creeks. Piceance and Yellow Creeks drain 1629-km^2 and 668-km^2 , respectively.

Snow melt is the primary source of overland runoff in the Piceance Creek and Yellow Creek drainage basins. Precipitation occurs at higher elevations between November and March and melts in the spring as temperatures rise. Mean daily stream flow increases during the snow melt period of March through June, recedes during the summer months, and is minimum during the winter months. Stream flow after July is maintained by ground-water discharge which moves through the alluvium into the stream channels or appears as springs along the valley floors. Most of the total precipitation is lost through evapotranspiration.⁽¹²⁾

It should be pointed out that most of the basin water yield, about $29.61\text{ million m}^3/\text{year}$ ($24,000\text{ acre-ft/year}$), originates from above 2134 m ($7,000\text{ ft}$), or above the C-b tract. The surface water supplies of Piceance and Yellow Creeks are fully developed for irrigation purposes. Approximately 2060 hectares (5100 acres) in the Piceance Basin and 81 hectares (200 acres) in the Yellow Creek Basin are irrigated annually. Irrigation diversions begin in mid-March and continue through November. Streamflow losses from consumptive use by crops and evapotranspiration losses associated with irrigation practices have a marked influence on the stream flow hydrograph from March to November.

Chemical analyses of water samples show that the surface waters of both Piceance and Yellow Creeks can be classified as a mixed bicarbonate type in the upper reaches, grading to a sodium bicarbonate type in the lower reaches.

Concentrations of sodium, chloride, and fluoride all increase in the downstream direction. Coffin et al. reported a change in dissolved solids concentration from 600 mg/l in the upper reaches of these streams to 2000 mg/l at the White River. These water quality changes are the result of contributions to surface runoff from irrigation return flow and from ground-water discharge. Ground water in the Parachute Creek member of the Green River Formation below the Mahogany Zone generally contains high concentrations of sodium bicarbonate, chloride, and fluoride. Elevated fluoride concentrations in surface waters indicate that ground water from the Parachute Creek Member is discharged to Piceance Creek, Yellow Creek, and Black Sulfur Creek. The concentration of dissolved solids is higher at downstream stations on Piceance Creek throughout the year. This is due to increasing concentrations of dissolved solids in the ground-water discharge and to irrigation return flows at downstream points. Dissolved solids also increase in the down-stream direction in Yellow Creek due to ground-water inflow from the Parachute Creek Member, which outcrops in the lower reaches of the stream.

Ground Water. The major water-bearing strata are located in the Uinta and Green River Formations. The Garden Gulch Member, which consists of marlstone, is relatively impermeable and forms the lower boundary of the aquifer system in much of the area of Piceance Basin. The Parachute Creek Member, which overlies the Garden Gulch Member, contains the most permeable materials in the Green River Formation with higher thickness and porosity. Since little ground-water development has occurred, the ground-water system is in equilibrium, which means that change in storage is negligible, or inflow to the basin is nearly equal to outflow. The direction of ground-water flow is toward the north central parts of the basin along the axis of the main synclinal structure.

The recharge pattern in the basin given by Weeks et al. indicates that most recharge by local precipitation occurs in the western, southern, and eastern elevations of the basin. Ground-water discharge from the basin occurs mostly to creeks with some discharge directly to the White River in the northern parts of the basin.

Previous investigators have represented the basin as consisting of two major aquifers, an upper aquifer and a lower aquifer. However, in most parts

of the basin, the two aquifers are effectively separated by the Mahogany Zone, which acts as a confining layer. Furthermore, in some parts of the basin, an alluvial aquifer with distinct properties overlies the upper aquifer. Therefore, the aquifer system generally consists of three aquifers and one confining layer (aquitard). Although in most modeling efforts the alluvial aquifer has been incorporated into the upper aquifer, the characteristics of four layers are discussed separately here.

The areal extent of the alluvial aquifer is limited. The aquifer consists of gravel, sand, and clay of variable thickness throughout the basin reaching a maximum of about 43 m (140 ft). Maximum saturated thickness is approximately 31 m (100 ft). Permeability is generally high and the transmissivities range from $250 \text{ m}^2/\text{day}$ to $1900 \text{ m}^2/\text{day}$ (2700 to $20,000 \text{ ft}^2/\text{day}$). The alluvial aquifer is unconfined and, because of its limited areal extent, it can be treated as part of the upper aquifer.

The saturated thickness extending from the Mahogany Zone to the surface is generally referred to as the upper aquifer. It consists of fractured, lean oil shale (marlstone) of the Parachute Creek Member above the Mahogany Zone and fractured marlstone, siltstone, and sandstone of the Uinta Formation. The thickness of the upper aquifer increases eastward. At the C-a and C-b tracts, the average thickness of the upper aquifer is 325 m (1066 ft) and 79 m (260 ft), respectively. Figures 7.6 and 7.7 illustrate the location of the upper and lower aquifers with respect to the geological formations on Tracts C-a and C-b and also the interval of interest for oil shale exploitation. In these figures, letters R and L refer to rich and lean oil-shale layers.

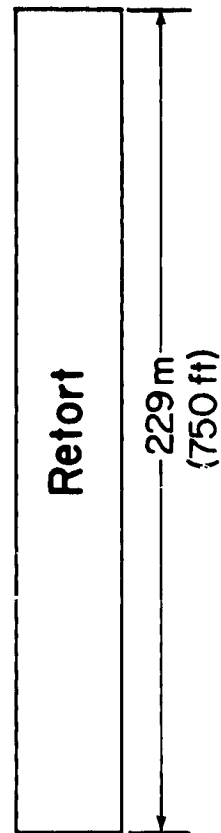
Permeability is mainly due to fracture porosity. The marlstone beds in the lower part of the aquifer are more brittle and therefore more susceptible to fracturing, causing higher permeability in that part of the aquifer.⁽¹⁴⁾ The transmissivity values vary from 0.7 to $88 \text{ m}^2/\text{day}$ (8 to $1000 \text{ ft}^2/\text{day}$). Although short-term pumping tests indicate confined conditions, the upper aquifer is generally believed to act as an unconfined aquifer.

Over the C-a Tract, the upper aquifer consists mainly of the Mahogany Zone overlain by A-Groove (Figure 7.6). Below the Mahogany Zone, alternating layers of lean and rich oil shale extend down to a depth of approximately 200 m (650 ft).

Over the C-b tract, the upper aquifer consists of various zones with different material and hydraulic properties. A lean oil shale zone, which is more fractured than other parts of the aquifer, exists between the Four Senators Zone and A Groove (Figure 7.7). The A Groove, which is located on top of the Mahogany Zone, is highly conductive to water. The thickness of the A Groove is about 5 to 8 m (16 to 26 ft). Permeability of materials above and below the A Groove in both vertical and horizontal directions is much lower than that of the A Groove.

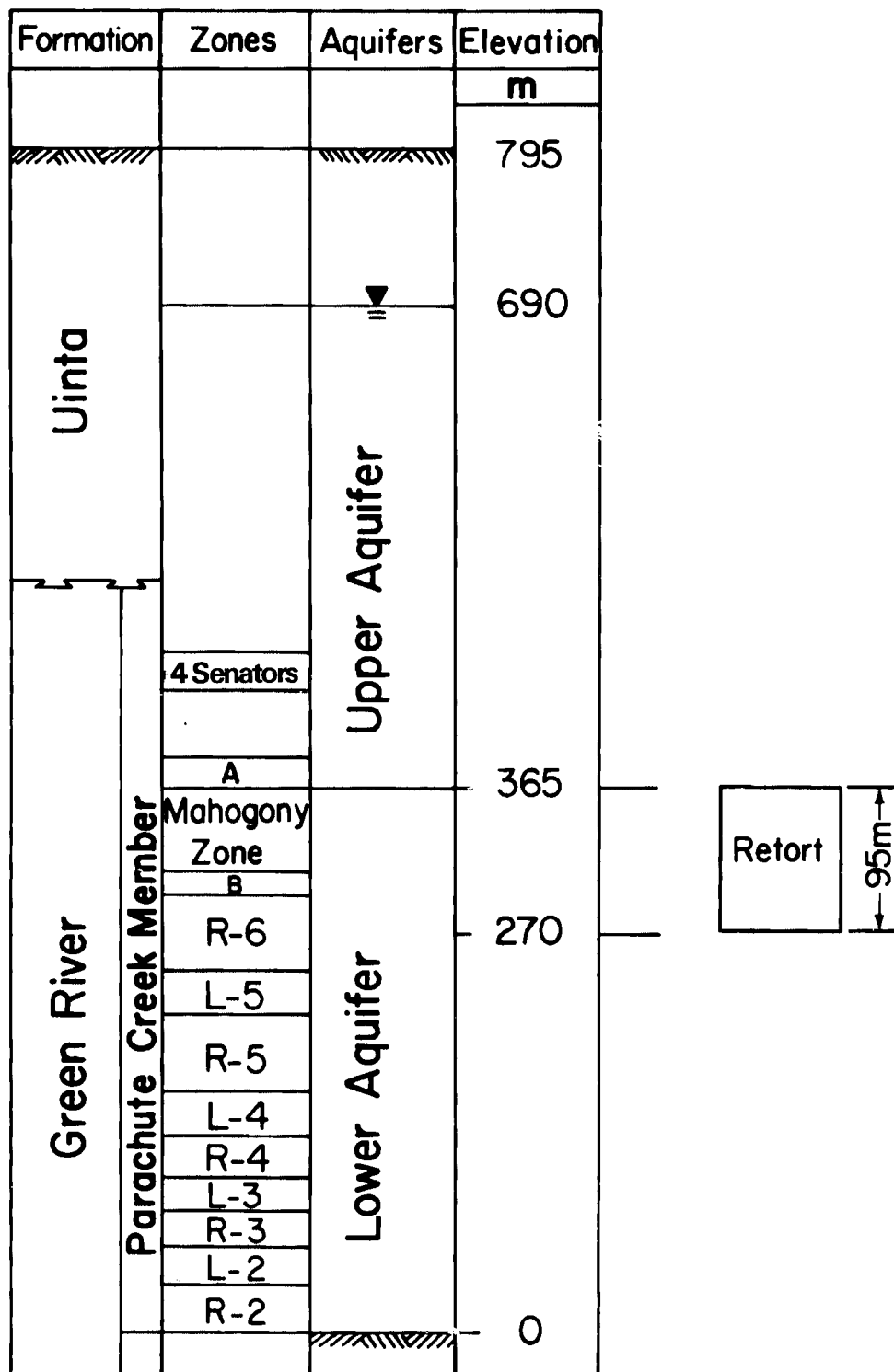
Below the A Groove, a confining layer called the Mahogany Zone extends throughout the basin separating the upper and lower aquifers except in recharge and discharge areas. Vertical exchange of water and solutes between the aquifers through the confining layer is possible through fractures present in the Mahogany Zone. Although the Mahogany Zone is located within the lower aquifer in Figure 7.7, its material and hydraulic properties are quite different. The thicknesses of the Mahogany Zone in the C-a and C-b tracts are 36 m and 55 m, respectively. According to the "Technology Characterization and Production Scenarios" report prepared for this assessment (Volume 2),⁽¹⁵⁾ the retort interval on the C-b tract is 95 m (320 ft); the retorting interval for C-a tract, according to Rio Blanco Oil Shale Project,⁽¹⁶⁾ is 229 m (750 ft). Contradictory values of hydraulic conductivity (both vertical and horizontal) have been reported for the Mahogany Zone, ranging from nonmeasurable⁽¹⁷⁾ to 0.11 m/day (0.36 ft/day) obtained from isolated intervals.⁽¹⁸⁾ In the Weeks et al. model, a vertical hydraulic conductivity of 4×10^{-4} m/day is assumed. If the Mahogany Zone were impermeable, much larger hydraulic differences between the lower and upper aquifers would be developed than have been observed.⁽¹⁰⁾ Recently, it has been emphasized by Smith⁽¹³⁾ that the confining layer is continuous throughout the system and the water yield in abandoned vertical MIS retorts would be extremely small, indicating very low transmissivities. On the

Formation	Zone	Aquifer	Elevation (m)
Green River Formation	Parachute Creek Member	Upper Aquifer	306
			272
			249
			213
			193
		Aquitard	
		Lower Aquifer	73
			0



FXBL 8011-2310

FIGURE 7.6. Stratigraphy of the C-a Tract and Location of the Mining Zone(6)



FXBL 8011-2306

FIGURE 7.7. Stratigraphy of the C-b Tract and Location of the Mining Zone⁽⁶⁾

C-a tract, an aquitard is present which extends from a depth of approximately 100 m (330 ft) to the bottom of the R-5 layer (Figure 7.6). Data on hydraulic properties of this layer are scarce.

The lower aquifer consists of the fractured oil shale and marlstone of the Parachute Creek Member underlying the Mahogany Zone. The secondary porosity and permeability have been enhanced by solution of primary minerals, mostly nahcolite.⁽¹⁰⁾ The thickness of this aquifer varies from place to place, and in the C-a and C-b tracts, it is approximately 75 m and 365 m, respectively. The bottom of the lower aquifer lies on the relatively impervious materials of the Garden Gulch Member.

The data on transmissivities are highly variable and range up to $180 \text{ m}^2/\text{day}$ ($2000 \text{ ft}^2/\text{day}$). Although the existing data are derived from a number of aquifer tests, since they represent a small area of influence, the values may not be typical. The data on transmissivity of the lower aquifer on the C-a tract appears to be more reliable than that of the upper aquifer. Pumping test data indicate that the permeability of the lower aquifer is about $90 \text{ m}^2/\text{day}$ ($1000 \text{ ft}^2/\text{day}$).⁽¹⁶⁾

MIS Development

The construction of MIS retorts will change the geohydrologic conditions at Tracts C-a and C-b. The specific effects at the two tracts will differ because of differences in the existing systems, discussed above, and because of differences in the size, timing, and configuration of the retorts and the procedures by which dewatering is to be accomplished. Some details concerning these MIS developments are presented here to establish the bases for analysis.

The C-b Tract. According to the Tipton and Kalmbach analysis,⁽¹⁴⁾ internal mine drainage is preferable to deep wells for dewatering the C-b tract because wells must necessarily penetrate far below the retort level, unfavorably effecting economics. Being deeper, they may pump poorer quality water to the surface. Another reason for not using deep wells is that near ultimate dewatering levels, the wells may yield very little and additional wells may be required.

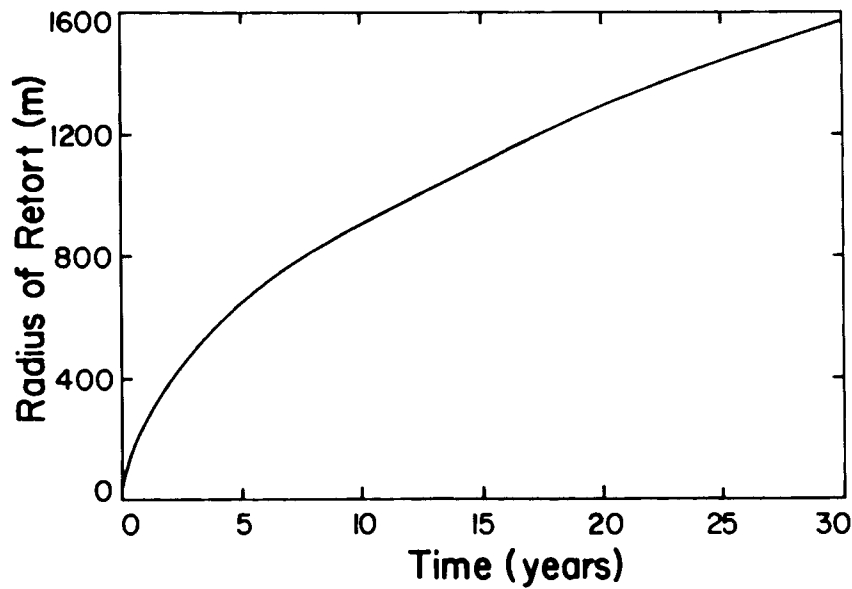
The smallest physical unit in the proposed MIS system is a retort with dimensions of 61 m x 61 m (200 ft x 200 ft) in plan and 95 m (310 ft) in height. The volume of each retort is 0.351 million m³ (12.4 million ft³). The retorts are created by blasting after mining and hoisting 20% to 25% of the in-place material. The mined material is hoisted to the surface to provide sufficient void space for rubblization.

The retorting interval of interest starts just below the top of the Mahogany Zone and ends just above the bottom of the R-6 Zone as shown in Figure 7.7. Individual retorts are separated by pillars. It is proposed that the plan area of pillars associated with each retort will be about 60% of the retort area. A collection of eight retorts form a cluster, and 32 clusters form a panel. At a production level of 9120 m³/day (57,000 bbl/day), 15 panels are proposed to be developed during the 60-year life of the project. Therefore, each panel lasts four years.⁽¹⁵⁾

Since each panel consists of 256 retorts, the rate of development will be 64 retorts per year. Taking the total area of retorts and panels into account, the rate of development of the retorted region will be approximately 38 hectares (94 acres) per year in plan. Using this rate of retort expansion represented in cylindrical geometry, the increase in the radius of the retorted area with time is as shown in Figure 7.8.

The C-a Tract. The proposed mine dewatering system at Tract C-a will consist of pumping wells and mine drainage through drifts and underground workings.⁽¹⁶⁾ This system will be continually modified with the addition of new wells and abandonment of old wells as the mine expands in time. The analysis by Mehran et al. assumes that the total dewatering is accomplished by internal drainage.

The geometry of retorts varies according to the phase of the project. In the first phase (MDP) of the project, the retorts have dimensions of 30 m x 30 m (100 ft x 100 ft) in plan and 122 m (400 ft) in height. However, in the commercial phase, the retorts will have the dimensions of 46 m x 91 m (150 ft x 300 ft) in plan and 229 m (750 ft) in height. Only commercial-sized retorts are used in the study by Mehran et al.⁽⁶⁾



FXBL 8011-2301

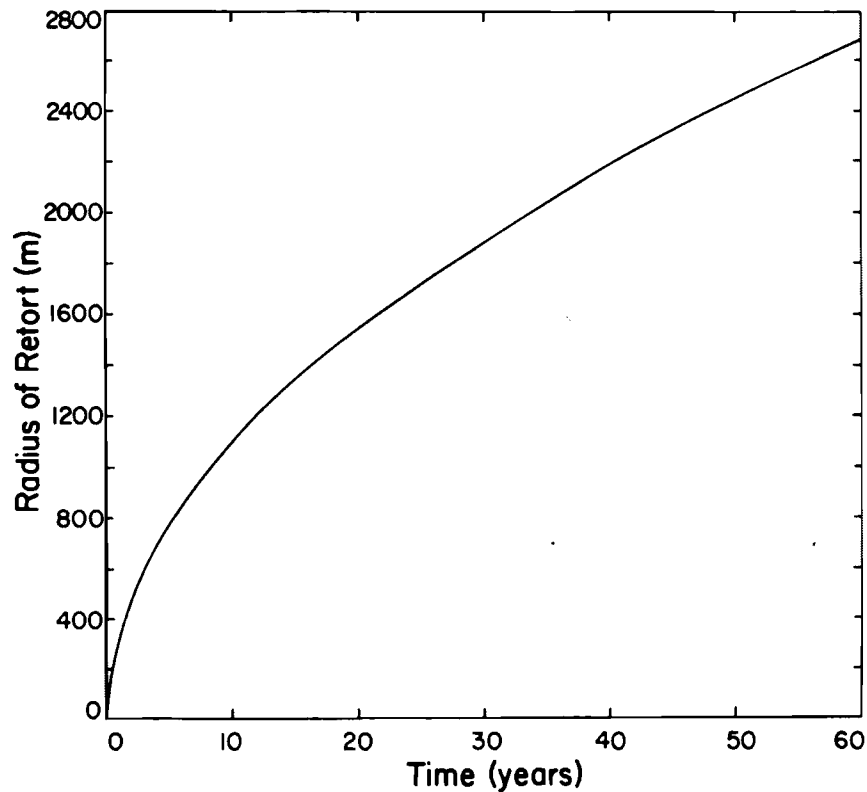
FIGURE 7.8. Rate of Expansion of the Retorted Area With Time in the C-b Tract

The retorting interval in the commercial phase begins from the top of the Mahogany Zone and extends to the bottom of the R-4 Zone as shown in Figure 7.6 (above). According to the Revised Detailed Development Plan,⁽¹⁶⁾ for 30 years of production on one-half of the tract, 932 retorts will be developed covering a plan area of approximately 390 hectares (960 acres). Assuming an average pillar size in plan equal to that of the retorts, the retorted area will advance at approximately 26 hectares (64 acres) per year. Figure 7.9 shows the expansion of the retorted area with time.

Dewatering

Simulations of the dewatering of the aquifers at Tracts C-a and C-b were run by Mehran et al. The results and their significance are presented in this section. The assumptions and the details of the analyses are described in Volume 5 of this report.

The C-b Tract. The variation of inflow rate for the 60-year life of the project at the C-b tract is shown in Figure 7.10. The expansion of the mine is the primary reason for continuous but gradual increase in mine inflow rate which peaks at $0.9 \text{ m}^3/\text{sec}$ (about 14,200 gpm). Assuming a production level of



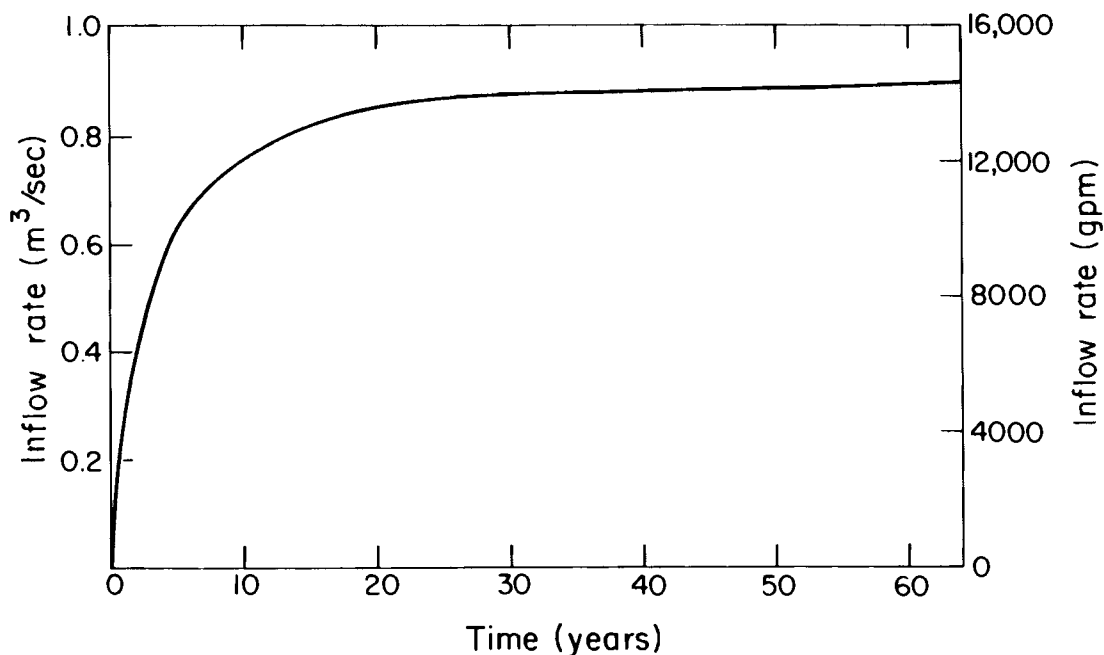
FXBL 8311-2303

FIGURE 7.9. Rate of Expansion of the Retorted Area with Time in the C-a Tract

50,000 barrels per day and water consumption of 2.1 barrels per barrel of oil,⁽¹⁸⁾ only $0.193 \text{ m}^3/\text{sec}$ (3,100 gpm) of pumped water will be used. Therefore, the balance must either be reinjected into the ground, used for stream flow augmentation, or disposed of as waste.

The results show that large quantities of water must be pumped to the surface which will require large quantities of energy. Assuming an approximate pumping rate of $1 \text{ m}^3/\text{sec}$ (15,000 gpm) from a depth of 400 m (1300 ft), the power requirements at 50% efficiency will be about 8 MW.

As desaturation proceeds, the phreatic surface (or ground-water table) becomes dynamic and moves downward as shown in Figure 7.11. The position of the phreatic surface (water table) as a function of time is shown in this figure together with the location of the expanding retort. This figure demonstrates that the tail of the phreatic surface intersecting the roof of the



XBL 8011 - 2319

FIGURE 7.10. The 60-Year Simulation of Dewatering for the C-b Tract

retort always lags the front of the mined region. This means that the retorting process may have to be delayed until the water table reaches the periphery of the caved region.

Figure 7.11 also shows the effect of dewatering at distances far away from the center of the tract. The drawdown of the phreatic surface at 3.5 km from the center of the tract, which is the approximate location of the Piceance Creek, is shown in Figure 7.12 which indicates that the phreatic surface could be lowered by as much as 100 m (330 ft) or more after 60 years of dewatering. The estimate of drawdown by Tipton and Kalmbach, Inc.⁽¹⁴⁾ at the end of 60 years is less than 60 m (200 ft) at a distance of 3 km (9,800 ft) from the center of the tract. This suggests that water may be lost from local streams and wells. Additional study is required to quantify this effect.

The C-a Tract. In the dewatering simulations of the C-a Tract, it is assumed that the thickness of the retort interval is 229 m (750 ft) from the top of the Mahogany zone to the bottom of the R-4 layer as shown in Figure 7.6, above. The variation of the inflow rates for a 30-year simulation of

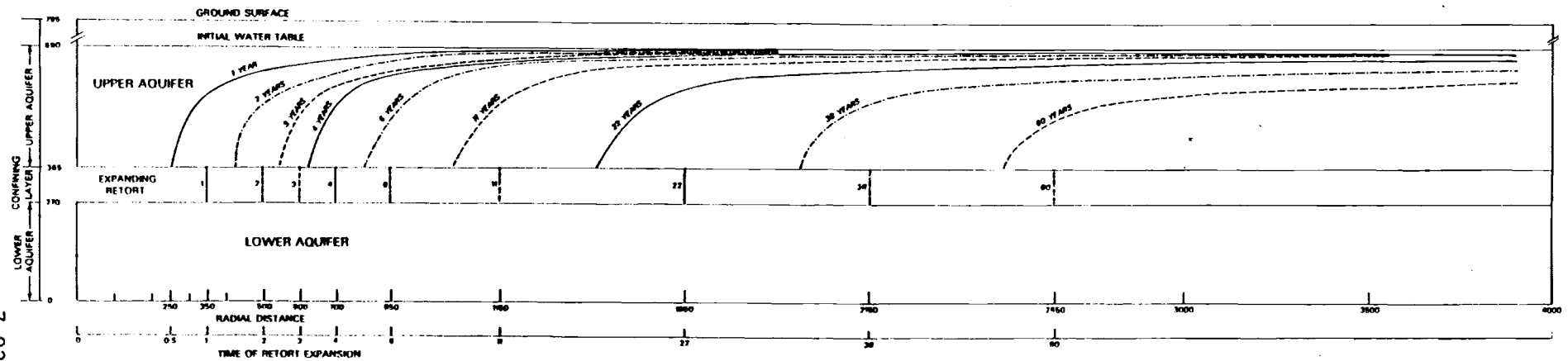
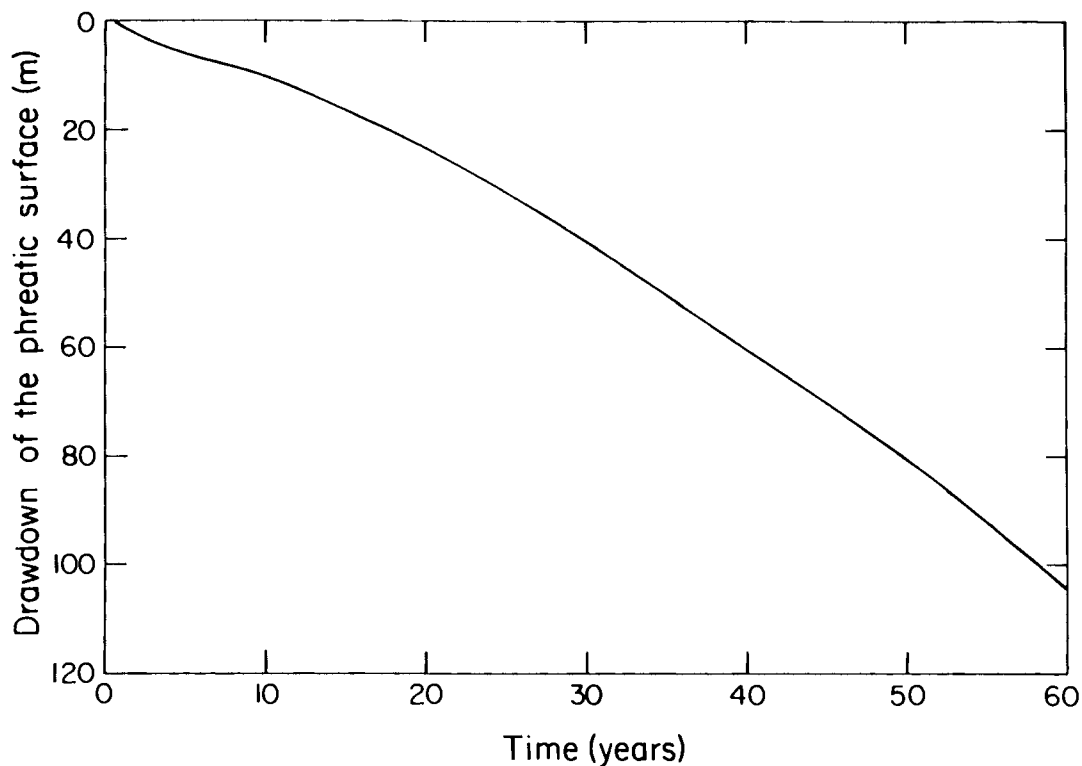


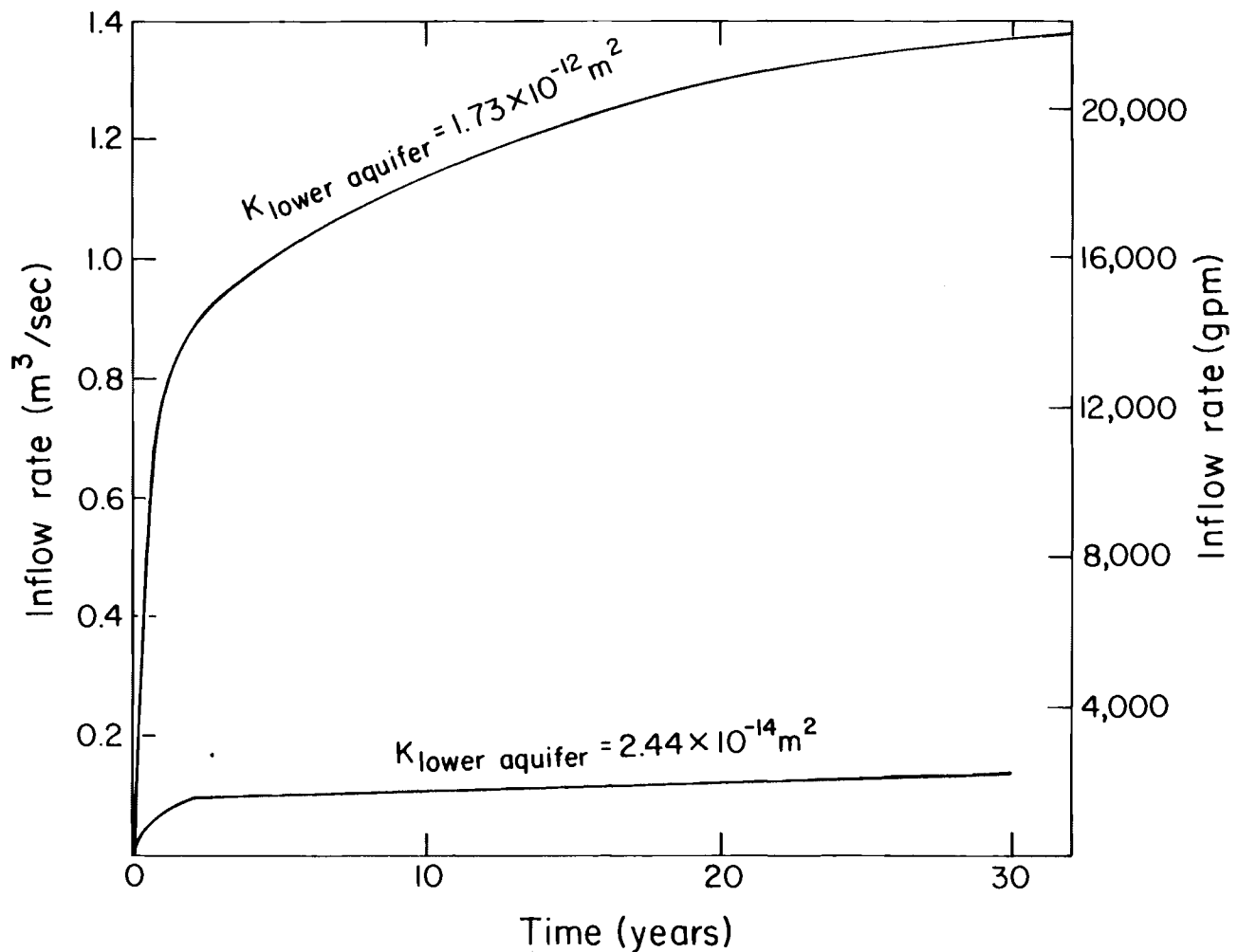
FIGURE 7.11. The Position of the Phreatic Surface for Dewatering the C-b Tract



XBL 8011-2314

FIGURE 7.12. Drawdown of the Phreatic surface for the 60-Year Simulation of Dewatering at a Radial Distance of 3.5 km from the Center of the C-b Tract (approximate location of Piceance Creek)

dewatering is shown in Figure 7.13 using two saturated permeabilities for the lower aquifer. The smaller inflow rate reaches a value of $0.15 \text{ m}^3/\text{sec}$ (2,300 gpm) at the end of 30 years. The larger inflow rate corresponds to the case where the transmissivity of the lower aquifer is assumed to be $87 \text{ m}^2/\text{day}$ (7,000 gpd/ft).⁽¹⁶⁾ The inflow rate in this case is about 10 times the previous case, indicating that the lower aquifer plays a significant role in the dewatering operation at the C-a Tract. This behavior is expected because, while the thickness of the upper aquifer is very small, the aquitard constitutes a large portion of the overall aquifer system. It is clear that since the contribution of the upper aquifer to the total flow into the mine is small, the effect of porosity and unsaturated properties of the upper aquifer on flow rates would also be insignificant.

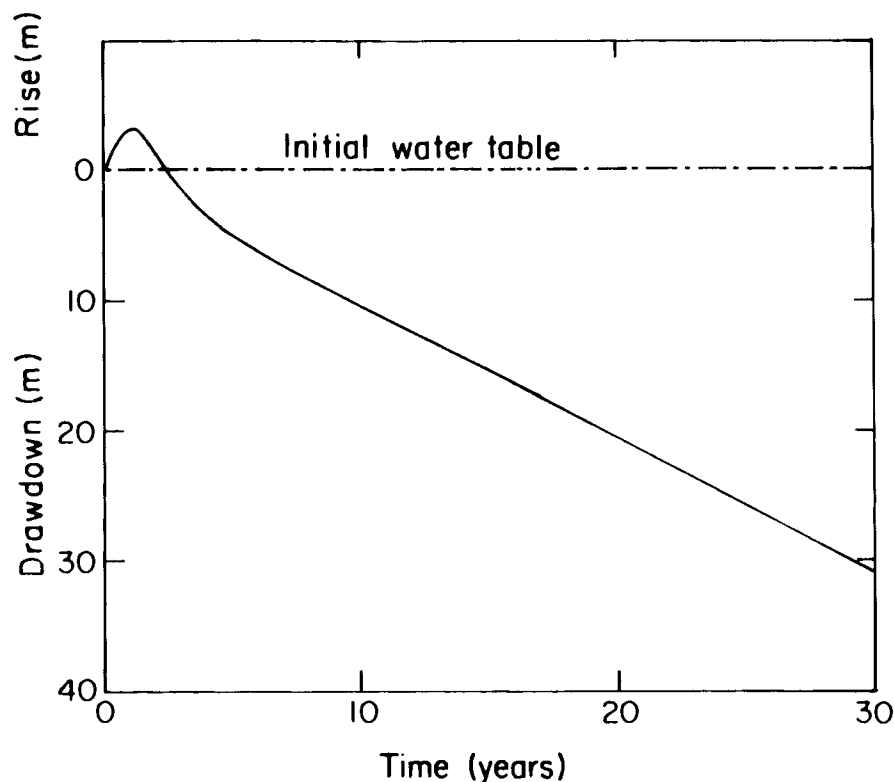


XBL 8011 - 2315

FIGURE 7.13. Variations of Inflow Rates with Time Over the C-a Tract for Two Permeabilities for the Lower Aquifer

Water use on the C-a Tract during the commercial phase is estimated to be $0.0875 \text{ m}^3/\text{sec}$ (1,400 gpm).⁽¹⁶⁾ The results of this study show that even the lowest estimates of lower aquifer permeability can furnish more than the required water consumption.

The fluctuation of the water table at a radial distance of 5 km from the center of the tract (approximate location of the Yellow Creek) for the high permeability case is shown in Figure 7.14. The water table initially rises up to about 15 months because of the effect of increased natural recharge from the



XBL 8011-2316

FIGURE 7.14. Water Table Fluctuations at a Radial Distance of 5 km from the Center of the C-a Tract

local ground surface, after which the influence of dewatering becomes dominant. The maximum drawdown of the phreatic surface after 30 years of dewatering is estimated to be 31 m.

Comparison with Other Studies. A comparison of the results of the Mehran et al. analyses with the results of Tipton and Kalmbach, Inc.⁽¹⁴⁾ and Golder Associates⁽¹⁸⁾ is provided in Volume 5. In general, the Mehran et al. results show a greater drawdown than the other two studies. Mehran et al. note that this difference may be explained by the fact that these studies neglected vertical infiltration from the region above the mine roof and ignored drainage contribution from desaturation.⁽⁶⁾

7.3.3 Reinvasion of Ground Water into the Dewatered Retort Areas

Due to its environmental implications, the reinvasion of water subsequent to retort abandonment is one of the crucial environmental aspects of the MIS process. Reinvasion of water into the retorts could result in leaching of soluble chemical species from the spent shale and their transport to surrounding ground water and surface water supplies. The Mehran et al. study,⁽⁶⁾ conducted in support of this assessment, examined the process of reinvasion of Tract C-b.

For the analysis of reinvasion, we are confronted with a few uncertainties. The thermal regime of the spent shale at the time of abandonment is an unknown which can have a substantial influence on the flow of water. Secondly, the state of saturation in the retorted region, which is influenced by retort abandonment control technologies, is not known. Thirdly, it is not known how the construction and burning of the MIS retorts will have changed the behavior of the entire aquifer system affecting the wetting process.

In the reinvasion analysis at the C-b Tract, Mehran et al. assumed no change in hydraulic properties of the upper and lower aquifers following retorting, even though they recognized that this is a gross simplification of actual field conditions. Because of rubblization and oil recovery, it was assumed that the retorted region has a porosity of 30% to a radial distance of 2,650 m (8,690 ft) while the remaining part of the confining layer maintains its original properties. Porosity increase will undoubtedly increase the hydraulic conductivity of the medium by many orders of magnitude. In the Mehran et al. analysis, it was assumed that hydraulic conductivity is 10,000 times greater than in the original confining layer. Furthermore, the retorted region was assumed to be near residual saturation.

The results indicate that reinvasion takes place primarily in the vicinity of the periphery of the retorted region because of the high conductivity of that region. Gradually, the water table rises along the bottom length of the retorted region, starting with the upper surface of the lower aquifer. This behavior prevents the invasion of water into the upper aquifer for decades and perhaps centuries. Obviously, the reinvasion rate varies from place to place

depending on the nature of saturation and other hydraulic properties of the medium. The results show that the average rise of the phreatic surface along the vertical section of the periphery of the retorted region is approximately 0.54 m/year.

The profiles of the phreatic surface after 200 years show that the upper aquifer remains unaffected by the invading waters (Figure 7.15). This could have favorable environmental consequences by allowing sufficient time for control technologies to be implemented. Due to its high hydraulic conductivity, the retorted region will act as a powerful sink to concentrate flow paths. Therefore, one should expect the reinvasion process to be extremely slow due to the large volume of void spaces that have to be filled and the extremely low hydraulic conductivity resulting from the very low saturation.

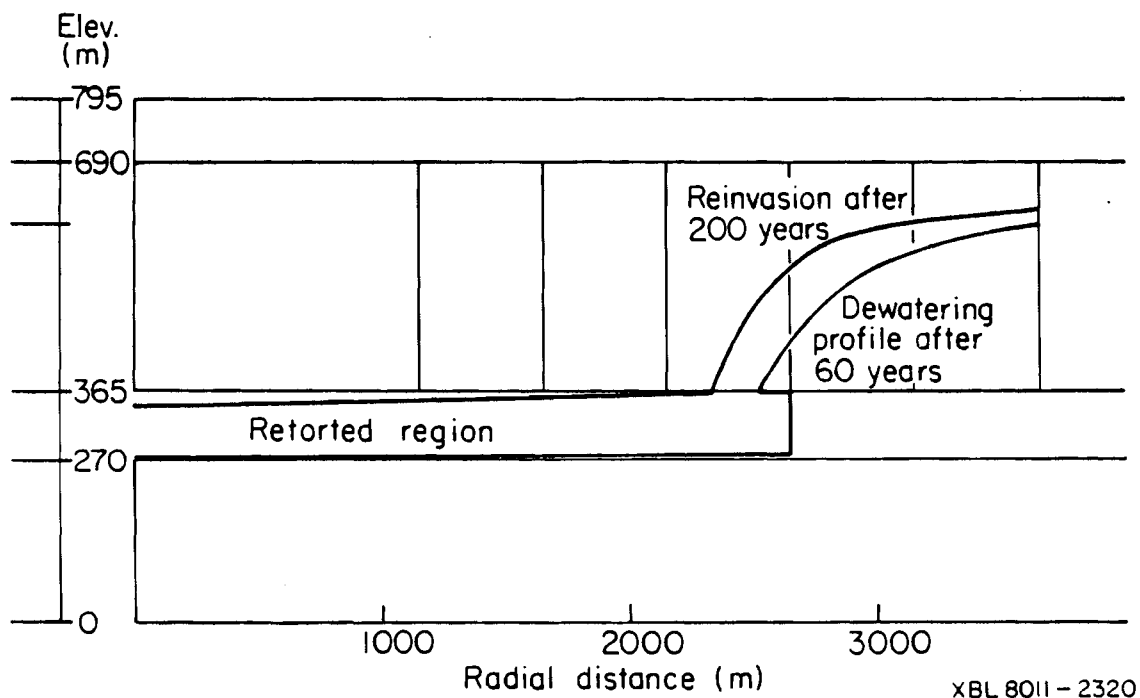


FIGURE 7.15. The Profile of Phreatic Surface After 200 Years of Reinvasion at the C-b Tract

7.4 IMPACTS ON GROUND-WATER QUALITY

Impacts of a shale oil industry on ground-water quality may result from surface disposal piles of raw or spent shale and reinvasion and leaching of burned and abandoned MIS retorts and oil shale mines. These impacts are discussed in this section.

7.4.1 Impacts from Disposal Piles

Enormous quantities of spent shale from various above ground retorting processes will be disposed of in piles constructed in canyons or on the ground surface. There will also be temporary and/or permanent piles of raw shale. There is some potential for contamination of ground water, especially in the shallow alluvial system, from runoff or leachates from these piles.

The composition and construction of waste piles are discussed extensively in Chapter 6 and Volume 4 of this assessment report. In general, the performance of such piles and the consequences of possible runoff and leachates are highly uncertain because of the many variables affecting these results and because of the lack of experience with large raw or spent shale piles.

The content of leachates from laboratory and field experiments has been shown to vary substantially depending upon the retorting processes. In general, however, leachates from raw shale may contain elevated levels of boron and fluorine; leachates from retorted shale may contain salts (sodium, calcium, magnesium, sulfate, and chloride), other cations (potassium and lithium), reduced sulfur species, mobile trace anions (e.g., boron, fluorine, and molybdenum), and organic carbon. Over time, the characteristics of leachates from a pile may be altered by natural weathering reactions and microbial action. These processes are under study at the present time. A summary of leachate content from experiments with spent shale from the paraho Process is given in Table 6.7, above.

Pile designs proposed by the industry incorporate dikes, drainage channels, and retention ponds to prevent runoff from surrounding areas from entering piles and to preclude runoff from spent or raw shale piles from reaching natural surface waters. They also incorporate pile linings, possibly compacted spent shale, to retard or eliminate percolation of leachates into ground-water

aquifers. With revegetation, there is expectation that no leachates will reach the bottom of the piles and that any surface runoff will approach the characteristics of runoff from natural land surfaces. For these reasons, most studies assume that surface piles will not have significant effects on ground-water quality (e.g., Fox).⁽¹⁾

7.4.2 Impacts from Underground Operations

During the time that oil shale is being mined and MIS retorts are being prepared and burned, dewatering will prevent any significant contact between ground waters and the operational sites. After operations cease, however, ground waters will eventually reinvade these areas. Unless effective control measures are developed and implemented, these waters will contact raw and spent shale and will leach chemical species which can be carried through aquifers to wells and to surface waters.

Leaching of underground mines that are not backfilled with spent shale probably will not cause any major changes in ground-water characteristics, since the aquifers are naturally composed of oil shale. If the mines are backfilled with spent shale, however, invading ground waters will contact the spent shale and leach from it chemical species not characteristic of the natural ground waters. In this case, these mines will be similar in their potential impacts to abandoned MIS retorts.

Since MIS retorts will span vertically the entire Mahogany Zone, it follows that when the aquifers are reinvaded by ground waters after the retorting is completed, the retorts will serve as conduits for the lower quality water in the lower aquifer to mix with the higher quality water in the upper aquifer.^(1,4) Irrespective of any leaching from the spent shale that may occur during passage through these conduits, this mixing could result in reducing the quality and potential usefulness of the upper aquifer water. To the extent that surface streams are fed by the upper aquifer, they may also be degraded.

