

CHAPTER 8

Environmental Considerations

Contents

	<i>Page</i>		<i>Page</i>
Introduction	255	Policy Options for Water Quality Management	314
Summary of Findings	256	Safety and Health.	315
Air Quality	256	Introduction	315
Water Quality.	256	Safety and Health Hazards	316
Occupational Health and Safety	257	Summary of Hazards and Their Severity.	322
Land Reclamation.	258	Federal Laws, Standards, and Regulations.	324
Permitting.	259	Control and Mitigation Methods	325
Air Quality +	259	Summary of Issues and R&D Needs	326
Introduction	259	Current R&D Programs.	326
Pollutant Generation	259	Policy Considerations.	327
Air Quality Laws, Standards, and Regulations	263	Land Reclamation.	328
Air Pollution Control Technologies	269	Introduction	328
Pollutant Emissions.	278	Reasons for Reclamation	329
Dispersion Modeling.	279	Regulations Governing Land Reclamation.	329
A Summary of Issues and Policy Options.	288	Reclamation Approaches.	330
Water Quality.	291	The Physical and Chemical Characteristics of Processed Shale	332
Introduction	291	Use of Topsoil as a Spent Shale Cover	335
Pollution Generation.	292	Species Selection and Plant Materials	336
Summary of Pollutants Produced by Major Process Types.	294	Review of Selected Research to Date.	339
Effects of Potential Pollutants on Water Quality and Use.	295	Summary of Issues and R&D Needs	341
Water Quality in the Oil Shale Region.	296	Policy Options for the Reclamation of Processed Oil Shales.	342
Water Quality Regulations.	297	Permitting.	343
Technologies for Control of Oil Shale Water Pollution	304	Introduction	343
Ultimate Disposition of Waste Water	308	Perceptions of the Permitting Procedure.	344
Monitoring Water Quality	309	Status of Permits Obtained by Oil Shale Developers	345
Information Needs and R&D Programs	311	The Length of the Permitting Procedure	346
Findings on Water Quality Aspects of Oil Shale Development.	314	Disputes Encountered in the Permitting Procedure	346

	Page
Unresolved Issues.	347
Attempts at Regulatory Simplification.	348
Policy Options.	349
Chapter8 References.	352

List of Tables

TableNo,	Page
34. Pollutants Generated bythe Colony Development Project	262
35. PollutantsGenerated by the Rio Blanco Project on TractC-a.	263
36. Pollutants Generatedbythe Occidental Operation on TractC-b	263
37. The Federal and State Ambient Air Quality Standards and Prevention of Significant Deterioration Standards That Influence Oil Shale Development	266
38. National Standards for Prevention of Significant Deterioration of Ambient Air Quality,	267
39. National New Source Performance Standards for Several Types of Facilities	269
40. EPA Standards for Best Available Air PollutionControl Technologies for Oil Shale Facilities.	269
41. Technological Readinessof Air Pollution Control Technologies	276
42. Costs of AirPollutionControl	277
43. Pollutants Emitted by theColony Development Project	278
44. Pollutants Emitted by theRio Blanco Project on Tract C-a.	278
45. Pollutants Emitted by the Occidental Operation on TractC-b	279
46. A Summary of Emission Rates From Five Proposed Oil Shale Projects.	279
47. A Comparison of Atmospheric Emissions Used in Modeling Studies.	282
48. Modeling Results for Federal Oil Shale Lease TractC-a	284
49. Models Used in SupportofPSD Applications for Oil Shale Projects	285
50. Areas of Inadequate Information and Suggested R&D Responses	288
51. Generation Rates for Principal Water Pollutants for Production of 50,000 bbl/d of Shale Oil Syncrude.	294
52. Quality of Some SurfaceStreams in the Oil Shale Region	297
53. Quality of GroundWaterAquifers in the Piceance Basin.	297

	Page
54. Effluent Limitations for Petroleum Refineries Using BestPracticable Pollution Control Technology.	299
55. Effluent Limitations for Best Available Technology Achievable for Petroleum Refinery Facilities	299
56. New Source Performance Standards for Petroleum Refineries	300
57. Colorado Water Quality Standards for Stream Classification B2	301
58. Utah Water Quality Standards for Stream Classification CW	301
59. Proposed Water Quality Criteria for Designated Uses.	302
60. Primary Drinking WaterStandards	303
61. Proposed Secondary Drinking Water Regulations.	303
62. The Types of Contaminants in Oil Shale Wastewater Streams and Some Potential Processes for RemovingThem	305
63. Relative Rankings of the Water Treatment Methods	306
64. Estimated Costs of Water Pollution Control in Oil ShalePlants.	306
65. Sampling Schedule Summary for Surface and Ground Water Monitoring Program at Tract C-b During Development Phase.	312
66. Animal Studies on the Carcinogenicity of Oil Shale and ShaleOil	320
67. Benzo(a)pyrene Content of Oil Shale and Its Products and of Other Energy Materials	320
68. The Chemical and Physical Properties of Processed Shales	332
69. Estimates of Reclamation Needs Under Various Levels of Shale Oil Production.	338
70. Status of the Environmental Permits for Five Oil Shale Projects,	345

List of Figures

	Page
59. Designated Class I Areas in Oil Shale Region	268
60. Computation Modules in Atmospheric Dispersion Models	281
61. An Aboveground Spent Shale Disposal Area	307
62. Summary of Occupational Hazards Associated With Oil ShaleDevelopment.	323

Environmental Considerations

Introduction

The region where oil shale development will take place is, at present, relatively undisturbed. The construction and operation of plants would emit pollutants and produce large amounts of solid waste for disposal. As a consequence, air, water, and soil could be degraded and the topography of the land could be altered. The severity of these impacts will depend on the scale of the operations and the kinds of processing technologies used, as well as the control strategies that must be adopted to comply with environmental regulations.

Control strategies have been proposed for purifying water and airborne emissions streams, for revegetation, for protecting wildlife, and for other specific areas of environmental concern. However, control technologies that are applied to one area could adversely affect another area. For example, to control air pollution, airborne streams are scrubbed to capture dust and gaseous contaminants. This produces sludges and wastewater that have to be disposed of along with other wastes. All of these have the potential to adversely affect the land and the water.

Airborne pollutants, such as trace metals, might enter surface streams and ground water in fugitive dust and or rainfall and could alter the chemical and biological balances of the water systems. Plant and animal life as well as human health could be harmed both by an increase in water contamination and by the entry of the contaminants into the food chain. Similarly, without adequate controls, the piles of solid waste could contaminate the air and water through fugitive dust

emissions and by the leaching of soluble constituents into surface and ground water systems. Water quality could thus be degraded by altered nutrient loading, changes in dissolved oxygen, and increased sediment and salinity.

For these reasons, each potential environmental effect along with its control technology should be examined with respect to its net impact on the total environmental system. To do this requires full understanding of the separate impacts on air, water, and land, the interaction between the individual parts of the ecosystem, and the efficacy of the control strategies. Such an analysis needs a complete and accurate data base which is as yet unavailable because no commercial oil shale plants have been built. OTA's environmental analysis, therefore, is limited to examining the effects that an oil shale industry would have on the separate areas of air, water, land, and occupational health and safety. In order to provide a basis for policy analysis, the effects are quantified wherever possible and related to a production of 50,000 bbl/d. For each of the areas examined:

- impacts of oil shale operations are described;
- applicable laws and regulations are summarized, and their significance to oil shale analyzed;
- control strategies proposed for compliance with the laws and regulations are described and evaluated; and
- policies that could be focused on key issues and uncertainties are identified and discussed.

Summary of Findings

Air Quality

Because of the oil shale region's rural character, its air is relatively clean and unpolluted. Occasionally, however, high concentrations of hydrocarbons (possibly from vegetation) and particulate from windblown dust occur. The development of a large oil shale industry (or any industrial or municipal growth) will degrade the air's visibility and quality. Even if the best available control technologies are used and compliance is maintained with the provisions of the Clean Air Act, its amendments, and the applicable State laws, degradation will occur. It will take place not only near the oil shale facilities but also in nearby pristine areas (e.g., national parks, wilderness areas). Some places may be affected more than others from local concentrations of pollutants caused by thermal inversions.

Findings of the analysis include:

- Oil shale mining and processing will produce atmospheric emissions including those pollutants for which National Ambient Air Quality Standards (NAAQS) have been established (i.e., sulfur dioxide, particulate, carbon monoxide, ozone, lead, and nitrogen oxides); as well as various other currently unregulated pollutants (such as silica, sulfur compounds, metals, trace organics, and trace elements).
- Under the Clean Air Act, oil shale development will have to comply with NAAQS and State air quality standards; maintain air quality, especially visibility, in adjacent Class I areas (e.g., national parks); comply with prevention of significant deterioration (PSD) increments (these specify the maximum increases in the concentrations of sulfur dioxide and particulate that can occur in any region); comply with New Source Performance Standards (NSPS); and apply the best available control technology (BACT).
- A wide variety of control technologies could be applied to the emissions streams from oil shale processes. They are fairly well developed and have been successfully used in similar industries. They should be adaptable to the first generation of oil shale plants. However, full evaluation will not be possible until they have been tested in commercial-scale oil shale plants for sustained periods.
- The costs of controlling air pollution will be particularly sensitive to the strictness of the environmental regulations and to the design characteristics and size of each project. Preliminary estimates indicate that air pollution control could cost from \$0.91 to \$1.16/bbl of syncrude produced (roughly 3 to 5 percent of the selling price of the oil).
- The only means for predicting the long-range impacts of oil shale emissions on ambient air quality in the oil shale area and in neighboring regions are mathematical dispersion models, which are the Environmental Protection Agency's (EPA) tool for enforcing the provisions of the Clean Air Act. Modeling of oil shale facilities presents a number of problems because of the topography and meteorology of the region, the chemistry of the emissions, and the unknown quantities of emissions expected from commercial-size facilities. In addition, dispersion models developed to date have been primarily for flat terrain. Thus, their predictions contain significant inaccuracies. More R&D needs to be undertaken in this area.
- Even with the use of BACT, the industry's capacity will be limited by the air quality standards governing PSD. A preliminary modeling study by EPA has indicated that an industry of up to 400,000 bbl/d in the Piceance basin could probably comply with the PSD standards for Flat Tops (a nearby Class I area) if the plant sites were dispersed. Additional capacity could be installed in the Uinta basin, which is at least 95 miles from Flat Tops. A 1-million-bbl/d industry could probably not be accommodated because at least half of its capacity (500,000 bbl/d) would be located in the Piceance basin. Policy options to address this limitation include the application of more stringent emission standards, changes in PSD increment allocation procedures, and amending the Clean Air Act.

Water Quality

Water quality is a major concern in the oil shale region, especially in regard to the salinity and sediment levels in the Colorado River system. The potential for pollution from oil shale development could come from

point sources such as cooling system discharges; from nonpoint sources such as runoff and leaching of aboveground waste disposal areas and ground water leaching of in situ retorts; and from accidental discharges such as spills from trucks, leaks in pipelines, or the failure of containment structures. Unless these pollution sources are properly controlled, the lowered quality of surface and ground water resources could adversely affect both aquatic biota and water for irrigation, recreation, and drinking.

Specific findings include the following:

- Surface discharge from point sources is regulated under the Clean Water Act, and ground water reinjection standards are being promulgated under the Safe Drinking Water Act. Solid waste disposal methods may be subject to the Toxic Substances Control Act and the Resource Conservation and Recovery Act. The general regulatory framework is therefore in place, although no technology-based effluent standards have been promulgated for the industry under the Clean Water Act. Nonpoint sources present regulatory and technological difficulties, and at present are subject to less stringent controls.
 - Developers are currently planning for zero discharge to surface streams and to reinject only excess mine water. This eliminates point discharge problems because most wastewater will be treated for re-use within the facility, and untreatable wastes will be sent to spent shale piles. The costs of this strategy are low to moderate, and development should not be impeded by existing regulations if it is used.
 - A variety of treatment devices are available for the above strategy, and many of them should be well-suited to oil shale processes. However, uncertainties exist regarding whether conventional methods would be able to treat wastewaters to discharge standards because they have not been tested with actual oil shale wastes under conditions that approximate commercial production. There are also a number of uncertainties regarding the control of nonpoint pollution sources. For example, no technique has been demonstrated for managing ground water leaching of in situ retorts, nor has the efficacy of methods for protecting surface disposal piles from leaching been proven. It is not known to what extent leaching will occur, but if it did, it would degrade the region's water quality.
- Although control of major water pollutants from point sources is not expected to be a problem, less is known about the control of trace metals and toxic organic substances. Research is needed to assess their potential hazards and to develop methods for their management. Other laboratory-scale and pilot-plant R&D should be focused on characterizing the waste streams, on determining the suitability of conventional control technologies, and on assessing the fates of pollutants in the water system. Extensive work is already underway; its continuation is essential to protecting water quality, both during the operation of a plant and after site abandonment.

Occupational Health and Safety

The oil shale worker will be exposed to occupational safety and health hazards. Many of these—such as rockfalls, explosions and fires, dust, noise, and contact with organic feedstocks and refined products—will be similar to those associated with hard-rock mining, mineral processing, and the refining of conventional petroleum. However, the workers might be exposed to unique hazards due to the physical and chemical characteristics of the shale and its derivatives, the types of development technologies to be employed, and the scale of the operations. Potential risks include safety hazards that might result in disabling or fatal accidents, and health hazards stemming from high noise levels, contact with irritant and asphyxiant gases and liquids, contact with likely carcinogens and mutagens, and the inhalation of fibrogenic dust.

Specific findings include:

- Only a few fatalities have occurred during the mining of over 2 million tons of shale and the production of over 500,000 bbl of shale oil. The accident rate has been one-fifth that for all mining, and much lower than that for coal mining. However, this record was achieved in experimental mines that employed, for the most part, experienced miners. Whether safety risks will increase or decrease as mining activities are expanded cannot be predicted.
- Although the carcinogenicity of oil shale dusts and crude shale oil has been demonstrated by some investigators, the conflicting results of other studies combined with an overall lack of information pre-

elude a determination of the severity of the risk. The incidence of diseases in other industries indicates that exposure to these materials could be hazardous.

- The large variety of substances that will be encountered in retorting may present as yet undetected health hazards. Of special concern is the possibility of carcinogens in shale oil and its derivatives. Possible synergistic effects from the products of modified in situ (MIS) operations (which combine mining with retorting) could increase the level of risk.
- Shale oil refining poses no special hazards since most of its problems will be similar to those experienced in conventional petroleum refining.
- Health and safety hazards will be reduced by using pollution control technologies for air and water pollutants and by requiring specific industrial hygiene practices. These are required by law and are expected to be implemented by oil shale developers. However, it is essential that R&D on the nature and severity of health effects keep pace with the development of the industry. Such information will be useful in identifying and mitigating long-term effects on workers and the public.

Land Reclamation

An industry will require land for access to sites, for the facilities, for mining, for retorting, for oil upgrading, and for waste disposal. The extent to which development will affect the land on and near a given tract will be determined by the location of the tract; the scale, type, and combination of processing technologies used; and the duration of the operations. The facilities must comply with the laws and regulations that govern land reclamation and waste disposal. Nevertheless, there will still be effects on land conditions (through altered topography) and wildlife (through changes in forage plants and habitats). In addition, unless appropriate disposal and reclamation methods are developed and applied, the large quantities of solid wastes that will need to be handled could pollute the air with fugitive dust and the water with runoff and leachates from storage piles and waste disposal areas.

Specific findings include:

- Several approaches can be used to reduce the deleterious effects associated with the disposal of spent oil shale. These include reducing surface wastes by using in situ processing or returning wastes to mined out areas; the chemical, physical, or vegetative stabilization of processed shale; and combinations of the above.
- Research has shown that vegetation can be established directly on processed oil shales. However, intensive management is required, including the leaching of soluble salts, the addition of nitrogen and phosphorus fertilizers, and supplemental watering during establishment. Revegetating spent shale covered with at least 1 ft of soil is less susceptible to erosion and does not require as much supplemental water and fertilizer. Adapted plant species are required for either option,
- The long-term stability and character of the vegetation is unknown, but research on small plots suggests that short-term stability of a few decades is likely **if sufficient topsoil is added.**
- Reclamation plans will have to be site specific since environmental conditions vary from site to site. Proper management will be required in all instances, if only to maintain plant communities in surrounding areas. It is even more important in the reclaimed areas.
- Shortages of adapted plants and associated support materials such as mulches probably would occur if a large (ea. 1 million bbl/d) industry is established. The problem is compounded by the increasing demands from other mining operations such as coal and other minerals.
- The Surface Mining Control and Reclamation Act provides for the kind of comprehensive planning and decisionmaking needed to manage the land disturbed by coal development. New reclamation standards that are applied to oil shale should provide for postmining land uses that are ecologically and economically feasible and consistent with public goals.

Permitting

During the past 10 years an increasingly complex system of permits has been developed to assist the Federal, State, and local governments in protecting human health and welfare and the environment. Permits are the enforcement tool established by Congress and the States to determine whether a prospective facility is able to meet specific requirements under the law.

Operation of an oil shale facility requires more than 100 permits from Federal, State, and local agencies. Included are those for environmental maintenance, for protection of worker health and safety, and for the construction and operation of any industrial facility (e.g., building code permits, temporary permits for the use of trailers, sewage disposal permits). Of these 100 permits, about 10 major environmental ones require substantial commitments of time and resources.

Findings of the analysis include:

- The time required for preparing and processing a permit application depends on the type of action being reviewed, the review procedures stipulated under the law, the criteria used by agencies to judge the application, and the amount of public participation and controversy that is brought to bear. If Federal land is involved, then an environmental impact statement (EIS) will most likely be required. The EIS process may take at least 9 months after the developer applies for permission to proceed with the project. In the case of the current Federal lease tracts, additional time was needed to prepare detailed development plans (DDP) for approval by the Area Oil Shale Super-

visor of the U.S. Geological Survey (USGS). Once the requirements for an EIS and DDP are satisfied, obtaining all of the needed permits can take more than 2 years. The project would not necessarily be delayed by the full length of the permitting schedule, because other predevelopment activities such as engineering design, contracting, and equipment procurement could proceed in parallel, if the developer were willing to accept the risk that some of the permits might not be obtainable.

- The principal problems encountered to date with the permitting process are related to the needs of the regulatory agencies for technical information and to differing interpretations of environmental law. Future problems may be more critical than those encountered thus far. Several relevant regulations are still pending that may increase costs or force changes in the design of process facilities or control technologies. They may also add to the control requirements. Another problem that might emerge is the ability of regulatory agencies to handle the increasing load of permit applications and enforcement duties.
- Several attempts are being made to simplify regulatory procedures. These include the streamlining of permitting procedures within specific agencies; the design and testing of a permit review procedure for major industrial facilities that will coordinate the reviews by Federal, State, and local regulators; and the proposed Energy Mobilization Board to expedite agency decisionmaking and reduce the impacts of new regulatory requirements. Colorado has recently announced a joint review process designed to accomplish the first two of these ends.

Air Quality

Introduction

The maintenance of air quality is necessary for the development of an environmentally acceptable oil shale industry. In this section:

The types of atmospheric contaminants produced by oil shale unit operations are characterized.

- Rates are estimated for the generation of air contaminants.
- The applicable Federal and State air quality regulations and standards are described.
- The effects of these regulations and standards on a developing oil shale industry are analyzed.

- The air pollution control technologies that may be applied to untreated emission streams are described and evaluated. The net rates at which pollutants will be emitted in treated streams are estimated.
- Modeling procedures that may be used to predict and monitor compliance with air quality regulations are discussed.
- Potential problems that commercial-scale operations may encounter in meeting standards are identified.
- Key findings are summarized.
- Policy options are discussed.

Pollutant Generation

Oil shale mining and processing will produce atmospheric emissions including those pollutants for which NAAQS have been established: sulfur dioxide (SO₂), particulate, carbon monoxide (CO), ozone (O₃), lead, and nitrogen oxides (NO_x); as well as various other currently unregulated pollutants, such as silica, sulfur compounds, metals, carbon dioxide (CO₂), ammonia (NH₃), trace organics, and trace elements. The following discussion examines the types of pollutants generated by each unit operation. Where data are available, the rates at which these contaminants will be produced by different oil shale facilities are estimated.

Unit Operations and Pollutants

Mining can be carried out either using underground (room and pillar) or surface (open pit) methods. The sequential steps in room-and-pillar mining are drilling, blasting, mucking (collection of the blasted shale), primary crushing, and conveying the reduced shale to the surface for retorting. Potentially hazardous substances (silica, salts, mercury, lead) may be released during blasting. Methane may be released from underground gas deposits, and CO, NO_x, and hydrocarbons (HC) may be emitted by incomplete combustion of the fuel oil used both for blasting and in mobile equipment. In addition, particulate can be emitted as a result of blasting, raw shale handling and disposal, and activities at the

minesite that produce fugitive dust (particulate matter discharged to the atmosphere in an unconfined flow stream).

Atmospheric emissions are expected to be much larger in open pit than in room-and-pillar mining because of the significantly larger quantities of solids that must be handled on the surface. The mine dust problem will be further aggravated by road dust from transportation of overburden, and wind-blown dust from all operations.

Storage, transport, and crushing of oil shale result in the emission of particulate, CO, NO_x, SO₂, and HC from fuel in diesel engines, and particulate and silica from fugitive dust. Dust is the chief pollutant. The amount generated depends on the grade of ore, the extent to which its size must be reduced for retorting, the number of transfer points in the transportation system, and the level and effectiveness of control strategies used.

Retorting technologies generate process heat by the combustion of fossil fuels, which produces a number of atmospheric emissions. The amount of SO₂ emitted depends on the sulfur content of the fuels used in the plant and the extent to which sulfur-containing product gases are treated. The volume and concentration of hydrogen sulfide (H₂S), carbonyl sulfide (COS), and carbon disulfide (CS₂) in the offgas streams from retorts depend on the type of retorting technology. COS has been detected in the offgases from Lawrence Livermore Laboratory's simulated MIS retorts and trace quantities of COS and CS₂ have been reported in the offgases from the Occidental MIS process under certain operating conditions. It is not known whether the retort offgases from the Paraho, Union "B," TOSCO II, or Superior processes contain COS or CS₂.

The major source of NO_x emissions is the combustion of fuel in boilers, air compressors, and diesel equipment. The specific levels depend on the combustor design, the extent of onsite fuel use, and the nitrogen content of the fuels used to produce process heat or steam. Most of the fuels consumed in oil

shale plants will be produced onsite. Both directly heated aboveground retorts (AGR) and MIS generally produce sufficient low-Btu gas to meet retorting requirements, plus an excess for other onsite uses such as power generation. Indirectly heated aboveground retorts produce less fuel gas, but it has a higher heating value. In either case, it is possible that some shale oil will be burned for process heat. Since both retort fuels (gases and shale oil) contain nitrogen, they could potentially emit more NO_x .

HC and CO will be emitted primarily in the exhausts of mobile equipment and in flue gases from boilers and other combustors. HC will also be emitted in vapors from oil storage tanks, pumps, flanges, seals, and compressors, and CO by blasting and rubblization during the preparation of MIS retorts. Emission levels from storage tanks should not vary with the type of retorting technology. The other HC and CO sources have a dependence on retorting technology that is similar to that described for NO_x . Equipment-related emissions are a function of the amount of solids that need handling on the surface.

The quantities and the chemical properties of the particulate emitted vary with retorting technologies. Retorts like TOSCO II that require fine shale feed and produce very fine retorted shale, produce the largest amounts.

The pyrolysis of an organic material like oil shale kerogen produces a certain amount of polycyclic organic matter (POM). POM, which is found in conventional crude oils, has also been found in the carbonaceous retorted shales from TOSCO II, Union "B," and Paraho indirect retorts. It is rarely found in retorted shale that has been subjected to a strong oxidizing environment such as that encountered in the Paraho direct retort.

Trace elements (particularly the heavy metals) may be released by retorting operations. Compared with average rocks, Green River oil shale contains much higher levels of selenium and arsenic; moderately higher levels of molybdenum, mercury, antimony, and boron; and lower levels of cobalt, nickel,

chromium, zirconium, and manganese.¹ At typical retorting temperatures (ea. 900° F (480° C)), it is generally accepted that most trace elements are not volatilized. They leave the retort in the spent shale product and in particulate entrained in retort gases and shale oil. Possible exceptions are antimony, arsenic, beryllium, boron, copper, fluorine, lead, mercury, nickel, selenium, and zinc, which could leave the retort as vapor and be condensed in the liquid product.² The heavy metals in raw shale oil are of economic concern because they tend to destroy the effectiveness of the catalysts used for refining. * Their removal is not expected to present any major problems to the refiner. Several proprietary techniques are available for this purpose. It has also been recognized that refining catalysts need careful disposal because they may contain nickel, cobalt, molybdenum, chromium, iron, and zinc, in addition to trace elements captured from the shale oil. Emissions can occur during the onsite regeneration of these catalysts and during the disposal of spent catalysts in landfill operations.

Upgrading, refining, gas cleaning, and power generation produce such pollutants as CS_2 , COS, SO_2 , H_2S , NH_3 , and HC; with HC being the dominant fugitive emission.³ Particulate such as fly ash are also produced.

The handling and disposal of raw and retorted shale could create serious fugitive dust problems. This dust may contain harmful particulate and possibly POM. The problems are most severe for technologies like TOSCO II that produce very fine spent shale. Dust production should be less of a problem with aboveground retorts like those of Paraho and Union "B" that produce coarse spent shale. They should be even less significant for MIS because spent shale will remain underground and will not be subjected to wind erosion.

The Amounts of Pollutants Produced

It is difficult at present to estimate the quantities of air contaminants that would be

*Refinery modifications to mitigate this problem are discussed in ch. 5.

produced by a commercial-size oil shale facility. The only field measurements that have been made to date have been for the small-scale, short-term pilot-plant or semiworks operations of Colony Development, Paraho, and Occidental Oil Shale.⁴ These facilities do not simulate normal operating conditions in a full-size facility, and the measurements that have been made have been mostly of the regulated pollutants. Only a few of the nonregulated pollutants such as trace elements have been measured, and those measurements that have been reported show considerable variation. Pollution production estimates must therefore be confined to regulated pollutants and must strongly rely on theoretical calculations.

The quantities of pollutants produced in an industrial facility can be estimated by applying pollutant generation factors to the mass flows of material through the plant. The procedure used for the calculation, although an approximation, gives estimates of the problem's scope. Generation factors obtained from the literature were applied to the mass balances published for Colony's proposed TOSCO II retorting plant on Parachute Creek, for Rio Blanco's combination of MIS and AGR processing on tract C-a, and for the Occidental MIS operation on tract C-b. All flows were scaled to a uniform production level of 50,000 bbl/d of shale oil syncrude. The results are summarized in tables 34 through 36. Note

that the tables show levels of pollutant generation, not pollutant release.

Of the three designs—Colony, Rio Blanco, and Occidental—Colony produces the largest amount of particulate. This plan uses both the most underground mining and TOSCO II AGR, which requires a fine shale feed and produces a very finely divided shale. This retorting method is also responsible for Colony's exceptionally high production of HC. In the TOSCO II retorting system, vaporized shale oil and gases evolved during pyrolysis are stripped of high molecular weight HC in a condenser, and then burned to reheat the heat carrier balls. Because combustion is incomplete, lighter weight HC are entrained in the offgas stream from the ball heater.

In generating steam for power, the Occidental design in which large quantities of low-Btu gas are burned produces the most NO_x emissions. Rio Blanco, which plans to burn coke from the upgrading units, produces less NO_x but more particulate. Colony's on-site pollutant production in this step will be negligible because it plans to purchase most of its electricity from offsite powerplants.

The emission of SO₂, produced in the NH₃ and sulfur recovery processes, is about the same for all three designs. Although both Colony's and Rio Blanco's CO emissions are higher than Occidental's, the differences are not significant.

Table 34.—Pollutants Generated by the Colony Development Project^a (pounds per hour)^b

Operation	Particulate	SO ₂	NO _x	HC	CO
Mining	1,480	0	250	50	440
Shale preparation	15,940	0	0	0	0
Retorting ^c	11,440	150	1,430	480	60
Spent shale treatment and disposal	1,350	0	130	10	0
Upgrading	trace	10	20	10	trace
Ammonia and sulfur recovery ^d	0	32,200	0	0	0
Product storage	0	0	0	150	0
Steam and power	—	—	—	—	—
Hydrogen production	10	30	80	trace	10
Total	30,220	32,390	1,910	700	510

^aTable shows the level of pollutant generation, not pollutant release.

^bR_{syn} = 100,000 bbl/d of shale oil syncrude production; TOSCO II retorting, scaled 1050,000 bbl/d of shale oil syncrude production.

^cFigures do not include components of the product gas and vapor stream also, equivalent of H₂S in retort gas stream.

SOURCE T C Borer and J W Hand, /der//hcall/on and Proposed Control 01 Air Pollutants from Oil Shale Operations, prepared by the Rocky Mountain Division, The Pace Company Consultants and Engineers, Inc for OTA, October 1979

Table 35.-Pollutants Generated by the Rio Blanco Project on Tract C-a*(pounds per hour)^b

Operation	Particulates	so ₂	NO _x	HC	co
Mining	1,050	4	340	80	430
Shale preparation	7,200	0	200	0	0
Retorting	8,900	52	320	100	0
Spent shale treatment and disposal	650	0	0	0	0
Upgrading	7	0	7	13	0
Ammonia and sulfur recovery ^d	0	19,200	0	0	0
Product storage	0	0	0	105	0
Steam and power	210	250	1,220	13	0
Hydrogen production	-	-	-	-	-
T o t a l	18,017	19,506	2,087	311	430

^aTable shows the level of pollutant generation not pollutant release
^bUnderground mining modified in situ retorting scaled to 50,000 bbl/d of shale oil syncrude
^cFigures do not include components of the product gas and vapor stream
^dSO₂ equivalent of H₂S in retort gas stream

SOURCE T C Borer and J W Hand *Identification and Proposed Control of Air Pollutants from Oil Shale Operations* prepared by the Rocky Mountain Division The Pace Company Consultants and Engineers Inc for OTA October 1979

Table 36.-Pollutants Generated by the Occidental Operation on Tract C-b*(pounds per hour)^b

Operation	Particulate	so ₂	NO _x	HC	co
Mining	4,540	0	300	120	180
Raw shale disposal	450	0	100	10	0
Retorting	0	0	0	0	0
Upgrading	10	10	80	trace	10
Ammonia and sulfur recovery ^d	0	24,000	0	0	0
Product storage	0	0	0	80	0
Steam and power	20	trace	2,800	0	0
Hydrogen production	80	20	220	20	20
T o t a l	5,100	24,030	3,500	230	210

^aTable shows the level of pollutant generation not pollutant release
^bUnderground mining modified in situ retorting scaled to 50,000 bbl/d of shale oil syncrude
^cFigures do not include components of the product gas and vapor stream
^dSO₂ equivalent of H₂S in retort gas stream

SOURCE T C Borer and J W Hand *Identification and Proposed Control of Air Pollutants from Oil Shale Operations* prepared by the Rocky Mountain Division The Pace Company Consultants and Engineers Inc for OTA October 1979

It should again be noted that the tables show the amounts of pollutants generated, not the amounts released. Pollutant emissions are regulated by laws and standards, which are discussed in the next section. Compliance with these laws and standards requires pollution control technologies, which are discussed later in the chapter.

Air Quality Laws, Standards, and Regulations

Introduction

The existing and proposed regulations and standards governing air pollution from the oil shale industry are discussed here because they will affect the design and operating characteristics of oil shale facilities. They

may also act to constrain the ultimate size of the oil shale industry.

Air quality regulation is called for by the Federal Clean Air Act of 1970, as amended in 1977, hereafter referred to as the "Act." Regulations and standards arising from this Act are implemented at the Federal level by EPA and at State levels in conjunction with additional regulations and standards imposed by the individual States. The following discussion first highlights major provisions of the Act, and then analyzes those that are particularly significant for oil shale development.

Highlights of the Amended Clean Air Act

The Clean Air Act, as amended, establishes a national program to regulate air

pollution in order to maintain or improve air quality. The Act is universally applicable, but its provisions are most strongly directed to those areas having the cleanest air (nondegradation areas) and those where air pollution may be hazardous to public health (nonattainment areas). The major elements of the program established by the Act are:

- the establishment of NAAQS for criteria air pollutants,
- the submission by each State of a State implementation plan (SIP) to achieve and maintain Federal air quality standards,
- the preconstruction review of major new stationary sources, and
- PSD.

National ambient air quality standards.—Regulation under the Act focuses on six criteria pollutants: particulate, SO₂, CO, NO_x, O₃, and lead. Two types of ambient air quality standards are designated: primary standards, which protect human health; and secondary standards, which safeguard aspects of public welfare, including plant and animal life, visibility, and buildings. The Act sets forth an exact timetable by which primary standards are to be met. Secondary standards are to be met on a more flexible schedule.

To achieve air quality goals, areas with air cleaner than NAAQS were divided into Classes I, II, and III. Certain Federal areas that existed when the Act was passed (e.g., national parks, wilderness areas) were immediately designated as Class I areas where air quality was to remain virtually unchanged. All others were designated as Class II—areas in which some additional air pollution and moderate industrial growth were allowed. Individual States or Indian governing bodies can redesignate some Class II areas to Class III—areas in which major industrial development is foreseen and contamination of the air up to one-half the level of the secondary standards would be permitted. The States or Indians can also redesignate Class II areas as Class I. Either type of redesignation is subject to hearings and consultations with the man-

agers of affected Federal lands (and States in the case of Indian action).

The classification of an area with respect to the ambient air quality has important consequences. The Act divided the Nation into 247 air quality control regions (AQCRs) so that pollution control programs could be locally managed. Compliance with an NAAQS is generally determined on an AQCR basis, but EPA allows smaller area designations for some pollutants, if that is more suitable for controlling pollution.

These AQCR designations are highly significant. Regions that are found by EPA to be in nonattainment status—areas where air pollution presents a danger to public health—are subject to a particular set of restrictions under the Act. On the other hand, nondegradation regions—where air is cleaner than the standards—are subject to a different set of regulations, which are intended for “prevention of significant deterioration.” Regardless of an area’s classification, almost every new major source of pollution is required to undergo a preconstruction review.

State implementation plan.—Each State must submit an implementation plan for complying with primary and secondary standards. A State can decide how much to reduce existing pollution to allow for new industry and development. State plans must also include an enforceable permit program for regulating construction or operation of any new major stationary source in nonattainment areas, or significant modification to an existing facility. New processing plants and power stations must also satisfy emission standards set forth in the SIP.

Preconstruction review of major new stationary sources.—Under the SIP, each new construction project is subjected to five types of preconstruction review. The objective of the review process is to determine:

- compliance with NAAQS and State Air Quality Standards (AQS);
- compliance with any applicable NSPS; suitability for a nonattainment area;

- suitability for a nondegradation area. (PSD regulations, including the use of BACT and PSD increments* will apply); and
- visibility.

The major elements of these preconstruction review procedures are:

- **Review for compliance with NAAQS.** The applicant must submit plans and specifications for review that show: methods of operation, quantity and source of material processed, use and distribution of processed material, and points of emission and types and quantities of contaminants emitted; a description of the pollution control devices to be used; an evaluation of effects on ambient air quality and an indication of compliance with PSD restrictions; and plans for emission reduction during a pollution alert. A permit will not be given if it is shown that the source will interfere with the maintenance of any ambient air quality standard or will violate any State air quality regulation.

Review for compliance with NSPS. The Act directed EPA to set national standards for fossil fuel powerplants, refineries, and certain other large industrial facilities. If NSPS have been established for the new source, it must be shown that the facility will not interfere with the attainment or maintenance of any standard and that BACT will be used for reducing pollution.

- **Review in nonattainment areas.** In nonattainment areas, a new facility may be built only if: by the time operations commence total emissions from it, and other new and existing sources, will be less than the maximum allowed under SIPS; the source complies with the more stringent of either emission limitations required by the State or achieved in practice by such a source; and the owner or operator demonstrates that all other ma-

ajor stationary sources owned or operated by him in the State comply with emission limitations.

- **Review in nondegradation areas.** This type of review, which concerns PSD, is discussed below.

The prevention of significant deterioration.—All SIPS must specify emission limitations and other standards to prevent significant air quality deterioration in each region that cannot be classified for particulate or SO₂, or has air quality better than primary or secondary NAAQS for other pollutants, or cannot be classified with regard to primary standards because of insufficient information.

Under these PSD standards, maximum allowable increases in concentration of SO₂ and particulate are specified for each area class. For the other criteria pollutants, maximum allowable concentrations for a specified period of exposure must not exceed the respective primary or secondary NAAQS, whichever is stricter.

A State can redesignate a Class II or III area with respect to PSD only if it follows certain procedures. These include an assessment of the impacts of the redesignation, public notice and hearings of such a redesignation, and approval by EPA.

If a facility's construction began after January 1, 1975, a special preconstruction review must be undertaken if it is located in a nondegradation area. To obtain a permit for such a facility, an applicant must demonstrate that it will not cause air pollution in excess of NAAQS or PSD standards more than once per year in any AQCR. BACT must be used for all pollutants regulated by the Act, and the effects of the emissions from the facility on the ambient air quality in the areas of interest must be predicted. The air quality impacts that could be caused by any growth associated with the facility must also be analyzed.

*In part BACT is required to assure that no single facility will consume the entire PSD increment.

Implications of the Clean Air Act for Oil Shale Development

The following provisions of the Act have particular significance for oil shale development:

- compliance with NAAQS and State AQS;
- maintenance of air quality, especially visibility, in adjacent Class I areas (e.g., national parks);
- compliance with PSD increments;
- compliance with NSPS; and
- the application of BACT.

National Ambient Air Quality Standards.—Ambient air quality standards promulgated by individual States cannot be less stringent than the national standards. Thus, the States set the controlling standards if there is an approved SIP. Utah's standards are identical to the national standards, while Colorado and Wyoming have set more stringent standards for a number of the criteria pollutants. Table 37 shows both the national standards (the same for Utah), and Colo-

rado's and Wyoming's standards. In addition to the standards shown for Wyoming, the State has also promulgated regulations to limit ambient concentrations of H₂S, hydrogen fluoride, and other pollutants. The standards are more relevant to large coal-fired powerplants than they are to oil shale processing.

Since the national standards are primarily directed to urban areas, they should not seriously restrict oil shale development in the near future. The annual-average pollution levels allowed by ambient standards are much higher than the values normally measured in the oil shale development area. However, the short-term standards for particulate and HC are occasionally exceeded by natural emissions such as windblown dust and HC aerosols produced by revegetation. Such naturally caused infractions of NAAQS could have restricted regional development. They actually did affect oil shale development schedules on the four lease tracts located in Colorado and Utah. According to the provi-

table 37.—The Federal and State Ambient Air Quality Standards and Prevention of Significant Deterioration Standards That Influence Oil Shale Development (concentrations in micrograms per cubic meter)

Pollutant	Ambient air quality standards					Prevention of significant deterioration standards	
	Federal (primary) human health	Federal (secondary) public welfare	Wyoming ^a	Colorado ^a	Utah ^a	Federal (Class I)	Federal (Class II)
SO₂							
Annual arithmetic mean, . . .	<i>80</i>	None	60	80	<i>80</i>	2	20
24-hour maximum . . .	365	None	260	365	365	5	91
3-hour maximum	None	1,300	1,300	700	None	25	512
Particulates							
Annual geometric mean. . . .	75	<i>60</i>	60	45	75	5	19
24-hour maximum	260	150	150	150	260	10	37
VO, (as NO_x)							
Annual arithmetic mean.	100	100	100	100	100	None	None
Oxidants (as O₃)							
1-hour	240	240	160	<i>160</i>	240	None	None
CO							
8-hour maximum	10,000	10,000	10,000	10,000	10,000	None	None
1-hour maximum	40,000	40,000	40,000	40,000	40,000	None	None
Lead							
Quarterly	1.5	1.5	<i>1.5</i>	1.5	1.5	None	None
Nonmethane hydrocarbons							
3-hour maximum (6-9 am) . . .	160 ^b	160 ^b	160 ^b	160 ^b	160 ^b	None	None

^aState ambient air quality standards are identical to the Federal primary standards unless printed in italics. The stricter standard is the controlling standard.

^bNot a standard, a guide to show achievement of O₃ standard.

^cAllowable Incremental change in ambient concentration.

SOURCE: Office of Technology Assessment.

sions of the Act, the tracts and their environs were nonattainment areas. As such, they were not subject to any additional development. This potential barrier was cited by some of the tract lessees in their requests for activity suspensions in the fall of 1976.

In December 1976, EPA ruled that new development could proceed in a nonattainment area if the developer would offset new emissions by reducing the same emissions from an existing source in the same area. Although possibly applicable to urban or industrialized areas, such a policy was not relevant to the oil shale regions because there are no substantial existing industries against which to offset oil shale emissions. EPA made a subsequent ruling in July of 1977 that air quality problems arising from natural sources would not preclude oil shale development, providing that facilities complied with emission and PSD standards. The history of this ruling and its effects are discussed in detail in the analysis of the Prototype Oil Shale Leasing Program. (See vol. II.)

A second consideration is the visibility protection afforded to Federal mandatory Class I areas under the Act. Regulations are to be promulgated by EPA by November 1980, and by the States by August 1981. These regulations may affect the siting of future oil shale facilities.

Compliance with standards for PSD.—PSD standards exist for Class I, II, and III areas. The oil shale area is a Class II region, which means that some additional pollution will be allowed, but pollution up to the level of ambient air quality standards will not be acceptable. EPA's PSD standards define the maximum allowable increases in SO₂ and particulate concentrations. These standards are shown in table 38.

In summary, an oil shale facility will have to meet the PSD requirements for Class II areas, and moreover, it will not be allowed to degrade air quality in nearby Class I areas beyond the limits specified under the PSD provisions of the Act. Because most pollutants emitted by oil shale facilities can travel long distances, the stringent PSD increments

Table 38.—National Standards for Prevention of Significant Deterioration of Ambient Air Quality
(concentrations in micrograms per cubic meter)

Pollutant	Averaging time	Maximum allowable increase		
		Class I	Class II	Class III
Particulates	Annual	5	19	37
	24 hour	10	37	75
SO ₂	Annual	2	20	40
	24 hour	5	91	182
	3 hour	25	512	700

^aEPA is presently developing incremental standards for HC, CO, O₃, NO_x, and Pb.

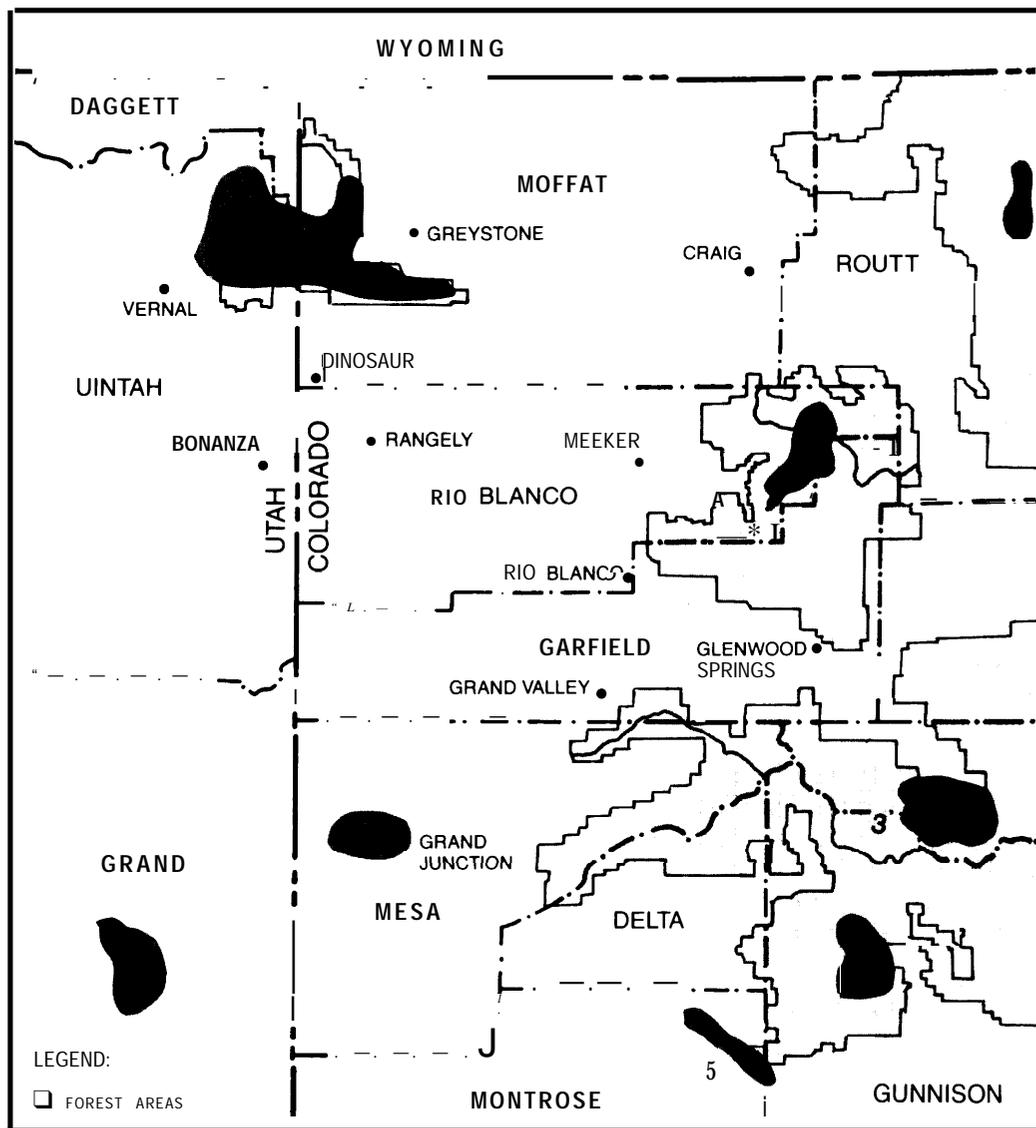
SOURCE: Environmental Protection Agency Work Group *Pollution Control Guidance for Oil Shale Development Appendices to the Revised Draft EPA Cincinnati/Ohio July 1979* p. 0-17.

for Class I areas could affect the siting of oil shale facilities. Figure 59 shows the Class I areas located near oil shale country in Colorado, Utah, and Wyoming. The two Colorado areas nearest the oil shale deposits are the existing Flat Tops Wilderness and the proposed Dinosaur National Monument.

Preconstruction review for oil shale facilities.—Under the Clean Air Act, each new oil shale plant must be evaluated during a preconstruction review to determine its ability to comply with NAAQS and PSD regulations. Projected emission levels will be regulated by EPA's NSPS, State emission standards, and the mandated use of BACT.

At present, there are no Federal emission standards that deal specifically with oil shale operations. However, NSPS have been developed for fossil-fuel-fired steam generators, petroleum refineries, and Refinery Claus Sulfur Recovery Plants. Table 39 lists the existing and proposed NSPS for these facilities as a guideline to what might be considered for oil shale plants. In addition, Colorado has developed emissions standards for shale oil production and refining that limit the sum of all SO₂ emissions from a given facility to 0.3 lb/bbl of oil produced or processed. Plants smaller than 1,000 bbl/d are exempt. Another Colorado regulation limits H₂S ambient concentrations from all shale oil plants to 142 micrograms per cubic meter (142 μg/m³ or 0.1 p/m). Utah and Wyoming do not have applicable emission limits. BACT standards have been developed by EPA for those oil shale facilities that have applied for PSD permits, as

Figure 59.— Designated Class I Areas in Oil Shale Region



AREA DESIGNATIONS

Federal Mandatory Class I Areas: 1, 2, 3,4, 6

Colorado Class I Areas: 5, 6,8

Draft Proposed (NPS) Class I Areas: 6, 8

CLASS I AREAS

- | | |
|-------------------------------------|--|
| 1. Flat Tops Wilderness | 5. Black Canyon of the Gunnison Monument |
| 2. Mount Zirkel Wilderness | 6. Colorado National Monument |
| 3. Maroon Bells—Snowmass Wilderness | 7. Arches National Park |
| 4. West Elk Wilderness | 8. Dinosaur National Monument |

SOURCE: Environmental Protection Agency Work Group, *Pollution Control Guidance for Oil Shale Development. Appendices to the Rev/seal Draft*, U.S. Environmental Protection Agency, Cincinnati, Ohio, July 1979, p.D-41

Table 39.—National New Source Performance Standards for Several Types of Facilities^a

Operation	Pollutant	Removal or emission standard ^b	Status
Fossil fuel fired steam generators	Particulates	0.1 lb/m Btu	Existing
	SO _x , NO _x	0.8 lb/m Btu for gaseous fuels; 0.3 lb/m Btu for liquid fuels	
Petroleum refineries	H ₂ S	0.1 gr/scf (dry)	Existing
	HC	Floating roof tanks or vapor recovery systems if true vapor pressure is between 1.5 and 11.1 lbf/in ² a and reporting system only if pressure is less than 1.5 lbf/in ² a	
Refinery Claus sulfur recovery plants	H ₂ S	0.1 gr/scf (dry)	Existing
	Sulfur	250 p/m SO ₂ for oxidation systems, 300 p/m total sulfur and 10 p/m H ₂ S for reduction systems	
Gas turbines	NO _x	75 p/mat 15Y0 oxygen	Proposed for units over 10 m/ Btu per hour
	so,	150 p/m	
Gasification plants	Sulfur	99.0% removal and 250 p/m total sulfur	Guideline
	HC	100 p/m	
Field gas processing units	H ₂ S	160 p/m	Proposed
	SO ₂	250 p/m for oxidation systems	
	Sulfur	300 p/m for reduction systems	

^aPresented as a guide to what might be considered for oil shale facilities

^blbf/in²a = pounds per square inch absolute p/m = per millionscf = standard cubic feet

^cStandards for fossil fuel fired steam generators being revised

SOURCE Environmental Protection Agency Work Group *Pollution Control Guidance for Oil Shale Development Appendices to the Revised Draft*, EPA Cincinnati Ohio July 1979 p D 34

shown in table 40. These standards specify levels of removal efficiency for specific pollutants, and in some cases also define the maximum concentration that will be allowed in the emitted stream.

In summary, oil shale facilities will have to undergo preconstruction review. BACT will be required for all pollutants regulated by the Act, and plants will have to comply with ambient air quality and PSD standards for Class II areas. Facility siting might be affected by PSD standards in adjacent Class I areas. The effects of visibility standards, which have yet

to be promulgated, cannot be determined at this time.

Air Pollution Control Technologies

In order to comply with the air quality laws and regulations, oil shale facilities will have to control their pollutant emissions. Various aspects of pollutant control are discussed in this section.

- The control technologies that can be used to reduce emissions of particulate, H₂S, sulfur compounds, NO_x, HC, and CO are described, and their potential applications to oil shale mining and processing are discussed.
- The technological readiness of these techniques are evaluated.
- The costs of air pollution control in commercial-scale oil shale plants are estimated.

Technologies and Applications

DUST CONTROL

Water sprays.—Water sprays can be used to control fugitive dust. If adjusted properly, no surface runoff will result. Water sprays

Table 40.—EPA Standards for Best Available Air Pollution Control Technologies for Oil Shale Facilities^{a,b}

Pollutant	Removal requirement	Maximum emissions
Sulfur	99.0% total recovery	15 p/m H ₂ S (reduction systems) 250 p/m SO ₂ (oxidation systems)
Particulates	99.0% from combustion gas streams	No standard
	99.80% from materials-handling gas streams	
	Fugitive dust control	
NO _x	Complete combustion	0.5lb/mBtu
CO	Complete combustion	No standard
HC	Complete combustion	No standard

^ap/m = parts per million

^bThese standards have been used in EPA's PSD decision process in the past

SOURCE Environmental Protection Agency Work Group *Pollution Control Guidance for Oil Shale Development Appendices to the Revised Draft*, EPA Cincinnati Ohio July 1979 p D 35

are about 80-percent efficient for particles larger than about 5 microns, * but less so for smaller ones. Adding a wetting agent reduces the surface tension and improves the wetting, spreading, and penetrating characteristics of the water, increasing efficiency to 90 to 98 percent. Chemical binders, such as latex or bitumastics, can also be added. They aid in particle agglomeration and also increase the efficiency of removal. Water sprays, with or without chemical additives, are potentially applicable to raw and spent shale storage and disposal, to crushing and screening, to mining and blasting, and to surface transportation. They could also control traffic dust from temporary roads. Larger, more heavily traveled roads would probably need to be paved.

Cyclones.—Cyclone separators remove dust by means of centrifugal force. Single cyclones remove about 90 percent of the larger particles, but less than 50 percent of those smaller than about 10 microns. Their removal efficiencies could be increased by using second-stage cleaning in scrubbers, filters, or precipitators. Cyclones will be used largely to clean retort gases, and possibly for primary dust control in crushers and enclosed conveyors.

Scrubbers.—Wet scrubbers use water to remove dust entrained in gas streams. Many different types of devices are available, including spray chambers, wet cyclones, mechanical scrubbers, orifice scrubbers, venturi scrubbers, and packed towers. High-energy venturi scrubbers are probably the only type that have sufficiently high removal efficiencies to satisfy emissions standards. Efficiencies between 93.6 and 99.8 percent have been achieved for particles smaller than 5 microns, but these efficiencies entail high pressure losses and constant gas flow rates. Scrubbers require considerably more energy than baghouse filters or electrostatic precipitators. Scrubbers for particulate removal will

probably be used for gas streams from retorts and solid heaters.

Baghouse filters.—Fabric filters are generally used where higher removal efficiency is required for particles smaller than about 10 microns. A large number of bag-shaped filters would be needed to clean large gas flows. In general, all of the filters would be enclosed in the same structure, called a "baghouse," and would share input and output gas manifolds. As a gas stream passes through the baghouse, dust is removed by one or more of the following physical phenomena: intersection, impingement, diffusion, gravitational settling, or electrostatic attraction. The initial filtration creates a layer of dust on the bag fabric. This layer is primarily responsible for this method's high removal efficiency; the filter cloth serves mainly as a support structure. The operation is very similar to that of a household vacuum cleaner.

The efficiency of a baghouse filter depends on the particle size distribution, the particle density and chemistry, and moisture. Under most conditions a properly designed and operated baghouse will achieve a removal efficiency of at least 99 percent for particles as small as 1 micron. Baghouse filters are likely to be used for dust removal from crushers, screens, transfer points, and storage bins.

Electrostatic precipitators.—In electrostatic precipitators, an electrical charge is induced on the surface of a dust particle and the particle is captured on a screen having elements with the opposite charge. Dry precipitators have been used for many years; wet precipitators and charged droplet scrubbers have been developed more recently. All types are in common use in the electrical power generating industry, in cement and steel plants, and in many other industries. Precipitators have removal efficiencies of up to 99.9 percent, require little maintenance, can handle large flow rates, and have low energy requirements. They might be used in several oil shale operations, including mine ventilation and the second-stage cleaning of dust-

*A micron is one-millionth of a meter. Removal efficiencies for different particle sizes are important because effects on respiration and visibility vary with the particle size.

laden streams from crushers and conveyors. A wet precipitator was used at the Paraho demonstration plant for the combined removal of shale oil vapors and particulate from the retort offgas. One is being used in the Petrosix plant in Brazil for the same purpose.

HYDROGEN SULFIDE CONTROL

The systems for removing H_2S that are likely to be used for oil shale operations can generally remove at least 98 percent of this pollutant. They will probably be applied to gas streams from retorting and upgrading operations.

Stretford Process.—In this process, the gas stream is scrubbed in an absorption tower with a solution containing sodium carbonate, sodium metavanadate, and anthraquinone disulfonic acid (ADA). Reduction of the metavanadate with H_2S in solution causes sulfur to precipitate. The metavanadate is regenerated by oxidation with the ADA, and the reduced ADA is then regenerated by being oxidized in an air stream. The process was developed for coal-gas treatment, but it has been used for many other purposes in a number of plants, especially oil refineries, in the United States and Europe.

Any COS and CS_2 that may also be in the gas stream would not be removed in this process and their presence would interfere with H_2S removal. Therefore, before H_2S removal the gas stream would need to be pretreated to remove these compounds.

Selexol and other physical absorption processes.—In these processes, H_2S is dissolved in a solvent and subsequently recovered. The solvent is recycled. The earliest process, a simple water wash, was inefficient because H_2S is not very soluble in water. Modern processes use solvents in which it is more readily dissolved.

Absorption processes are usually used for treating high-pressure gases and for reducing the concentrations of H_2S and other sulfur compounds to extremely low levels. These processes involve the selective absorption of H_2S from gases containing CO_2 . This produces an H_2S -rich stream that can be processed in a

Claus plant (see below). Absorption processes can also remove sulfur compounds, such as COS, CS_2 , mercaptans, and thiophenes, which cannot be processed in a Stretford unit. Because of its low cost and simplicity, the Selex-01 process is a good candidate for use in oil shale plants.

Claus process.—The Claus process, which is perhaps the oldest and best known method for recovering sulfur from streams that contain both H_2S and SO_2 , has several variations. With a feed stream containing only H_2S , the required SO_2 is obtained by oxidizing part of the H_2S to SO_2 by burning it in air, and then mixing the combustion products with the feed stream. The SO_2 and H_2S are then reacted with each other in a series of converters to produce elemental sulfur, which is removed by condensation. The feed stream must have a relatively high concentration of sulfur compounds in order to achieve a high conversion efficiency with reasonable equipment size.

This process has problems with both maintenance and downtime, thus backup units are often needed. Problems arise from sulfur condensation in the supply and product pipelines. The procedures for startup and shutdown are time-consuming, and moisture and CO_2 in the feed gas are particularly troublesome.

The tail or treated gas from a Claus plant still contains fairly sizable concentrations of H_2S and SO_2 . It can be recirculated, mixed with a large volume of stack gas and released, or treated in other systems. In oil shale plants, it is likely that the Claus plant effluent would require further treatment before being released. Processes developed specifically for this purpose include the SCOT, Beavon, and IFP techniques described below,

SCOT (Shell Claus Offgas Treating) process. In this process, the offgas is heated with a reducing gas such as hydrogen, and the mixture is passed through a cobalt-molybdate catalyst bed where all the sulfur compounds are reduced to H_2S . The gas is then sent through an absorber where the H_2S is dissolved and

concentrated. The concentrated H_2S is liberated from the absorbing medium by heating and is returned to the Claus plant.

The SCOT process is adversely affected by high concentrations of CO_2 . Since gaseous emissions from oil shale processing are expected to be rich in CO_2 , higher rates of recycling, more complete fuel combustion, and perhaps steam injection to dissolve the CO_2 may be necessary.

- Beavon process. In this process, the tail gas from a Claus plant is mixed with hot combustion gases and passed through a catalyst where all the sulfur compounds are converted to H_2S . The H_2S -rich gas is cooled by a slightly alkaline buffer solution and then treated in a Stretford unit. The Beavon process is also adversely affected by high CO_2 concentrations in the feed stream. Its use in oil shale plants would require adaptations similar to those needed for the SCOT process.
- IFP [Institute Francais du Petrok] process. The basic reaction in this process is the same as in the Claus process except that it takes place in a liquid rather than a gaseous phase. The liquid is a polyalkylene glycol with a 5-percent concentration of a glycol ester catalyst. Both H_2S and SO_2 are very soluble in this liquid, and efficient conversion to sulfur results. The most important operating variable is the H_2S to SO_2 ratio which must be at least 2. The process is flexible and can accommodate wide changes in contaminant concentrations while maintaining constant conversion rates. Also, because the gases can be treated at higher temperatures than in other processes, heat losses are reduced.

SULFUR DIOXIDE CONTROL

The amount of SO_2 that will have to be removed will depend on the prior degree of gas treatment and the type of fuel used in processing. Most oil shale plants will probably use desulfurized fuel for heating, processing, and power generation. Where large amounts of SO_2 are emitted, such as in the tail gas of a

Claus plant, its control may be required. The following technologies could be used for this purpose.

- Wellman-Lord process. This is a versatile process, widely used by many different industries, and should be adaptable to the oil shale industry. Colony plans to use it for a commercial-scale above-ground retorting plant.

This process relies on the reaction of SO_2 with sodium sulfate to produce sodium bisulfite. The bisulfite solution is next heated in an evaporator. This reverses the reaction, liberating a concentrated stream of SO_2 . The SO_2 can then be converted to either elemental sulfur or sulfuric acid. The regenerated sodium sulfate produced when the reaction is reversed by heating, is dissolved and recycled. The current version of this process is considered to be a second-generation technique for SO_2 removal. Previous problems with sludge production and scaling have been reduced.

- Double alkali process. Double alkali technology resembles conventional wet stack-gas scrubbing methods but avoids most of their problems by using two alkaline solutions, sodium hydroxide and sodium sulfite, to convert SO_2 to sodium bisulfite. The spent scrubber solution is regenerated by using lime or limestone to convert the bisulfite to sodium hydroxide and a precipitate that is a mixture of calcium sulfite and calcium sulfate. The precipitate sludge, which contains the captured SO_2 , can be disposed of in ponds.

Performance of the system is well-established, and over 99-percent SO_2 removal has been achieved with SO_2 concentrations in the treated flue gas of less than 10 p/m. Potential environmental problems are associated with waste disposal because the solid residue contains soluble alkaline sodium salts that could pollute surface and ground water in the vicinity of disposal sites.

- Nahcolite ore process. Nahcolite is a mineral that contains 70 to 90 percent

sodium bicarbonate. It is found in the oil shale deposits in the central Piceance basin of Colorado. When crushed and placed in contact with hot flue gases in a baghouse, nahcolite converts SO_2 to dry sodium sulfate. Typically, 20 percent of the required nahcolite would be used to precoat the filter bags in the baghouse, and the remainder would be sprayed directly into the flue gas stream. The sodium sulfate produced and any unreacted nahcolite would be sent to disposal. Pilot-plant experiments have shown that SO_2 removal efficiencies are between 50 to 80 percent depending on flow rates through the baghouse and the ratio of nahcolite to SO_2 .

NITROGEN OXIDES CONTROL

Nitrogen oxides are produced in the combustion of fuels. NO_x control can be approached in two ways: by adjusting combustion conditions to minimize NO_x production, or by cleaning the NO_x that is produced from the stack gases. At present oil shale developers plan to design combustor conditions for low NO_x production. Gas cleaning systems could be added in the future, if the need arises for further NO_x control. However, with proper design and maintenance of combustion equipment, external control systems will probably not be needed in order to comply with existing regulations.

HYDROCARBON AND CARBON MONOXIDE CONTROLS

The emission of HC and CO will be caused by the incomplete combustion of the fuel for the boilers, furnaces, heaters, and diesel equipment used in oil shale plants. The control of external combustion sources such as boilers is primarily through proper design, operation, and maintenance. Well-designed units emit negligible amounts of CO and only small amounts of HC. Instrumentation is needed to assure proper operating conditions, and comprehensive maintenance programs will be needed to keep emission levels from rising due to fouling and soot buildup. The proper maintenance of diesel and other internal combustion engines can similarly keep HC and CO emissions very low. Treating

the flue gas from combustion sources for particulate or SO_2 will also reduce HC and CO emissions. With proper maintenance, it will probably be unnecessary to further reduce emissions from these sources.

Other emissions of HC will be caused by preheating raw shale prior to retorting and by storing crude shale oil and refined products. Incineration is probably the only realistic way to control them. Storage tank emissions can be minimized by using floating-roof tanks, which can accommodate higher vapor pressures than cone-roof tanks without the need for venting.

OTHER EMISSIONS CONTROLS

Emission control by direct flame incineration systems (also called thermal combustion) is widely used to reduce the amounts of HC vapors, aerosols, and particulate in gas streams. These systems are also used to remove odors and reduce the opacity of plumes from ovens, dryers, stills, cookers, and refuse burners. The operation consists of ducting the process exhaust gases to a combustion chamber where direct-fired burners burn the gases to their respective oxides. A well-designed plant flare system is a good example of direct incineration control.

Catalytic incineration is also used for the same purpose. The chief difference is that the combustion chamber is filled with a catalyst. On contact with the catalyst, certain components of the process gases are oxidized. The use of a catalyst allows more complete combustion at lower temperatures, thus reducing fuel consumption and allowing the use of less expensive furnace construction. However, catalysts are generally selective and may not destroy as many contaminants as direct flame incineration. In addition, because of the potential for catalyst fouling and poisoning, gas streams may need to be cleaned of smoke, particulate, heavy metals, and other catalyst poisons.

Condensation is usually combined with other air pollution control systems to reduce the total pollutant load on more expensive control equipment. When used alone, conden-

sation often requires costly refrigeration to achieve the low temperatures needed for adequate control.

Several methods can be used for cooling the gas streams. In surface condensers, the coolant does not contact the vapor or condensate; condensation occurs on a wall separating the coolant and the vapor. Most surface condensers are common shell-and-tube heat exchangers. The coolant normally flows through the tubes; the vapor condenses on the cool outside tube surface as a film and is drained away to storage or disposal.

Contact condensers usually cool the vapor by spraying a liquid, at ambient temperature or slightly cooler, directly into the gas stream. They also act as scrubbers in removing vapors that do not normally condense. The use of quench water as the cooling medium results in a waste stream that must be contained and treated before discharge.

The equipment used for contact condensation includes simple spray towers, high-velocity jets, and barometric condensers. Contact condensers are, in general, less expensive, more flexible, and more efficient in removing organic vapors than surface condensers. On the other hand, surface condensers recover marketable condensate and present no waste disposal problem. Surface condensers require more auxiliary equipment and need more maintenance.

Condensers have been widely used (usually with additional equipment) in controlling organic emissions from petroleum refining, petrochemical manufacturing, drycleaning, decaising, and tar dipping. Refrigerated condensation processes are being used for the recovery of gasoline vapors at bulk terminals and service stations.

The Technological Readiness of Control Methods

As indicated, there are a wide variety of control technologies that could be applied to the emissions streams from oil shale processes. The selection of suitable technologies for a given facility would be based on a number of factors. The degree of control needed

for each regulated pollutant would depend on the size of the facility; its location; the nature of the oil shale deposit; the mining, processing, and refining methods; the desired mix of products and byproducts; the characteristics of untreated emissions streams; and the emissions levels allowed by applicable environmental standards. The specific control equipment selected would be influenced by all of these factors, plus such considerations as the proximity to water and electrical power, the availability of land for solid waste disposal, the labor and material requirements for maintenance, the ease of operation, the demonstrated reliability in similar industrial situations, the availability of equipment, the experience of the developer, and the cost.

An important consideration is the relative technological readiness of each control method being considered. A developer needs confidence that a method can be directly transferred to oil shale operations from other industries without undergoing extensive R&D. All of the techniques described previously have been applied to industrial processes similar to those encountered in mining, retorting, and upgrading of oil shale and its products. However, there are three characteristics of the potential oil shale industry that require extrapolating these technologies beyond the present levels of knowledge: the scale of oil shale operations, the physical characteristics of the shale, and the nature of the emissions streams.

Scale of operation.—The proposed mining operations are among the largest ever conceived and as such will require extraordinary efforts to control air pollution. For example, underground mining on tracts U-a and U-b would have mine ventilation rates as high as 12 million ft³/min. Cleaning this volume of gas could be both difficult and expensive. The large ventilation volume is required by mining health and safety regulations and cannot be reduced.

Open pit mines could be much larger than underground mines. Problems with fugitive dust would be increased by the larger quantities of solids that must be handled on the

surface. Much relevant experience has been gained through the extraction and processing of other minerals such as coal, copper, uranium, and bauxite. The simpler control techniques (such as water sprays) have been thoroughly demonstrated. However, the potential size of oil shale mines may create problems for the more complex, collection-type control systems that have worked well in smaller mines. The cost of air pollution control for deeply buried oil shale deposits is not known. The amount of overburden that must be removed, and for which pollution control would be needed may be prohibitively large.

Physical characteristics of the shale.—Oil shale is a fine sedimentary material held together by its kerogen content. When processed in certain retorts (such as TOSCO II or Lurgi-Ruhrgas) the shale can disintegrate into fine particles that are more difficult to collect and control than other mineral dusts. Other retorts (such as Union “B” or Paraho) will produce a coarser product with fewer problems from dust. It is uncertain whether electrostatic precipitators will perform effectively in commercial-scale operations because not much is known about the electrical properties of raw and spent shale particulate.

Characteristics of emissions streams.—To date, the streams from small-scale versions of discrete subprocesses (such as pilot retorts) have been used to obtain preliminary evaluations of the efficiencies of pollution control technologies. It is not known whether these streams accurately represent the streams that would have to be controlled in an integrated commercial-scale plant. For example, it is not certain that the pollutants generated by commercial-scale retorting, when combined with the pollutant streams from other subprocesses (such as upgrading), could be adequately controlled with conventional methods. Also, the effect of volatilized trace elements on the catalysts used in the SCOT and Beavon tail-gas cleaning systems and in incinerators has not been determined. The concentration of some of the pollutants generated by certain processes may be too low for efficient control. For example, it is unknown

whether conventional H₂S control methods will work well with the low H₂S concentrations in the offgas from MIS retorting. Removal efficiencies that are too low could have conflicted with EPA’s previous BACT standards for oil shale facilities, which required 99-percent total sulfur recovery, no matter how small the concentration of sulfur compounds in the raw gas stream.

The technological readiness of the major control techniques is summarized in table 41. The readiness of dust control methods is shown to range from low to high, with a high confidence in water sprays, cyclones, and scrubbers and a medium confidence in baghouses and a low to medium confidence in electrostatic precipitators. Similar ranges are shown for the other control techniques. The readiness of the nahcolite SO₂ removal process is rated as low because only a few test results have been published for its performance with oil shale streams. Also, the technology is relatively new and has not been used extensively in other industries.

The Claus H₂S process is regarded highly because it has a long record of successful application worldwide. The SCOT and Beavon tail-gas cleaning systems have a high rating because they are generally used in conjunction with the well-established Claus systems. The fact that the feed to these systems would already have been treated in a Claus unit removes some of the doubts about the effects on their removal efficiencies of the unique characteristics of oil shale emissions streams. Combustion methods and evaporation controls to reduce HC and CO emissions also have a high rating because they should not be sensitive to any great extent to the scale of operation or stream characteristics. Fugitive HC and CO emissions are much more difficult to control.

The other control techniques are given medium ratings either because they have not been tested with oil shale streams for sustained periods or because the effects on their removal efficiencies of the projected characteristics of streams from commercial-scale

Table 41 .-Technological Readiness of Air Pollution Control Techniques

Pollutant and control system	Readiness rating	Comments
Dust		
Water sprays	High	Effective and in general use with wetting agents added as needed, Low cost, Increased water needs,
Road paving	High	Also reduces vehicle maintenance,
Cyclone separators	High	Low cost, Effective only for large particles.
Scrubbers	High	Low capital cost and maintenance requirements, High energy and water requirements needed for high removal efficiency.
Bag house filters	Medium	High efficiency, Moderate energy and maintenance requirements, Low cost. Not suitable for high-temperature gas streams. Requires more area than other systems, Waste-disposal experience lacking
Electrostatic precipitators	Low to medium	Efficiency sensitive to dust loading, temperature, and particle resistivity. Good removal efficiency, Low operating costs and maintenance. Good for large gas volumes. High capital cost.
H₂S		
Stretford process	Medium	Extensive application in refining industry, Good for large volumes of dilute gases, Being tested for MIS gases,
Selexol, purisol, rectisol, istosoliam, fluor solvent, and other physical systems	Medium	Being tested for coal gasification streams, No experience with oil shale emissions,
Claus process	High	Extensive experience in several industries. Needs concentrated feed streams. High maintenance needs and downtime,
Tail gas cleaning		
SCOT process	High	Long experience with Claus plants.
Beavon process	High	Long experience with Claus plants,
IFP process	Medium	Used with Claus plants that produce elemental sulfur May be applicable directly to retort gases,
SO₂		
Wellman-Lord process	Medium	Thirty Installations worldwide High capital cost. High energy requirements,
Double alkali process	Medium	Used successfully in Japan since 1973. Waste disposal could be costly,
Nahcolite ore process	Low	Limited but successful testing to date,
NO_x		
Combustion control	High	Can easily be designed into new plants Low capital and operating cost,
Diesel exhaust control	Medium	Recirculation of exhaust gases can lead to maintenance problems.
HC and CO		
Combustion control	High	Use of excess air easily accomplished,
Evaporation control	High	Use of floating roof tanks is very effective but Increases capital costs,
Control of fugitive emissions	Low	Control is difficult because of the large number of dispersed sources

SOURCE: T. C. Borer and J. W. Hand *Identification and Proposed Control of Air Pollutants from Oil Shale Operations* prepared by the Rocky Mountain Division The Pace Company Consultants and Engineers Inc for OTA, October 1979

plants are still not known. In the case of the Stretford process, work is underway by Occidental Oil Shale which, if successful, could significantly improve its readiness.

In general, the control technologies appear to be fairly well-developed, and should be adaptable to the first generation of oil shale plants. Full evaluation will not be possible until the methods have been tested in commercial-scale operations for sustained periods.

Costs of Air Pollution Control

The costs of controlling pollutants from an oil shale plant would be particularly sensitive to the lifetime of a project, the plant de-

sign, the scale of operation, and the extent of emission removal required by environmental standards. Small-size, temporary plants such as modular demonstration facilities would probably be designed for minimum front-end costs; therefore, control systems with small capital requirements would be used rather than those with low operating costs. The latter systems would be economically attractive over the 20-year operating life of a commercial plant but not over the 2- to 5-year lifetime of a modular plant. The design of the plant would also have an effect on the costs of control. Systems to recover the byproducts sulfur and NH₃ could be included in an integrated facility, for example, not specifically for air pollution reduction but to increase plant reve-

nues. Additional control technologies would be needed to satisfy environmental standards, but overall control costs would be considerably less than if byproducts were not recovered,

Another example of the effect of facility design on control costs is whether the processes of upgrading and refining are included. If so, other subprocesses such as retorting could take advantage of the efficient control systems that are an integral part of any modern refinery. If refining was not done onsite, control systems would still have to be provided for the other operations. The same degree of removal efficiency could be achieved but with higher costs.

The relation of the cost of pollutant control to the degree of removal is usually not linear, i.e., the costs generally are considerably higher to increase a pollutant's removal from 98 to 99 percent than from 90 to 95 percent. Consequently, most control costs will be strongly influenced by the degree of removal required by environmental standards. Higher removals will be more costly for individual plants but would allow the region to accommodate a larger industry within the framework of the air quality regulations.

The Denver Research Institute (DRI) recently estimated the costs of environmental control in the three projects for which pollut-

ant generation was summarized in tables 34 through 36,³ DRI's hypothetical control systems were based primarily on developer plans but in some cases were modified to cover technologies having higher projected removal efficiencies. Two regulatory scenarios were considered. Under the "less strict" scenario for particulate control in the Colony plant, for example, it was assumed that particulate reductions from point sources would average 98.5 percent, and that for nonpoint sources of fugitive dust reductions of 92.2 percent would be required. The average particulate reduction for the plant was assumed to be 98.3 percent. Under the "more strict" scenario, overall particulate reductions of 99.5 percent were assumed for point and nonpoint sources. With some differences, similar control scenarios were assumed for other regulated pollutants, and for the other two oil shale projects. Results of DRI's analysis for the "more strict" case are shown in table 42.

As can be seen, the control costs for individual contaminants vary widely from project to project. In each project, however, the largest capital and operating costs are for SO₂ and particulate removal. Capital costs for SO₂ control equipment, for example, are over \$25 million for the tract C-a and C-b projects, which strongly rely on MIS retorting and which will have to clean large quantities of

Table 42.—Costs of Air Pollution Control (thousand dollars)

	Colony project ^a			Tract C-b project ^b			Tract C-a project ^c		
	Overall reduction	Capital cost	Operating cost	Overall reduction	Capital cost	Operating cost	Overall reduction	Capital cost	Operating cost
Fugitive dust	92.2%	\$ 1,460	\$ 564	98.4%	\$ 1,460	\$ 577	High ^d	\$ 1,460	\$ 543
Particulates	99.5%	29,400	6,499	80.2%	5,792	1,530	99.6%	34,340	8,499
Sulfur dioxide	99.0%	9,910	7,240	99.0%	26,210	11,187	99.0%	29,800	12,844
Nitrogen oxides	(e)	(f)	(f)	(e)	12,866	3,882	(e)	12,866	3,882
HC and CO	50.5%	f 7,785	3,766	56.5%	240	50	89.0%	878	182
Total.		\$58,555	\$18,069		\$46,588	\$17,226		\$79,344	\$25,950
Cost per bbl of daily capacity		\$ 1,246			\$ 817			\$ 979	
Cost per bbl of oil produced		—	\$ 1.16		—	\$ 0.91		—	\$ 0.97

^a47,000 bbl/d of shale oil syncrude ^b57,000 bbl/d of crude shale oil ^c81,000 bbl/d of crude shale oil
^dR.D.s are paved Water sprays used for disposal areas ^eMaximum reduction achievable through adjustment of combustion conditions
^fLow reduction requirements because of low-temperature retorting and use of low-nitrogen fuel in combustors

SOURCE: Data adapted from Denver Research Institute *Predicted Costs of Environmental Control for A Commercial Oil Shale Industry Volume I—An Engineering Analysis* prepared for the Department of Energy under contract No. EP 78-S-02-5107 July 1979 pp. 407-414

dilute retort gas. A much lower capital investment (about \$10 million) is needed for the Colony project because the TOSCO II retorts produce a much smaller volume of retort gas.

According to DRI's analysis, the overall costs of air pollution control range from \$0.91 (C-b project) to \$1.16 (Colony project) per bbl of oil produced. These costs would have been considered very high in the early 1970's when oil was selling for about \$4/bbl. They are less significant under present conditions with oil prices exceeding \$30/bbl.

Pollutant Emissions

Controlled emissions rates are summarized in tables 43 through 45 for three oil shale projects for which pollutant generation rates were calculated previously. It was assumed that the raw emissions streams from the unit

operations in each facility would be treated in control systems similar to those for which DRI prepared cost estimates. In the Colony project, for example, it was assumed that dusty air streams from crushers and ore storage areas would be processed in baghouses, as would the flue gas from the retort preheater. Flue gases from the retort and the spent shale moisturizer would be treated in a hot precipitator. A Stretford unit would be used for removal of sulfur compounds. NO_x and CO emissions would be reduced by combustion controls on all burners, and HC emissions would be reduced with floating-roof storage tanks and a thermal oxidizer flare system.

Table 46 summarizes the rates of pollutant emissions both for the three projects, and for modular demonstration projects proposed by Union Oil Co. and Superior Oil. The Union and Superior results are presented for their ac-

Table 43.--Pollutants Emitted by the Colony Development Project (pounds per hour)^a

Operation	Particulate	so _x	NO _x	HC	co
Mining	10	0	2.5 ^o	50 ^b	440 ^b
Shale preparation	60	0	0	0	0
Retorting	120	140	1,430	270	50
Spent shale treatment and disposal	40	0	130 ^b	10 ^b	0
Upgrading	trace	10	20	10	trace
Ammonia and sulfur recovery	0	100	0	0	0
Product storage	0	0	0	20	0
Steam and power	0	trace	20	trace	trace
Hydrogen production	10	30	80	trace	10
Total	240	280	1,930	360	500 +

^aRetorting scaled to 50000 bbl/d of shale oil syncrude production

^bThese emissions are not included in Colony PSO permit application

SOURCE: T. C. Borer and J. W. Hand, *Identification and Proposed Control of Air Pollutants From Oil Shale Operations*, prepared by the Rocky Mountain Division, The Pace Company Consultants and Engineers Inc for OTA, October 1979

Table 44.--Pollutants Emitted by the Rio Blanco Project on Tract C-a (pounds per hour)^a

Operation	Particulate	so _x	NO _x	HC	co
Mining	20	0	340	6	435
Shale preparation	26	0	0	0	0
Retorting	92	52	320	98	0
Spent shale treatment and disposal	32	0	0	0	0
Upgrading	6	0	6	13	0
Ammonia and sulfur recovery	0	0	0	0	0
Product storage	0	0	0	105	0
Steam and power	210	250	1,220	13	0
Hydrogen production	-	-	-	-	-
Total	386	302	1,886	235	435

^aRetorting scaled to 1050,000 bbl/d of shale oil syncrude production

SOURCE: T. C. Borer and J. W. Hand, *Identification and Proposed Control of Air Pollutants from Oil Shale Operations*, prepared by the Rocky Mountain Division, The Pace Company Consultants and Engineers Inc for OTA, October 1979

Table 45.—Pollutants Emitted by the Occidental Operation on Tract C-b (pounds per hour)^a

Operation	Particulate	SO ₂	NO _x	HC	CO
Mining	20	0	300	10	180
Raw shale disposal	80	0	100	10	0
Retorting	10	0	0	0	0
Upgrading	10	10	80	trace	10
Ammonia and sulfur recovery	0	240	0	0	0
Product storage	0	0	0	80	0
Steam and power	20	trace	2,800 ^b	0	0
Hydrogen production	80	20	220	20	20
Total	220	270	3,500	120	210

^aUnderground mining; MIS retorting scaled 1050000 bbl/d of shale; 011 syncrude production

^bAssumes gas turbines for power generation

SOURCE: T. C. Borer and J. W. Hand, *Identification and Proposed Control of Air Pollutants from Oil Shale Operations* prepared by the Rocky Mountain Division, The Pace Company Consultants and Engineers, Inc. for OTA, October 1979.