Fox⁽¹⁾ conducted a specific detailed analysis to predict the composition of MIS leachates and the rates at which they would be transported into surface streams. In this work, reported values from laboratory leaching experiments using distilled water were used to determine the mass of various elements

available for leaching (mg of leached element per 100 g of spent shale), and published hydrologic data were used to predict the velocity of ground water leaving MIS retorts. This section, except where otherwise attributed, is based upon this work.⁽¹⁾

Estimates of leachate transport presented here are calculated without numerical modeling, using stated assumptions regarding leachate composition and flow direction. A more detailed analysis using numerical modeling is currently in progress at Lawrence Berkeley Laboratory.

MIS Leachate Composition

In estimating the composition of leachates coming from abandoned MIS retorts, the following assumptions were made:

1. Most leachable constituents are removed with the passage of the first two to six pore volumes of leach water. (One pore volume is the amount of water necessary to fill all of the void spaces--"pores"--in a retort.)
2. The actual mass of material leached per unit mass of spent shale is similar to that obtained in laboratory studies.
3. The leachate concentration leaving the retort is constant.
4. The spent retort intersects a ground-water aquifer and ground water migrates vertically through the retort.
5. The initial hydraulic gradients present before retorting would re-establish themselves after the site is abandoned.

These assumptions have substantial significance. More than six pore volumes might be required to remove the readily soluble material from a field retort due to differences between laboratory and field spent shales. Field conditions will differ from laboratory conditions since the water will not be distilled, the contact times will be much longer (one to ten years), the temperature at abandonment will vary from ambient to almost 1000°C, the particles will be highly variable in size, and a large segment of the oil shale zone will be contacted. The nature of the retorted shale in the field may differ from the laboratory shale since retorting temperatures may be higher. If

temperatures exceed 800°C, relatively insoluble silicates will form, reducing the concentration of some leachate constituents.

The constant concentration of leachates leaving the retorting area is reasonable for vertical flow since many retorts will be available for sequential leaching as the ground water reinvades more and more of the area. As the leachate concentration decreases from some, it will be increasing from others in which ground-water invasion and leaching began later. If the flow of leachate through retorts were horizontal instead of vertical, then there would be opportunity for the chemical species from one retort to interact with those in another retort, possibly altering the eventual leachate composition.

The results of the analysis are summarized in Table 7.2. As is explained below, the steady-state flow of water through the retorts on Tract C-a is expected to be from the upper aquifer to the lower aquifer; flow through C-b retorts is expected to be in the opposite direction. Therefore, the initial leach water will have a composition similar to Column (2) of Table 7.2, and for tract C-a the leachate will have a composition similar to Column (6). Similarly on Tract C-b, the initial water will have a composition similar to the lower aquifer, Column (5), and the concentrated leachate will approximate the composition of Column (7).

By comparing the lower values in Column (6) (C-a leachates) with the values in Column (3) (lower aquifer water), one observes that the leaching process increases the concentrations of Al, Cl, CO_3 , Fe, Li, NO_3 , Si, Mg, SO_4 , and phenols. The concentrations of TDS, B, F, HCO_3 , and Na will decrease. Others will stay constant. If the higher values in Column 6 are used, the concentrations of all of the constituents of the lower aquifer water will be increased. Comparing Column 7 (C-b leachates) with Column 4 (upper aquifer water) gives comparable information for Tract C-b. Using the lower values in Column 7 indicates that increases in the upper aquifer concentrations will occur for Al, B, Cl, Cr, CO_3 , F, Fe, HCO_3 , K, Li, Na, NO_3 , Pb, Si, TDS, and TOC; SO_4 , Ca, and Mg will decrease and Zn will remain constant. If the higher values in Column (7) apply, then major increases will occur in the concentrations of all constituents of the upper aquifer water.

TABLE 7.2. Estimated Composition of Leachate Exiting an In-Situ Retort Located on Lease Tracts C-a and C-b(1,20,21)

Constituent	Distilled Water Leachate Composition Summary mg/100 g (1)	Predevelopment Ground Water Quality, (a) mg/l				Leachate composition, mg/l	
		Tract C-a		Tract C-b			
		Upper	Lower	Upper	Lower	Tract (b) C-a (6)	Tract (c) C-b (7)
		Aquifer (2)	Aquifer (3)	Aquifer (4)	Aquifer (5)		
Al	0.095 to 2.8	0.14	0.24	0.3	0.3	0.49 to 31	0.87 to 53
B	0.001 to 0.14	0.33	0.84	1.4	36	0.33 to 1.9	36 to 39
Ca	0.03 to 210	35	8.8	32	14	35 to 2350 ^(d)	14 to 3950 ^(d)
Cl	5.5	12	22	26	1200	32 to 73	1234 to 1300
CO ₃	30 to 215	0.88	69	21	220	110 to 2400	408 to 4250
Cr	0.002 to 1.8	<0.01	<0.01	0.002 to 0.3	<0.009	<0.02 to <20	0.1 to 34
F	1.2 to 4.2	0.41	15	10	21	4.8 to 47	29 to 100
Fe	0.0004 to 0.042	5.0	0.78	0.5	0.8	5.0 to 5.5	0.8 to 1.6
HCO ₃	22 to 40	482	842	790	4000	560 to 920	4140 to 4750
K	0.07 to 18	2.2	2.6	2.2	21	2.5 to 200	21 to 360
Li	0.020 to 0.42	0.13	0.13	<3.1	10	0.20 to 4.8	10 to 18
Mg	0.002 to 8.0	52	20	42	11	52 to 140 ^(d)	11 to 160 ^(d)
Na	0.05 to 235	212	397	330	2500	212 to 2800	2500 to 6900
NO ₃	0.2 to 2.6	0.21	0.1	0.41	0.46	0.94 to 30	1.7 to 49
Pb	0.014 to 0.017	0.17	0.21	0.01	0.03	0.22 to 0.36	0.12 to 0.35
Si	25 to 88	26	10	17	13	120 to 990	170 to 1660
SO ₄	0.28 to 130	325	112	220	63	326 to 1800 ^(d)	65 to 2500 ^(d)
Zn	0.001 to 0.025	0.26	0.24	0.2	0.2	0.26 to 0.54	0.2 to 0.7
TDS	0 to 2800	905	1075	1100	6190	905 to 31,700	6190 to 58,700
TOC	1.0 to 38	8.5	11	3	10	12 to 430	16 to 720
Phenols	0.02 to 0.04	0.003	0.002	---	---	0.04 to 0.44	0.06 to 0.8

(a) Summarized from source (20) for Tract C-a and (21) for Tract C-b.

(b) Assumes the retort is leached with upper aquifer water, that the mass of spent shale in the retort is 1.1×10^9 g, and that the volume of water contained by the retort is 5.0×10^8 liters.

(c) Assumes the retort is leached with lower aquifer water, that the mass of spent shale in the retort is 7.5×10^8 kg, and that the volume of water contained by the retort is 2.0×10^8 liters.

(d) These constituents may be reduced on passage through the ground-water aquifer.

In some cases, leached constituents may react chemically with compounds present in the ground waters and effectively remove (precipitate) them. Examples are the formation of CaCO_3 and $\text{Mg}(\text{OH})_2$.

Impacts of retort leaching on C-b would be more immediate and significant than those on C-a. The C-b leaching would contaminate upper aquifer water which is used now for some agricultural purposes and, subsequently, would affect the quality of alluvial aquifer and surface waters fed by the upper aquifer waters. Contamination of the lower aquifer water by retorts on Tract C-a might degrade upper aquifer water through slow leakage through the Mahogany Zone, but this might take thousands of years. However, initial leaching on Tract C-a would be upward from the lower to the upper aquifer due to

significant drawdown from dewatering. Under these conditions, the upper aquifer water would be contaminated, and secondary impacts, such as effects on Yellow Creek, would be more immediate.

MIS Leachate Transport

The lower aquifer has a higher hydraulic head than the upper aquifer throughout most of the Piceance Creek Basin. The difference, however, is almost always less than 30 m and is typically less than 15 m. The flow of ground water through the retorts from one aquifer to the other will depend upon the size and direction of this head difference, the distance between the aquifers, and the permeability of the retorts and surrounding aquifers. The conditions affecting this vary throughout the Piceance Creek Basin, making specific predictions for an industry very uncertain. However, evidence suggests that on Tract C-a the direction of ground-water flow will likely be from the upper to the lower aquifer.⁽¹⁰⁾ The permeability of the upper aquifer (0.5 m/day) will control the flow of leachate through each retort. Assuming a head difference between the aquifers of 7.6 m, water will move through a retort on C-a at the rate of 207 m per year, and the average residence time in the retort will be one year.

On Tract C-b, the water will flow through the retorts from the lower aquifer to the upper aquifer.⁽¹⁰⁾ Because of the low permeability of the lower aquifer (0.03 to 0.09 m per day), water will move through the retort at 14 to 43 m per year, and its average residence time in the retort will be from three to ten years.

Contamination from leaching of in-situ retorts will take a very long time to move through the aquifers. These leachates will eventually discharge into surface waters. From Tract C-a, steady-state leachates will tend to move into and through the lower aquifer. Since the lower aquifer is not hydraulically connected to the Yellow Creek system, leachates would have to migrate upward, through vertical fractures in the oil shale, to reach surface streams, a process that could take millenia. However, initial leachates, formed under nonequilibrium conditions, would migrate upward through the retorts and into the upper aquifer, discharging into Yellow Creek more than a century after they

left the retort. At Tract C-b, both initial and steady-state leachates would move up through the retort into the upper aquifer. It would take two to fourteen centuries for this contamination to reach Piceance Creek through the upper aquifer.

The concentration of leachates may be reduced by dispersion, adsorption, and precipitation in the aquifers. On the other hand, organic matter in the leachates may complex the metal ions, increasing their mobility. By consuming the oxygen available in the ground water, organic matter may also lower the pH, allowing iron, manganese, and other elements in the aquifer media to be dissolved. The systems involved in leachate transport and chemical and physical reactions are too complicated to allow definite predictions of the changes which will occur.

Fox summarizes her findings as follows:⁽¹⁾

"In summary, this analysis suggests that the composition of ground waters in the vicinity of an in-situ facility will approach that of in-situ leachate (Table [7.2]). However, because the velocity of ground waters is low, centuries may pass before the leachate travels an appreciable distance from the facility, although water transport along the fractures may reduce this time estimate. The distance from the source that each constituent will travel will depend on the ground-water flow velocity and the amount of retardation experienced. After a sufficient period of time, ranging from several years to several hundreds of years, and depending on the specific site, the composition of local ground waters may approach the leachate composition shown in Table [7.2]."

The significance of these changes is suggested by Table 7.3. The current limited use of aquifer waters for irrigation of salt-resistant crops, and the potential for use of the waters with limited treatment as a domestic supply or for livestock would be lost. Furthermore, a hazard would be created since domestic use of the water by unsuspecting individuals could expose those individuals to toxic or carcinogenic constituents in the leachates.

Contamination of the upper aquifer is likely to result in contamination of Yellow Creek, Piceance Creek, and other streams in the Upper Colorado River Basin. These impacts are explored in Chapter 8 of this report.

TABLE 7.3. Comparison of Predevelopment and Postdevelopment Ground-Water Quality with Water Levels Not to be Exceeded in Main Water Mass^(1,22)

Parameters	Water Quality Criteria			Tract C-a			Tract C-b		
	Domestic Water Supplies,(a) mg/l	Livestock Watering,(a) mg/l	Irrigation,(a) mg/l	Predevelopment Ground-Water Quality		Post- development Ground Water Quality, mg/l	Predevelopment Ground-Water Quality		Post- development Ground Water Quality, mg/l
				Upper	Lower		Upper	Lower	
				Aquifer, mg/l	Aquifer, mg/l		Aquifer, mg/l	Aquifer, mg/l	
Al	---	5.0	5 to 20	0.14	0.24	0.49 to 31	0.3	0.3	0.87 to 53
B	(b)	5.0	0.75 to 2.0	0.33	0.84	0.33 to 1.9	1.4	3.6	36 to 39
Cl	250	---	(c)	12	22	32 to 73	26	1200	1234 to 1300
Cr	0.05	1.0	0.1 to 1.0	<0.01	<0.01	<0.03 to <20	0.002 to 0.3	<0.009	0.01 to 34
F	1.4 to 2.4	2.0	1 to 15	0.41	15	4.8 to 47	10	21	29 to 100
Fe	0.3	None	5 to 20	5.0	0.78	5.0 to 5.5	0.5	0.8	0.8 to 1.6
Li	---	---	0.075 to 2.5	0.13	0.13	0.20 to 4.8	<3.1	10	10 to 18
NO ₃ -N	10	100 ^(d)	None	0.21	0.1	0.94 to 30	0.41	0.46	1.7 to 49
Pb	0.05	0.1	5 to 10	0.17	0.21	0.22 to 0.36	0.01	0.03	0.12 to 0.35
SO ₄	250	---	---	325	112	326 to 1800	220	63	65 to 2500
Zn	5	25	2.0 to 10	0.26	0.24	0.26 to 0.54	0.2	0.2	0.2 to 0.7
Phenols	0.001	---	---	0.003	0.002	0.04 to 0.44	---	---	0.06 to 0.8

(a) Summarized from Source (22).

(b) Inadequate data available to set standard.

(c) Variable; depends on soil condition.

(d) NO₃ + NO₂.

7.5 POTENTIAL ENVIRONMENTAL CONTROL STRATEGIES FOR MIS OPERATIONS

A variety of strategies have been proposed for preventing or controlling the leaching of abandoned MIS retorts. None of these methods have been tested; all have unresolved technical issues associated with them. Clearly, acceptable methods will have to be developed before a commercial MIS industry is possible. A summary of methods explored to date is presented in Table 7.4. Brief notes on each strategy, as discussed by Fox⁽¹⁾ and Fox et al.⁽⁴⁾ follow.

7.5.1 Site Selection

The purpose of this strategy is to locate MIS retorts in ground-water free zones. This would minimize or eliminate in-situ leachate formation and transport, and it represents the most desirable condition for protecting ground water from degradation. There are presently inadequate data to determine with certainty whether or not MIS retorts can be completely contained in dry zones, and, if so, what fraction of the resource can be recovered using this control strategy.

7.5.2 Grouting

The three principal environmental problems associated with MIS retorting--contamination of surface and ground waters, subsidence, and low resource recovery--may be alleviated by filling the abandoned in-situ retorts with a grout based on surface spent shale. This grout would fill the voids, reducing the permeability of the retorts and provide protection against subsidence by increasing retort stiffness and strength. If adequate strength could be developed in the grouted retort, it may be feasible to retort some of the pillars left between the retorts, thus improving resource recovery. A cheap material, such as spent shale, would have to be used as the basis of such a grout because 0.25 to 0.34 m³ of voids must be filled for each barrel of oil recovered. Thus, conventional grouting materials are too costly for this application.

The successful application of this proposal requires the development of grouting criteria, formulation of an adequate grouting recipe, and development of methods to successfully distribute the grout within the retort. Work to date has focused on the development of a grout; little or no research has been

TABLE 7.4. Candidate Control Strategies for MIS Retorts(a)

<u>Control Strategy</u>	<u>Projected Cost(a) per Barrel of Oil</u>		<u>Unresolved Technical Questions</u>
	<u>C-a</u>	<u>C-b</u>	
Site Selection	Not Applicable		Fraction of resource that is recoverable.
Grout Abandoned Retorts with Spent Shale	\$0.49(b)	\$0.35(b)	Penetration of grout through rubble; permanence of non-cementitious grout.
	\$0.65(c)	\$1.30(c)	Ultimate permeability of retort.
In-Place Precipitation of Calcite to Seal Pores(d)	\$1.88	\$1.15	Eventual solution of precipitates.
Grout Curtain	\$0.74	\$2.85	Feasibility of drilling closely spaced, parallel holes 1000 to 2000 ft deep.
Design Retorts with Hydraulic Bypass(d)	\$0.46	\$1.76	Effectiveness is uncertain; feasibility of producing adequate permeability by grouting a tight formation.
Cap Rock in Place	Not Applicable		Long-term stability of cap rock.
Recover and Treat Leachate	\$0.67	\$0.59	Economics of treatment process and brine disposal
Treat Leachate in situ by Adsorption and Ion Exchange	Too Costly		
Modify Retort Operating conditions	0	0	Effect of operating conditions on minor constituents; adequacy of process control.
Self Treatment(d) (no action)	0	0	Effectiveness uncertain.

(a) Cost per barrel in 1979 dollars based on combined surface and in-situ retorting, 40% voids on Tract C-a and 23% on Tract C-b.

(b) Air-level drilling.

(c) Ground-level drilling.

(d) Possible application in conjunction with another technology; not adequate by itself.

conducted on grouting criteria and grout distribution. Experimental work has consisted of exploratory laboratory research focused on the development of a grout from raw or spent shale.

7.5.3 In-Place Precipitation of Calcite to Seal Pores

In-place formation of a calcite precipitate may be used to seal pores in abandoned retorts. Hydrated lime would be placed into the retorts as a slurry and reacted with CO_2 in invading ground waters. The basis of this process is the reaction of carbonate in the ground waters with calcium hydroxide in the slurry to form calcite.⁽²³⁾

In addition to placing limestone in retorts, some free lime may be present in surface and in-situ spent shale. Heistand et al.⁽²⁴⁾ found up to 7.7% free lime in surface retorted shale. If free lime is present in spent shales, it will react like emplaced lime to precipitate calcite. Thus, surface or in-situ spent shale could be substituted for some of the lime. This needs to be investigated experimentally. However, it appears that calcite precipitation will not be economically feasible as a control technology.

7.5.4 Grout Curtain

Constructing a grout curtain to route flow around retorting sites is one possible control technology to prevent ground water from leaching abandoned retorts. The use of a grout curtain to stop ground-water flow is not a novel concept. However, there are special conditions of this proposed application for MIS abandonment procedures that may make it difficult or expensive.

The first condition is the depth at which the curtain must be constructed. Holes must be drilled about 300 m deep, with very small deviation, in order to form a continuous curtain. This may be difficult to achieve. A second problem arises because the formations which are to be grouted (the aquifers) are of very low permeability, and it may be difficult to inject grout, especially a suspension grout such as portland cement, into so tight a formation. The selection of a grout for this application will depend upon the distribution of fracture sizes in the formation to be grouted. If permeability is due to a few large fractures (>0.01 cm), these may be satisfactorily grouted by portland cement. However, if permeability is due to the presence of many small

fractures, a more expensive chemical grout would be needed. The amount and cost of grouting material needed would be determined by the porosity of the formation.

Little information is currently available in the literature to answer any of these questions, and there are no oil-shale specific investigations on this control method. Exploratory drilling and a test grouting program will be necessary to assess the feasibility of this control technology. A ground-water flow model will have to be used to evaluate the efficacy of a grout curtain. Ground-water quality and leachate transport, as a function of curtain location, thickness, and permeability, will have to be studied. If these results are encouraging, field studies will have to be conducted to determine the fracture size distribution and density.

7.5.5 Design Retorts with Hydraulic Bypass

When retorts connect two aquifers which are at different piezometric heads, ground water may flow through the abandoned retorts from one aquifer to another, transporting leachate from the abandoned retorts into the aquifer at the lower pressure. This leaching flow can be minimized by designing retorts or retort blocks in such a manner as to force ground-water flow through parallel paths of greater permeability instead of through the abandoned retorts. A hydraulic bypass or shunt could be installed for this purpose when the retorts are constructed.

A bypass is simply a series of holes drilled around the perimeter of a block of retorts and might be a palisade or curtain of wells or drill holes. The holes are not grouted but are left open to permit water to pass from one aquifer to another.

Some ground-water flow, however, would still pass through abandoned retorts. Therefore, this control measure dilutes leachate by mixing it with bypass flow. The required degree of leachate dilution would dictate the design of the bypass and the retort sealing.

A hydraulic bypass would minimize vertical but not horizontal flow through retorts. Therefore, a grout curtain or some other means of deterring

horizontal flow may be required, depending on retort-aquifer geometries. The potential benefits of this control strategy could be quantified by computer modeling of the ground-water system.

7.5.6 Cap Rock in Place

In the Piceance Creek Basin, oil shale is located beneath the water table in the rich Mahogany Zone which lies between two confined aquifers. Retorts that intersect either aquifer will be flooded after being abandoned. This control strategy would retain a cap rock of undisturbed oil shale material above and/or below the retorts to prevent flooding by ground water. However, because the Mahogany Zone itself is permeable, a retort constructed entirely within the zone or protected by a cap rock might still be flooded by ground water, but the rate of flow through the retort would be relatively slow.

An in-situ cap rock requires that an entire retort be confined within a dry zone, which might be from 100 to 200 ft thick. However, MIS retorts must be tall to be economic. Fenix and Scisson,⁽²⁵⁾ for example, cite 200 ft as the minimum retort height in their economic analysis of retorting methods. Other proposed retorting systems use retorts 300 to 750 ft high. Applying a cap rock strategy in the Mahogany Zone would require using retorts far shorter than the minimum recommended by Fenix and Scisson.

Even if the Mahogany Zone were deep enough to permit efficient retorting with a cap rock in place, this technology would be difficult to use as a control measure. The retort would have to be completely isolated from the aquifers. No fractures could be present in the cap rock either before or after retorting or it would not be able to serve its preventative purpose of keeping ground water from penetrating the retort. If the cap rock were to collapse during retorting, remedial measures would have to be taken to repair the damage. Occidental has experienced some difficulty with the stability of the cap rock (sill pillar) over Retort 6 which deteriorated during that run.⁽²⁶⁾ Good hydrologic data, probably involving extensive testing, would be needed to guarantee the integrity of the cap rock.

This control strategy may be uneconomical, and site-specific evaluation is required. The restriction of retort size and unrecovered oil shale in the

cap rock would increase the unit cost of oil recovery. It is not applicable for Tracts C-a and C-b due to their unique geologic and hydrologic conditions.

7.5.7 Recover and Treat Leachate

Control technologies discussed thus far are based on minimizing the flow of ground water through abandoned retorts. An alternative strategy is to intentionally leach the retorts, recover the leachate, treat it, and either dispose of it or reuse it for further leaching. Several laboratory investigations have shown that the concentrations of organics and inorganics decrease rapidly with leaching flow. Thus, treating a finite volume of leachate may be sufficient to remove enough of the leachable material in spent retorts to protect ground-water quality.

Little experimental work has been conducted on this control technology. Before it can be adequately evaluated as a control method, data need to be developed on the availability of water for leaching, the quality of leachate, the kinetics of leachate formation, the volume of water that must be treated, and methods of leachate treatment. A large amount of water is needed for leaching. Estimates indicate that 10 to 14 million gallons per day of water would be required for two pore volumes of leaching per 50,000 barrel-per-day capacity. Detailed estimates of water availability for this purpose should be made. A plan for handling, storing, and reusing leachate and disposing of the brine streams from treatment must be worked out. The volume of leachate that must be treated needs to be defined so that treatment costs, which are strongly dependent on leachate volume, can be determined. This will require the development and use of a kinetic model of the leaching process. Methods of treating the produced leachate must be selected and tested in laboratory- and pilot-scale treatability studies. These studies should be conducted using field spent shales, and the result of this work corroborated in larger scale field tests.

7.5.8 Treat Leachate In-Situ by Adsorption and Ion Exchange

Collecting and treating leachate on the surface involves costs for pumping and re-injection and is sensitive to the kinetics of leaching and the rate of re-invasion of retorts by ground water. These would not be problems if

treatment were accomplished in-situ by adsorption and ion exchange. In principle, an adsorbent could be placed in a retort to remove organics from leachate and mixed ion-exchange resins used to remove dissolved cations and anions. The amount of these materials needed would depend on the amount and nature of organics and inorganics to be removed from solution and the capacity of these materials to remove pollutants. The data available suggest that over 100 equivalents of anions and cations and 30 mg/l TOC would have to be removed for two pore volumes of leaching per barrel of oil recovered. While the TOC could probably be economically controlled using an adsorbent resin, the cost of ion exchange resin to remove this large quantity of TDS would be prohibitive. Therefore, this strategy would not provide adequate salinity control at a reasonable cost.

The cost of the method depends upon the amount of organics and inorganics to be removed and the cost of the required amounts of adsorbent or ion-exchange resin. Based upon an expected leachate composition for treating two pore volumes of leachate, using ion-exchange resins for TDS removal by this method is too costly to be considered.

7.5.9 Modification of Retort Operating Conditions

Several studies have shown that the leachability of spent shale depends upon retort operating conditions. Conditions which would minimize the leachability of spent shale include: combustion retorting to burn off char; use of sweep gas to remove CO_2 ; high temperatures, about 1000°C , to promote silication reactions; steam retorting; and a slow retorting rate. If these conditions are used, it may be possible to produce a spent shale with adequate strength and a sufficiently low leachability to minimize water quality and structural problems of in-situ retorts. These conditions approximately coincide with those presently proposed for use by the developers of lease Tracts C-a and C-b. However, it is presently uncertain whether the conditions proposed by the developers are adequate to mitigate leaching problems. Related issues--namely composition of the leachate, pollutant transport, and the controlling regulatory framework--need to be addressed.

Additional research is required to further explore the effect of retorting conditions on the solubility of a broader range of constituents, including trace organic and inorganic compounds. The effect of shale composition, retorting temperature, retorting rate, input gas composition, and particle size on the solubility of major and minor elements needs to be determined. Trade-offs between oil production and leachability need to be explored in economic studies.

7.5.10 Self Treatment

As a general rule, all natural waters have some capacity for self-purification. Mechanisms of self-treatment in Piceance Creek Basin aquifers might include precipitation, natural decomposition of complex organic molecules, microbial degradation, and adsorption and ion exchange on aquifer media. Since it is anticipated that it will take many years for discharged leachate to reach any downstream users or surface waters, even a slow rate of self-treatment may be sufficient to preserve ground-water quality. This self-treatment capacity of aquifers has never been measured, but controlled laboratory or field studies could quantify that capacity. This rate of self-treatment could then be used in computer models of an aquifer-retort system. Given present information, this method is too uncertain to be considered a viable choice.

7.6 REFERENCES FOR CHAPTER 7

1. Fox, J. P. 1980. Water-Related Impacts of In-Situ Oil Shale Processing. LBL-6300. Lawrence Berkeley Laboratory, Berkeley, California.
2. Sladek, T. A. 1974-1975. "Recent Trends in Oil Shale," Parts 1, 2, and 3. Colorado School of Mines Mineral Industries Bulletin.
3. Crawford, K. W., C. H. Prien, L. B. Baboolal, C. C. Shih, and A. A. Lee. 1977. A Preliminary Assessment of the Environmental Impacts from Oil Shale Development. Report by TRW Environmental Engineering Division and Denver Research Institute by U.S. Environmental Protection Agency, Contract 68-02-1881. EPA 600/7-77-069. U.S. Environmental Protection Agency, Cincinnati, Ohio.
4. Fox, J. P., P. Persoff, P. Wagner, and E. J. Peterson. 1980. "Retort Abandonment--Issues and Research Needs." Presented at Oil Shale, The Environmental Challenges, Vail, Colorado, August 11-14.

5. The John Muir Institute, Inc. 1980. Institutional Constraints on Alternative Water for Energy: A Guidebook for Regional Assessments. Prepared for U.S. Department of Energy under contract to Los Alamos Scientific Laboratory. DOE/EV/10180-01. Washington, D.C.
6. Mehran, M., T. N. Narasimhan, and J. P. Fox. 1981. An Investigation of Dewatering for the Modified In-Situ Retorting Process, Piceance Creek Basin, Colorado. Available as Volume 5 of this assessment report.
7. Robson, S. G. and G. J. Saulnier, Jr. 1980. Hydrogeochemistry and Simulated Solute Transport, Piceance Basin, Northwestern Colorado. U.S. Geological Survey Open-File Report 80-72.
8. U.S. Congress, Office of Technology Assessment. 1980. An Assessment of Oil Shale Technologies. U.S. Government Printing Office, Washington, D.C.
9. Sinor, J. E. 1977. "Disposal of Mine Water from a Deep Oil Shale Mine." In Proceedings of the Second Pacific Chemical Engineering Congress, Vol. II.
10. Weeks, J. B., G. H. Leavesley, F. A. Welder, and G. J. Saulnier. 1974. Simulated Effects of Oil Shale Development on the Hydrology of Piceance Basin, Colorado. U.S. Geological Survey Professional Paper 908.
11. Coffin, D. L. F. A. Welder, and R. K. Glanzman. 1971. "Geohydrology of the Piceance Creek Structural Basin Between the White and Colorado Rivers, Northwestern Colorado." U.S. Geological Survey Hydrological Investigation Atlas, HA-370.
12. Wymore, I. F. 1974. Estimated Average Annual Water Balance for Piceance and Yellow Creek Watersheds. Environmental Resources Center, Technical Report No. 2, Colorado State University, Fort Collins, Colorado.
13. Smith, J. W., T. N. Beard, and L. G. Trudell. 1979. Oil Shale Resources of the Naval Oil Shale Reserve No. 1, Colorado. Laramie Energy Technology Center, RI-79/2, Laramie, Wyoming.
14. Tipton and Kalmbach, Inc. 1977. Hydrology, Mine Dewatering and Water Use and Augmentation, C-b Tract, Piceance Creek Basin, Colorado. Report to Occidental Oil Shale, Inc.
15. Energy Development Consultants, Inc. 1981. Technology Characterization and Production Scenarios. Available as Volume 2 in this assessment report.
16. Rio Blanco Oil Shale Project. 1977. "Revised Detailed Development Plan, Tract C-a," in Mining, Processing and Support Facilities, Vol. 2. Gulf Oil Corporation, Standard Oil Company (Indiana).

17. Weeks, J. B., and F. A. Welder. 1974. Hydrologic and Geophysical Data from the Piceance Basin, Colorado. U.S. Geological Survey, Colorado Water Resources Basic Data Release No. 35.
18. Golder Associates. 1977. Water Management in Oil Shale Mining: Volume I, Final Report. Prepared for U.S. Department of Interior, Bureau of Mines.
19. Garland, T. R., R. E. Wildung, and H. P. Harbert. 1979. "Influence of Irrigation and Weathering Reactions of the Composition of Percolates from Retorted Shale in Field Lysimeters." In: Proceedings of 12th Annual Oil Shale Symposium. Colorado School of Mines, Golden Colorado.
20. Gulf Oil Corporation and Standard Oil Company (Indiana). 1977. Final Environmental Baseline Report for Tract C-a and Vicinity, Rio Blanco Oil Shale Project. Denver, Colorado.
21. Ashland Oil, Incorporated, and Occidental Oil Shale, Incorporated. 1977. Environmental Baseline Program: Final Report for Period November 1974-October 1976, Oil Shale Tract C-b.
22. National Academy of Sciences, National Academy of Engineering. 1973. Water Quality Criteria 1972: A Report of the Committee on Water Quality Criteria. U.S. Environmental Protection Agency Report EPA-R3-73-013.
23. Persoff, P., and P. Fox. 1980. Control Strategies for Abandoned In-Situ Oil Shale Retorts. Lawrence Berkeley Laboratory Report LBL-8780.
24. Heistand, R. N., D. B. Jones, and L. L. Morriss. 1978. "Free Lime in Retorted Oil Shale." Energy Sources, 4(2) 195.
25. Fenix and Scisson, Engineers. 1976. Technical and Economic Study of the Modified In-Situ Process for Oil Shale. Report to U.S. Bureau of Mines, Contract SO 241073.
26. Occidental Oil Shale, Inc. 1979. Occidental Vertical Modified In-Situ Process for the Recovery of Oil from Oil Shale, Phase I: Final Report for the Period November 1, 1976-April 30, 1979.

8.0 SURFACE WATER IMPACTS

The land and local surface waters of the oil shale region are very rural in character. The land has been only sparsely settled; much of it is wholly undeveloped. Water from the Piceance and Yellow Creeks is used largely for irrigated agriculture. The Piceance and Yellow Creeks have limited value for sport fishing^(1,2) due to the intermittent flow of many tributaries and heightened salinity in lower reaches.

The local streams in the oil shale region drain into the White River or the Colorado River main stem. Quantity and quality changes in these streams, resulting from a shale oil industry, will be of importance because of the very intensive demands placed on the Colorado River system as a whole for recreational, domestic water supply, and agricultural purposes. Irrigation is by far the largest user. In 1973 in the Upper Colorado River Basin, 4.26 billion m^3 (3,496,000 acre-ft) of water were used. Of this 2.65 billion m^3 (2,175,000 acre-ft) were used on irrigated agriculture and 794.0 million m^3 (651,000 acre-ft) were exported for use outside of the basin, while 111.0 million m^3 (91,000 acre-ft) were used for urban water supply and 72.0 million m^3 (59,000 acre-ft) were used in energy development.⁽³⁾

A shale oil industry will draw heavily on the surface water resources of the local streams and the White River, as discussed in Section 4.2 of this report. Dewatering of ground water aquifers to enable mining and modified in-situ (MIS) retorting of oil shale (see Chapter 7) will reduce the ground-water flow into local streams; this flow supplies an estimated 80% of the total flow in Piceance and Yellow Creeks except during spring snowmelt.⁽⁷⁾ Changes in surface water quality could result from surface runoff carrying silt and other constituents, contamination from raw or spent shale piles, or liquid wastes from shale oil production. They could also come from discharge of dewatering water, reduction of water flow (which would otherwise dilute contaminants), or contamination of ground water which feeds the surface streams.

This chapter examines the potential impacts of a shale oil industry on surface water quality and quantity. It will consider first a description of surface water resources, then the laws and regulations applicable to these

waters. It will look at changes possible in water quantity, and finally it will examine potential quality changes from dewatering, liquid effluents from shale oil production, surface runoff, and contamination of ground waters.

8.1 DESCRIPTION OF SURFACE WATER RESOURCES

There are several good descriptions of surface water resources in the Upper Colorado Basin. A good overview is provided by Fox;⁽⁴⁾ much of this section is based on her report and one prepared for this assessment by Mehran, Narasimhan, and Fox.⁽⁵⁾ A complete description is not provided here, but those aspects most critical to considering impacts from a shale oil industry are highlighted.

8.1.1 Colorado River Basin Overview

The Colorado River Basin is typically viewed as two separate basins, the "Upper Basin" and the "Lower Basin." The point of division is Lees Ferry, located just south of the Arizona-Utah state line (Figure 8.1).

The Lower Basin is not of direct interest in this assessment, except that the demands for water from the lower Basin impose constraints on water use in the Upper Basin. Under the terms of the Colorado River Basin Compact, the Upper Basin is committed to passing 10.37 billion cubic meters (8.5 million acre-ft) of water through to the Lower Basin each year. Further, the salinity of water passing into Mexico in the lower Basin is controlled under agreement with Mexico. This has resulted in constraints on the addition of salinity within each of the basin states.

The Upper Basin has a drainage area of about 283,700 km² (109,600 mi²). It is about 880 km (550 miles) long and 560 km (350 miles) wide. It has three major subregions: the Green River, the Upper Main Stem, and the San Juan-Colorado. The Piceance Creek Basin drains into the White River Sub-basin, which is included in the Green River Basin, and the Upper Main Stem.

The Upper Colorado River Basin is characterized by highly variable climatic conditions that produce significant seasonal and annual differences in precipitation, runoff, and evaporation affecting the amount, quality, and use of water.

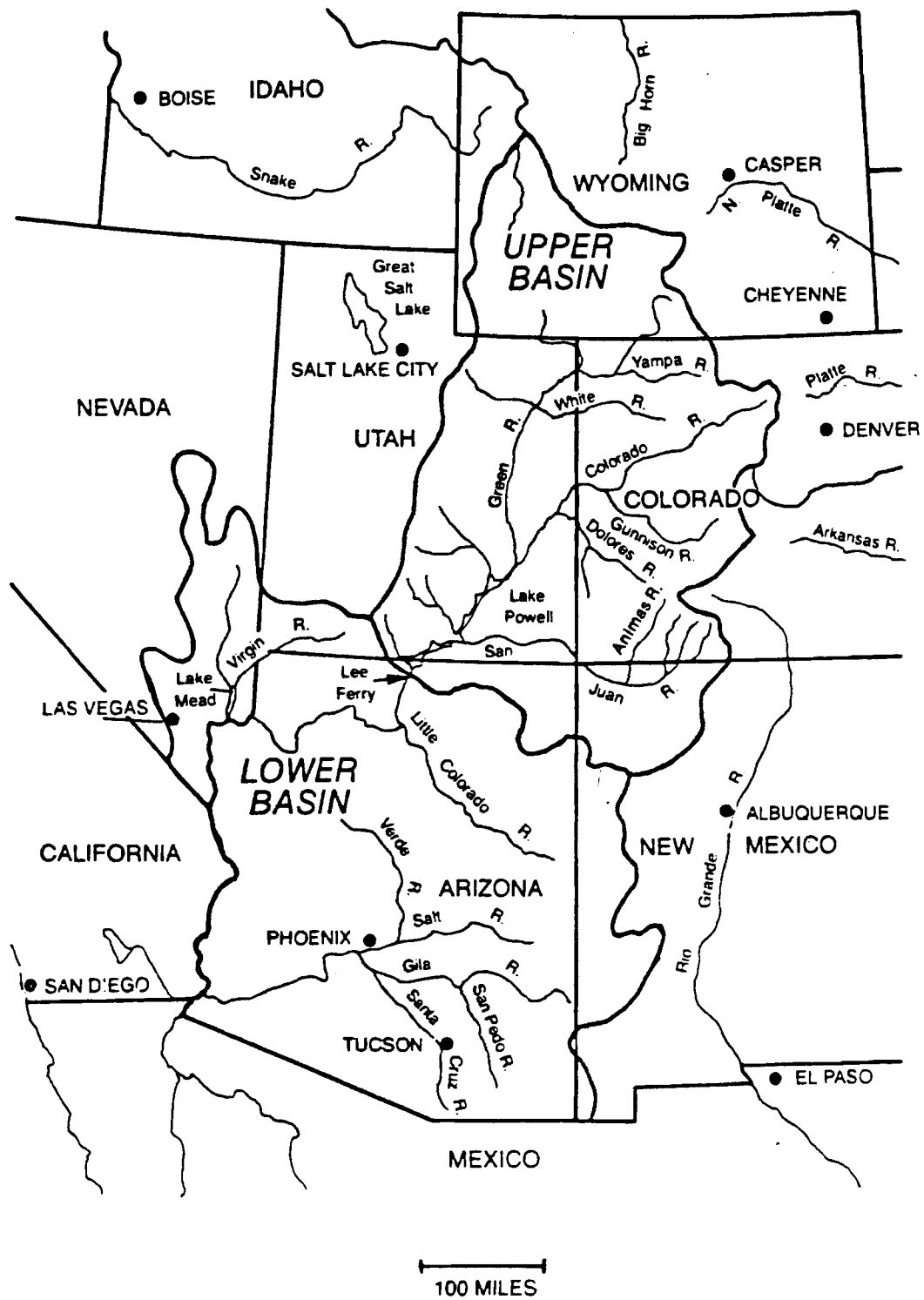


FIGURE 8.1. The Upper and Lower Colorado River Basins(6)

Annual precipitation within the Upper Colorado basin ranges from about 15 cm (6 in.) in desert areas to over 100 cm (40 in.) at higher elevations.

The intensity of precipitation is highly variable. For most of the basin, precipitation in amounts over 0.25 cm (0.1 in.) per day occurs on an average of about 10 to 50 days per year. Precipitation is generally heaviest during the winter and spring months.

During the period from late October through mid-April, most precipitation throughout the basin occurs in the form of snow. Annual snowfall ranges from 760 cm (300 in.) in the higher elevations to about 13 cm (5 in.) in the lower elevations. Maximum snow accumulation occasionally exceeds 254 cm (100 in.) in the higher elevations and does not completely melt until late summer.

Most streamflow in the basin is derived from snow melting in the mountainous areas; the result is high flow conditions in May and June, medium flow conditions in April and July, and low flow conditions during the remainder of the year.

The average annual discharge of the Colorado River at the mouth of the Upper Colorado River Basin is about 15.1 billion m^3 (12.4 million acre-ft) (based on 1965 conditions). However, significant variations in annual runoff occur as a consequence of both annual variations in precipitation and long-term climatic trends. During the period 1914-1965, the average annual discharge varied from a low of 5.4 billion m^3 (4.4 million acre-ft) to a high of 26.7 billion m^3 (21.9 million acre-ft).

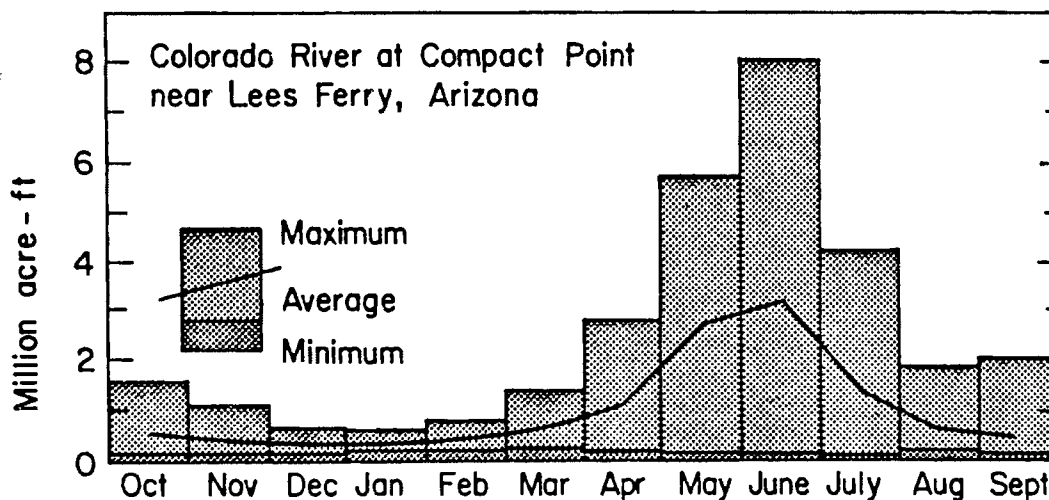
The Green River Subregion, representing about 41% of the total basin area, contributes about 38% of the total discharge at Lees Ferry. The average annual unit discharge of the subregion is about $0.0016 \text{ m}^3/\text{sec}/\text{km}^2$ ($0.15 \text{ cfs}/\text{mi}^2$), although the average annual unit discharge of higher-order tributaries ranges up to $0.0292 \text{ m}^3/\text{sec}/\text{km}^2$ ($2.7 \text{ cfs}/\text{mi}^2$). Within this subregion, greater runoff occurs near the headwaters at higher elevations while lesser runoff occurs at lower elevations.

Annual evaporation rates for lakes and reservoirs throughout most of the basin vary from less than 76 cm (30 in.) at higher elevations to more than 152 cm (60 in.) in lower valleys. Evaporation rates throughout the basin vary

both seasonally and annually, and they are affected by wind conditions, temperature, solar radiation, and relative humidity.

Seasonal and annual variations in streamflow exist throughout the basin as a consequence of both climatic variations and water withdrawals. An example of seasonal variation in streamflow is presented in Figure 8.2, which describes the monthly discharge of the Colorado River at Lees Ferry. As the figure shows, the period of greatest flow occurs during May and June when snowmelt from higher elevations begins to appear at Lees Ferry. After June, the average monthly flow begins to decrease due to irrigation water requirements and lesser snowmelt.

In a major river system with variable flow in a region of low water availability and high demand, it is not surprising to find extensive development of reservoirs. As of 1965, a total of 581 reservoirs, each with a capacity of more than 61,000 m³ (50 acre-ft), had been developed within the Upper Colorado River Basin (Table 8.1). Excluding reservoirs committed exclusively to fish and wildlife or municipal and industrial use, they had a total capacity of 36.2 billion m³ (29.7 million acre-ft). The most important reservoirs in



XBL 7812-12616

FIGURE 8.2. Seasonal Variation in Discharge for the Colorado River at Lees Ferry, Arizona. (4,7)

TABLE 8.1. Reservoirs in the Upper Colorado River Basin as of 1965(4)

Reservoir	Number	Active Capacity	
		Billion ³ Meters	Million Acre-Ft
Irrigation	309	3.4	2.8
Fish and Wildlife	232	---	---
Municipal and Industrial	30	---	---
Main Stem Regulation	2	31.3	25.7
Export Regulation	<u>8</u>	<u>1.5</u>	<u>1.2</u>
Total	581	36.2	29.7

the basin include Lake Powell, Flaming Gorge Reservoir, Navajo Reservoir, Blue Mesa Reservoir, and Fontenelle Reservoir.

Reservoirs in the basin are normally filled during the snowmelt runoff period and during the non-irrigating season when available water exceeds demand. As stream flows diminish in late summer, water stored in reservoirs is released to supplement natural flows in order to meet municipal, industrial, and irrigation water requirements. For irrigation, water is released from reservoirs primarily from July to October; reservoir releases for municipal and industrial requirements are made at those times of the year when natural streamflows cannot meet demands.

Generally, surface water is of relatively good quality throughout the Upper Colorado River Basin and its three hydrologic subregions. Surface waters are normally of excellent quality near headwaters at higher elevations, whereas, as streams progress downward, their quality deteriorates as a consequence of hydrologic, geologic, and human factors. Some tributary streams, including those in the oil shale region, show locally high levels of dissolved solids and certain specific contaminants, especially in their lower reaches.

The principal water quality problem within the basin is high concentrations of total dissolved solids (TDS). Major factors responsible for high TDS levels include leaching processes acting on geologic formations and evapotranspiration associated with irrigation activities.

TDS concentrations vary considerably throughout the basin. Near headwaters at higher elevations, TDS levels of many streams are less than 20 mg/l, whereas at lower elevations several streams have TDS levels approaching 3000 mg/l. TDS concentrations generally increase as a stream progresses from its headwaters to lower elevations, primarily due to the types of rocks underlying a stream's drainage basin. Near headwaters, rocks are mainly igneous and metamorphic (relatively insoluble), while at lower reaches the drainage basin is often overlain by sedimentary rocks containing minerals that are considerably more soluble.

In addition to TDS increases, the ionic composition of water changes as streams progress from headwaters to lower elevations. The headwaters mainly contain calcium and bicarbonate, whereas, as streams progress downward, their TDS reflects greater proportions of sodium, magnesium, sulfate, and chloride, primarily as a consequence of leaching processes.