Table 46.—A Summary of Emissions Rates From Five Proposed Oil Shale Projects

Project and retorting technology	Shale oil production	Pollutant emissions, lb/hr				
		Particulates	SO ₂	NO _x	HC	CO
Colony TOSCO II aboveground retort	50,000 bbl/d syncrude	240	280	1,930	360	500
Rio Blanco MIS plus Lurgi-Ruhr gas aboveground retort	50,000 bbl/d syncrude	386	302	1,886	235	435
Occidental MIS	50,000 bbl/d syncrude	220	270	3,500	120	210
Superior Superior retort plus nahcolite and alumina recovery	11,500 bbl/d crude	75	347	172	20	47
Union Union Oil 'B' aboveground retort	9,000 bbl/d crude	35	81	100	59	43

SOURCE: T. C. Borer and J. W. Hand, *Identification and Proposed Control of Air Pollutants From Oil Shale Operations* prepared by the Rocky Mountain Division, The Pace Company Consultants and Engineers, Inc. for OTA, October 1979.

tual design conditions, which provide about one-fifth of the shale oil produced by the other projects. Because emissions rates are not always directly related to plant capacity, the much smaller modular projects are not expected to have equivalently lower rates of emissions. In fact, SO₂ release from the Superior project (11,500 bbl/d) is expected to be significantly higher than from the three 50,000-bbl/d projects. In part, the high rate of Superior's emissions is related to the nature of its process, which includes unique sub-processes for the recovery of nahcolite and alumina. They also arise from the scale of operation, which does not encourage the use of large-scale, costly controls that would be cost-effective for the larger operations at Colony and on the lease tracts.

EPA has granted PSD permits for the Colony and Union projects at the levels of operation listed above. Permits have also been

granted for modular-scale operations on C-a (1,000 bbl/d) and C-b (5,000 bbl/d). EPA therefore expects the projected emissions rates at these production levels to comply with all applicable Federal and State emissions regulations. However, it should be noted that the evaluation of the environmental impacts of oil shale development also requires a consideration of the effects of the emitted pollutants on ambient air quality, which is protected by NAAQS and PSD limitations. Without large-scale operating facilities, the effects of emissions on air quality can only be predicted by using mathematical models.

Dispersion Modeling

The Nature of Dispersion Models

The Clean Air Act, through the regulations promulgated for attainment of NAAQS and

PSD standards, requires the use of mathematical models to relate the emissions from a source and the resulting incremental impact that the source causes on a point some distance away. At present, models are EPA's tool for enforcing the provisions of the Act and are the only means for predicting long-range impacts of oil shale emissions on ambient air quality in the oil shale area and in neighboring regions.

Air quality models are mathematical descriptions of the physical and chemical processes of transport, diffusion, and transformation that affect pollutants emitted into the atmosphere. In these models, specified emissions rates and atmospheric parameters are used as input data, and the effects on ground-level pollutant concentration and visibility of plume rise, dispersion, chemical reaction, and deposition are simulated. Some models are designed to simulate small-scale airflow patterns over complex terrain within a few miles of the pollution source. These near-source models can predict the effects of oil shale emissions in the immediate vicinity of the plant. They are used during preconstruction review to indicate the facility's expected compliance with PSD regulations.

Other models simulate broader airflow behavior over distances of hundreds of miles. These regional dispersion models could be used to simulate the effects on a large area of an entire industry, including numerous individual plants. Regional-scale models can be used to predict impacts on air quality in nearby Class I areas. The time scale of the input data and the output predictions should be appropriate to the size of the region being simulated. Small increments can be used for near-source modeling; increments of several days for regional dispersion models.

Most models incorporate a series of computational modules, as shown in figure 60. A major difference between the models lies in the manner in which the input data are manipulated and in the application of the computational modules. Usually, not all of the modules are used in any given model. Near-source models need to simulate complex air

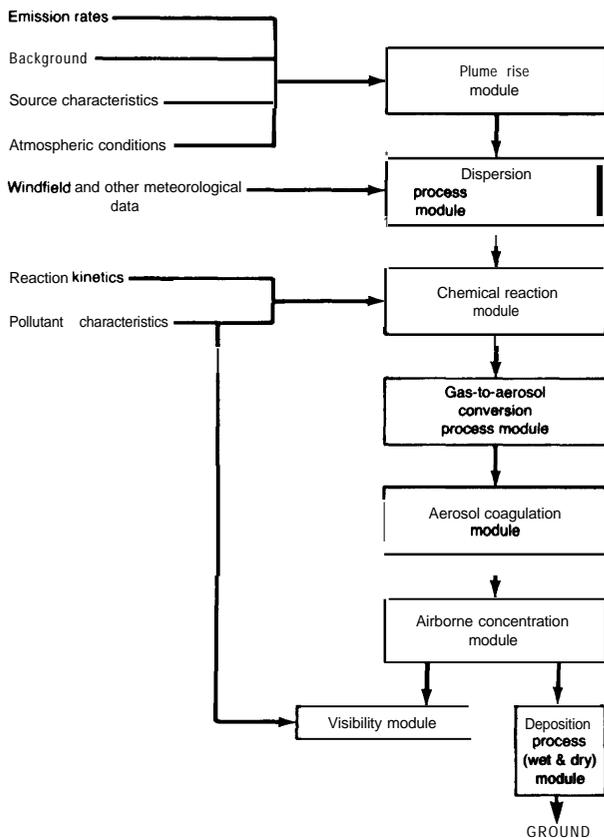
flow near prominent terrain features, but can usually ignore chemical reaction, aerosol coagulation, deposition, and visibility effects, which generally become most significant over larger distances and longer time periods. In contrast, regional models can sometimes ignore terrain features, but must consider long-range atmospheric conditions and their effects on chemical reaction, coagulation, deposition, and visibility.

A key feature that must be considered in evaluating the use of any model to estimate compliance with NAAQS and PSD regulations is its ability to simulate worst case conditions, which are those meteorological conditions that lead to the highest ground-level concentrations. These conditions vary depending on the location of the emitting facility, its configuration, and the nature of the surrounding terrain. Some candidate worst case conditions for the oil shale region include:

- several days of atmospheric stagnation during which emissions would accumulate under an inversion in a valley;
- a looping stack-gas plume that would bring maximum pollutant concentrations directly to ground level;
- a plume trapped in a stable atmospheric layer and transported essentially intact to nearby high terrain;
- fumigation, when a plume is transported from a stable layer at medium heights to the ground level. (Fumigation conditions normally persist for less than an hour. They are usually the worst case for emissions released from stacks); and
- moderate wind conditions in which a stable polluted layer spreads uniformly and causes visibility reduction over a large area. (This is usually the worst case for emissions released near ground level.)

It is reasonable to assume that some worst case conditions (e. g., several days of atmospheric stagnation) could occur several times a year, while others might occur only a few times over the lifetime of an oil shale project and might not be detected during a 1- to 3-

Figure 60.—Computation Modules in Atmospheric Dispersion Models



SOURCE: E. G. Walther, et al. *The Evaluation of Air Quality Dispersion Modeling for Oil Shale Development* prepared for OTA by the John Muir Institute for Environmental Studies, Inc. October 1979.

year environmental monitoring program prior to the start of constructing a project,

Gaussian models* and grid models are commonly used to simulate near-source dispersion effects. Gaussian models were developed for the relatively simple air flow patterns over flat terrain. They can be modified, with a significant loss of accuracy, to simulate complex flow around terrain obstacles, and up and down valley floors. They can simulate some worst-case conditions, such as very low wind speeds, but not looping plumes or variations in wind direction with in-

*A Gaussian model is based on a theoretical pattern of frequency distribution in which a bell-shaped (or normal) curve shows the distribution of probability associated with different values of a variable quantity—in this case pollutant concentrations.

creasing altitude. Their mathematical expressions are relatively simple, and can often be run on a hand calculator. However, most Gaussian models rely on straight-line simulation of pollutant trajectories and do not consider spatial, temporal, and vertical variations in atmospheric conditions. As a result they tend to overestimate ground-level pollutant concentrations at distances greater than 30 miles from the source.

Numerical or non-Gaussian models such as grid models are more useful for simulating near-source complexities. They estimate pollutant concentrations at each point in a three-dimensional pattern overlying the region of interest. For detailed computations and high accuracy, the spacing of the grid points must be small and the time interval between successive iterations must be short. Because of these characteristics and due to the complex mathematical manipulations used, grid models require the use of high-speed computers, and input data must include highly detailed wind field information. Such information is usually not easily obtainable without a very expensive atmospheric monitoring program.

Grid models can also be used for simulating long-range effects over a large region if information is available on conditions in the upper atmosphere. In these applications, terrain details usually become less important. Complex terrain features, which must be accurately simulated in near-source modeling, can be simulated through use of an average roughness factor. However, because of the longer timespan being modeled, slow chemical reactions that involve, for example, SO_2 and NO_x , become significant. Aerosol size distribution (critical in visibility analysis) and the contributions of other polluting sources are also important.

A critical problem in applying regional models is caused by the fact that pollutants pass through several meteorological regimes on their path from source to deposition point. Budget models, which divide the affected region into discrete air cells, can be useful under these circumstances because they deal only with the flow of air into and out of one

cell and with the reactions that occur within the cell. If the cell size or iteration increment is too large, important details such as rapid deposition in transition areas between lowlands and mountains may be missed. These deficiencies can be compensated for by using time trajectory models, numerical fluid flow models, box models, or sector average models.

Problems With Dispersion Modeling in the Oil Shale Region

Modeling of oil shale facilities presents a number of problems because of the topography and meteorology of the oil shale region, the chemistry of oil shale emissions, and the unknown quantities of emissions expected from commercial-size facilities. Dispersion models developed to date have been primarily for flat terrain. The terrain of the oil shale region is very complex, including many valleys and canyons. Furthermore, some developers have proposed siting their plants in the middle of a cliff face or near a canyon rim. Simulating this geometry presents unique modeling problems. In addition, the chemistry of oil shale emissions is quite different from that of powerplants in urban areas and may lead to increased oxidant formation through

photochemical reactions between HC and NO_x. * Thus, the conventional set of reactions used to model urban photochemistry would have to be augmented to accurately simulate the oil shale situation.

Also, oil shale operations emit much fugitive dust. Proper modeling of these emissions must consider the role of wind in creating the emissions as well as its role in dispersing them. In the mountainous areas downwind of oil shale plants, precipitation may cause the wet deposition of the oil shale emission, thus lessening the regional transport of visibility impacts but increasing impacts on ground-level ecological systems.

Another problem in developing accurate dispersion predictions for oil shale facilities is the fact that the input data on emissions can only be estimated, since no commercial-size plants have yet been built. This problem is exemplified in table 47, which presents a summary of emissions data used in several early modeling studies. These studies varied widely with respect to the quantities of the emissions that were assumed for various types of retorting technologies and the levels

*Photochemical reactions are induced in the atmosphere by ultraviolet radiation from the Sun.

Table 47.—A Comparison of Atmospheric Emissions Used in Modeling Studies

Study and site	Retort	Production capacity (bbl/day)	Study date	Total emissions (lb/hr)			
				so*	NO _x	HC	Particulates
Battelle Colorado	TOSCO II	50,000	1973	143	732	300	1,285
Federal Energy Administration Colorado	TOSCO II	50,000	1974	1,332	1,464	317	741
Stanford Research Institute Colorado and Utah	TOSCO II	100,000	1975	3,111	4,078	600	650
Colony Colorado	TOSCO II	63,000	1975	282 317	1,806 1,746	324 304	829 842
Tract C-b Colorado	TOSCO II	45,000	1976	267 353	1,634 1,894	262 313	776 968
Tract C-a Colorado	TOSCO II	6,000 56,000	1976	26 265	322 994	112 185	148 573
Tracts U-a and U-b Utah	Paraho	10,000 50,000	1976	8.4 148	108 1,369	0.88 55	68 452

SOURCE: Adapted from the Environmental Protection Agency *A Preliminary Assessment of the Environmental Impacts From Oil Shale Developments* July 1977 p 110

of production. Even if the estimates for the TOSCO II operations are scaled to the same production capacity, they vary by as much as an order of magnitude. Much of this discrepancy is associated with assumptions by analysts about environmental-control technologies and their efficiencies. Although individual modeling runs provide some insight into site-specific air quality effects for a given retort capacity under specific meteorological conditions, substantial variations in the input-data assumptions prohibit comparing different retorts, levels of development, and plant locations.

The Application of Dispersion Models to Oil Shale Facilities

The application of flat-terrain models to the oil shale region requires many adaptations in order to provide rough estimates of the impacts of a particular facility on ambient air quality. Near-source models have been used to estimate the effects of emissions from single proposed facilities. Such effects must be modeled to qualify for a PSD permit from EPA. A preliminary study has also been undertaken by EPA to estimate the regional effects of several oil shale plants. Since only estimates are available for the levels of emissions from commercial-size facilities, modeling results can only be considered approximate.

One example of the use of near-source models was a study performed for Colony Development by Battelle Northwest Laboratories. Colony was considering two plant locations: one in the valley of Parachute Creek, the other on an adjacent site atop Roan Plateau. A model predicted that NO_x concentrations near the valley site would exceed the national standards; SO_2 and particulate would barely meet the standards. The model predicted that the corresponding pollution levels near the plateau site would be an order of magnitude lower. Because of this prediction, Colony selected the plateau location.⁶⁷

Another example is the work undertaken for Federal lease tract C-a. Models were run for widely different operating conditions, in-

cluding completely different retorting technologies and levels of operations. As noted in volume II, the tract C-a lessees originally contemplated open pit mining and aboveground retorting in a combination of TOSCO II and directly heated retorts (like the Paraho kiln). In phase I, a single TOSCO II retort would be used to produce from 4,500 to 9,000 bbl/d of shale oil. In phase II, several TOSCO II and directly heated retorts would be used to produce up to 55,800 bbl/d. The lessees conducted modeling studies that estimated the air quality impacts of each development phase. Both long- and short-term effects were studied with an EPA Gaussian Valley model, modified to account for the mixing-layer effects of rough terrain and for inversion episodes. Results were reported in the DDP in March 1976.⁹

The lessees subsequently adopted a new plan that was also phased but which involved underground mining and MIS processing. The lessees prepared a revised DDP and performed new modeling studies. Two mathematical models were used: long-term (annual) effects were studied with an EPA model modified for high terrain and atmospheric stability; shorter term (3 to 24 hours) effects were studied with a modified Gaussian model. As in the earlier modeling studies, meteorological measurements made on the tract were used as input data to the models. Worst case predictions for both phases were reported in the revised DDP in May 1977.⁹

The results of both sets of studies are reported in table 48. Predictions are presented for both offtract ambient air quality and for the incremental quality degradation. Also shown are the relevant NAAQS (either primary or secondary, depending on which is more stringent), the Federal PSD increment limitations, and the corresponding Colorado ambient air standards. All standards shown are those that currently apply to the oil shale region.

The models predicted that both phases of both plans should be in compliance with applicable standards. However, the off tract concentration of nonmethane HC was pre-

Table 48.—Modeling Results for Federal Oil Shale Lease Tract C-a

Pollutant	Averaging time	National standards				Colorado standards				Revised DDP (May 1977)				Original DDP(March 1976)			
		NAAQs ^a		PSO increment		Ambient Air		PSD Increment		Offtract ambient air		Offtract increment		Offtract ambient air		Offtract increment	
		Class I	Class II	Class I	Class II	Category I	Category II	Phase I'	Phase II'	Phase I'	Phase II'	Phase I'	Phase II'	Phase I'	Phase II'	Phase I'	Phase II'
		MIS	MIS/TOSCO II	MIS	MIS/TOSCO II	TOSCO II	Aboveground	TOSCO II	Aboveground	TOSCO II	Aboveground	TOSCO II	Aboveground	TOSCO II	Aboveground		
S O ₂	Annual	80	20	80	20	8.4	8	3.2	2.7	10	11	1	2				
	24-hour	365		365	91	102	8	5	3	23	28	14	19				
	3-hour	1,300	512	700	512	352	25	30	20	91	103	82	94				
NO _x	Annual	100	None	100	None	8	13	6	11	16	10	14	8				
Particulates	Annual	60	19	45	19	9	12	0.3	3	16	22		10				
	24-hour	150	37	150	37	10	12	1	3	34	41	22	29				
Nonmethane																	
H C	3-hour	160	None	160	None	65	90	0.3	25	221	129	156	64				
Lead	Quarterly	15	None	15	None	—	—	—	—	—	—	—	—				
O	1-hour	240	None	160	None	—	—	—	—	—	—	—	—				

^aStricter of primary and secondary standards. ^bCapacity 4,000 bbl/d (MIS). ^cCapacity 57,000 bbl/d (MIS) + 19,000 (TOSCO II). ^dCapacity 9,000 bbl/d (TOSCO II).
^eCapacity 55,800 bbl/d (TOSCO II and e 9 -Paraho). ^fNot a standard a guide to show achievement of the O, standard

SOURCE: Data adapted from original and revised detailed development plan for tract C-a. See refs 8-9.

dicted to exceed the Federal and State guidelines during Phase I of the old plan. It should also be noted that in the old plan the off tract increment for HC is only slightly less than the 3-hour average guideline. In the new plan, however, offsite concentrations and increments for both phases are well within compliance.

With respect to the effect of scale of operation, the table indicates that, in general, the impact of the smaller scale phases of both plans are nearly equal to those of the corresponding larger scale phases. This is explained by the lessees' intent to use the first phase of each plan to obtain reliable data on emissions levels and dispersion characteristics, and then to use these data to design control technologies for the subsequent commercial phases. Also, final commitment to the commercial operations was not to be made until technical and economic feasibility studies, based on operating data obtained in the early phases, could be completed. To avoid unnecessary capital commitment in the initial phases, the first facilities were designed for minimum investment requirements.

It is difficult to interpret the technology-related effects of old and new plans for tract C-a because the levels of operation are different, and different models were used to simulate air quality impacts. However, a qualitative comparison is possible. The table indicates that the original concept (open pit mining and aboveground retorting) would have caused higher ambient levels of SO₂,

particulate, and nonmethane HC and lower levels of NO_x than the revised concept (underground mining, MIS, and limited above-ground retorting). Although the revised facility is to have 36 percent more shale oil capacity, ambient air impacts and PSD increments are generally lower.

With respect to regional modeling, EPA has used a modified Gaussian model to predict the effects on air quality at the Flat Tops Wilderness Area of oil shale operations at the Colony site (50,000 bbl/d), on tract C-a (1,000 bbl/d), on tract C-b (5,000 bbl/d), and at the Union site (9,000 bbl/d). * The total shale oil production was about 65,000 bbl/d, of which about 77 percent was assumed to come from Colony's TOSCO II retorts. The model was limited in that only one source could be modeled at a time, so four runs were needed to model the industry. In each run it was assumed that the wind was blowing from the source directly to Flat Tops. The cumulative impacts of the industry were estimated by adding the increments from each source. Results indicated that about 20 percent of the PSD increment for particulate would be consumed, and about one-third of the SO₂ increment. Simple linear scaling would indicate that the industry would be limited to about 217,000 bbl/d by the PSD restrictions on SO₂, and to about 325,000 bbl/d by the particulate PSD.

*Flat Tops Wilderness Area is approximately 65 miles from tract C-a, and 50 miles from tract C-b and the proposed Colony and Union projects.

Such scaling is highly inaccurate for a number of reasons. First, Gaussian models tend to overestimate ground-level concentrations of SO₂, because they do not allow for formation of sulfate particles from SO₂ and their subsequent deposition. Second, it is impossible for the wind to be blowing from four directions at the same time. Third, the projected SO₂ and particulate concentrations at Flat Tops were affected strongly by the Colony project, which is predicted to emit more SO₂ and particulate than the technologies proposed by tract C-a, tract C-b, and Union. It was EPA's opinion that a better estimate would be that as much as 400,000 bbl/d could be accommodated in the Piceance basin by the PSD standards for Flat Tops.¹⁰ EPA's analysis did not consider any project in the Uinta basin, the eastern edge of which is about 95 miles from Flat Tops. Therefore, there are no estimates available of the additional capacity that could be installed in Utah without exceeding the PSD restrictions at Flat Tops. The proposed Dinosaur National Monument, about 50 miles north of tracts U-a and U-b, could also limit operations in Utah if it is designated as a Class I area. *

Evaluation of Modeling Efforts

Table 49 lists the models used by oil shale developers to support PSD applications for their projects. EPA has accepted the results of these studies as evidence of expected compliance with air quality regulations, and PSD permits have been granted. Note that, with

*A Department of the Interior task force in September 1979 recommended that the Dinosaur National Monument be designated as a Class I area.

the exception of the Colony project, only small-scale plants were modeled. Some developers, such as Rio Blanco and the tract C-b lessees, have also modeled the effects of commercial-scale operations at the same locations. However, EPA has not yet evaluated the results of these studies for adequacy under the PSD-permitting process.

The widespread reliance on the Gaussian Valley model should also be noted. All of the developers relied on this model for simulation of near-source effects. PSD permits were granted for the projects because the models represented the state-of-the-art of near-source dispersion, and because most of the projects were of relatively small scale. The models used are deficient in many respects. For example, the Gaussian Valley model can be used for estimating pollutant dispersion in stable atmospheric conditions in complex terrain. However, as described previously, it tends to overestimate SO₂ concentrations and cannot handle most worst-case conditions. Also, Gaussian models when applied to complex terrain introduce error by a factor of 5 to 10 when computing concentrations on high-terrain features. This factor of error in the model's capability, coupled with a 2 to 5 error factor in estimating emission concentration, increases the level of uncertainty in determining compliance with air quality standards. In a recent workshop conducted by the National Commission on Air Quality, it was recommended that the Valley model be used only for screening purposes in complex terrain situations, and that it not be used for determination of compliance with NAAQS or PSD standards.

Table 49.—Models Used in Support of PSD Applications for Oil Shale Projects

Project	Retorting technology	Maximum shale 011 production	Model used
Colony Development Operation	TOSCO II	46,000 bbl/d	Gaussian Valley model, modified for rough terrain, to study effects of long-distance transport. Box model for effects of trapping inversions near source.
Union 011 Co Long Ridge	Union "B"	9,000 bbl/d	Modified Gaussian Valley model.
Rio Blanco 011 Shale (tract C-a)	Modular MIS	1,000 bbl/d	Modified Gaussian Valley model
C-b Shale 011 Venture (tract C-b)	Modular MIS	5,000 bbl/d	Modified Gaussian Valley model
Occidental 011 Shale Inc Logan Wash	Modular MIS	5,000 bbl/d	Modified Gaussian Valley model

SOURCE: Office of Technology Assessment

Other models that have been used to predict emissions from proposed oil shale facilities include the CRSTER and the AQPUF2. * The CRSTER model is generally used by EPA to simulate effects of emissions from tall stacks in complex terrain. It tends to overestimate pollutant concentrations where plumes are intercepted by terrain features higher than the plume rise height. " The CRSTER model used by Rio Blanco in their DDP could not handle fugitive dust emissions, gravitational settling, separated stacks, chemical reactions in the plume, some high-terrain features, and a change of wind direction with height. All of these variables are important to accurate prediction of some near-source effects. The AQPUF2 model also used by Rio Blanco in their DDP for short-term studies was better able to simulate plume behavior in complex wind fields and to compare the effects of emitting stacks a significant distance apart from each other. The effect of wind speed on the generation of fugitive emissions was not simulated in any of the models used.

Research and Development Needs

The problems of modeling pollutant dispersion in the oil shale area are also encountered in other regions with complex terrain, such as the Ohio River Valley and the Four Corners area of Colorado, Utah, Arizona, and New Mexico. The Dispersion Modeling Panel at a recent workshop conducted by the National Commission on Air Quality recommended the following research on the modeling of atmospheric dispersion in such areas:^{1]}

- . Regional models should be developed that can simulate effects at long distances from the sources. For SO₂, these distances could approach 600 miles. Upwind pollutant concentrations should be determined and used as input data to the models.
- The regional models should allow the use of a fine-resolution grid spacing near the pollution sources, and a coarse spacing at greater distances. Given this capabil-

ity, near-source effects and more distant impacts could be modeled simultaneously.

- Chemical reaction and deposition modules should be included wherever the modeled region is large enough for these effects to be significant.
- A simulation of photochemical oxidant formation and of the conversion of SO₂ to sulfates should be combined in the same model.

More specific research needs can be identified for the oil shale region. The models used to date have given only rough estimates of the impacts of oil shale development on ambient air quality. Because the models are only approximations, they cannot provide definitive answers to crucial air quality questions. No commercial-scale oil shale facilities exist that could supply the data for verification. Furthermore, essential information is lacking on meteorological conditions in locations other than in the immediate vicinities of some of the proposed development sites.

The models themselves need to be improved for the oil shale region. Near-source models need to be modified to better simulate chemical reaction, coagulation, deposition, and visibility effects of oil shale plumes during stagnation periods. Models are also needed that can simulate the effects that several facilities would have on air quality in a small area having complex terrain. This capability will be critical in evaluating the effects of second-generation oil shale plants. A good site for analysis would be the southeastern corner of the Piceance basin. PSD permits have already been issued for three projects in this area, which contains much of the privately owned oil shale land in Colorado. More applications may be submitted in the near future. Models are also needed that can simulate the effects of wind rate on generation and transportation of fugitive dust from storage and disposal areas.

Many of these improvements also are needed by regional dispersion models. In particular, existing models should be modified to simulate long-range visibility effects of oil

*CRSTER is a Gaussian model developed by EPA, AQPUF2 is a segmented-plume Gaussian rough-terrain model.

shale plumes. This capability will be required to respond to the forthcoming visibility regulations. Visibility models exist that deal with the formation of aerosols and particulate from SO_2 and NO_x , but these models are applicable to examinations of urban smog and powerplant emissions. Greater emphasis would have to be given to HC reactions in order to modify these models to simulate oil shale plume effects.

The need to model the cumulative impacts on regional air quality is particularly important. Each scenario should include specifications for the locations of oil shale plants, a characterization of their pollution control technologies, and estimates of their emissions rates. The region's meteorology would have to be accurately characterized over periods of several days, or for at least the time required for the full impact of the combined emissions to be experienced in nearby Class I areas. Computational modules would have to be included for the effects of emissions, dispersion, aerosol dynamics, chemical reaction, deposition, and visibility. The model also should handle differences between daytime and nighttime mixing heights and atmospheric chemistry. In addition, the regional models would have to be validated, either through tracer studies in the oil shale region itself or by examining the ability of the model to simulate the behavior of emissions from a group of coal-fired powerplants or smelters.

One type of tracer study that could be used to validate the models is the release of sulfur hexafluoride, or a similar tracer compound, followed by the monitoring of tracer concentrations at numerous ground-level locations. A dense pattern of monitoring stations would be needed to locate maximum concentrations, because the widely varying wind patterns in the oil shale region prevent any attempt to characterize total wind fields by interpolating data from a few stations. Baseline measurements of pollutant concentrations and visibility parameters upwind from the source would be required to accurately simulate the chemical interactions of the tracer plumes.

The state-of-the-art of near-source and regional dispersion modeling is being advanced by R&D programs under the sponsorship of EPA and other organizations. The following projects are of particular importance to evaluating the air quality impacts of oil shale plants.

- EPA is funding a project with DRI to combine information on oil shale emissions and meteorology, and to use regional models to assess air impacts from several commercial-size oil shale facilities. The model will also handle emissions from other sources such as traffic, powerplants, and other mineral-processing plants.
- EPA is funding a project with the University of Minnesota to develop a simple model of aerosol dynamics, including conversion of gases to aerosols, that may be of use in evaluating the effects of the chemistry of oil shale plumes on visibility.
- Los Alamos Scientific Laboratory is funding a project with the John Muir Institute for Environmental Studies to develop a multiple-source visibility model that could be applied to regional dispersion studies in the oil shale area. In a related study, the University of Wyoming and Los Alamos are funding a project to develop a regional haze model which might be useful in assessing visibility effects of oil shale plumes.
- EPA is funding an in-house project at Research Triangle Park to develop a multiple-layer atmospheric model that is designed to explain regional O_3 patterns in the Northeast. It may also be useful for explaining the high O_3 concentrations encountered in the oil shale area.
- EPA is funding a project with Systems Applications, Inc., to model the air quality effects of oil shale industries with capacities of 400,000 bbl/d (including tract C-a, tract C-b, Colony, Union, Superior, tract U-a, and tract U-b) and 1 million bbl/d. The model will handle all

sources simultaneously and will model visibility effects. The project is designed as an extension to EPA's early regional modeling exercise. Its major objective is to estimate cumulative impacts on existing and proposed Class I areas such as Flat Tops.

A Summary of Issues and Policy Options

Issues

INADEQUATE INFORMATION

Extensive work has been undertaken in the public and private sectors to determine the degree of pollution control that will have to be used by oil shale facilities to protect air quality. However, no large-scale facilities exist to verify the predictions arising from this work. Furthermore, the dispersion characteristics of treated emissions streams cannot be accurately predicted because modeling and monitoring methods are not yet adequate. In its present state of development, modeling can be used, but the results must be carefully interpreted. Therefore, it is not known what impacts oil shale unit operations will have on air quality at various shale oil production levels. Specific areas of uncertainty and some

suggested R&D responses are summarized in table 50. Some of the uncertainties, such as dispersion behavior, could be reduced somewhat by means of laboratory studies and computer simulations; others, such as the performance characteristics of control technologies, may necessitate full-size facilities and extended programs under actual operating conditions. It is important that emissions studies and monitoring and modeling programs keep pace with oil shale development.

LIMITS ON OIL SHALE DEVELOPMENT

The atmosphere has a finite carrying capacity; that is, it can only disperse limited quantities of airborne pollutants. The effect of the carrying capacity of air in the oil shale region on the long-term development potential of oil shale resources is unknown. A crude regional modeling study undertaken by EPA has indicated that an industry of **200,000** to **400,000** bbl/d could probably be controlled to meet PSD regulations in the Piceance basin. It is unclear whether a larger industry (the order of 1 million bbl/d) could be established in the Piceance and Uinta basins without violating air quality regulations.

Additional questions arise regarding the manner in which PSD increments will be allo-

Table 50.—Areas of Inadequate Information and Suggested R&D Responses

Area of uncertainty	Relevance	Research need
Baseline air quality conditions and meteorological characteristics	Inhibits accurate modeling of emissions dispersion and deposition	Regional characterization studies, including measurement of visibility and concentrations of criteria and noncriteria pollutants and determination of meteorology, especially with respect to worst case conditions.
Emissions characteristics	Prevents evaluation of control effectiveness and cost and reduces modeling accuracy.	Characterization of stream and fugitive emissions, beginning with pilot-plant studies and continuing with first-generation modules and pioneer commercial-size plants. Streams from individual unit operations should be integrated to simulate expected commercial conditions.
Performance of control technologies	Inhibits modeling and cost estimation.	Additional pilot-plant and demonstration-plant programs.
Dispersion behavior	Inhibits evaluation of near-source and regional air quality impacts.	Improvement in modeling and monitoring techniques for complex terrain, including development and validation of near-source and regional dispersion models. Models to be validated for the terrain and meteorology of the 011 shale region and for emissions similar to those expected from 011 shale operations.
Trace element behavior	Inhibits evaluation of the effects of 011 shale development on human health, plants, and animals.	Monitoring of trace element concentrations in process feed streams, treated emissions streams, and fugitive emissions. Examination of the effects of conventional control technologies on trace elements. Determination of the relationships between trace element concentrations in soils and plants and nutritional problems. Development of indicator species. Studies of the synergistic effects of trace elements on vegetation.

SOURCE: Office of Technology Assessment

cated to potential oil shale developers. The oil shale region has been designated Class II, but several Class I areas exist nearby that could be affected by oil shale operations. The law prohibits any facility to exceed the PSD limitation in any area, including the area in which the facility is to be sited and any adjacent areas. Thus, oil shale developers will have to demonstrate that their facilities will satisfy both Class II PSD standards and Class I standards.

Under the present regulatory structure, PSD increments are allocated on a first-come, first-serve basis. The first oil shale plants in a given area could exhaust the entire increments. If this occurs, subsequent developers, who might be delayed by the preliminary status of their processing technologies, will not be able to locate in the same area, regardless of the efficiency of their air quality control strategies.

Under the provisions of the Act, new facilities can be located in a polluted area if they are able to offset their emissions by reducing the emissions of other industrial plants in the same area. This strategy may be feasible in urban industrialized areas, especially where existing facilities are old and do not employ state-of-the-art air pollution control methods. It is not applicable to the oil shale areas at present because there are few industrial facilities against which to offset new emissions. It probably will continue to be inapplicable as the area industrializes, because any new plants will be built with the best available control technologies to reduce emissions to minimum levels. A subsequent oil shale developer would thus be forced to improve on these control methods. It is uncertain whether this could be done at reasonable cost.

These constraints could result in each oil shale plant being surrounded by a buffer zone in which no additional industrial activities (including oil shale development) would be allowed. Without reliable regional air quality modeling studies, it is impossible to predict the width of these buffer zones. However, it is very possible that such zones could substantially reduce the area of a given oil

shale basin that could be developed, and thus limit the ultimate size of the industry that could operate within the basin,

UNDEFINED REGULATIONS

The Clean Air Act stipulates a need to protect visibility in Federal mandatory Class I areas. While regulations are to be promulgated by EPA by November 1980, and by the States by August 1981, uncertainties still exist as to the potential implications for oil shale development in regard to the siting of future oil shale facilities. In addition, EPA is presently developing incremental PSD standards for HC, CO, O₃, NO_x, and lead. Oil shale facilities will have to comply with these new standards.

Another area of uncertainty concerns emission standards for hazardous air pollutants under section 112 of the Clean Air Act. To date, the emissions that are regulated are asbestos, vinyl chloride, mercury, and beryllium. Controls have been required for industries that produce these substances at high rates. To date, the oil shale industry has not been included under the regulations for these pollutants because it is expected that they will be generated at low levels, if at all. However, EPA is in the process of developing hazardous emissions standards for POM, arsenic, and possibly other substances. It does not appear at this time that these substances will be regulated for oil shale operations, but the regulations could be applied to oil shale if the substances are found in the emissions streams during future characterization studies. Furthermore, it is also possible that additional regulations could be promulgated for substances that have already been detected in these streams.

It should also be noted that a recent U.S. Circuit Court of Appeals decision in the case of *Alabama Power, et al. v. EPA* may result in significant changes in the PSD regulations. The definition of baseline conditions, fugitive dust control requirements, and monitoring requirements are among the issues on which the court has rendered a decision. As a result of the decision, EPA proposed certain revisions to the PSD regulations on September 5,

1979. However, the effect of the court decision and the proposed regulations on the conditions for PSD permits for oil shale facilities is unclear at this time.

Policy Options

LIMITS ON DEVELOPMENT

Siting constraints will probably not be severe for an oil shale industry of 200,000 to 400,000 bbl/d. However, it appears likely that a large industry (the order of 1 million bbl/d) could encounter siting difficulties because of the Class H status of the resource region, the possibility that the initial facilities will exhaust the total PSD increments over large areas, and the existence of Class I areas near the region. If this appears to be the case, there are several possible actions that could be taken. These are briefly described below.

- Retain the current regulatory structure. This option would not alter existing air quality standards and PSD regulations as promulgated under the Clean Air Act. Under existing law, all oil shale facilities would have to undergo a preconstruction review before a PSD permit would be granted. The use of BACT would be required, and the developer would have to demonstrate that air quality regulations would not be violated either within the Class II area of development or in nearby Class I areas. As indicated previously, the current policy of allocating PSD increments on a first-come, first-serve basis might constrain the commercialization of those technologies that are in the early phases of development, and in addition might limit the ultimate size of an oil shale industry within the resource region.
- Coordinate issuance of PSD permits for oil shale plants. This option would not alter existing PSD regulations as promulgated under the Clean Air Act. However, it would change the current approach to the issuance of PSD permits for oil shale plants by EPA. Rather than issuing PSD permits on a first-come, first-serve basis, EPA would encourage coordination with

all prospective oil shale developers prior to their preparation of PSD applications. This effort would seek a coordinated strategy for maximizing shale oil production while maintaining the ambient air quality at regulated levels. Implementation could be constrained by, for example, antitrust laws.

- Alter existing regulatory procedure in allocation of PSD increments. Under this option, EPA would allocate a portion of the total PSD increment to each firm when it applied for a PSD permit. The remaining portions of each increment would be reserved for future industrial growth. Although this option would allow for a certain level of additional growth, it could impose technical and economic burdens on the individual applicants, because each proposed facility would be required to maintain lower emission levels than would be the case under the existing regulatory structure.
- Redesignation of the oil shale region from a Class II to a Class III area. This option would lower air quality but would allow for more industrial development. The action would be initiated at the State level, with final approval being necessary from EPA. The following criteria would have to be satisfied:
 - the Governors of Colorado, Utah, or Wyoming must specifically approve the redesignation after consultation with legislative representatives, and with final approval of local government units representing a majority of the residents of the area to be redesignated;
 - the redesignation must not lead to pollution in excess of allowable increments in any other area; and
 - other procedural and substantive requirements for redesignation under State and Federal law must be satisfied.

While such an option would appear to allow for about twice as much oil shale development as is presently possible under a Class II area designation, con-

straints would still occur because of the nearby Class I areas.

- Amend the Clean Air Act. This congressional option would exempt the oil shale region from compliance with certain provisions of the Clean Air Act. Congress might direct EPA and the States in question to redesignate the oil shale region from a Class 11 area to a Class 111 area, and to exempt the oil shale developers from maintaining the visibility and air quality of nearby Class I areas. This option would remove the major uncertainties surrounding the siting of oil shale facilities within the resource region itself, and would remove any siting barriers connected with the degradation of nearby Class I areas. Such an option would allow development up to the Class III standards, which permit lower air quality than Class II standards. Thus, this option would allow an industry of up to 800,000 bbl/d to be sited in the Pice-

ance basin and an unknown amount in Utah and Wyoming, but at the cost of increased air pollution.

IMPROVE TECHNICAL INFORMATION

Additional analysis is needed of the potential effects of oil shale development on air quality. Such analysis will be useful in identifying long-term R&D needs in protecting air quality and in identifying siting problems imposed by existing air quality regulations and standards. Some options for improving the quality of technical information might include: the further development of existing R&D programs, the coordination of R&D work by Federal agencies, the redistribution of funds within agencies for air quality research, increased appropriations to agencies to accelerate their air quality studies, and the passage of new legislation specifically tied to funding R&D relating to air quality impacts at various levels of oil shale development.

Water Quality

Introduction

Development and operation of oil shale facilities could contaminate surface and ground water from point sources such as cooling water discharges, nonpoint sources such as runoff and erosion, and accidental discharges such as spills from trucks, leaks in pipelines, or the failure of containment structures. The pollutants could adversely affect aquatic biota, irrigation, recreation, and drinking water. The severity of these impacts will be determined by the scale of operation, the processing technologies used, and the types and efficiencies of the pollution controls.

The water systems may be affected during the operating lifetime of an oil shale facility, and such long-term impacts as those from the leaching of disposal piles could continue for many years after operations ceased. Accurate prediction of the impacts requires an understanding of the characteristics, transport routes, and fates of the pollutants that

might be released. Much work has been done to describe the quantity and quality of surface and ground water resources in the oil shale region. However, little is known about the nature and ultimate impacts of the pollutants produced by oil shale processing. For example, a number of these pollutants may be carcinogenic, mutagenic, and *teratogenic*.^{*} Information is not available on the risks posed by these pollutants at the levels likely to be encountered in the surface and ground water affected by oil shale development.

In this section:

- The types of wastewaters produced by oil shale operations are characterized.
- Rates for the generation of these contaminants are estimated.
- Potential impacts of effluent streams on surface and ground water are identified.

^{*}Carcinogens cause cancer. Mutagens cause mutations in offspring. Teratogens cause fetal defects.

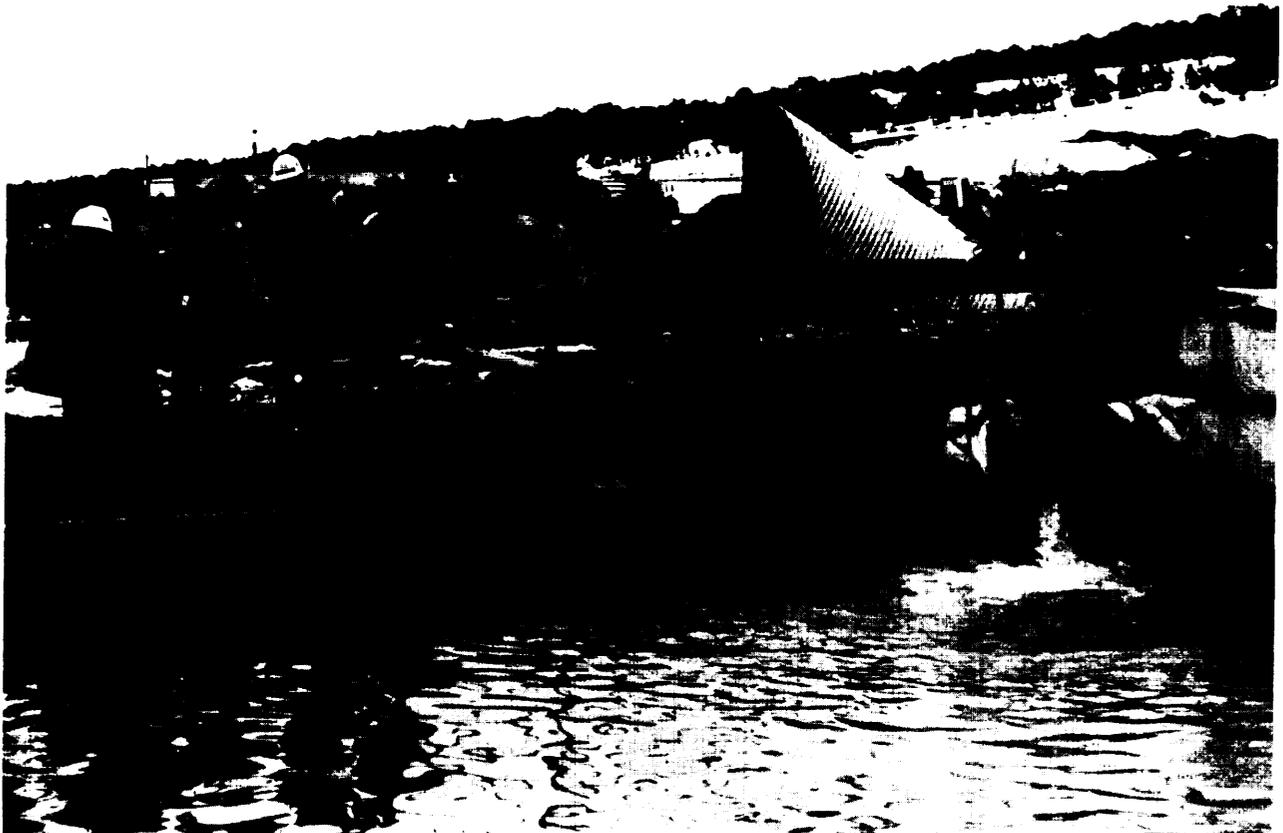
- The quality of surface and ground water resources in the oil shale region is examined.
- The applicable Federal and State water quality regulations and standards are described.
- The effects of these regulations and standards on a developing oil shale industry are analyzed.
- The pollution control strategies that may be applied are described and evaluated. The net rates at which pollutants will be emitted in treated streams are then estimated.
- Procedures for predicting and monitoring compliance with water quality regulations are discussed.
- Issues and R&D needs are summarized.
- Policy options are discussed.

Pollution Generation

The following discussion examines the types of effluents generated by various oil shale processes. Where data are available, the rates at which these effluents are produced by different types of facilities are estimated.

Unit Operations and Effluent Streams

Mining will produce dusty air and gases that must be cleaned to protect the miners. Wet scrubbing of this mine ventilation air will produce wastewater streams that will have to be treated. If the shale deposits are located in ground water aquifers, then mine drainage water will be produced that must be consumed, discharged to a surface stream, or re-



1%0(0 credit OTA staff

Mine dewatering at tract C-a— water quantity has been greater than anticipated at this site

injected into the aquifers. The drainage waters will contain inorganic salts, chloride and fluoride ions, and boron. They should not contain significant concentrations of dissolved gases or organic chemicals, although dissolved H_2S may be found in some locations.

Retorting produces water by combustion of hydrogen, by release of moisture present in the feed shale, and by chemical decomposition of kerogen. In some aboveground retorts (such as TOSCO 11 and Lurgi-Ruhrigas), this water is entrained in the retort's gas stream and is condensed when the product gas is cooled. This "gas condensate" will be contaminated with NH_3 , CO_2 , H_2S , and volatile organics, but will not contain appreciable quantities of inorganic salts. In other processes (such as in situ retorting or the Paraho or Union "B" aboveground retorts) some of the water may condense within the retort or in the oil/gas separators. This "retort condensate" will contain H_2S , NH_3 , CO_2 , and dissolved organics, plus inorganic salts that have been leached from the shale in the retort. Trace elements and toxic metals could also be present.

Upgrading will include several operations: gas recovery, hydrogen generation, gas-oil and naphtha hydrogenation, delayed coking, NH_3 /acid-gas separation, foul-water stripping, and sulfur recovery. Gas recovery and hydrogen generation produce little wastewater. However, hydrotreaters and cokers produce foul condensates that are contaminated with dissolved gases and organics. Gases are usually removed within the upgrading unit. Thus, the principal pollutants in the final effluent stream are dissolved organic compounds.

Air pollution control.—Dust scrubbers and water sprays will produce an effluent that contains suspended solids and dissolved inorganic salts. Effluent streams from gas cleaning devices will also contain solids and salts as well as HC , H_2 , NH_3 , phenols, organic acids and amines, and thiosulfate, and thiocyanate ions. The principal sources of wastewater will be scrubbers and units for the recovery of sulfur and NH_3 .¹⁴ Different devices

produce significantly different quantities of wastewater with different types and concentrations of contaminants. For example, a Claus/Wellman Lord sulfur recovery system would produce a neutralized acidic wastewater;¹⁵ a Stretford sulfur absorption unit would not.

Steam generation and water cooling.—High-quality water must be used to generate steam for power generation or process needs. Generally, the boiler feedwater must be treated to remove inorganic salts. The treatment (usually lime softening or ion exchange) generates liquid wastes. In addition, the water in a boiler becomes concentrated in dissolved materials, and a portion must be continually replaced with freshwater. The chemical species in the boiler wastewater (blowdown) will be similar to those in the raw water, but they will be more concentrated.

Wet cooling towers will be used to cool the water that is used in heat exchangers. Cooling towers work by evaporating a portion of the water passing through them. This evaporation concentrates the chemicals that enter with the feedwater, just as in a boiler. The water that must be removed to control the accumulation of solids (blowdown) will be chemically similar to the feedwater but will also contain chemicals that are added to control the growth of algae in the tower.

Spent shale disposal.—Spent shale from aboveground retorting will be exposed to leaching by rainfall, snowmelt, or irrigation water. If wastes are disposed of by backfilling mines, they may be leached by ground water. Leachates from various spent shales have been studied by a number of investigators.^{16 17} Their properties vary widely with the retorting process but in general they contain significant concentrations of total dissolved solids (TDS), sulfate, carbonate, bicarbonate, and other inorganic ions, and lesser amounts of trace elements and organic compounds. They are alkaline, with pH values ranging from 8 to 13. Their addition to the naturally occurring waters in the oil shale region could result in significant water quality changes, but the severity of the risk is diffi-

cult to ascertain. For example, one leachate was tested according to EPA procedures, and the spent shale could not be classified as a hazardous waste on the basis of its trace elements and toxicity.¹⁸ However, some spent shales could be classified as hazardous because of the presence of organic residues.¹⁹

Leaching of in situ retorts.—In situ retorting presents an environmental problem because ground water is found in many of the deposits to which this process could be applied. The increases in permeability that would result from mining, fracturing, and retorting would facilitate leaching after dewatering operations are discontinued. Soluble materials in the spent shale would thus enter the ground water and would eventually reach surface streams. Such transport would take long periods of time. However, if aquifers are contaminated, cleanup would be virtually impossible.

Summary of Pollutants Produced by Major Process Types

Approximate rates of generation of major pollutants are summarized for four facilities in table 51. * Five factors should be kept in mind in reviewing this table:

- The rates are for the generation of pollutants—not for their release to the environment. The rate of release will be determined by the strategies that are used to remove the contaminants.
- Retort condensates are not shown for the AGR processes because it is assumed that the retorts will be operated at temperatures that will avoid condensation of water vapors within the retort. This should be achievable with most retorting systems. However, others (like the Union “B”) may produce substantial quantities of retort condensate.
- No mine drainage water is shown for the aboveground plants because it is assumed that they will not be sited in ground water areas. This assumption re-

*See app.C for details,

Table 51.—Generation Rates for Principal Water Pollutants for Production of 50,000 bbl/d of Shale Oil Syncrude (tons/d)^a

	Type of retorting facility			
	Aboveground direct	Aboveground indirect	MIS	MIS/aboveground
Gas condensates				
N H ₂	75.6	147	276	189
H ₂ S	0.9	2.3	15	1.1
C O ₂	136	17.5	541	371
BOD	19.2	28.5	18.5	127
Subtotal	232	63	837	574
Retort condensates				
N H ₂	(b)	(b)	3.5	2.4
H ₂ S	(b)	(b)	—	—
C O ₂	(b)	(b)	48.2	331
BOD	(b)	(b)	10.1	7.3
Subtotal	—	—	62	43
Upgrading condensates				
N H ₂	134.2	134.2	134.2	134.2
H ₂ S	58.8	58.8	58.8	58.8
C O ₂	1.4	1.4	1.4	1.4
B O D	3.7	3.7	3.7	3.7
Subtotal	198	198	198	198
Blowdown and waste treatment				
Ca/Mg/Na ^d	6.0	6.3	12.2	11.2
Chloride	5.3	5.7	0.9	0.8
Fluoride	—	—	0.3	0.2
Sulfate	6.5	6.8	8.4	7.6
Subtotal	18	19	22	20
Mine drainage treatment				
CO ₃ =/HCO ₃ -e	(f)	(f)	23.1	23.1
Boron	(f)	(f)	0.1	0.1
Ca/ Mg/Na ^d	(f)	(f)	14.5	14.5
Chloride	(f)	(f)	0.7	0.7
Fluoride	(f)	(f)	0.5	0.5
Silica	(f)	(f)	0.5	0.5
Sulfate	(f)	(f)	12.6	12.6
Subtotal	—	—	52	52
Total	488	295	1,171	887

^aTons per stream day

^bAssumes above-ground retorts operated at temperatures that do not produce condensate

^cIncludes water pretreatment Above-ground plants use Colorado River water MIS and MIS/

above-ground plants use mine drainage water

^dCalcium magnesium and sodium ions

^eCarbonate and bicarbonate ions

^fAssumes above-ground retorting plants are not located in ground water areas

SOURCE: Office of Technology Assessment

fleets present developer proposals. It would not be valid for future plants in the center of the Piceance basin.

- No retort leachates are shown for the MIS retorts because the rate of leaching and the efficacy of control systems cannot be accurately estimated. One study estimated that a commercial MIS facility might yield over 2,000 ton/d of soluble salts, but only crude estimates were made of the rate of release.²⁰

No rates are shown for trace elements, heavy metals, or toxic organic chemicals because these are produced in much smaller amounts than the major pollutants. However, they can be both more hazardous and more difficult to remove.²¹⁻²⁸

The estimates indicate that MIS processing on tract C-b will produce the greatest quantity of wastewater contaminants for treatment, mostly because of the large gas condensate stream. A substantial difference is shown between the aboveground direct and above-ground indirect plants with respect to the rates at which pollutants are generated in the gas condensate streams: the directly heated facility produces about four times as much dissolved gas (largely CO₂ and NH₃). This is because more air is introduced into directly heated retorts. The trend is consistent with the even higher gas condensate production of the MIS retorts, which are also assumed to be directly heated.

Effects of Potential Pollutants on Water Quality and Use

Salinity

Oil shale development could increase the salinity in surface and ground water systems through two processes:

- Concentration of naturally occurring saltwater as high-quality water is withdrawn for consumptive uses. (This effect is discussed in ch. 9.)
- Salt loading from leaching of waste disposal piles and in situ retorts, from release of saline mine or process waters, and from ground water disturbances caused by reinfection.

Salinity increases are a significant problem because as water becomes more mineralized, its municipal, domestic, ecological and agricultural utility is reduced. * If dissolved solids

*This is of major importance because the Colorado River system is one of the most important river systems in the Southwest. It serves approximately 15 million people. Municipalities, agriculture, energy production, industry and mining, recrea-

increase over 500 mg/l, treatment for municipal and industrial water users becomes more costly, and the yield of irrigated farmlands might be reduced.²⁹ For public drinking water supplies, EPA recommends limits of 500 mg/l for dissolved solids and 250 mg/l for both chlorides and sulfates.³⁰

Oil and Grease

Because large amounts of shale oil will be produced, processed, and transported, there is a possibility of oilspills. If they cannot be contained or removed, detrimental impacts would occur to aquatic biota. Small spills, such as from pipeline leaks, could cause local damage. If undetected, the long-term impacts could be substantial. Oil and grease in public water supplies cause an objectionable taste and odor, and might ultimately endanger public health.

Suspended Solids

Sedimentation problems will be increased because large amounts of land will be disturbed, which will increase the area's susceptibility to erosion. Suspended solids make surface water cloudy and increase its temperature, thereby affecting aquatic life. Suspended solids in industrial waters can damage some types of equipment.

Temperature Alteration

An industry may alter stream temperatures by discharging warm waste streams, by consuming cool water, or by lowering the ground water table. Discharges from powerplants could also increase temperatures, but the developers do not expect to do this. The construction of new reservoirs could also alter stream temperatures. While temperature is not a critical factor in water for industrial use, for drinking, or for irrigation,

tion, wildlife, Federal lands, and Indian reservations all compete for its waters. Presently, salinity of the Colorado River at Hoover Dam is 745 mg/l. Unless efficient control technologies can be employed, estimates have indicated that a large oil shale industry has the potential, due to salt loading and salt concentration, to increase the salinity level at Hoover Dam by several mg l.

large variations would affect all aquatic life, both directly and indirectly (e.g., by influencing their susceptibility to disease and toxic compounds.)3] Because the Colorado River system is large, and variations in water temperatures occur naturally, it is not expected that oil shale development will significantly affect its temperature.³²

Nutrient Loading

The potential sources of nitrogen and phosphorous are ground water discharge, runoff from raw and spent shale, municipal wastes, and chemical fertilizers used for reclaiming land. These nutrients would adversely affect nearby surface waters, but the effect on the total river system is uncertain. The overall impact will depend on where the facilities are located and on the degree of waste treatment used.

Toxic Substances

Sources of toxic trace elements and organic chemicals include stack emissions from processing operations, chemicals used in upgrading and gas processing, leachates from raw and retorted shale, and associated industrial and municipal wastes. These substances are of concern because of their potential impact on aquatic life, and on human health through drinking water supplies and irrigation. Concentrations of certain minerals in the region's water already exceed the limits set for certain water uses. * Oil shale development could increase these levels and could also add other toxic contaminants. For example, cadmium, arsenic, and lead, and other heavy metals could be leached from spent shale piles. Organic compounds (phenols, benzene, acetone) that are suspected carcinogens and that have been identified by EPA as high-priority hazardous water pollutants also are found in oil shale process waters.

*For example, the boron content in Eva ma lion Creek, near lease tracts U-a and U-b exceeds the irrigation standard. See the next section on water quality in the oil shale region for a more detailed discussion,

Microbial Contamination

The microbial contamination of surface waters could occur if rapid population growth overloads sewage treatment facilities. (See ch. 10 for a discussion of the problems of rapid growth.) Improperly treated sewage containing viruses, bacteria, and fungi could be released into the water system. These problems could be controlled by the construction or expansion of sewage treatment plants.

Water Quality in the Oil Shale Region

The current properties of the water define how it must be treated before it can be used in oil shale facilities. More importantly, they define the level to which wastewater must be treated before it can be discharged. In general, regulations do not permit the discharge or reinfection of wastewater unless it is at least as pure as the receiving stream or aquifer. As indicated by the data in table 52, the quality of surface streams is highly variable. It also tends to deteriorate between upstream and downstream reaches, as exemplified for Piceance Creek east and west of tract C-b. All of the streams described in the table satisfy the standards promulgated by EPA and the U.S. Public Health Service for the maintenance of aquatic life and wildlife. Moreover, with the exception of Evacuation Creek, all are suitable for irrigation water supplies and for livestock watering. Evacuation Creek's boron content exceeds the irrigation standard, and its dissolved solids level exceeds the livestock watering standard. However, none of the streams satisfies the standards for public drinking water. The standard for dissolved solids is exceeded by all the streams, especially Yellow Creek and Evacuation Creek. Evacuation Creek also exceeds the standard for boron, sodium, and sulfate ions. The sodium standard is also exceeded by Yellow Creek, and the sulfate standard by all three creeks and the spring.

Ground water is generally of poorer quality than surface streams. The quality of alluvial aquifers and of the upper and lower bedrock

Table 52.—Quality of Some Surface Streams in the Oil Shale Region (mg/l)

Basin	Piceance	Uinta	Piceance	Piceance	Piceance	Piceance	Piceance	Uinta
Stream	Colorado River	White River	Piceance Creek east of C-b	Piceance Creek west of C-b	Yellow Creek	Spring at Willow Creek	Wallow Creek	Evacuation Creek
Reference	14	15	16	16	17	16	16	15
Ammonia	NA ^a	0.06	NA	NA	0.153	0.1	0.1	0.06
Bicarbonate	168	241	542	601	1,470	606	540	575
Boron	NA	0.088	NA	NA	0.642	0.2	0.6	1.95
Calcium	72	72	70	79	319	143	161	214
Carbonate	NA	0.2	0.0	0.0	118	0.1	0.1	0.0
Chloride	205	42	16	14	124	4.0	0.8	66
Dissolved solids	734	551	718	944	2,430	995	910	4,948
Fluoride	NA	0.03	1.0	0.7	2.09	1.7	1.4	0.9
Hardness	NA	299	NA	NA	541	576	516	1400
Magnesium	19	29	47	69	112	53	28	209
pH	NA	8.2	8.2	8.2	8.7	7.9	7.9	7.9
Silica	7.0	13	16	17	105	13	13	10
Sodium	153	78	130	160	746	138	125	972
Sulfate	158	188	170	300	550	350	310	2,889

^aSee reference list^bData not available

SOURCE: Office of Technology Assessment

ground water aquifers in the Piceance basin near Federal lease tracts C-a and C-b is shown in table 53. * Water from the alluvial and upper aquifers could be used for irrigation, but its high dissolved solids content could harm many crops. Water from the lower aquifer could be used only with very tolerant plants on permeable soil, and that from some portions of the aquifer could not be used at all because the lithium and boron concentrations would be toxic to many plants. Except for the lower aquifer, the ground water resources could be used for livestock. All of the water would be suitable for maintenance of aquatic life and wildlife.

None of the aquifers meets drinking water standards. Special problems are encountered with boron, which in one sample of lower aquifer water exceeded the drinking water standard by a factor of 320.³⁴ Also, the average fluoride concentration in lower aquifer water is about 28 times the drinking water standard.³⁵ Dissolved solids concentrations in the lower aquifer range from a level that would satisfy drinking water standards (500 mg/l) to over 40,000 mg/l. A concentration of 63,000 mg/l was reported for one sample.³⁶

³⁴The ground water resources of the Piceance basin are described in ch.9. The bedrock aquifers are separated by the oil shale deposits of the Mahogany Zone. Alluvial aquifers are generally found near the surface in valley walls and floors.

Table 53.—Quality of Ground Water Aquifers in the Piceance Basin (mg/l)

Aquifer Referenced	Alluvial 17	Alluvial 16	Upper 16	Lower 16
Ammonia	0.337	NA ^a	NA	NA
Bicarbonate	573	1,220	550	9,100
Boron	1.25	NA	NA	NA
Calcium	102	57	50	7.4
Carbonate	11.4	NA	NA	NA
Chloride	17.9	42	16	690
Dissolved solids	1,190	1,750	960	9,400
Fluoride	0.367	4.6	1.4	28
Hardness	600	NA	NA	NA
Magnesium	83.9	80	60	9.5
pH	6.5	NA	NA	NA
Silica	NA	NA	NA	NA
Sodium	202	490	210	3,980
Sulfate	467	430	320	80

^aSee reference list^bData not available

SOURCE: Office of Technology Assessment

Water Quality Regulations

Regulations for the maintenance of surface and ground water quality have been promulgated under the Clean Water Act and the Safe Drinking Water Act. They are implemented at the Federal and State levels, together with additional State standards. In the following discussion, the provisions of these Acts that are of particular significance to oil shale are emphasized.

The Clean Water Act

The objective of the Federal Water Pollution Control Act (FWPCA) is “to restore and maintain the chemical, physical, and biological integrity of the Nation’s waters.” In 1972, FWPCA was amended to establish a complex program to clean up the Nation’s waterways by limiting the effluents of all classes of pollutants. These limits were to be tightened until the ultimate goal of no pollution discharge into navigable waters was achieved. The mining industry had difficulties meeting the requirements of this program. Congress responded to these problems, and to the recommendations of the National Commission on Water Quality, by further amending the Act in 1977. The amended Act, now called the “Clean Water Act” refined FWPCA’s regulatory scheme for point sources and emphasized the control of toxic effluents. EPA, the Army Corps of Engineers, and the States are responsible for implementing and enforcing this Act.

The goals of the Act are:

- the discharge of pollutants into navigable waters shall be eliminated by 1985;
- wherever attainable, water quality which provides for the propagation of fish, shellfish, and wildlife and for recreation in and on water, shall be achieved by July 1, 1983;
- discharge of toxic pollutants in toxic amounts shall be prohibited; and
- a major R&D effort shall be made to develop the technology necessary to eliminate the discharge of pollutants into the navigable waters, the waters of the contiguous zones, and the oceans.

To achieve these goals, emissions standards are to be set to limit discharges from point and nonpoint sources, and ambient standards are to be established for the quality of surface waters.

Effluent standards.—Different approaches are used for control of point and nonpoint sources. Point sources release a collected stream of pollutants through sewers, pipes, ditches, and other channels. These can

be monitored and regulated with some precision, and they are suited to the application of control devices. Nonpoint sources are sites from which there is uncollected runoff. Examples are irrigated fields and waste disposal areas. They present regulatory and technological difficulties, and as a result, they are subject to less stringent legal controls.

FWPCA established a complex regulatory scheme to control pollution from industrial point sources:

- by July 1977, all nonmunicipal polluters must use the “best practicable pollution control technology currently available” (BPT); public sewage works must use secondary treatment;
- by July 1983, nonmunicipal point sources must use the “best available technology economically achievable” (BAT), municipal sewage treatment plants must use the “best practicable waste treatment technology;”
- special effluent standards for toxic pollutants must be met prior to the 1977 deadline;
- new facilities must use the “best available demonstrated control technology;” and
- special restrictions, based on ambient water quality standards, must be used if the national effluent standards will not meet water quality targets in a given basin.

The 1977 amendments changed this framework: the July 1977 BPT deadline was extended until April 1, 1979, for point-source polluters who demonstrated a good-faith effort to achieve compliance, and the BAT provisions were completely revised. Industrial point-source pollutants were divided into three classes—toxic, conventional, and nonconventional. Each is treated differently. Toxic pollutants cause death, disease, behavioral abnormalities, cancer, genetic mutations, physiological malfunctions, or physical deformations in any organisms or their offspring. Sixty-five toxic pollutants must meet the BAT standards by July 1, 1984; others must meet BAT standards within 3 years

after effluent limitations are established. Conventional pollutants include biological oxygen-demanding substances, suspended solids, fecal coliform, and changes in pH. They are subject to the application of “best conventional control technology” by July 1, 1984. In general, this standard is less stringent than the BAT standard. Nonconventional pollutants—those classified as neither toxic nor conventional—will be subject to the BAT standards no later than July 1, 1987.

Specific limits on these effluents must be adhered to by individual polluters. In practice, effluent limitations are developed by EPA for each industry. No discharge of any pollutant from a point source is allowed unless a National Pollutant Discharge Elimination System (NPDES) permit has been granted. To obtain a permit, the polluter must meet the applicable effluent limitations, technology standards, and water quality goals. Permits are obtained from EPA or from the individual States, if they have taken over the regulatory role. Cancellation of permits for noncompliance is one method of enforcing the Act, because without a permit, many industrial operations cannot be carried out. It should be noted that permits do not simply recapitulate the effluent guidelines; additional ambient standards may also be imposed.

Special attention is given to new sources and to sources that discharge into publicly owned treatment works. In practice, performance standards for new sources are often equivalent to the 1983 BAT limitations developed for existing industries. Any new source that complies with an applicable standard of performance is not to be subjected to more stringent standards during the first 10 years of operation.

Expected effluent limitations for oil shale facilities.—EPA has not yet developed standards of performance for oil shale facilities. However, standards have been established for petroleum refining, which has several similarities. The BPT standards shown for petroleum refining in table 54 were based on

Table 54.—Effluent Limitations for Petroleum Refineries Using Best Practicable Pollution Control Technology (BPT)
(pounds per 1,000 bbl of feedstock)

Effluent characteristic	Effluent limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Biochemical oxygen demand (BOD ₅)	192	102
Total suspended solids	132	84
Chemical oxygen demand	136	70
Oil and grease	60	32
Phenolic compounds	014	0068
Ammonia as N	83	38
Sulfide	0124	0056
Total chromium	029	017
Hexavalent chromium	0025	0011
pH	Must be within the range of 6.0 to 9.0	

SOURCE: E. R. Bales and T. L. Thoenes (eds.), *Pollution Control Guidance for Oil Shale Development*, Appendix Environmental Protection Agency Cincinnati, Ohio, July 1979, p. 9.

the following wastewater management procedures:

- sour water stripping to reduce NH₃ and H₂S;
- segregation of sewers;
- no discharge of polluted cooling water; and
- oil, solids, and carbonaceous wastes removed just prior to discharge.

The BAT standards illustrated in table 55 were defined using additional treatment

Table 55.—Effluent Limitations for Best Available Technology Achievable (BAT) for Petroleum Refinery Facilities
(pounds per 1,000 bbl of feedstock)

Effluent characteristic	Effluent limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Biochemical oxygen demand (BOD ₅)	32	2.6
Total suspended solids	3.0	2.6
Chemical oxygen demand	168	134
Oil and grease	060	0.48
Phenolic compounds	0015	0010
Ammonia as N	20	15
Sulfide	0066	0042
Total chromium	015	0.13
Hexavalent chromium	0.0033	0.0021
pH	Must be within the range of 6.0 to 9.0	

SOURCE: E. R. Bales and T. L. Thoenes (eds.), *Pollution Control Guidance for Oil Shale Development*, Appendix Environmental Protection Agency Cincinnati, Ohio, July 1979, p. 11.

methods now practiced by some petroleum refineries. These methods include:

- use of air cooling rather than wet cooling towers;
- reuse of sour water stripper wastes;
- reuse of cooling water in the water treatment plant;
- using treated wastewater as coolant water, scrubber water, and in the water treatment plant;
- reuse of boiler blowdown as boiler feed-water;
- use of closed cooling water systems, compressors, and pumps;
- use of rain runoff as cooling tower make-up or water treatment plant feed; and
- recycling of untreated wastewaters wherever practical.

NSPS for petroleum refineries, based on a combination of BPT and BAT standards, are shown in table 56. New sources must meet discharge standards that reflect the greatest degree of effluent reduction which the EPA Administrator determines to be achievable through application of the best available demonstrated control technology, process alterations, or other methods including, where practicable, zero discharge systems.

Federal ambient water quality standards.—The Water Quality Act of 1965 required the States to adopt ambient standards

for interstate waters. FWPCA required State standards for intrastate waters as well. EPA will develop the standards if a State fails to do so.

The ambient standards are the basis for preventing the degradation of presently clean waterways. The regulations provide, without qualification, that “No further water quality degradation which would interfere with or become injurious to existing instream water uses is allowable.” Thus, if a stream is suitable for the propagation of wildlife; for swimming; or for drinking water, then it must remain suitable for these uses. Because small increases in pollutant loads may not be inconsistent with protecting a possible present use, the States are allowed to decide whether “to allow lower water quality as a result of necessary and justifiable economic or social development.” Such decisions cannot be applied to waters that constitute an outstanding national resource (e.g., national parks, wilderness areas), and they cannot allow water quality to fall below the levels needed to protect fish, wildlife, and recreation.

Before a State can issue a discharge permit it must have a program for reviewing and revising its water quality standards. EPA established the following guidelines for State review and revision:

- standards must be reviewed every 3 years and revised where appropriate;
- standards must protect the public health and welfare, and not interfere with downstream water quality standards; existing standards must be upgraded where current water quality could support higher uses than those presently designated;
- existing standards must be upgraded to achieve FWPCA’s 1983 goal of fishable and swimmable waters, where attainable. Attainability is to be determined by environmental, technological, social, economic, and institutional factors; and
- existing water quality can degrade in only specific instances, for example, if existing standards are not attainable

Table 56.—New Source Performance Standards for Petroleum Refineries (pounds per 1,000 bbl of feedstock)

Effluent characteristic	Effluent Limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Biochemical oxygen demand (BOD ₅)	147	7.8
Total suspended solids	9.9	6.3
Chemical oxygen demand	104	54
Oil and grease	4.5	2.4
Phenolic compounds	0.105	0.051
Ammonia as N	8.3	3.8
Sulfide	0.093	0.042
Total chromium	0.220	0.13
Hexavalent chromium	0.019	0.0084
pH	Must be within the range of 60 to 90	

SOURCE: E. R. Bales and T. L. Thoenes, eds., *Pollution Control Guidance for Oil Shale Development*, Appendix Environmental Protection Agency, Cincinnati, Ohio, July 1979, p. 012.

because of natural conditions such as leaching.

Once an ambient standard is established, a State must identify stream reaches for which the 1977 effluent limitations are not sufficiently stringent. For such areas, the State must determine the total maximum pollutant loads that will allow the ambient standard to be met. This information is used to set more stringent effluent standards.

Current State standards for Colorado and Utah.—In Colorado, streams may be assigned to one of four categories. Drainage from lease tracts C-a and C-b would discharge to the portion of the White River from the mouth of the Piceance Creek to the Colorado/Utah State line. This area is in Colorado's water category B2. These waters are suitable, or are to become suitable, for customary raw water purposes (e.g., irrigation, livestock watering) except for primary contact recreation. * The water quality criteria for category B2 are listed in table 57. Colorado also has an anti-degradation policy applicable to all streams.

Utah has 11 stream classifications. Two streams in and around oil shale tracts U-a and U-b, Evacuation Creek, and the White River, are classified as CW (i.e., warm water fisheries). Their waters are suitable for all

*Primary contact recreation includes swimming, water skiing, and diving.

Table 57.—Colorado Water Quality Standards for Stream Classification B2

Parameter	Criteria for B2 streams
Settleable solids floating solids taste, odor, color and toxic materials	Free from
Oil and grease	Cannot cause a film or other discoloration
Radioactive material	Drinking water standards
Fecal conform bacteria	Geometric mean less than 1,000 units per 100 milliliters
Turbidity	Cannot increase more than 10 units
pH	60 to 90
Temperature	Maximum 900 F Change Streams 50 F Lakes 30 F

SOURCE: E. R. Bates and T. L. Thoen (eds.), *Pollution Control Guidance for Oil Shale Development*, Appendix, Environmental Protection Agency, Cincinnati, Ohio, July 1979, p. D-20.

raw water uses (except contact recreation) without treatment, but with coagulation, sedimentation, filtration, and disinfection prior to use as domestic water supply. Temperature limitations are also imposed. The water quality criteria for class CW are shown in table 58. In addition, Utah, like Colorado, has an anti-degradation policy.

Table 58.—Utah Water Quality Standards for Stream Classification CW

Parameters	Criteria for CW streams
Radioactive and chemical	Drinking water standards
Settleable solids, floating solids, taste, odor, color, and toxic materials, turbidity, etc	Free from
Total coliform bacteria	Less than 5,000 units per 100 milliliters
Fecal conform bacteria	Less than 2,000 units per 100 milliliters
pH	65 to 85, no increase >0.5
Biochemical oxygen demand (BOD)	Less than 5 milligrams per liter
Dissolved oxygen	>6.0 milligrams per liter
Temperature	Maximum 680 F

SOURCE: E. R. Bates and T. L. Thoen (eds.), *Pollution Control Guidance for Oil Shale Development*, Appendix, Environmental Protection Agency, Cincinnati, Ohio, July 1979, p. 021.

Proposed State standards.—FWPCA required the States to designate areawide pollution control planning agencies. The Colorado West Area Council of Governments and the Uinta Basin Council of Governments have been designated for the oil shale region. These agencies are to plan, promulgate, and implement a program designed to protect surface water quality. Stream classifications and water quality standards are to be developed. The multiple-use classifications proposed for streams, which may supersede existing classifications previously discussed, include:

- Class I—aquatic life, water supply, recreation, and agriculture;
- Class II—water supply, recreation, and agriculture;
- Class III—recreation and agriculture; and
- Class IV—agriculture.

The respective water quality criteria are shown in table 59. The classifications and the quality criteria will apply to all streams in the oil shale region.

Table 59.—Proposed Water Quality Criteria for Designated Uses

Parameter	Water supply	Aquatic life/ wildlife	Recreation	Irrigation	Livestock
Alkalinity as CaCO ₃	—	30-130 mg/l ^f	—	—	—
Aluminum-total	—	0.1 mg/l	—	5.0 mg/l ^b , 20.0 mg/l ^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 ^b	—	—	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	0.05 mg/l ^d
Chloride-total	250 mg/l	—	—	—	—
Chromium-total	0.05 mg/l	0.3 mg/l ^e	—	0.1 mg/l ^b , 1.0 mg/l ^d	0.1 mg/l
Fecal coliform	2,000/100 ml ^f	2,000/100 ml ^e	200/100 ml	1,000/100 ml	1,000/100 ml
Color	0.75 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	0.020 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 ^{b,c}	—
Iron-dissolved	0.03 mg/l	0.3 mg/l ^b	—	—	—
Lead-total	0.05 mg/l	0.03 mg/l	—	5 mg/l ^b , 10 mg/l ^{e,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 ⁱ	—
Nitrate-tl	10 mg/l	—	—	100 mg/l	NO ₃ + NO ₂ 100 mg/l
Dissolved oxygen	40 mg/l ⁱ	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 ^g	—
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 ^j	—	—	—
Silver-dissolved	—	0.0001 mg/l	—	—	—
Sodium	270 mg/l ^h	—	—	—	—
Sulfate-total	250 mg/l	—	—	—	—
TDS	500 mg/l ^a	—	—	(1)	3,000 mg/l ^a
TSS	—	25 mg/l-median ^k	—	—	—
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
 500-1000 mg/l
 Water that may have adverse effects on many crops and requires careful management practices
 1,000-2000 mg/l
 Water that can be used for tolerant plants on permeable soils with careful management practices
 2,000-5000 mg/l
^jValue represents maximum increase in ambient concentration due to discharge
^kCold water maximum is 200 C, warm water maximum is 30° C, and both Categories limit temperature changes to 3° C

SOURCE: E. R. Bates and T. L. Thoen (eds.) *Pollution Control Guidance for Oil Shale Development Appendix*, Environmental Protection Agency, Cincinnati, Ohio, July 1979 pp. D-29-D-30

The Safe Drinking Water Act of 1974

This Act protects drinking water systems through primary and secondary ambient standards, monitoring programs, and a pro-

gram for ground water protection. It is administered by EPA and by the States.

The primary standards are intended to protect health to the extent feasible, given the

restraints of existing treatment techniques and their costs. Interim standards were issued by EPA during 1975 and 1976 and were put into effect in June 1977 (see table 60). These standards established both maximum contaminant levels and monitoring requirements for 10 inorganic and 6 organic chemicals, radionuclides, microbiological contaminants, and turbidity. A study by the National Academy of Sciences of the health effects of drinking water contaminants is to be the basis for revised primary standards. The study was completed in June 1977, but the revised standards have not yet been issued.

Secondary standards, published in 1977, deal with contaminants that affect the odor and appearance of water but do not directly affect health (see table 61). They are not federally enforceable and are only guidelines to the States. The States may include monitoring requirements in their laws and regulations.

Table 60.—Primary Drinking Water Standards (mg/l)

	Maximum concentration
<i>Inorganic chemicals (except fluoride)</i>	
Arsenic	0.05
B a r i u m	10
C a d m i u m	0.01
C h r o m i u m	0.05
L e a d	0.05
Mercury	0.002
Nitrate (as N)	100
S e l e n i u m	0.01
S i l v e r	0.05
<i>Fluoride</i>	
(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
<i>Chlorinated hydrocarbons</i>	
E n d r i n	0.0002
L i n d a n e	0.004
M e t h o x y c h l o r	0.1
T o x a p h e n e	0.005
<i>Chlorophenoxys</i>	
2, 4-D (2, 4-dichlorophenoxyacetic acid)	0.1
2, 4, 5-TP (Silvex)	0.01

SOURCE: E. R. Bates and T. L. Thoen (eds.), *Pollution Control Guidance for Oil Shale Development*, Appendix Environmental Protection Agency, Cincinnati, Ohio, July 1979, pp. D-32-D-33.

Table 61.—Proposed Secondary Drinking Water Regulations

Pollutant	Proposed level	Principal effects
C h l o r i d e	250 mg/l	Taste
Color	15 color units	Appearance
Copper	1 mg/l	Taste, fixture staining
Corrosivity	(Noncorrosive)	Deterioration of pipes, unwanted metals in drinking water
Foaming agents	0.5 mg/l	Foaming, adverse appearance
Hydrogen sulfide	0.05 mg/l	Taste, brown stains on laundry and fixtures
Manganese	0.05 mg/l	Taste, brown stains, black precipitates
O d o r	3 threshold odor number	Odor
pH	6.5-8.5	Corrosion below 6.5, incrustations, bitter taste, lowered germicidal activity of chlorine over 8.5
Sulfate	250 mg/l	Taste, laxative effects
Total dissolved solids	500 mg/l	Taste, reduction in life of hot water heaters, precipitation in cooking utensils
Z i n c	5 mg/l	Taste

SOURCE: E. R. Bates and T. L. Thoen (eds.), *Pollution Control Guidance for Oil Shale Development*, Appendix Environmental Protection Agency, Cincinnati, Ohio, July 1979, p. D-33.

Ground Water Quality Standards

Federal.—The Safe Drinking Water Act applies to deep-well injection of waste into aquifers with less than 10,000 mg/l TDS that are, or could become, sources of public drinking water. Seepage from pits, ponds, and lagoons is not regulated at this time.

Colorado.—No specific standards have been promulgated for ground water quality. However, the basic standards applicable to all other State waters do apply. Regulations are being developed that will limit the discharge or injection of some contaminants. Permits are now required for injection wells, and they will be required in the future for wastewater disposal in pits, ponds, and lagoons if there is a possibility of discharge to a ground water system.

Utah.—Utah also has no special standards for ground water. However, ground water is considered part of the State waters, so general water quality standards do apply. Discharges to sources of potable water must not cause the water quality to exceed drinking water standards.