It is estimated that the Upper Colorado River Basin contributes about 7.9 million metric tons of TDS to Lees Ferry each year, based on 1965 conditions. Of this total, approximately 33% is contributed by the Green River Subregion, 48% by the Upper Main Stem Subregion, and 19% by the San Juan Subregion. The TDS concentration of the Colorado River at Lees Ferry is estimated to be about 580 mg/l.⁽⁴⁾

In addition to geographic variations in TDS, there also exist significant seasonal variations in TDS concentrations throughout the basin. Generally, for unregulated streams, TDS levels are low during high streamflow conditions in the spring, and high during low streamflow conditions in the late summer.

Of an estimated 7.9 million metric tons of TDS generated each year in the Upper Colorado River Basin, 1.8 to 3.0 million metric tons are from irrigation return flows and 4.9 to 6.1 million metric tons are from natural sources. All other sources are insignificant by comparison.⁽⁴⁾

Suspended sediment is also a significant problem in the Upper Colorado River Basin.

8.1.2 Streams in the Oil Shale Region

The primary surface streams draining to the south from the oil shale region include Roan and Parachute Creeks, which flow into the Upper Main Stem. The Yellow and Piceance Creeks, which flow northward, flow into the White River, which flows westward and empties into the Green River (Figure 8.3). The Green River flows southward to its confluence with the Upper Main Stem southwest of the oil shale region (Figure 8.1). The White River drainage area (about 2297 km²) is the area of principal interest from the perspective of surface water impact. The Piceance and Yellow Creeks drain 1629 km² and 668 km², respectively.

Within the Green River Subregion, annual precipitation runs from about 15 cm (6 in.) to more than 102 cm (40 in.), with an average of 15 to 51 cm throughout most of the subregion. Precipitation is heaviest near headwaters at higher elevations; lighter precipitation occurs on lower elevation plains and valleys.

The primary source of stream flow in the Piceance Creek and Yellow Creek drainage basins is snow melt. Precipitation occurs at higher elevations, mostly above 2134 m (7,000 ft.), or above the C-b tract, between November and March and melts in the spring as temperatures rise. Mean daily stream flow increases during the snow melt period of March through June, recedes during the summer months, and is minimum during the winter months. This pattern is evident in Figure 8.4, which shows the discharge by month from the Green River. Table 8.2 shows the range of flows in Piceance Creek.

Stream flow after July is maintained by ground water discharge which moves through the alluvium into the stream channels or appears as springs along the valley floors. Most of the total precipitation is lost through evapotranspiration.⁽⁹⁾ Irrigation diversions begin in mid-March and continue through November. Streamflow losses from consumptive use by crops and evapotranspiration losses associated with irrigation practices have a marked influence on the stream flow hydrograph from March to November.

In the Green River Subregion prior to 1960, there were 41 major storage reservoirs, each with a capacity of at least 1220 m³ (1000 acre-ft) and with a

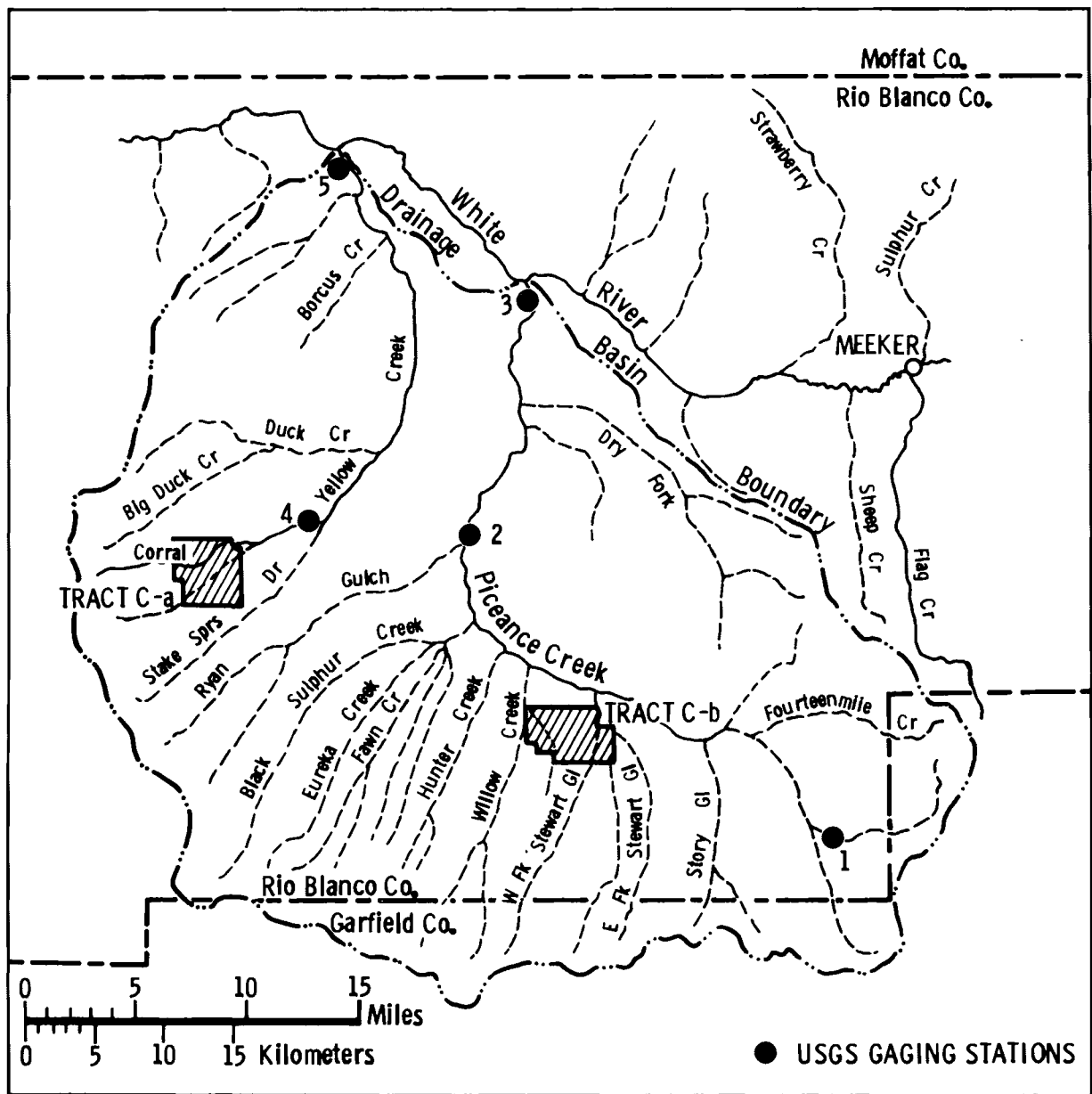
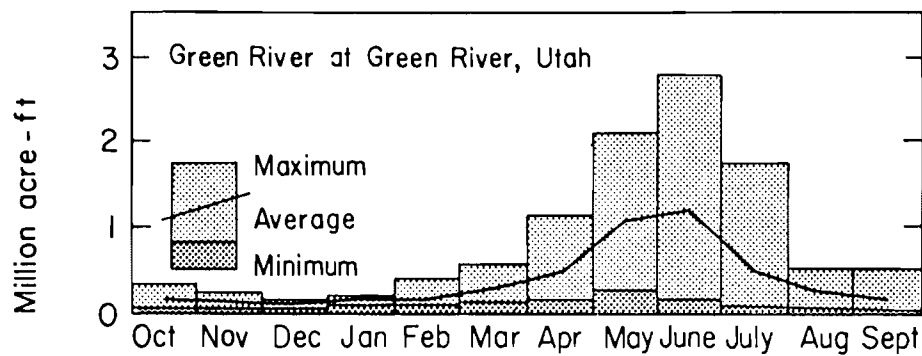


FIGURE 8.3. Drainage Pattern for Piceance and Yellow Creeks(5,7)

total usable capacity of 703 million m^3 (576,000 acre-ft). Since 1960, the reservoirs shown in Table 8.3 have been developed in the subregion. Additional reservoirs are being considered as sources of water for energy development.

Similar to the entire Upper Colorado River Basin, the quality of surface water within the Green River Subregion is generally good, the major quality



XBL 7812-12694

FIGURE 8.4. Seasonal Variation in Discharge for the Green River at Green River, Utah^(4,8)

TABLE 8.2. Historical Annual Flowrates for Five Sample Stations in the Piceance Basin⁽¹⁰⁾

Map No. (a)	USGS Code No.	Number of Observations	(cubic meters/second)				Standard Deviation
			Maximum Value	Minimum (cms)	Median Value	Mean	
1	09306007	1627	2.86	0.02	0.21	0.27	0.27
2	09306200	5113	5.60	0.01	0.45	0.52	0.33
3	09306200	3652	8.40	0.01	0.56	0.63	0.53
4	09306222	1662	0.22	0.00	0.01	0.03	0.03
5	09306255	2191	14.00	0.00	0.04	0.05	0.31

(a) See Figure 8.3.

TABLE 8.3. Major Reservoirs Developed Since 1960 in the Green River Subregion⁽⁴⁾

Reservoir	Capacity	
	million meters ³	thousand acre-ft
Flaming Gorge Reservoir	4,293	3,520
Fontenelle Reservoir	421	345
Steinaker Reservoir	41	33.3
Joes Valley Reservoir	67	54.6

problem being relatively high TDS levels. The TDS concentration at various points along the Green River is shown in Table 8.4. As shown in the table, TDS levels increase by about 50% as the Green River progresses downstream from Wyoming to Utah. Other major rivers within the subregion also have TDS problems. Big Sandy Creek has a TDS concentration ranging from 1000 to 2000 mg/l and Price River has a TDS of 3000 mg/l at its mouth.

The White River, which receives flow from smaller streams draining the tracts directly, originates in Colorado in the mountains east of Meeker and is low in dissolved solids and high in suspended solids from erosion. From September through February, this pattern is reversed and dissolved solids are high and suspended solids are low. This pattern is caused by the flow switching from predominately surface snowmelt to predominately ground water. The principal ions in the White River near Watson are calcium, sodium, magnesium, potassium, bicarbonate, chloride, and sulfate.

The quality of Evacuation Creek, which drains into the White River near Watson, Utah, is considerably different from that of the White River. This stream is sustained by ground-water seepage for all but a few days of the year.⁽¹⁾ However, the quality of the sustaining aquifer is much different from the aquifer feeding the White River. Alkalinity, conductivity, dissolved solids, sulfate, sodium, magnesium, and hardness are much higher in Evacuation Creek than in White River.

Piceance Creek, Parachute Creek, and Yellow Creek drain Colorado oil shale areas. The quality in all three is affected significantly by irrigation practices, and the concentration of dissolved solids, fluoride, sodium, etc.,

TABLE 8.4. Average TDS Concentration at Various Points
Along the Green River⁽⁴⁾

<u>Station Location</u>	<u>TDS Concentration (mg/l)</u>
Green River at Green River, Wyoming	316
Green River near Greendale, Utah	419
Green River near Ouray, Utah	397
Green River at Green River, Utah	465

increases in the downstream direction. In all three cases, the major river receiving the flow from these streams is of much higher quality than the streams themselves.

The quality in each of the three streams is distinctly different. Alkalinity, conductivity, fluoride, hardness, magnesium, sodium, and sulfate are high in Yellow Creek; while alkalinity, conductivity, magnesium, sodium, and sulfates are lower in Piceance Creek than in Yellow Creek. Parachute Creek concentrations typically fall between those two.

The Upper Main Stem of the Colorado River, like the White River, receives flow from smaller streams which drain oil shale tracts directly. The quality of the Upper Main Stem in areas of oil shale activity is similar to that of the White River; dissolved solids and alkalinity are low compared to streams draining into the river. The predominate ions are calcium, chloride, sodium, and sulfate.

8.2 WATER QUALITY LAWS, STANDARDS, AND REGULATIONS

Water quality in the Colorado River Basin is subject to regulation under Federal and state laws and under treaty with Mexico. The specific applicability of some regulations to shale oil production is not in all cases established since regulations have not been issued for the shale oil industry.

8.2.1 Federal Water Pollution Control Act

This law is really a compilation of numerous amendments. The latest of these amendments were enacted with the expressed ultimate objective of eliminating discharges of liquid wastes to surface waters. While it is not clear that such a goal is in fact to be achieved, the law does provide mechanisms for strict control of discharges. Under a provision on effluent limitations and control technologies, regulations describing the minimum acceptable wastewater treatment technologies for shale oil plants may be promulgated. No such regulations have been developed to date, but regulations for similar industries (e.g., coal mining and petroleum refining) serve as guides to what the shale oil industry can expect. The limits for petroleum refining are shown in Table 8.5.

TABLE 8.5. Effluent Limitations for Petroleum Refineries⁽¹¹⁾

Effluent Characteristic	Best Practicable Pollution Control Technology (BPT), Pounds per 1000 bbl of Feedstock		Best Available Pollution Control Technology (BAT), Pounds per 1000 bbl of Feedstock		New Source Performance Standards, Pounds per 1000 bbl of Feedstock	
	Average of Daily Values for Thirty Consecutive Days Shall not Exceed		Average of Daily Values for Thirty Consecutive Days Shall not Exceed		Average of Daily Values for Thirty Consecutive Days Shall not Exceed	
	Maximum for One Day		Maximum for One Day		Maximum for One Day	
Biochemical Oxygen Demand (BOD ₅)	19.2	10.2	3.2	2.6	14.7	7.8
Total Suspended Solids	13.2	8.4	3.0	2.6	9.9	6.3
Chemical Oxygen Demand	136	70	16.8	13.4	104	54
Oil and Grease	6.0	3.2	0.60	0.48	4.5	2.4
Phenolic Compounds	0.14	0.068	0.015	0.010	0.105	0.051
Ammonia as N	8.3	3.8	2.0	1.5	8.3	3.8
Sulfide	0.124	0.056	0.066	0.042	0.093	0.042
Total Chromium	0.29	0.17	0.15	0.13	0.220	0.13
Hexavalent Chromium	0.025	0.011	0.0033	0.0021	0.019	0.0084
pH	6.0	to 9.0	6.0	to 9.0	6.0	to 9.0

Under the section of the laws concerned with stream standards, federally approved interstate water quality standards and state-adopted water quality standards have been established. Water quality criteria recommended by EPA are summarized in Table 8.6. Standards are also set by most states. Those for Colorado and Utah most relevant to the oil shale region are presented in Tables 8.7 and 8.8.

Toxic pollutants are controlled under the Federal Water Pollution Control Act Amendments. EPA is to publish and maintain a list of toxic pollutants subject to control. The agency may prohibit any discharge of such pollutants or it may regulate such discharges to ensure that the resulting concentrations in streams are below toxic thresholds.

Under the provision for areawide waste treatment planning, the oil shale area will come under requirements for inclusion in areawide or statewide plans. These plans will include regulation of non-point discharges, such as runoff from shale piles and mining and retorting areas.

Thermal discharges are limited under the law. These discharges are included in the effluent limitations provisions in the act. They will be regulated to prevent damage to fish and other aquatic life.

The National Pollution Discharge Elimination System (NPDES) is the implementation provision for the effluent limitations. Under this provision, no discharge can be made without a valid discharge permit issued by the appropriate state agency, where the state has qualified, or by EPA. Both Colorado and Wyoming have qualified to issue the permits; Utah has not.

Present plans of oil shale firms are to have no discharges into streams at all from shale processing. Instead, they will treat wastewaters as necessary and recycle them. Residuals may be disposed of with spent shale. The significant exception to this overall rule is the prospective discharge of dewatering effluents, necessary for mining and, especially, for modified in-situ retorting. Anticipated treatment and recycling or disposal of liquid wastes are discussed below in Section 8.4.

TABLE 8.6. Proposed Water Quality Criteria for Designated Uses⁽¹¹⁾

Parameter	Water supply	Aquatic life/wildlife	Recreation	Irrigation	Livestock
Alkalinity as CaCO ₃	—	30 - 130 mg/l ^a	—	—	—
Aluminum-total	—	0.1 mg/l	—	5.0 mg/l ^b , 20.0 mg/l ^{a c}	5.0 mg/l ^a
Aluminum-dissolved	—	0.1 mg/l ^a	—	—	—
Total ammonia as N	0.5 mg/l ^a	—	—	—	—
Unionized ammonia as N	—	0.02 mg/l	—	—	—
Arsenic-total	0.01 mg/l	0.05 mg/l	—	0.1 mg/l	0.2 mg/l ^d
Barium-total	1.0 mg/l	—	—	—	—
Beryllium-total	—	1.1 mg/l	—	0.1 mg/l ^b , 0.5 mg/l ^{c d}	—
Boron	1.0 mg/l ^a	—	—	0.75 mg/l ^e	5.0 mg/l ^d
Cadmium-total	0.01 mg/l	0.003 mg/l	—	0.01 ^b , 0.05 mg/l ^{c f}	0.05 mg/l ^d
Chloride-total	250 mg/l	—	—	—	—
Chromium-total	0.05 mg/l	0.3 mg/l ^f	—	0.1 mg/l ^b , 1.0 mg/l ^{c d}	0.1 mg/l
Fecal coliform	2,000/100 ml ^f	2,000/100 ml ^a	200/100 ml	1,000/100 ml	1,000/100 ml
Color	75 color units ^a	—	—	—	—
Copper-total	1.0 mg/l	0.030 mg/l	—	0.2 mg/l ^b , 5.0 mg/l ^c	0.5 mg/l ^d
Cyanide	0.20 mg/l	0.005 mg/l	—	0.2 mg/l	0.2 mg/l
Hardness	—	—	—	—	—
Iron-total	—	1.0 mg/l	—	5 mg/l ^b , 20 mg/l ^{a c}	—
Iron-dissolved	0.3 mg/l	0.3 mg/l ^a	—	—	—
Lead-total	0.05 mg/l	0.03 mg/l	—	5 mg/l ^b , 10 mg/l ^{c f}	0.1 mg/l
Manganese-total	0.05 mg/l	1.0 mg/l	—	0.2 mg/l ^b , 10 mg/l ^{c d}	—
Manganese-dissolved	0.05 mg/l	—	—	—	—
Mercury-total	0.002 mg/l	0.00005 mg/l	—	—	0.00005 mg/l ^a
Molybdenum-total	—	—	—	0.01 mg/l ^b , 0.05 mg/l ^c	0.5 mg/l
Nickel-total	—	0.1 mg/l	—	0.1 mg/l ^f	—
Nitrate-N	10 mg/l	—	—	100 mg/l	NO ₃ + NO ₂ 100 mg/l
Dissolved oxygen	4.0 mg/l ^f	5.0-6.0 mg/l min.	2.0 mg/l min.	2.0 mg/l	2.0 mg/l
pH	5.0-9.0	6.5-9.0	6.5-9.0	4.5-9.0 ^a	—
Phenols	0.001 mg/l	0.001 mg/l	—	—	—
Total PO ₄ -P	—	0.025 mg/l - lakes ^a	—	—	—
Phthalate esters	—	0.003 mg/l	—	—	—
PCB	—	0.000001 mg/l	—	—	—
Selenium-total	0.01 mg/l	0.05 mg/l	—	—	0.5 mg/l
Silver-total	0.05 mg/l	0.0001-0.0025 mg/l ^g	—	—	—
Silver-dissolved	—	0.0001 mg/l	—	—	—
Sodium	270 mg/l ^{a h}	—	—	—	—
Sulfate-total	250 mg/l	—	—	—	—
TDS	500 mg/l ^a	—	—	(i)	3,000 mg/l ^a
TSS	—	25 mg/l-median ⁱ	—	—	—
H ₂ S (undissociated)	0.05 mg/l	0.002 mg/l	—	—	—
Temperature	—	(k)	—	—	—
Zinc-total	5.0 mg/l	0.03 mg/l	—	2.0 mg/l	25 mg/l ^d

Unless otherwise indicated, the recommended criteria correspond with proposed State standards.

^aCWA 208 recommendation only (no proposed State standard).

^bContinuous irrigation, all soils (match WQCC proposed State standards).

^cShort-term irrigation, neutral to alkaline fine textured soils.

^dFor agricultural uses, the WQCC, except in a few instances, did not distinguish between irrigation and livestock uses. The CWA 208 attempted to distinguish the differences. Therefore, under livestock there are numerous differences between 208 and WQCC numbers. Under irrigation the lower recommended criteria match WQCC numbers.

^eLong-term irrigation on sensitive crops.

^fDiffers from proposed State standards.

^gLimiting concentration dependent on hardness.

^hMaximum concentration for a moderately restricted sodium diet.

ⁱWater from which no detrimental effects will usually be noticed. 500 mg/l

Water which can have detrimental effects on sensitive crops. 500-1,000 mg/l

Water that may have adverse effects on many crops and requires careful management practices. 1,000-2,000 mg/l

Water that can be used for tolerant plants on permeable soils with careful management practices. 2,000-5,000 mg/l

^jValue represents maximum increase in ambient concentration due to discharge.

^kCold water maximum is 20° C, warm water maximum is 30° C, and both categories limit temperature changes to 3° C.

TABLE 8.7. Colorado Water Quality Standards for Selected Uses and Parameters⁽¹²⁾

	AQUATIC LIFE		
STANDARD	COLD WATER BIOTA	WARM WATER BIOTA	AGRICULTURE
PHYSICAL:			
D. O. (mg/l) ^(a)	6.0; 7.0- SPAWN ^(b)	5.0	AEROBIC ^(c)
pH (STD. UNITS)	6.5-9.0	6.5-9.0	
SUSPENDED SOLIDS	(d)	(d)	(d)
TEMPERATURE (°C)	MAX 20 ⁰ w/3 ⁰ INCREASE ^(e)	MAX 30 ⁰ w/3 ⁰ INCREASE ^(e)	
INORGANICS:			
AMMONIA (mg/l as N)	0.02 UNIONIZED	0.06 UNIONIZED	
CHLORINE (mg/l)	0.003	0.003	
TOTAL RESIDUAL			
CYANIDE (mg/l)	0.005	0.005	0.2
FREE			
NITRATE (mg/l as N)			100 ^(f)
NITRITE (mg/l as N)	0.05	0.5	10 ^(f)
SULFIDE AS H ₂ S (mg/l)	0.002 UNDISSOCIATED	0.002 UNDISSOCIATED	
BORON (mg/l)			0.75
TOTAL METALS (mg/l):			
ALUMINUM (SOLUBLE)	0.1	0.1	
ARSENIC	0.05	0.05	0.1
BERYLLIUM	0.01 - 1.1	0.01 - 1.1 ^(g)	0.1
CADMIUM	0.001 - 0.015 ^(g)	0.001 - 0.015 ^(g)	0.01
CHROMIUM- TRIVALENT	0.1	0.1	0.1
CHROMIUM- HEXAVALENT	0.025	0.025	0.1
COPPER	0.005 - 0.04 ^(g)	0.005 - 0.04 ^(g)	0.2
IRON	1.0	1.0	
LEAD	0.004 - 0.150 ^(g)	0.004 - 0.150 ^(g)	0.1
MANGANESE	1.0	1.0	0.2
MERCURY	0.00005	0.00005	
NICKEL	0.05 - 0.40 ^(g)	0.05 - 0.40 ^(g)	0.2
SELENIUM	0.05	0.05	0.02
SILVER	0.00010 - 0.00025 ^(g)	0.00010 - 0.00025 ^(g)	
THALLIUM	0.015	0.015	
URANIUM	0.03 - 1.4 ^(g)	0.03 - 1.4 ^(g)	
ZINC	0.05 - 0.60 ^(g)	0.05 - 0.60 ^(g)	2.0

(a) WHERE DISSOLVED OXYGEN LEVELS LESS THAN THESE LEVELS OCCUR NATURALLY, A DISCHARGE SHALL NOT CAUSE A FURTHER REDUCTION IN DISSOLVED OXYGEN IN RECEIVING WATER.

(b) A 7 mg/liter STANDARD, DURING PERIODS OF SPAWNING OF COLD WATER FISH, SHALL BE SET ON A CASE-BY-CASE BASIS AS DEFINED IN THE NPDES PERMIT FOR THOSE DISCHARGERS WHOSE EFFLUENT WOULD AFFECT FISH SPAWNING.

(c) AN EFFLUENT SHALL BE REGULATED TO MAINTAIN AEROBIC CONDITIONS, AND A GUIDELINE OF 2.0 mg/liter DISSOLVED OXYGEN IN AN EFFLUENT SHOULD BE MAINTAINED, UNLESS DEMONSTRATED OTHERWISE.

(d) SUSPENDED SOLID LEVELS WILL BE CONTROLLED BY EFFLUENT LIMITATION REGULATIONS, BASIC STANDARDS, AND BEST MANAGEMENT PRACTICES (BMP'S).

(e) TEMPERATURE SHALL MAINTAIN A NORMAL PATTERN OF DIURNAL AND SEASONAL FLUCTUATIONS WITH NO ABRUPT CHANGES AND SHALL HAVE NO INCREASE IN TEMPERATURE OF A MAGNITUDE, RATE, AND DURATION DEEMED DELETERIOUS TO THE RESIDENT AQUATIC LIFE. GENERALLY, A MAXIMUM 3°C INCREASE OVER A MINIMUM OF A FOUR-HOUR PERIOD, LASTING FOR 12 HOURS MAXIMUM, IS DEEMED ACCEPTABLE FOR DISCHARGES FLUCTUATING IN VOLUME OR TEMPERATURE. WHERE TEMPERATURE INCREASES CANNOT BE MAINTAINED WITHIN THIS RANGE USING RECOGNIZED CONTROL MEASURES, THE COLORADO WATER QUALITY DIVISION WILL DETERMINE WHETHER THE RESULTING TEMPERATURE INCREASES PRECLUDE AN AQUATIC LIFE CLASSIFICATION.

(f) IN ORDER TO PROVIDE A REASONABLE MARGIN OF SAFETY TO ALLOW FOR UNUSUAL SITUATIONS SUCH AS EXTREMELY HIGH WATER INGESTION OR NITRITE FORMATION IN SLURRIES, THE NO₃-N PLUS NO₂-N CONTENT IN DRINKING WATERS FOR LIVESTOCK AND POULTRY SHOULD BE LIMITED TO 100 ppm OR LESS, AND THE NO₂-N CONTENT ALONE BE LIMITED TO 10 ppm OR LESS.

(g) A RANGE OF VALUES IS LISTED. APPLICATION OF THE RESPECTIVE VALUES IN THE RANGE IS DEPENDENT ON THE WATER HARDNESS OR ALKALINITY.

Safe Drinking Water Act

This act has two major provisions of interest to shale oil producers. First, waters used for public domestic supplies are protected from discharges or seepage from industrial activities which would render them unfit for use under established drinking water standards (Table 8.9).

The second provision of interest concerns injection of wastes into underground formations where drinking water supplies might be affected. Criteria and standards effective July 24, 1980, specify the construction, operation, and monitoring of injection wells.⁽¹³⁾ This provision is of interest in light of the possible use of injection to return dewatering water to the producing aquifer downgrade from mines and MIS retorts and to reinject retort water or other liquid wastes. J. E. Sinor has studied several options for treating and/or disposing of dewatering water and concluded that due to the very high cost of desalinization, reinjection is the most economical choice of those approaches studied.⁽¹⁴⁾

Resource Conservation and Recovery Act

The implications of this act for shale oil production are discussed in some detail above in Section 6.4 of this report. In general, the act calls for the application of strict regulations for the disposal of any wastes determined by EPA to be toxic or hazardous. It might be judged applicable to the disposal of spent shale and any liquid wastes added to the spent shale. To date it does not appear that the wastes will be declared toxic or hazardous, but the possibility remains.

Limitations on Salinity in the Colorado River

Whether water is taken from surface streams or underground aquifers, there is concern about the salinity effects in the Colorado River of depletion and the disruption of the stream beds and underground water-bearing strata caused by mining, well drilling, and spent shale storage. The Colorado River is already salt laden from withdrawal of water for agricultural use. Heavy depletion will increase salinity.

TABLE 8.9. Primary Drinking Water Standards (mg/l)⁽¹¹⁾

	<u>Maximum Concentration</u>
Inorganic Chemicals (except fluoride)	
Arsenic	0.05
Barium	1.0
Cadmium	0.01
Chromium	0.05
Lead	0.05
Mercury	0.002
Nitrate (as N)	10.0
Selenium	0.01
Silver	0.05
Fluoride (degrees Fahrenheit)	
53.7 and below	2.4
53.8 to 58.3	2.2
58.4 to 63.8	2.0
63.9 to 70.6	1.8
70.7 to 79.2	1.6
79.3 to 90.5	1.4
Chlorinated Hydrocarbons	
Endrin	0.0002
Lindane	0.004
Methoxychlor	0.1
Toxaphene	0.005
Chlorophenoxy	
2,4-D (2,4-dichlorophenoxyacetic acid)	0.1
2,4,5-TP (Silvex)	0.01

Increased salinity threatens the utility of water resources, particularly for downstream users. An EPA report prepared in 1971 projected damage to Lower Basin users (Arizona, California, New Mexico, and Mexico) to increase from \$16 million in 1970 to \$41 million by the turn of the century if planned salinity control measures were not developed; the Bureau of Reclamation in 1975 found existing damage at \$53 million annually and estimated costs of \$125 million by the year 2000.⁽¹⁵⁾

With the increasing salinity reaching 1500 ppm in water entering Mexico in 1962, the Mexican government, having a right to a portion of the Colorado River water, initiated a series of negotiations with the U.S. which resulted in

Minute 218 and subsequent U.S. reduction in salinity levels in Mexico's water to 1240 ppm in 1971 . Eventually Minute 242 was adopted which required the salinity of water delivered to Mexico be at a level no more than 115 ppm (30 ppm) in excess of the water at Imperial Dam, which is near the lower end of the U.S. portion of the Colorado River.

Recognizing the problem of increased salinity in the Colorado River Basin, the seven basin states and EPA adopted a policy to maintain salinity at 1972 levels. The seven Colorado River Basin states negotiated in August 1975 an agreement known as the "Proposed Water Quality Standards for Salinity Control." EPA subsequently issued regulations, which call for maintenance of salinity at or below the 1972 average value.⁽¹⁶⁾ These regulations were issued pursuant to the Colorado River Basin Salinity Control Act, passed June 24, 1974 for the purpose of maintaining salinity control for the protection of lower river users.⁽¹⁷⁾ The Colorado River Salinity Control Act provides funding for construction of a large desalting complex in the lower basin. It also creates four salinity control projects in the Upper Basin and expedites planning for other salinity control projects. The states have adopted, and the U.S. Environmental Protection Agency has approved, numeric salinity criteria at three downstream, Lower Basin stations. These criteria are shown in Table 8.10.

8.3 WATER QUANTITY CONCERNS

The quantity of surface water available for any use in the event of a shale oil industry in western Colorado will be affected by consumption of surface water by the industry or because of removal and use or discharge of ground water. Ground water removal may reduce the flow of surface streams that are

TABLE 8.10. Salinity Criteria for Colorado River(18)

<u>Location</u>	<u>Flow-Weighted Annual Average Salinity (mg/l)</u>
Below Hoover Dam	723
Below Parker Dam	747
At Imperial Dam	879

fed in part by ground water. If the ground water is treated and discharged to local surface streams, it may result in abnormally high flows in these streams. Changes in water quantity may also contribute to impacts on water quality (discussed in Section 8.4) The importance of these changes depends upon the character and value of the streams affected. This section examines possible changes in water quantity and the significance of these changes.

8.3.1 Effects of Consumption of Surface Water

In light of the surface water sources considered to be applicable to an oil shale industry, the State of Colorado has concluded that a 500,000 barrel per day industry could be supported without having to forego other projected consumptive uses of water.⁽¹⁹⁾ A supporting study, "The Upper Colorado River Basin 13(a) Assessment," conducted by the Colorado Department of Natural Resources⁽¹⁸⁾ concluded that an "emerging energy technology (EET)" industry including 1.3 million barrels per day of shale oil and 2 billion standard cubic feet per day of gas from high BTU gasification of coal, could be supported without having to reduce significantly other projected consumptive uses in the Upper Colorado River Basin. While this statement indicates that such major economic considerations as irrigated agriculture would not be damaged, it leaves open the possibility of impacts on in-stream uses of water, such as fisheries and boating.

While the Scenarios considered in the Colorado assessment are not similar to the 300,000 bpd scenario studied in the present study (Table 8.11), the Colorado study is of interest since it looks at developments of shale oil and

TABLE 8.11. Approximate Size and Distribution of Shale Oil Industry in Upper Colorado River Basin 13(a) Assessment (1000 bpd)

	<u>Baseline Scenario</u>	<u>Accelerated Scenario</u>	<u>DOE Assessment Scenario</u>
White River Basin, Colorado and Utah	590	970	175
Upper Colorado Main Stem, Colorado	<u>110</u>	<u>330</u>	<u>120</u>
Total	700	1300	295

other synfuel industry substantially larger than in the present study. If the projected impacts of the larger industry are found to be in an acceptable range, then the impacts of the 300,000 bpd development would also be expected to fall within this range. Accordingly, the Colorado study is examined in some detail here.

The Upper Colorado River Basin "13(a)" Assessment studied developmental scenarios with three different levels of emerging energy technologies "EET's" (Synfuels) and three levels "without EET." The without EET scenarios show three major water use trends. First, irrigated agriculture is projected to continue expanding, thereby remaining the dominant user of water. It accounts for just over 60% of the total year 2000 depletions (i.e., water consumption) in each of the three levels. The second major trend is a further increase in exports to areas outside the Upper Basin (i.e., to the Front Range urban corridor in Colorado, the Rio Grande Basin in New Mexico, and the Bonneville Basin in Utah). The third trend is the projected increase of 350% to 500% over present levels for consumption by thermal electric generating facilities.

The "with EET" scenarios add to the "without EET" projections of water use increments for two alternative levels of synfuels development. The "accelerated" level is based on an EET industry including 1.3 million barrels per day (bpd) of shale oil and the equivalent of 300,000 bpd of high-Btu coal gasification. While the report does not specify the size and geographic distribution of the shale oil industry, the projected water consumption data suggest that it would be approximately that shown in Table 8.11. For comparison, the scenario for the assessment that is the focus of the present report is also shown in the table.

Surface water supplies for shale oil production in the Colorado study are taken from the basins of the White River and the Upper Colorado Main Stem. The associated development of other synfuels and supporting communities is likely with either the 13(a) Assessment scenarios or with the DOE scenario. Therefore, the impact on water quantity of the scenarios in the 13(a) Assessment is of interest in considering the impact on water quantity from the DOE scenario.

Table 8.12 shows the annual water consumption anticipated for the high "without EET" scenario and alternative levels of "with EET" in the two basins. The high economic scenario has been chosen here since it produces a worst case from an environmental point of view. In this circumstance, the table shows that the White River Basin would need to supply approximately 296,000,000 m³/yr (243,000 acre-ft/yr) and 416,000,000 m³/yr (341,000 acre-ft/yr) for the base-line and accelerated EET development scenarios, respectively. The Upper Colorado River Main Stem River Basin would have to supply 1,633,000,000 m³/yr (1,339,000 acre-ft/yr) and 1,700,000,000 m³/yr (1,394,000 acre-ft/yr), respectively, for the same scenarios. In the White River Basin, the bulk of the demand would come from the EET and associated growth; in the Upper Colorado Main Stem, the EET and associated growth would be a minor portion of the overall demand.

TABLE 8.12. Year 2000 Water Depletions^(a) for Synfuels Scenarios, Upper Colorado River Basin 13(a) Assessment⁽¹⁸⁾
(million meters³ per year)

River Basin ^(b)	Scenario ^(b)	Non-EET Uses	EET	Growth associated with EET	Total
W	HWO	123	0	0	123
W	HWB	123	150	23	296
W	HWA	123	250	43	416
UC	HWO	1,598	0	0	1,598
UC	HWB	1,598	28	7	1,633
UC	HWA	1,598	85	17	1,700

(a) This table reflects average annual depletions under year 2000 projected conditions of development. It does not include evaporation from reservoirs that are determined to be necessary for the benefit of EET developments.

(b) W--White River Basin, Colorado and Utah

UC--Upper Colorado Main Stem River Basin, Colorado.

(c) HWO--High economic development without emerging energy technologies (EET) development

HWB--High economic development with baseline EET (700,000 bpd shale oil)

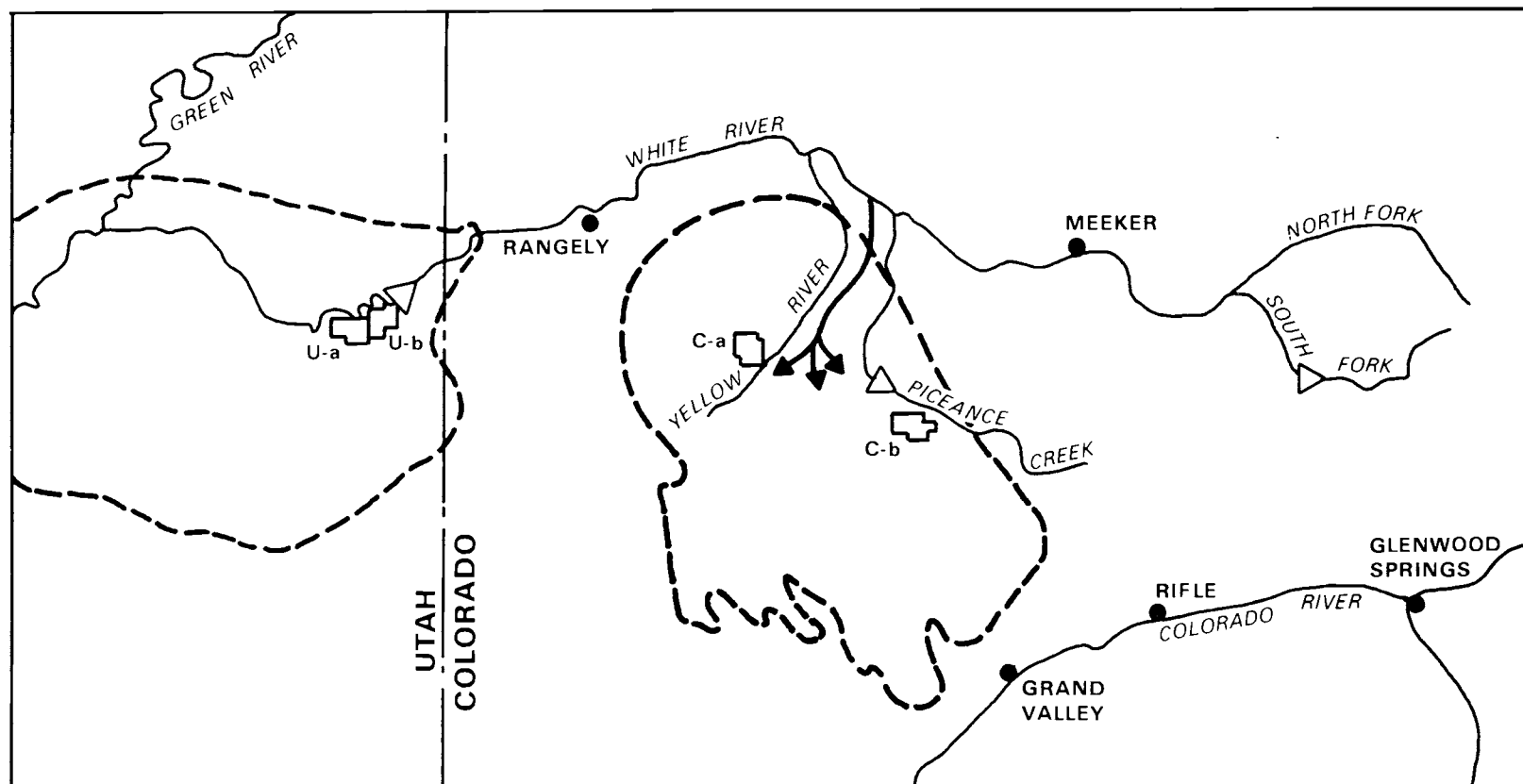
HWA--High economic development with accelerated EET (1,300,000 bpd shale oil).

In the White River Basin, the average annual virgin yield (1906-1974) is 693 million m^3 (568,000 acre-ft), 61% of which occurs between April and July. Supporting the accelerated EET scenario would demand about 60% of the total annual yield; the baseline scenario would require 43% of the total annual yield. No more than 12 million m^3 (10,000 acre-ft) per year could be acquired from Piceance Creek, assuming continuation of present irrigation demands.⁽¹⁸⁾

If water supplies are to come from surface sources only, it is clear that reservoirs will have to be constructed to store spring flows. The Upper Colorado River Basin 13(a) Assessment calls for one on the Piceance Creek, one on the South Fork of the White River, and one on the White River in Utah (Figure 8.5). The Utah reservoir project has been authorized and funded by action of the 1977 Utah legislature.

With the same non-EET-specific development, the DOE scenario would require about 180 million m^3 (150,000 acre-ft) per year of water from the White River Basin, about 60% as much as required by the baseline scenario, and about 26% of the average annual virgin flow. Accordingly, the reservoir support needed would be reduced, but some would be necessary due to the seasonal nature of the flow in the basin. The principal impacts on water quality would be reduction of the April through July peak flows, pooling of water behind any dam(s) constructed, direct withdrawal from the run of the river flows (reducing flows during the non-peak months), and consumption of most of the water from Piceance Creek not used for irrigation. Alternative sources of water (e.g., purchase of water from agricultural activities or use of ground water) or lower levels on non-EET-specific development would result in smaller impacts on surface water quality in the basin.

In the Upper Colorado Main Stem, the average annual virgin yield (1906-1974) immediately above the confluence with the Gunnison River is 4.513 billion m^3 (3.7 million acre-ft). The baseline "with EET" scenario would require 1.633 billion m^3 (1.34 million acre-ft), or about 36% of the virgin flow. However, only about 32 million m^3 (26,000 acre-ft) of this would be needed for EET and associated growth. The needs for the DOE scenario would be similar.



LEGEND

-  AREA OF 25 gal/ton OR RICHER OIL SHALE, 10 FEET OR MORE THICK
-  ASSUMED RESERVOIR (GENERALIZED)
-  ASSUMED DIRECT FLOW DIVERSIONS AND DIVERSION OF WATER RELEASED FROM UPSTREAM RESERVOIR STORAGE

0 16 32
KILOMETERS

FIGURE 8.5. White River Basin Schematic of Assumed Reservoir and Diversion Facilities⁽¹⁸⁾
(baseline case EET projection)

The Upper Colorado River Basin 13(a) Assessment indicates that perhaps 12 million m³ (10,000 acre-ft) of the necessary water could be taken from Roan and Parachute Creeks during spring runoff, assuming storage facilities were created. Other water needed could be taken by direct flow diversions from the main stem by exercising junior water rights. Some storage (18 to 43 million m³, or 15,000 to 35,000 acre-ft) would be needed upstream, or similar amounts would have to be purchased from Federal reservoirs, to preclude interruption of the industry about two years out of ten when senior water rights would take water needed by the industry. The hydrologic impacts of the EET industry and associated development would, in fact, be insignificant in the Main Stem basin.⁽¹⁸⁾

8.3.2 Effects of Ground Water Removal

As described in detail in Chapter 7, removal of ground water may result in loss of flow in small streams in the oil shale region, especially Piceance and Yellow Creeks. This would result from elimination of flow into the streams from aquifers. Ground-water mining in the Piceance Creek Basin would not have similar effects on the White River or the Upper Colorado River Main Stem, since the Piceance Creek Basin is perched on a plateau above these major tributaries.

It is reasonable to assume that some water needs of a shale oil industry will be met through use of ground water, since the cost of drilling and equipping wells is only 5% to 10% of the cost of developing surface supplies from the White and Colorado Rivers.⁽¹⁸⁾ However, quality constraints may limit the use of ground water.

Major impacts on surface hydrology are likely only from dewatering of aquifers for purposes of oil shale mining and modified in-situ (MIS) retorting (see Chapter 7). Extensive dewatering will likely reduce or eliminate the non-peak flow in reaches of the Piceance and Yellow Creeks. The effect could persist for centuries after mining and retorting operations are completed.

While dewatering may eliminate ground-water seepage as an input to reaches of Piceance and Yellow Creeks, it will also generate water to be discharged to surface streams or to be reinjected. As noted above, work by Sinor⁽¹⁴⁾ indicates that reinjection is a likely choice. However, if treatment and surface

discharge were the method of choice, the dewatering water would augment substantially the flows in the Piceance and Yellow Creeks. Work by Mehran et al.⁽¹⁵⁾ indicates that 50,000 bpd MIS development on Tract C-b might generate a net (above project water needs) of about 0.5 to 0.7 m³/sec. This would amount to 15.8 million m³/yr (13,000 acre-ft/yr) to 22.1 million m³/yr (18,000 acre-ft/yr). If all of this were discharged to Piceance Creek and dewatering did not affect the base flow in the Creek, then the discharge would approximately double the historic mean flow of Piceance Creek (see Table 8.2, above). Similarly, Mehran et al. estimate that the discharge of dewatering water from Tract C-a with an MIS industry of 57,000 bpd and an above-ground industry of 19,000 bpd would be greater than the need of the C-a project. One estimate by Mehran et al. indicates a net discharge from the tract of as little as 0.0125 m³/sec (394,000 m³/yr, or 323 acre-ft/yr); another estimate indicates a net discharge of 0.9 m³/sec (28.4 million m³/yr, or 23,300 acre-ft/yr) to 1.2 m³/sec (37.8 million m³/yr, or 31,000 acre-ft/yr). The second set of estimates would result in mean flows in Yellow Creek of 18 to 24 times historic normal mean flows (Table 8.2).

Clearly discharges of dewatering water into Piceance and Yellow Creeks could result in substantial flooding, at least during times of normal high flows. It is unlikely that the hydrological effect of these flows on the White River would create serious problems.

8.4 WATER QUALITY CONCERNS

A shale oil industry may affect surface water quality in several ways. In light of the intense use of and dependence on the Colorado River and its tributaries for irrigation, domestic water supplies, and recreation, any degradation of water quality is of clear importance. Dewatering of aquifers for mining and for modified in-situ retorting may affect the salinity of streams by reducing of ground water seepage into streams and by discharging dewatering waters into streams. Liquid effluents from retorts and upgrading facilities could reach surface streams. Surface runoff from development sites may carry heavy loads of suspended solids as well as dissolved contaminants from raw shale, spent shale, and spills of chemicals or crude shale oil. Finally, if MIS retorts

result in contamination of ground water after the water reinvades dewatered aquifers, it is possible that the contaminated ground water will eventually reach streams in the oil shale region through aquifers. This section examines these potential problems.

8.4.1 Current Surface Water Quality

Surface water quality in the basins of the White River and the Upper Colorado Main Stem is much affected by sediment and by dissolved salts. The sources of both of these conditions are natural as well as human.

As shown in Table 8.13, significant concentrations of suspended sediment occur in the Colorado River and its principal tributaries. High concentrations of suspended sediment in streams and rivers are detrimental to aquatic communities because they inhibit light transmission required for photosynthesis, smother benthic organisms, and clog the gills of fish. Furthermore, suspended sediment decreases the useful lifespan of reservoirs (by settling and slowly filling them), and it impairs the utilization of surface water as municipal, industrial, and irrigation water supply.

Suspended sediments are a significant consideration to the development of a shale oil industry. They will affect the useful life of reservoirs and diversion works constructed as part of the water supply and spent shale disposal systems. Construction activities, mining and crushing of oil shale,

TABLE 8.13. Suspended Sediment Concentrations of the Upper Colorado River Basin (Long-Term Averages: 1914-1957)(4,8)

<u>Gaging Station</u>	<u>Weighted Average Suspended Sediment Concentration, ppm</u>
Yampa River Near Maybell, Colorado	196
Green River at Green River, Utah	3,760
Gunnison River Near Grand Junction, Colorado	806
Colorado River Near Cisco, Utah	2,050
San Juan River Near Bluff, Utah	13,500
Colorado River at Lees Ferry, Arizona	5,800

transportation, and disposal of waste raw and spent shale all have the potential to produce additional sediment loads. The high natural loads may require extra caution in conducting these activities.

Dissolved salts are a much greater problem due to their potential impairment of water use downstream in the Colorado River. Table 8.14 shows estimated inflow of total dissolved solids (TDS) by subregion and source in the Upper Colorado River Basin. The table shows that all other sources are insignificant in comparison to natural sources and irrigation return flows. Shale oil production has the potential to add substantially to the load in the Green River and Upper Main Stem subregions, as is discussed in later sections of this chapter.

With expectations of further growth in irrigated agriculture, industry, and urbanized areas, it is anticipated that TDS loads in streams of the Upper

TABLE 8.14. Contributions of TDS by Natural and Man-Made Sources in the Upper Colorado River Basin in 1965^(a)

Subregion	(metric tons per year)				
	Municipal Wastewater Effluent	Effluent from Manufacturing Activities	Irrigation Return Flow	Natural Point Sources ^(b)	Natural Point Sources ^(c)
Green River	4,181	1,814	830,000 to 1,292,000	131,900	1,033,000 to 1,487,000
Upper Main Stem	4,308	3,809	785,000 to 1,402,000	515,900	1,868,000 to 2,485,000
San-Juan, Colorado	5,714	2,086	185,000 to 316,000	10,400	748,000 to 880,000
Total	14,203	7,709	1,809,000 to 3,010,000	658,200	3,649,000 to 4,852,000

(a) These data were taken from Reference 4 and were recalculated for this table to present them in metric units.

(b) Point sources are springs and seeps that discharge into streams.

(c) Nonpoint sources are surface runoffs from natural watersheds.

Colorado River Basin will increase in the future. The high current loads and the expected future increases impose a high degree of responsibility on the shale oil industry to control waste discharges and runoff so that contributions of TDS will be minimized.

Current loads of contaminants in streams of the Piceance Creek Basin render these waters unfit for use as public water supplies. In the upper reaches of Piceance Creek and Yellow Creek, concentrations of sulfate and dissolved solids exceed the limits of 250 mg/l and 500 mg/l established by the U.S. Public Health Service for public water supplies.^(20,21) Water in the lower reaches of these streams is unacceptable for domestic use because the fluoride concentration exceeds twice the optimum limit of 1.0 mg/l established by the U.S. Public Health Service.⁽²⁰⁾

Information on water quality in streams of the oil shale region is provided in Table 8.15. As is apparent in that table, the conditions are highly variable from stream to stream.

8.4.2 Salinity Effects of Dewatering

As part of this assessment, a specific analysis was conducted⁽¹⁰⁾ to estimate the water quality effects of discharging dewatering water from Tracts C-b and C-a directly into Piceance and Yellow Creeks, respectively. The analysis assumed average discharges of 0.014 m³/S (0.5 cfs) from Tract C-b and 0.006 m³/S (0.2 cfs) from Tract C-a, respectively. No other impacts or discharges were included in this analysis.

In the analysis, two cases were addressed to project a possible range of resulting surface water residual concentrations. The concentration changes were projected for the White River at Station 5 (Figure 8.3, above) and at Lees Ferry on the Colorado River. In one case, the water of the upper aquifer was assumed to be discharged without pollutant removal. This case is assumed to characterize the lower limit of potential residual concentration changes in the surface streams. In the second case, which is provided to bracket the higher resulting surface water concentrations, the lower aquifer water was assumed to be discharged without residual removal during dewatering pumping. The concentrations used to characterize the upper and lower aquifers at Tracts C-a

TABLE 8.15. Chemical Composition of Surface Waters Draining Oil Shale Regions in Colorado and Utah⁽⁴⁾ (mg/ , except for conductivity)

		White River, near Watson ^a	Evacuation Creek, near mouth ^b	Piceance Creek ^c	Yellow Creek, near White River ^d	White River, near Neekere ^e	Colorado River, near Cameo ^f	Parachute Creek, below Grand Valley ^g
Alkalinity	min.	172	351	268 ^h	894	80	87	-
	max.	236	444	765 ^h	1510	148	148	-
	avg.	199	404	489 ^h	1303	94	111	-
Aluminum	min.	0.00	.00	-	-	-	-	-
	max.	0.050	.09	-	-	-	-	-
	avg.	0.018	.011	-	-	-	-	-
Ammonia (NH ₃)	min.	0.01	0.01	-	-	-	-	-
	max.	0.19	0.11	-	-	-	-	-
	avg.	0.06	0.06	-	-	-	-	-
Arsenic	min.	0	0.002	0.000	0.002	-	-	-
	max.	0.004	<0.006	0.005	0.009	-	-	-
	avg.	0.002	0.003	0.002	0.005	0.0030 ⁱ	-	-
Barium	min.	-	-	0.000	<0.1	-	-	-
	max.	<0.1	<0.1	0.2	0.4	-	-	-
	avg.	<0.1	<0.1	<0.087	0.2	-	-	-
Bicarbonate	min.	132 ^j	428	258 ^h	843	97	97	-
	max.	314 ^j	541	933 ^h	1620	180	181	-
	avg.	195 ^j	493	558 ^h	1353	113	129	363
Boron	min.	0.07 ^j	1.9	0.11	0.41	-	0.000	-
	max.	0.19 ^j	2.5	0.33	0.73	-	0.090	-
	avg.	0.064 ^j	2.2	0.22	0.61	-	0.035	-
Chemical oxygen demand	min.	0	6	-	-	8 ⁱ	-	-
	max.	38	35	-	-	150 ⁱ	-	-
	avg.	10	24	-	-	83 ⁱ	-	-
Cadmium	min.	<	-	0.00	<0.001	-	-	-
	max.	<0.001	0	<.015	0.001	-	-	-
	avg.	<0.001	0	<.001	0.001	-	-	-
Calcium	min.	28 ^j	140	41 ^h	15	29	30	-
	max.	100 ^j	200	100 ^d	130	73	80	-
	avg.	56 ^j	172	77	38	40	52	86.
Carbonate (CO ₃)	min.	0	0	0 ^h	0	0	0	-
	max.	3	0	0 ^h	313	9	0	-
	avg.	0.2	0	0 ^h	115	1	0	-
Chloride	min.	8.2 ^j	49	9.1 ^h	93	3.2	16	-
	max.	140 ^j	60	25 ^h	130	33	205	-
	avg.	30 ^j	54	13.8 ^h	118	9.5	83	18
Chromium	min.	-	-	0.00	-	-	-	-
	max.	<0.01	0.03	0.09	-	-	-	-
	avg.	<0.01	<0.01	<.006	-	-	-	-
Conductivity, µmhos/cm	min.	328 ^j	1300	600 ^h	2410	207	275	-
	max.	1160 ^j	5500	2240 ^h	3724	577	1270	-
	avg.	631 ^j	4666	1380 ^h	3425	297	657	-

TABLE 8.15. (contd)

		White River, near Watson ^a	Evacuation Creek, near mouth ^b	Piceance Creek ^c	Yellow Creek, near White River ^d	White River, near Hekker ^e	Colorado River, near Cameo ^f	Parachute Creek, below Grand Valley ^g
Copper	min.	0.001	0.001	0.00	0.002	-	-	-
	max.	0.006	0.004	0.012	0.009	-	-	-
	avg.	0.003	0.002	0.003	0.004	0.005 ⁱ	-	-
Cyanide	min.	0.00	0.00	0.00	-	-	-	-
	max.	0.01	0.00	0.02	-	-	-	-
	avg.	0.00	0.00	0.00	-	-	-	-
Dissolved oxygen	min.	-	-	9.0 ^h	6.9	11.6	-	-
	max.	-	-	12.4 ^h	11.2	12.2	-	-
	avg.	-	-	10.6 ^h	8.9	11.8	-	-
Fluoride	min.	0.2 ^j	0.6	0.4 ^h	1.3	0.1	0.1	-
	max.	0.7 ^j	0.9	1.2 ^h	2.6	0.5	0.6	-
	avg.	0.3 ^j	0.8	0.7	2.1	0.2	0.3	-
Hardness (CaCO ₃)	min.	110 ^j	1000	190 ^h	420	98	100	-
	max.	340 ^j	1200	700 ^h	670	250	280	-
	avg.	221 ^j	1120	489	551	134	180	-
Iron	min.	0.010	0.02	0.01 ^h	0.02	0.02	0.010	-
	max.	0.270	0.05	0.16 ^h	0.40	0.21	0.060	-
	avg.	0.023	0.03	0.07 ^h	0.07	0.06	0.047	-
Lead	min.	0.000	0.000	0.00	0.001	-	-	-
	max.	0.002	0.003	<0.016	0.013	-	-	-
	avg.	0.001	0.002	<0.003	0.004	0.001 ⁱ	-	-
Lithium	min.	-	0.00	0.00	0.08	-	-	-
	max.	0.03	0.15	0.02	0.18	-	-	-
	avg.	<0.015	0.13	0.007	0.14	-	-	-
Magnesium	min.	11 ^j	150	21 ^h	50	6.3	6.5	-
	max.	34 ^j	180	110 ^h	140	17	21	-
	avg.	20 ^j	164	72	111	8.5	12.3	60
Manganese	min.	0.000	0.03	0 ^h	0.00	0.00	0.000	-
	max.	0.030	0.19	0.25 ^h	0.25	0.03	0.090	-
	avg.	0.009	0.08	0.05 ^h	0.04	0.02	0.012	-
Mercury	min.	0.0000	-	0.00	0	-	-	-
	max.	0.0002	0.0003	0.0008	0	-	-	-
	avg.	0.00003	<0.0001	<0.0001	0	0.0 ⁱ	-	-
Molybdenum	min.	0.001	0.037	-	-	-	-	-
	max.	0.004	0.067	-	-	-	-	-
	avg.	0.003	0.052	-	-	-	-	-
Nickel	min.	0.000	0.002	-	-	-	-	-
	max.	0.012	0.009	-	-	-	-	-
	avg.	0.003	0.006	-	-	-	-	-
Nitrate	min.	0.00	0.00	0.22	-	-	-	-
	max.	0.39	0.32	3.7	-	-	-	-
	avg.	0.13	0.07	1.4	-	-	-	1.39
Nitrite	min.	0.00	0.00	0.00	-	-	-	-
	max.	0.01	0.03	0.13	-	-	-	-
	avg.	0.00	0.01	0.03	-	-	-	-
Phosphorus	min.	0.00	0.01	0.00 ^h	0.00	0.01	-	-
	max.	0.74	0.05	0.14 ^h	1.80	0.03	-	-
	avg.	0.12	0.03	0.04 ^h	0.17	0.03	-	-

TABLE 8.15. (contd)

		White River, near Watson ^a	Evacuation Creek, near mouth ^b	Piceance Creek ^c	Yellow Creek, near White River ^d	White River, near Meeker ^e	Colorado River, near Cameo ^f	Parachute Creek, below Grand Valley ^g
pH	min.	7.1 ^j	7.8	7.5 ^h	8.0	7.9	7.1	-
	max.	8.3 ^j	8.7	8.4 ^h	8.8	8.8	8.5	-
	avg.	7.8 ^j	8.2	8.0 ^h	8.5	8.0	7.8	8.0
Potassium (K)	min.	1.1 ^j	1.8	2.4 ^h	3.9	1.1	1.4	-
	max.	4.5 ^j	12	4.9 ^h	6	2	5.7	-
	avg.	2.1 ^j	7.8	3.3 ^h	4.5	1.2	2.9	-
Selenium (Se)	min.	0.001	0.000	0.00	0.000	-	-	-
	max.	0.002	0.002	0.002	0.003	-	-	-
	avg.	<0.001	0.0008	0.001	0.002	0.004 ⁱ	-	-
Silica (SiO ₂)	min.	9.8 ^j	7.6	1.4 ^h	6.9	4.4	3.9	-
	max.	19 ^j	10	21 ^h	13	16	12	-
	avg.	13.4 ^j	8.8	16.3 ^h	9.5	10.4	8.7	-
Silver	min.	-	-	-	-	-	-	-
	max.	<0.001	<0.002	-	-	-	-	-
	avg.	<0.001	<0.002	-	-	-	-	-
Sodium	min.	14 ^j	680	66 ^h	630	3.8	18	-
	max.	150 ^j	780	380 ^h	800	25	150	-
	avg.	51 ^j	728	155 ^h	717	8.6	65	143
Solids, dissolved	min.	203 ^j	3290	392 ^h	1740	124	172	-
	max.	713 ^j	4070	1630 ^h	2590	353	743	-
	avg.	415 ^j	3826	949 ^h	2369	181	388	701
Solids, suspended	min.	-	-	-	-	23 ⁱ	-	-
	max.	-	-	-	-	95 ⁱ	-	-
	avg.	-	-	-	-	71 ⁱ	-	-
Sulfate	min.	51 ^j	2000	110 ^h	400	22	36	-
	max.	320 ^j	2400	570 ^h	750	120	190	-
	avg.	130 ^j	2160	334 ^h	587	45	93	394.
Sulfide	min.	0.0	0.0	0.0	-	-	-	-
	max.	0.3	0.3	0.9	-	-	-	-
	avg.	0.1	0.06	0.2	-	-	-	-
Zinc	min.	0.010	-	0.00	0.00	-	-	-
	max.	0.110	0.06	0.06	0.02	-	-	-
	avg.	<0.025	<0.027	0.019	0.01	0.06 ⁱ	-	-

^aData from Ashland; (1) period of record is August 1974-May 1975; averages are arithmetic.

^bData from U.S. Department of the Interior; (22-26) period of record is August 1974-February 1975; averages are arithmetic.

^cData from Ashland; (27) for Piceance Creek below Rio Blanco; period of record is October 1974-September 1975; averages are arithmetic.

^dData from U.S. Department of the Interior; (26) period of record is May-September 1974; averages are flow-weighted.

^eData from U.S. Department of the Interior; (26) for White River near Meeker, October 1973-September 1974; averages are flow-weighted.

^fData from U.S. Department of the Interior; (22-26) period of record is October 1970-September 1974; averages are flow-weighted.

^gData from ARCO; (28)

^hData from U.S. Department of the Interior; (22-26) for Piceance Creek below Ryan Gulch; period of record is December 1970-September 1974; averages are flow-weighted.

ⁱData from U.S. Department of the Interior; (26) for White River below Meeker; period of record is April-September 1974; averages are flow-weighted.

^jData from U.S. Department of the Interior; (22-26) period of record is October 1970-September 1974; averages are flow-weighted.

and C-b are those presented in Table 8.16. The concentrations and flowrates used to characterize the base surface stream condition of the White River and Colorado River at Lees Ferry are those presented in Tables 8.17 and 8.18, respectively. It was assumed that normal flows were not diminished by dewatering. As indicated in Figure 8.3, the White River drains Yellow Creek, where effluents from Tract C-a are assumed to originate; and Piceance Creek, where effluents from Tract C-b are assumed to originate. The White River

TABLE 8.16. Ground-Water Quality for Constituents Included in Dewatering Discharge Analysis⁽⁴⁾ (mg/l)

Constituent	Tract C-a		Tract C-b	
	Upper Aquifer (2)	Lower Aquifer (3)	Upper Aquifer (4)	Lower Aquifer (5)
B	0.33	0.84	1.4	36
Ca	35	8.8	32	14
F	0.41	15	10	21
Mg	52	20	42	11
Na	212	397	330	2500
TDS	905	1075	1100	6190

TABLE 8.17. Annual Mean Flowrates and Concentrations of Constituents Included in Dewatering Discharge Analysis: White River (near Watson, Utah)

Parameter	Water Year						
	1973	1974	1975	1976	1977	1978	1979
Q (m ³ /s)	---	17.3	18.8	15.1	8.67	24.2	26.7
	----- (mg/l) -----						
Boron	0.091	0.093	0.072	0.071	0.075	0.062	0.085
Calcium	65.67	70.69	64.52	65.95	71.33	68.80	65.17
Fluoride	0.35	0.34	0.26	0.28	0.32	0.24	0.25
Magnesium	24.25	27.46	25.22	25.95	28.00	24.40	22.17
Sodium	75.08	85.40	64.96	62.21	76.50	57.00	59.67
TDS	511.67	542.92	478.96	485.89	557.00	468.20	476.60

TABLE 8.18. Annual Mean Flowrates and Concentrations of Constituents Included in Dewatering Discharge Analysis: Colorado River at Lees Ferry⁽¹⁰⁾

Parameter	Water Year						
	1973	1974	1975	1976	1977	1978	1979
Q(m ³ /s)	355.9	371.5	453.1	343.4	402.3	446.0	281.5
	----- (mg/l) -----						
Boron	0.167	0.135	0.077	0.089	0.092	0.078	0.120
Calcium	73.20	71.62	69.27	69.50	71.33	77.00	72.55
Fluoride	0.32	0.27	0.26	0.31	0.30	0.30	0.30
Magnesium	24.80	25.37	25.09	24.25	25.75	27.36	26.27
Sodium	75.30	74.00	72.91	74.17	76.92	82.45	81.45
TDS	558.83	548.69	531.18	530.25	556.58	594.45	583.27

flows westward into Utah where it meets the Green River, which finally empties into the Colorado River in southern Utah.

Table 8.19 is a summary of seven parameters and their projected surface water concentration changes in the White River and at Lees Ferry at the lower extreme of the Upper Colorado River. The projections are based on the assumptions that:

1. The concentrations in Table 8.16 are representative of the upper and lower aquifers.
2. The average quality and flowrates reported in 1978 are representative of the surface stream characteristics in 1990.
3. All dewatering pumping effluent will be discharged to the surface stream untreated.
4. The discharged residuals are conserved in the surface stream, (i.e., they are not removed by adsorption, precipitation, or other mechanisms).
5. The quality and flowrate of ground water discharged from the respective tracts remain constant.
6. Mining of effluents with stream flows is complete.

TABLE 8.19. Resulting Concentrations in Stream Quality from Aquifer Pumping⁽¹⁰⁾ (mg/l, except SAR^(a))

White River	1978	Upper Aquifer Discharge			Lower Aquifer Discharge		
		C _R		%	C _R		%
B	0.062	0.091	0.029	46.8	0.783	0.72	1163.9
Ca	68.8	67.8	-1.0	-1.4	67.2	-1.6	-2.3
F	0.24	0.4355	0.195	81.5	0.77	0.53	221
Mg	24.4	24.97	0.57	2.3	24.1	-0.30	1.2
Na	57	63.66	6.66	11.7	108.3	51.3	111.1
TDS	468.2	487.7	19.5	4.2	591.1	122.9	26.2
SAR	1.5	1.68	0.18	12.0	2.88	1.38	92.0

Colorado River	1978	C _R			C _R		
				%			%
B	0.0775	0.091	0.013	17.4	0.1176	0.04	51.7
Ca	77	76.93	-0.07	-0.1	76.90	-0.1	-0.13
F	0.30	0.31	0.01	3.3	0.329	0.03	9.7
Mg	27.36	27.40	0.04	0.15	27.34	-0.02	-0.1
Na	82.45	82.78	0.33	0.4	85.27	2.82	3.4
TDS	594.45	595.3	0.85	0.1	600.4	5.95	1.0
SAR	2.05	2.06	0.01	0.5	2.13	0.08	3.9

(a) SAR--Sodium Adsorption Ratio

$$C_R = \frac{C_1 Q_1 + C_2 Q_2 + C_3 Q_3}{Q_1 + Q_2 + Q_3} = \text{resulting concentration}$$

C_R = projected resulting concentration

C_1 = concentration of parameter in effluent from Tract C-a (see Table 8.17)

Q_1 = flowrate of effluent from Tract C-a (0.2 m³/s)

C_2 = concentration of parameter in effluent from Tract C-b (see Table 8.17)

Q_2 = flowrate of effluent from Tract C-b (0.5 m³/s)

C_3 = concentration of parameter at White River or Lees Ferry (use Tables 8.18 and 8.19)

Q_3 = flowrate of stream at White River or Lees Ferry (use Table 8.18 and 8.19).

Assumptions: Stream flow is 1978 mean.

Net discharge from Tract C-a = 0.2 m³/s
from Tract C-b = 0.5 m³/s.

The projected concentrations at the White River (Station 5 in Figure 8.3) would increase by as much as 111% for sodium if the lower aquifer effluent were discharged (high pollution case) and would raise the existing Sodium Adsorption Ratio (SAR) from 1.58 to 2.88 which is an important change; an SAR value between 0 and 10 is adequate for irrigation.

The low range of potential changes in residual concentrations is assumed to be represented by the case where water from the upper aquifer is discharged. In this case the sodium concentration in the White River is projected to increase by 11.7% to 63.7 mg/l; the resulting SAR would increase to 1.68.

Boron concentrations are projected to increase by 0.029 mg/ to 0.72 mg/l in the White River, resulting in stream concentrations between 0.091 to 0.78 mg/l. The element is essential to plant growth but is extremely toxic at concentrations when only slightly above optimal conditions. The EPA criteria call for a limit of 0.75 mg/l of boron to protect sensitive crops from damage with long-term irrigation (Table 8.6 above). Based on this consideration, boron concentrations would exceed the criterion if lower aquifer water were discharged at the assumed rates at Tract C-b and Tract C-a.

Fluoride concentrations are projected to increase by 0.2 to 0.5 mg/l to 0.43 to 0.77 mg/l in the White River. Domestic water supplies are limited to 0.4 to 2.4 mg/l, depending on the temperature where the fluoride would be consumed in potable water.⁽³⁰⁾ These limits are set under the Safe Drinking Water Act. The average concentration of fluoride in 1978 at the White River sample station was 2.4 mg/l--the equivalent of the upper allowable limit for drinking water. Since drinking water standards apply to water distributed for human consumption, water from this source would require fluoride removal in the treatment for water supply. The total dissolved solids are projected to increase from 468 mg/l to between 487 mg/l and 591 mg/l. This represents a potential increase of 20 to 123 mg/l in the White River.

The effects of dewatering pumping and ground-water discharge on the water quality at Lees Ferry would be smaller because of dilution effects of the Colorado River and its tributaries which are unaffected by oil shale water discharges. Boron could increase from 0.08 mg/l in 1978 to 0.12 mg/l in the high

pollution case. In the case where only upper aquifer water is discharged, the boron concentration could increase to 0.09 m/l. As indicated in Table 8.19, sodium could increase to 85 mg/l in the high pollution case and the SAR increase from 2.05 to 2.13. The average annual fluoride concentration is presently 0.30 mg/l and could be increased in the high pollution case by about 10% to 0.33 mg/l at Lees Ferry. The projected increase in TDS concentrations, if oil shale dewatering pumping effluents were discharged to the surface water in the Piceance Basin, would range from 0.85 to 5.95 mg/l.

It is apparent that some treatment of dewatering water would be necessary if it were to be released to surface streams. De-fluoridation would clearly be necessary; boron would probably have to be removed from water discharged from Tract C-b. Reinjection, as noted above, is a reasonable alternative. Another possibility would be to store the water and distribute it for use in surface retorting at other sites in the Piceance Creek Basin.

Dewatering could reduce or eliminate ground water input to reaches of Piceance and Yellow Creeks. As noted in Table 8.15, above, the concentrations of dissolved solids in these creeks are much higher than in the White River. Table 8.16 shows that TDS concentrations in ground water are even higher. The high concentrations in the creeks is attributed to the inflow of ground water. Therefore, dewatering may actually improve the salinity problem in the White River and, ultimately, in the Green and Colorado Rivers downstream from the White River. No quantitative estimates have been made of the loss of ground water feed to Piceance and Yellow Creeks or the impact of this loss on water quality in the White, Green, and Colorado rivers.

8.4.3 Process Effluents

A shale oil industry will occupy a considerable land area. It will produce waste products which, if released to surface waters, could result in contamination dangerous to natural ecological systems and to human health. This section considers the nature of these wastes and some options for treating and reusing or disposing of them.

Source and Composition of Effluents

Most oil shale developers plan to discharge no process effluents at all, except for dewatering water. Instead, these effluents will be treated as necessary and reused. Some are expected to be used in dust control and in compacting spent shale piles.

J. P. Fox and T. E. Phillips⁽³¹⁾ have examined shale oil effluents and treatment options. Much of the material in this section is taken from their work. They note that water is used in shale oil production for a wide variety of functions, including mining operations, dust control, steam and power generation, compaction of processed shale, irrigation, potable water supply, and pre-refining upgrading. Effluents coming from these uses include mine waters, brines from ion exchange, reverse osmosis, filtration, and other treatment processes; storm water runoff from the plant area; and various process waters. Most of these effluents can be treated through conventional processes developed in other industries. The exceptions--retort water and gas condensate from retorts, and mine waters--are unique to the shale oil industry.

Retort water and gas condensate are produced during retorting from combustion, mineral dehydration, input steam, and ground water intrusion. They are complex chemically, and they contain high concentrations of a large number of dissolved organic and inorganic constituents. Production may be as much as 0.1 to 22 barrels per barrel of shale oil.⁽³²⁾ Surface processes will be in the range of about 0.10 to 0.30 barrels per barrel of oil; in-situ processes will range from 0.4 upward. Extreme values (e.g., 22 barrels per barrel of oil) will not be typical if dewatering is adequate before a retort is fired.⁽³¹⁾

Retort water condenses in the retort with the oil, and it can be separated from the oil on the surface by heat treatment and decantation.⁽³³⁾ Gas condensate is removed from the gas stream in a condenser train or in gas scrubbing systems.⁽³⁴⁾ Because the retort water flows through the spent and raw shale, it dissolves constituents from the shale and from the oil. The gas condensate leaves the retort as steam. It does not, therefore, have the opportunity to

dissolve chemical species from the shale or oil, but it does dissolve gases such as ammonia and carbon dioxide.⁽³¹⁾ Table 8.20 summarizes the composition of retort water, gas condensate, and mine water.

Mine waters are essentially aquifer water, except that they may contain some wastes--suspended solids, oil, and grease--from drilling and mine operations.

Wastewater Management

The oil shale region is an area that is typically water short. Energy development, agricultural use, and other demands will make water increasingly difficult to obtain. Accordingly, it will be beneficial to the shale oil industry to conserve water, treating and reusing it wherever possible. Since extensive treatment would be required before it could be discharged to surface streams, the cost of treating it to a quality adequate for reuse will be less than the cost of discharging it.

Table 8.21 shows the levels of treatment necessary for various water sources, including wastewaters, for use or disposal in various ways. Clearly, the industry will select treatment techniques and water applications for each available water source that are likely to minimize costs over the period of anticipated industry life.

Treatment methods are still undergoing development and testing. Table 8.22 shows the status of research efforts. Research has been focused on retort water, which is recognized as the most difficult treatment problem and, as shown in Table 8.21, the one source of water requiring extensive treatment for almost every disposal or reuse alternative. Removal of organics is the area in which least success has been achieved.

Treatment and disposal research is hindered by basic data needs. Available effluents for research are not representative of commercial processes. Furthermore, conventional analytical methods are not suitable for shale oil liquids due to interferences.⁽³¹⁾

TABLE 8.20. Composition of Retort Water, Gas Condensate, and Mine Water(4,31,34,35,36) (mg/ , except as noted)

Parameter	Retort Waters (35,36)	Gas Condensate (34)	Mine Water (4)
Alkalinity (as CaCO_3)	18,000 to 111,000	25,000	70 to 4,500
Bicarbonate (as HCO_3)	4,200 to 74,000	--(a)	85 to 25,000
Biochemical Oxygen Demand	350 to 5,500	500	--(a)
Carbon, Inorganic	2,000 to 19,000	--	--
Carbon, Organic	2,000 to 19,000	1,100	1 to 70
Carbon Dioxide	--	18,900	--
Carbonate (as CO_3)	0.0 to 15,000	--	1 to 2,000
Chemical Oxygen Demand	8,500 to 43,000	2,300 to 3,800	--
Conductivity (mhos/cm)	15,000 to 193,000	--	600 to 45,000
Nitrogen, Ammonia (as NH_3)	2,000 to 13,000	7,600	0.1 to 200
pH	8.1 to 9.4	8.6 to 8.8	6.0 to 9.3
Solids, Dissolved	1,800 to 24,000	440 to 500	400 to 42,000
Solids, Volatile	2,100 to 119,000	260	--
Sulfate (as SO_4)	40 to 2,200	5.6	4 to 900
Major Elements (concentration 0.1%)	C, H, N, S	--	C, H, S
Minor Elements (concentration 0.1% to 1 ppm)	Al, As, Ca, Cl, Fe, K, Na, Ni, Zn, B, F	--	B, Ca, Cl, F, Mg, K, Si, Na, N
Trace Elements (concentration 1 ppm)	Ba, Br, Cd, Ce, Co, Cr, Cs, Cu, Eu, Ga, Ge, Hf, Hg, I, La, Mg, Mn, Mo, Pb, Zn, Sb, Se, Sm, Sr, Ta, Th, Ti, U, V, W, Y, Yb	--	Al, As, Ba, Br, Cr, Co, Cu, Ga, I, Fe, Pb, Li, Mn, Hg, Mo, Ni, Rb, Sc, Se, Ti, V, Zn

(a) A dash (--) signifies that no data are available.

TABLE 8.21. Treatment Requirements for Reuse and Disposal⁽³¹⁾

		Potential Water Sources							
Uses		Local surface waters	Mine waters	Retort water	Raw domestic sewage	Cooling tower blowdown	Boiler blowdown	Storm water runoff	Prerefining process effluents
Discharge	Surface water discharge	N/A	●	●	●	●	●	0	●
	Ground water discharge	N/A	●	●	●	●	●	0	●
	Land treatment	N/A	0	●	0	0	0	0	0
	Evaporation	N/A	0	●	0	0	0	0	0
Reuse	Cooling water (3 cycles)	0	●	●	●	●	●	0	●
	Boiler feedwater (medium-pressure boilers)	0	●	●	●	●	●	0	●
	Domestic water	0	●	N/A	N/A	N/A	N/A	N/A	N/A
	Prerefining process water	0	●	●	●	●	●	0	●
	Revegetation	0	0	●	●	0	0	0	0
	Mining	0	0	●	●	0	0	0	0
	Spent shale disposal	0	0	●	●	0	0	0	0

● Extensive treatment
 ● Modest treatment
 0 Minimal or no treatment
 N/A not applicable or not recommended

TABLE 8.22. Summary of Process Specific Research on Retort Water, Gas Condensate, and Mine Waters⁽³¹⁾

	<u>Retort Water^a</u>	<u>Gas Condensate^a</u>	<u>Mine Water^a</u>
OIL AND SOLIDS			
Gravity Separation			
Filter Coalescence			
Coagulation/Flocculation	●		
Dissolved Air Flotation			
Filtration			
DISSOLVED GASES AND INORGANICS			
Stripping	●	●	
Ion Exchange	●		
Reverse Osmosis	?		●
Chemical Treatment	0		
Breakpoint Chlorination			
Spent Shale Treatment	●	●	
DISSOLVED ORGANICS			
Activated Sludge	?		
Anaerobic Fermentation	0		
Rotating Biodisc Contactor	0		
Activated Carbon Adsorption	●		
Resin Adsorption	0		
Chemical Oxidation	0		
Electrolytic Oxidation	0		
Reverse Osmosis	?		
Ultrafiltration			
Solvent Extraction	0		
Wet Air Oxidation	?		
TRACE CONSTITUENTS			
Chemical Treatment	0		
Ion Exchange			
Adsorption	?		
COMBINED TREATMENTS			
Reverse Osmosis	?		
Distillation	●		
Crystallization			
Solar Evaporation			

^a blank indicates research is in progress or has not been conducted.

0 = experimental studies conducted; process not suitable for water and additional research not recommended.

● = experimental studies conducted; process appears suitable if certain operational problems are resolved.

? = research in progress; results inconclusive or incomplete.

Adequate sample selection and preservation methods are unknown. Therefore, the results obtained by various investigators are not always comparable. Retort water composition will change during the course of a retorting run,⁽³²⁾ necessitating more samples and complicating the operation of some treatment processes.

Almost no treatment work has been conducted on surface retort waters because it was previously anticipated that the waters would not require treatment; they are produced in small volumes and were slated for hot spent shale moisturization. However, a recent ruling by the State of Colorado will require the removal of organics from these waters and recent concern about the escape of volatiles, including NH_3 , may require the removal of dissolved gases.⁽³¹⁾

To date treatability studies have focused on individual processes. A commercial plant will employ many such processes in series. The interfacing of various processes has not been investigated,⁽³¹⁾ and it must be before treatment performance can be assessed.

Initial studies of treatment methods tended to avoid such processes as reverse osmosis because of high cost. However, poor performance of many conventional and chapter treatment methods suggest that high-cost options such as reverse osmosis and distillation may be economical. Preliminary results of current studies on the application of evaporation⁽³⁷⁾ and reverse osmosis⁽³⁴⁾ to retort waters are encouraging.

Research on treatment of gas condensate has not been extensive, but results indicate that it will be straightforward.⁽³¹⁾ Hicks et al.⁽³⁴⁾ have achieved 90% removal of organics and 98% removal of ammonia in stripping experiments. Fox et al.⁽³⁷⁾ have removed 65% to 99% of the inorganic carbon and 49% to 75% of the conductivity using spent shale treatment.

Mine water treatment does not appear to present special problems except for their large volume (see Chapter 7 and Volume 5 of this report).⁽³¹⁾

The oil shale study prepared by the Office of Technology Assessment⁽²²⁾ presents a summary table showing a broad range of treatment options and estimates of their respective removal efficiencies, reliabilities, adaptabilities, and costs. This table is reproduced as Table 8.23.

TABLE 8.23. Relative Rankings of the Water Treatment Methods^(22,39)

Contaminant	Technology	Removal efficiency, %	Relative reliability	Relative adaptability	Relative cost
Oil and grease	Dissolved air flotation	90	Very high	Very high	Medium
	Coalescing filter	99	High	High	Medium
	Clarification	80	Very high	Very high	High
Dissolved gases	Air stripping	80	High	High	Medium
	Steam stripping	95	Very high	High	Medium
	Flue gas stripping	95	High	Medium	Medium
	Biological oxidation	High	Medium	Medium	Low
Dissolved organics	Activated sludge	95 BOD/40 COD	High	Medium	Low ^(a)
	Trickling filter	85 BOD	High	Medium	Low ^(a)
	Aerated lagoon	80 BOD	Medium	Medium	Low ^(a)
	Rotating contactor	90 BOD/20-50 COD	High	Medium	Low ^(a)
	Anaerobic digestion	60-95 BOD	High	Medium	Medium ^(a)
	Wet air oxidation	64 BOD/74 COD	Medium	High	Very high
	Photolytic oxidation	99 BOD	Medium	Very high	Very high
	Carbon adsorption	99 BOD	Medium	High	Medium
	Chemical oxidation	90 BOD/90 COD	Very high	Very high	High
	Electrolytic oxidation	95 BOD/61 COD	Medium	Very high	High
Suspended solids	Clarification	50	High	High	Medium
	Pressure filtration	95	High	High	Medium
	Multimedia filtration	95	Very high	High	Low
Dissolved solids	Clarification	Low except for metals	High	Medium	Medium
	Distillation	99	Medium	Low	Very high
	Reverse osmosis	60 - 95	Medium	Medium	Medium
	Ion exchange	High	High	Low	High
	Electrodialysis	10 - 40	Medium	Medium	Very high
Sludges	Thickening	Product 6-8% solids	Very high	High	Medium
	Anaerobic digestion	Low	High	Medium	Medium
	Vacuum filtration	Product 20-35% solids	High	High	High
	Sludge drying beds	Product 90% solids	Medium	Low	Medium
	Evaporation basins	Product 95% solids	Very high	Low	Low
	Filter press	Product 35% solids	Very high	High	High
	Aerobic digestion	Low	Low	Low	High

^(a)The cost of these processes is related to the concentrations of dissolved organics in the wastewater. The cost can be quite high if the organics concentrations are high, as in the case of retort water.

8.4.4 Surface Runoff

Construction and operation of a shale oil facility will disturb the natural vegetative cover of the land, replacing it with roads, plant facilities, etc., resulting in increased potential for sediment-laden surface runoff. Industry can and will control this using standard erosion control practices, such as installing and maintaining sediment ponds. Therefore, this is not considered to be a serious problem, and it will not be discussed further here.

More serious concern is directed toward potential runoff from surface storage and disposal piles of raw and spent shale. This problem and available control methods are explored in depth in Chapter 6 and Volume 4 of this report.

Enormous quantities of spent shale from various above ground retorting processes will be disposed of in piles constructed in canyons or in deposits on the ground surface. There will also be temporary and/or permanent piles of raw shale. The performance of storage and waste piles and the consequences of possible runoff and leachates are highly uncertain due to the lack of field experience with such large raw or spent shale piles and to the physical and chemical complexity of the problem. The problem is discussed in some detail in Chapter 6 and Volume 4 of this report.

There is, of course, the possibility of accidental spills of chemicals, shale oil, or waste fluids at production sites or in transportation corridors. The Federal Water Pollution Control Act requires each person storing minimum quantities of oil or hazardous substances to prepare and maintain a spill prevention control and countermeasure plan. This plan must describe the facility's strategy for preventing oil or hazardous substance spills from reaching navigable waters.⁽⁴²⁾

The Council on Environmental Quality has recently issued a final revision to the National Oil and Hazardous Substances Pollution Contingency Plan. The purpose of the plan is to act as the basis for coordinating Federal response in the event of an accidental discharge of oil or hazardous substances. The revisions attempt to generate greater state and local participation, incorporate a national inventory of equipment resources which could respond to an oil or hazardous substance spill, create a mechanism for outside advice in the event of an incident, provide for field tests for government responsiveness, and make binding the advice given by the Fish and Wildlife Service in regards to endangered species.⁽⁴²⁾

These measures will not guarantee that no spills will happen, of course, but they will ensure that precautions taken in the shale oil industry are comparable to those taken in other similar industries whose operations are licensed.

8.4.5 Potential Impacts on Surface Waters from Aquifer Contamination

The potential leaching of chemicals from the spent shale in abandoned modified in-situ (MIS) retorts is a major concern in considering a shale oil

industry. While it may take centuries for it to happen, the potential long-term effect could be serious due to the critical issue of salinity in the Colorado River system and the slow self-purification properties of ground-water aquifers. Leachates could result in salinity increases in the Colorado River at Lees Ferry (bottom of the Upper Colorado River Basin) of from 2 to 56 mg/l and in the Piceance Creek at White River of from 1,740 to 46,100 mg/l.⁽⁴³⁾ Other estimates have indicated that activities at Tract-b might result after 60 years in an increase in total dissolved solids in Piceance Creek of 750 to 1,750 mg/l, with an increase of 20,000 mg/l near the mine.⁽⁴⁴⁾ For Tract C-a after 60 years, effects in Yellow Creek have been predicted to be minor, but near the mine an increase of 40,000 mg/l might occur.⁽⁴⁴⁾ By contrast, Federal total dissolved solids standards for drinking water call for a limit of 500 mg/l; irrigation standards are 500 to 1000 mg/l for sensitive plants and 2000 to 5000 mg/l for tolerant species.

In addition to concerns about salinity from leaching of in situ retorts, are concerns about pH and certain chemical species. Of particular importance are toxic trace elements, such as arsenic, selenium, boron, fluorine, molybdenum, and vanadium, that have been observed in spent shale leachates.⁽⁴³⁾

Chapter 7 of this report explores in depth the potential effect of modified in-situ (MIS) retorts on water quality in the upper and lower aquifers at Tracts C-b and C-a. While several techniques for preventing aquifer contamination from MIS retorts are being developed and examined, none has yet been shown to be both feasible and adequate. Fox's analysis,⁽⁴⁾ reported in Chapter 7, assumes the application of no controls, and it makes several assumptions to simplify the computation. The results are indicated in Table 8.24. As stated by Fox:

In summary, this analysis suggests that the composition of ground waters in the vicinity of an in-situ facility will approach that of in-situ leachate.... However, because the velocity of ground waters is low, centuries may pass before the leachate travels an appreciable distance from the facility, although water transport along the fractures may reduce this time estimate. The distance from the source that each constituent will travel will depend on the ground-water flow velocity and the amount of retardation experienced. After a sufficient period of time, ranging from several years to several hundreds of years; and, depending on the specific site, the composition of local ground waters may approach the leachate compositions....

TABLE 8.24. Comparison of Predevelopment and Post Development Ground-Water Quality⁽⁴⁾

Parameters	Tract C-a			Tract C-b		
	Predevelopment Ground-Water Quality		Post-development Groundwater Quality (mg/l)	Predevelopment Ground-Water Quality		Post-development Ground-Water Quality (mg/l)
	Upper Aquifer (mg/l)	Lower Aquifer (mg/l)		Upper Aquifer (mg/l)	Lower Aquifer (mg/l)	
Al	0.14	0.24	0.49 to 31	0.3	0.3	0.89 to 53
B	0.33	0.84	0.33 to 1.9	1.4	3.6	36 to 39
Cl	12	22	32 to 73	26	1200	1234 to 1300
Cr	0.01	0.01	0.02 to 20	0.002 to 0.3	0.009	0.01 to 34
F	0.41	15	4.8 to 47	10	21	29 to 100
Fe	5.0	0.78	5.0 to 5.5	0.5	0.8	0.8 to 1.6
Li	0.13	0.13	0.20 to 4.8	3.1	10	10 to 18
Na	212	397	212 to 2800	330	2500	2500 to 6900
NO ₃ -N	0.21	0.1	0.94 to 30	0.41	0.46	1.7 to 49
Pb	0.17	0.21	0.22 to 0.36	0.01	0.03	0.12 to 0.35
SO ₄	325	112	326 to 1800	220	63	65 to 2500
Zn	0.26	0.24	0.26 to 0.54	0.2	0.2	0.2 to 0.7
TDS	905	1075	905 to 31,700	1100	6190	6190 to 68,700
TOC	8.5	11	12 to 430	3	10	16 to 720
Phenols	0.003	0.002	0.04 to 0.44	---	---	0.06 to 0.8

Fox continues the analysis of potential impacts of in-situ retort leaching to evaluate worst case conditions of contamination of surface waters by contaminated ground water. She notes that in-situ spent-shale leachate will travel through aquifers of the Piceance Creek Basin for centuries. Eventually, assuming no change in the hydrologic system, the leachates will discharge into either Piceance Creek or Yellow Creek or their tributaries. She has prepared quantitative estimates of the impacts on surface water from sodium (Na), total dissolved solids (TDS), and total organic carbon (TOC). Similar calculations can be made for other constituents. Some simplifying assumptions are necessary:

1. Leachate is discharged along the full length of the Piceance Creek and Yellow Creek from a single line source of retorts as a step function.
2. The leachate from both lease tracts arrives at Yellow Creek and Piceance Creek at about the same time, one to three centuries after site abandonment.
3. The base flow discharging into Yellow Creek and Piceance Creek will have the same composition as the post-development ground water shown in Table 8.26. In other words, there is no significant retardation of TDS, Na, or TOC during aquifer transport.
4. About 80% of the flow of Piceance Creek and Yellow Creek is from the upper aquifer.
5. The average annual discharge of ground water into the Piceance Creek and Yellow Creek is 15.27 million m³ (12,520 acre-ft). Approximately 14.15 million m³ (11,600 acre-ft) per year of this discharges annually into Piceance Creek and the balance into Yellow Creek.⁽⁷⁾
6. The increase in TDS, Na, and TOC in surface waters will be the same as the increase in these parameters in the ground waters, attenuated by dilution from tributary streams.

The potential effect of the discharge of in-situ leachate from a single line source of retorts into surface streams, calculated using the

above-described procedure, is summarized in Table 8.25. This table presents the average annual discharge and estimated maximum possible increase in TDS, Na, and TOC at four points in the Upper Colorado River Basin due to the discharge of ground-water-borne, in-situ spent shale leachate into surface waters. If pulses from several line sources of retorts arrived at the streams simultaneously, the increases would be correspondingly larger. It would take centuries for the concentrations shown in this table to be reached.

The assumptions may not be representative of reality. Fox has shown, for instance, that flow through the C-a retorts may very well be downward into the lower aquifer. In this event, she predicts that the arrival of leachates from Tract C-a to Yellow Creek might not occur for thousands of years. This would prolong the length of time over which contamination would continue, but it would reduce the concentration of contaminants in the surface waters.

There is evidence that Piceance Creek is fed in part from the alluvial aquifer and in part from the upper aquifer. This would result in a dilution of the contaminated ground water as it entered the Creek. Similar conditions might exist in Yellow Creek as well.⁽⁴⁾

Finally, Fox notes that contrary to the assumptions, it is likely that some constituents in leachates would be reduced during aquifer transport while others would be increased. Sodium, for instance, would probably not be affected by transport, but some constituents of TDS would probably be attenuated. TOC values might be greatly reduced, but other organics in the oil shale of the aquifers might be dissolved and added to the leachate.⁽⁴⁾

Clearly, accurate predictions of effects of MIS retort leaching are beyond the limits of current knowledge. However, the work done to date makes it apparent that some contamination of surface streams would be likely if effective preventative measures are not developed and implemented.