Implications of Water Pollution Control Standards and Regulations for Oil Shale Development

As indicated above, the primary objective of the Clean Water Act is to eliminate the discharge of pollutants into navigable waters by the late 1980's. In order to accomplish this objective all potential polluters, including oil shale developers, will be required to apply BAT, BPT, and NSPS. Point source discharge is well-regulated under the Act, and it is expected that oil shale developers would comply with the stipulations promulgated in regard to NPDES. As will be discussed in the following section, the pollution control technologies that are being applied to oil shale wastewater effluents are designed for zero discharge. However, in some instances (e.g., excess water from mine dewatering) it will need to be discharged back into surface waters or re-injected into underground aquifers. In this case, water will have to be treated to meet the standards stipulated under the NPDES permit system or by the Safe Drinking Water Act for re-infection—that is surface and ground water quality criteria and water use classifications will have to be maintained as stipulated by the States and EPA. In addition, it is expected that oil shale facilities will have to meet NSPS comparable to those developed for petroleum refining facilities.

Technologies for Control of Oil Shale Water Pollution

Treatment of Point Sources*

Contaminants may be removed from wastewater by physical, chemical, or biological means. For complex wastes, a series of devices using each of these principles will be necessary.

Physical treatment devices apply gravity, electrical charge, and other physical forces to contaminants to remove them from wastewater. Typical operations are gravity separation, air flotation, clarification, filtration, stripping, adsorption, distillation, reverse os-

mosis, electro-dialysis, thickening, and evaporation.

Chemical treatment devices use chemical properties or chemical reactions to remove contaminants. Such systems can destroy hazardous substances that are not amenable to conventional physical and biological systems. For oil shale wastewaters, the most important devices are those that could oxidize organic compounds or reduce salt concentrations. Included are ion exchange, wet air oxidation, photolytic oxidation, electrolytic oxidation, and direct chemical oxidation.

Biological treatment devices contact a waste with a population of micro-organisms that digest its organic contaminants. By controlling the size of the population, and by adjusting oxygen and nutrient levels and equalizing the conditions of the entering stream, it is possible to develop and acclimate micro-organisms that can nearly eliminate many hazardous organic compounds. Biological treatment systems can be divided into two groups:

- aerobic processes (such as activated sludge, trickling filters, rotating biological contractors, aerated lagoons, composting, and stabilization ponds) in which the population is maintained under oxygen-rich conditions and the organic compounds are decomposed to CO₂ and water; and
- anaerobic processes (such as digestion) in which oxygen levels are relatively low and the organic compounds are degraded to CO and methane gas.

Treatment systems.—Most devices can remove some but not all contaminants. In a treatment system, different wastewaters are sent to different devices, each of which removes a specific type of pollutant. The relationships among contaminants, the streams in which they are likely to occur, and the treatment processes of choice are shown in table 62. Although all contaminants may be found in nearly all streams, the streams associated with each contaminant have been limited to those in which concentrations will be high

*Details of the various technologies are described in app. D.

Table 62.—The Types of Contaminants in Oil Shale Wastewater Streams and Some Potential Processes for Removing Them

Contaminant	Stream	Potential process
Suspended solids	Mine drainage	Clarification
	Retort condensate	Filtration
	Cooling tower blowdown	
Oil and grease	Retort condensate	Gravity separation
	Gas condensate	Emulsion breaking
	Coking condensate	
Dissolved gases	Retort condensate	Steam stripping
	Gas condensate	
	Coking condensate	
Dissolved inorganics	Mine drainage	Chemical oxidation
	Retort condensate	Ion exchange
	Gas condensate	Reverse osmosis
	Cooling tower blowdown	Adsorption
	Ion exchange regenerants	Evaporation
Dissolved organics	Retort condensate	Solvent extraction
	Gas condensate	Adsorption
	Coking condensate	Biological oxidation
	Hydrotreating condensate	Ultrafiltration
		Reverse osmosis
Trace elements and metals	Retort condensate	Chemical oxidation
	Gas condensate	Ion exchange
		Adsorption
Trace organics	Retort condensate	Ultrafiltration
	Gas condensate	Reverse osmosis
	Upgrading condensate	Adsorption
Toxics	Retort condensate	Chemical oxidation
	Gas condensate	Incineration
	Upgrading condensate	
Sanitary wastes	Domestic service	Biological treatment

SOURCE R F Probst, H Gold and R E Hicks *Water Requirements, Pollution Effects, and Costs of Water Supply and Treatment for the Oil Shale Industry*, prepared for OTA by Water Purification Associates, October 1979.

enough to require removal prior to discharge or reuse.³⁷⁻³⁸

Many of the devices listed in table 62 have been tested individually on oil shale wastewaters and have been found to provide some degree of control.³⁹⁻⁵⁰ Of great importance is the performance of these units when combined to form a “treatment train” for a specific wastewater. A separate train—consisting of several individual treatment devices in series—will be needed for each stream because, in general, each will contain different types of contaminants. Each contaminant will require a different type of removal process. For example, retort condensates may contain suspended solids, oil and grease, dissolved gases, organics, inorganic, and trace ele-

ments. Mine drainage water may contain only dissolved solids.

The removal efficiencies, reliabilities, adaptabilities, and relative costs of some point source control devices are summarized in table 63. This information comes almost entirely from experience in other industries. Few of the technologies have been tested with oil shale wastewaters, and none has been tested in the complex treatment trains that will be necessary to deal with the wastes that will be encountered in commercial-scale oil shale plants. The degree of adaptability of each technology is particularly important because it indicates the likelihood that the technique will transfer without difficulty to the oil shale situation.

Most suitable technologies.—The following technologies appear most suitable:

- for oil and grease: dissolved air flotation or coalescing filters;
- for dissolved gases: air or steam stripping;
- for dissolved organics: rotating biological contractors or trickling filters for first-stage removal, carbon adsorption, or wet air oxidation for polishing;
- for suspended solids: pressure or multimedia filtration;
- for dissolved solids: reverse osmosis for first-stage removal, clarification for second-stage, and ion exchange for polishing; and
- for sludges: filtration and evaporation.

Costs.—Control costs depend on the operating characteristics of the oil shale facility and on the treatment methods selected. The only published cost estimates were prepared for the Department of Energy (DOE). These estimates, upgraded for OTA to include the cost of treating excess mine drainage water, appear in table 64. Total treatment costs range from about \$0.25 to \$1.25/bbl of shale oil syncrude. The low estimate applies to aboveground retorting plants; the high to MIS facilities in ground water areas. Although sizable, the control costs should not themselves preclude profitable operations.

Table 63.—Relative Rankings of the Water Treatment Methods

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
	Trickling filter	85 BOD	High	Medium	Low
	Aerated lagoon	80 BOD	Medium	Medium	Low
	Rotating contactor	90 BOD/20-50 COD	High	Medium	Low
	Anaerobic digestion	60-95 BOD	High	Medium	Medium
	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

SOURCE Adapted from *Assessment of Oil Shale Retort Wastewater Treatment and Control Technology*, Hamilton Standard Division of United Technologies July 1978 pp 2-12 to 2-24

Table 64.—Estimated Costs of Water Pollution Control in Oil Shale Plants (\$/bbl of shale oil syncrude)^a

Wastewater stream	Above-ground direct	Above-ground indirect	MIS	MIS/aboveground
Gas condensate	\$0.11	\$0.13	\$0.45	\$0.31
Retort condensate	-	-	0.13	0.09
Upgrading condensate	0.12	0.12	0.12	0.12
Excess mine drainage	-	-	0-0.55	0-0.55
Total	\$0.23	\$0.25	\$0.70-1.25	\$0.52-1.07

^aPlants produce 50,000 bbl/d of syncrude. Aboveground plants are assumed to be not located in ground water areas. Cost estimates include operating expenditures and capital amortization. They also include nonwastewater costs such as boiler feedwater treatment costs.

SOURCE R F Probst, H Gold and R E Hicks, *Water Requirements, Pollution Effects and Costs of Water Supply and Treatment for the Oil Shale Industry*, prepared for OTA by Water Purification Associates, October 1979

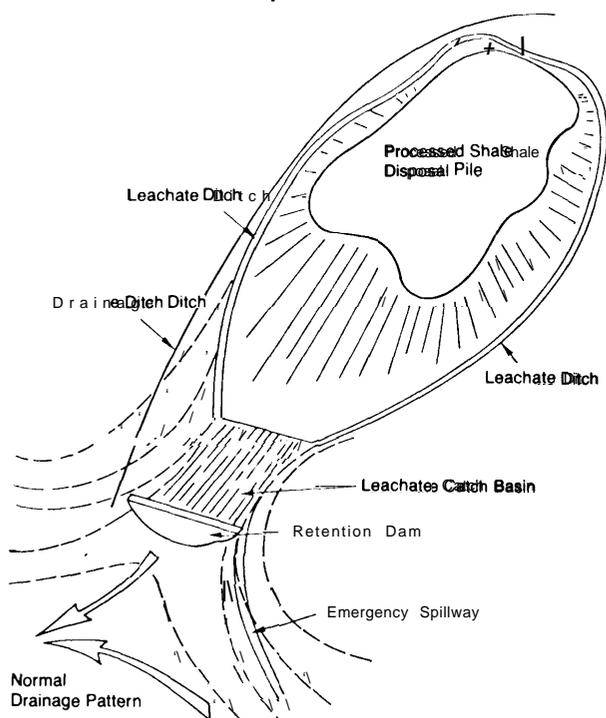
Control of Nonpoint Sources

The major potential nonpoint sources are leachates from aboveground storage of raw or spent shale and from abandoned in situ re-

torts. For an aboveground retorting facility, the leaching problem may be reduced by disposal of the solid wastes in canyons, and capturing and treating any leachate that does occur. (See figure 61.) It is hoped that the moistened and compacted spent shale will be impermeable to the flow of water. The top of the pile will be covered with topsoil or another growth medium that will be permeable but that will not contain substantial quantities of soluble contaminants. Any leachates that reach the catchment basin would be treated. This method may be effective during the lifetime of the facility.

Tests of these control strategies have not simulated conditions of commercial-scale disposal piles, and past research investigations are limited in their applicability. Questions persist concerning shale pile permeability,

Figure 61.—An Aboveground Spent Shale Disposal Area



SOURCE: *Surface Mining of Non-Coal Minerals*, National Academy of Sciences, Washington, D. C., 1979, p. 126.

erosion potential, reclamation effectiveness, and the balance between erosion and soil production rates. Water and leachates may percolate into underlying alluvial aquifers. * These effects need careful monitoring at pioneer commercial facilities.

The efficacies of these control strategies after site abandonment are even less certain. Long-term monitoring and custodial care may be required to assure that contaminants are not released from the catchment basin as a result of dam failure or extraordinarily heavy rainfall or snowfall,

For in situ processing, laboratory experiments indicate that high temperatures convert soluble solids in spent shale into insoluble mineral complexes. If such temperatures could be achieved in commercial-scale oper-

*There are other techniques as well. For example, preleaching of spent shale, capillary brakes, and covering spent shale with open pit overburden. See the section on land reclamation in this chapter for more detail.

ations, they might serve as a primary method for reducing leaching. Several uncertainties prevent assessing the feasibility of this approach. For example, the mineral complexes produced in the field would have to remain insoluble for long periods of time even if the retorts were backflooded. Also, to eliminate leaching, all of the spent shale in the retorts would have to be insoluble. Because control of MIS retorting is difficult, portions of the retorts may not become hot enough to produce the insoluble complexes. Control of retorting temperatures in TIS processing is even less certain. Since there would be massive amounts of waste, increased percolation by ground water, and thus greater leaching potential, these uncertainties may mandate the adoption of retort abandonment strategies.

Retorted shale can form a cement-like material if it is properly prepared, and water slurries of finely crushed retorted shale could be injected into burned-out retorts to fill void areas and to make the spent shale impermeable to water flow. To prevent leaching, the cement formed from the injected slurry would have to have very low permeability; otherwise, the cement itself might produce a troublesome leachate, thereby compounding ground water pollution. Distributing the slurry uniformly within the retort may also prove difficult.

Another approach would be to pump freshwater through the retort to intentionally leach out the soluble components. The leachates could be treated and then reinjected on a downgradient from the retorts. It is possible that leaching could be accelerated in this way, but the process might be costly and time-consuming and the technology has yet to be developed.

“Hydrologic barriers” might be used to prevent or control the flow of water into the retort area, thereby preventing the dispersion of leachates. One possibility is drilling a continuous series of holes around the retort area and filling them with a cementitious slurry. By itself, this technique may not be fully effective since the retorts may be in aquifer-

fers in which water moves vertically. The effectiveness could be increased by cementing (grouting) the retorts to seal their more permeable zones and fractures.

Another possibility would be to divert a major portion of the ground water flow around the retort area. In this "hydraulic bypass" option, artificial channels or barriers would capture most of the ground water flowing toward the retort area, direct it around the area, and then return it to the ground water system.

Ultimate Disposition of Wastewater

At present, no developer plans to discharge wastewaters to surface streams; rather, the final wastes will be disposed of by recycling, evaporation, and reinfection. In the future, consideration may be given to treating and discharging all surplus process waters. This would be much more expensive than treatment to industrial standards, but it would reduce the impacts of development by augmenting stream flows in a water-short region. If this option is adopted, water treatment needs will increase significantly and highly efficient treatment methods will be necessary.

Recycling

Present developer plans call for treating and recycling wastewaters whenever practical. This depends only on the ability of waste treatment systems to purify the wastewaters so that they could be reused in other portions of the process. Nearly all of the wastewaters could be reused after appropriate treatment for cooling tower makeup, for dust control, for shale disposal, for leaching, for revegetation, and for generating steam that could be injected into either aboveground or in situ retorts. As discussed previously, efficient, reliable, adaptable, and cost-effective methods appear to be available for the major contaminated streams. Their capability of treating the wastes to discharge or reinfection standards is not relevant as long as the streams are to be recycled.

Treated cooling tower wastewater could be reused after dilution with other treated streams. Treated gas condensates are also suitable for cooling water because they should have low concentrations of inorganic contaminants and volatile organics. Retort condensates could also be used after their dissolved substances are removed.

Water quality criteria have not been established for dust control, shale disposal, or revegetation, but water similar to river water would probably be acceptable. It should be possible and practical to treat gas condensates to this level. Treated retort condensates should also be acceptable, although successful treatment has yet to be demonstrated. Steam raising, for example, with the thermal sludge system, is at present a more reliable option. These condensates (either treated or untreated) could also be used as a slurry medium for grouting in situ retorts. Tests would be needed to determine if the wastewater contaminants were truly immobilized so that they could not be leached by ground water.

Evaporation

Most of the wastewaters will be disposed of in dust control and in the waste disposal piles. The sludges and concentrates from wastewater treatment will also be added to the disposal piles. In essence, this converts a point source of pollution, which would be highly regulated under existing laws, to a nonpoint discharge, which is not well-regulated at present. However, the treated wastewaters would be quite different from the raw streams described in table 51. For example, most of the NH_3 and H_2S will have been removed from the gas condensates and recovered as byproducts. The CO_2 will also have been removed and vented to the atmosphere. The concentration of NH_3 could be further reduced by biological treatment and by using the treated condensates as cooling water. The small quantity remaining may be useful as fertilizer for reclaiming the waste disposal areas. Most of the potentially harmful organ-

ic compounds could be removed by biological treatment and the more resistant ones by adsorption. However, some organic matter is likely to reach the shale disposal area. It is not known whether the organics will remain locked within the shale pile or will be leached.

Similar treatment could be used for the retorting and upgrading condensates, although the chemicals in the retort condensate could pose some special treatment problems. If thermal sludge systems were used, both the inorganic and the nonvolatile organic contaminants would be reduced to a stable sludge suitable for disposal in a sanitary landfill or in a hazardous-waste disposal area. The volatile organics would be entrained in the steam and subsequently incinerated in the retorts.

Reinfection

Reinfection may be legally allowed if the quality of the injected water is at least as high as that in the affected aquifer. Injection of condensates or other highly contaminated wastes would not be permitted without a high degree of treatment. However, mine drainage water might be reinfected if it had not been degraded by evaporation or chemical change while on the surface. Otherwise, it first would have to be treated or diluted.

Until commercial-scale oil production begins, essentially all mine drainage water will require disposal, probably by reinfection. It is generally assumed that the chemicals in the drainage water would not cause significant changes in the quality of the source aquifers. However, water quality could be degraded because of the increased ground water flow, the exposure of new mineral surfaces by fracturing, and the changes in underground microbial populations. If such changes occurred, the treatment or disposal conditions would have to be adjusted to compensate for them.⁵¹ This might include treating the drainage to a purity higher than that of the source aquifer.

Monitoring Water Quality

Because much surface water comes from ground water discharge, it is necessary to monitor both surface and ground water to help prevent environmental damage. Monitoring provides a continuous check on compliance with regulations, a record of changes resulting from development, and a measure of the effectiveness of pollution control procedures.

Surface Water Monitoring

Surface water monitoring should include:

- instream sampling and chemical analysis to detect and characterize pollutants of point and nonpoint origin;
- detection of spills and faulty containment structures that could result in accidental discharges;
- measurement of streamflows to assess effects of dewatering operations and consumptive uses; and
- measurement of aquatic biota to determine the changes resulting from development,

A monitoring program is defined by the number and location of sampling stations, the parameters measured, the sampling frequency and collection methods, the accuracy and precision of the analytical techniques, and the quality assurance safeguards. Traditional monitoring methods may not be well-suited for the oil shale situation. The uncertain pollutant release rates and pathways and the wide variations in regional water quality, complicate the development of a suitable program and limit the use of conventional techniques.

The number and location of sampling stations depend on the objective of the monitoring program. For example, if the objective is to detect changes over an entire basin, the stations would be located in the lower reaches of major tributaries. They could de-

tect major changes but would be unable to pinpoint their cause. In contrast, stations near pollution sources could both measure the local effects of pollutant discharge and identify the source. An oil shale program could include stations on major streams, as well as on the minor tributaries that drain each development site. Special stations are also needed near solid waste disposal areas to detect leaching.

The selection of chemical, physical, and biological parameters to be measured will be based on the types and concentrations of pollutants that might be discharged, the ease of analysis, and the characteristics of the water in the affected streams and aquifers. The possible parameters include the concentrations of the pollutants themselves as well as the levels of "indicator" parameters that provide a measure of the potential environmental disturbance. These include pH, dissolved oxygen, hardness, temperature, flow rate, and the characteristics of the aquatic biota.

Biological parameters are especially useful because they reflect the stability and response of the ecosystem. Aquatic organisms are natural monitors of water quality since they respond in a predictable manner to the presence of most types of pollutants. Changes may indicate problems that are not easily detected by direct measurements of water quality. For example, heavy metals and some organic compounds tend to concentrate in the biota. Their levels in the tissues of certain fish could help predict pollution concentrations that are not readily measurable in the water itself. Communities that could be monitored include invertebrates, fish, algae, and bacteria.

The sampling frequency can also vary. Ephemeral tributaries, for example, could be monitored only during periods of heavy rainfall or snowmelt; mainstream tributaries could be monitored continuously. Frequent monitoring of all possible parameters would be very expensive and time-consuming. Therefore, priorities must be established on the basis of cost, utility of the data, and the potential for severe environmental impacts.

Ground Water Monitoring

Observation wells are used to detect trends in water quality and to measure the effects of operations such as wastewater reinfection. The locations of the monitoring stations should be selected according to:

- the locations of the potential pollutant sources;
- the geology and hydrology of the site to be monitored;
- the probable movement and dispersion of pollutants underground; and
- the potential for hydrologic disturbances of, for example, dewatering wells.

EPA has developed a monitoring methodology for the oil shale area.⁵² The important considerations are:

- the identification of potential pollutants;
- the definition of hydrogeology, ground water use, and existing quality;
- the evaluation of the potential for infiltration of wastes by seepage;
- the evaluation of pollutant mobility in the affected aquifers;
- the priority ranking of pollution sources based on the mass, persistence, toxicity, and concentration of the wastes; their mobility; and their potential for harm to water users; and
- the design and implementation of programs for near-surface aquifers, deep aquifers, and injection wells.

The siting of wells for near-surface aquifers is extremely important. They should be placed down the ground water hydraulic gradient (i.e., "downstream") from possible pollution sources such as reinfection wells, reservoirs, and disposal piles. The wells should allow sampling from different depths, and the chemical and physical parameters should be selected according to hydrological characteristics as well as the properties of potential pollutants. Deep aquifers should be monitored near dewatering wells, in situ retorts, and reinfection wells. Monitoring of salinity, TDS, and water level should be emphasized. Monitoring deep aquifers in the Piceance basin is especially difficult because the

ground water flows through fractures and faults and not through the more common uniformly porous media. A further complication is the different permeability of adjacent strata. Even flow rates are hard to measure in a fractured-rock system, and it is difficult to properly site the monitoring stations.

The monitoring of surface and ground water quality is exemplified by the program on Federal lease tract C-b that has been underway since 1974. The sampling schedule and water quality parameters are listed in table 65. Thirteen surface water gauging stations have been constructed: nine on ephemeral streams and four on perennial drainages. Nine springs and seeps are also monitored. Temperature and conductivity are measured continuously at all stations on the perennial streams. Dissolved oxygen, pH, and turbidity are measured continuously at several of these stations; other parameters are measured monthly, quarterly, or semiannually.

Water levels in alluvial aquifers are measured continuously at 18 test wells. Conductance, pH, temperature, and dissolved oxygen will be measured monthly. The quantity and quality of water in the deeper bedrock aquifers are measured at 17 wells in the upper aquifer and 14 in the lower aquifer. Samples are obtained for water quality twice a year, and water levels are measured monthly. Water quality is also measured in reservoirs, waste disposal piles, and mine sumps.

Information Needs and R&D Programs

Insights into the water quality impacts of oil shale development have been obtained from laboratory and pilot plant studies, from a few field tests in the Piceance basin, and from experience in related industries. Additional measurements and R&D programs are needed to help reduce the level of uncertainty. Uncertainties will remain, however, until experience has accumulated from commercial-sized modules and plants.

Need for Reliable Data on Wastewater Quality

Reliable data are lacking on the characteristics of the gas, retort, and upgrading condensates from all of the proposed development technologies. The data should be obtained with pilot plants that integrate several streams and several control devices and that simulate commercial-scale conditions. In commercial plants, wastewaters may be mixed and the interactions of contaminants from the different streams will affect treatability. Therefore, analyses of separate streams are not sufficient.

More reliable estimates are needed of the quality and quantity of the mine drainage water that will be encountered in specific areas. This information would help determine how the water would have to be treated for surface discharge, and would allow a comparison to be made between surface discharge and other disposal methods.

Studies of leachates are also needed; in particular, on their ability to penetrate the linings of disposal ponds and catchment basins.

Need for Assessing Control Technologies

Although individual methods have been tested successfully on a small scale, the performance of an integrated treatment system has yet to be evaluated with actual effluent streams. This could be done, for example, by testing relatively inexpensive pilot-scale systems as part of a retort demonstration program. These tests would help determine, for example, if the dissolved organics in retort condensates can be adequately controlled with a series of conventional treatment processes. The distribution and control of trace elements could also be assessed.

Need for Cost Information

According to present estimates, wastewater treatment costs are expected to be only a small fraction of the total cost of shale oil pro-

Table 65.—Sampling Schedule Summary for Surface and Ground Water Monitoring Program at Tract C-b During Development Phase

	Surface water	Seeps and springs	Ground water
Alkalinity	M(Z), Q(O,PC)	0	Q(AI), SA(Aq)
Ammonia	M(Z)Q(o,PC)	Q	Q(AI), SA(Aq)
Arsenic	M(Z)O(o,PC)	Q	Q(AI), SA(Aq)
Barium	—	—	(L i s a A(AI))
B e r y l l i u m	Q	—	—
Bicarbonate	M(Z) Q(o,PC)	—	—
B A D	—	Q	SA(AI), SA(Aq)
Boron	M(Z)-Q(o,PC)	Q	Q(AI), SA(Aq)
Cobalt	—	—	SA(Aq)
Color	—	—	—
COD	Q	Q	Q(AI), SA(Aq)
Coliform, total and fecal	0	S	—
Conductivity, specific	—	M	Q(AI)
Copper	Q	Q	Q(AI), SA(Aq)
Cyanide	Q	—	—
Dissolved oxygen	M(Z)Q(o,PC)	M	M(AI)
Fluoride	M(Z), Q(o,PC)	Q	Q(AI), SA(Aq)
Hardness	—	Q	Q(AI), SA(Aq)
Iron	—	Q	Q(AI), SA(Aq)
Lead	Q	Q	Q(AI), SA(Aq)
Lithium	Q	Q	Q(AI), SA(Aq)
Magnesium	M(Z), Q(o,PC)	Q	Q(AI), SA(Aq)
M a n g a n e s e	M(Z) Q(o,PC)	Q	Q(AI), SA(Aq)
Mercury	Q	Q	Q(AI), SA(Aq)
Molybdenum	Q	Q	Q(AI), SA(Aq)
Nickel	—	Q	Q(AI), SA(Aq)
Nitrate	M(Z)-Q(o,PC)	Q	Q(AI), SA(Aq)
Nitrogen (Kjeldahl)	M(Z), Q(o,PC)	Q	Q(AI), SA(Aq)
Odor	—	—	—
Oil and grease	Q	Q	Q(AI), SA(Aq)
Phosphate	M(Z)-Q(o,PC)	—	—
Pesticides	—	—	SA(Aq)
Phenol	Q	Q	A(AI), SA(Aq)
Potassium	M(Z), Q(o,PC)	Q	Q(AI), SA(Aq)
Radiation, alpha	Q	S	SA(AI), SA(Aq)
Radiation, beta	Q	S	SA(AI), SA(Aq)
Sediment	M(Z), Q(o,PC)	—	—
Silica	M(Z), Q(o,PC)	—	—
Sulfate	M(Z), Q(o,PC)	0	Q(AI), SA(Aq)
S u l f i d e	0	—	—
Suspended solids	—	—	—
Turbidity	—	—	—
PA	M(Z), Q(o,PC)	M,Q	M,Q(AI)
Total dissolved solids	M(Z), Q(o,PC)	Q	Q(AI)
Water level	—	—	M E S A
Stream flow	M(Z) Q(o,PC)	Q,SA,A	—
Water temperature	M(Z) Q(o,PC)	M,Q	M, Q(AI), SA(Aq)
Dissolved organic carbon	M(Z) Q(o,PC)	S	SA(AI), SA(Aq)

KEY A = Annually (Z) = Major gaging stations only
 SA = Semiannually (o) = All gaging stations except major stations
 S = Semimonthly (PC) = Piceance Creek gaging stations
 Q = Quarterly (AI) = Alluvial wells
 M = Monthly (Aq) = Deep aquifers

SOURCE E R Bales and TL Thoen (eds) *Pollution Control Guidance for Oil Shale Development Appendices to the Revised Draft Report*, compiled by Jacobs Environmental Division for Environmental Protection Agency Cincinnati Ohio July 1979 pp C-84-C-85

duction. However, inadequate attention to water management could seriously impede a project's construction and operation. Thus, water treatment although not costly by itself could ultimately cause substantial cost escalations.

Lower cost treatment options should also be explored. For example, the thermal sludge system could significantly reduce treatment costs by raising steam directly from process condensates. Another promising procedure is the removal of dissolved organics from

treated condensates in the cooling water circuit.

Discharging suitably treated wastewaters (especially excess mine water) to surface streams should be investigated as a mechanism for supplementing the region's scarce water resources. Some of the contaminants in the treated wastes may require special attention, and means to remove them should be explored.

Need for Evaluating the Potential Impacts of Effluent Streams

Information is needed on the impacts of the pollutants on the environment. In particular, research is needed on the effect of the leaching of spent shale and other solid wastes on salinity, sediment loading, temperature, nutrient loading, and microbial populations of surface waters. This work should address the impacts that might occur both during the operation of a facility and after the facility's useful lifetime.

Specific R&D Needs

Research is needed in the following specific areas:

- characterization of the wastewaters, especially for the presence of trace metals and organic chemicals produced by each retorting process;
- determination of the applicability of conventional treatment methods to oil shale wastewater and development of new treatment methods if necessary;
- determination of the changes in ground water quality and flows resulting from mine dewatering;
- development and demonstration of methods to prevent leaching of MIS retorts by ground water;
- studies to simulate and test the percolation of rainfall and snowmelt through spent and raw shales and native soils and to assess resulting leachates;
- standardization of leachate sampling techniques;

- development of reliable models and testing them under simulated worst case conditions, such as massive failure of a containment structure; and
- research on the restoration of aquifers disturbed by in situ processing,

Current R&D Programs

Below is a partial listing of the ongoing and proposed R&D programs by the Federal Government and the private sector:

- Under EPA grants, Colorado State University is studying the water quality within the oil shale areas, the leaching characteristics of raw and retorted oil shale, and the surface stability and water movement in and through disposal piles. Specific objectives include developing procedures for assessing the quantity and quality of surface and subsurface runoff from solid waste piles.
- Under an EPA contract, TRW and DRI are studying the environmental impact of oil shale development, including an evaluation of technologies for wastewater control.
- DOE's Office of the Environment is assessing water quality aspects of the Paraho process.
- DOE and the State of Colorado are developing a program related to water pollution from MIS retorting.
- Under EPA contracts, the Monsanto Research Corp. is investigating the treatment of retort wastewaters and is studying the potential of in situ retorting for air and water pollution.
- The National Bureau of Standards, in cooperation with EPA and other agencies, is developing methods for measuring the environmental effects of increased energy production.
- In its oil shale program management plan, DOE has proposed to:
 - assess the effect of mine and retort backfilling on ground water quality;
 - study the leachability of raw and spent shale and the effect of disposal on surface and ground water quality;

- investigate the need for long-term care of surface disposal areas; and
- design a solid waste disposal plan for a commercial MIS facility.
- The National Science Foundation is sponsoring work to characterize the contaminants in spent shale and to develop techniques for managing them.
- EPA is preparing a pollution control guidance document for an oil shale industry, that will consider all aspects of surface and ground water quality.

Findings on Water Quality Aspects of Oil Shale Development

Water quality is of major concern in the oil shale region, especially in regard to the salinity and sediment levels in the Colorado River system. Oil shale development has the potential for water pollution, the extent of which will depend on the processing technologies employed, the scale of operation, the types and efficiencies of the pollution control strategies used, and the regulations that are imposed.

Surface discharge from point sources is regulated under the Clean Water Act, and ground water reinfection standards are being promulgated under the Safe Drinking Water Act. Solid waste disposal methods may be subject to the Toxic Substances Control Act and the Resource Conservation and Recovery Act. The general regulatory framework is therefore in place, although no technology-based effluent standards have been promulgated for the industry under the Clean Water Act.

Developers are currently planning for zero discharge to surface streams and to reinject only excess mine water. Most wastewater will be treated for reuse within the facility; untreatable wastes will be discarded in spent shale piles. The costs of this strategy are low to moderate, and development should not be impeded by existing regulations if it is implemented.

A variety of treatment devices are available for the above strategy, and many of them

should be well-suited to oil shale processes. It is less certain that the conventional methods would be able to treat wastewaters to discharge standards because they have not been tested with actual oil shale wastes under conditions that approximate commercial production. Furthermore, no technique has been demonstrated for managing ground water leaching of in situ retorts, nor has the efficacy of methods for protecting surface disposal piles from leaching been proven. It is not known to what extent leaching will occur, but if it did, it would degrade the region's water quality.

Although control of major water pollutants from point sources is not expected to be a severe problem, less is known about control of trace metals and toxic organic substances. Research is needed to assess the hazards posed by these pollutants and to develop methods for their management. Other laboratory-scale and pilot plant R&D should be focused on characterizing the waste streams, determining the suitability of conventional control technologies, and assessing the fates of pollutants in the water system. Such work is underway; its continuation is essential to protecting water quality, both during the operation of a plant and after site abandonment.

Policy Options for Water Quality Management

For Increasing Available Information

Options for increasing the overall level of information regarding pollutants, their effects, or their control include the evolution of existing R&D programs, the improved coordination of R&D work by Federal agencies, increasing or redistributing appropriations to agencies to accelerate their surface and ground water quality studies, and the passage of new legislation specifically tied to evaluating water quality impacts. For example, pioneer plants receiving Federal assistance could be required to monitor water quality effects, with particular emphasis on non-point discharges. Procedures for implementa-

tion could be similar to those for the existing Federal Prototype Leasing Program. Mechanisms for implementing these options are similar to those discussed in the air quality section of this chapter.

For Developing and Evaluating Control Technologies

The Government could expedite the availability of proven controls by accelerating its efforts to design, develop, and test treatment technologies for oil shale wastewaters. To be most effective, this work would have to be coordinated with private efforts to develop the oil shale processing methods. This could be done under cost-sharing arrangements, including tests at the sites of retort demonstration projects. (EPA is presently conducting a program for retorting wastewaters under a contract with Monsanto Research Corp.)

For Developing Regulatory Procedures

The present approach could be followed in which regulations evolve as the industry and its control technologies develop. An approach could also be used in which standards would be set that would not change for a period of say, 10 years, after which they could be adjusted to reflect the experience of the industry. This would remove most of the uncertain-

ty about environmental regulations that is now deterring developer participation. However, the standards would have to be carefully established to assure that they were both attainable at reasonable cost and adequate to protect the environment. Mechanisms for implementing improved regulation of nonpoint discharges include extension and modification of the Surface Mining Control and Reclamation Act for oil shale, special controls regulating nonpoint discharges under the Clean Water Act, or applying the Resource Conservation and Recovery Act waste disposal standards to low-grade/high-volume materials.

For Ensuring the Long-Term Management of Waste Disposal Sites and Underground Retorts

These areas may require monitoring for many years after the projects are completed. Long-term management could be regulated under the Resource Conservation and Recovery Act, which allows EPA to set standards for the management of hazardous materials, including mining and processing wastes. No such action has yet been taken by EPA, but Congress could direct it to do so. Congress could also require the developers to guarantee such management by incorporating appropriate provisions in any bill encouraging oil shale development.

Safety and Health

Introduction

Anticipating occupational and environmental health and safety hazards is an important consideration in the development of an oil shale industry. Anticipation and planning, especially in the early phases of the industry, should guide efforts to reduce health and safety risks and costs to society. To bring attention to known hazards, and to point out potential ones, this section covers the following subjects:

- the health and safety hazards associated with oil shale operations;
- the environmental risks if contaminated air and water are released;
- the applicable Federal health and safety laws, standards, and regulations;
- the control and mitigation methods that could be applied to these risks;
- the issues regarding the coordination of monitoring and education efforts;
- the R&D needs; and
- the policy options.

Safety and Health Hazards

Occupational Hazards

Workers will be exposed to a number of occupational safety and health hazards during the construction and operation of an oil shale facility. Many of these hazards—such as rockfalls, explosions and fires, dust, noise, and contact with organic feedstocks and refined products—will be similar to those associated with hard-rock mining, mineral processing, and the refining of conventional petroleum. However, due to the physical and chemical characteristics of shale and shale oil, the types of development technologies to be employed, and the scale of operations, oil shale workers might be exposed to unique hazards. They will be discussed as follows: safety hazards that might result in disabling or fatal accidents; and health hazards stemming from high noise levels, contact with irritant and asphyxiant gases and liquids, contact with likely carcinogens and mutagens, and the inhalation of fibrogenic dust.

SAFETY HAZARDS

Mining.—The similarity of hard-rock mining to underground or open pit oil shale mining makes it possible to project likely occupational safety risks. During mining, accidents result from rock and roof falls, explosions and fires, bumps and falls, electrocution, heavy mining equipment, and vehicular traffic. Hard-rock mining is a high-risk occupation; fatalities are five times more frequent in the mining and quarrying industry than in manufacturing. The frequency of disabling injuries from underground mining (excluding the coal industry) is two and a half times higher than from manufacturing.⁵³ Mining coal is even more dangerous.

While most hazards to oil shale miners would be similar to those experienced by hard-rock workers, some are unique to oil shale. A number of the oil shale facilities are planning to use MIS processes in which part of the deposit is mined out and the remainder is then rubble and burned underground. The high temperatures and fires involved in MIS

may expose miners to risks that are not experienced in other underground mining activities. The hazard of mine flooding is not unique to oil shale, nor would it be encountered in all oil shale mines. However, it could be severe in mines that are developed within ground water areas. While the mining zones would be dewatered before mining could begin, there could be flooding if the pumps failed.

Retorting and refining.—Potential hazards associated with the retorting and upgrading of shale oil include explosions, fire and heat, bumps and falls, electrocution, and handling hot liquids. However, the degree of risk for workers involved in the processing of oil shale and its derivatives would not be expected to be so high as in mining.

The processes involved in retorting and upgrading (e.g., materials handling, crushing, solids heating and cooling, waste disposal, and the handling of hot and hazardous liquids) are generally similar to those used in other operations such as mineral processing (e.g., limestone calcining, roasting of taconite and copper ores, and leaching) and conventional petroleum refining. Although no comparative study has been undertaken, there are few unique features associated with retorting, upgrading, and refining that would justify expecting higher worker safety risks than those in similar industries.

HEALTH HAZARDS

Mining.—During oil shale mining, as discussed in the section of this chapter on air quality, hazardous substances including silica dust will be generated by blasting and drilling. In addition, blasting, raw shale handling and disposal, and other activities at the minesite will produce fugitive dust. Silica-containing dusts are noteworthy because they have been the single greatest health hazard throughout the history of underground mining. Silica is highly toxic to alveolar macrophages—“scavenger” cells that move about on the inside of the lung and engulf and remove foreign particles that might damage the lung. Silicosis, “shalosis,” and chronic

bronchitis* are among the diseases that may result from the inhalation of oil shale dust.

A survey conducted by the U.S. Public Health Service (USPHS) between 1958 and 1961 found excessive dust levels in 6 out of 67 inspected mines.⁵⁴ The chest X-rays of 14,076 miners employed in 50 hard-rock mines indicated that 3.4 percent had silicosis.⁵⁵ * * * These measurements were made before modern mine hygiene practices were required by the relatively recent occupational safety and health regulations and a more recent study undertaken by the Mining Safety and Health Administration showed marked improvements in mine dust levels. This study examined 22 hard-rock mines, 8 of which were included in the USPHS study, and found none of them in violation of the dust standards,⁵⁶ * * *

Although few studies have been undertaken on the direct association between oil shale mining in the United States and the incidence of lung disease, there are studies on the prevalence of lung disease in oil shale miners in Estonia. Estonia mined 25 million tons of oil shale in 1973, and has had oil shale operations for several decades. While the results of the Estonian studies are more intriguing than convincing, they do suggest an association between oil shale mining and pulmonary fibrosis—an increase in the amount of fibrous material in the lung. One study also indicated that chronic bronchitis was 2 to 2-1/2 times more prevalent in 189 Estonian oil shale miners than in a similarly aged control population.” (A similar degree of excess bronchitis has been observed in coal miners in the

United States and England,⁵⁸ and in gold miners in South Africa.⁵⁹)

In another study, postmortem examination of 30 Estonian oil shale workers who died of accidents and various other diseases⁶⁰ found that all had pulmonary fibrosis and one-fourth displayed classic silicotic nodules. * An examination of 1,000 Estonian oil shale workers failed to reveal any cases of pneumoconiosis, a pulmonary disease caused by inhaled dusts. However, the workers had been involved in the industry for only 5 to 14 years. Twenty years of exposure are usually required for the symptoms of the disease to be detected by a chest X-ray. Because Estonian industrial hygiene standards are not known, the Estonian studies can only suggest an association between oil shale mining and lung disease. The Estonian studies provide no information about the risk levels to be expected in mines maintained under U.S. health and safety standards.

Studies of occupational diseases among oil shale miners in the United States have been limited because relatively few people have worked in the industry. A study was undertaken involving miners from the oil shale research center at Anvil Points, Colo., which has operated intermittently since 1946. Eighty-six workers were identified, but only 39 of them had been exposed to oil shale for one or more years. Those 39 were compared with 26 other workers from the facility (e.g., office workers, administrators) who had not been directly involved in the mining operations. Results showed a twofold higher incidence of pneumoconiosis in the oil-shale exposed population. However, the interpretation of these results is complicated by the fact that most of the oil shale miners had previously worked in uranium-vanadium mines or milling operations which are known to be causes of pneumoconiosis.⁶¹ Further evaluation of these populations was not performed because of the age of the workers, their varying levels of exposure, and their limited experience in oil shale mining.

*Silicosis is a disabling fibrotic disease of the lungs caused by inhalation of silica dust and marked by shortness of breath. “Shalosis” is a disease of the lungs and is related to specific exposures of oil shale mine dust. It resembles silicosis: its existence as a specific disease remains to be proved. Inflammation of the bronchial tubes, or any part of them, is known as bronchitis.

**The 3.4 percent is probably a low estimate; generally sick individuals who have left the work force or moved for health and other reasons are under-represented in such surveys. If such individuals had been examined the incidence of silicosis might have been higher.

***This study is expected to be released in the near future along with a companion study undertaken by the National Institute of Occupational Health and Safety which examines the health status of miners from 22 hardrock mines.

*Silicotic nodules are small lumps on the surface of the lung formed as a response to deposition of silica specks.

A separate study of employees at the same facility between 1974 and 1978 found no adverse health effects.⁶² An examination of the death certificates of 167 oil shale workers undertaken by the National Institute for Occupational Safety and Health (NIOSH) failed to reveal any association between oil shale exposure and respiratory diseases.⁶³ Because of the limited number of workers studied, their relatively short exposures to oil shale mining, and in some cases their exposures to other kinds of mining, no firm conclusions can be drawn from these studies.

Some animal studies have demonstrated relationships between oil shale exposure and respiratory diseases, but the results conflict with those of other experiments, making it difficult to draw conclusions. One study indicated that Estonian oil shale had a weak fibrogenic* action in rats; both oil shale and spent shale ash produced pulmonary fibrosis in white rats after the dusts were deposited into the trachea.⁶⁴ Another study reported pulmonary effects when Syrian hamsters were exposed via intratracheal administration or inhalation to finely ground oil shale dust and retorted shales.^{65,66} Increased alveolar macrophage activity was also noted. The same study found that retorted shale dust was associated with inflammation, and frequently caused increases in the fibrous material in the lung (fibrosis) and excessive growth of cells that line the lung cavities (epithelial hyperplasia). However, a 2-year study with rats, which evaluated the effects of raw or spent shale dust instilled intratracheally in multiple exposures over an 8-month period, found essentially no pulmonary fibrosis. The investigator considered the results to be negative.⁶⁷

Another area of concern is the possible exposure to carcinogens (e.g., polycyclic aromatic hydrocarbons—PAHs) and trace elements that might be produced during mining. The NIOSH mortality study mentioned earlier found that the percentage of oil shale workers who had died from colon and respi-

*A fibrogenic substance is conducive to the generation of fibrous materials in the respiratory tract.

ratory cancers was greater than the percentage in the white male populations of Colorado and Utah.⁶⁸ Whether oil shale exposure contributed to the higher incidence is unclear, and the incidence rate among miners was not higher than that of the white male population in the United States.

A cancer morbidity study undertaken by the Rocky Mountain Center for Occupational and Environmental Health found more cytological atypia* in the sputum and urine of oil shale miners than among controls, but no association was found between exposure and skin diseases. These data will be further studied to identify any associations between such abnormalities and occupational exposures. Animal studies undertaken to date have not demonstrated that oil shale dust is carcinogenic.

A third potential health hazard to oil shale miners is exposure to excessive noise levels, particularly in underground operations carried out in relatively confined spaces. Noise arises from numerous sources such as booster fans, pneumatic drills, blasting, conveyors, and mining machines. The Bureau of Mines studied 19 pieces of diesel-powered mining equipment and found only 2 had noise levels below the current standards (90 decibels), and one of these exceeded the standard in an underground environment. One study estimated that of the 37,000 workers employed in 650 metal and nonmetal mines, approximately 14,000 (38 percent) were exposed to diesel-powered equipment noise levels greater than the standard.** Of these, 2,430 (17 percent) were overexposed on a time-weighted-average basis.⁶⁹ Evidence indicates exposure to noise from a large number of mining machines would produce hearing loss if the exposures exceeded 8 hours per day.⁷⁰ Higher short-term noise exposures may occur during

*Cytological atypia are premalignant cell types observed in the examination of the body fluids.

**A major health issue is the long-term effect of diesel smoke exposure in underground mining environments. The National Academy of Sciences is conducting a study in this area which will be released in the near future. The health implications of diesel equipment used in underground oil shale mines is unknown at this time.

blasting. High noise levels are a potential hazard not only to hearing, but to the cardiovascular and nervous systems as well, and pose a safety hazard.

Retorting and refining.—Retorting oil shale at high temperatures forms PAH-containing carcinogens of which 3,4-benzo(a)pyrene (BaP) is the most studied. PAHs are a major potential health hazard for retorting and refining workers in the oil shale industry because of their carcinogenicity. The problems that might be encountered in oil shale refining are similar to those of conventional oil refineries, where liquids and gases are transported in airtight pipes under strict maintenance to detect and repair leaks.

Crude oil contains an enormous variety of potentially hazardous compounds. Even more are produced during refining. Work crews involved in inspection, repair, and maintenance are the most likely to be exposed to PAHs. Other hazardous substances found in crude oil include chlorine, sulfur, nitrogen, and heavy metals (e.g., vanadium, arsenic, nickel, and cobalt). Toxic contaminants evolved during the refining process include H₂S, hydrogen chloride, hydrochloric acid, SO₂, sulfuric acid, methane, ethane, methanol, nitric acid, NO_x, mercaptans, CO, and benzene.

The high rate of cancer of the scrotum found in 19th century chimney sweeps and mulespinners* is of historical interest because it indicates that long exposure of scrotal skin to PAH-containing oils and soots can cause cancer. In addition to scrotal cancer, cancers of the skin, lung, and stomach have also been observed after latent periods of up to 20 years following exposure to PAH-containing substances. While the known carcinogen BaP was identified in Scottish shale oil,⁷¹ a study found only a low incidence rate (less than 0.1 percent per year) of skin cancer for 5,000 Scottish oil shale workers between 1900 and 1922.⁷²

*Mulespinners were workers who lubricated the “mules” (spindles) in the Scottish spinning and weaving industry. Shale-derived lubricants were commonly used in this industry.

Refined Scottish shale oils were known to be carcinogenic, but the disease was largely preventable by personal cleanliness. It is believed that the disease occurred because the workers wore the same clothes on the job day after day. The clothing was rarely, if ever, laundered, and eventually it became impregnated with shale oil. Contact between the soaked clothing and the areas where cancers occurred was nearly continuous during each working day. This factor, coupled with the fact that daily bathing was rare, undoubtedly contributed to the high incidence of cancer.

Two Estonian studies have shown an association between oil shale processing and cancer. A study of 2,003 Estonian oil shale workers with a total of 21,495 person-years exposure during the period between 1959 and 1975 found a significant excess of skin cancer (fivefold for females and threefold for males).⁷³ An unusually high incidence of stomach and lung cancer was found among persons in the rural areas of Estonia where the oil shale industry is located. ” There is no information on the working conditions in Estonian oil shale operations; nor are data available on the ambient concentrations of shale-derived pollutants in the vicinity of the plants. It is therefore impossible to relate the Estonian experience to problems that might be encountered in the United States.

Evaluating chemical carcinogenicity in animal experiments is an accepted method for predicting carcinogenicity in humans. Investigations that tested the carcinogenicity of oil shale and shale oil in laboratory animals are shown in table 66. A conclusion that can be drawn from these studies is that shale oil is a carcinogen when painted on animal skins. The experiment conducted by Biology Research Consultants (ref. 80 in table 66), in which hairless mice were bedded in raw or spent oil shale, found no carcinogenic hazard. However, this study did not examine the oil shale extracts (e.g., shale oil tar and coke) with which carcinogenicity has been associated.

Both the Kettering Laboratory (ref. 79) and Eppley Institute (ref. 81) studies conclusively

Table 66.—Animal Studies on the Carcinogenicity of Oil Shale and Shale Oil

Nature of study	Ref. ^a	Materials tested	Organs	Tumerous	animals/animals	exposed
			examined			
Skin painting study of mice, rats, and rabbits	75	Scottish shale oils "green oil" "blue oil" "unfinished gas oil" "lubricating oil"	skin		9/100	
			skin		12/100	
			skin		1/50	
			skin		3/50	
Skin painting of mice	76	CHCl ₃ extract of Scottish oil shale Scottish shale oil	skin		0/20	
			skin		6/10	
Skin painting of mice	77	Shale oil	skin		1,284/10,000	
Skin painting of mice	78	Shale oil Composite petroleum control	skin		(35%-90% tumerous)	
			skin		(0%-8% tumerous)	
Skin painting of mice (Kettering study)	79	Crude shale oil Hydrotreated oil BaP control	skin		39/40	
			skin		5/37	
			skin		27/27	
Exposure to shale dust (Biology Research Consultants)	79	Oil shale powder	skin		0/12	
		Oil shale powder	lungs		2/24	
		Spent shale powder	skin		0/12	
		Spent shale powder	lungs		1/24	
		Powdered corn cobs (control)	skin		0/12	
		Powdered corn cobs (control)	lungs		6/24	
Skin painting of mice (Epley study)	79	Benzene extract of shale oil coke	skin		48/50	
		TOSCO II effluent	skin		1/50	
		Benzene extract of raw shale oil	skin		0/50	
		Benzene extract of spent shale	skin		6/50	
		Benzene control	skin		0/50	
		None (control)	skin		0/100	
Intratracheal Instillation in hamsters (Epley study)	79	Raw oil shale	(b)		0/100	
		Spent shale	(b)		0/100	
		Shale 011 coke	(b)		0/100	
		TOSCO II effluent	(b)		0/100	
		BaP control	(b)		27/100	
		Saline control	(b)		0/100	
		None (control)	(b)		0/200	

^aSee reference list ^bRespiratory systemSOURCE William Rom et al *Occupational/Environmental Health and Safety Aspects of a Commercial Oil Shale Industry* prepared for OTA by Rocky Mountain Center for Occupational and Environmental Health University of Utah December 1979

show that crude shale oil, shale oil tars, and shale coke have carcinogenic properties, which may be related to their BaP content. The second Epley study (ref. 82), which investigated respiratory system carcinogenicity, found no effect. This contrasts to the skin exposure experiments. Whether or not oil shale and its derivatives are less of a threat to the respiratory system than to the skin deserves further study.

Although BaP may not be the only carcinogen in shale oil and its products, it is probably the most potent. The study summarized in table 67 shows that hydrotreating shale oil

Table 67.—Benzo(a)pyrene Content of Oil Shale and Its Products and of Other Energy Materials

Substance	BaP concentration, p/b ^a
Raw oil shale	14
TOSCO II retorted shale	28
TOSCO II atmospheric effluent	140
TOSCO II retort coke	129
Raw shale oil from Colorado	3,200
Hydrotreated shale 011 (0.25% N ₂)	800
Hydrotreated shale 011 (0.05% N ₂)	690
Coal	4,000
Libyan crude 011	1,320
Asphalt from conventional crude	10,000-100,000

^aParts per billionSOURCE R. M. Coomes *Carcinogenic Testing of Oil Shale Materials* Twelfth Oil Shale Symposium Proceedings Golden Colo. The Colorado School of Mines Press November 1979

significantly reduces its BaP content,'⁸⁴ Such a reduction should be reflected in a lessening of its carcinogenicity. This predicted effect of hydrotreating was confirmed by the animal tests of the Kettering experiment (ref. 79, table 66).

The Estonian epidemiological studies and the animal studies show that crude shale oil, shale oil tars, and shale coke are all carcinogenic. Most of the studies to date suggest that carcinogenicity is restricted to the skin. Occupational skin diseases from exposure to certain industrial oils have long been a problem, as was seen in the case of the scrotal cancer among chimney sweeps. One study showed that the effects of oil contact with the skin range from acute inflammation to keratosis (pitch warts which are regarded as a premalignant skin change.)⁸⁴ Studies of oil shale retorting workers in the United States in the early 1950's did not reveal any problems with occupational skin disease, but workers were exposed for a short time only.⁸⁵

A synergistic relationship has been found between the ultraviolet radiation in sunlight and coal-tar pitch volatiles in causing skin diseases. A similar synergism might cause occupational skin diseases in oil shale workers on the Colorado plateau, where ultraviolet radiation levels are higher than at lower elevations.

Refining shale oil will be similar to other refining operations. Available epidemiological studies do not lead to clear-cut conclusions about relationships between working in refineries and cancer. A retrospective mortality study sponsored by the American Petroleum Institute that covered 17 U.S. oil refineries and over 20,000 workers was reported in 1974.⁸⁶ The study group included every worker employed in the refineries for at least one year between January 1, 1962, and December 31, 1971. A 94-percent followup was obtained. There were 1,165 deaths; 1,145 death certificates were obtained. The standardized mortality ratio (SMR) for all causes of death among refinery workers was 69.1 compared with the base rate of 100 for the U.S. male population. The lower death rate among

refinery workers was attributed to the "healthy worker effect;" i.e., employed workers are healthier on the average than the general population. Respiratory cancer increased with increasing exposure to aromatic HC, but was still lower than found in the general population (SMR of 79.9).

On the other hand, two epidemiological studies published by Canadian investigators showed an increased cancer risk for refinery workers. In a group of 15,032 male employees who worked for the Imperial Oil Co. between 1964 and 1973, there were 1,511 deaths. Eighty percent were ascribed to circulatory system disease and to malignant abnormal growths (neoplasm). Mortality from all malignant neoplasms in the exposed group was greater than in the nonexposed group. Cancers of the digestive and the respiratory systems increased with duration of employment.⁸⁷

A further study examined 1,205 men who had been employed for over 5 years by Shell Oil Canada in East Montreal,⁸⁸ { Their mortality rate was compared with death rates for the Province of Quebec. The study group was relatively small, and only 108 deaths were observed. An increased incidence of cancer of the digestive system (SMR of 117) was not statistically significant, and there was no evidence of excessive lung cancer (SMR of 35.4). An excess of brain cancer was found among those who had been exposed less than 20 years, but it caused only three of the deaths.

Societal Hazards

Air pollutants include particulate, gases, and trace-metal vapors. Particulate which contain absorbed PAH can be carcinogenic. The sulfur and nitrogen-containing emissions are respiratory irritants. Among the sulfur-containing pollutants, the effects of acid sulfates, sulfuric acid, and SO₂ dissolved in aerosols are the best documented. All three are irritants and can make breathing difficult. In addition, some epidemiological evidence relates chronic bronchitis and respiratory diseases to SO₂ and to particulate con-

centrations in the air. Oxides of sulfur and nitrogen, transported from industrial areas, may cause acidic rainfall that may reduce the productivity of forest vegetation and kill fish by increasing the acidity of lakes and streams. NO_x oxides can react with HC in the atmosphere to produce O_3 , photochemical smog, and acid rain. Airborne NH_3 may cause headaches, sore throats, eye irritations, coughing, and nausea in humans.

Among the trace elements that may be emitted, mercury, lead, cadmium, arsenic, and selenium are considered to be potential air and water pollutants. Arsenic is a carcinogen, which when inhaled or ingested in large amounts, may also cause peripheral vascular disease and neuropathy. * Mercury is a special problem because its vapors can pollute the air and earth many miles from the plantsite. It can also contaminate surface streams and ground water aquifers. It can enter the food chain through the actions of micro-organisms, and can also pose a risk of irreversible neurological damage to humans who eat fish that have been contaminated by mercury in streams.

Leachates from aboveground disposal areas and burned-out in situ retorts also pose potential problems. PAHs, salts, and metals may dissolve in surface streams and ground water and infiltrate public drinking water supplies. Water-soluble salts in spent shale contain as much as 40 percent of the total benzene-soluble organic matter. All of these materials can be dissolved in water and dispersed through soils. The exact nature of the threat posed by these materials to human health is unknown since, for example, PAHs are found throughout nature. However, the PAH content of spent shale leachates (up to 100 to 1,000 times higher than is found in normal ground or surface water) is a matter for concern. Fluoride, if released in excessive amounts in contaminated water, may cause fluorosis (reduced bone strength and debilitation) and mottle tooth enamel.

*Neuropathy refers to pathological changes in the peripheral nervous system.

The severity of these hazards will depend on many factors. Many of the risks could be very small if they are anticipated, and if appropriate control strategies are designed and followed. If caution is not employed, or if there are catastrophic failures in the control systems during or after plant operation, damage could be severe and long lasting.

Summary of Hazards and Their Severity

The safety and health hazards that might be associated with oil shale mining, retorting, and refining are identified in figure 62. They are ranked according to their known potential to cause injury or death. As shown, mining has the highest potential for accidents, due to risks from rockfalls, explosions, moving equipment, and general working conditions. There were two fatalities during the mining of over 2 million tons of shale and the production of over 500,000 bbl of shale oil. The accident rate has been one-fifth that for all mining, and much lower than that for coal mining. However, this record was achieved in small-scale experimental mines that employed, for the most part, experienced hard-rock miners. Whether safety risks will increase or decrease as mining activities are expanded cannot be predicted. Risks might increase as the work force expands to include inexperienced miners and as large, rapidly moving mining equipment is used. On the other hand, the large mines proposed for oil shale plants may reduce risks because of the additional room in which to maneuver machines.

Fires and explosions are also identified as a hazard in mining. Although no severe fires have occurred to date, laboratory studies indicate that airborne shale dust can propagate a methane explosion. Methane has been found in low concentrations in some oil shale deposits, especially those in the saline zone of the Piceance basin. Oil shale dust is, however, far less explosive than coal dust.

Dust is a major health hazard. Its effect on the respiratory system is well-known. Excessive noise is also a recognized hazard. Cancer

Figure 62.—Summary of Occupational Hazards Associated With Oil Shale Development

Occupational Risks	Potential Effect	Relative Ranking		
		Mining	Retorting	Refining
Accidents	Injury or death	[]	[]	[]
Fires and explosions	Injury or death	[]	[]	[]
Noise	Hearing loss or neurological damage	[]	[]	[]
Dust	Lung disease	[]	[]	[]
Dust	Dermatitis	[]	[]	[]
Chemical Exposure	Cancer	[]	[]	[]
Chemical Exposure	Dermatitis	[]	[]	[]
Chemical Exposure	Poisoning	[]	[]	[]
Chemical Exposure	Irritant gases	[]	[]	[]

KEY:

- Higher level of risk
- Medium level of risk
- Lower level of risk

SOURCE Office of Technology Assessment

from oil shale mining has not been identified as a major hazard. Although the carcinogenicity of oil shale dusts and crude shale oil has been demonstrated by some investigators, insufficient information and the conflicting results of other studies prevent a determination of the severity of the risk. However, the incidence of diseases in other industries indicates that exposure to these materials could be hazardous. Worker health should be carefully monitored if health damage is to be avoided, and prevention techniques improved, as the oil shale industry develops.

Retorting is regarded as having medium risks in all areas. This ranking primarily reflects the low level of knowledge about retorting and its health and safety effects. However, the large variety of substances that will be encountered in retorting (from raw shale dust to trace-element emissions) may pose as yet undetected health hazards. Of special concern is the possibility of carcinogens in shale oil and its derivatives. Possible synergisms in MIS operations (which combine mining with retorting) could increase the level of risk.

In contrast, shale oil refining is regarded as posing no special hazards in many areas and only moderate risks in the others. This is because most of the problems that will be associated with shale oil processing should be similar to those experienced in conventional petroleum refining.

Federal Laws, Standards, and Regulations

This section discusses the Federal laws and standards applicable to oil shale occupational health and safety, and some aspects of environmental health. Other laws which govern specific impacts on air, water, and land are discussed elsewhere in this chapter.

Occupational Safety and Health Act of 1970

This Act was passed to assure every working person "safe and healthful working conditions;" it established the Occupational Safety

and Health Administration (OSHA) under the Department of Labor. Most OSHA standards promulgated under the Act pertain to safety, e.g., walking and working surfaces, fire protection, and personal protective equipment. In addition, health standards have been promulgated to limit worker exposure to hazardous chemicals and physical hazards, such as noise and crystalline silica.

OSHA recently published a policy for the identification, classification, and regulation of toxic substances posing occupational carcinogenic risks. Under this policy, a substance shown to cause cancer in two animal studies can be classified as a "category I" carcinogen and regulated to control worker exposure to the lowest feasible levels. Whether any two of the positive carcinogenicity results mentioned in table 66 are sufficient to cause a category I classification awaits NIOSH review.

The Federal Mine Safety and Health Amendments of 1977 (FMSHA)

These amendments apply to all metal and nonmetal mines. They prescribe health and safety standards "for the purpose of the protection of life, the promotion of health and safety, and the prevention of accidents." FMSHA established the Mine Safety and Health Administration (MSHA) in the Department of Labor, and directed the Secretary of Labor to develop, promulgate, revise, and enforce health and safety standards for workers engaged in underground and surface mineral mining, related operations, and preparation and milling. In addition, each mine operator is to have a mandatory health and safety training program. FMSHA also authorized the Secretary of Labor to require frequent inspections and investigations of mines: at least four times a year in the case of underground mines, and at least twice a year in surface mines. Records of mine accidents and exposures to toxic substances are to be maintained by mine operators.

Section 101(a) of FMSHA requires that standards on toxic material or harmful physi-

cal agents be set to “most adequately assure ... (on the basis of the best available evidence) that no miner will suffer material impairment of health or functional capacity (even if such miner has regular exposure to the hazards dealt with by such standard for the period of his working life).” NIOSH has the responsibility to determine when the material or agents are toxic at the concentrations found in the mine.

Warning labels, protective equipment, and control procedures are to be employed “to assure the maximum protection of miners.” Medical examinations and tests, where appropriate, are to be provided at the operator’s expense to determine whether a miner’s health is adversely affected by exposures.

Memorandum of Understanding Between OSHA and MSHA

Because of the overlapping jurisdiction between OSHA and MSHA, an interagency agreement was executed on March 29, 1979, to allocate the responsibilities for mining safety between the two agencies. The agreement established that as a general policy, unsafe and unhealthful working conditions on minesites and in milling operations would come under the jurisdiction of MSHA. Where these do not apply, or where no MSHA standards exist for particular working conditions, OSHA and its regulations would apply. Where uncertainties arise about jurisdiction, the appropriate MSHA District Manager and OSHA Regional Administrator (or the respective State designees in those States with approved mine-safety plans) shall attempt to resolve the matter. If they cannot do so, the issue will be referred to the national offices of the two agencies. If the issue cannot be resolved at that level, it will be referred to the Secretary of Labor for a final ruling.

The Toxic Substances Control Act of 1976 (TSCA)

TSCA covers the manufacturing, processing, distribution, use, and disposal of chemical substances in commerce. However, it

should be noted that if specific operations are regulated by other laws (e.g., Clean Air Act, Clean Water Act) their authority would probably take precedence over regulations promulgated under TSCA. TSCA regulations would be promulgated only when regulations under the other Acts failed to remove a hazard. Also, chemicals that are not sold in commerce are considered “R&D substances” and are exempt from some of the requirements under the Act.

Under TSCA, EPA must require industry to give notice 90 days prior to beginning the manufacture of any new substance that is not listed on EPA’s Inventory of Existing Chemicals. EPA can also require industry to test the toxicity of chemicals already in commerce that may pose an unreasonable risk to human health or the environment. Shale oil and its refined products are included in the inventory list and therefore are not subject to pre-market regulations, but testing can be required under other sections of TSCA if the Administrator of EPA determines such substances may pose an “unreasonable risk” to health or the environment.

Control and Mitigation Methods

Some of the oil shale’s health and safety hazards can be reduced by using the pollution control technologies described elsewhere in this chapter. Others will require specific industrial hygiene controls. The three major control methods are:

- worker training programs, including an intensive training program for new workers and refresher courses for workers throughout their careers;
- the design and maintenance of safe working environments; and
- health monitoring programs, including examinations and recordkeeping.

Initial training programs and refresher courses are required by OSHA and MSHA. These agencies also promulgate standards for working environments. Health inspections are sometimes included in OSHA/MSHA routine inspections, and special health inspec-

tions can be made if the agencies determine that a serious health hazard exists. At present, exchange of worker-health information among companies is not required, although some companies, especially in the coal mining industry, have organized such programs to provide data regarding occurrences of black lung among miners who change jobs within the industry.

Summary of Issues and R&D Needs

Issues

The effect of the scale of operation of future oil shale facilities on worker safety is still unknown. As indicated previously, the oil shale industry to date has a good safety record. It is not clear whether or not this record can be maintained in large facilities and in a large industry.

The protection of worker health and safety in an industry that is developing with great speed is also a major concern. To prevent undue risks, it is important that the health hazards of oil shale and its related materials be identified, and that appropriate measures be employed for their control.

R&D Needs

Research is needed in the following areas in order to improve the understanding of the potential effects of oil shale development on the workers and on the public:

- additional data gathering and analysis are needed on the health effects of particulate generated during oil shale mining and processing. Studies should include: a) identification of absorbed PAHs; b) determination of particulate size distributions; c) evaluation of the risk of fibrogenicity and carcinogenicity; d) ranking of the unit operations in terms of their degree of risk; and e) determination of their health effects on nearby communities with respect to, for example, chronic bronchitis;
- characterization of worker exposure to PAHs, other chemical hazards, and

physical agents such as ionizing radiation, heat, and noise stress;

- evaluation of devices for controlling worker exposure, such as hermetic seals, ventilation equipment, and personal protective equipment;
- environmental monitoring to determine ambient levels of PAHs, trace elements, and other potentially harmful substances;
- determination of the pathways followed by PAHs, salts, toxic trace elements, and other substances; and
- additional controlled animal experiments to determine the toxicity, mutagenicity, and other characteristics of the raw materials and products encountered in oil shale processing, and evaluation of their synergistic interrelationships.

A mechanism that would aid in all of these studies, and in other ones that evolve as the industry is created, would be an oil shale health registry or central repository for the health records of oil shale workers. These data would aid in the statistical work needed to detect extraordinary health trends among the workers. These, in turn, could be related to working conditions and used to improve preventive and protective measures.

Current R&D Programs

The following is a partial listing of the health and safety R&D projects now underway both in the private sector and by Government agencies.

- Tosco is studying the fire and explosion potential of oil shale mining and processing.
- The American Petroleum Institute is studying the effects of oil shale on fetuses by exposing pregnant rats to raw and spent shale dust and shale oil.
- EPA is performing or contracting work through 10 of its laboratories to support the regulatory goals of the agency and to ensure that an oil shale industry will be developed in an environmentally accept-

able manner. The EPA Cincinnati laboratory is studying the handling of raw shale and the disposal of spent shale. Air pollution, wastewater characteristics, and water treatment methods are also being studied and evaluated. The Las Vegas laboratory is attempting to design and implement an optimal wastewater treatment system. The Athens, Ga., laboratory is characterizing retort effluents and developing instrumentation and control systems. Biological and health effects studies are being conducted at the Gulf Breeze and Duluth laboratories; these are designed to determine pathways by which HC enters the food chain, to characterize the aquatic life in the oil shale region before oil shale development occurs, and to determine the carcinogenic, mutagenic, and fetal effects of oil shale and its derivatives and wastes. EPA is also preparing pollution control guidance documents for the oil shale industry.

DOE is conducting source characterization studies to determine emissions properties and their health effects. Included is an extensive program for sampling retort liquids, solid products, and wastes. Streams to be sampled include mine vent gases, mine air, retort water, raw and retorted shale, process water, and particulate. Biological testing will be conducted to include short- and long-term animal exposure tests and medical and epidemiological studies of oil shale workers.

- The U.S. Department of Agriculture is sponsoring work related to the social consequences of oil shale development and the revegetation of solid waste disposal areas.
- The National Science Foundation is sponsoring projects to characterize the contaminants in spent shale and to develop techniques for managing them.

Policy Considerations

The major issue surrounding the health and safety aspects of oil shale development is the paucity of information on the nature and severity of the health effects of oil shale, its derivatives, waste products, and emissions. The effect of the scale of operation of oil shale facilities on worker safety is also unknown. Policy options for addressing these issues follow,

Inadequate Information

Additional study is needed to determine the effects on human health of the various chemical substances and particulate encountered during the mining and processing of oil shale and its products and wastes. Such information would be useful in identifying and mitigating long-term health effects on workers and the public. It would also be useful in setting new standards for worker health and safety. Options for increasing the amount of information include expanding existing R&D programs; coordinating R&D work by Federal agencies; increasing appropriations to agencies to accelerate their health effects studies; and passing new legislation specifically calling for study of the health and safety aspects of oil shale development. Methods for implementing these options are similar to those described in the air quality section of this chapter.

Health Surveillance

Collection and maintenance of oil shale workers' health records in a health registry would facilitate hazard identification and planning to reduce risks. The registry might be located in a regional medical center, with or without Federal agency input. Funding could be provided by Government, labor, or the oil shale developers, or by a cost-sharing arrangement between these groups. The reg-

istry location could be the focus of regular meetings to exchange health and safety information and to disseminate basic scientific findings that apply to the oil shale industry.

Exposure Standards

As information about chemical health hazards is developed and analyzed, NIOSH and MSHA should determine whether exposure

standards are necessary to protect worker health and safety. In addition, sampling methods should be in place to monitor exposures.

Worker-Education Campaigns

Worker education is already a part of the mining industry. Information about newly identified risks should be conveyed to workers as soon as possible.

Land Reclamation

Introduction

An oil shale industry will use land for access to sites, for facilities, for mining, for retorting, for oil upgrading, and for waste disposal. The extent to which development will affect the land on and near a given tract will be determined by the location of the tract; the scale, type, and combination of mining and processing technologies used; and the duration of the operations. Comparatively little land will be disturbed by the retorts and upgrading facilities themselves, but much larger areas will be disrupted by mining activities and waste disposal operations, particularly if the deposits are developed by open pit mining in conjunction with aboveground retorting, which produces retorted shale as a process waste.

It has been estimated that a 1-million-bbl/d industry using aboveground retorts would process approximately 600 million tons of raw oil shale per year, and would require the disposal of approximately 10 billion ft³ of compacted spent shale. Less of the surface would be disturbed by in situ retorting, although the surface would nevertheless be disturbed by drill pads. However, the disturbance would be different and less drastic than from an open pit operation. At the same time, the amount of subsurface disturbance for a given level of oil production would be increased because, although with an in situ process relatively little oil shale is mined, oil recovery rates are lower and some leaner oil shales would be retorted. Subsurface disrup-

tion from underground mining and in situ development could affect aboveground conditions through subsidence in the mined-out areas. But this might not happen until long after operations at the site have ceased.

Oil shale plants must be built to comply with the laws and regulations that govern land reclamation and waste disposal. Nevertheless, there will still be effects on the topography (ultimately the terrain could be modified to a landscape unlike the original) and on wildlife (through changes in forage plants and habitats). In addition, unless appropriate control methods are developed and applied, as required by law, the large quantities of raw and retorted shale could pollute the air with fugitive dust and the water with both runoff and the effluent that has percolated through raw shale storage piles and waste disposal areas. Solid wastes such as catalysts, water treatment sludges, and refinery coke, will be produced in relatively small amounts, but will contain toxic components that could degrade water quality unless properly controlled. Similar care will be needed to remove, store, dispose, and revegetate the large amounts of overburden that will be handled in open pit mining operations.

Several avoidance and mitigation strategies have been proposed to minimize the overall land impacts of oil shale development. Oil shale plants, access corridors, and disposal areas could be sited to avoid esthetic deterioration and improve the feasibility of land reclamation and revegetation programs; and

mining and in situ retorting could be designed to decrease surface subsidence or reduce its rate. In addition, most development plans propose to protect existing wildlife habitats and migration routes, where possible, and to enhance the characteristics of adjacent areas to promote wildlife readjustment. Reclamation and revegetation techniques have been developed and tested on a small scale over limited periods of time for aboveground solid waste disposal, and backfilling mines has been suggested to reduce the quantity of solid material that must be disposed of on the surface.

As with air and water control methods, a number of uncertainties surround the feasibility of methods for minimizing land disturbance and its effects on wildlife. At issue are the feasibility of land restoration and revegetation techniques, and the adequacy of strategies to control the leaching of solid waste and raw shale piles. The methods for disposing of solid wastes by backfilling mines and for controlling leachates from solid waste disposal piles and underground retorts were discussed previously in the water quality section. In this section the reclamation and revegetation of processed shales on the surface are examined.

Reasons for Reclamation

The primary purpose of reclaiming the solid wastes is to reduce their detrimental effects. These include: changes in the landscape, the disruption of existing land uses, the loss of the biological productivity on a given land surface, and the degradation of air and water quality by erosion and leaching. In addition, secondary impacts such as fugitive dust would affect not only the immediate area but adjacent areas as well.

Regulations Governing Land Reclamation

In order to ensure that mining operations will incorporate reclamation concepts and minimize adverse effects, legislation has been passed and regulations have been promul-

gated governing oil shale mining, processing, and waste disposal,

Each State in the oil shale region has reclamation laws that apply to all mining operations. USGS has regulations that control oil shale operations only on Federal lands. In addition, the Department of the Interior (DOI) established environmental stipulations governing lands under the Prototype Oil Shale Leasing Program that include additional specific reclamation standards. The Surface Mining Control and Reclamation Act (SMCRA), passed in 1977, provides a system of comprehensive planning and decisionmaking needed to manage land disturbed by development. However, the Act applies only to coal, and the detailed reclamation standards promulgated under it may not be appropriate to oil shale in all cases. However, it provides a guide to measure the strictness of other laws applicable to oil shale for matters that are not specific to coal.

The Colorado Mined Land Reclamation Act is administered by a board and division within the Department of Natural Resources. It requires permits for each mine operation, stipulates application procedures and criteria for permit approval, requires surety (e.g., performance bonds), and sets procedures for enforcement and administration. The Act's performance standards are similar in concept to those established by the Federal Coal Act. They are not, however, as detailed since they must apply to all minerals from oil shale to sand and gravel (except for coal, which has been amended to correspond to the new Federal requirements); and, in some cases, they are not so strict. For example, an operator may choose the postmining use of affected land; whereas, the Federal standard requires approval of such use by the permitting authority according to strict criteria. Also, an operator may substitute other lands to be revegetated if toxic or acid-forming materials will prevent their successful vegetation, and the mitigation of such conditions is not feasible. Mining would probably be prohibited under similar conditions by Federal standards, if they were applicable to oil shale.

The Utah Mined Land Reclamation Act is administered by the Board of Oil, Gas, and Mining. It provides for various powers of the board, administrative procedures, surety, and enforcement. However, the Utah law only establishes general reclamation goals and does not set detailed environmental performance standards as do SMCRA and the Colorado law. These goals include minimizing environmental degradation or “future hazards to public safety and welfare” and establishing “a stable ecological condition comparable with . . . land uses.” They are open to broad discretionary interpretation by the Oil, Gas, and Mining Board.

The Federal standards that do apply to oil shale are limited to Federal lands;* they do not govern operations on private land, and are in no way comparable to the detailed standards that apply to coal under SMCRA. For example, 30 CFR 231.4 establishes very general goals requiring reclamation to “avoid, minimize or repair” environmental damage. Specific details must be set by site-specific leases. It is not applicable to true in situ oil shale methods using boreholes and wells, thus will not govern spent shale leaching for this technology. Part 23 of title 43 authorizes, but does not require, the Bureau of Land Management (BLM) District Managers to formulate reclamation requirements and USGS Mining Supervisors to set standards for mine plans.

More important are specific lease stipulations. Environmental stipulations have been included in the Prototype Oil Shale Leases governing operations on current Federal lease tracts. The reclamation and revegetation performance standards that are included take into account the experimental nature of the program. For example, lessees are given 10 years to demonstrate a necessary revegetation technology; however, operations must cease if such technology is not developed. The lease and the environmental stipulations are administered under the broad discretion of the Area Oil Shale Supervisor, who has re-

*About 70 percent of the oil shale land, containing about 80 percent of the resources, is federally owned.

quired “best available control technologies” to minimize all environmental damage.

In summary, while reclamation is required under State laws, there are no performance standards specific to oil shale. Regulations vary and are not so strict as the general requirements of the Federal coal law. There are additional requirements that pertain to Federal leases.

Reclamation Approaches

Several reclamation approaches can be used to reduce the deleterious effects associated with the disposal of spent oil shale. These include returning surface wastes to mined-out areas; the chemical, physical, or vegetative stabilization of processed shale; and combinations of these approaches.

Reducing Surface Wastes

Mine backfilling was discussed in the section on water quality. As was indicated, the disposal of wastes underground will be more expensive than surface disposal, but there could be less surface subsidence caused by the collapse of overburden materials above the mined-out rooms.

Chemical or Physical Stabilization

One approach that can be used to reduce erosion on disposal sites is to use chemical or physical methods to stabilize the processed shale. Chemical stabilization may be short term—from a few months to a couple of years—or longer term. Short-term methods consist of spraying biodegradable chemicals on the surface; these reduce wind and water erosion by binding particles together. Such chemicals have been used along with revegetation to achieve temporary stability.⁸⁹ The chemicals do not appear to inhibit seed germination; however, they are expensive and, at best, temporary.

Longer term stabilization consists of adding materials such as emulsified asphalt or processed limestone to induce chemical reac-

tions that harden the mixtures. Hardening can be accomplished by wetting of shales processed at high temperatures, followed by compaction. The hardened products have the advantages of relatively high resistance to erosion and reduced leaching of soluble salts into the ground water. Their disadvantages are that they are esthetically unattractive and cannot support vegetation unless covered by a suitable plant growth medium. The long-term effects of chemical stabilization are at present unknown.

Erosion can be reduced physically by covering the processed shale with a layer of rocky material. Like the chemical approaches, physical methods inhibit the establishment of a vegetative cover, are not esthet-

ically pleasing, and restrict the future uses of the land.

Vegetative Stabilization

Vegetation offers the most esthetically pleasing and productive means of stabilizing waste materials. It also allows for multiple land use. In addition, vegetation theoretically offers a means of continually adapting to the changing environmental conditions that are likely to occur on the disposal site over time.

Vegetation will also reduce the overland flow of water and sedimentation during intense storms by increasing the permeability of the soil. This will increase the infiltration of water, thus reducing surface water and pollution and flood hazards. Vegetative cover

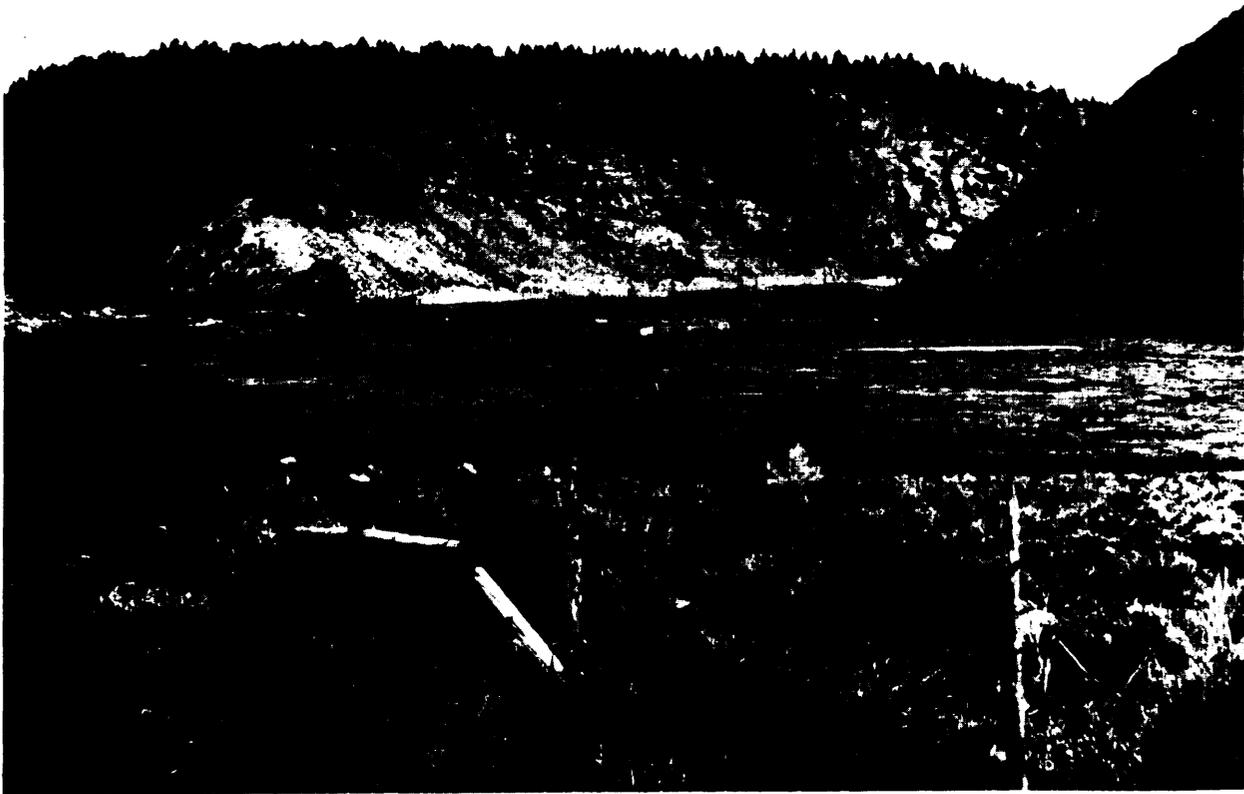


Photo credit OTA staff

A variety of plant life will be required for revegetation of spent shale areas

will tend to ameliorate micro-climatic conditions and also reduce wind erosion and extremes in soil temperatures.