TABLE 8.25. Estimated increase in TDS, Na, and TOC in Surface Waters of the Upper Colorado River Basin Due to Discharge of In-Situ Leachates from Tracts C-a and C-b into Piceance Creek and Yellow Creek as Base Flow⁽⁴⁾

Watercourse	Average Annual Discharge, (million m ³ /yr) (1)	Maximum Possible Increase (mg/l)		
		Na (2)	TDS (3)	TOC (4)
Piceance Creek at White River ^(a)	17.68	1740 to 5260	4100 to 46,100	10 to 570
Yellow Creek at White River ^(a)	1.40	0 to 2100	0 to 24,600	3 to 340
White River Near Watson, Utah	648.87	50 to 150	110 to 1310	0.3 to 16
Green River Near Green River, Utah	5,399.5	6 to 18	13 to 160	0.03 to 2
Colorado River at Lees Ferry, Arizona	15,156	2 to 6	5 to 56	0.01 to 0.7

(a) It is assumed that the leachate from Tract C-a discharges into Yellow Creek and from C-b into Piceance Creek.

8.5 REFERENCES FOR CHAPTER 8

1. Ashland Oil, Inc., and Occidental Oil Shale, Inc. 1975. Oil Shale Tract C-b: Environmental Baseline Program, November 1974-October 1976, Final Report, Volume 4, Ecology.
2. Gulf Oil Corporation, and Standard Oil Company (Indiana). 1977. Rio Blanco Oil Shale Project: Final Environmental Baseline Report for Tract C-a and Vicinity, Book 1.
3. Colorado River Basin Salinity Control Forum. 1975. Proposed Water Quality Standards for Salinity Including Numeric Criteria and Plan at Implementation for Salinity Control.
4. Fox, J. P. 1980. Water-Related Impacts of In-Situ Oil Shale Processing. LBL-6300. Lawrence Berkeley Laboratory, Berkeley, California.
5. Mehran, M., T. N. Narasimhan, and J. P. Fox. 1981. An Investigation of Dewatering for the Modified In-Situ Retorting Process, Piceance Creek Basin, Colorado. Available as Volume 5 of this report.
6. Stockton, C. W., and G. C. Jacoby. 1976. "Long-Term Surface-Water Supply and Streamflow Trends in the Upper Colorado River Basin Based on Tree-Ring Analyses." Lake Powell Research Project Bulletin No. 18, (March).
7. Weeks, J. B., G. H. Leavesley, F. A. Welder, and G. J. Saulnier. 1974. Simulated Effects of Oil Shale Development on the Hydrology of Piceance Basin, Colorado. U.S. Geological Survey Professional Paper 908.
8. Upper Colorado Region State-Federal Inter-Agency Group. 1971. Upper Colorado Region Comprehensive Framework Study.
9. Wymore, I. F. 1974. Estimated Average Annual Water Balance for Piceance and Yellow Creek Watersheds. Environmental Resources Center, Technical Report No. 2, Colorado State University, Fort Collins.
10. Torpy, M. F. 1981. Oil Shale Development in the Piceance Basin and Potential Water Quality Changes. Available as Volume 6 of this assesment report.
11. Bates, E. R., and T. L. Thoem (eds.). 1979. Pollution Control Guidance for Oil Shale Development: Appendix. Draft. Environmental Protection Agency, Cincinnati, Ohio. As presented in U.S. Congress, Office of Technology Assessment. 1980. An Assessment of Oil Shale Technologies. U.S. Government Printing Office, Washington, D.C.
12. Bureau of National Affairs. Current. Environment Reporter: State Water Laws. Bureau of National Affairs, Inc., Washington, D.C.

13. Bureau of National Affairs. Current. Environment Reporter: Federal Regulations. Bureau of National Affairs, inc., Washington, D.C.
14. Sinor, J. E. 1977. "Disposal of Mine Water from a Deep Oil Shale Mine." in Proceedings of the Second Pacific Chemical Engineering Congress, Vol. II.
15. Radosevich, G., D. Skogerboe, D. McWhorter, and W. Walker. 1977. "Salinity Management Alternatives for Oil Shale Water Supplies." Natural Resources Journal 17(3):461
16. 40 CFR Section 120.5 (1976).
17. Colorado River Basin Salinity Control Act, U.S. Code 1976 Title 43, Sections 620d, 1543, 1571 et seq., June 24, 1974, P.L. 93-320, 88 Stat. 266.
18. Colorado Department of Natural Resources. October 1979. Upper Colorado River Basin 13(a) Assessment: The Availability of Water for Oil Shale and Coal Gasification Development in the Upper Colorado River Basin: Summary Report, a report to the U.S. Water Resources Council, Public Review Draft. Denver, Colorado.
19. Colorado Department of Natural Resources. 1979. Colorado Oil Shale: The Current Status. Prepared under U.S. Department of Energy Contract No. DE-FG48-79R800212.001. Colorado Geological Survey, Denver.
20. U.S. Public Health Service. 1962. "Drinking Water Standards." U.S. Public Health Service Publication 956.
21. Everhart, W. H., and B. E. May. 1973. "Effects of Chemical Variations in Aquatic Environments." Biota and Chemistry of Piceance Creek, Vol. 1. U.S. Environmental Protection Agency Report No. EPA-R3-73-011a, Washington, D.C.
22. U.S. Congress, Office of Technology Assessment. 1980. An Assessment of Oil Shale Technologies. U.S. Government Printing Office, Washington, D.C.
23. U.S. Department of the Interior. 1970. Water Resources for Colorado: Part 2, Water Quality Records.
24. U.S. Department of the Interior. 1971. Water Resources for Colorado: Part 2, Water Quality Records.
25. U.S. Department of the Interior. 1972. Water Resources for Colorado: Part 2, Water Quality Records.
26. U.S. Department of the Interior. 1973. Water Resources for Colorado: Part 2, Water Quality Records.

27. U.S. Department of the Interior. 1974. Water Resources for Colorado: Part 2, Water Quality Records.
28. Ashland Oil, Inc., and Occidental Oil Shale, Inc. 1977. Modifications to Detailed Development Plans, Oil Shale Tract C-b.
29. Atlantic Richfield Co. 1974. An Environmental Impact Analysis for an Oil Shale Complex at Parachute Creek, Colorado, Colony Development Operation.
30. Bureau of National Affairs. Current. "Drinking Water." Environment Reporter: Federal Regulations. Bureau of National Affairs, Washington, D.C.
31. Fox, J. P., and T. E. Phillips. 1980. "Water Management Strategies-- Issues and Research Needs." Presented at Oil Shale, The Environmental Challenges, Vail, Colorado, August 11-14, Lawrence Berkeley Laboratory Report LBL-11214.
32. Farrier, D. S., J. E. Virgona, T. E. Phillips, and R. E. Poulson. 1978. "Environmental Research for In-Situ Oil Shale Processing." Proceedings of the 11th Oil Shale Symposium, Colorado School of Mines, Golden, Colorado.
33. Burton, R. S., III, "Method of Breaking Shale Oil-Water Emulsion," U.S. Patent 4, 109,718, August 1976.
34. Hicks, R. E., R. F. Probststein, I. Wei, D. S. Farrier, J. Lotwala, and T. E. Phillips. 1980. "Wastewater Treatment and Managenent at Oil Shale Plants." Proceedings of the 13th Oil Shale Symposium, Colorado School of Mines, Golden Colorado.
34. Fox, J. P., D. S. Farrier, and R. E. Poulson. 1978. Chemical Characterization and Analytical Considerations for an In-Situ Oil Shale Process Water. Laramie Energy Technology Report LETC/RI-78/7.
36. Fox, J. P. 1980. The Partitioning of Major, Minor, and Trace Elements During Simulated In-Situ Oil Shale Retorting. Ph.D. Dissertation, University of California, Berkeley, California.
37. Peters, H. H. 1980. Shale Oil Waste Water Recovery by Evaporation. Final report to Battelle, Pacific Northwest Laboratory by Resources Conservation Company, Seattle, Washington.
38. Fox, J. P., D. E. Jackson, and R. H. Sakaji. 1980. "Potential Uses of Spent Shale in the Treatment of Oil Shale Retort Waters." Proceedings of the 13th Oil Shale Symposium, Colorado School of Mines, Golden, Colorado.
39. Hamilton Standard Division of United Technologies. 1978. Assessment of Oil Shale Wastewater Treatment and Control Technology.

40. Margheim, G. 1975. Water Pollution from Spent Oil Shale. Ph.D. Thesis, Colorado State University, Fort Collins, Colorado.
41. Stollenwerk, K. G., and D. D. Runnells. 1977. "Leachability of Arsenic, Selenium, Molybdenum, Boron, and Fluoride from Retorted Oil Shale." Proceedings of the Second Pacific Chemical Engineering Congress, Vol. II.
42. Spence, H. M. 1980. "Oil Shale and the Environment." Presented at The Outlook for Oil Shale. Synfuels Week conference, Denver, Colorado, June 19, 1980.
43. Fox, J. P. 1979. Water Quality Effects of Leachates from an In-Situ Shale Industry. Lawrence Berkeley Laboratory Report LBL-8997.
44. Robson, S. G., and G. J. Saulnier, Jr. 1980. Hydrogeochemistry and Simulated Solute Transport, Piceance Basin, Northwestern Colorado. U.S. Geological Survey Open-File Report 80-72.

9.0 ECOLOGICAL SYSTEMS LEVEL RESPONSES TO SHALE OIL DEVELOPMENT

Some fifty million years ago, a large body of water covered what is now the area occupied by the upper Colorado River Valley in the Rocky Mountains of the United States. During the time the lake, called Lake Unita, was in existence, large amounts of organic material were deposited on the bottom. Over time, these deposits solidified into what may be the richest deposit of shale oil in the world.⁽¹⁾ Subsequent plate-tectonic activity over geologic time has caused the disappearance of the large lake, the upthrust of the Rocky Mountains, and vast changes in the climate of the area. These changes have produced a series of ecosystem formations typical of xeric environments at moderate to high elevations.

These ecosystems are vegetatively characterized by pinyon pine (Pinus edulis)-juniper (Juniperus osteosperma) associations in mountain and hillside locals, sagebrush (Artemisia tridentata)-grass (typically Hilaria jamesii and Sitanion hystrix) associations in the desert grassland type, blackbrush communities (Coleogyne ramosissima), greasewood communities (Sarcobatus vermiculatus) and saltbush (Atriplex nuttallii) associations.

Fauna commonly associated with the above vegetation types include (on a migratory or resident basis) the black-tailed jackrabbit (Lepus californicus), yellow-bellied marmot (Marmota flaviventris), Colorado chipmunk (Eutamias quadrivittatus), deer mouse (Peromyscus maniculatus), desertwood rat (Neotoma lepida), coyote (Canis latrans), raccoon (Procyon lotor), elk (Cervus canadensis), mountain sheep (Ovis canadensis), mule deer (Odocoileus hemionus), and pronghorn antelope (Antilocapra americana). In addition, more than 250 species of birds, reptiles, and some amphibians have been reported in the area.⁽²⁾

The following brief literature survey describes the present ecosystem level conditions and possible effects that might be induced should full-scale shale oil development occur in the Piceance Creek Basin. The information is taken primarily from RBOSP^(3,4) unless otherwise noted.

9.1 INTRODUCTION

In general, the present conditions and trends of the ecological and agricultural systems of the Piceance Basin should continue in the absence of a shale oil industry. Many of the natural systems exhibit drastic seasonal and annual fluctuations in composition, abundance and/or productivity in response to variations in climatic patterns and other external forces. Usually these fluctuations are offset or damped by reciprocal changes in other parts of the system, thus, the system as a whole exhibits a "dynamic equilibrium." The ecological systems in the Basin are also influenced by resource management policies, including vegetation manipulation, water storage projects and operation, livestock grazing, wildlife management, and other resource developments, such as coal. In addition to considering the effect of a shale oil industry per se, it is important to consider synergistic effects of these management policies. The Piceance Basin is a unique collection of many diverse, dynamic ecological systems under different management policies. Therefore, although present conditions and trends may be expected to continue, the future conditions will differ somewhat from present conditions, regardless of the development of a shale oil industry. The most significant changes will be associated with anticipated urban extension and changes in land use practices.

The Piceance Basin will continue to feel the effects of increased development, even in the absence of a shale oil industry. The region consists of large, relatively productive arid and semi-arid shrublands, and isolated highlands; most agriculture is conducted along the bottomlands along creeks and is primarily for livestock. As water becomes more available for irrigation, more land will be converted from range use to agriculture. The region will continue to be important for hunting and grazing, though the quality of both is likely to decrease with increasing pressures and demands upon the natural systems. Regional population growth is likely to have the greatest effect through urbanization of range and farmland and through associated human activity. Although urban growth or industrialization may be restricted to one particular area, human activity extends throughout the region and has the potential to create drastic changes in the natural plant and animal communities. Recovery of these communities will require decades due to the fairly harsh climatic and

soil conditions. Much more intensive management by all natural resource agencies and private developers will be required to maintain the quality and productivity of the natural and agricultural systems, even in the absence of a shale oil industry. With proper management, the region should support healthy natural plant and animal communities, productive range and farmland, and a certain level of urbanization and industrialization. Under improper management, the relatively fragile natural systems will deteriorate rapidly and be slow to recover.

9.2 PROJECTIONS OF FUTURE CONDITIONS WITH SHALE OIL DEVELOPMENT

9.2.1 Soils

Most of the adverse environmental impacts on land features would occur during the construction phase. The only other significant adverse impact could occur should there be an accident or natural disaster causing an oil leak or spill from storage tanks or pipelines.

During construction, vegetation will be disrupted at the complex site. Erosion is common to the area because of weather extremes. Severe thunderstorms with very high rates of precipitation are especially effective in eroding the soil and causing the streams in the area to become highly sedimented. During construction of the complex, the erosion potential will be increased wherever and whenever protective cover is removed and existing drainage paths are changed or disrupted.

Revegetation of the disturbed area is important to reduce any adverse impacts and to help prevent soil erosion. Chemical characteristics of the soil influence the ease with which it can be revegetated. Special care should be taken to use soils with the lowest salinity for "top soils" since top soils are more difficult to revegetate with desirable plants. High saline concentrations also enhance the spread of halogeton (Halogeton glomeratus), a plant poisonous to livestock, especially sheep. It thrives on disturbed halophytic sites and long linear disturbances, such as pipelines and roads, which enhance its spread

into new areas.^(5,6) In general, surface soils should be removed and "stored" during complex construction and returned to cover appropriate areas when shale oil extraction plants have been built.

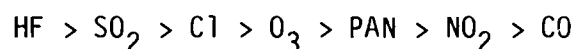
9.2.2 Water Resources

Water quality will decrease as a result of an increase in sediment loads and concentrations of total dissolved solids (TDS) concentrations. These increases will affect turbidity, water temperature, oxygen content, metallic and non-metallic concentrations. Shale oil development will also affect amounts of surface flow and flow patterns. The primary source for increased sediment loads and TDS concentrations will be the 400 million tons of processed shale oil over years of extraction, raw shale, spent catalyst, green coke, and process water. Increased sediment loads and TDS levels will be caused by extraction, plant construction, various pipelines, road construction of water intake facilities on the Colorado River near Grand Valley.

Some increased runoff resulting in increased sediment load and TDS may be expected from powerline construction and service facilities related to increased population. Clean-up of oil spills will also produce increased sediment levels and TDS concentrations. This latter will depend on the size of the spill, time of year, presence or absence of access roads to the spill, and size and number of equipment.

9.2.3 Vegetation

Plants themselves are emitters of compounds which in the last century have become known as pollutants. Four of these compounds are hydrogen sulfide, ammonia, nitrous oxide, and a broad class of hydrocarbons. Plants can also break down toxic compounds for their use. An alfalfa canopy was observed to remove gases from the air in the following order from greatest removal rate to no removal at all:



The rate of uptake was observed to increase with the water solubility of the compounds.⁽⁷⁾

Plant stack emissions of hydrocarbons, SO_2 , NO_2 , and particulates are the primary concern of this ecological assessment. Pollutants which are well-studied and known to have a major impact on agriculture are ozone and other oxidents, sulfur dioxide, fluorine, and ethylene.⁽⁸⁾ Compounds which are considered possible pollutants are ammonia, chlorine, volatile trace metals, phenols and other organic compounds, and particulates. Secondary photochemical reactions may further result in production of serious plant toxicants.

Acid rain is a serious problem in mesic climates, but in dry regions is not likely to be a serious problem. Significant amounts of acid precipitation occur only at conjunction of two rare events in arid regions: very heavy rainfall along with heavy SO_2 pollution (J. L. Dodd, personal communication, February 23, 1980).

Because dosages of the pollutants necessary to induce acute, short-term, vegetation injury are rather high and the projected range of average daily pollutant levels in the basin is rather low, the probability of acute injury is minimal. However, chronic injury resulting from long-term, low-level exposure may be significant (Table 9.1).

Both acute and chronic effects may change the diversity, productivity, and stability of biotic communities. If the vegetational disturbance became excessive, soil erosion could also become a serious problem. These changes would in turn affect the animal components of the ecosystem via changes in habitat, food availability, and population dynamics.

Sensitivity

Impact is affected by climatological factors such as humidity, radiant intensity, soil water, and soil nutrient supply. Most plants display maximum absorption and sensitivity when environmental conditions are most favorable for maximum growth, i.e., temperatures $>40^\circ\text{F}$, relative humidity $>50\%$, daylight, and ample soil water. Plants growing at maximum rates are normally more susceptible to injury than those growing at a reduced rate because of reduced stomatal resistance. Any genetic or environmental factor which reduces growth rate, such as age of plant or unfavorable environmental conditions, will normally increase stomatal resistance and thereby decrease absorption and sensitivity.

TABLE 9.1. Types of Chronic Low-Level Plant Effects and Probable Mechanisms Involved⁽⁷⁾

Type of Effect	Probable Mechanisms	Pollutants Involved ^(a)
Reduced Growth	Decreased <u>photosynthesis</u>	SO ₂ , O ₃ , NO _x , HF, PAN,
	Increased <u>respiration</u>	Pb, HF, SO ₂
	Biochemical changes	
	Enzyme inhibition	SO ₂ , O ₃ , PAN, HF, As
	Electron (energy) transport	HF, O ₃ , PAN
	Effects on photopigments	SO ₂ , HF, O ₃ , PAN, NO _x
	<u>Stomatal function</u>	SO ₂ , O ₃
	Membrane permeability	O ₃ , PAN, SO ₂ , HF, metals
	Premature senescence of leaves	SO ₂ , O ₃ , PAN, NO ₂
	Physical changes	
	UV reflectivity	Acid rain
	Heat exchange	Acid rain
	Gas exchange	Acid rain
	Changes in symbiosis	O ₃ , acid rain
	Effects on nutrient flux	SO ₂ , acid rain
Reduced Reproduction	Reduced carbohydrate availability for reproductive structures	SO ₂ , O ₃ , HF, PAN, Pb, NO ₂
	Effects on reproductive processes	
	Flower or fruit production	Smog, HF, SO ₂
	Pollen germination or tube elongation	SO ₂ , O ₃ , HF
	Mutagenesis	SO ₂
	Effects on pollinating insects	HF
Increased Morbidity	Inadequate carbohydrate supply to support autotrophic respiration and resist diseases;	SO ₂ , O ₃ , HF, PAN, NO ₂ ,
	Reduced growth and loss of ability to compete with other vegetation	heavy metals

(a) Includes pollutants for which specific effects have been documented and those whose biochemical symptomology strongly implicate them as probable causal agents.

Each species has unique stomatal responses, and pre-exposure conditions cause unpredictable stomatal responses. Therefore, general stomatal conditions of the field site at the outset of exposure are very difficult to quantify.

Levels of sensitivity and accumulation effects have not been adequately field-tested or field-simulated until recently when such a study was done by an EPA-funded project in Montana near a coal-fired powerplant. Most of the research is on sulfur dioxide; however, some work has been conducted on plant uptake of fluorides, nitrogen dioxide, and mercury. It is generally accepted that field experiments are preferable to greenhouse experiments in the study of atmospheric pollutant effects on plants because natural environmental fluctuations affect synergistic reactions, susceptibility, and dosages. However, the highly variable conditions of a field experiment present unique research problems.

Plant Group Response

The Pinyon-Juniper plant group, Juniperus osteosperma and Pinus edulis, appears to be relatively resistant to SO_2 and NO_2 .^(9,10) Sagebrush, Artemesia tridentata, and wheatgrass, Agropyron smithii, are of intermediate sensitivity to SO_2 .⁽⁹⁾ Hill et al.⁽¹⁰⁾ found that arid perennial grasses, including two other species of Agropyron, were generally of low sensitivity to SO_2 , with the exception of the highly sensitive Indian Ricegrass, Oryzopsi hymenoides.⁽¹¹⁾

Impacts of Pollutants on Plants

Sulfur Dioxide. Inter-relations of time and concentration (effective dose) are being studied in order to assess current standards. Studies on doses lower than standard legal doses are not yet complete, but indications are that relaxation of the EPA standards will establish SO_2 as a widespread influential factor affecting the structure and function of many ecosystems.

SO_2 -sensitive plants have been identified by Jacobson and Hill,⁽¹²⁾ Davis and Wilhour,⁽¹³⁾ and Hill et al.⁽¹⁰⁾ (Table 9.2). Complicating factors are discussed by Benedict and Breen,⁽¹⁴⁾ Davis and Gerhold,⁽¹⁵⁾ Davis and Wilhour,⁽¹³⁾ Dreisinger and McGovern,⁽¹⁶⁾ Guderian,⁽¹⁷⁾ Krupa,⁽¹⁸⁾ Linzon,⁽¹⁹⁾ Skelly and Lambe,⁽²⁰⁾ and USEPA.^(21,22) Karnowsky⁽²³⁾ discusses the sensitivity of Populus tremuloides.

TABLE 9.2. Percent of the Total Leaf Area Injured by Different Concentrations of SO₂ in Two-Hour Field Fumigation Studies^{(10)(a)}

Species	Average Percent Injury, SO ₂					
	0.5 ppm	1 ppm	2 ppm	4 ppm	6 ppm	10 ppm
Abies concolor (White Fir)		0		0	0	
Abies lasiocarpa (Alpine Fir)					0	22
Acer glabrum (Rock Mountain Maple)		0		10	60	
Achillea millefolium (Yarrow)		0	0	0	16	38
Agoseris glauca (Mountain Dandelion)		0	0	10	15	
Agropyron canium (Wheatgrass)		0	0	0	0	78
Agropyron desertorum (Crested Wheatgrass)					20	
Ambrosia sp. (Ragweed)		0	0	0	1	1
Amelanchier utahensis (Utah Serviceberry)	0	0.2	3	22	33	80
Artemisia ludoviciana (Louisiana Sage)		0		0	21	
Artemisia tridentata (Big Sagebrush)			0	4	9	2
Aster chilensis (Aster)		0	0	1	5	
Astragalus utahensis (Locoweed)		2	0	30	50	
Atriplex canescens (Fourwing Saltbush)				0	0	
Atriplex confertifolia (Shadscale)				0	0	
Bromus ciliatus (Fringed Brome)		0	0	0	13	96
Bromus inermis (Smooth Brome)						0.6

(a) Most data points represent only a few trials.

TABLE 9.2. (contd)

Species	Average Percent Injury, SO ₂					
	0.5 ppm	1 ppm	2 ppm	4 ppm	6 ppm	10 ppm
<i>Bromus tectorum</i> (Cheatgrass)			0	0		10
<i>Cercocarpus ledifolius</i> (Curl-Leaf Mountain Mahogany)					0.4	25
<i>Cercocarpus montanus</i> (Mountain Mahogany)				5		
<i>Chenopodium fremontii</i> (Goosefoot)		0	2	5	7	
<i>Crysothamnus nauseosus</i> (Big Rubber Rabbitbrush)				0	1	40
<i>Crysothamnus stenophyllus</i> (Little-Leaf Rabbitbrush)				0		
<i>Chrysothamnus viscidiflorus</i> (Sticky-Flower Rabbitbrush)		0		0	5	
<i>Cirsium undulatum</i> (Thistle)		0		6	14	
<i>Cowania mexicana</i> (Cliffrose)					0	3
<i>Descurainia californica</i> (Tansy Mustard)				0		40
<i>Ephedra viridis</i> (Mormon Tea)		0		0	2	95
<i>Equisetum</i> sp. (Horsetail)		0	0	0	0	
<i>Eriogonum racemosum</i> (Buckwheat)		0		43	19	
<i>Euphorbia serpyllifolia</i> (Spurge)		0	0	12	15	
<i>Eurotia lanata</i> (Winterfat)				6	0	
<i>Geranium richardsonii</i> (White Geranium)			3	7	86	
<i>Gila aggregata</i> (Scarlet Gilia)			0.8	3	14	
<i>Gutierrezia sarothrae</i> (Snakeweed)			0	0	21	78

TABLE 9.2. (contd)

Species	Average Percent Injury, SO ₂					
	0.5 ppm	1 ppm	2 ppm	4 ppm	6 ppm	10 ppm
Juniperus osteosperma (Utah Juniper)					0	28
Juniperus scopulorum (Rocky Mountain Juniper)		0		0	0	25
Machaeranthera canescens (Spiny-Leafed Aster)				25		
Malacothrix sonchoides (Desert Dandelion)				0		
Opuntia sp. (Prickly Pear Cactus)					0	
Oryzopsis hymenoides (Indian Ricegrass)	0.2	2	2	17	29	90
Oryzopsis micrantha (Ricegrass)				4		
Pachystima myrsinites (Mountain Lover)					0	
Penstemon sp. (Penstemon)				15		70
Picea pungens (Blue Spruce)			0	0	0	
Pinus edulis (Pinyon Pine)				0	0.06	2
Pinus ponderosa (Ponderosa Pine)				0	0	1
Populus angustifolia (Narrowleaf Cottonwood)	0	0	2	11	20	
Populus tremuloides (Quaking Aspen)	0	0	0	12	7	0
Pseudotsuga taxifolia (Douglas fir)				0	0.8	
Quercus gambelii (Gambel Oak)					0	8
Rhus trilobata (Squawbush)					0.3	0
Rosa Woodsii (Wild Rose)		0	1	15	90	60

TABLE 9.2. (contd)

Species	Average Percent Injury, SO ₂					
	0.5 ppm	1 ppm	2 ppm	4 ppm	6 ppm	10 ppm
<i>Salsola kali</i> (Russian Thistle)				7	3	
<i>Senecio streptanthifolius</i> (Groundsel)				0	8	
<i>Sitanion hystrix</i> (Squirreltail)			0			
<i>Sphaeralcea</i> sp. (Cutleaf Globe Mallow)			0	0.03	17	40
<i>Sphaeralcea parvifolia</i> (Globe Mallow)	20	22	43	38	30	
<i>Sporobolus cryptandrus</i> (Sand Dropseed)		0	0	0	0	0
<i>Stipa occidentalis</i> (Needlegrass)					0	73
<i>Symphoricarpos oreophilus</i> (Snowberry)		0.3	6	18	32	
<i>Tragopogon dubius</i> (Goatsbeard)			0	4	8	
<i>Trisetum spicatum</i> (Trisetum)						90
<i>Viola</i> sp. (Viola)					25	
<i>Yucca</i> sp. (Yucca)						0

The gaseous pollutants considered here; SO₂, NO₂, and hydrocarbons; enter the plants primarily via the stomata. (17,21,24-27) Stomates have been induced to open in some plants and induced to close in others by fumigation with SO₂.

Mansfield and Majernik (28) reported an increase in stomatal opening in response to SO₂ exposures at relative humidities above 40% but a depression of opening at lower relative humidities. Buron and Cornic (29) found that a 3-min exposure of 2.5 ppm SO₂ induced stomatal opening in *Sinapsis alba* plants but a 40-min exposure induced closure. Biscoe et al. (30) found that low

concentrations of SO_2 up to 0.5 ppm induced stomata to open in vicia faba. Unsworth et al.⁽³¹⁾ reported stomatal opening was increased in numerous crops by ambient SO_2 levels.

To the contrary, Jensen and Kozlowski⁽³²⁾ found four tree species had reduced SO_2 absorption rates after 20 hours of pre-fumigation with 0.75 ppm SO_2 . Bonte et al.⁽³³⁾ found that SO_2 induced Pelargonium hortorum stomata to close. Jerry Dodd (personal communication) indicated that Agropyron smithii stomata were induced to close by SO_2 fumigation. In summary, the response of stomates to SO_2 exposure shows conflicting results and is not adequately understood at this time.

Once SO_2 enters the leaf it quickly goes into solution in the aqueous medium bathing the mesophyll cells. SO_2 has a relatively high solubility in water.⁽²⁶⁾ Hocking and Hocking⁽³⁴⁾ suggest that sulfur enters the mesophyll cells primarily in the form of aqueous, unreacted sulfur dioxide ($\text{SO}_2 \cdot \text{H}_2\text{O}$). Once in the cells, it is converted to sulfite (SO_3) and bisulfite (HSO_3) ions.⁽³⁵⁾ SO_3 is then converted to sulfate (SO_4) which in turn is converted to organic sulfur.⁽³⁶⁻⁴⁰⁾ In high concentrations both SO_3 and SO_4 can be toxic to plants.

Agropyron smithii was studied as a perennial producer species in the Montana grasslands. SO_2 was found to stimulate new leaf growth while simultaneously accelerating senescence.⁽⁴⁰⁾ Lesions typical of SO_2 toxicity were not found. Since this new leaf production was noted only after midsummer, the authors hypothesized that during the early part of the growing season, plants incorporated atmospheric sulfur without any adverse effects; however, with the reduced metabolic activity in late summer, a plant's capacity to incorporate this sulfur is limited, and SO_2 derivatives accumulated to levels disrupting normal leaf physiological processes.

Dodd et al.⁽⁴¹⁾ reported that in long-term SO_2 field fumigations of Agropyron smithii at concentrations less than or equal to 0.1 ppm, increased leaf senescence was observed for the reduced growth portion of the growing season (mid-June to mid-July) but not for the high-growth portion (beginning growth to mid-June). They concluded the reason for this was that, during the high-growth

period, the plants grew at a sufficient rate to incorporate SO_2 sulfur into normal metabolites, thereby preventing toxic levels of SO_3 or SO_4 from accumulating. This hypothesis is supported by the work of Miller and Xerikos.⁽⁴²⁾ They found the greater SO_2 resistance of certain cultivars of soybeans to be a function of their ability to rapidly convert SO_3 to SO_4 . After the SO_3 flux into plant tissue surpasses the plants' ability to convert it to SO_4 , detrimental levels of SO_3 may build up in the tissue. SO_3 is estimated to be 30 times more toxic than SO_4 because of its reducing potential.⁽³⁸⁾ It is also hypothesized that as SO_3 progressively accumulates in leaf tissue above a deleterious threshold level, all plants probably exhibit a similar injury response curve.

Chronic injury occurs in response to long-term, relatively low-level exposures to SO_2 . It is a result of the deleterious levels of SO_4 maintained in the leaf tissue over an extended period of time^(37,38,43) and of the long-term cumulative effects of sub-acute levels of SO_3 in leaf tissue, as suggested by Ziegler's⁽⁴⁴⁾ and Malhorta and Hocking's⁽⁴⁵⁾ discussions on the effects of SO_3 on enzymes and chlorophyll. Chronic injury, depending on its degree, may manifest itself by necrosis, chlorosis, increased leaf senescence, and/or reduced productivity.

From the literature it appears that chronic responses start to significantly manifest themselves after about one month's duration. Nearly all of these experimentally determined chronic responses are based on a continuous or regular fumigation pattern at a constant level of exposure.

Chronic visible injury response to SO_2 exposure has been reported for a variety of different plants under a variety of different exposure concentrations and durations. However, there seems to be a void of comprehensive long-term investigations on chronic plant responses to SO_2 under varying but controlled conditions of plant sensitivity and exposure concentration and duration. Results from a number of investigations on chronic plant response are presented in Figure 9.1. These investigations were conducted under favorable growth conditions, i.e., conditions of reduced stomatal resistance. The plotted responses suggest a basic linear increase in injury with increasing

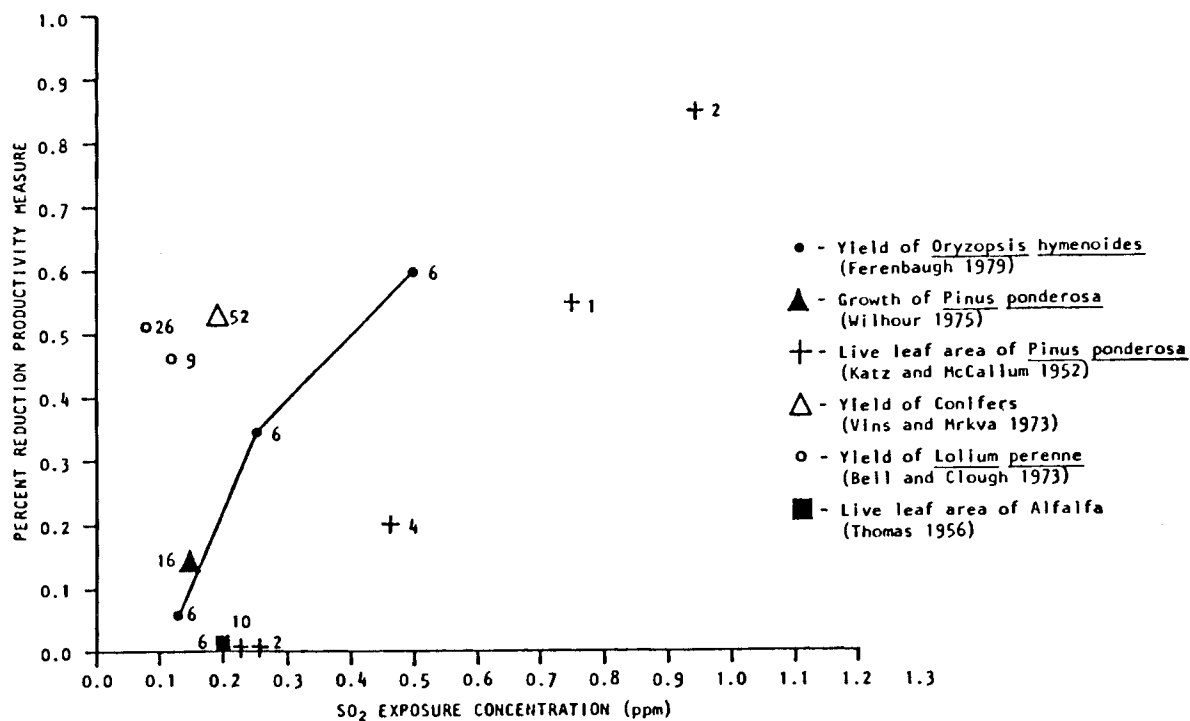


FIGURE 9.1. Measures of Sensitive Plant Responses to Relatively Long-Term SO₂ Exposure. Numbers by date points indicate weeks of exposure

SO₂ concentration of approximately equivalent exposure durations. They also suggest that the incipient injury threshold concentration is higher for resistant plants.

A number of investigators have reported that reduction in yield is apparent in plants fumigated with SO₂ until levels sufficient to cause visible damage are reached. (46-54)

Reduction in alfalfa yield was not measurable by Thomas⁽⁵⁵⁾ and Katz⁽²⁴⁾ below a minimum of 5% of the leaf area destroyed. Katz reported that exposures of 7 hours at 1.1 ppm SO₂ produced no leaf injury, whereas exposures of 66 hours at 0.46 ppm produced 11.3% visible injury and reduced yield about 12%. However, subtle injury due to atmospheric SO₂ in eastern Colorado resulted in physiological injury without accompanying visible injury. Thomas⁽⁵⁵⁾ fumigated alfalfa in field plots and found that continuous doses of 0.2 ppm reduced the photosynthetic rate about 10% on the twenty-third day of treatment; noticeable

effects had begun on the tenth day. At 0.3 ppm, a 25% reduction in photosynthetic rate was noted after two weeks of continuous fumigation. Although part of this was attributed to visible injury (leaf damage), a slightly heavier dose of 0.45 ppm significantly reduced photosynthetic rate without visible injury. The normal photosynthetic rate recovered after one to two hours. Visible injury did not occur until 1.0 ppm for two hours was reached. The photosynthetic rate (measured as CO_2 uptake) was reduced from 60% of normal at the lower dosages to 30% of normal at the higher dosage.

Bennett and Hill⁽⁵³⁾ found that two-hour exposures of barley and alfalfa to increasing concentrations of SO_2 between 0.2 and 1.0 ppm progressively increased apparent photosynthetic inhibition without causing visible injury. Siji and Swanson⁽⁵⁶⁾ exposed corn, grown in hydroponic solution, to one-hour exposures of 1.0 and 3.0 ppm SO_2 and observed 13% and 60% reductions in apparent photosynthesis and no visible injury. Bell and Clough⁽⁵⁷⁾ reported a significant reduction in yield, number of leaves and tillers, and total leaf area in Lolium perenne (Perennial Ryegrass) without visible injury when exposed to either 0.067 or 0.12 ppm SO_2 throughout the entire growing season. Bleasdale⁽⁵⁸⁾ found analogous responses when exposing Lolium perenne to ambient air containing concentrations of SO_2 generally <0.2 ppm for long periods.

Recent field research has been conducted on plots of native mid-grass prairie in southeastern Montana by scientists from the USEPA, Montana State University, University of Montana, and the Natural Resource Ecology Laboratory at Colorado State University. The research has been conducted throughout the growing seasons of 1975 through 1979. Treatments have been applied to the grassland ecosystems for durations of 30 days at median concentrations of 0.02, 0.05, and 0.10 ppm SO_2 with large daily fluctuations. Other sites were continuously fumigated with 0.2, 0.4, and 0.7 ppm of SO_2 during the entire growing seasons of 1975 and 1976. Reports from these experiments show that:

- sulfur dioxide stimulated western wheatgrass leaf growth by increasing the number of leaves per plant, but that, probably through an increase in physiological activity, the leaves senesced more rapidly;

- sulfur dioxide treatments did not significantly alter the net production, the growth rates, the net assimilation rates, nor the leaf area ratios of western wheatgrass or the entire community;
- the effects of SO_2 on leaf growth and the nitrogen:sulfur ratios in plant material, indicated possible sulfur deficiency in the grasslands studied.⁽⁴⁰⁾

The effect of SO_2 on photosynthesis is not always inhibitory. A number of studies have found an apparent stimulation of photosynthesis at low levels of exposure. Thomas and Hill⁽⁵⁹⁾ found the photosynthetic rate in alfalfa to increase slightly in response to SO_2 fumigation of 0.24 ppm for 3 days, 0.19 ppm for 11 days, and 0.14 ppm for 39 days. Katz et al.⁽⁶⁰⁾ found SO_2 exposures of 0.16 to 0.18 ppm caused an apparent increase of photosynthesis in alfalfa. Thomas et al.⁽⁶¹⁾ observed an increase of apparent photosynthesis in alfalfa grown in sulfur deficient soil at 0.1 ppm SO_2 . However, at the same concentration, they found photosynthetic inhibition in plants grown in sulfur-adequate soil. Muller et al.⁽⁶²⁾ found SO_2 levels above 0.1 ppm inhibited photosynthesis in field-fumigated soybeans whereas SO_2 levels below 0.1 ppm stimulated photosynthesis. In a six-week laboratory fumigation of the sensitive perennial grass Oryzopsis hymenoides, Ferenbaugh⁽³⁵⁾ observed an increase in yield of 19% and 21% at SO_2 fumigation levels of 0.03 and 0.06 ppm, respectively. Ziegler⁽⁴⁴⁾ reports a 40% increase in net photosynthesis at an SO_3 concentration of 0.25 M.

The fertilizing effect of sulfur, an important plant nutrient, by SO_2 exposure is not the only explanation for the observed increases in productivity at low levels of SO_2 exposure. Libera et al.⁽⁶³⁾ reported that photoreduction of NADP to NADPH in the Hill-reaction was stimulated by the presence of SO_3 at 0.25 to 3.0 M concentrations in isolated spinach chloroplasts. Ziegler and Libera⁽⁶⁴⁾ further examined this physiological stimulation of photosynthesis. Their findings suggest that SO_3 is oxidized, forming HSO_3 , which acts as an additional electron acceptor in Photosystem I, thus being reduced to SO_3 . An additional electron acceptor might be particularly advantageous at high photosynthetic rates where electron acceptors would more likely be limiting. At increased SO_3 levels the benefits of an additional electron acceptor are

outweighed by the competitive inhibition of ribulose -1, 5-diphosphate carboxylase (RuDP-carboxylase)⁽⁴⁴⁾ in C-3 and C-4 plants and by the competitive inhibition of phosphoenolpyruvate carboxylase (PEP-carboxylase)⁽⁶⁵⁾ and inhibition of malate dehydrogenase⁽⁶⁶⁾ in C-4 plants by SO_3 ions.

From these studies it is apparent that physiological injury does occur. Even the enhancement of plant process rate appears to take its toll through early leaf senescence. Normally, concentrations exceeding 0.15 ppm are sufficient to induce measurable subtle injury even for short-term exposures. Sprugel et al.⁽⁶⁷⁾ report even lower threshold levels in soybean plants. SO_2 has been reported to affect not only photosynthesis but also respiration. The cumulative effect of altering these processes would reduce yield.

The physiological and biochemical investigations of SO_2 effects on photosynthesis reveal a rather consistent pattern of response to increasing SO_2 concentration from low levels. Above SO_2 concentrations of about 0.01 ppm, which is considered "normal" air,^(44,68) there is a stimulation of net photosynthesis.^(44,61,63,69) Apparently above SO_2 exposure levels of about 0.1 to 0.2 ppm, the detrimental photosynthetic effects of SO_3 outweigh its stimulation effect.^(35,61,62,63,64,69,70) This upper threshold also depends on factors such as the plant species, age,⁽⁴⁴⁾ and growth rate.

Nitrogen Oxides. Air pollution-related nitrogen oxides-- NO_x --encompass nitrous oxide (N_2O), nitric oxide (NO), and nitrogen dioxide (NO_2).

Plants readily absorb NO_2 because it is highly water-soluble. Uptake is enhanced by temperature increases, low CO_2 concentrations, and high humidity.^(71,72)

In the atmosphere, nitrogen oxides have a relatively short residence time of approximately five days.⁽⁷⁾ The N_2O may react with ozone to produce NO_2 . On the other hand, partly oxidized hydrocarbons are unstable and may react with NO to produce NO_2 and ozone.⁽⁷³⁾

In oats and alfalfa, NO and NO_2 levels below 0.6 ppm for 45 to 90 min inhibited apparent photosynthesis.⁽⁷⁴⁾ Growth suppression and leaf distortion occurred at 0.5 ppm over several weeks while visible injury was not noticed until concentrations exceeded 50 ppm over 8 hours, 150 ppm over 4 hours, or

250 ppm over 1 hour. Taylor and Eaton,⁽⁷⁵⁾ MacLean et al.,⁽⁷⁶⁾ and Mudd⁽⁷⁷⁾ found that NO_2 had only a slight effect on transpiration rate and stomatal diffusion resistance.

When NO_2 enters the leaf it reacts with the aqueous medium bathing the mesophyll cells and forms a stoichiometric mixture of nitrous and nitric acids.⁽⁷⁸⁾ When the concentrations of these acids exceed a given threshold, injury occurs. The biochemical effects include enzyme inactivation, chlorophyll impairment, increased amino acid synthesis, and decreased organic acid synthesis.⁽⁷⁸⁾

NO_2 injury manifests itself similarly to SO_2 injury.⁽⁷⁸⁻⁸²⁾ However, the dosages required to produce degrees of injury similar to SO_2 require concentrations of NO_2 approximately three times greater than for SO_2 .⁽⁸⁰⁾ Middleton et al.⁽⁸³⁾ found three to four times as much NO_2 was required to produce the same degree of injury as that produced by SO_2 in pinto beans. Van Haut and Stratman⁽⁸⁴⁾ fumigated 60 plant species with a 1:1 mixture of nitrogen oxide (NO) and NO_2 and compared the degree of acute leaf injury to that caused by SO_2 . They found similar injury for the two groups of pollutants but NO_2 was 1.2 to 5 times less toxic. The incipient visible injury (~5% necrosis) threshold concentration for short-term exposures listed by Heck and Brandt⁽⁸⁵⁾ indicate that the threshold concentrations are approximately three times higher for NO_2 at all five exposure durations up to eight hours. Although concentrations of NO_2 seldom reach the injury threshold when acting alone, White et al.⁽⁸⁶⁾ observed a synergistic effect on the apparent photosynthesis of alfalfa when combined with SO_2 . They reported that when alfalfa was exposed to two-hour doses of 0.25 ppm of SO_2 or NO_2 the apparent photosynthesis rate was reduced only 2% to 3% by SO_2 , and NO_2 caused no reduction. However, a fumigation of a mixture of the two pollutants resulted in a 9% to 15% inhibition of apparent photosynthesis.⁽⁸⁷⁾ Tingey et al.⁽⁸⁸⁾ reported that below 2 ppm NO_2 or 0.5 ppm SO_2 no leaf injury occurred, but plants exposed to mixtures of 0.05 to 0.25 ppm of both gases were injured, indicating a synergistic effect.

Hill et al.⁽¹⁰⁾ in fumigation experiments on 87 native cold desert species failed to observe synergistic effects using mixtures with as much as 28% NO_2 . However, at the relatively high exposure concentrations they were using (0.5,

1, 2, 4, 6, and 10 ppm) NO_2 probably had a rather small contributing effect, as suggested by White et al.⁽⁸⁹⁾ who showed the contributing effect of NO_2 becoming progressively less with increasing concentrations of SO_2 until a negligible contribution existed at 0.5 ppm SO_2 .

Effects on alfalfa of SO_2 alone and in combination with O_3 and NO_2 with 1-hour doses of <0.5 ppm are listed below:

- Alfalfa 0.15 ppm SO_2 inhibits photosynthesis, percent not given⁽⁸⁹⁾
0.15 ppm NO_x synergistic effects
- Alfalfa 0.15 ppm SO_2 greater than additive inhibition (7%)⁽⁹⁰⁾
0.15 ppm NO_2
- Alfalfa 0.30 ppm SO_2 additive inhibition of photosynthesis⁽⁹⁰⁾
0.10 ppm O_3
- Two-hour exposure of $\text{NO}_2 + \text{SO}_2$ @ 0.15 ppm caused 7% reduction in apparent photosyntheses⁽⁸⁹⁾
- Four-hour exposure of 0.10 ppm SO_2 caused 24% leaf injury⁽⁹¹⁾
0.10 ppm O_3
- Douglas Fir <0.01 ppm SO_2 growth abnormalities
0.01 ppm NO_2 needle loss
0.07 ppm HF tissue loss
0.05 ppm O_3
4 month average during growing season⁽⁹²⁾

In summary, nitrous oxides are significant pollutants in themselves and contribute considerably to the formation of other pollutants by participation in photochemical reactions. The gross effects of acute NO_2 exposures on metabolism, growth, and yield of crop plants, population changes in natural plant communities, and the importance of soils and vegetation canopies as sinks for the removal of NO_2 are not well understood.^(81,82) NO_2 can be phototoxic at high levels, but exposure, dose, and response information is scarce.⁽⁹³⁾

Hydrocarbons. Hydrocarbons are of concern due to possible accumulative effects within the food chain. Accumulation to toxic levels varies by

species,⁽⁹⁴⁾ but it appears that hydrocarbons can react with enzymes and may also behave as plant hormones. Other hydrocarbon complexes can damage membrane permeability.⁽⁹⁵⁾

After reviewing the literature on hydrocarbon effects on plants, the National Air Pollution Control Administration⁽⁹⁶⁾ reported that ethylene (C_2H_4) is the only hydrocarbon that should have adverse effects on vegetation at ambient concentrations of one ppm or less. The hydrocarbon gases closest in effect to ethylene are acetylene and propylene, but concentrations of at least 60 to 500 times that of ethylene are required to produce adverse effects.⁽⁹⁶⁾

Atmospheric ethylene is degraded by three mechanisms: ozone oxidation, a light-dependent reaction with NO_2 , and uptake by soil microflora.⁽⁹⁷⁾

Unlike most air pollutants, ethylene does not directly cause destruction of plant tissues.⁽⁹⁸⁾ Its primary effect appears to be one of growth regulation. Some of the more important growth-regulating responses caused by ethylene are inhibition of shoot and root elongation, hastening of fruit ripening, epinasty of leaves, inhibition of leaf expansion, inhibition of flowering, and increased senescence and abscission of leaves.⁽⁹⁹⁾ Ethylene is, in fact, a natural physiological product of plants. Its production in various plant parts is generally observed to increase during the latter stages of maturation or aging in these parts.

At one ppb over 24-hour dose duration, marigolds were injured.⁽⁹³⁾ Chronic effects are distortion of growth, epinasty, chlorosis, necrosis, leaf and bud abscission, and stimulation of lateral buds and shoot.⁽¹⁰⁰⁾ Ethylene effects have also been described as growth inhibition, loss of geotropic sensitivity, leaf drop, and development of abnormal growths.⁽⁷⁾

Although ethylene most likely comes into contact with receptive plant tissues via the stomata, it is not metabolized or taken up by plants.⁽⁹⁹⁾ Hansen⁽¹⁰¹⁾ found that if levels of ethylene surrounding plant material are monitored, they are never observed to decrease. Consequently, after a short period of time, <24 hours, the internal leaf and atmospheric concentration of

ethylene reach equilibrium. Therefore, a daily average projected ethylene concentration probably adequately represents daily average internal leaf concentration.

Burg⁽¹⁰²⁾ suggests that ethylene inhibits elongation in stems and roots by inducing cell-wall microfibril deposition which allows for greater radial expansion and inhibits longitudinal expansion of the cells.

Ethylene apparently reduces leaf expansion by inhibiting cell division.⁽¹⁰³⁾ Middleton et al.⁽⁸³⁾ found that concentrations as low as 0.05 ppm caused abnormal growth of marigold and 0.1 ppm caused abnormal leaves in tomato.

Flowering is apparently one of the plant processes most sensitive to ethylene exposure. Abeles and Heggestad⁽⁹⁹⁾ reported the number of Cutler soybean flowers was reduced by 91% in response to fumigation with ethylene at 0.025 ppm for 50 days. They also reported that the number of male cucumber flowers was reduced by 83% by the same ethylene concentration for 46 days. Heck et al.⁽¹⁰⁴⁾ reported that while fumigating four cotton plants with 0.6 ppm ethylene for three months, only one flower was observed, whereas for the same period 13 flowers were observed on the four central plants. Their examination of the effect of ethylene on flower production, plant height, leaf area, and leaf abscission in cotton indicates inhibition of flower production to be the most dramatic response.

Epinasty in plants also appears to be quite sensitive to ethylene exposure. Epinasty occurred in sensitive plants after a 3-hour exposure to a 3 ppm ethylene concentration and after a 24-hour exposure to a 0.3 ppm ethylene concentration.⁽⁹⁶⁾ Exposure to as little as 0.001 ppm for 20 hours caused epinasty in the very sensitive African marigold.⁽⁹⁶⁾

Leaf senescence is also accelerated by ethylene exposure. Increased chlorophyllase activity, believed to play a role in chlorophyll degradation, was observed in response to ethylene exposure.⁽¹⁰⁵⁾ Protein and RNA levels in leaves have been observed to diminish after ethylene exposure.⁽¹⁰⁵⁾ In addition, leaf abscission has been found to be directly coupled to increased leaf senescence.⁽⁹⁷⁾

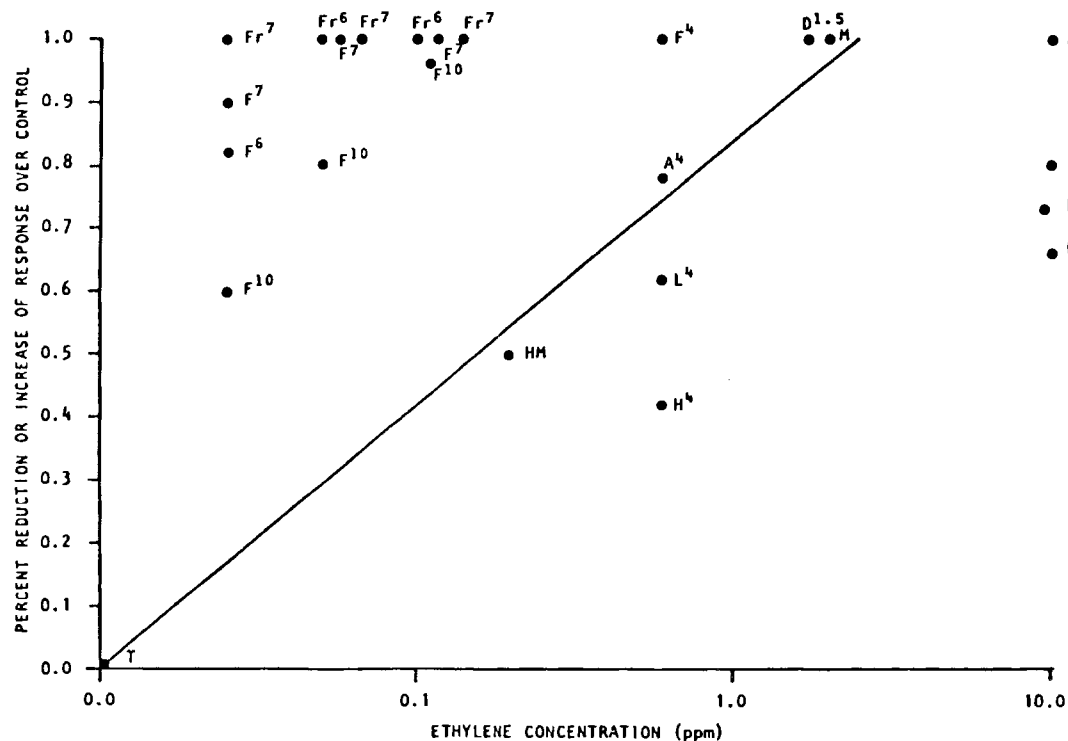
The data on leaf senescence suggest that the ability of ethylene to accelerate degradation is indirect.⁽¹⁰⁵⁾ Ethylene appears to regulate some master reaction, such as control of auxin levels, which in turn regulates the juvenility of plant tissue.⁽¹⁰⁵⁾

Even though ethylene causes a multiplicity of effects in plants, there is a feeling that rather uniform doses produce threshold, half-maximal, and maximal responses for numerous different effects. Using results reported for a number of ethylene fumigation studies, Burg⁽¹⁰²⁾ summarizes threshold, half-maximal, and maximal response ethylene concentration levels for nine different plant responses. His reported levels show this uniformity and suggest that the threshold, half-maximal, and maximal responses occur rather consistently around 0.01, 0.2, and 2 ppm, respectively. Abeles et al.⁽⁹⁷⁾ states that the threshold and half-maximal response ethylene concentration levels for shoot elongation are 0.01 and 0.1 ppm, respectively. However, he indicates that saturation (maximal) response occurs at 10 ppm. These observations suggest a linearly increasing plant response with the increasing log of ethylene concentration. Figure 9.2 shows the results of a number of long-term investigations on plant response to ethylene fumigation. Burg's⁽¹⁰²⁾ threshold, half-maximal, and maximal response concentrations are also plotted here. These observed long-term responses seem fairly compatible with Burg's⁽¹⁰²⁾ response levels.

Carbon Monoxide. Plants will not be affected by carbon monoxide since they do not remove CO from the air. The dose required to cause plant injury is extremely high.⁽⁹⁾

Particulates. Particulate pollution is unique in several ways. Its effect is very local due to a low dispersion rate (high rate of deposition) directly related to particulate sizes.

Because particulates are suspended solids rather than atmospheric gases, they are often discussed in terms of heavy metals emitted during combustion or in terms of dust-suspended solids with varying diameters. To date, the data base from which to draw specific conclusions is very limited. Little data is



Hypothesized General Response Concentrations (Burg 1968)

- T - threshold response
- HM - half-maximal response
- M - maximal response (assumed to result in complete inhibition)
- - line visually fitted to T, HM, and M

Results of Abeles and Heggestad (1973)

- F10** - flower production in Dwarf Bolero Marigold
- F7 - flower production in Cutler Soybean
- Fr7 - fruit production in Cutler Soybean
- Fr6 - fruit production in Red Kidney Bean

Results from Cotton Fumigation (Heck et al. 1961)

- A⁴ - leaf abscission
- F⁴ - flower production
- H⁴ - plant height
- L⁴ - leaf area

Results of Heck and Pires (1962a)

- A¹ - cowpea leaf abscission
- Ha¹ - cowpea plant height
- Hb¹ - soybean plant height
- L¹ - corn leaf length

Results of Heck and Pires (1962b)

- D1.5 - cowpea plant death
- L1.5 - *Avena sativa* leaf length

** exposure time in weeks

FIGURE 9.2. Various Plant Responses to Long-Term Ethylene Exposure

available on the delayed effects on plants and effects on soil.⁽¹⁰⁶⁾ Not only has research been sparse and inconsistent, but toxicity indices are of little use due to the multitude of unique plant-soil combinations.⁽¹⁰⁷⁾

In general, metal particulates that gain entry via stomates remain biologically inert, whereas metals entering via root uptake can cause immediate phytotoxicity. Accumulation to toxic levels is also species-specific.⁽⁹⁴⁾ Although accumulator plants may have developed a mechanism for coping with potential toxic concentrations such an accumulation may have deleterious effects on the ecosystem.⁽¹⁰⁸⁾

Heavy metal particulates may cause visible lesions or physiological alterations. Physiological alterations in plants can have delayed but long-term effects on the ecosystem, especially as soil chemistry is altered.⁽¹⁰⁶⁾

Dust particulates affect plants differently depending upon the size of the particulate. The finer sizes tend to enter stomates and clog physiological mechanisms, whereas the larger particles remain external, possibly reducing photosynthetic utilization of sunlight. If rainfall dissolves chemical constituents of the dust particle, further damage can occur.

Other. Ozone, NO_x , sulfur, carbon, hydrocarbons, and related acids contribute to photochemical smog. The sun's ultraviolet rays are naturally converted by high altitude stratosphere ozone and therefore do not reach the earth. Lower energy ultraviolet rays, however, do filter through and break apart the NO_2 molecule producing nitric oxide (NO) and oxygen atoms (O). The oxygen atoms combine with molecular oxygen to produce ozone which reacts with NO producing NO_2 and O_2 . Yet a small amount of ozone becomes established in the lower atmosphere. In addition, hydrocarbons in smog indirectly provide a way for newly formed NO to be re-oxidized to NO_2 without using ozone, thereby allowing ozone accumulation. Peroxyacyl nitrate (PAN) is a potent eye irritant and a plant irritant causing chlorosis.⁽⁷³⁾ PAN can be formed from a reaction of most hydrocarbons with ozone. Also, nitric oxide strips an oxygen atom from a hydrocarbon, which in return reacts with O_2 and NO_2 to form PAN.

PAN-induced injury is dependent on the age of leaves⁽¹⁰⁹⁾ and such environmental factors as sunlight.⁽¹¹⁰⁾

Another pollution factor in photochemical pollution is that SO_2 and O_3 mixtures, and SO_2 and NO_2 mixtures are known to have synergistic effects on plants.

9.2.4 Fauna

Sulfur Dioxide

SO_2 exposure may affect forage quality. A reduction in crude protein was noted with increasing SO_2 concentrations after two years of fumigation. Crude protein content decreased from 10% to 8% after a second year of exposure to very low levels of SO_2 . Herbivores will be affected by secondary (food chain or habitat change) impacts.

It is possible that animals with more mucosal tissues relative to their body size would be more sensitive to exposure. Chronic exposure over several months resulting in irreversible pulmonary dysfunction in dogs occurs at $13,000 \text{ gm}^{-3}$. At 500 gm^{-3} , pulmonary problems which have been observed are reversible.⁽¹¹¹⁾ Some insects are adversely affected at low levels of SO_2 , but no threshold has been identified.⁽¹¹²⁾ Table 9.3 summarizes current knowledge of SO_2 effects on animals.

Nitrogen Oxides

Possible effects upon guinea pigs have been noted during exposure for several days at levels of about 1000 gm^{-3} .⁽¹¹³⁾ More definitive effects occur only above 2000 gm^{-3} over several hours or 1000 gm^{-3} over several months. Table 9.4 summarizes current knowledge of NO_x effects on animals.

Carbon Monoxide

The lowest exposure producing structural changes to the heart and brain of animals is 50 ppm (58 gm^{-3}). This level is still far above expected pollution levels.⁽¹¹⁴⁾

Hydrocarbons

Derivatives of aliphatic and alicyclic hydrocarbons can cause biologically reactive effects at 500 ppm. The aromatic hydrocarbons are both biochemically

TABLE 9.3. Summary of Toxicological Experiments with Sulfur Dioxide (SO₂)(a)

Species	Concentration (10 ⁵ µg/m ³)	Duration	Effects
Monkey	<0.034	78 weeks	None
Donkey	<0.078 <0.78		None Impaired bronchial clearance
Dog	0.13	21 hr/day for 620 days	None
Monkey	0.13	78 weeks	None
Guinea Pig	<0.13	22 hr/day for 365 days	None
Dog	0.13	21 hr/day for 225 days	Increased pulmonary resistance
Rat	0.026 to 0.079	12 hr/day for 4 months	None
Mouse	0.18 to 0.26	7 days	Increased sensitivity to pneumonia infection
Rabbit	0.26	3 to 10 days	Increased S-sulfonate clearance
Mouse	0.26	Up to 72 hours	Lesions in respiratory tract
Rat	0.26	6 hr/day, 5 days/week, for 113 days	None
	2.6	6 hr/day, 5 days/week, for 22 days	40% mortality
	~15	6 hr/day, 5 days/week, for 12 days	~90% mortality
Guinea Pig	0.26	6 hour/day for 20 days	None
Cat	0.52		Increase in pulmonary flow resistance
Rabbit	~0.52	14 and 62 hours	Formatin of S-sulfonate
Mouse	13	5 min/day, 5 days/week for 300 days	Accelerated onset of neoplasia
Hamster	14	3 hr/day for 75 days	Increased pulmonary infection
Dog	13 to 14	2 hr/2 times/week for 4 to 5 months	Change in goblet cells of bronchi and bronchioles

(a) Data extracted from summary of Colluci(111) and presented in order of increasing concentration, except where there is more than one entry for a single experiment.

TABLE 9.3. (Contd)

Species	Concentration ($10^5 \mu\text{g}/\text{m}^3$)	Duration	Effects
Rat	13 to 78		Change in goblet cell release
	26	Up to 6 weeks	None
	52	Up to 6 weeks	Bronchial damage
	104	Up to 6 weeks	Death within 22 days
Rat	78	6 hr/day for 10 days	Increased acid phosphatase activity
Rat	78	2 hours	Gastric inhibition
Mouse	≤ 78	10 exposures of 10 min with 3 or 7 min recovery between exposures	Initial decrease in respiratory rate, then progressive return to preexposure rate; desensitization to successive exposure
Mouse	Various		Sensitized mice to pneumonia infection

TABLE 9.4. Summary of Toxicological Experiments with Sulfur Dioxide (NO_x)(a)

Species	Concentration ($10^5 \mu\text{g}/\text{m}^3$)	Duration	Effects
<u>Acute</u>			
Guinea Pig	0.10 to 0.20	4 to 24 hr/day for up to 14 days	Elevated protein in urine
Guinea Pig	0.04	Up to 21 days	Increased average area per alveolar wall cell
Mouse	0.02 to 0.30	Up to 17 hours	Impaired bacterial defense
Monkey	0.2 to 1.0	2 hours	Decreased tidal volume, progressive histopathological damage
Rat	0.30 to 0.34	48 hours	Increase in Type II pneumocytes
Rabbit	0.16 to 1.2	3 hours	Impaired bacterial defense at all levels of exposure
Hamster	0.60 to 0.70	7 to 10 days	Bronchiolitic lesions

(a) Data extracted from summary of Ziskind and Hausknecht⁽¹¹³⁾ and presented in order of increasing concentration, except where there is more than one entry for a single experiment.

TABLE 9.4. (Contd)

Species	Concentration ($10^5 \mu\text{g}/\text{m}^3$)	Duration	Effects
<u>Chronic</u>			
Mouse	0.01	Up to 12 months	Reduction of functional lung tissue
Monkey	0.02	493 days	Slight to moderate emphysema
Monkey	0.04	14 months	Hypertrophy of bronchiolar epithelium in bronchiole
Rat	0.02	14 months	Marginal changes in epithelium
Guinea Pig	0.02	6 months	Higher mortality
Rat	~0.06	9 months	Decrease in lung compliance
Rat	0.04	Lifetime	"Emphysema-like" injury suggested
Rat	0.04	Up to 360 days	Increase in number of cells preparing to divide
	0.34	Up to 7 days	
Rat	0.12	6 weeks	Interstitial edema, vascular congestion
Rat	0.20	90 days	Decreased body size
Rat	0.30	90 days	Decreased body size
Mouse	~0.80	Up to 8 weeks	Epithelial damage near terminal bronchioles
Hamster	0.9 to 1.1	10 weeks	Respiratory rate increased, hyperplasia and hypertrophy in terminal and respiratory bronchioles

and biologically active, and are also more irritating. At levels of 25 ppm, systematic injury can result from the inhalation of vapors or aromatic compounds.

Other

In general, animal effects are very closely related to photochemical smog. However, some data is available on specific aldehydes. At a level of 0.06 ppm (70 gm^{-3}) eyes are irritated. A level of 2 ppm (2460 gm^{-3}) has been found to double the total expiratory resistance of guinea pigs.⁽⁹⁶⁾

9.2.5 Wildlife

Most of the area affected by shale oil mining embodies a unique combination of natural and cultural conditions that promote good upland habitat, which is ecologically fragile. Desert floras and the associated fauna are of relatively recent origin.⁽¹¹⁵⁾ Existing as they do in water scarce regions, these formations are especially responsive to perturbations in rainfall regimes. They are, therefore, particularly susceptible to man-induced changes in available water and run-off patterns. The Federal Task Force concedes that mule deer, elk, pronghorn antelope, and sage grouse would decline in numbers due to industrial activity and increased human population.⁽¹¹⁶⁾ Even if revegetation programs were successful, at least 15 years would be required for shrubs and trees to become capable of providing food and cover for mule deer. Restoration of pinyon-juniper areas may take 50 to 100 years.⁽¹¹⁶⁾ Besides altering the habitat, the shale oil industry will also drastically affect water availability and quality.⁽¹¹⁷⁾

Cringan⁽¹¹⁸⁾ and Carlson and Cringan⁽¹¹⁹⁾ have evaluated the impacts of shale oil development during three phases of development (construction, operation, and post-operation) and at three levels of influence (local, intermediate, and extended). Impacts at Tract C-a are expected to be greater than at Tract C-b, due to the use of open-pit mining and the greater production rate expected at Tract C-a.

Greatest impact will occur at the local level of influence. The major factors here will be the operating procedures, disposal of residues, and the actual mine sites. Nearly all species of wildlife are expected to decline because of loss of habitat and from all forms of human activity. Many mammals and bird species will be reduced by 25% to 50% within 3 to 10 years. These reduced populations include mountain lions, bobcats, elk, black bear, skunks, porcupines, coyotes, weasels, badgers, mule deer, wild horses, golden eagles, bald eagles, sage grouse, mourning doves, owls, woodpeckers, turkey vultures, nighthawks, and hummingbirds.

Intermediate impacts will be caused primarily by downstream water pollution. Species inhabiting riparian communities will consequently be most

affected. Mammal species, such as muskrats and raccoons, and waterfowl and shorebirds will undergo moderate to high declines.

Maintenance of riparian habitats might mitigate the above declines as would development of compensatory tracts of lands.

The extended impacts will come primarily from the expected influx of residents due to the available job market. Mammal and avian species will undergo moderate to high declines as a result. New (human) community developments are expected to cause major problems for waterfowl, great blue heron, chukar, and beaver.

A mature, producing oil shale industry would also be detrimental to the local livestock because of reduced water supplies for cattle. However, this livestock reduction, if followed by reduced predator control, might help increase the populations of coyote, bobcat, black bear, mountain lion, and golden eagle.

In all, it seems likely that beaver, mountain lion, elk, and sage grouse would be eliminated from the shale oil region by a mature shale oil industry. It is likely that only beaver and elk would be reestablished after operations cease.

One further aspect of human disturbance in the area deserves mention; that of road-kill of mule deer. Rio Blanco County consistently has a large number of deer-auto collisions and in combination with Garfield County, has often led the state in highway deer-kill. Most of these kills occur along Colorado Highway 13 south of Meeker and Colorado 64 west of Meeker. Both of these highways cut across deer migration routes and lie in a portion of their winter range.⁽¹²⁰⁾ Such accidents pose a danger not only to the animal involved but to the automobile occupants as well.

Mule deer constituted nearly all the road-kills, most of which were mature doe.⁽¹²¹⁾ Between 1968 and 1970, 338 known highway-kills were reported in Rio Blanco County.⁽¹²²⁾ However, a road-strip count of dead deer indicated that 45% of the deer hit by automobiles get far enough away from the highway after being hit that they are neither detected nor reported.⁽¹²³⁾

The monthly kill is primarily a function of the average hourly traffic volume, rather than deer abundance near the highway.⁽¹²⁴⁾ Myers⁽¹²⁵⁾ found that although weekly spotlight counts showed deer were concentrated along the highway between January and April, 40% of the total yearly collisions occurred in October, November, and July. The October deer-auto kill is three times higher than any other month.⁽¹²²⁾ This high October rate results from the combination of the large number of migrating deer and the heavy hunter-traffic volume. Over 50% of the collisions occur on weekend evenings,⁽¹²⁵⁾ with 71% of the collisions occurring at known deer crossings.^(122,123)

The monthly road-kill is also related to the relative ruggedness of the terrain along the roadway.⁽¹²⁴⁾ Myers⁽¹²⁶⁾ found that 6% of the adjacent land was relatively flat, 60% was gently rolling, 20% was moderately rough, and 11% was rough. The vegetation types consisted of 43% sagebrush, 10% pinyon-juniper, and 22% other browse. Most collisions take place at lower elevations, in moderately rough to rough terrain with a high percentage of pinyon-juniper close by.⁽¹²⁶⁾

Removal of brush from highway edges has no significant effect in decreasing the number of accidents.⁽¹²⁶⁾ However, installation of 8-ft fencing reduced deer crossings by 82% and reduced deer kill 61% on Colorado Highway 82.⁽¹²⁷⁾ One-way gates in conjunction with 8-ft fences were 96.2% effective in one-way passages allowing deer to escape the highway right-of-way.^(128,129)

9.2.6 Mule Deer Harvest

For almost 100 years the mule deer in the area of the White River drainage have been a major source of protein food and recreation for local citizens. In addition, for some 50 years these residents have enjoyed a significant income from outsiders through sale of pass-rights, guiding services, food and lodging, retail sales of hunting supplies, and automotive supplies. Statewide comparisons of deer-hunter success ratios by hunting units show that the Basin units have been consistently among the highest in Colorado for the past 20 years.^(4,130) These trends and figures should continue with shale oil development, providing industrial developments and other related activities do not destroy the deer winter habitat.

9.2.7 Agriculture

The proposed developments and the attendant water supply augmentation would provide water for industrial, municipal, and domestic use in connection with anticipated exploitation of local coal and shale oil reserves. Local agriculture could be stabilized and enhanced through provision of a more firm water supply for irrigation of an estimated 10,500 acres of land presently providing a surplus crop of wheat to non-surplus feed crops (such as alfalfa) for livestock. Regulated streamflow and reservoir levels would enhance recreation, fisheries, and maintenance of wildlife.⁽¹³⁰⁾

9.3 REFERENCES FOR CHAPTER 9

1. Colony Development Operation (CDO). 1974. An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado. Vol. I. 349 pp.
2. Marr, J. C., C. Mutel and D. Buckner. 1973. Ecological Study of a Possible Oil Products Pipeline Corridor in Western Colorado and Eastern Utah. Second draft. University of Colorado, Boulder, Colorado.
3. Rio Blanco Oil Shale Project (RBOSP). 1976a. Progress Reports 7 and 9. Gulf Oil Corporation-Standard Oil Company (Indiana).
4. Rio Blanco Oil Shale Project (RBOSP). 1977. Final Experimental Baseline Report for Tract C-a and Vicinity. Books 1 and 2. Gulf Oil Corporation-Standard Oil Company (Indiana).
5. Eckert, R. E., Jr., and R. E. Kinsinger. 1960. "Effects of Halogeton glomeratus Leachate on Chemicals and Physical Characteristics of Soils." Ecology 41:764-772.
6. Kinsinger, F. E., and R. E. Eckert, Jr. 1961. "Emergence and Growth of Annual and Perennial Grasses and Forbs in Soils Altered by Halogeton Leachate." J. Range Manage. 14:194-197.
7. Carrier, R. 1977. Plant Interactions. In Braumstein, H., E. Copenhaver, and H. Pfuderer (eds.). Environmental Health and Control Aspects of Coal Conversion: An Information Overview, Vol. 2. Oak Ridge National Laboratory, Oakridge, Tennessee. ORNL/EIS-95.
8. Heck, W. 1973. Air Pollution and the Future of Agricultural Production. In Naegele, J. "Air Pollution Damage to Vegetation." Advances of Chemistry 122:118-130. American Chemical Society.

9. Dvorak, A. 1978. Impacts of Coal-Fired Power Plants on Fish, Wildlife, and Their Habitats. U.S. Fish and Wildlife Service. FWS/OBS-78/29.
10. Hill, A. C., S. Hill, C. Lamb, and T. W. Barrett. 1974. "Sensitivity of Native Desert Vegetation to SO₂ and to SO₂ and NO₂ Combined." J. Air Poll. Control Assoc. 24:153-157.
11. Gaud, W. S. 1979. Environmental Impact Studies of the Navajo and Kaiparowits Power Plants. Final Report, June 1, 1975-May 31, 1976. Northern Arizona University.
12. Jacobsen, J. S., and A. C. Hill. 1970. Recognition of Air Pollution Injury to Vegetation: A Pictorial Atlas. Air Pollution Control Association, Pittsburgh, Pennsylvania.
13. Davis, D. D., and R. G. Wilhour. 1976. Susceptibility of Woody Plants to Sulfur Dioxide and Photochemical Oxidants: A Literature Review. Corvallis Environmental Resource Laboratory, Corvallis, Oregon. Ecological Resource Service. 71 pp.
14. Benedict, H. M., and W. H. Breen. 1955. "The Use of Weeds as a Means of Evaluating Vegetation Damage Caused by Air Pollution." Proc. Nat. Air Poll. Symp. 3:177.
15. Davis, D. D., and H. D. Gerhold. 1976. "Selection of Trees for Tolerance of Air Pollutants." Better Trees for Metropolitan Landscapes Symposium Proceedings USDE-Forest Service Gen. Tech. Rep. NE-22:61-66
16. Dreisinger, B. R., and P. C. McGovern. 1970. Monitoring Atmospheric Sulfur Dioxide and Correlating Its Effects on Crops and Forests in the Sudbury Area, p. 11-28. In Linzon, S. N. (ed.). Impact of Air Pollution on Vegetation Conference, Ontario Dept. of Energy and Resource Management, Toronto. 122 pp.
17. Guderian, R. 1977. Air Pollution: Phytotoxicity of Acidic Gases and Its Significance in Air Pollution Control. Springer-Verlag, Berlin. 127 pp.
18. Krupa, S. U. 1976. Impact of Air Pollutants on Terrestrial Vegetation, p. 43-96. In Wood, F. A. (ed.). The Role of Disease in Environmental and Ecological Management of National Parks, Vol. 1. Ann. Rep. to Nat. Park Serv., U.S. Dept. of Int. 221 pp.
19. Linzon, S. N. 1978. Effects of Airborne Sulfur Pollutants on Plants, p. 109-162. In Nriagu, J. O. (ed.). Sulfur in the Environment: Part II Ecological Impacts. John Wiley & Sons. 816 pp.
20. Skelly, J. M., and R. C. Lambe. 1974. The Diagnosis of Air Pollution Damage to Plants. Va. Coop. Ext. Serv. No. 568. 16 pp.

21. U.S. Environmental Protection Agency. 1973. Effects of Sulfur Dioxides in the Atmosphere on Vegetation. Report No. EPA-R3-73-030. Nat. Environ. Res. Centr. USEPA, Raleigh, North Carolina. 43 pp.
22. U.S. Environmental Protection Agency. 1976. Diagnosing Vegetation Injury Caused by Air Pollution. Hicks, D. R. (ed.). EPA Cont. Pub. No. 68-02-1344.
23. Karnowsky, D. F. 1977. "Evidence for Genetic Control of Response to Sulfur Dioxide and Ozone in Populus tremuloides". Can. J. For. Res. 7:437-440.
24. Katz, M. 1949. "Sulfur Dioxide in the Atmosphere and Its Relation to Plant Life." Ind. Eng. Chem. 41:2450-2465.
25. Thomas, M. D., and R. H. Hendricks. 1951. Effect of Air Pollution on Plants, p. 233-278. In Air Pollution. World Health Organization Monograph Ser. No. 46, New York, Columbia University Press.
26. Bennett, J. H., A. C. Hill and D. Gates. 1973. "A Model for Gaseous Pollutant Sorption by Leaves." J. Air Poll. Control Assoc. 23:957-962.
27. Steinhardt, I., G. G. Fox and W. E. Marlatt. 1976. "Modeling the Uptake of SO₂ by Vegetation." USDA For. Serv. Ga. Tech. Rep. RM32:209-213.
28. Mansfield, T A., and O. M. Majernik. 1970. "Can Stomata Play a Part in Protecting Plants Against Air Pollution?" Environ. Poll. 1:149-154.
29. Buron, A., and G. Cornic. 1973. "Effect of Sulfur Dioxide on Gas Exchange in White Mustard (Sinopsis alba)." Bull. Soc. Voudoise Sci. Nat. 71:451-461
30. Biscoe, P. V., M. . Unsworth and H. R. Pinckney. 1973. "Effects of Low Concentrations of Sulfur Dioxide on Stomatal Behavior in Vicia faba." New Phytol. 72:1299-1306.
31. Unsworth, M. H., P. V. Biscoe and H. R. Pickney. 1972. "Stomatal Responses to Sulfur Dioxide." Nature 239:458-459.
32. Jensen, K. R., and T. T. Kozłowski. 1975. "Absorption and Translocation of Sulfur Dioxide by Seedlings of Four Forest Tree Species." J. Environ. Qual. 4:379-382.
33. Bonte, J., L. DeCormis and P. Louguet. 1975. "Effect of Sulfur Dioxide Pollution on the Degree of Opening of Pelargonium x hortorum Stomata." C. R. Hebd. Seances Acad. Sci. Series D. 280:2377-2380.
34. Hocking, D., and M. B. Hocking. 1977. "Equilibrium Solubility of Trace Atmospheric Sulphur Dioxide in Water and Its Bearing on Air Pollution Injury to Plants." Environ. Poll. 13:57-64.

35. Ferenbaugh, R. 1979. Effects of Sulfur Dioxide on the Growth and Productivity of the Desert Grass, Oryzopsis hymenoides, Including a Literature Survey of the General Effects of Sulfur Dioxide on Vegetation. In Gaud, W., Environmental Impact Studies of the Navajo and Kaiparowits Power Plants. Environ. Impact Studies, Northern Arizona University, Flagstaff, Arizona.
36. Thomas, M. D., R. H. Hendricks, L. C. Bryner, and G. R. Hill. 1944. "A Study of the Sulfur Metabolism of Wheat, Barley, and Corn Using Radioactive Sulfur." Plant Phys. 19:227-244.
37. Daines, R. H. 1968. Sulfur Dioxide and Plant Response. J. Occupational Medicine 10:516-524.
38. Barrett, T. W., and H. M. Benedict. 1970. Sulfur Dioxide. In Jacobson, J. S., and a. C. Hill (eds.). "Recognition of Air Pollution Injury to Vegetation: A Pictorial Atlas." J. Air Poll. Control Assoc., Pittsburgh, Pennsylvania.
39. Schiff, J. A., and R. C. Hodson. 1973. "The Metabolism of Sulfate." Ann. Rev. Plant Phys. 24:381-414.
40. Heitschmidt, R. K., W. K. Lauenroth and J. L. Dodd. 1978. "Effects of Controlled Levels of Sulfur Dioxide on Western Wheatgrass in a South-eastern Montana Grassland." J. Applied Ecol. 14:859-868.
41. Dodd, J., W. Lauenroth, G. Thor, and M. Coughenhour. 1979. Effects of Chronic Low-Level SO₂ Exposure on Producers and Litter Dynamics, p. 384-477. In Preston, E., and T. Gullett (eds.). The Bioenvironmental Impact of a Coal-Fired Power Plant. EPA-600/3-79-044.
42. Miller, J. E., and P. B. Xerikos. 1979. "Residence Time of Sulfite in SO₂ 'Sensitive and Tolerant' Soybean Cultivars." Environ. Poll. 18:259-264.
43. Kabe, W. 1976. "Effects of Sulfur Dioxide on Terrestrial Vegetation." Ambio. 5:213-218.
44. Ziegler, I. 1975. "The Effect of SO₂ Pollution on Plant Metabolism." Residue Rev. 56:79-105.
45. Malhotra, S. S., and D. Hocking. 1976. "Biochemical and Cytological Effects of Sulfur Dioxide on Plant Metabolism." New Phytol. 76:227-237.
46. O'Gara, P. J. 1922. "Sulfur Dioxide and Fume Problems and Their Solutions." In Fourteenth Semi-Annual Meeting of the American Institute of Chemical Engineers. J. Ind. Eng. Chem. 14:744.

47. Hill, G. R., and M. D. Thomas. 1933. "Influence of Leaf Destruction by Sulfur Dioxide and by Clipping on Yield of Alfalfa." Plant Phys. 8:223-245.
48. Swain, R. E., and A. B. Johnson. 1936. "Effect of Sulfur Dioxide on Wheat Development." Ind. Eng. Chem. 28:42-47.
49. Katz, M., and G. A. Ledingham. 1939. Experiments on Yield of Barley and Alfalfa. In Effect of Sulfur Dioxide on Vegetation. Nat. Res. Council of Canada, Ottawa.
50. Brisley, R. H., C. R. Davis, and J. A. Booth. 1959. "Sulfur Dioxide Fumigation of Cotton with Special Reference to Its Effect on Yield." Agron. J. 51:77-80.
51. Faller, N. 1970. "Effects of Atmospheric SO₂ on Plants." Sulfur Institute J. 6:5-7.
52. Davis, C. R. 1972. "Sulfur Dioxide Fumigation of Soybeans: Effect on Yield." APCA J. 22:964-966.
53. Bennett, J. H., and A. C. Hill. 1973. "Inhibition of Apparent Photosynthesis by Air Pollutants." J. Env. Quality 2(4):526-530.
54. Bennett, J. H., and A.C. Hill. 1973. "Absorption of Gaseous Air Pollutants by a Standardized Plant Canopy." J. Air Poll. Control Assoc. 23:203-206.
55. Thomas, M. D. 1956. "The Invisible Injury Theory of Plant Damage." J. Air Poll. Control Assoc. 5:205-208.
56. Siji, J W., and C. A. Swanson. 1974. "Short-Term Kinetic Studies on the Inhibition of Photosynthesis by Sulfur Dioxide." J. Environ. Qual. 3:103-107.
57. Bell, J. N. B., and W. S. Clough. 1973. "Depression of Yield in Ryegrass Exposed to Sulfur Dioxide." Nature 241:47-49.
58. Bleasdale, J. K. A. 1973. "Effects of Coal-Smoke Pollution Gases on the Growth of Ryegrass (Lolium perenne L.)." Environ. Poll. 5:272-285.
59. Thomas, M. D., and G. R. Hill. 1937. "Relation of Sulfur Dioxide in the Atmosphere to Photosynthesis and Respiration of Alfalfa." Plant Phys. 12:309-383.
60. Katz, M., G. A. Ledingham and A. E. Harris. 1939. Carbon Dioxide Assimilation and Respiration of Alfalfa Under Influence of Sulfur Dioxide. In Effect of Sulfur Dioxide on Vegetation. Natural Resource Council of Canada, Ottawa.

61. Thomas, M. D., R. H. Hendricks, T. R. Collier, and G. R. Hill. 1943. "The Utilization of Sulfate and Sulfur Dioxide for the Sulfur Nutrition of Alfalfa." Plant Phys. 18:345-371.
62. Muller, R. N., J. E. Miller, D. G. Sprugel, and H. J. Smith. 1977. Photosynthetic Response of Field-Grown Soybeans to Fumigations with Sulfur Dioxide. In Radiological and Environ. Res. Division Ann. Rep., Argonne National Laboratory. (ANL-77-65 Part III).
63. Libera, W., H. Ziegler and I. Ziegler. 1973. "Stimulation of Hill-Reaction and CO₂ Fixation in Isolated Spinach chloroplasts by Low Concentrations of SO₃." Planta (Berl.) 109:269-279.
64. Ziegler, I., and W. Libera. 1975. "The Enhancement of CO₂ Fixation in Isolated Chloroplasts by Low Sulfite Concentrations and by Ascorbate." Z. Naturforsch. 30c:634-637.
65. Ziegler, I. 1973. "Effect of Sulfite on Phosphoenolpyruvate Carboxylase and Malate Formation in Extracts of Zea mays." Phytochemistry 12:1027-1030.
66. Ziegler, I. 1974. Malate Dehydrogenase in Zea mays: Properties and Inhibition by Sulfite." Biochem. Biophys. Acta 364:28-37.
67. Sprugel, D. G., J. E. Miller, P. B. Xerikos, and N. J. Smith. 1979. Effects of Chronic Sulfur Dioxide Fumigation on Development Yield and Seed Quality of Field-Brown Soybeans: Summary of 1977 and 1978 Experiments, p. 1-10. In Radiological and Environmental Research Division Annual Report. Ecol. January-December 1978. Argonne National Laboratory, Argonne, Illinois. Prepared for the USDOE Contract W-31-109-Eng-38.
68. Garland, J A., and J. R. Branson. 1976. "The Mixing Height and Mass Balance of SO₂ in the Atmosphere Above Great Britain." Atmos. Environ. 10:353-362.
69. Ziegler, I. 1972. "The Effect of SO₃ on the Activity of Ribulose-1, 5-Diphosphate Carboxylase in Isolated Spinach Chloroplasts." Planta 103:155-163.
70. Malhorta, S. S. 1977. "Effects of Aqueous Sulfur Dioxide on Chlorophyll Destruction in Pinus contorta." New Phytol. 78:101-109.
71. Srivastava, H. S., P. A. Jolliffe and V. C. Runeckles. 1975. "The Effects of Environmental Condition on the Inhibition of Leaf Gas Exchange by NO₂." Canadian J. Bot. 53:475-482.
72. Srivastava, H. S., P. A. Jolliffe and V. C. Runeckles. 1975. "Inhibition of Gas Exchange in Bean Leaves by NO₂." Canadian J. Bot. 53:466-474.

73. Holum, J. R. 1972. Elements of General and Biological Chemistry. John Wiley & Sons, Inc., New York, New York. 578 pp.
74. Hill, A. C., and J. H. Bennett. 1970. "Inhibition of Apparent Photosynthesis by Nitrogen Oxides." Atmos. Environ. 4:341-348.
75. Taylor, O. C., and F. M. Eaton. 1966. "Suppression of Plant Growth by Nitrogen Dioxide." Plant Phys. 41:132-135.
76. MacLean, D. C., D. C. McCune, L. H. Weinstein, R. H. Mandl, and G. N. Woodruff. 1968. "Effects of Acute Hydrogen Fluoride and Nitrogen Dioxide Exposures on Citrus and Ornamental Plants of Central Florida." Environ. Sci. Tech. 2:444-449.
77. Mudd, J. B. 1973. Biochemical Effects of Some Air Pollutants on Plants, p. 31-47. In Naegele, J. A. (ed.). Air Pollution Damage to Vegetation. Adv. in Chem. Ser. 122, American Chemical Society, Washington, D.C.
78. Taylor, O. C., C. R. Thompson, D. T. Tingey, and R. A. Reinert. 1975. Oxides of Nitrogen, p. 122-139. In Mudd, J. B., and T. T. Kozlowski (eds.). Responses of Plants to Air Pollution. Academic Press, New York, New York.
79. National Air Pollution Control Administration (NAPCA). 1971. Air Quality Criteria for Nitrogen Oxides. AP-84. Washington, D.C.: National Air Pollution Control Administration.
80. MacLean, D. C. 1975. "Stickstoffoxide als Phytotoxische Luftverunreinigungen." Staub-Reinhalt. Luft. 35:205-210.
81. Glass, N. R. (ed.). 1978. Environmental Effect of Increased Coal Utilization: Ecological Effects of Gaseous Emissions. EPA-600/7-78-108. USEPA, Government Printing Office, Washington, D.C. 51 pp.
82. Glass, N. R. 1978. Ecological Effects of Atmospheric Deposition. EPA, ORD Decision Series, Energy/Environment EPA-600/9-78-022, October. p. 113-119.
83. Middleton, J. T., E. F. Darley and R. F. Brewer. 1958. "Damage to Vegetation from Polluted Atmospheres." J. Air Poll. Control Assoc. 8:9-15.
84. Van Haut, H. and H. Stratmann. 1961. "Die Analyse von Schwefeldioxydwirkungen auf Pflanzen in Laboratoriumsversuch." Staub 21(2):52-56.
85. Heck, W., and C. Brandt. 1977. Effects on Vegetation. In Stern, A. (ed.). Air Pollution: The Effects of Air Pollution, Vol. 2. Academic Press, New York, New York.

86. White, K. L., A. C. Hill and J. H. Bennett. 1974. "Synergistic Inhibition of Apparent Photosynthesis Rate of Alfalfa by Combinations of Sulfur Dioxide and Nitrogen Dioxide." Environ. Sci. and Tech. 8:574-576.
87. National Air Pollution Control Administration (NAPCA). 1970. Air Quality Criteria for Sulfur Oxides. AP-50. U.S. Dept. of Health, Education and Welfare. Washington, D.C.: National Air Pollution Control Administration.
88. Tingey, D. T., R. A. Reinert, J. A. Dunning, and W. W. Heck. 1971. "Vegetation Injury from the Interaction of Nitrogen Dioxide and Sulfur Dioxide." Phytopathol. 71:1506-1511.
89. White, M. D. 1974. Legal Problems in the Acquisition of Suitable Water Supplies for Oil Shale Operations in Western Colorado. p. 12-21. In Water Resources Problems Related to Mining: Proceedings No. 18.
90. Heagle, A. S. 1973. "Interactions Between Air Pollutants and Plant Parasites." Ann. Rev. Phytopathology 11:365-388.
91. Tingey, D. T., L. Bard and R. W. Field. 1978. The Relative Sensitivity of Selected Plant Species to Several Pollutants, Singly and in Combination. In The Bioenvironmental Impact of a Coal-Fired Power Plant, Third Interim Report, Colstrip, Montana. 521 pp.
92. U.S. Environmental Protection Agency. 1971. Mt. Storm, West Virginia--Gorman, Maryland, and Luke, Maryland--Feyser, West Virginia Air Pollution Abatement Activity. 67 pp.
93. Neagle, J. A. 1974. Effect of Pollution on Plants, p. 83-100. In Sox, N. I. (ed.). Industrial Pollution, Van Nostrand Reinhold Co., New York, New York.
94. Ratsch, H. C. 1971. Heavy-Metal Accumulation in Soil and Vegetation from Shelter Emissions. EPA 660/3-74-012. National Environmental Research Center, Washington, D.C.
95. Auerbach, S. I. 1975. Hearings on Cost and Effects of Chronic Low-Level Environmental Pollution. Testimony presented to the Subcommittee on Environment and Atmosphere, U.S. House of Representatives, 94th Congress First Session, November 12, No. 49, Washington, D.C., U.S. Government Printing Office. pp. 511-537.
96. National Air Pollution Control Administration (NAPCA). 1970. Air Quality Criteria for Hydrocarbons. AP-64. U.S. Department of Health, Education and Welfare. Washington, D.C.: National Air Pollution Control Administration.
97. Abeles, F., L. Craker and G. Leather. 1971. "Abscission: The Phyto-gerontological Effects of Ethylene." Plant Phys. 47:7-9.