Combinations of Stabilization Methods

Perhaps the most effective means of stabilizing waste piles will be combinations of approaches such as hardening the processed shales by chemical means and then establishing vegetation on a friable soilcover atop the solidified wastes. The vegetative stabilization of soil-covered spent shale appears to be the preferred reclamation approach because the chemical and physical properties of processed shale make it much less amenable to supporting plant growth that resembles the diversity and density of the present natural vegetation ecosystems.

The Physical and Chemical Characteristics of Processed Shale

The physical and chemical characteristics of the processed shale are determined by the source of the raw shale; its particle size after crushing; and the retorting parameters such as temperature, flow rate, and carbonate decomposition, which vary with different retorting processes.

The characteristics of processed shales that make them undesirable as a plant growth media are:

- small particle size (texture), which encourages erosion; and compaction or cementation, which results in low permeability to water and poor root penetration;
- high pH (i. e., high alkalinity), which discourages plant growth by making essential nutrients insoluble and therefore unavailable;
- high quantities of soluble salts, including elements toxic to plant growth that inhibit water and nutrient uptake; and
- the dark colors of some spent shales, which absorb solar radiation thus producing high temperatures that inhibit seed germination and dry the soil through evapotranspiration.

The characteristics of spent shale from several processes are summarized in table 68 and discussed below.

Texture

Raw shale that is finely crushed, as in the TOSCO II process, produces a fine silty spent shale that is highly susceptible to erosion. However, if the shale is coarsely crushed as in the gas combustion processes, a coarse-textured spent shale is produced that is less susceptible to erosion. The resistance to wet-

Table 68.—The Chemical and Physical Properties of Processed Shales

Process	Processing temperature	Color	Texture ^a	Salinity ^b	pH
TOSCO II	Low	Black	Fine	18	9.1
Gas Combustion	High	Gray	Coarse	14	8.7
Paraho					
Directly heated	High	Gray	Coarse	7	12.2
Indirectly heated	Low	Black	Coarse	10	12.3
Union					
"A" retort	High	Gray	Coarse	3-4	11.4
"B" retort	Low	Black	Coarse	13	8.5
Lurgi-Ruhrgas	Low/high	Gray	Fine/coarse	3-7	11-12

^aFine-textured processed shales are predominantly smaller than 2 mm while coarse-textured processed shales are predominantly larger than 2 mm
^bThe electrical conductivity (mmho/cm) of a saturated extract prepared from spent shale particles smaller than 2 mm

SOURCE Plant Resources Institute *The Reclamation of Processed Oil Shale*, prepared for OTA, January 1980

ting of the spent shale originally produced in the TOSCO process^{90,91} has been overcome by introducing steam in the last step of the process. Spent shales produced by retorting at higher temperatures have not been reported as resistant to wetting.

The capacity of spent shales to retain water is moderate. Infiltration rates on fine-textured spent shale (TOSCO II) range from near zero to as high as 3 to 4 cm/hr.^{92,93} Those for uncompacted coarse-textured spent shale are higher.⁹⁴ Rates of from 2 to 4 cm/hr will be sufficient for the surface runoff to be absorbed from most low-intensity storms but not from high-intensity ones that occasionally occur during the summer. Moistening and compacting the spent shales may achieve close to zero infiltration rates which could be important for reducing the leaching of salts into the ground water. Compaction is more desirable for spent shales deep in the pile, beyond the plant rooting zone; uncompacted materials may be preferable near the surface directly under the topsoil layer.

Erosion Control

Because small particle size encourages erosion, erosion control is needed to prevent sediments and toxic elements from entering the aquatic ecosystems downstream, or the increase of dust in the air. Additionally, erosion removes the surface layers that encourage plant growth, which take time to develop.

The steepness of the slopes, their length, the drainage provided, control structures, the density of vegetation on the slopes, and the types of spoils and soil materials on the site will affect the extent of erosion. Mulching, surface manipulation, and the timing of topsoil placement, followed by the immediate establishment of vegetation, will usually reduce erosion rates.⁹⁵ Flatter or shorter slopes will also aid in erosion control. The recommended design slope of 4:1 (horizontal: vertical) with 20-ft benches every 50 ft of vertical rise is considered prudent and necessary. A slope of

3:1 was found to be the maximum allowable for slope stability.”

Water diversion and sediment and drainage catchments are proposed to collect materials washing off site in order to prevent their entering the aquatic ecosystem. It is likely that sediment basins will require long-term maintenance to prevent their filling up and releasing toxic substances.

Furrowing, pitting, and gouging are other useful methods of surface manipulation. Shallow furrowing on the contour cuts down on erosion losses. Pitting and gouging not only control erosion but also act as a moisture collector.” They are particularly useful in dry areas and where vegetation is dependent on snowmelt. A variation of gouging is accomplished by using a land imprinting machine.” On soil-covered processed shales, the depth of the depressions will be determined by the thickness of the soil cover necessary to prevent the processed shale from being exposed.

Mulches of various types have been used both to establish vegetation and to reduce the temperature of the soil surface.⁹⁹ Hydro-mulch, applied at a rate of 1,500 lb/acre is one that is preferred in some studies.¹⁰¹ However, it is expensive and, in some cases, has been reported to provide little beneficial effect on already established stands. () A cheaper natural mulch applied at a rate of 3,000 lb/acre,¹⁰² such as native hay or straw, is more likely to be used, but it must be taken from a certified weed-free field to prevent introducing weedy species. It is uncertain that sufficient mulch will be available, especially weed-free hay, for an oil shale industry of 1 million bbl/d within 10 years.

Straw or hay mulches often need to be stabilized by the addition of emulsified asphalt (300 gal/acre), ’03 or by crimping into the soil. Rock mulches have been found to be superior to barley straw with respect to plant survival and growth.¹⁰⁴ Excelsior type materials, are also very effective, but they are costly and attract rodents. ’05

Cementation

Processed shales retorted at high temperatures and then moistened harden within about 3 days in a reaction similar to that which takes place in cement.¹⁰⁶ The product of spent shale cementation is still susceptible to weathering, and the reaction generally takes place deeper in the waste pile where the process is accelerated by compaction, heat, and high pressure. If shale hardened by this process were to be exposed by erosion, it might prove to be impenetrable to moisture and plant roots.

Alkalinity

Processed shales retorted at temperatures of about 500° C (900° F) are less alkaline (pHs ranging from 8 to 9*), than those retorted at 750° to 800° C (1,400° to 1,500° F) (pHs of 11 to 12). In general, the higher the alkalinity of its leachates, the lower the concentrations of soluble salts in the processed shale. At higher pHs many plant nutrients are insoluble, and plants will generally not grow in a strongly alkaline soil medium.

If processed shales are to be used directly as a growth medium, their alkalinity must be reduced. This can be done by leaching following deposition and proper compaction, or by adding costly acids or acid-formers.¹⁰⁷ Exposure to the atmosphere over a period of several months to several years will reduce it naturally.

Nutrient Deficiencies

Spent shales have been shown to be highly deficient in the forms of nitrogen and phosphorus available to plants.¹⁰⁸ Therefore nitrogen and phosphorus fertilizers need to be added. These can be applied at any time of year but spring fertilization has been recommended to prevent burning and to reduce fertilizing weedy species.¹⁰⁹ It will probably be necessary to fertilize with nitrogen for several years until the ecosystem begins to fix and recycle its own nitrogen.¹¹⁰

*PH is a means of expressing acidity or basicity. It ranges from 1, highly acidic through 7, neutral, to 14, highly alkaline.

Another means of assisting plants to survive in nutrient-deficient soils is by inoculating them with selected strains of fungi that produce mycorrhizae. Mycorrhizae are structures that combine the plant root and a fungus to increase the survival and growth of plants in nutrient-deficient soils by increasing nutrient uptake and resistance to a variety of stresses.

Free-living soil microbes are expected to begin recolonization of the disturbed area. They will be valuable in fixing nitrogen from the atmosphere and recycling organic forms. How soon this will begin is not known. It is known, however, that wetting and drying stored topsoil deteriorates the conditions favorable to such microbes. For this reason, prior to use topsoil should be deeply buried to prevent the wetting and drying that occurs near the surface.¹¹¹

Plant species used to reclaim spent shales possibly will require inoculation with mycorrhizal fungi to enhance their growth and survival.¹¹² Colonizing species on disturbed lands are often nonmycorrhizal.¹¹³ It has also been found that with increasing soil disturbance or the addition of processed shale, the ability of the soil to be infected with mycorrhizal fungi decreases. The most successful revegetation species become mycorrhizal only late in their establishment. There appears to be no significant effect of the seed mixture, the fertilizer, the mulch, or irrigation on a soil's potential for mycorrhizal infection following its disturbance.¹¹⁴

Salinity

Because spent shales are often quite salty, they present major problems for establishing vegetation, and for the water quality from surface runoff or drainage through them.¹¹⁵⁻¹²⁰ High concentrations of salt in the soil media restrict water and nutrient uptake. * These can only be lowered by leaching with supplemental water.

*Electrical conductivity is a measure of a soil's salinity. A conductivity of 4 mmho/cm is considered saline, and above 12 mmho/cm, highly saline.

Leaching

Depending on the characteristics of the spent shales, about 5 acre-ft of water per acre will be needed for leaching and plant growth.¹²² This is based on a net requirement of 48 inches of leaching water and an 80-percent irrigation efficiency. The actual supplemental water needed will vary with annual precipitation, evaluation, and aspect. To ensure adequate infiltration and to prevent erosion, it should be continually applied at low rates (e. g., 2 to 3 cm/hr) and in a spray form. Leaching will probably not be uniform over the entire surface, therefore surface monitoring and additional localized leaching may be needed.

Toxicity

High concentrations of boron in spent shale can be toxic to plants. On the other hand, the elements molybdenum, selenium, arsenic, and fluorine (also found in shale) are generally not toxic to plants. However, when these elements are taken up by plants, they can become toxic to grazing animals. Susceptibility to such toxicity varies among animal species as well as within a species. It is dependent on the concentration of the elements within the plant, the size of the animal, its daily diet, and its general physiological condition. The conditions that encourage the uptake of these elements by plants, and their resulting toxicity in animals are complicated and poorly understood. Proper management should help to avoid or alleviate the problems with livestock. This can be achieved by restricting livestock grazing to seasons when the elements are present at low concentration in the plants, by varying the mix of plant species to be used in the grazing areas, and by feeding sequestering supplements to reduce the toxicity of the elements. The management of wildlife, however, is very difficult and problems will persist in this realm.

The dominant soluble ions in spent shale are sodium and sulfate, with abundant calcium, magnesium, and bicarbonate also present. Of the trace elements identified in proc-

essed shale leachates, selenium and arsenic are not cause for concern, but fluorine, boron, and molybdenum are more serious. 'z] Plants grown on processed oil shales and soil-covered processed shales in northwestern Colorado have been found higher in molybdenum and boron than plants grown in ordinary soil, although their selenium, arsenic, and fluorine contents were moderate.¹²⁴

Excessive Heat

The color of the processed shale reflects the amount of residual carbon on the retorted particles. Black and gray processed shales are produced by low- and high-temperature processes, respectively. The color influences the surface temperatures of the plant growth media which, in turn, affects seed germination and the plant-water relationship. The dark-colored material warms up earlier in the spring, inhibits seed germination more, and creates drier soils than does lighter colored processed shale. Temperatures of up to 78° C (196° F) have been reported for the TOSCO II material.^{125 126} The color can be modified to a certain extent by the use of surface mulches or a covering of topsoil-like material, which reduces many of the salinity and alkalinity problems as well as the need for supplemental water.

Another temperature problem encountered in the massive disposal of spent shales is that the processed shales will probably go into the disposal pile at temperatures in excess of 40° C (98° F). This will create a heat reservoir. It is not known how long it will take to cool. If a spent shale pile is warmer than normal soils within the area, the site would be drier than expected because of the increased potential for evapotranspiration.

Use of Topsoil as a Spent Shale Cover

An alternative to revegetating directly on spent shale is the establishment of vegetation on a cover of topsoil or topsoil-like overburden material placed over the spent shale. Such a soil cover offers several advantages.

Because it does not have the problems of high salinity and alkalinity, no supplemental water is required for leaching. The material is a more suitable medium for plant growth because it has greater water-holding capacity, more nutrients, and promotes a more intimate relation with plant roots.

Economics and a possible lack of longevity are the primary disadvantages of using a soil cover. Additional costs would be incurred for segregating suitable materials from those with undesirable properties, for transporting and storing materials, and for surfacing over the spent shales. In time, the natural geological process of erosion may eventually cut through the soil cover and expose the spent shale. An artificial soil profile using overburden materials between the topsoil and the spent shale would greatly reduce, if not eliminate, the problem. With proper management most erosion should be localized. However, with improper management such as overgrazing, reductions in vegetative cover could occur that would allow larger areas to be exposed. If erosion were gradual over a few hundred years, the vegetation possibly would adapt to the thinning soil cover, and natural leaching and weathering could render the spent shale a more suitable growth medium. Despite these disadvantages, the use of a soil cover will provide for the more rapid establishment of a vegetative cover that will persist longer than would vegetation established directly on spent shale.

The depth of the soil cover needed will vary from site to site, but will generally range from 1 to several ft in thickness.^{127 128} Soil surveys of the Piceance basin indicate that sufficient soil and soil-like material exists in the disposal sites, particularly those with deep alluvial deposits, and this should provide adequate cover material.

The selection of topsoil or topsoil-like overburdens will have to be based on chemical and physical analyses. This is important because the soil types and their toxicities vary. The treatment of the soil cover will be similar to the treatments of soil used for the reclamation of surface-mined coal areas, about which there is more knowledge.¹²⁹ Soil surveys of the

basins will also be useful in deciding what materials to use. It is doubtful that the capillary rise of salts will be a problem unless soils are continually exposed to saturated conditions. This might happen if improper engineering of the disposal site created seeps or allowed ponding.

Species Selection and Plant Materials

The selection of plant materials to be used in reclaiming processed shale is determined by several factors, the most important of which is species adaptability. Adaptability (suitability) is intimately tied to the ability of a plant to complete its entire lifecycle, and to reproduce itself from year to year over a long period. The plant's growth form, drought resistance or tolerance to stress, mineral nutrition requirement, and reproduction characteristics must all be considered. In addition to being adapted to the growth medium, plants must also be adapted to local temperatures, elevation, slope, aspect, and wind conditions. They should be able to survive the weeds and animals that may invade the site. Palatability to livestock and wildlife as well as availability of seed and competition among species being planted are also important factors.

In addition to the results of actual revegetation test plots, several information sources and guides are available to assist in the selection of species adapted to conditions likely to be encountered in oil shale reclamation.¹³⁰⁻¹³⁴ These include the Plant Information Network computerized data bank located at Colorado State University.¹³⁵

In general, mixtures of various grasses, forbs, shrubs, and in some cases trees, are desirable because they offer a greater range of adaptation.¹³⁶ Mixtures may include species adapted to each of the different microclimates, moisture levels, and soils. The results of using a well-planned mixture can be a fast-establishing, long-term cover that is less vulnerable to pests, disease, drought, and frost.

Recommended mixtures used in test plots may include both indigenous (native) and in-

roduced perennial species. In one study, a mixture of native and introduced species displayed the highest productivity and allowed the least amount of invasions by weeds.’}’ Although a mixture of non-native species had a higher plant density, it also allowed the greatest invasion of weeds.¹³⁸ Weeds are undesirable in that most are annuals (complete their lifecycle in 1 year) dependent on precipitation; they are therefore an unreliable erosion control. They also compete with the more desirable perennial species (species that persist for several years) for water and nutrients. These annuals are expected to disappear with natural succession over a few years.

Species selection is complex and involves, in addition to considerations of the species itself, a tradeoff among many interacting factors.¹³⁹ These include: Federal, State, and local reclamation requirements; rehabilitation and land use objectives; the nature of the site; the timing of the program; species compatibility; mechanical limitations in planting; seed and seedling availability; maintenance after planting; and cost,

Seeds

Planting seed by drilling or broadcasting is a common way of establishing vegetation in a reclamation plan. Seed is available commercially from collectors and seed companies.¹⁴⁰ While many commonly used seeds are available from dealers under contract, procedures for cultivating wildland plants for seed production have generally not been developed. Also, certain varieties of the native plant species may not be available from commercial sources. Until reliable seed production techniques are developed (which may require up to 10 years), seeds for propagating native plants will generally have to be collected from wildland populations. This may be a problem for a large oil shale industry, since seed production from wildland populations can be unpredictable from year to year; some native species produce abundant seed crops only in years when conditions are especially favorable.

Seeding is best done in late fall or early spring when soil moisture is high, although the operation of seeding equipment in the spring may be hampered by wet soil conditions.” Seeding rates may vary from 10 to 30 lb of pure live seed per acre depending on slope and whether the seed is broadcast or drilled. Drier exposures and broadcast techniques require more seed.

Another problem in propagating plants from seed is dormancy of seed. Extensive treatment of the seed may be required in order to overcome it. For these reasons, vegetative propagation is a necessary alternative to seed propagation for producing planting stock of native species.

Containerized Plants

Container-grown plants have been successfully used in several oil shale revegetation studies.¹⁴²⁻¹⁴⁴ They offer several advantages over seed:¹⁴⁵

- they make efficient use of scarce seed or seeds especially adapted for harsh sites,
- plant survival and growth are optimized by rapid root growth into the surrounding soil,
- well-developed plants are generally able to withstand grazing or other stresses, and
- they can be inoculated with fungi just before seeding to ensure the development of mycorrhizae.

Container-grown plants can be hardened to the fluctuating and more extreme environmental conditions they will encounter at the revegetation site by gradually exposing them to drier conditions and greater temperature extremes. The higher cost of container-grown stocks is offset by their better survival rate.¹⁴⁶ They are recommended for fall or early spring planting on harsh sites where establishment of seeds may be difficult or impossible due to erratic or low precipitation or other environmental stresses. Bare root stock is another alternative, but can only be used with sufficient soil moisture to ensure good root penetration into the growth medium.¹⁴⁷

Timing of Reclamation

Initiation of revegetation efforts will be delayed during the first 3 to 10 years of operation until sufficient waste materials have been compacted and require further stabilization. Disposal will likely begin at one end of a canyon and fill up in strips rather than gradually filling the entire canyon. This will allow early stabilization of narrow strips of land thereby minimizing the size of active disturbance.

Once revegetation begins, reclamation needs will gradually increase as portions of disposal sites are prepared for planting. At full production, reclamation needs would depend on processing rates and method of disposal. (See table 69.)

Complete filling of canyon disposal sites may take up to 30 years or more depending on processing rates and the sites' disposal capacities. Early revegetation of narrow strips will permit the evaluation of reclamation techniques, and allow for any modifications that may be needed during subsequent revegetation efforts.

Cost of Reclamation

Estimates of average reclamation costs range from \$4,000 to \$10,000/acre depending on the site conditions and the land use to be achieved. If disposal is completely on the surface, this represents only about 1.4 to 4.4 cents/bbl of shale oil for a 50,000-bbl/d operation.

Protection of the Reclaimed Site

The reclaimed areas should be protected by proper management and monitoring to ensure that stability is maintained. Protection will be needed whenever the vegetation on the site may be threatened by livestock (including feral horses), wildlife, invading weeds, or human activity. This can be done largely by controlling the degree of use.

The impact of livestock use on the erosion of revegetated spent shale is unknown; it is possible that erosion of the finer processed shales on steep slopes could be substantial. Erosion from livestock use on soil-covered shales would be less of a problem. This as-

Table 69.—Estimates of Reclamation Needs Under Various Levels of Shale Oil Production

	Production level (bbl/day)				
	50,000	50,000 ^a	100,000	250,000	1,000,000
	Required annual disposal area (acres) ^b				
	698-796	279-318	138-159	344-398	1,378-1,592
Water requirements (5 acre-ft/acre)	349-398 acre-ft/yr	140-159 acre-ft/yr	690-795 acre-ft/yr	1,720-1,990 acre-ft/yr	6,890-7,960 acre-ft/yr
Fertilizer					
Nitrogen (80 lb/acre)	5,584-6,368 lb/yr	2,232-2,544 lb/yr	11,040-12,720 lb/yr	27,520-31,840 lb/yr	110,240-127,360 lb/yr
Phosphorus (80 lb/acre)	5,584-6,368 lb/yr	2,232-2,544 lb/yr	11,040-12,720 lb/yr	27,520-31,840 lb/yr	110,240-127,360 lb/yr
Seed (30 lb pure live seed/acre)	2,094-2,388 lb	837-954 lb	4,140-4,770 lb	10,320-11,940 lb	41,340-47,760 lb
Containerized plants (300/acre)	20,940-23,880 pits/yr	8,370-9,540 pits/yr	41,400-47,700 pits/yr	103,200-119,400 pits/yr	413,400-477,600 pits/yr
Mulch					
Wood fiber (1,500 lb/acre)	104,700-119,400 lb/yr	41,850-47,700 lb/yr	207,000-238,500 lb/yr	516,000-597,000 lb/yr	2,067,000-2,388,000 lb/yr
straw (3,000 lb/acre) w/asphalt binder (300 gal/acre)	209,400-238,800 lb/yr	83,700-95,400	414,000-477,000 lb/yr	1,032,000-1,194,000 lb/yr	4,134,000-4,776,000 lb/yr
	20,940-23,880 gal/yr	8,370-9,540 gal/yr	41,400-47,700 gal/yr	103,200-119,400 gal/yr	413,400-477,600 gal/yr

^aAll numbers are approximate. Actual needs will vary with aridity of the site (elevation, slope, and aspect) adapted plant species selected and soil amendments rewed.

^bAssumes 60-percent disposal in underground mine workings.

^cAssumes disposal pile 45.7 meters (150 ft) deep. Acreage estimates were based on Pollution Control Guidance for Oil Shale Development, Environmental Protection Agency, Cincinnati, Ohio, July 1978 P 3-68.

SOURCE: Plant Resources Institute. The Reclamation of Processed Oil Shale prepared for OTA, January 1980.

pect of postmining land use will require careful monitoring. Indirect methods for protecting a site against livestock include adding less palatable species to the seed mixture, providing salt blocks and permanent water supplies away from the seeded areas, controlling livestock numbers, herding, fencing, and, if necessary, repellents.¹⁴⁸

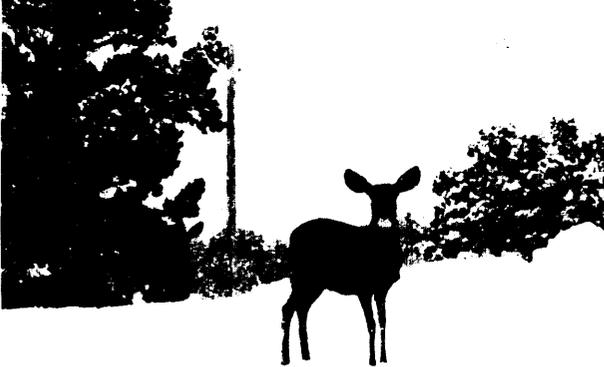


Photo credit OTA staff

Reclaimed sites will have to be protected from wildlife

Protection against wildlife will also be required. This includes large herbivores as well as small burrowing animals such as pocket gophers that can be expected to move into the revegetated area. If not controlled, overutilization of vegetation may occur and toxic compounds may be brought to the surface by burrowing animals.¹⁴⁹

Monitoring and subsequent management must also ensure that refertilization, seeding, and additional control of erosion or weeds, are provided if necessary. Similarly, monitoring plant succession, productivity, and utilization should all be included in the reclamation management plan.¹⁵⁰

Review of Selected Research to Date

Research undertaken on the topic of oil shale reclamation falls into two categories:

- baseline studies that describe the ecological characteristics of the existing environment in the oil shale basins, and
- characterization studies of processed shale and the testing of reclamation methods.

Data from both types of research are needed in designing, directing, and assessing past and future reclamation studies.

Baseline Studies

A general description of the vegetation of the oil shale basins can be found in chapter 4. Additional descriptions that contribute to the baseline data are available for Federal lands from BLM's Unit Resource Analysis¹⁵¹ and Management Framework Plans.¹⁵² More specific vegetation inventories have also been made for site-specific areas within these basins such as transmission and pipeline corridors, Land classification systems have also been developed for the piceance basin,^{153 154} Eighteen phyto-edaphic units (plant-soil units) were identified.¹⁵⁵ The description of each unit provides information on soil, vegetation, climate, aspect, and landform interpretations and hazards of land use. A section on reclamation considerations is provided to identify the most hazardous characteristics of the unit (e. g., the potential for erosion and slumping) that need special attention and care, particularly after disturbance as a result of oil shale development. Management recommendations and alternatives are supplied to overcome the identified limitations.

Other information on plant community relationships (phytosociology) is currently being gathered by Colorado State University for the Piceance basin. This will help the land managers and reclamation specialists to select the proper species to be used in reclamation. Such studies are lacking for the basins in Wyoming and Utah, and few physiological studies have been conducted with existing plant species at the proposed disposal sites or with plant materials to be used in reclamation to determine their tolerance limits to the various adverse conditions likely to be en-

countered. Little is known about the natural genetic differences that exist in native plant communities. These might make the plants more or less adaptable to adverse environmental conditions encountered in oil shale reclamation.

Reclamation Studies

Investigations to determine the management needed to produce conditions favorable to the establishment and growth of plants on processed shales were initiated by private industry in the mid-1960's.¹⁵⁷ These were based on previous knowledge developed by range managers, biologists, and numerous arid and semiarid studies, as well as other baseline information from the oil shale basins.

Where possible, the sites for reclamation tests have been selected to simulate, as closely as possible, the environmental conditions to be encountered during the reclamation of disposal sites used for large-scale production. Sites have been selected in high- and low-rainfall areas, with various combinations of slope, aspect, and processed shale materials. However, most revegetation experiments have been hampered by a lack of processed shale. This shortage, coupled with the high costs of transporting retorted shales to field sites (in some cases from as far away as California), have restricted both the size of the test plots (2 to 5,000 ft²), and the type of processed shale evaluated.

To date, field studies using spent oil shales as plant growth media have centered on the TOSCO II, Union "A" and "B," and Paraho materials.¹⁵⁷⁻¹⁶² These studies show that with intensive treatments plant growth can be established directly on spent shales, although use of a soil cover is more successful.

It is difficult to compare the results of revegetation studies with the various processed shales because the experimental designs varied so widely. Different plant species were used, and fertilizer, mulch, slope, aspect, and soil cover also varied. Most of the early (1965 to 1973) revegetation studies for Colony used spent shale from the TOSCO II

process.¹⁶³ During these studies the basic chemical data needed to design a reclamation program were incorporated into greenhouse and small field plots (100 ft²). Revegetation work on other processed shales, all of which are coarser, had been confined to Union Oil plots planted in 1966 and Colorado State University plots planted in 1973. In the late 1960's and early 1970's, larger field plots (41,000 ft²) were built using many of the results of the earlier experiments, including the effects of soil supplements such as fertilizer and organic matter.

Since the early 1970's, studies have been conducted on disturbed soils without processed shales to determine the establishment of plant species, microbial activity, and long-term successional trends. These studies were encouraged by the finding that the revegetation of soil-covered processed shales was more successful than revegetation directly on processed shales. This was because the soil cover does not have the adverse chemical and physical properties of processed shale that inhibit plant growth.

Supplemental water has been used to establish plants in most of the processed shale revegetation studies. The addition of 10 to 13 inches of water during the first growing season with no subsequent irrigation has resulted in the establishment of a vegetative stand and the persistence of adapted species for several years. The salt leaching requirement (5 acre-ft of water per acre) is in addition to this supplemental water. Only limited success in seeding and transplanting into spent shale without supplementary water has been reported.¹⁶⁴ However, establishment without supplemental water might be achieved by mulching with straw or hay and allowing salts to be leached by natural precipitation prior to seeding or planting, although the time period required for this could be unreasonable. Micro-watersheds consisting of low-level diversion barriers or mounded spent shale have also been proposed and initiated to concentrate water for plant growth.¹⁶⁵

Several researchers have worked on the problems of leaching soluble salts from the processed shales and the surface stability of several retorted shales including TOSCO II.¹⁶⁶⁻¹⁷² It appears unlikely that salts will migrate to the surface by capillary rise in most areas of low precipitation. Only in areas where soils were saturated by supplemental water was there temporary desalinization of surface layers. When the supplemental water was discontinued, surface salinity began to drop due to leaching from natural precipitation. From these studies a better understanding has developed of solutions to the problem of establishing a self-sustaining vegetative cover.

Several studies are continuing, and a new successional study has been initiated¹⁷³ to evaluate the long-term feasibility of using processed shales directly as plant growth media and the influence of various depths of soil cover over spent shale. It has been set up in the Piceance basin to obtain information related to the reseeded of disturbed areas in order to reestablish a diverse, functional ecosystem in as short a time as possible. Various seed mixtures, ecotypic varieties of native species, microbial activities, seeding techniques, fertilizer levels, irrigation, and mulching treatments are being evaluated. In addition, the rate and direction of plant succession is being monitored to identify significant trends in vegetation changes, and to determine how these trends are influenced by the various treatments and practices,¹⁷⁴

Few studies have been conducted on raw shale. This is because in the past it has been assumed that most raw shale of commercial quality will be retorted. Additionally, the raw oil shales are hard and resilient. When mined, the shale fractures into coarse fragments that have extremely low water-holding capacities, which renders them undesirable growth media. For these reasons, it is likely that raw shale of noncommercial quality would be buried deeper in the disposal piles and not used as a growth medium,

Summary of Issues and R&D Needs

Research to date has shown that with intensive management vegetation can be established directly on processed oil shales. The primary requirements are the leaching of high levels of soluble salts with supplemental water, the addition of nitrogen and phosphorus fertilizers, and the use of adapted plant species. However, the establishment of vegetation on spent shales covered with at least 1 ft of soil is preferred because it is less susceptible to erosion and does not require as much supplemental water and fertilizer. Adapted plant species are required for either soil-covered or spent shales.

The long-term stability and the self-sustaining character of the vegetation is unknown, but if sufficient topsoil is applied the results of research on small plots indicates that short-term stability of a few decades appears likely. Monitoring and subsequent management must ensure that any necessary re-fertilization, seeding, and erosion and weed control be provided. The reclamation management plan must also include monitoring plant succession, productivity utilization, and the presence of high concentrations of elements toxic to plants and animals.

Whether or not the revegetation of spent shales is considered successful depends on the desired land use and the performance standards applied to measure the success. For example, the reestablishment of vegetation that reduces erosion and is productive, self-sustaining, and compatible with surrounding vegetation might be considered successful for livestock but not for wildlife use. The minimum requirements for vegetation should be to stabilize the disposal sites so that the detrimental effects caused by erosion can be minimized. Where ecologically feasible, multiple land use of disposal sites should be encouraged.

Reclamation plans will have to be site specific since environmental conditions vary

from site to site. Proper management will be required in all instances, if only to protect plant communities in surrounding areas from harm. Proper management is even more important in the reclaimed areas. If the vegetative cover were completely lost, the negative effects would increase. The conditions would not be as severe as those without any reclamation because they would be reduced by restrictions in slope, catchment and diversion dams, and other mitigation completed in the early stages of reclamation.

If revegetation completely failed, productive land use would be severely reduced or eliminated. It is doubtful that, after once being reclaimed, conditions would deteriorate to the point of eliminating all vegetation from a disposal site, although a natural succession of species would occur that would favor those that had superior adaptability to the harsh conditions. Weedy or unpalatable species of less use to livestock and wildlife would undoubtedly invade the sites.

The types of reclamation needs for a large-scale industry (1 million bbl/d) are similar to those generated for a small industry (50,000 bbl/d), but differ in the amounts of materials that will be required and the rates at which they must be supplied. It is probable that shortages of adapted plant materials and associated support materials (such as mulches and greenhouse facilities) would occur at the higher production rates. The problem is compounded by the fact that demands for plant materials are increasing from other mining operations such as coal and uranium. The severity of the shortages will depend on whether the oil shales are processed in situ or surface retorted, and whether the processed shales are disposed of underground or on the surface. Surface reclamation needs will be somewhat less demanding with MIS processing or with underground disposal of surface-retorted shales.

Research on the reclamation of processed shales is continuing. Areas of major concern requiring additional study include:

- the selection and propagation of species especially adapted to conditions likely to

be encountered in the reclamation of the spent shales. This should include the identification of ecotypic variations, seed production by cultivating adapted wildland plants, and research to determine species performance under abnormal conditions (e.g., drought, salinity, and high temperatures);

- the role and use of soil microbes and mycorrhizal fungi in soil building and plant growth. Successful reclamation will depend on developing a protocol to select and/or maintain the essential mycorrhizal fungi in disturbed habitats or to develop methods to reinoculate these fungi in habitats where they are absent;
- the plant succession for large areas of a few hundred acres in size under natural and disturbed conditions, including the influence of animals on revegetated surfaces;
- the toxicity of elements such as fluorine, boron, molybdenum, selenium, and arsenic to plants and grazing animals. A program to monitor these elements should be established on newly reclaimed areas at least for the first few years;
- the probable heat retention within the disposal pile and its effect on reclamation timing and revegetation;
- the rates of erosion on large, reclaimed areas of a few hundred acres in size. Information is needed on how much water runs off the area following snowmelt in the spring and after high-intensity summer storms, including how much sediment and soluble salts will be contained in the water; and
- the viability of vegetation on raw shale,

Policy Options for the Reclamation of Processed Oil Shales

For Increasing Available Information

More information is desirable on reclamation methods and the selection of proper plant species for revegetation programs. Options for obtaining this information include the

evolution of existing R&D programs by the U.S. Department of Agriculture (USDA), EPA, and other agencies; the improved coordination of R&D work by these agencies; increasing or redistributing appropriations to accelerate reclamation and revegetation studies; and the passage of new legislation specifically for evaluating the impacts of land disturbance. Mechanisms are similar to those discussed in the air quality section of this chapter.

To Develop Reclamation Guidelines for Oil Shale

SMCRA provides for comprehensive planning and decisionmaking to manage disturbed land. However, in general, the reclamation standards promulgated under the act are only appropriate for coal, but not necessarily for oil shale. Thus, new reclamation guidelines specifically for oil shale may be desirable, with standards for postmining land uses that are ecologically and economically feasible and consistent with public goals. If the Act were amended to encompass oil shale, Congress could direct that reclamation guidelines be developed by DOI's Office of Surface Mining, either alone or in conjunction with other agencies. Alternatively, Congress could pass new legislation calling for the preparation and implementation of reclamation guidelines for oil shale.

To Expand the Production of Seeds and Plant Materials

While many common seeds are available from commercial dealers, procedures for cul-

tivating specific wildland plants for seed production have generally not been developed. Also, seeds of certain native plant species are not commercially available.

A shortage of seeds could be a problem for a large oil shale industry. For example, the USDA's plant materials centers often require up to 15 years to identify and develop adapted species for release to commercial suppliers or to industry for trial plantings. Furthermore, the centers intentionally limit their activities so that they will not compete with commercial producers. Thus, they have not developed mass production capabilities, nor have they adopted some of the more recent propagation technologies (such as micropropagation, cutting, and fungal and bacterial inoculation) that are used commercially. In order to meet the future demands of a large oil shale industry, it may be necessary for the centers to expand their facilities and propagation capabilities. This could be costly in terms of facilities, technologies, and personnel. Policy mechanisms for expanding cooperative agreements between the centers and commercial producers need to be developed. These activities would not only benefit oil shale, but also most other reclamation and arid and semiarid revegetation projects as well.

Permitting

Introduction

During the past 10 years an increasingly complex permitting system has been developed to assist the Federal, State, and local governments in protecting human health and welfare and the environment. Permits are the enforcement tool established by Congress and

the States to determine whether a prospective facility is able to meet specific requirements under the law. The operation of an oil shale facility requires well over 100 permits and other regulatory documents from Federal, State, and local agencies. They include the permits for maintaining the environment and for protecting the health and safety of work-

ers, and in addition, those that would be needed for any industrial or commercial activity: building code permits, permits for the use of temporary trailers, sewage disposal permits, and others. Of these, a few—the major environmental ones—require substantial commitments of time and resources. The major environmental permits that must be obtained prior to the operation of an oil shale facility are:

- a PSD permit required under the Clean Air Act;
- an Air Contaminant Emissions permit required by the State of Colorado;
- a Special Primary Land Use permit—which is required for plant siting in Rio Blanco County;
- a Mined Land Reclamation permit required by the State of Colorado;
- an NPDES permit required under the Clean Water Act;
- a section 404 Dredge and Fill permit under the Clean Water Act if the operation affects navigable waters;
- a Subsurface Disposal permit as required by the State of Colorado if water is reinfected;
- a permit for the disposal of solid wastes generated by the facility required under RCRA;
- testing of effects, recordkeeping, reporting, and conditions for the manufacture and handling of toxic substances as stipulated under TSCA; and
- an EIS as required by the National Environmental Policy Act—if an oil shale plant involves a major Federal action significantly affecting the environment.

The responsibilities for reviewing and approving applications are distributed among many Federal, State, and local agencies. Federal agencies include EPA, the Department of the Treasury, DOI (including BLM and USGS), the Department of Defense (e.g., the Army Corps of Engineers), and the Interstate Commerce Commission. State entities in Colorado include the Department of Health, the Department of Natural Resources, and the State Engineer. Because of varied and overlapping

regulations and statutes it has often been difficult to know which agency must be contacted, and which permits are required from which entity.

The following discussion examines:

- how various parties view the permitting process;
- the current status of oil shale developers in obtaining the needed permits;
- the time required for preparing and processing permit applications;
- the disputes encountered so far in obtaining such permits;
- the potential difficulties that might be encountered by a developing oil shale industry; and
- possible policy responses to permitting issues.

Perceptions of the Permitting Procedure

The various parties interested in environmental permits for oil shale facilities have widely divergent views concerning the effectiveness and problems of the permitting procedure. Industry is concerned about the length of time it takes to obtain permits and the uncertainty of obtaining them. The environmental community is watchful of the procedure's effectiveness in enforcing the law; and the regulators themselves are troubled by their limited personnel and budgetary resources.

The high cost of oil shale projects makes unexpected delay costly, and industry is concerned with uncertain agency decision schedules or with unpredictable litigation that can delay or prevent project construction. Furthermore, some regulations and standards have not yet been set because of a lack of sufficient knowledge about the impacts of shale operations and the effectiveness of their control. Developers are particularly worried about the effects of new regulations (such as for visibility maintenance as part of the PSD process) on process design and project economics. They are concerned that new regulations could necessitate costly retrofits to ex-

isting plants or even the cessation of operations. For facilities under construction, the new regulatory requirements may mean redesign or addition of environmental control equipment or strategies. These uncertainties increase the risk that a project, once started, may not be completed. Prospective developers also express their frustration over the lengthy and expensive procedures for preparing permit applications (including monitoring and modeling requirements) to meet some environmental statutes. This discontent is sometimes compounded by overlapping agency jurisdictions and by repetitive paperwork.

The environmental community asserts that, given the complexity of oil shale operations, the extensive application and review procedures are necessary to fully assess environmental impacts, the effectiveness of control measures, and compliance with environmental law. They suggest, in fact, that agency enforcement of environmental laws is too often compromised by weak regulations and by a lack of essential information on which both to base permitting decisions and to enforce the conditions of the permits. Informed, meaningful public involvement in the processing of environmental permits is therefore promoted by environmental groups to ensure that all points of view are represented in agency proceedings. It is particularly important, these groups hold, that the technical analyses on which agency decisions depend are subjected to independent scrutiny. However, they believe that adequate provisions

are seldom made for public participation, and access is not provided to the information needed to evaluate the applications. They note that few agencies have an affirmative public involvement process. They find it is often difficult to follow and monitor agency decisionmaking.