98. Crocker, W. 1948. Growth of Plants. Reinhold Publishing Corp., New York, New York. 459 pp.
99. Abeles, F., and H. Heggstad. 1973. "Ethylene: An Urban Air Pollutant." J. Air Poll. Control Assoc. 23:517-521.
100. Brandt, C. S., and W. W. Heck. 1968. Effect of Air Pollutants in Vegetation, p. 401-443. In Stern, A. C. (ed.). Air Pollution, Vol. I, Second Edition., Academic Press, New York, New York.
101. Hansen, E. 1942. "Quantitative Study of Ethylene Production in Relation to Respiration of Pears." Bot. Gaz. 103:543-558.
102. Burg, S. 1968. "Ethylene, Plant Senescence and Abscission." Plant Phys. 43:1503-1511.
103. Burg, S., A. Apelbaum, W. Eisinger, and B. Kang. 1971. "Physiology and Model of Action of Ethylene." Hort. Sci. 6:359.
104. Heck, W., E. Pires and W. Hall. 1961. "The Effects of a Low Ethylene Concentration on the Growth of Cotton." J. Air Poll. Control Assoc. 11:549-556.
105. Abeles, F. 1973. Ethylene in Plant Biology. Academic Press, New York, New York. 301 pp.
106. National Air Pollution Control Administration (NAPCA). 1979. Air Quality Criteria for Particulate Matter and Sulfur Oxides. Vol. III. Welfare Effects. Environmental Protection Agency. Washington, D.C. (second draft).
107. Lagerwerff, J. V. 1967. Heavy-Metal Contamination of Soils. In Agriculture and the Quality of Our Environment. AAAS Publication No. 85. N. C. Brady, Ed. pg. 343-366. Washington, D.C.: American Association for the Advancement of Science.
108. Tyler, G. 1972. "Heavy Metals Pollute Nature, May Reduce Productivity." Ambio 4:52-59.
109. Dugger, W. M., Jr., O. C. Taylor, E. Cardiff, and C. R. Thompson. 1962. "Stomatal Action in Plants Related to Damage from Photochemical Oxidants." Plant Phys. 37:487-491.
110. Taylor, O. C., W. M. Dugger, Jr., E. A. Cardiff, and E. F. Darley. 1961. "Interaction of Light and Atmospheric Photochemical Products (Smog) Within Plants." Nature 192:814-816.

111. Colucci, A. V. 1976. Sulfur Oxides: Current Status of Knowledge. EPRI EA-316. Prepared by Greenfield, Attaway & Tyler, Inc., San Rafael, California, for the Electric Power Research Institute, Palo Alto, California.
112. Lewis, R. A., and S. O. Lefohn. 1976. Bioenvironmental Impact of a Coal-Fired Power Plant. First Interim Report, Colstrip, Montana, December 1974. NTS, Washington, D.C. 117 pp.
113. Ziskind, R., and D. Hausknecht. 1976. Health Effects of Nitrogen Oxides. EPRI 571-1A. Prepared by Science Applications, Inc., El Segundo, California, for the Electric Power Research Institute, Palo Alto, California. 39 pp.
114. National Air Pollution Control Administration (NAPCA). 1970. Air Quality Criteria for Carbon Monoxide. AP-62. U.S. Department of Health, Education and Welfare. Washington, D.C.: National Air Pollution Control Administration.
115. Axelrod, D. I. 1950. Evolution of Desert Vegetation in Western North America. Carnegie Institute, Washington, D.C. Publication No. 590, pp. 215-306.
116. Weaver, G. D. 1973. Environmental Hazards of Oil Shale Development-- Summary Report and Recommendations. Ph.D. thesis, Johns Hopkins University, Baltimore, Maryland. 65 pp.
117. Quale, T. R. 1973. The Colorado Oil Shale and Its Effects on the Mule Deer of the Piceance Creek Basin. Colorado State University, Special Studies Report. 14 pp.
118. Cringan, A. T. 1974. Regional Oil Shale Study. Environmental Impact of Prototype Shale Leases Upon Wildlife in Colorado, Piceance Creek Basin, Rio Blanco and Garfield Counties, Colorado. Thorne Ecological Institute, Boulder, Colorado. 79 pp.
119. Carlson, L. W., and A. T. Cringan. 1975. "Oil Shale Development and Wildlife in Northwestern Colorado." Wildl. Soc. Bull. 3:7-12.
120. Yeager, L. E. (ed.). 1972. Deer-Vehicle Accidents, p. 4-5. In Colorado Game Res. Review 1970-71, Colorado Department of Game, Fish and Parks, Denver, Colorado. 49 pp.
121. Boyd, R. J. 1964. Study of Deer Losses on Colorado Highways, p. 36-41. In Game Res. Rep., Colorado Department of Game, Fish and Parks, Denver 4:1-69.
122. Pojar, T. M. 1971. Deer-Auto Accident Investigations, p. 275-318. In Game Res. Rep., Colorado Department of Game, Fish and Parks, Denver 7:225-366.

123. Boyd, R. J. 1962. Study of Deer Losses on Colorado Highways, p. 93-100. In Quarterly Progress Report Colorado Department of Game and Fish, Denver 10:1-137.
124. Yeager, L. E. (ed.). 1970. Deer-Vehicle Accident, P. 17-19. In Colorado Game Res. Review 1969. Colorado Department of Game, Fish and Parks, Denver. 35 pp.
125. Myers, G. T. 1970. An Investigation of Deer-Auto Accidents, p. 403-437. In Game Res. Rep., Colorado Department of Game, Fish and Parks, Denver 7:287-455.
126. Myers, G. T., and D. F. Reed. 1969. Deer-Vehicle Collisions in Colorado, p. 10. In Fourteenth Trans. Summer Conf. Central Mtns. and Plains Sec. of the Wildlife Soc. 18 pp.
127. Woodward, T. N. 1973. An Evaluation of Deer-Proof Fence Length Required to Prevent Deer Movements on or Across High-Speed Highways, p. 197-202. In Game Res. Rep., Colorado Division of Wildlife, Denver 7:45-275.
128. Reed, D. F. 1973. Investigation of One-Way Deer Structures, p. 171-175. In Game Res. Rep., Colorado Division of Wildlife, Denver 7:45-275.
129. Reed, D. F. 1975. An Evaluation of 8-ft (2.44-m) Fence Length Required to Prevent Movements on or Across High-Speed Highways, p. 315-320. In Game Res. Rep., Colorado Division of Wildlife, Denver 7:191-504.
130. McKean, W. T., and W. T. Burkhard. 1978. Fish and Wildlife Analysis for the Yellow-Jacket Project, July 1975 to January 1978. Prepared for the U.S. Bureau of Reclamation by the Colorado Div. of Wildlife. 543 pp.

10.0 HEALTH AND SAFETY

Most fossil fuels are made up of biologically active compounds which can lead to one or more distinct toxic effects. Oil shale and shale oil liquids are no exception. Accordingly, this area was one focus of study in this assessment. The material in this chapter is drawn almost entirely from work done for this assessment by L. M. Holland.⁽¹⁾ It is presented at greater length in Volume 8.

The data available to establish the potential health effects of a U.S. oil shale industry are meager and cannot yet be used for comparative risk analysis. Historical evidence indicates a carcinogenic potential associated with the crude oils and oil by-products but a relatively low respiratory hazard. This historical experience is drawn largely from foreign industries using geologically different shales and technically different extraction processes.

The biological and health effects of the oil shale industry should be assessed before the industry is developed. Identifying hazards and modes of mitigating them, however, will be difficult because of the complexity both of the potential exposure and of the materials involved. The simple recognition of a toxic effect by a particular process-stream product or one of its sub-mixtures is not useful unless the probability for, and mode of, exposure are considered at the same time. Similarly, it is not enough to consider effects on presumed target organs or tissues without regard to metabolic pathways, potential late effects, and developmental and genetic phenomena.

10.1 DIRECT TOXICITY

Russian studies of the health effects of shale oil reveal the possibility of direct toxicity. According to Veldre and Janes,⁽²⁾ those oils or fractions which originated from low temperature extraction processes or were marginally volatile at low temperature were the least toxic of the materials tested. The most toxic material tested was the diesel oil fraction. Direct toxicity of shale oils could be estimated approximately from the phenol content. In general, crude oils produced by direct coal liquefaction are more toxic than those from shale, and those from shale are more toxic than petroleum crude. In both

acute and chronic toxicity experiments, many of the symptoms described were attributable to disturbances of the central nervous system. Long-term exposure led to a variety of systemic changes including anemia, leukemia, reduction in blood glucose levels, and changes in certain liver and kidney functions.

10.2 SKIN DISEASES

The occupational diseases most often associated with shale oil production have been skin cancer and various benign dermatoses. Skin diseases in oil shale workers were first described in 1922 by Alexander Scott for Scottish workers.^(3,4) Other investigators in the United Kingdom developed experimental evidence of the carcinogenic potency of various shale oil products,⁽⁵⁻⁹⁾ and Bogovski⁽¹⁰⁻¹³⁾ and others^(14,15) in Estonia have studied shale oil carcinogenesis using several in vivo systems.

L. M. Holland summarized some of the Scottish experience in his supporting study for this assessment.⁽¹⁾ He notes that an early and thorough investigation of occupational disease was the study of paraffin workers and oil workers associated with the Scottish oil shale industry performed by Alexander Scott in 1923.⁽⁴⁾ Scott described, in great detail, the various manifestations of skin disease found in oil shale workers and discussed the etiology, anatomical location of lesions and pathology and suggested prophylactic measures. Seven distinct occupational dermatoses were described: 1) Occupational comedones (acne), 2) Folliculitis and follicular dermatitis, 3) Pustular dermatitis, 4) Papular dermatitis, 5) Erythema simplex, 6) Dermatitis erythematosa, and 7) Epithelioma (Paraffin Workers Cancer). Of these papular dermatitis and follicular dermatitis (destruction of hair follicles) were the most common and epithelioma was the most important because of the life-threatening potential.

In 1922 Scott described occupational cancer among Scottish shale oil workers and stated that the incidence was approximately 1.5% over a 22-year period.⁽³⁾ This incidence rate is given as a percent of workers observed without a description of the total industrial population or calculation of the years of exposure although a selected group of workers had a minimum of 18 years of service. Scott pointed out three important factors in the occurrence of occupational cancer among shale workers: 1) age at first observation,

2) length of service and 3) influence of job assignment upon location of lesion. From his observations it is apparent that most skin cancers occurred in workers over 40 years of age with more than 18 years of service. The influence of work assignment on anatomical location of the lesion is illustrated by his data which show a predominance of arm, hand, head and neck neoplasms among paraffin shed workers compared to a high incidence of scrotal cancers among oil workers, retort men and still workers. Scott concluded that direct contact with paraffin was largely restricted to the upper parts of the body while contact with the ash, coke and other "gritty material" experienced by the oil workers was less restricted. He considered that difficulty with, or lack of, personal hygiene was an important factor in the high incidence of scrotal cancer. While paraffin workers cancer was recognized as an occupational disease by the British Workmen's Compensation Act of 1906 the Scottish oil shale workers were not officially included until 1920.

Scott described the neoplastic conditions he observed as epitheliomata, and included both benign and malignant tumors. The fatal cases in this series were apparently due to local invasion rather than distant metastases although the investigative techniques of the day may have precluded precise diagnosis.

In 1922, Southam and Wilson described the prevalence of scrotal cancer among "mule spinners" in the British textile industry. The lubricating oils used, of the "paraffin series" and largely shale oil derived, saturated the clothing of the iniquinal region of the workers.⁽¹⁶⁾

In 1926, White discussed occupational dermatoses and stated that the [natural] "petroleums do not usually inaugurate neoplasms" but that in oil shale workers, the prospect of developing cancer is 0.5%.⁽¹⁷⁾

Soviet studies of oil shale workers reveal that women who had spent from 10 to 20 years in the industry had an increased incidence of skin cancers. Of 2,069 workers (men and women) studied, 89 individuals with diagnosed cancers were identified. Of these, 23.6% were stomach cancers, 15.7% were skin cancers, 13.5% were lung cancers, and 13.5% were tumors of the uterus. The rate

of incidence of all of these cancers, except skin cancers in women, were within the range of incidence observed in people who were not associated with the shale oil industry.⁽¹⁸⁾

Most fossil liquids, including natural petroleums, have carcinogenic potential. A series of studies have been conducted in attempts to compare the carcinogenic and dermatotoxic potency of different types of oils.^(19,20) These studies rely on periodically painting the skins of mice with oils and then observing the number of animals on which tumors are produced. In general, synthetic oils appear to have a higher carcinogenic potential than natural petroleums. The potency of shale oils, however, is perhaps lower than that of many coal-derived liquid fuels. Early results indicate that the carcinogenic potency of crude shale oils is significantly lowered by hydrotreating. Middle distillate shale oils, however, appear to be less carcinogenic than either the crude or the hydrotreated crude shale oils, even though the middle distillates appear to exhibit more systemic toxicity.

While experiments involving mouse skin painting provide some information about the relative potential of various oils, however, they also leave many questions unanswered. The skin is not just a protective sheet of cells, but is a complex organ with distinct metabolic functions and rich enzymatic activity. It is probable that components applied to the skin are enzymatically activated and may be selectively absorbed through the skin in a way that may lead to systemic toxicity or to tumorigenesis in distant organs. Recent experiments have demonstrated an apparent nephrotoxicity in mice receiving skin applications of both oils and distillation products.⁽²¹⁾

Rodent skin painting studies are empirical and are particularly applicable to such complex mixtures as shale oil, but they should not be used to condemn specific products or processes out of hand. More studies that attempt to determine which components of the mixture are active and in what way (i.e., initiation, promotion, antagonism) are needed. They should take into account such factors as host response, effect on tumor angiogenesis, inhibition of host activating systems, mouse strain differences, and the like.

In addition, most of the evidence of skin cancer in the industrial work force is drawn from a time when knowledge of industrial hygiene was less sophisticated and personal hygiene was of less social importance. These observations are meaningful only when they are considered along with the data from studies of modern oil refinery workers where the incidence of skin cancer has been shown to compare favorably with that observed in other worker groups.

10.3 RESPIRATORY ILLNESS

Mining and crushing of raw shale and the disposal of spent shale have the potential for releasing fine dust particles in a size range known to be deposited and retained in the lungs. The size of shale pieces used in surface retorting varies with the process, and because of differences in particle size, the resulting spent material will present varying pulmonary hazards. Much of the concern over pulmonary hazard is related to industrial environments but the possible release of certain criteria pollutants (NO_x , SO_x) and an increase in dusty conditions in the area could lead to regional problems. The modified in-situ (MIS) technique, where two dozen or more large retorts will be burning simultaneously in mine drifts adjacent to underground areas in which new retorts are being prepared, appears particularly hazardous. This special set of conditions presents the possibility of combined exposures.

Evidence of lung disease resulting from exposure to oil shale dust comes from two sources: studies of Estonian mine workers and experimental animal studies in the United States. The Estonian oil shale workers show an incidence of chronic bronchitis, mild pneumoconiosis, emphysema and upper respiratory illnesses (chronic hypertrophic rhinitis and atrophic rhinitis) which is greater than in the general population. In general, incidences are relatively low, probably due to the low free-silica content of the shale and the low concentration of dust in the mines.⁽²²⁾ In the United States, animal studies have concentrated on the effect of shale dust administered either as inhaled aerosols or by repeated intratracheal installation. In general, no tumors have been observed, but there is evidence of fibrotic changes when highly concentrated aerosols have been used.

Animal studies, although useful, have many limitations. They cannot measure all possible effects. The choice of species can influence the outcome of the experiment. In addition, intratracheal administration cannot substitute for inhalation exposure, but the dose retained can be estimated more accurately than in inhalation studies.⁽²³⁾

A recent study of workers at the U.S. Bureau of Mines Anvil Point oil shale facility at Rifle, Colorado, who were employed between 1947 and 1969 shows that the 713 men studied had higher-than-anticipated death rates due to respiratory and digestive cancer. However, most of the dead were smokers and had also worked in uranium mines. The results of the study were, therefore, not conclusive.⁽²⁴⁾

10.4 EXPOSURE ROUTES FOR GENERAL TOXICITY

Questions of potential toxic and genetic impacts on human populations from a shale oil industry are difficult to address from work with intact animal systems. Relevant simulations of human exposures are difficult to accomplish in animals, because routes of exposure, dose levels, and opportunity for contact in human populations are hard to predict.

L. M. Holland⁽²¹⁾ notes that the most immediate question is the potential for water contamination. Both surface waters and regional aquifers are vulnerable to contamination from product oils, process effluents, spent or partially processed shales, and other industrially related materials. This is a matter of particular importance since the affected human populations would include the general public in the region, not only the oil shale workers. It is important to know not only if the contaminated waters are biologically active, but what the contaminants are, their origins (both generic and process induced), and what procedures are necessary for clean-up. While the identification of likely chemical components from uncontrolled shale oil production processes has proceeded to a substantial extent, quantitative estimates of emissions and effluents from prospective commercial shale oil operations are very crude at best.

Among the systemic effects that might result from contamination of regional water supplies are disturbances of the germinal tissues as a mutation,

a failure of reproduction, or a direct effect on fetal development.⁽²¹⁾ Gregg⁽²⁵⁾ has measured the embryotoxicity of one untreated retort or product water and identified an unusual number of defects of the palate in mouse embryos. While no significant changes in fetal numbers and weights were noted, the lesions of the palate exhibited a dose response. No overt signs of maternal toxicity were noted. Measurements of the direct toxicity and teratogenic potential of the so-called Omega-9 water associated with true in-situ retorting near Rock Springs, Wyoming have been largely negative. This material is apparently a mixture of ground water and water associated with the in-situ burn.⁽²⁶⁾

Careful attention should be given to the possibility of contamination of soil and water with toxic trace elements and to the potential for bioaccumulative phenomena. Some of these materials do not reveal their biological activity easily, with the result that chemical detection must be heavily relied upon for the identification of hazard.

10.5 REFERENCES FOR CHAPTER 10

1. Holland, L. M. 1981. Health and Safety Impacts from Shale Oil Development. Available as Volume 8 in this assessment report.
2. Veldre, I. A., and H. J. Janes. 1979. "Toxicological Studies of Shale Oils, Some of Their Components and Commercial Products." Environ. Health Pers. 30:141.
3. Scott, A. 1922. "On the Occupation Cancer of the Paraffin and Oil Workers of the Scottish Shale Oil Industry." Brit. Med. J. (Dec.).
4. Scott, A. 1923. "The Occupation Dermatoses of the Paraffin Workers of the Scottish Shale Oil Industry: With a Description of the System Adopted and the Results Obtained at the Periodic Examinations of These Workmen." In: Eighth Scientific Report on the Investigations of the Imperial Cancer Research Fund. Taylor and Francis, London.
5. Twort, C. C. and J. M. Twort. 1930. "The Relative Potency of Carcinogenic Tars and Oils." Jour. of Hyg. 29:373-379.
6. Twort, C. C. and J. M. Twort. 1931. "The Carcinogenic Potency of Mineral Oils." Jour. of Hyg. 30:204-226.
7. Leitch, A. 1922. "Paraffin Cancer and It's Experimental Production." Brit. Med. J. 1104.

8. Berenblum, I. and R. Schoental. 1943. "Carcinogenic Constituents of Shale Oil." Brit. J. Exp. Path. 24:232-238.
9. Berenblum, I. and R. Schoental. 1944. "The Difference in Carcinogenicity Between Shale Oil and Shale." Brit. J. Exp. Path. 25:95-96.
10. Bogovski, P. A. and F. Vinkmann. 1979. "Carcinogenicity of Oil Shale Tars, Some of Their Components, and Commercial Products." Environ. Health Pers. 30:165-169.
11. Bogovski, P. A. 1961. The Cancerogenic Effect of Estonian Oil-Shale Processing Products. Tallinn (English Summary).
12. Bogovski, P. A. and H. I. Mirme. 1979. "Cocarcinogenicity of Phenols from Estonian Shale Tars (Oils)." Environ. Health Pers. 30:177-178.
13. Bogovski, P. A. 1959. "Occupational Skin Tumours Induced by Products of Thermal Treatment of Mineral Fuels." Vopr. Onkol. 5:No. 10, 486-497 (English translation).
14. Vosamae, A. I. 1979. "Carcinogenic Studies of Estonian Oil Shale Soots." Environ. Health Pers. 30:173-176.
15. Veldre, I. A. and H. J. Janes. 1979. "Toxicological Studies of Shale Oils, Some of Their Components, and Commercial Products." Environ. Health Pers. 30:141-146.
16. Southam, A. H. and S. R. Wilson. 1926. "Cancer of the Scrotum: Etiology, Clinical Features and Treatment of the Disease." Brit. Med. J. 2:1971.
17. White, R. P. 1926. "Modern Views of Some Aspects of the Occupational Dermatoses." Journ. of Ind. Hyg. 29:373-379.
18. Purde, M. and M. Rahu. 1979. "Patterns in the Oil Shale Area of the Estonian S.S.R." Environ. Health Pers. 30:209-210 (1979).
19. Holland, J. M., M. S. Whitaker, J. W. Wesley. 1979. "Correlation of Fluorescence Intensity and Carcinogenic Potency of Synthetic and Natural Petroleum to Mouse Skin." American Industrial Hygiene Association Journal 40:496.
20. Holland, L. M. and J. S. Wilson. 1980. "The Epidermal Carcinogenicity of Two Shale Oils and Two Natural Petroleums," in: Biomedical and Environmental research Program of Los Alamos Scientific Laboratory Progress Report, LA-8577-PR.
21. Holland, L. M. 1980. "Studies of the Biology and Toxicology of Oil Shale Materials." Presented at Oil Shale: The Environmental Challenges, Vail, Colorado, August 11-14, 1980.

22. King, V. A. 1979. "Morphological Investigations of Fibrogenic Action of Estonian Oil Shale Dust." Environ. Health Pers. 30:153.
23. MacFarland, H. N. 1976. "Repository Toxicology," in Essays in Toxicology, Vol. 7, p. 121.
24. "NIOSH Downplays Oil Shale-Cancer Link." May 12, 1980. Synfuels Week, p. 4.
25. Gregg, C. P. and J. Y. Hutson. 1981. "The Prenatal Toxicology of Oil Shale Retort Water in Mice." In: Los Alamos Integrated Oil Shale Health and Environmental Program; A Status Report, LA-8665-SR.
26. Hepler, D. I., A. S. Schafer, K. A. Larson and D. S. Farrier. 1979. Animal Toxicity Evaluation of an In-Situ Oil Shale Retort Water. Prepared for U.S. Department of Energy. NTIS, Springfield, Virginia.

11.0 SOCIOECONOMIC ACCEPTABILITY

The experiences of energy-impacted communities within the Rocky Mountain Region have drawn attention to the effects of energy development on communities. Socioeconomic impacts are anticipated to be a greater potential constraint for oil shale development than any other environmental impact of development.

This section focuses on the northwestern region of Colorado, where development of an oil shale industry would most probably produce the greatest impacts. The section's objective is to present sufficient descriptions of likely changes in socioeconomic variables to evaluate the need for mitigation in affected communities. The study region is described briefly. For a given energy production scenario, the magnitude of socioeconomic impacts depends on the temporal and geographical distribution of the population increases caused by the scenario. The distribution of these population increases is estimated by a model. Socioeconomic impacts analyzed in this section are based on this estimated distribution.

Only socioeconomic impacts from oil shale development are considered here. If other energy resources--coal, oil, gas--are also developed, impacts could be more severe. Furthermore, the analysis has been restricted to six major towns in the region--Grand Junction, Rifle, Glenwood Springs, Meeker, Rangely, and Craig--and the as yet unconstructed town of Battlement Mesa.

The analysis presented in this chapter has been taken almost entirely from the report on a supporting study conducted by Carolyn Mangeng et al. of Los Alamos National Laboratory.⁽¹⁾ That report is Volume 9 of this assessment report. Except where otherwise designated, all information and conclusions should be attributed to that supporting study.

11.1 THE STUDY REGION

The focus of this socioeconomic analysis is the four northwestern Colorado counties--Moffat, Rio Blanco, Garfield, and Mesa (see Figure 11.1). In addition to rich oil shale deposits, this region also contains vast coal reserves

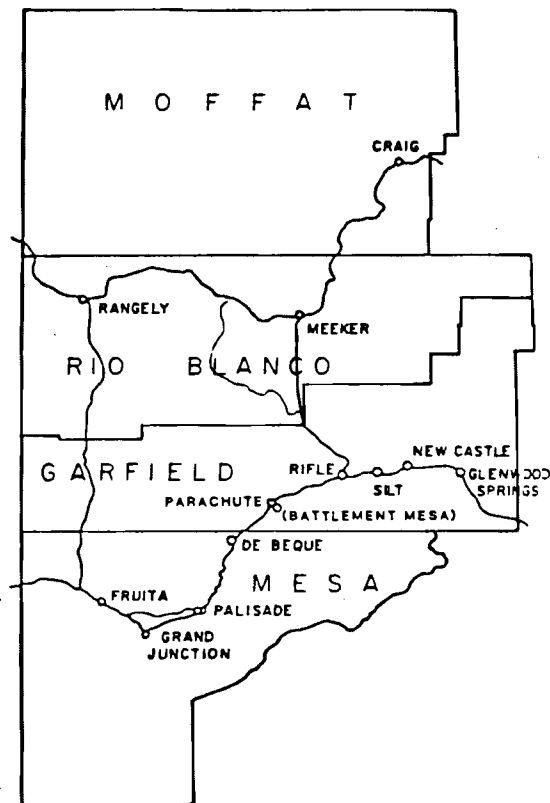


FIGURE 11.1. Oil Shale Country, Northwest Colorado

and important oil fields, as well as natural gas. Furthermore, nahcolite and dawsonite deposits are associated with the oil shale, and are expected to be developed by multiminerall extraction ventures. Large-scale development of these energy and mineral resources would alter profoundly the economy of this region, which is already in transition. Energy development now leads all other sectors as the top income source in Moffat, Garfield, and Rio Blanco Counties (see Table 11.1).

Historically, the most important sector of the economy has been agriculture, which as recently as 1950 employed over 30% of the labor force in Garfield County, 26% in Rio Blanco, and 22% in Mesa County. However, agricultural employment has been declining steadily. In 1979, it was 4.5%, 9.7%, and 4.0% for these same three counties, respectively. While agriculture has declined, tourism has grown due to the recreational resources of the region. Contract construction, retail trade, and services have grown as a result of the tourism.

TABLE 11.1. Personal Income by Selected Major Sources, 1978(2)

	Total Personal Income	Per Capita Income (actual \$)	Farming	Mining	Construction	Manufacturing	Transportation and Public Utilities	Retail Trade	Services	State and Local Government
Garfield County		7,574								
Thousands of \$	148,194		3,504	17,196	11,462	2,054	10,231	15,643	15,795	9,747
% of Total			2.4	11.6	7.7	1.4	6.9	10.6	10.7	6.6
Mesa County		7,217								
Thousands of \$	498,491		1,171	29,799	45,759	31,768	30,469	53,271	70,637	45,974
% of Total			0.2	6.0	9.2	9.2	6.4	10.7	14.2	9.2
Moffat County		9,166								
Thousands of \$	100,628		5,281	26,858	22,276	---	3,262	8,205	4,190	4,838
% of Total			5.3	26.7	22.1	---	3.2	8.2	4.2	4.8
Rio Blanco County		8,940								
Thousands of \$	46,005		4,485	13,365	3,617	605	3,295	2,117	1,873	5,530
% of Total			9.8	29.1	7.9	1.3	7.2	4.6	4.1	12.0
Colorado		8,116								
Thousands of \$	21,673,092		363,203	678,271	1,310,309	2,831,623	1,432,337	1,904,728	2,916,516	2,020,269
% of Total			1.7	3.1	6.0	13.1	6.6	8.8	13.4	9.3

Employment growth of 12.7% for 1977-78 and 11% for 1978-79 has been attributed in part to the increasing importance of recreational activities in the region.⁽³⁾ In terms of nonagricultural employment, this four-county region is one of the fastest growing of all planning regions in Colorado.

The region is rural, sparsely-populated, and contains only a handful of communities larger than a few thousand people. In the 1970s, the population of these communities was mainly stable, with only minimal growth (see Table 11.2). The metropolitan area of Grand Junction, however, has experienced rapid growth in recent years that local government has had difficulty managing. It has an estimated 50,000 people in the metro area and is the commercial and distribution center of the region, providing medical, education, banking, and other services to surrounding counties. The rapid growth has been accompanied by a proliferation of special districts to provide services to residents. In addition, over 100 housing subdivisions are under development outside of the city limits. The city is served by air, rail, bus and major highway transportation.

Up the Colorado River and I-70 from Grand Junction are DeBeque, Parachute, and Rifle. Because many of DeBeque's residents work in Grand Junction or Rifle; DeBeque lacks its own industrial or commercial tax base. Parachute, an agricultural community located at the entrance to the Parachute Creek Basin, is the site of several proposed commercial oil shale facilities. The town has a large number of retired persons on fixed incomes and one of the highest mill levies in the region. No new homes have been built since 1963, and the growth of the town is limited by land and water constraints.⁽⁵⁾ The site of the proposed new company town of Battlement Mesa is across the river from Parachute.

Located at the Junction of I-70 and State Highway 13 is Rifle, an area trade center since the turn of the century. Rifle continues to serve a large surrounding area with retail and educational services, medical care, and entertainment. It has enjoyed growth in tourism-related industries in recent years. Agriculture is also an important local concern.

Glenwood Springs, to the east of Rifle, is the commercial heart of eastern Garfield County and anticipates continued economic growth stimulated by recreational activities and energy development other than oil shale.

TABLE 11.2. Population Changes, 1970-1979⁽⁴⁾

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Garfield County										
Total	14,821	15,447	15,945	16,445	17,177	17,912	18,403	18,976	19,605	20,251
Carbondale	726	783	829	875	1,002	1,128	1,552	1,685	1,965	2,282
Glenwood Springs	4,106	4,208	4,289	4,370	4,861	5,351	4,092	4,090	3,847	3,604
Parachute	270	269	268	267	286	304	366	382	412	442
New Castle	499	529	552	576	658	740	539	545	514	483
Rifle	2,150	2,110	2,078	2,046	2,031	2,016	2,235	2,248	2,288	2,320
Silt	434	462	484	506	554	608	817	878	1,008	1,147
All Unincorporated	6,636	7,086	7,445	7,805	7,785	7,765	8,802	9,148	9,571	9,973
Mesa County										
Total	55,374	55,659	56,689	57,718	60,097	62,474	65,560	67,347	69,760	72,263
Collbran	225	213	204	195	203	211	286	296	331	370
DeBeque	155	158	161	163	220	276	253	268	285	303
Fruita	1,822	1,868	1,904	1,941	2,043	2,145	2,276	2,348	2,437	2,526
Grand Junction	24,105	24,703	25,182	25,661	26,731	27,801	25,323	25,452	24,955	24,405
Palisade	874	894	910	926	905	883	1,021	1,045	1,095	1,146
All Unincorporated	27,193	27,823	28,328	28,832	29,995	31,158	36,401	37,938	40,657	43,494
Moffat County										
Total	6,525	6,650	6,751	6,850	8,062	9,274	9,888	10,438	11,262	12,151
Craig	4,629	4,578	4,538	4,497	5,575	6,653	6,412	6,765	7,103	7,446
Dinosaur	247	255	261	267	289	311	336	351	369	388
All Unincorporated	1,649	1,817	1,952	2,086	2,198	2,310	3,150	3,322	3,790	4,317
Rio Blanco County										
Total	4,842	4,909	4,961	5,015	5,182	5,348	5,075	5,112	5,088	5,064
Meeker	1,597	1,674	1,736	1,798	1,892	1,985	1,823	1,859	1,850	1,840
Rangely	1,591	1,599	1,604	1,610	1,701	1,792	1,843	1,883	1,933	1,982
All Unincorporated	1,654	1,636	1,621	1,607	1,589	1,571	1,409	1,370	1,305	1,242

Silt and New Castle are small agricultural communities lying between Glenwood Springs and Rifle. Both depend on Rifle or Glenwood Springs for many retail and service facilities. The amount of growth these communities can bear is limited by geographical constraints.

Meeker is the only urban area in eastern Rio Blanco County. It is primarily an agricultural community and is a supply center to ranches in the area. Meeker has the lowest mill levy of any community in the region yet provides its residents with a broad range of services. Meeker anticipates a substantial amount of growth from both coal and oil shale development, and has adopted a strict policy of orderly growth management. Rangely is the only other urban area in Rio Blanco county. The town's population would welcome a new source of economic growth as the oil boom draws to a close.

The second largest city in the four-county region is Craig, located in Moffat County about 50 miles north of Meeker. The city has many new public facilities, new housing, more industrial and rail facilities than any other city in the region except Grand Junction, and provides services to a large surrounding region. Craig expects further population and economic growth in response to development of the area's energy resources.

11.2 THE DOE OIL SHALE SCENARIO

DOE's oil shale development scenarios are discussed in Section 3.5 of this report. Table 11.3 provides construction and operation work force estimates. Development of these projections required an evaluation of possible shale oil production levels for each company, characterization of each extraction technology, and estimates of facility expansion plans beyond the time period of this assessment. Since no large-scale oil shale facility has ever been built these estimates may be in error.

Regardless of the accuracy of work force estimates, there are several inherent features of the DOE scenario that will influence the socioeconomic impacts. These features include 1) timing of the different oil shale developments, 2) construction period, and 3) employment profiles.

TABLE 11.3. DOE Scenario of Oil Shale Work Force

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
<u>Colorado</u>											
Garfield County											
Union (const.)	300	800	700	700	800	700	200	0	0	0	0
(oper.)	100	250	400	400	400	400	550	700	700	700	700
Anvil Points											
(const.)	0	300	500	200	250	400	200	100	0	0	0
(oper.)	80	200	300	300	300	300	300	450	450	550	550
Colony											
(const.)	400	600	1,000	1,500	2,000	2,000	2,000	2,000	2,000	1,500	1,000
(oper.)	150	300	500	800	800	800	800	1,200	1,500	1,800	2,000
Chevron/Mobil											
(const.)	0	0	0	0	100	300	500	500	600	600	200
(oper.)	0	0	0	0	100	100	200	300	300	500	500
<u>Rio Blanco County</u>											
Superior											
(const.)	0	0	150	275	450	800	710	100	400	600	100
(oper.)	20	50	110	185	405	540	600	920	920	1,200	1,200
C-a (const.)	0	0	0	100	300	300	500	1,000	1,500	800	500
(oper.)	0	250	350	300	300	300	300	600	1,000	1,200	1,500
C-b (const.)	0	0	0	100	300	300	500	1,000	1,500	800	500
(oper.)	0	250	350	300	300	300	300	600	1,000	1,200	1,500
<u>Utah</u>											
Uintah County											
Sand Wash											
(const.)	0	0	0	100	300	500	500	500	100	100	100
(oper.)	0	0	0	100	100	200	200	300	300	350	350
U-a, U-b											
(const.)	0	0	0	100	300	500	500	200	100	0	0
(oper.)	0	0	0	100	200	300	300	300	400	400	400
Total	1,050	3,000	4,360	5,560	7,705	9,040	9,160	10,770	12,770	12,300	11,100

The total work force required is very large for a region in which the current total labor force is estimated at less than 60,000.⁽⁶⁾ In the counties of Rio Blanco and Garfield, where most of the facilities will be located, the current total work force is 14,756.

The construction work force will fluctuate with the construction schedules of the various facilities. Drops in work force occurring between the construction phases of various facilities could imply changes in worker residences, aggravating problems the region already will experience in accommodating the large influx of temporary workers. Although the oil shale construction work force is large, the growth and continuing presence of a substantial operation work force will moderate the employment decline after the peak year. This characteristic can be seen in the total work force estimates of most of the individual facilities in the scenario.

11.3 POPULATION

Population impacts of the anticipated energy development in northwest Colorado have been estimated by a great number of research organizations and government agencies. Although many different methods of estimating total population growth have been employed, probably the greatest source of disagreement between the estimates is the difference in assumptions regarding the levels and types of energy development that will occur. The population projections of this analysis include only the impacts of DOE's oil shale scenario. If any other energy development were to occur simultaneously, population growth would be underestimated.

In view of the simultaneous development of several major energy resources in the region, it is difficult to attribute observed socioeconomic effects to the development of any single energy resource. Impacts must be analyzed in terms of total employment in the area and total in-migration of new population. Because of the low unemployment rates (3.7% to 6.9%)⁽⁶⁾ of the four northwest counties of Colorado, it is likely that nonlocal employees will account for almost 100% of the energy-induced employment. Population pressures experienced in any one town or county may result from more than one type of energy

facility. Therefore, demand for new or expanded public facilities and services may not necessarily be attributable to any one type of facility.

11.3.1 Geographic Distribution

Given the work force projections discussed above, the settlement patterns of in-migrant employees must be estimated. There are many factors that influence these patterns, not all of which can be readily quantified. Furthermore, these factors vary in relative importance with respect to the values and expectations of the analyst and the individual employees.

The distribution pattern developed for this study is based on the growth pressures implied by the specific construction and operation schedules of the nine oil shale facilities in the DOE scenario. These facilities are grouped by regions, and thus residential patterns of workers from facilities in the same region are identical. Distribution numbers in each region are allowed to change with population pressures exerted by oil shale development in other regions. In addition, emphasis is placed upon the impact of municipal growth management policies on settlement patterns. The distribution model takes into account housing availability, costs of housing, excess capacity in public infrastructure, and access to major transportation corridors and regional trade centers.

The population distribution patterns assume that development will occur in and around the existing communities of Rifle, Meeker, Rangely, Grand Junction, Glenwood Springs, and Craig. Small communities, however, also are expected to be affected by the population influx, although the capture rate is estimated to be very small. Mobile home parks and a few dwellings will be available for in-migrant construction and operating workers. An increasing share of the incoming population in the south is expected to be received by Battlement Mesa. After several years, parks, shopping centers, permanent homes, schools and other community services could be established in Battlement Mesa, and thereby attract greater numbers of employees who might otherwise have settled in Rifle, Grand Junction, or in the little towns along I-70.

The distribution model assumes no uncontrolled growth. There are several reasons for this assumption. Many municipalities in the study region have

strongly encouraged new development in areas within the town rather than on the periphery or beyond municipal boundaries.

Rio Blanco County, in particular, has adopted a very strong position against uncontrolled, or "laissez-faire", growth. Services such as fire and police protection, educational facilities, and utilities are more difficult and much more expensive to provide to scattered sites of development than to higher density communities. The need for these immediate services induces the proliferation of special districts that exacerbate planning and management problems of municipal officials. In addition, scattered development is associated with increased traffic and fuel use, consumption of agricultural land, lack of community identity, and disregard for existing community goals.

Concentrated growth in and around existing communities allows more efficient and less costly provision of public services and expansion of public infrastructure.⁽⁷⁾ Public transportation services can reduce private vehicle use, and children need not be bused long distances to school. Agricultural lands are more easily preserved.⁽⁸⁾

Concentrated growth in and around existing communities, however, requires a concerted planning, coordination, and growth management effort on the part of local officials, including careful land use planning and development of comprehensive fiscal policies. Lack of experience can handicap these efforts. Furthermore, these activities must be undertaken in a public arena where land use planning is anathema to many, where the approach to problem solving is informal and ad hoc, and where individual freedom of action and economic pursuit are paramount. Consequently, population growth may well occur outside of towns, scattered in developments along major transportation corridors.⁽⁸⁾

The distribution model was used to forecast settlement patterns of the employees associated with the DOE scenario discussed in Section 11.2.

The results are shown in Table 11.4. According to these estimates, rapid and steady growth will occur in Battlement Mesa, Rifle, and Meeker. Rangely will experience substantial growth, although less spectacular than the growth in Rifle or Meeker. Small towns and rural areas will experience a comparatively small net growth, although they will temporarily suffer from the influx

of large numbers of workers during the years if there are substantial incremental increases in the oil shale industry's manpower requirements.

In addition, Rifle and Meeker reflect the changes in the oil shale production scenario. An enormous worker influx will occur in 1988, the impacts of which could be alleviated through the provision of bachelor quarters. Attractive, though temporary, housing for the nonlocal workers has been provided by industry to secure employee satisfaction and work force stability. Nonlocal married workers leave their families at home and, in effect, become weekend commuters. Such a solution may be preferable to searching for adequate housing for the entire family, and the business community may welcome the advantages of added revenues without the full cost of providing for families.

11.3.2 Indirect Employment

To assess total employment impacts of oil shale production, induced indirect employment must be estimated. This assessment uses employment multipliers to estimate indirect employment. Two methods were used.

The Los Alamos method is based upon the DRI demonstration methodology for the Rio Blanco County analysis.⁽⁹⁾ It uses a two-year lagging multiplier of 0.5 (0.25 per year) applied to 50% of the construction force per year. A three-year lagging multiplier that varies both in period of application and magnitude was applied to the remaining 50% of the construction force. The multipliers for the operations work force vary by town but no lag is assumed. The second method employed multipliers used in the Colorado West Area Council of Government's (COG) population projections.

Comparison of the results of these two methods for Battlement Mesa, Meeker, and Grand Junction (Table 11.5) reveals some differences in projected indirect employment impacts. In general, the multipliers in the COG matrix are higher than the effective multipliers in the Los Alamos method. The Grand Junction multipliers, however, are similar. Thus indirect employment impacts predicted by the COG method for Meeker and Battlement Mesa are larger than those estimated by the other method, and the impacts predicted for Grand Junction are similar.

TABLE 11.4. Geographic Distribution of Work Force

	<u>1980</u>	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>	<u>1986</u>	<u>1987</u>	<u>1988</u>	<u>1989</u>	<u>1990</u>
Colorado:											
Battlement Mesa	0	367	1190	1759	2612	2750	2612	3150	3330	3390	2970
Rifle	415	917	1303	1518	1726	1871	1943	2163	2808	2600	2385
Meeker	8	220	384	504	822	1016	1164	1688	2528	2320	2120
Rangely	4	85	157	332	621	898	952	1074	1284	1215	1115
Grand Junction	155	367	510	390	475	500	475	525	555	265	495
Glenwood Springs	51	147	205	235	297	310	317	422	527	482	447
Craig	4	10	52	92	171	260	262	364	514	560	460
Other	417	887	559	470	385	460	460	439	639	615	555
Utah	0	0	0	260	585	975	975	845	585	553	553

TABLE 11.5. Geographic Distribution of Nonbasic Work Force Comparison of Los Alamos and COG Methods

<u>Method</u>	<u>1980</u>	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>	<u>1986</u>	<u>1987</u>	<u>1988</u>	<u>1989</u>	<u>1990</u>
LASL											
Battlement Mesa	0	241	931	1623	2356	2737	2953	2869	3684	3816	3420
Meeker	9	264	413	480	746	987	1164	1745	2431	2094	2456
Grand Junction	157	443	775	798	847	866	933	1027	1029	1142	757
COG											
Battlement Mesa	0	147	476	1404	2612	3850	3657	4410	4662	4746	5346
Meeker	3	132	307	403	657	1219	1396	2025	3033	2784	2544
Grand Junction	231	550	765	585	807	850	807	892	943	960	841

Family and Household Multipliers

Total population impacts are calculated from basic and nonbasic employment projections. Much uncertainty lies in the number of family members who will accompany energy workers. Table 11.6 presents family size multipliers used in this analysis.

Total Population Impacts

The results of the population impact analysis using the LASL method are shown in Table 11.7.

The pace of oil shale development early in the decade is reflected in the growth of Battlement Mesa, Grand Junction, and Rifle. Substantial population pressures arise by 1986, accelerating the rate of growth in Meeker, Rifle, and, to a lesser extent, in Craig and Glenwood Springs. Relatively steady growth is experienced in Rangely and Battlement Mesa. Most of the communities show a drop in population in 1990 that is a direct result of the decline in the oil shale work force implied by the scenario.

The results of applying the COG distribution and multipliers to the DOE scenarios are somewhat different. The total peak year population is greater 43,410--about 11% for the region.

Total population growth, including baseline, nonenergy-related growth, is given in Table 11.8. A graphical representation of these data appears in Figure 11.2. Calculations were based on the Los Alamos distribution and indirect employment multipliers. The nonenergy-related growth was estimated by taking a

TABLE 11.6. Family Size Multipliers

	<u>Percent Single (or without family)</u>	<u>Percent Married</u>	<u>Family Size</u>
Construction Workers	50	50	2.1
Operations Workers ^(a)	20	70	3.1
Nonbasic ^(b)	9	40	3.1

(a) 10% operation workers to be supplied by construction work force.

(b) 51% to be supplied by other work force families.