The regulators feel overwhelmed by the increasing number of permits and by the complexity of the review. They believe that their personnel and financial resources are too limited for the present caseloads and certainly will be dwarfed by any rapid increase in applications arising from an expanding energy industry, EPA's Region VIII, for example, includes not just the oil shale region, but most of the Western coal and uranium resources. Regulatory personnel also contend that they are handicapped by inadequate technical information about the technologies that they must review and assess.

Status of Permits Obtained by Oil Shale Developers

The number of permits needed for a given facility depends on its site; on whether it involves Federal land; on the scale, type, and combination of processing technologies used; and on the duration of the operations. As stated previously, the permits range from those required for a temporary trailer to the major environmental permits required under Federal and State regulations and standards. Table 70 shows the status of the major per-

Table 70.-Status of the Environmental Permits for Five Oil Shale Projects

Project	Type of tract	EIS	DDP approval	PSD permit	Regular open mining permit	NPDES permit
Rio Blanco	Federal lease tract	Final programmatic	Yes ^a	For 1,000 bbl/d	Yes	1st phase
	C-a	Issued ^a				
Cathedral Bluffs	Federal lease tract	Final programmatic	Yes ^a	For 5,000 bbl/d	Yes	1st phase
	C-b	Issued ^a				
Long Ridge (Union) Colony	Private	Not applicable	Not applicable	For 9,000 bbl/d	Yes	Not required ^b
	Private ^c	Not applicable	Not applicable	For 46,000 bbl/d	Not yet applied	Not required ^b
Superior	Private/Federal ^d	Not applicable	Not applicable	Not yet applied	Not yet applied	Not yet applied

^aLitigation proceeding over approval of the modified DDP
^bThese operations do not plan to discharge to surface streams
^cExchange of Federal land and pipeline right of way over BLM land requested
^dLand exchange requested

SOURCE: Office of Technology Assessment

mits obtained by five oil shale developers. These facilities are presently in different stages of commercial development. The Rio Blanco, Cathedral Bluffs, Colony, and Superior projects involve Federal land, while the Union project is located on private holdings. DDPs for tracts C-a and C-b had to be approved by USGS because they are part of the Federal Prototype Oil Shale Leasing Program. Four of the projects have already been granted PSD permits for their facilities. Note, however, that with the exception of the Colony project, only small-scale, first-phase construction air emissions have been approved.

All of the facilities have to obtain Mined Land Reclamation permits. Rio Blanco, Cathedral Bluffs, and Union have all been approved for commercial-scale modular operations. Colony and Superior have not yet applied. NPDES permits are required under the Clean Water Act if a plant discharges to a surface stream. So far Rio Blanco and Cathedral Bluffs have received such permits for the first phase of their commercial development.

The Length of the Permitting Procedure

The time required for preparing and processing a permit application depends on the type of action being reviewed, the review procedures stipulated under the law, the criteria used by agencies to judge the application, and the amount of public participation and controversy. If Federal land is involved, then an EIS will most likely be required. This process may take at least 9 months after the developer applies for permission to proceed with the project.* Then the applications for the necessary construction and operation permits can be prepared and filed. In the case of the current Federal lease tracts, additional time was needed to prepare the DDPs for approval by the Area Oil Shale Supervisor of USGS.

Once the requirements for an EIS and DDP are satisfied, obtaining all of the needed per-

*The programmatic EIS for the Prototype Leasing Program took 4 years. Preparation of the draft EIS for the proposed Superior land exchange required 2 years.

mits can take more than 2 years. The preparation and review of the PSD application is perhaps the most comprehensive and time-consuming step. Baseline air monitoring is required, along with extensive dispersion modeling to estimate the effect of the plant's emissions on the region's air quality. Once this work is completed and an application submitted to EPA, the approval process, as stipulated under the law, can take as long as 1 year. However, EPA tries to rule on the application within 60 days, and to date an average of about 90 days has been required. (This includes internal staff review and a period for public comment.)

It should be noted that a project would not necessarily be delayed by the full length of the permitting schedule, because other predevelopment activities such as detailed engineering design, contracting, and equipment procurement could proceed in parallel, if the developer were willing to accept the risk that key permits might eventually prove to be unobtainable.

Disputes Encountered in the Permitting Procedure

The principal problems encountered to date are related to the needs of the regulatory agencies for technical information, to differing interpretations of environmental law, and, according to developers, to a lack of responsibility for timely action on the part of the agencies.

Occidental's application for a Subsurface Disposal permit for its sixth experimental MIS retort on its property near De Beque, Colo., was delayed for several months by the Colorado Water Quality Control Commission's consideration. (The commission had not required permits for the first five retorts.) The commission was concerned about the potential for ground water contamination by the abandoned MIS retorts and was not satisfied with the evidence presented by Occidental that pollution would not occur. Additional technical information was requested, and the commission insisted on a cooperative environ-

mental monitoring and research program involving DOE, the State of Colorado, and several universities. The dispute was resolved when Occidental agreed to the program and the investigators were given access to Oxy's site for sampling and experiments.

As work began on tracts C-a and C-bin late 1977, soon after DOI approved the modified DDPs, a dispute arose among several environmental groups, permitting agencies, and the lessees over the timing of required permits. EPA initially informed the lessees that air quality and State mining and reclamation permits would not be required until the mining of actual in situ retorts began. The environmental groups maintained that construction commenced with shaft-sinking and construction of the surface facilities needed for the MIS retorts. This work had already begun and, according to the environmental groups, permits should have been in hand. They further contended that the interpretation of "commencement of construction" used by the agencies evolved during meetings that were not open to public participation.

EPA's recently appointed Regional Administrator subsequently redefined "commencement of construction" to mean collaring of the shaft, an early activity in shaft-sinking operations. However, the State reclamation agency maintained that the developers were not responsible for the previous interpretation of the law. Therefore, operations could proceed. The State air pollution division postponed the deadline for application submission until the developers could submit the detailed engineering plans required for an emissions permit, but did not delay the construction. EPA issued the permit in an expeditious manner and work was not significantly delayed. Because a clear precedent was established, it is unlikely that this dispute will arise again. It took several months to resolve, but activities on the tracts continued during this period.

Finally, there has been protracted legal action between three environmental plaintiffs and DOI and the lessees of tracts C-a and C-b over the need for an EIS prior to DOI's ap-

proval of DDPs that were submitted by the lessees in 1976. This dispute has thus far not delayed construction on the tracts. It does, however, exemplify the type of uncertainty that the developers maintain, discourages them from initiating oil shale projects. The plaintiffs claim that no statement to date has adequately analyzed the effects of these plans. Defendants believe that the 1973 programmatic EIS appropriately evaluated the 1976 plans and the alternatives to their approval. The Federal district court agreed with the defendants. The case was heard by the 10th Circuit Court of Appeals which also ruled in favor of the defendants.

Other than these disputes, there have been no substantial interruptions that could be directly related to permitting. The only lengthy application review period involved Colony Development Operation's PSD air quality permit. EPA did not expedite its review of this permit because the applicant indicated it was still inactive, awaiting more favorable project economics. In addition, 1-year suspensions were requested in 1976 by the lessees of the Federal tracts partially because the baseline air quality conditions on the tracts exceeded the primary NAAQS for particulate and the guideline for HC. However, the suspensions were granted for reasons not related to the permitting process.

Unresolved Issues

Although many precedents have been established, there remain unresolved issues that sustain a level of uncertainty that may discourage some developers from proceeding, whether on private or Federal land. These uncertainties may be more critical than those encountered thus far. Several regulations are still pending that may increase costs or force changes in the design of process facilities or control technologies. They may also add to the control requirements. The pending regulations include:

- recordkeeping, reporting, and stipulations governing the manufacture and

handling of toxic substances as required under TSCA;

- disposal practices and standards for solid waste under RCRA;
- emission and ambient air standards for hazardous air pollutants under the Clean Air Act as amended;
- visibility protection requirements for mandatory Class I areas under the Clean Air Act as amended;
- possible application of the Safe Drinking Water Act to the brackish ground waters of the Piceance Basin; and
- possible application of SMCRA, or similar Federal-reclamation laws, to noncoal minerals.

Some environmental groups maintain that the effects of development are so poorly understood that development will entail significant risks. They believe that adequate regulations cannot be promulgated because knowledge is lacking about the severity of the risks and about the methods for their control. R&D and further experience with the industry's operations may result in the implementation of new regulations that will further reduce the economic attractiveness of oil shale projects. This, however, is an uncertainty which is inherent in any new industry.

Another problem that may emerge is whether regulatory agencies will be able to handle the increasing load of permit applications and enforcement duties. Budgets and personnel are limited, and the States in particular have experienced difficulty finding and keeping competent technicians and professionals. Increased oil shale operations, coal mining, oil and gas development, coal-fired powerplants and synthetic fuel facilities, uranium mines and mills, and other mineral development in the region will further tax their resources. The dissatisfaction expressed to date may be insignificant compared to that which is likely as agencies become more overloaded.

Attempts at Regulatory Simplification

Several attempts are being made to simplify regulatory procedures. A case in point is the action of EPA's Region VIII office to streamline the PSD permit application process. The office evaluated its experience with processing such permits and found that in a few cases, there are long review times when the applicant was not in a hurry to obtain a permit because the future of the project was uncertain. An example is the application for the Colony project, which has been suspended for several years. In other instances, delays resulted when the agency was deluged by permit applications prior to the enactment of new, stricter regulations. An example is the situation that arose in 1978 when the older PSD regulations, which did not require extensive baseline air quality monitoring, were replaced by new regulations that required monitoring for a 1-year period. When this happens, the agency's resources are overwhelmed and applications are delayed.

Other delays resulted when applications were incomplete (information was lacking) or when the information that was provided was deemed inadequate by the agency. The first informational problem could be easily reduced by a quick review of the application for completeness. The second is more difficult, because it involves scientific and technical judgment. It reflects, to an extent, the fact that the oil shale processes are new technologies and their effects are not totally understood. Standardized procedures are not always available for determining compliance with the law. This difficulty could be reduced by developing standard procedures wherever possible. This has been done already in some areas of the PSD process where, for example, the developers are required to use standard dispersion models authorized by EPA.

The Region VIII office recently issued a policy statement that addresses its efforts to im-

prove the permitting procedures. A key element is designing a standard application that defines the specific data needs and recommends procedures for obtaining the data. There is also an effort to educate developers in using the application by holding public workshops on the permitting procedure. Also, at the Federal level, one focus of the proposed Energy Mobilization Board is to expedite agency decisionmaking and reduce the impacts of new regulatory requirements that may emerge after construction or operations begin.

The State of Colorado, with funding from DOE, is designing and testing a permit review procedure for major industrial facilities that will coordinate the reviews by Federal, State, and local regulatory agencies. The procedure is also planned to expand the public's opportunities to become involved in all phases of project planning and review. It is being tested with a controversial molybdenum project near Crested Butte, Colo. A handbook will be developed on completion of the test. This may aid in applying similar methods to the permitting process for oil shale plants. *

Policy Options

The policy options presented here range from working to better understand complex regulatory processes, through using the results of such work to reduce the complexities, to waiving the laws or regulations. This range encompasses actions over which there is little disagreement through those which involve extreme controversy. Few would argue that regulatory procedures could be improved, while many would resist changes that could result in weakening environmental protections.

Study the Causes of Permitting Delays

Further study of the permitting procedure could help to identify and eliminate some of the causes of regulatory inefficiency. Such

studies have been conducted by EPA's Region VIII office for the PSD process. The National Commission on Air Quality is conducting a more comprehensive evaluation of alternative means for achieving the goals of the Clean Air Act with more manageable regulatory procedures. Similar studies could be made of other laws and regulations.

Increase the Resources of the Regulatory Agencies

Increasing the personnel and financial resources of the Federal regulatory agencies would allow them to improve their response capabilities. The agencies could also provide technical assistance to the State and local regulators to aid in their decisionmaking processes. However, a simple increase in agency funding, without a methodology for coordinating the expanded resources, would not guarantee that procedures would improve.

Improve Coordination Among Agencies and Between Agencies and the Public

The permitting process might be improved if coordinated reviews were conducted by the various agencies. This strategy would help to identify and reduce jurisdictional overlaps and to reduce personnel needs and paperwork loads. A major advantage would be the opportunity for sharing analytical responsibilities and results. The public hearings that are required for many separate permits could also be consolidated. The strategy could be patterned after the voluntary joint review processes that are being developed in Colorado and other States. However, unless the approach were mandated, it is questionable that interagency cooperation would be significantly improved.

Another approach would involve the establishment of a regional environmental monitoring system to determine baseline conditions within all areas to be affected by oil shale projects. The system could better characterize baseline conditions than could individual, uncoordinated monitoring programs. It might

*Colorado hopes this joint review process, which provides for concurrent rather than serial review of applications, will also reduce the time needed for review.

reduce the duration and the cost of the advance monitoring programs that are required of permit applicants. Site-specific measurements would still be required to characterize biological communities, soils, hydrology, and geology for projects involving Federal land. Baseline surveys could be conducted by Federal agencies on potential lease tracts to shorten the time between a leasing decision and commercialization. The cost of the program could be included in the cost of the lease. Individual monitoring of stack emissions, water discharges, and reclamation efforts would also still be needed as the projects proceeded.

Improved coordination of public participation might also shorten review time by reducing controversy, political confrontation, and litigation. Procedures might include advance public notification of the status of permit applications, the dissemination of technical information and R&D results, and the more direct involvement of the public in an agency's decisionmaking process through, for example, workshops and public meetings. It is possible that increasing the public's awareness of the characteristics of a project might lead to perceptions of greater risk. On the other hand, education could lessen nonproductive discussions and confrontations. In any case, it may be difficult to educate the public in the technical aspects that determine whether an application satisfies the standards. To maintain a high level of participation, some intervenor groups may seek financial and technical assistance. This would be controversial, especially from the point of view of the developers.

Clarify the Regulations and the Permitting Procedure

One option would be to expedite promulgation of standards for visibility and hazardous emissions under the Clean Air Act, and to set the as yet undefined NSPS for oil shale plants. Additional regulations could also be defined under RCRA, TSCA, and other laws. These actions would eliminate many of the regulatory uncertainties and would allow the

developers to integrate controls for the new standards into their plant designs. If it is desired to reduce developer risks, new standards should be firmly established and not subject to change for an extended period. This may not be appropriate, since early experience with the industry may indicate a need to modify the standards to achieve the desired level of protection. In addition, they may be difficult to establish. Excessively lax standards would not adequately protect the environment; excessively strict ones might unnecessarily preclude development. These hazards are particularly applicable to setting NSPS.

Another approach would be to simplify the permitting procedures themselves, based on information from the investigations suggested under the first option. This would have the advantage of retaining the protection of the existing laws while making it easier to comply with them. However, problems (such as the uncertain status of applications in progress) might arise during the transition from the old regulatory system to the new. It is also often difficult to isolate the substance of environmental protection laws from the implementation procedures. Any proposed changes in the procedures would need careful examination by the agencies, the developers, and the public.

A third approach would be to establish detailed, standardized specifications for permit applications. This would reduce the problem of insufficient data being provided with the applications and the delays that would be caused when agencies request the additional information they feel is necessary for a thorough review. Fully comprehensive standardized forms are probably not possible, and some interactions after an application is submitted will still be needed.

A fourth option would be to have a moratorium on new regulations until some of the actual effects of development are determined on the Prototype Program lease tracts. (Monitoring of environmental effects and development of control techniques is one of the major

objectives of the Program.) A disadvantage is that the regulatory uncertainties would remain. An advantage is that the regulations could be promulgated from a better knowledge base,

Expedite the Permitting Procedure

The proposed Energy Mobilization Board would expedite permitting by negotiating a project schedule with a developer and then enforcing the schedule by making regulatory decisions if the responsible agency does not do so within a specified period. Proponents of this strategy point out the advantages of a central authority that could provide a single point of contact between the developer and the regulatory system. Opponents feel that such an authority would add another layer of bureaucracy, would increase controversy over the projects that are expedited, and would ultimately not have substantial effects on permitting delays.

Another method would be to limit the period during which litigation can be initiated against a particular permitting action. This mechanism could be similar to that employed in the case of the Trans-Alaska oil pipeline. It would reduce the risk of agency actions being subjected to legal challenges that could jeopardize a project's completion schedule. It should be noted, however, that legal mechanisms already exist in some specific laws to limit the period of litigation. The expediting strategy could extend this protection to most, if not all, of the relevant statutes,

Limit the Application of New Environmental Laws and Regulations

Plants already under construction, or that are operating, could be exempted from the provisions of new environmental laws and regulations. This approach—"grandfathering"—is embodied in the legislation for the Energy Mobilization Board. It would remove many of the regulatory uncertainties. However, it is surrounded with controversy because new regulations might be needed to deal with problems that could not be discovered until after operations begin. Many of the present laws contain provisions to exempt existing facilities from new requirements. These include either automatic exemption clauses or economic criteria against which the new regulatory requirements must be tested.

Waiving Existing Environmental Laws

This strategy would exempt a project from the provisions of some or all existing environmental laws and regulations that might delay or prevent its construction and operation. This measure would remove virtually all of the problems and delays associated with the permitting. However, it would have serious political, environmental, and social ramifications since it could arbitrarily preempt environmental protection under the law. Furthermore, the waivers might give an undeserved competitive advantage to the developers who received them. The allocation of the waivers would be highly controversial. The extent to which this action would speed the deployment of the industry is unclear.

Chapter 8 References

- ¹Environmental Protection Agency, *Trace Elements Associated With Oil Shale and Its Processing*, EPA-908/4-78-003, prepared by TRW and DRI under contract No. 68-02-1881, May 1977, p. 2.
- ²T. C. Borer and J. W. Hand, *Identification and Proposed Control of Air Pollutants From Oil Shale Operations*, prepared by the Rocky Mountain Division, The Pace Co. Consultants and Engineers, Inc., for OTA, October 1979, p. 38.
- ³Environmental Protection Agency, *Monitoring Environmental Impacts of the Coal and Oil Shale Industries: Research and Development Needs*, EPA-600/7-77-015, February 1977, p. 138.
- ⁴Supra No. 2, at p. 20.
- ⁵Denver Research Institute, *Predicted Costs of Environmental Controls for a Commercial Oil Shale Industry: Volume I—An Engineering Analysis*, prepared for the Department of Energy under contract No. EP-78-S-02-5107, July 1979.
- ⁶Environmental Protection Agency, *A Preliminary Assessment of the Environmental Impacts From Oil Shale Development*, prepared by TRW and DRI under contract No. 68-02-1881 (EPA-600/7-77-069), July 1977, p. 104.
- ⁷Battelle Northwest Laboratories and Dames and Moore, *Environmental Impact Analysis: Appendix 13—Air Studies*, prepared for Colony Development Operation, October 1973.
- ⁸Rio Blanco Oil Shale Project, *Detailed Development Plan Tract C-a: Environmental Protection and Monitoring*, vol. 4, March 1976.
- ⁹Rio Blanco Oil Shale Project, *Detailed Development Plan Tract C-a: Environmental Protection and Monitoring*, vol. 3, May 1977.
- ¹⁰[statement by Terry Thoem, Environmental Protection Agency, Region VIII, as reported in the minutes of the 25th meeting of the Oil Shale Environmental Advisory Panel, Grand Junction, Colo., May 2 and 3, 1979, pp. 130-131,
- ¹¹National Commission on Air Quality, *Report of the Atmospheric Modeling Review Panel of the National Commission on Air Quality*, (preliminary draft), to be published in February 1980.
- ¹²Ibid.
- ¹³Ibid.
- ¹⁴E. F. Bates and T. L. Thoem (eds.), *Pollution Control Guidance for Oil Shale Development*, revised draft report, Environmental Protection Agency, Cincinnati, Ohio, July 1979, p. 4-46.
- ¹⁵Colony Development Operation, *An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado*, vol. I, 1974.
- ¹⁶J. C. Ward, G. A. Margheim, and G. O. Lof, *Water Pollution Potential of Spent Oil Shale Residues*, report for the Water Quality Office, Environmental Protection Agency, Colorado State University, Fort Collins, Colo., 1971.
- ¹⁷National Academy of Sciences, *Mining and Processing of Oil Shale and Tar Sands—A Working Paper Prepared for the Committee on Surface Mining and Reclamation*, Washington, D. C., 1979, p. 89.
- ¹⁸Supra No. 5.
- ¹⁹Ibid.
- ²⁰Supra No. 17, at p. 91.
- ²¹J. P. Fox, K. K. Mason, and J. J. Duvall, "Partitioning of Major, Minor, and Trace Elements During Simulated In Situ Oil Shale Retorting in a Controlled-State Retort," *Proceedings of the Twelfth Oil Shale Symposium* (J. H. Gary, cd.), Colorado School of Mines Press, Golden, Colo., 1979, pp. 58-71,
- ²²F. C. Hass, "Analysis of TOSCO II Oil Shale Retort Water," paper presented at ASTM Symposium D-199.33 on Analysis of Wastes Associated With Alternative Fuel Production, Pittsburgh, Pa., June 4-5, 1979.
- ²³E. W. Cook, "Organic Acids in Process Water From Green River Oil Shale," *Chemistry & Industry*, May 1, 1971, p. 485.
- ²⁴G. W. Dawson and B. W. Mercer, "Analysis, Screening and Evaluation of Control Technology for Wastewater Generated in Shale Oil Development," *Quarterly Reports*, Battelle Pacific Northwest Laboratory, Richmond, Wash., January 1977-March 1979.
- ²⁵Water Purification Associates, *A Study of Aerobic Oxidation and Allied Treatments for Upgrading In Situ Retort Waters*, contract No. EW-78-C-20-0018 with Laramie Energy Technology Center, Department of Energy, Quarterly Status Report, August 1979.
- ²⁶Supra No. 14.
- ²⁷Supra No. 21.
- ²⁸Supra No. 22.
- ²⁹National Academy of Sciences, *Water Quality Criteria, 1972*, Environmental Protection Agency publication (EPA-R-3-73-033), Washington, D. C., March 1973.
- ³⁰Ibid.
- ³¹Supra No. 14, at p. 3-64.
- ³²Ibid.
- ³³J. B. Weeks, et al., *Simulated Effects of Oil Shale Development on the Hydrology of Piceance*

Basin, Colorado, Professional Paper 908, U.S. Geological Survey, Washington, D. C., 1974, p. 34.

⁴⁴Ibid., p. 44.

⁴⁵Ibid., p. 39.

⁴⁶Ibid., p. 40.

⁴⁷Supra No. 14.

⁴⁸Supra No. 6.

⁴⁹A. L. Hines, *The Role of Spent Shale in Oil Shale Processing and the Management of Environmental Residues*, Department of Energy, report TID-28586, ERDA-Laramie Energy Research Center, Laramie, Wyo., April 1, 1978.

⁵⁰B. W. Mercer, et al., "Assessment of Control Technology for Shale Oil Wastewaters," paper presented at Environmental Control Technology Symposium, Department of Energy, November 1978.

⁵¹B. L. Harding and K. D. Lindstedt, et al., *Removal of Ammonia and Alkalinity From Oil Shale Retort Waters*, prepared for Laramie Energy Technology Center, Department of Energy, contract No. DE-AS20-78-ET-13096, April 1979.

⁵²K. D. Lindstedt and E. R. Bennett, *Report on Characterization and Treatment of Retort Waters From In Situ Oil Shale Retorting*, Civil, Environmental, and Architectural Engineering Dept., University of Colorado, August 1977.

⁵³Osmonics, Inc., "Application Test Report" (Study of the Application of Reverse Osmosis to Treatment of Oil Shale Wastewaters), report in preparation for Laramie Energy Technology Center, Department of Energy, 1979.

⁵⁴Water Purification Associates, *A Study of Reverse Osmosis for Treating Oil Shale Process Condensates and Excess Mine Drainage Water*, quarterly progress report, prepared for Laramie Energy Technology Center, Department of Energy, contract No. DE-AC20-79LC10089, September 1979.

⁵⁵E. A. Ossio, et al., "Anaerobic Fermentation of Simulated In Situ Oil Shale Retort Water," *American Chemical Society Division of Fuel Chemistry Reprints*, vol. 23, No. 2, 1978, pp. 202-213.

⁵⁶R. R. Spencer, *Anaerobic Treatment of Wastewater Generated During Shale Oil Production* (draft report), Battelle Pacific Northwest Laboratory, 1979.

⁵⁷Supra No. 24.

⁵⁸Supra No. 25.

⁵⁹B. Harding, et al., "Study Evaluates Treatments for Oil-Shale Retort Water," *Industrial Wastes*, September/October 1978, pp. 28-33.

⁶⁰A. B. Hubbard, "Method for Reclaiming Wastewater From Oil Shale Processing," *American Chemical Society Division of Fuel Chemistry*

Reprints, vol. 15, No. 1, March-April, 1971, pp. 21-25.

⁶¹Supra No. 14, at p. 3-44,

⁶²Ibid., p. 5-50.

⁶³National Safety Council, *Accident Facts*, stock No. 021.57, Chicago, 1977.

⁶⁴R. H. Flinn, et al., *Silicosis in the Metal Mining Industry: A Reevaluation, 1958-1961*, Public Health Service, Pub. No. 1076, 1963.

⁶⁵Ibid.

⁶⁶Personal communication with George Weems, Supervisory Physical Scientist, Industrial Health Branch, Denver Technical Support Center, Mining Safety and Health Administration, Department of Labor, Jan. 22, 1980.

⁶⁷I. P. Maripuu, Puusaar, "Spirographic and Roentgenofunctional Characterization of Pulmonary Emphysema in Bituminous Shale Miners," *Gyg. Tr. Prof. Zabol.*, vol. 15, No. 12, 1971, pp. 51-53.

⁶⁸W. K. C. Morgan and N. Zapp, "Respiratory Disease in Coal Miners," *American Review of Respiratory Diseases*, vol. 113, 1976, pp. 531-559.

⁶⁹L. M. Irwig and P. Rochs, "Lung Function and Respiratory Symptoms in Silicotic and Nonsilicotic Gold Miners," *American Review of Respiratory Diseases*, vol. 117, 1978, pp. 429-435.

⁷⁰V. A. Kung, "Morphological Investigations of Fibrogenic Action of Estonian Oil Shale Dust," *Environmental Health Perspectives*, vol. 30, 1979, pp. 153-156.

⁷¹W. E. Wright and W. N. Rem, "A Preliminary Report: Investigation for Shalosis Among Oil Shale Workers," presented at Park City Environmental Health Conference, Park City, Utah, Apr. 4-7, 1979.

⁷²J. Rudnick and G. L. Voelz, "An Occupational Health Study of Paraho Oil Shale Workers," presented at Park City Environmental Health Conference, Park City, Utah, Apr. 4-7, 1979.

⁷³J. Costello, "Morbidity and Mortality Study of Oil Workers in the United States," *Environmental Health Perspectives*, vol. 30, 1979, pp. 205-208.

⁷⁴Supra No. 107.

⁷⁵L. M. Holland, D. M. Smith, and R. G. Thomas, "Biological Effects of Raw and Processed Oil Shale Particles in the Lungs of Laboratory Animals," *Environmental Health Perspectives*, vol. 30, 1979, pp. 147-152.

⁷⁶L. M. Holland, W. D. Span, and L. L. Garcia, "Inhalation Toxicology of Oil Shale-Related Materials," presented at Park City Environmental Health Conference, Park City Utah, Apr. 4-7, 1979.

⁶⁷R. A. Renne, J. E. Lund, K. E. McDonald, et al., "Morphologic Effects of Intratrachially Administered Oil Shale in Rats," presented at Park City Environmental Health Conference, Park City, Utah, Apr. 4-7, 1979.

⁶⁸Supra No. 63.

⁶⁹B. T. Scheb, "Noise in the Mining Industry: Its Effects, Measurement, and Control," Proceedings of the Symposium on Industrial Hygiene for Mining and Tunneling, American Conference of Governmental Industrial Hygienists, Cincinnati, Ohio, 1978.

⁷⁰M. Blick, et al., "Noise," *Medicine in the Mining Industries* (J. M. Rogan, cd.), published by F. A. Davis, Philadelphia, Pa., 1974, p. 244.

⁷¹I. Berenblum and R. Schoental, "Carcinogenic Constituents of Shale Oil," *British Journal of Experimental Pathology*, vol. 24, 1943, pp. 232-239.

⁷²A. Scott, "The Occupation Dermatoses of the Paraffin Workers of the Scottish Shale Oil Industry," *British Medical Journal*, vol. 1, 1922, pp. 381-385.

⁷³M. Purde and S. Etlin, "Cancer Cases Among Workers in the Oil-Shale Processing Industry," presented at Park City Environmental Health Conference, Park City, Utah, Apr. 4-7, 1979.

⁷⁴M. Purde and M. Rahn, "Cancer Patterns in the Oil Shale Area of the Estonian Soviet Socialist Republic," *Environmental Health Perspectives*, vol. 30, 1979, pp. 209-210.

⁷⁵A. Leitch, "Paraffin Cancer and Its Experimental Production," *British Medical Journal*, vol. 2, 1922, pp. 1104-1106.

⁷⁶I. Berenblum and R. Schoental, "The Difference in Carcinogenicity Between Shale Oil and Shale," *British Journal of Experimental Pathology*, vol. 25, 1944, pp. 95-96.

⁷⁷C. C. Twort and J. M. Twort, "Classification of Four Thousand Experimental Oil and Tar Skin Tumors of Mice," *Lancet*, vol. 1, 1930, pp. 1331-1335.

⁷⁸J. M. Holland, et al., "Skin Carcinogenicity of Synthetic and Natural Petroleum," *Journal of Occupational Medicine*, vol. 21, 1979, pp. 614-618.

⁷⁹R. M. Coomes, "Carcinogenic Testing of Oil Shale Materials," *Twelfth Oil Shale Symposium Proceedings*, Golden, Colo., The Colorado School of Mines Press, November 1979.

⁸⁰Ibid.

⁸¹Ibid.

⁸²Ibid.

⁸³Ibid.

⁸⁴J. J. Zone, "Cutaneous Effects of Shale Oil," presented at Park City Environmental Health Conference, Park City, Utah, Apr. 4-7, 1979.

⁸⁵D. J. Birmingham, *Interim Report on the Shale Oil Study*, Public Health Service, Cincinnati, Ohio, 1955.

⁸⁶Tabershaw-Cooper Associates, Inc., *A Mortality Study of Petroleum Refinery Workers*, project OH-1, Medical Research Report No. EA-7402, American Petroleum Institute, September, 1974.

⁸⁷N. M. Hanis, K. M. Stavrakys, and J. L. Fowler, "Cancer Mortality in Oil Refinery Workers," *Journal of Occupational Medicine*, vol. 21, No. 3, 1979, pp. 167-174.

⁸⁸G. Theriault and L. Goulet, "A Mortality Study of Oil Refinery Workers," *Journal of Occupational Medicine*, vol. 21, No. 5, 1979, pp. 367-370.

⁸⁹M. B. Bloch and D. Kilburn (editors), *Processed Shale Revegetation Studies, 1965-1973, Colony Development Operation*, Atlantic Richfield Co., 1973.

⁹⁰W. R. Schmehl and B. D. McCaslin, "Some Properties of Spent Oil Shale Significant to Plant Growth," *Ecology and Reclamation of Devastated Land*, vol. I (R. J. Hutnik and G. Davis, eds.), published by Gordon and Breach, New York, 1973, pp. 27-43.

⁹¹J. C. Ward and S. E. Reinecke, *Water Pollution Potential of Snowfall on Spent Oil Shale Residues*, prepared by the Environmental Engineering Program, Department of Civil Engineering, Colorado State University for the Bureau of Mines, Laramie Energy Research Center, under grant No. 0111280, 1972.

⁹²Ibid.

⁹³James R. Meiman, *Infiltration Studies in the Piceance Basin, Colorado*, Thorne Ecological Institute, technical publication No. 12, 1975.

⁹⁴Ibid.

⁹⁵Forest Service, *Users Guide to Soils, Mining and Reclamation in the West*, general technical report INT-68, Intermountain Forest and Range Experiment Station, U.S. Department of Agriculture, 1979.

⁹⁶W. J. Culbertson, et al., *Processed Shale Studies: Environmental Impact Analysis*, Appendix 5, Colony Development Operation, Atlantic Richfield Co., 1974.

⁹⁷Supra No. 95,

⁹⁸R. M. Dixon, "Soil Imprinting for Increasing Land Productivity," presented at the 33rd Annual Meeting of Soil Conservation Society of America, July 30-Aug. 2, 1978, Denver, Colo. Also printed in the *Journal of Soil and Water Conservation*, 1978.

⁹⁹Supra no. 89.

¹⁰⁰Rio Blanco Oil Shale Co., *Revegetation Program 1978 Annual Report*, submitted to Rio Blanco Oil Shale Co., Denver, Colo., by NUS Corp., Den-

ver, Colo., March 1979.

¹⁰¹C. Wayne Cook, Rehabilitation Potential and Practices of Colorado Oil Shale Lands, progress report for period June 1978- May 31, 1979, prepared for the Department of Energy by Colorado State University under contract No. EY-76-S-02-4018, 1979.

¹⁰²C. Wayne Cook, et al., *Revegetation Guidelines for Surface Mined Areas*, Colorado State University, Range Science Department Science Series No. 16, 1974.

⁶⁰Ibid.

¹⁰⁴R. R. Ericsson and P. Morgan, "The Economic Feasibility of Shale Oil: An Activity Analysis," *Bell Journal of Economics*, vol. 9, 1978, pp. 457-487.

¹⁰⁵Supra No. 1.

⁶⁵Supra No. 96.

¹⁰⁷Ibid.

¹⁰⁸Supra No. 90.

¹⁰⁹Supra No. 100.

¹¹⁰R. C. Woodmansee, et al., "Nitrogen in Drastically Disturbed Lands," *Forest Soils and Land Use* (C. T. Youngberg, cd.), Department of Forest and Wood Sciences, Colorado State University, Fort Collins, 1979, pp. 376-392,

⁶¹Supra No. 101.

⁶²Ibid.

¹¹¹F. B. Reeves, et al., "The Role of Endomycorrhizae in Revegetation Practices in the Semi-Arid West: A Comparison of Incidence of Mycorrhizae in Severely Disturbed vs. Natural Environments," *American Journal of Botany*, vol. 66, No. 1, 1979, pp. 6-13.

¹¹⁴Supra No. 101.

¹¹⁵Supra No. 16.

¹¹⁶Supra No. 90.

¹¹⁷H. P. Harbert III, et al., *Vegetative Stabilization of Spent Oil Shales: Vegetation, Moisture, Salinity and Runoff 1973-1976*, 1978,

¹¹⁸H. p. Harbert III, et al., *Lysimeter Study on the Disposal of Paraho Retorted Oil Shale*, Industrial Environmental Research Laboratory, Office of R&D, Environmental Protection Agency, Cincinnati, Ohio (EPA-600/7-79-188), 1979.

¹¹⁹W. A. Berg, et al., *Vegetative Stabilization of Union Oil Company Process B Retorted Oil Shale 2975-1978*, Colorado State University Experiment Station, technical bulletin No. 135, 1979.

¹²⁰J. T. Herron, et al., *Vegetation and Lysimeter Studies on Decarbonized Oil Shale*, Colorado State University Experiment Station, technical bulletin No. 136, 1980.

¹²¹L. A. Richards (cd.), *Diagnosis and Improvement of Saline and Alkali Soils*, U.S. Department of Agriculture Handbook No. 60, 1954.

¹²²I. F. Wymore, *Water Requirement for Stabilization of Spent Shale*, doctoral dissertation, Colorado State University, Fort Collins, Colo., 1974.

¹²³D. D. Runnells, et al., "Release, Transport, and Fate of Some Potential Pollutants," in *Trace Elements in Oil Shale*, report No. COO-401 7-2, Environmental Trace Substances Research Program, University of Colorado, Denver, Colo., 1978, pp. 49-97.

¹²⁴M. K. Kilkelly, et al., "Trace Elements in Plants Growing on Processed Oil Shales," in *Trace Elements in Oil Shale*, report No. COO-4017-2, University of Colorado, Denver, Colo., 1978, pp. 98-134.

⁶²⁵Supra No. 16.

¹²⁶Supra No. 117.

¹²⁷Ibid.

¹²⁸Supra No. 100.

¹²⁹Supra No. 96.

¹³⁰Fish and Wildlife Service, *The Plant Information Network: Volumes I-IV*, U.S. Department of the Interior FWS/OBS-77/38-41. Supporting computer data base located at the Department of Botany and Plant Pathology, Colorado State University, Fort Collins, Colo.

¹³¹C. M. McKell, et al., *Selection, Propagation, and Field Establishment of Native Plant Species on Disturbed Arid Lands*, Institute for Land Rehabilitation, Utah Agricultural Experiment Station, Utah State University, 1979.

¹³²Soil Conservation Service, *Plant Materials for Use on Surface Mined Lands in Arid and Semi-Arid Regions*, U.S. Department of Agriculture handbook SCS-TP 157, Lincoln, Nebr. (in press).

⁶¹ Forest Service, *User Guide to Vegetation, Mining and Reclamation in the West*, general technical report INT-64, Intermountain Forest and Range Experiment Station, U.S. Department of Agriculture, 1979.

¹³⁴A. Plummer, et al., *Restoring Big-Game Range in Utah*, Utah Division of Fish and Game publication No. 68-3, 1968.

¹³⁵Supra No. 130.

¹³⁶Supra No. 133.

¹³⁷Supra No. 101.

¹³⁸Ibid.

¹³⁹Supra No. 133.

¹⁴⁰K. A. Crofts and C. M. McKell, *Sources of Seeds and Planting Materials in the Western States for Land Rehabilitation Projects*, Utah Agri-

culture Experiment Station Land Rehabilitation Series No. 4, Logan, Utah, 1977.

¹⁴⁴Supra No. 133.

¹⁴⁵Supra No. 101.

¹⁴⁶Supra No. 100,

¹⁴⁷N. C. Frischknecht and R. B. Ferguson, *Revegetating Processed Oil Shale and Coal Spoils on Semi-Arid Lands*, interim report, EPA-600/7-79-068, Environmental Protection Agency, Cincinnati, Ohio, 1979.

¹⁴⁸R. W. Tinus, et al. (eds.), *Proceedings of the North American Containerized Forest Tree Seedling Symposium*, Great Plains Agricultural Council publication No. 68, 1974.

¹⁴⁹Supra No. 131.

¹⁵⁰Ibid.

¹⁵¹Supra No. 132.

¹⁵²Supra No. 117.

¹⁵³Supra No. 132.

¹⁵⁴Bureau of Land Management, *Piceance Planning Unit Resource Analysis*, September 1970.

¹⁵⁵Bureau of Land Management, *White River Management Framework Plan*, January 1972.

¹⁵⁶K. C. Vories, *A Vegetation Inventory and Analysis of the Piceance Basin and Adjacent Drainages*, master's thesis, Western State College, Gunnison, Colo., 1974.

¹⁵⁷J. A. Tiedeman, et al., *Phyto-Edaphic Classification of the Piceance Basin*, Colorado State University, Range Science Department Science Series No. 31, 1978.

¹⁵⁸Ibid.

¹⁵⁹Rocky Mountain Oil and Gas Association Oil

Shale Committee, *Summary of Industry Oil Shale Environmental Studies and Selected Bibliography of Oil Shale Environmental References*, Denver, Colo., 1975.

¹⁶⁰Supra No. 89.

¹⁶¹J. M. Merino, et al., "Reclamation of Spent Oil Shale," *Mining Congress Journal*, vol. 63, No. 10, 1977, pp. 31-36.

¹⁶²Supra No. 117.

¹⁶³Supra No. 118.

¹⁶⁴Supra No. 119.

¹⁶⁵Supra No. 120.

¹⁶⁶Supra No. 89.

¹⁶⁷Ibid.

¹⁶⁸C. M. McKell, *Achieving Effective Revegetation of Disposed Processed Oil Shale: A Program Emphasizing Natural Methods in an Arid Environment*, Utah State University, Agriculture Experiment Station Land Rehabilitation Series No. 1, 1976.

¹⁶⁹Supra No. 16.

¹⁷⁰Supra No. 89.

¹⁷¹Supra No. 117.

¹⁷²Supra No. 90.

¹⁷³S. C. Lipman, "Union Oil Company Revegetation Studies," *Environmental Oil Shale Symposium*, Colorado School of Mines, Oct. 9-10, 1975, pp. 165-180.

¹⁷⁴Supra No. 119.

¹⁷⁵Supra No. 118.

¹⁷⁶Supra No. 101.

¹⁷⁷Ibid.