TABLE 11.7. Scenario-Induced Population--Los Alamos Method

	<u>1980</u>	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>	<u>1986</u>	<u>1987</u>	<u>1988</u>	<u>1989</u>	<u>1990</u>
Battlement Mesa	0	981	3,427	5,432	7,903	8,624	8,810	10,002	11,512	12,076	10,997
Rifle	1,123	2,749	4,073	4,738	5,233	5,642	6,005	6,987	8,892	9,047	8,856
Meeker	30	872	1,410	1,677	2,595	3,261	3,747	5,632	8,109	7,561	7,930
Rangely	14	337	565	1,061	1,878	2,767	3,056	3,803	4,450	4,395	4,204
Grand Junction	487	1,249	1,968	1,788	1,993	2,057	2,128	2,396	2,470	2,685	2,801
Glenwood Springs	105	333	486	563	684	720	758	1,024	1,276	1,434	1,295
Craig	10	29	114	206	404	614	637	967	1,266	1,624	1,333
Other	<u>868</u>	<u>1,918</u>	<u>1,374</u>	<u>1,212</u>	<u>943</u>	<u>1,060</u>	<u>1,091</u>	<u>3,344</u>	<u>1,583</u>	<u>1,827</u>	<u>1,607</u>
Total	2,637	8,468	13,417	16,677	21,633	24,745	26,232	32,155	39,558	40,649	38,303

TABLE 11.8. Projected Total Population Growth of Selected Communities

	<u>1980</u>	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>	<u>1986</u>	<u>1987</u>	<u>1988</u>	<u>1989</u>	<u>1990</u>
Battlement Mesa	0	981	3,425	5,432	7,903	8,624	8,810	10,002	11,512	12,076	10,997
Rifle	3,388	5,020	6,350	7,021	7,522	7,937	8,306	9,294	11,205	11,366	11,181
Meeker	1,930	2,783	3,332	3,610	4,539	5,216	5,711	7,609	10,097	9,560	9,940
Rangely	1,962	2,309	2,561	3,081	3,922	4,835	5,148	5,919	6,590	6,559	6,392
Grand Junction	27,443	28,606	29,726	29,947	30,553	31,018	31,490	32,159	32,634	33,250	33,047
Glenwood Springs	4,270	4,525	4,705	4,809	4,957	5,020	5,085	5,378	5,657	5,842	5,730
Craig	7,195	7,367	7,605	7,850	8,201	8,564	8,740	9,223	9,675	10,204	10,048

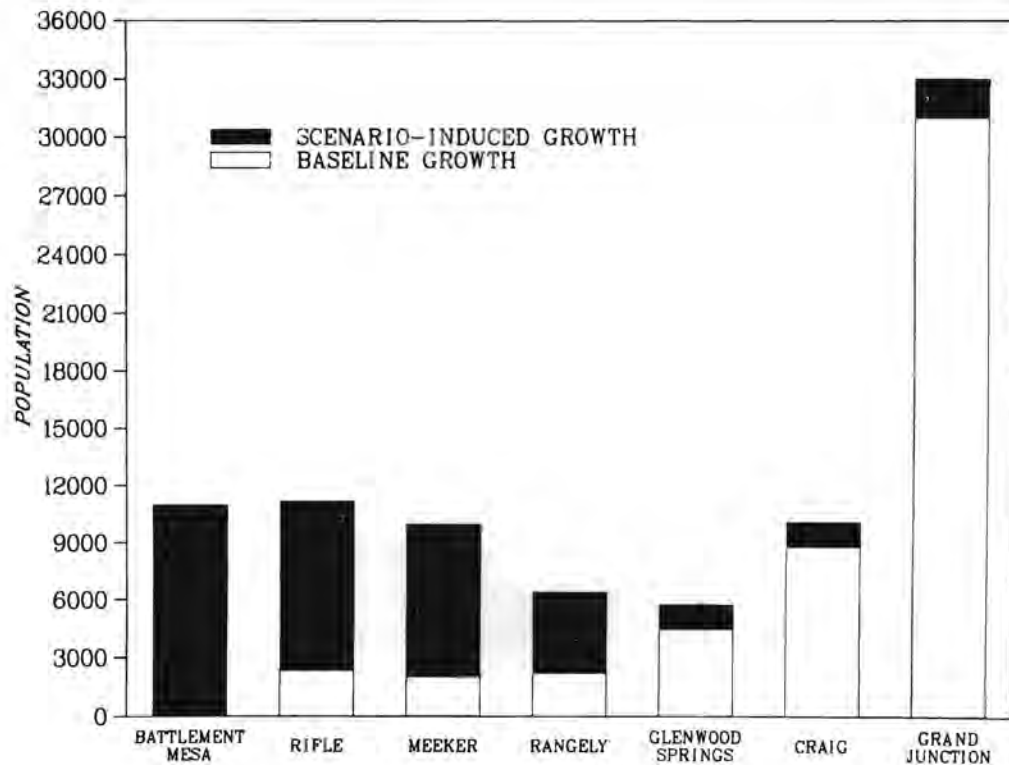


FIGURE 11.2. Relative Population Impacts by 1990 for Selected Colorado Communities

linear least squares fit of US Bureau of Census populations for 1960, 1970, and 1977. The slope of the fit, representing the average annual population increment, then was employed to estimate growth starting with the 1977 Census of populations of the communities in this study. This procedure should minimize the effect of recent growth in the communities caused by other energy-related industries, and should give a better representation of the nonenergy-related growth rate of the communities.

11.4 PUBLIC FACILITIES AND SERVICES

The arrival of a large number of new residents in a town creates an immediate need to expand existing public facilities and services. Rural communities have stable or slowly-growing populations and seldom have excess capacity in their infrastructure to accommodate a large population influx. The negative experiences common to many of the energy-impacted rural western communities in the past have been attributed in large part to the inadequacy of

public facilities and services,^(8,10,11,12) which led to a general deterioration of community conditions and a degradation of the quality of life.⁽¹¹⁻¹⁴⁾ Worker productivity declined dramatically and the rate of turnover increased. Among the most frequently-cited reasons for the inadequacy of public services and facilities in boom towns are the front-end capital financing, comprehensive planning, local government expertise, necessary information or uncertainty with respect to the scheduling and magnitude of developments, and the unmanageable rate of population increase.⁽¹¹⁻¹⁴⁾ Consequently, estimates of public facility needs have assumed major priority in planning for rapid population growth.

Public facility needs are difficult to estimate because they assume the residents will desire certain services. The cost of public services and facilities is even more difficult to estimate. In this study capital expenditures implied by the scenario-induced population in Colorado have been calculated using the state per capita cost estimates. Table 11.9 shows these estimates.

If costs of providing public services in Battlement Mesa are internalized by the company, total regional costs will be substantially lower. In addition, accounting for existing excess capacity in local water and sewerage treatment facilities also would lower these figures. However, accounting for local conditions, locally-perceived needs, or boom town inflation, or use of one of the other estimating procedures could increase these figures.

The most serious fiscal problem that faces local governments in energy-impacted communities is the "tax lead time." The revenues generated by the new tax base are not realized until several years after the initial requirement for massive amounts of capital to expand or build new public facilities. This revenue shortfall was shown in the "Tax Lead Time Study" to persist 5 to 8 years after the onset of the oil shale "boom."⁽¹⁵⁾ Ultimately, however, this study indicated that the oil shale industry would generate sufficient revenues to cover public expenditures despite initial shortfalls.

The Boom Town Financing Study⁽¹⁶⁾ concluded, in addition, that school districts would best be able to generate necessary capital funds, and that

TABLE 11.9. Estimates of Public Expenditures (in million of \$)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	Total (\$m)
Total Population	2,637	8,468	13,417	16,677	21,633	24,745	26,232	32,155	39,558	40,649	38,303	
Change in Population	2,637	5,831	4,949	3,260	4,956	3,112	1,487	5,923	7,402	1,091	-2,346	
Incremental Capital Costs (\$4725 per capita)	12.46	27.55	23.38	15.40	23.42	14.70	7.03	27.99	34.97	5.15	---	192.05
Population of Battlement Mesa	0	981	3,427	5,432	7,903	8,624	8,810	10,002	11,512	12,076	10,907	
Incremental Capital Costs if Battlement Mesa Population Excluded	12.46	22.92	11.83	5.93	11.74	11.30	6.15	22.35	27.84	2.49	---	135.02

municipalities would encounter the worst difficulties generating necessary front-end capital because the population influx would not be accompanied by a corresponding increase in the tax base. All planned oil shale facilities are located in remote parts of the region, well outside municipal boundaries.

A detailed fiscal analysis of the municipalities in the oil shale region is beyond the scope of this report. However, several demonstration runs were made using a state fiscal capacity evaluation model. Public facility needs were based on the population projections already discussed.

On the basis of user-specified parameters and local government financial data stored in the model, the model can project future capacity to generate property tax revenues, sales tax revenues, intergovernmental revenues, and revenues from charges, licenses, permits, fines, and franchise taxes. Plotted against projected operating expenditures, the amount of surplus revenue generating capacity can be shown. Capital needs, identified by the user, can be plotted against capital capacity to illustrate the fiscal calculations performed by the model. The model may be applied to several types of local jurisdictions, including counties, municipalities, water and sewer districts, and school districts.

The results of these model runs are shown in Figures 11.3 to 11.8. Deficits in 1981 and 1988 were estimated to be \$4,551,000 and \$4,717,900 in Rifle. The dramatic drop in capital needs at the end of the decade reflects the declining rate of population growth. The 1988 deficit in Meeker was projected to be \$7,017,300, a much large deficit than projected for Rifle in spite of the smaller population growth. The difference can be attributed largely to the different sales tax rates and taxable retail sales in those towns.

The model results indicated that scenario-induced population impacts in Rangely would create a deficit of \$2,649,800 in 1985. The estimated revenues of that year, moreover, would not cover projected operating expenditures. The impacts in Grand Junction, Craig, and Glenwood Springs were estimated to be substantially less, although capital capacity in Grand Junction was projected to fall short of capital needs in 1981 and 1982 by \$966,000 and \$753,200. As shown in Figure 11.6, Grand Junction's taxable retail sales were estimated at

RIFLE
FISCAL CAPACITY 1974-1990
 (DOLLARS IN THOUSANDS)
 % OF BASE SELECTIONS
 A.U.- 148%
 TAX.R.S.- 194%
 INTGOUT.- 141%
 SOLID MST.- 161%
 OP.EXP.- 177%
 OTHER REV.- 175%
 INCOME PER
 HOUSEHOLD- 125%

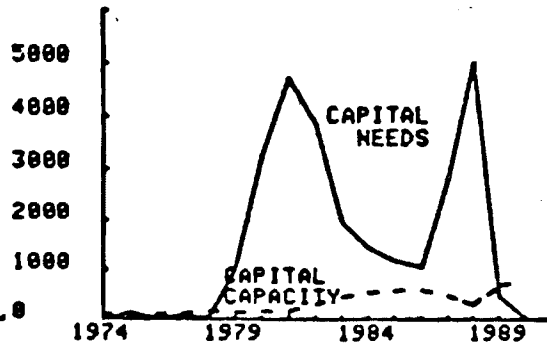
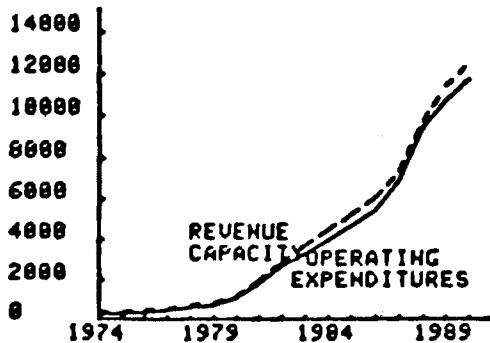
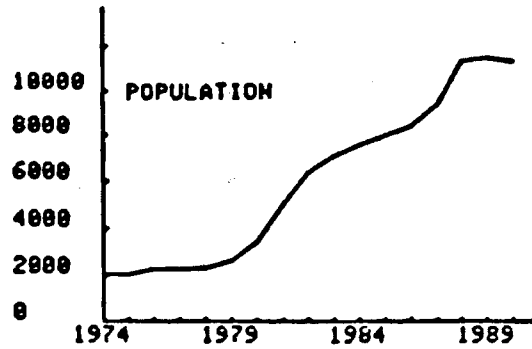


FIGURE 11.3. Projection of Fiscal Capacity of Rifle

MEEKER
FISCAL CAPACITY 1974-1990
 (DOLLARS IN THOUSANDS)
 % OF BASE SELECTIONS
 A.U.- 125%
 TAX.R.S.- 116%
 INTGOUT.- 126%
 SOLID MST.- 162%
 OP.EXP.- 115%
 OTHER REV.- 232%
 INCOME PER
 HOUSEHOLD- 116%

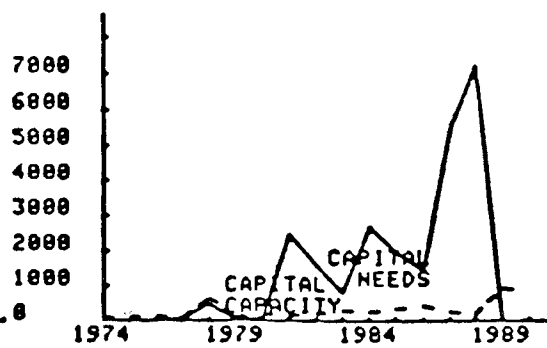
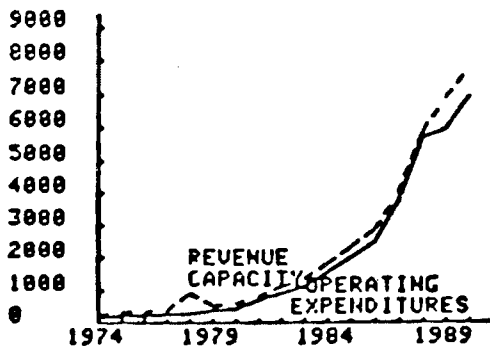
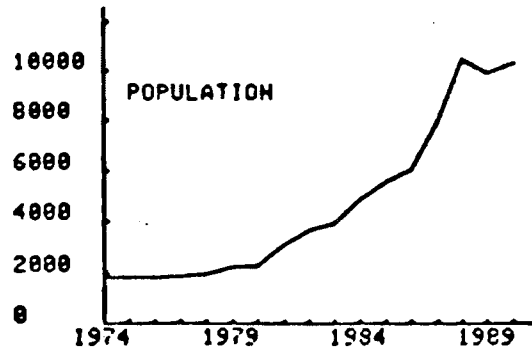


FIGURE 11.4 Projection of Fiscal Capacity of Meeker

RANGELY
FISCAL CAPACITY 1974-1990
 (DOLLARS IN THOUSANDS)
 % OF BASE SELECTIONS

A.U.-	97%
TAX.R.S.-	209%
INTGOUT.-	180%
SOLID WST.-	96%
OP.EXP.-	135%
OTHER REV.-	179%
INCOME PER.	
HOUSEHOLD-	131%

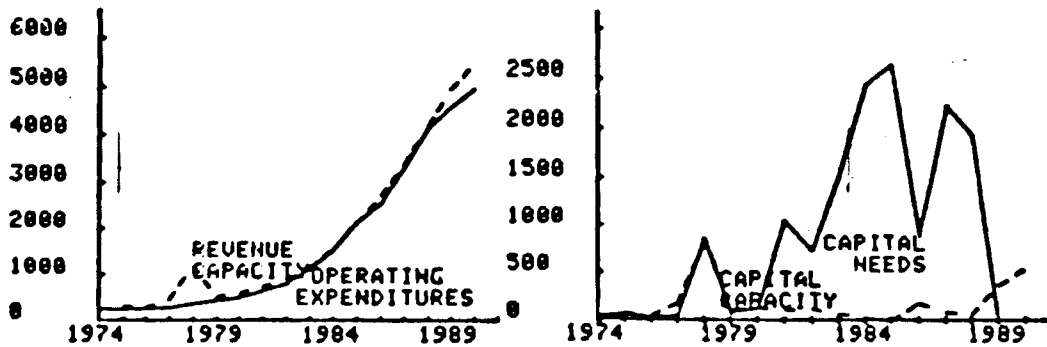
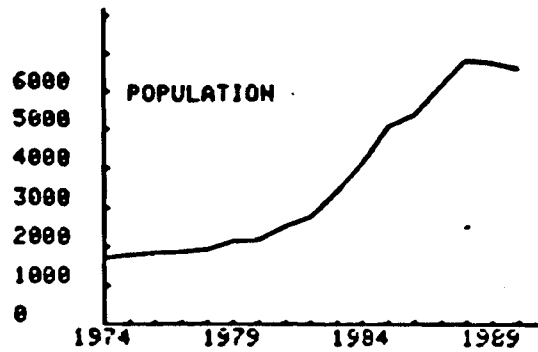


FIGURE 11.5. Projection of Fiscal Capacity of Rangely

GRAND JUNCTION
FISCAL CAPACITY 1974-1990
 (DOLLARS IN THOUSANDS)
 % OF BASE SELECTIONS

A.U.-	168%
TAX.R.S.-	182%
INTGOUT.-	83%
SOLID WST.-	96%
OP.EXP.-	150%
OTHER REV.-	142%
INCOME PER.	
HOUSEHOLD-	116%

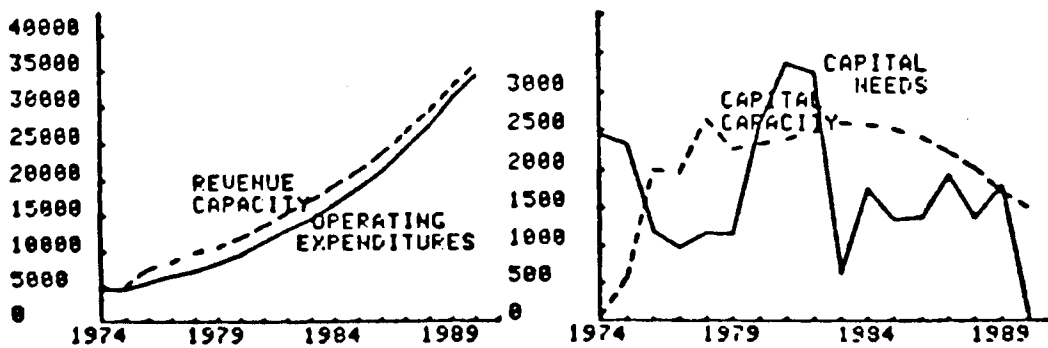
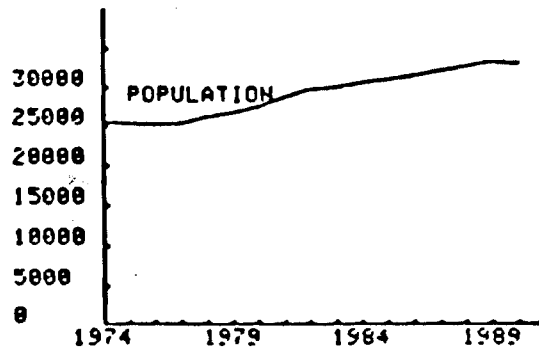


FIGURE 11.6 Projection of Fiscal Capacity of Grand Junction

CRAIG
FISCAL CAPACITY 1974-1990
 (DOLLARS IN THOUSANDS)
 % OF BASE SELECTIONS
 A.U.- 152%
 TAX.R.S.- 164%
 INTGOUT.- 109%
 SOLID WST.- 90%
 OP.EXP.- 104%
 OTHER REV.- 139%
 INCOME PER
 HOUSEHOLD- 107%

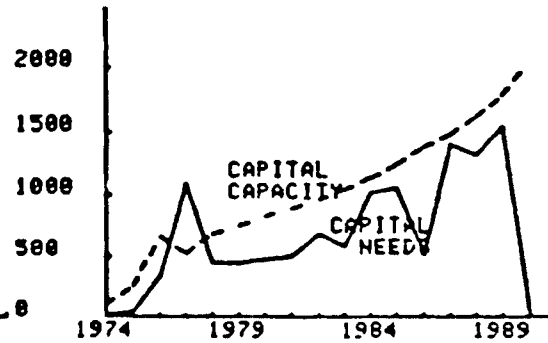
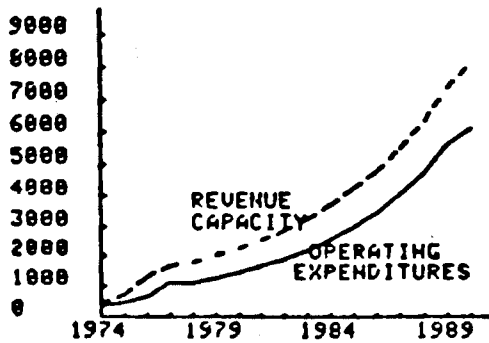
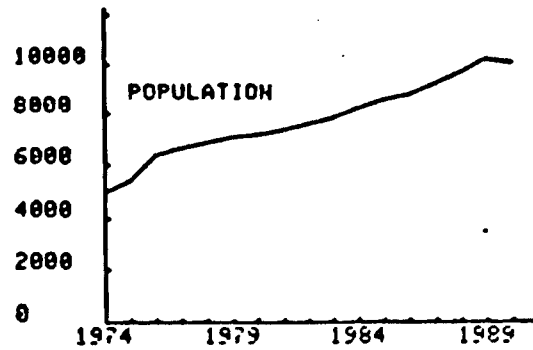


FIGURE 11.7. Projection of Fiscal Capacity of Craig

GLENWOOD SPRINGS
FISCAL CAPACITY 1974-1990
 (DOLLARS IN THOUSANDS)
 % OF BASE SELECTIONS
 A.U.- 172%
 TAX.R.S.- 459%
 INTGOUT.- 166%
 SOLID WST.- 153%
 OP.EXP.- 200%
 OTHER REV.- 196%
 INCOME PER
 HOUSEHOLD- 110%

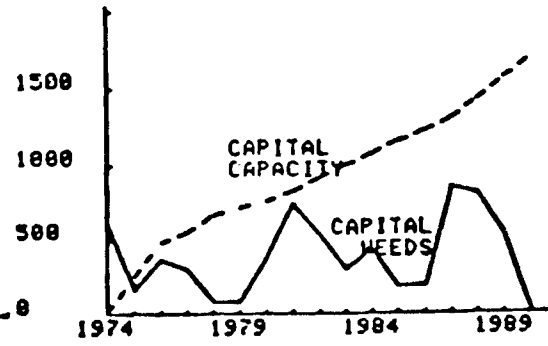
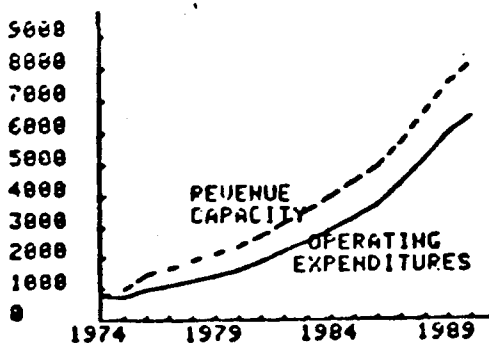
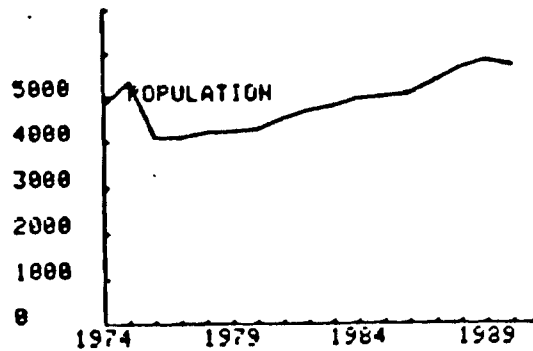


FIGURE 11.8 Projection of Fiscal Capacity of Glenwood Springs

182% of base. As shown in Table 11.7, above, the greatest scenario-induced population growth in Grand Junction will occur in 1981 and 1982. Consequently, the additional fiscal capacity projected for Grand Junction after 1983 is a reflection of the low population growth rate.

These figures should not be viewed as absolute levels of need. They illustrate the potential need for external financial assistance in these communities and/or changes in fiscal policies. Changes in fiscal policy could alter drastically the revenue picture.⁽¹⁵⁻¹⁷⁾ The many proposals to provide front-end financing for construction of needed public facilities have included establishment of a head tax on nonlocal workers to be paid by the employer, increased user fees, revenue-sharing among all levels of local government, use of severance taxes and monies in (and/or the interest from) the state's Oil Shale Lease Fund for impact assistance, and provision of federal assistance through existing channels and new legislation. Many of these proposals have been adopted, and millions of dollars already have been provided for capital expenditures in the communities that anticipate impacts from oil shale development.

The delay of the expected development of a commercial oil shale industry has provided several years in which revenues sources have been identified, issues of equity explored, and mechanisms for awarding assistance established. The state has initiated efforts to assemble and update public facility capacity data for communities throughout the state, and has developed several in-house computer models to assist impact forecasting. However, there is little agreement among Federal, state, and local government officials as to who should pay. Clearly, government at all levels has recognized that fiscal policy should be regarded as an interactive tool that can be used to effect change. Questions of equity, however, continue to handicap attempts to develop comprehensive fiscal programs that would release local government from the present perennial duties of grantsmanship.

11.5 HOUSING

One of the most critical problems in periods of rapid population growth is the supply of adequate housing. Lack of adequate housing has aggravated the

negative aspects of accelerated growth in many energy-impacted communities, and the problem has been described as a major contributing factor in the reduction of worker productivity and increased worker turnover.^(18,19) Both effects lead to a greater number of workers than estimated. Inadequate housing contributes directly to individual and family problems, and reduces the ability of the community to attract new residents, especially professionals and public employees required to support the community.

There are many reasons why adequate housing has not been available in energy boom towns. Among the most important is the uncertainty that surrounds energy development. Construction schedules of energy facilities are subject to many changes that stem from technology or economic changes or arise through the permitting process. In the case of large commercial oil shale facilities, the work force requirements remain to be confirmed by experience. Further uncertainty lies in the number of family members who will accompany energy workers.

Finally, developers are unwilling to build before the demand for housing exists, and are reluctant to do so when the possibility of a bust is great.⁽²⁰⁾

Another important reason for the lack of adequate housing has been the shortage of materials, labor, and capital. Energy development has affected small, isolated, rural communities that cannot generate adequate capital to finance a sudden increased demand for housing and cannot provide sufficient labor for housing construction. Labor shortages are further exacerbated by competition from the energy facility. To provide housing, outside developers must be brought in. Land speculation, in addition to labor and materials shortages, drives up the cost of housing in boom towns, whereas lack of mortgage money reduces the number of persons able to purchase housing. As a result, people are drawn by the need for shelter to live in tents or campers and to rent motel rooms by 8-hr shifts.

A Los Alamos simulation model for housing policies (BOOMH) has provided some insight into the interplay of specific housing supply and demand constraints characteristic of boom town conditions. The use of modular housing, relaxed regulations, land assembly, and financial aid to developers, for example, have been shown to eliminate the boom-induced inflation of housing

costs. On the other hand, even the implementation of supply-oriented policies may not overcome the negative effect of risk, and an adequate supply of housing may only be guaranteed through intervention by the state or Federal government or by the energy company.⁽²¹⁾

Battlement Mesa, a planned new community, will help the region in coping with the oil shale boom. ARCO developed plans for this community to be built near Parachute and to house 21,000 people. Exxon, which purchased ARCO's colony interests this spring, plans to proceed with the construction of the town.

According to the Garfield County Planning Director, more new housing units were approved in all of Garfield County in 1979 than in any previous year.⁽²²⁾ The August 1979 C-b monitoring report listed many new housing subdivisions under development in both Meeker and Rifle.⁽²¹⁾ Housing cost reflect inflationary tendencies, however. The median sales price of a single-family home in Rifle increased from \$49,500 to \$58,000, an increase greater than 17% from 1978 to 1979. Apartments are scarce and very expensive to rent. According to the 1979 DRI case study of Meeker,⁽⁹⁾ Rio Blanco County has had to rely on outside developers and capital for construction of new housing. Garfield County, on the other hand, has been able to support some local developers although not to the extent that Mesa County has. Of all three counties, DRI reported, the housing supply is greatest in Mesa County.

If the oil shale industry develops as described by the DOE Scenario, more than 8100 new households will enter the regional housing market by 1985, and an additional 4600 will enter by 1990 (assuming an average of 2.75 persons per household). If only half of these people were to purchase single-family houses at the 1979 median sales price reported in Rifle, \$261 million of mortgage capital would be required by 1985 and a total of \$404 million by 1990. There is some concern that availability of mortgage capital will prove to be a greater problem than construction of an adequate number of houses.⁽²³⁾

11.6 SOCIAL IMPACTS

Growth generated by oil shale development will bring changes in the communities' culture, social structures, and institutions.^(14,24) Reports on other western boom towns suggest that, unless effective strategies for managing these changes are conceived and implemented, these alterations can lead to high levels of individual stress, a deterioration of sense of community, an increase in social disruption, greater work force turnover, and an eventual lowered productivity in the oil shale industry. The following discussion will focus on factors that lead to these human problems of rapid growth and the development of mitigating measures by the community and industry.

The disruptive effects of rapid change on the social systems of small rural communities have been well documented. A study of Craig, Colorado, during its period of greatest growth (1976) noted dramatic increases in drug and alcohol abuse, family disturbances, child behavior problems, and crimes against persons.⁽²⁵⁾ The rate of increase substantially exceeded the growth rate of the community, and the data suggest that the problems were divided nearly evenly between long-time residents and newcomers.

A study conducted by the National Institute of Mental Health concludes that rapid change and/or community instability may be correlated with an increased risk of mental illness.⁽²⁶⁾ During the Gillette, Wyoming, boom of the 1970s, residents reported stress related to changes in living conditions, work, financial status, deficits in community services, and the demands of adjusting to life in a new community.

Among the first specific stresses faced by residents of a boom town are the anticipation and perceptions of the impending change. Cobb states that "anticipation of change may, in fact, produce more severe and/or different patterns of symptomatology than change itself."⁽²⁷⁾ With the problems of other boom towns being well publicized and with the continuing uncertainty about the actual levels of growth to be expected in the oil shale region, residents may begin to feel less secure, less in control of the destiny of their community, and may behave as if the change has actually occurred.

As social and institutional changes occur, both residents and newcomers may find that their previous roles have been altered, causing introspection and a need to deal with a new definition of expectations and socially acceptable behavior. To avoid the stress of these changes, individuals may withdraw from situations where interaction with strangers may be required.

As the number of changes in the community increases, the amount of stress is expected to increase, intensifying the individual's vulnerability. To keep up with the pace of change, he must regularly draw on his inner reserves of personal resources. If there is limited access to community centered support structures, he has fewer opportunities to replenish these reserves.

As there are few precedents in rapidly growing communities for government, industry, and the community to plan for social change cooperatively, such planning historically has not been a significant factor in policy deliberations. The success of such planning is dependent on several key issues:

- The scope and place of development. The growth scenario discussed in this report lends itself to potentially effective programs for change management tied to community integration.
- Planning the location of growth to center around the core of an existing community or the development of a new town. Each location requires a different approach to the development of a sense of community.
- The use of lead time. The amount of lead time and degree of commitment to human impact planning will determine the extent to which change management programs are in place at the time of impact.
- A focus on proactive (preventative) or reactive programs. Boomtown experiences indicate that unless funding stipulations emphasize prevention efforts, available resources will be used almost exclusively for reactive programming.

- The selection of a human impact planning body. Should planning and advisory authority be vested in a body external to government and industry? If so, how should that body be comprised and its authority supported and/or limited?
- The allocation of resources for change management. Who bears the cost of coping with human impacts; who determines appropriate expenditures; what is the process for negotiating responsibility?

Northwestern Colorado at present lacks an adequate formal human service structure to cope with major growth.⁽²⁸⁾ However, many formal human service needs of future oil shale employees and their families could be funded through company benefit policies, for example health insurance. As the tax base grows, local governments will be better able to fund social services.

Expanding traditional social services will probably not suffice to cope with the impacts of energy development. The changes caused by development can best be managed by promoting a positive sense of community. Two approaches to this are promoting community integration and reducing specific stress factors. Local resource planning groups are best qualified to manage a community integration program. A volunteer corps comprised of both current residents and newcomers recruited and supported by the human resources organization could carry out this program. The volunteers are trained in communication skills and in the recognition of common problems faced in moving to a new community. They would have the responsibility for carrying out the two primary tasks of the program: preparing a community information handbook and identifying and contacting newcomers. In this way, both general information and personal resources can be made available to newcomers shortly after their arrival in the community. Several major corporations have created their own internal volunteer programs to facilitate integration of employees into the community.

Industry, with the assistance of the human resources planning body, can initiate other programs that are designed to reduce stereotyping of industry employees and to ease their transition into the community. Such programs could include orienting new employees, encouraging employees to participate in community affairs, and presenting programs on the plans for oil shale development to

community groups. Companies could also limit the total number of newcomers by hiring locals and spouses of employees. Programs designed to minimize the impact of the construction phase of oil shale development are particularly important since this phase is socially disruptive. Integrating operations personnel into the community could become more difficult if severe construction phase impacts have been experienced.

The effectiveness of these prevention programs is dependent not only on their success during each phase of development, but also on the outcome expected by the public. As development approaches, the community may expect social disruption, based on the experiences of earlier boomtowns. Over the long run, the outlook can be more favorable because the rate of occurrence of social problems may fall below that of the predevelopment era. Also, eventually there are likely to be more community amenities available than in the past because an enhanced economy and more favorable cost-benefit ratios may provide new commercial, educational, recreational, cultural, and social resources. In a stabilized, cohesive community, these resources may meet the individual needs of long-time resident and newcomer alike.

11.7 PLANNING AND NEEDS ASSESSMENT

To meet the challenges of anticipated rapid growth, the state and local governments have initiated several mechanisms for planning and financing. Each incorporated municipality employs a full-time city manager. The towns of New Castle, Parachute, and DeBeque have jointly hired a town administrator circuit rider who will assist in their growth management process. The counties, too, have planning directors and their staffs who report to the Board of County Commissioners. Comprehensive or master land use plans have been developed for Rio Blanco County and Garfield County; the plan for Mesa County is under development. Land use plans have been adopted by Craig, Dinosaur, Rangely, and Fruita and are under development for Meeker, Glenwood Springs, Silt, Rifle, Battlement Mesa, Palisade, and Grand Junction.

Recognition of the importance of identifying community needs, has prompted the development of county impact mitigation task forces. Various organized into advisory and core committees, these task forces identify and evaluate

problems and needs of the local communities. The advisory committees submit applications to the core committees for consideration for Oil Shale Trust Fund appropriations. The members of the core committees represent several levels of government and industry. They determine the availability of resources to fund proposed projects and assign priorities to the projects according to a common set of criteria. Their recommendations are the basis of the Oil Shale Trust Fund request.⁽²⁹⁾

Planning activities at the regional level are sponsored by the Colorado West Area Council of Governments (COG). Upon request, this council provides technical assistance, especially to small communities, in planning for growth. The COG also attempts to assist local communities in the area of grantsmanship and is represented on the county impact mitigation task force core committees. In general, the COG acts as a clearinghouse, compiling and providing information on the existing social and economic conditions, issues, and growth-related impacts.

At the state level, there is a concerted effort to prepare for energy-related growth impacts. The Division of Energy and Minerals in the Department of Local Affairs administers the Local Government Severance Tax Fund, the Local Government Mineral Lease Fund, and the Oil Shale Trust Fund appropriations, and has developed an impact monitoring program. The Department of Local Affairs is in the process of collecting current data on public infrastructure throughout the state. The Department of Natural Resources is in the process of developing an information system to predict population impacts, land use impacts, water requirements, and other environmental impacts implied by energy production plans in northwestern Colorado.⁽³⁰⁾

There are several sources of financing available for planning, design, site acquisition, construction, facility improvements, and programs. The Oil Shale Trust Fund appropriations, made annually by the Colorado Legislative Joint Budget Committee, have increased from \$450,000 in 1975 to more than \$10 million in 1980. Requests also are made to the Impact Assistance Advisory Committee, upon whose advice the Local Government Mineral Lease and Severance Tax Funds are disbursed. The committee maximizes the limited financial resources by encouraging the leveraging of other sources of funds such as Federal grants

and loans. Many appropriations are for design and planning. In addition to seeking external sources of funding, Mesa County has appropriated a substantial portion of its P.I.L.T. (Payment in Lieu of Taxes) funds for facilities design.

As discussed above, preparation for the population growth induced by oil shale development and other energy and mineral development projects in this region depends upon timely growth management activities including the evaluation of short-term and long-range needs and the identification and acquisition of available resources. Although all counties in the region have initiated these processes, the uncertainty that surrounds oil shale development has introduced a certain amount of skepticism with respect to its likelihood. The urgency of planning for an oil shale industry, therefore, lacks credence.

11.8 REFERENCES FOR CHAPTER 11

1. Mangeng, C., D. A. Rapp, R. L. McKeown, and Jodi Kasover. 1981. A Review of Socioeconomic Impacts of Oil Shale Development. Available as Volume 9 of this assessment report.
2. Colorado Manpower Review. 1980. Colorado Department of Labor and Employment. 17(4--April).
3. Colorado Manpower Review. 1980. Colorado Department of Labor and Employment. 17(5--May).
4. Colorado Demographer's Office. Estimates.
5. McDowell-Smith and Associates. 1975. Evaluation of Selected Community Needs. Rifle, Colorado.
6. Colorado Manpower Review. 1980. Colorado Department of Labor and Employment. 17(3--March).
7. Real Estate Research Corporation. 1974. The Costs of Sprawl. Prepared for the Council on Environmental Quality.
8. Colorado West Area Council of Governments and the Oil Shale Regional Planning Commission. 1974. Impact Analysis and Development Patterns for the Oil Shale Region: Mesa, Garfield, and Rio Blanco Counties, Colorado. Denver, Colorado.
9. Denver Research Institute and Resource Planning Associates. 1979. Socio-economic Impacts of Western Energy Resource Development: Volume III: Case Studies.

10. Ford, F. A. 1978. "Social and Economic Impacts." Chapter 11 in National Coal Utilization Assessment: The Impacts of Increased Coal Use in the Rocky Mountain Region. Draft, Los Alamos National Laboratory, Los Alamos, New Mexico.
11. Cluett, C., M. Greene, and L. Radford. 1979. Individual and Community Response to Energy Facility Siting: A Review of the Literature. Battelle Human Affairs Research Centers, Seattle, Washington.
12. Gilmore, J. and M. Duff. 1974. A Growth Management Case Study: Sweetwater County, Wyoming. University of Denver Research Institute, Denver, Colorado; also available as Boom Town Management (Westview Press, Park, Colorado, 1975).
13. Markusen, A. R. 1978. "Socioeconomic Impact Models for Boom Town Planning and Policy Evaluation." Presented at the Western Regional Science Association Meeting, February 25, 1978.
14. Cortese, C. F. and B. Jones, 1979. "The Sociological Analysis of Boom Towns," in Boom Towns and Human Services, J. Davenport and J. Davenport, III, Eds. The University of Wyoming, Laramie.
15. W. Lamont, Study Team Director. 1974. Tax Lead Time Study for the Oil Shale Region. Prepared for the Regional Development and Land use Planning Subcommittee of the Governor's Committee on Oil Shale Environmental Problems.
16. Bolt, R. M., D. Luna, and L. A. Watkins. 1976. Boom Town Financing Study, Volume I. Analysis and Recommendations. Colorado Department of Local Affairs.
17. Santini, D. J., E. J. Stenehjem, and P. Meguire. 1978. Methods of Eliminating Potential Socioeconomic Constraints on Near-Term Coal-Energy Development. Argonne National Laboratory, Argonne, Illinois.
18. Ekland, R. L., and M. E. McGrane. 1977. Local Government Fiscal Capacity Evaluation System: Executive Summary. Colorado Department of Local Affairs, Division of Local Government.
19. Gilmore, J. S. 1976. Boom Towns May Hinder Energy Resource Development. Science 191, (February 13) 535-540.
20. Energy Research and Development Administration. Synthetic Liquid Fuels Development: Assessment of Critical Factors: Volume III Regionalized Industry, Social Impact, Coal Resource Depletion. ERDA 76-129/3.
21. Rink, R., and A. Ford. 1978. A Simulation Model for Boom Town Housing. Los Alamos Scientific Laboratory Report LA-7324-MS.

22. Courtesy of R. Baldwin, Garfield County Planning Director, February 29, 1980.
23. Courtesy of J. L. Ballagh, Armstrong Engineers and Associates, Inc., Grand Junction, Colorado, February 25, 1980.
24. Lantz, A., K. Sackett, and J. Halpern. 1980. "Alcohol Related Problems in Rapidly Growing Communities," in The Boom Town: Problems and Promises in the Energy Vortex, J. Davenport III, and J. A. Davenport, Eds. The University of Wyoming, Laramie.
25. Lantz, A. and R. L. McKeown. 1979. "Social/Psychological Problems of Women and Their Families Associated with Rapid Growth," in Energy Resource Development: Implications for Women and Minorities in the Intermountain West. (U.S. Commission on Civil Rights, Washington, D.C.
26. National Institute of Mental Health. 1974. A Model for Estimating Mental Health Needs Using 1970 Census Socioeconomic Data. U.S. Government Printing Office, Washington, D.C..
27. Cobb, S. 1976. "Social Support as a Moderator of Life Stress." Psychosomatic Medicine 38, 300-314.
28. Hoagland, M. 1978, "A New Day in Rural Mental Health Services." From a series New Dimensions in Mental Health. National Institute of Mental Health, Rockville, Maryland.

APPENDIX A

STUDY PARTICIPANTS

APPENDIX A

STUDY PARTICIPANTS

DOE Project Manager

G. J. Rotariu

Pacific Northwest Laboratory, Richland, Washington

D. L. Hessel, Project Manager, Panel Task Leader, Co-author of Main
Volume Report

I. S. Levy, Assistant Project Manager

J. S. Fruchter, Technical Task Leader

D. L. Brenchley, Technical Task and Panel Task Support

R. L. Drake, Air Quality

C. H. Huang, Air Quality

J. M. Zachara, Solid Waste

R. E. Wildung, Solid Waste

Argonne National Laboratory, Argonne, Illinois

M. Torpy, Surface Water

L. Habaggar, Surface Water

T. Surles, Surface Water

Lawrence Berkeley Laboratory, Berkeley, California

M. Mehran, Ground Water

T. N. Narasimhan, Ground Water

P. Fox, Ground Water

P. Persoff, Ground Water

A. Mathur, Ground Water

Los Alamos National Laboratories, Los Alamos, New Mexico

L. M. Holland, Occupational Health and Safety

C. Mangeng, Socioeconomic Impacts

Colorado State University, Fort Collins, Colorado

G. M. VanDyne (deceased), Ecological and Agricultural Systems Impacts

R. C. Jump, Ecological and Agricultural Systems Impacts

C. Loehle, Ecological and Agricultural Systems Impacts

L. D. Watson, Ecological and Agricultural Systems Impacts

N. R. French, Ecological and Agricultural Systems Impacts

Energy Development Consultants, Inc., Golden, Colorado

E. M. Piper, Technology Characterization and Scenario

J. S. Hutchins, Technology Characterization and Scenario

J. S. Broz, Technology Characterization and Scenario

Strasser Associates, Inc., Vienna, Virginia

G. Strasser, Policy Aspects and Panel Support, Co-author of Main Volume Report

University of Colorado, Denver, Colorado

W. R. Chappell, Policy

Technology Panel

<u>Participant</u>	<u>Affiliation</u>
Kay L. Berry	Rio Blanco Oil Shale Company Denver, Colorado
Brian Harney	Department of Energy Washington, D.C.
Robert Heistand	Development Engineering, Inc. Rifle, Colorado
Joseph Merino	TOSCO Vernal, Utah
Robert E. Thomason	Occidental Oil Shale, Inc. Grand Junction, Colorado

Impact Panel

<u>Participant</u>	<u>Affiliation</u>
Henry Ash	U.S. Department of the Interior Denver, Colorado
A. C. Bishard	Colorado Department of Health Denver, Colorado
Ray Cooper	Consultant to Department of Energy Washington, D.C.
David Mastbaum	Environmental Defense Fund Berkeley, California
Glen Miller	U.S. Geological Survey-AOSO Grand Junction, Colorado
Martin J. Redding	Quality Development Associates, Inc. Denver, Colorado
Terry Thoem	Environmental Protection Agency, Region VII Denver, Colorado

DISTRIBUTION

No. of
Copies

No. of
Copies

OFFSITE

A. A. Chrum
DOE Patent Division
9800 South Cass Avenue
Argonne, IL 69439

2 DOE Technical Information Center

H. Ash
U.S. Department of the Interior
Building 67, Room 820-A
Denver Federal Center
Denver, CO 80225

K. L. Berry
Rio Blanco Oil Shale Company
9725 E. Hampden Avenue
Denver, CO 80231

G. Bierman
Science Applications, Inc.
1710 Goodridge Drive
McLean, VA 22102

A. C. Bishard
Colorado Department of Health
4210 E. 11th Ave.
Denver, CO 80220

W. R. Chappell
University of Colorado
P.O. Box 136
Denver, CO 80202

J. A. Coleman
Office of Environmental
Assessments
Mail Stop E-201/Germantown
Washington, DC 20545

R. Cooper
Office of Health and
Environmental Research
U.S. Department of Energy
Washington, DC 20545

P. Fox
Lawrence Berkeley Laboratory
University of California
Berkeley, CA 94720

L. Habegger
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439

B. Harney
Office of Shale Resource
Applications
Technology Assessments Division
U.S. Department of Energy
Washington, D.C. 20545

R. Heistand
Development Engineering, Inc.
Box A
Anvil Point
Rifle, CO 81650

L. M. Holland
Los Alamos National Laboratory
P.O. Box 1663
Los Alamos, NM 87545

P. W. House
Office of Environmental
Assessments
U.S. Department of Energy
Washington, DC 20545

No. of
Copies

R. K. Lohrding
Los Alamos National Laboratory
P.O. Box 1663
Los Alamos, NM 87544

C. Mangeng
Los Alamos National Laboratory
P.O. Box 1663
Los Alamos, NM 87545

D. Mastbaum
Environmental Defense Fund
2606 Dwight Way
Berkeley, CA 94704

J. Merino
TOSCO
P.O. Box 814
Vernal, UT 84078

G. Miller
U.S. Geological Survey-AOSO
131 No. 6th, Suite 300
Grand Junction, CO 81501

D. M. Monti
Technology Assessments Division
Mail Stop E-201/Germantown
U.S. Department of Energy
Washington, DC 20545

E. M. Piper
Energy Development Consultants
2221 East Street
Golden, CO 80401

M. J. Redding
Quality Development Associates,
Inc.
1700 Broadway, Suite 830
Denver, CO 80290

G. J. Rotariu
Technology Assessments Division
Mail Stop E-201/Germantown
U.S. Department of Energy
Washington, DC 20545

No. of
Copies

A. Rudolph
Battelle Memorial Institute
505 King Avenue
Columbus, OH 43201

R. D. Shull
Regional Impacts Division
Mail Stop E-201/Germantown
U.S. Department of Energy
Washington, DC 20545

W. E. Siri
Lawrence Berkeley Laboratory
University of California
Berkeley, CA 94720

G. Strasser
Strasser Associates, Inc.
2616 Pine Knot Drive
Vienna, VA 22180

T. Surles
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439

T. Thoem
Office of Energy, Region VII
Environmental Protection Agency
1860 Lincoln
Denver, CO 80295

R. E. Thomason
Occidental Oil Shale, Inc.
P.O. Box 2999
Grand Junction, CO 81501

M. F. Torpy
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439

J. W. Skiles
Department of Range Science
Colorado State University
Ft. Collins, CO 80523

No. of
Copies

E. R. Williams
Regulatory Analysis Division
Mail Stop E-201/Germantown
U.S. Department of Energy
Washington, DC 20545

ONSITE

DOE Richland Operations Office

H. E. Ransom

35 Pacific Northwest Laboratory

W. J. Bair
D. L. Brenchley
C. E. Cearlock

No. of
Copies

K. R. Chase
R. L. Drake
H. Drucker
C. E. Elderkin
J. S. Fruchter
I. D. Hays
D. L. Hessel
I. S. Levy
B. W. Mercer
S. Marks (10)
J. M. Nielsen
B. E. Vaughan
R. E. Wildung
J. N. Zachara
Technical Information Library (3)
Publishing Coordination (KC)(2)
Economics Library (5)

