An Assessment of Oil Shale Technologies

June 1980

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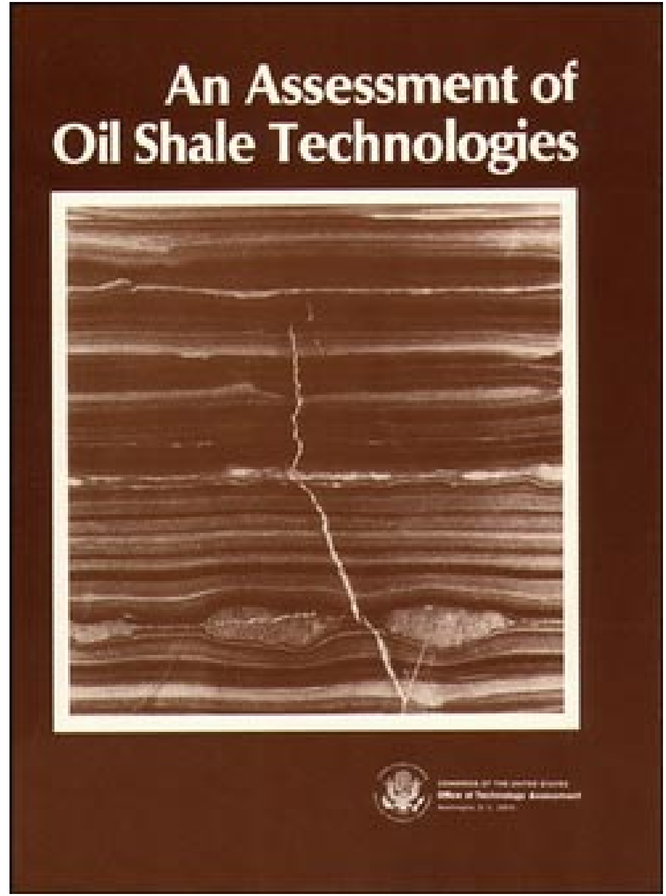

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Foreword

For many decades, the oil shale resources of the Western United States have been considered possible contributors to the Nation's liquid fuel supply. This volume reviews several paths to development of these resources and the likely consequences of following these paths. A chapter providing background information about the nature of oil shale is followed by an evaluation of technologies for recovery of shale oil. The economics and finances of establishing an industry of various sizes are analyzed. The fact that much of the best shale is located on Federal land is examined in light of the desire to increase use of the resources. The consequences of shale development in terms of impact on the physical and social environments, and a discussion of the availability of water complete the report.

Policy options addressing barriers that could hinder the establishment of the industry are presented. These options, designed primarily for Congressional consideration, are limited to the obstacles OTA identified as currently existing. Other issues, of equal importance for the protection of the environment and the communities, but not constraints to development, are discussed in the body of the report. The assessment deals only with oil shale; no systematic attempt was made in this study to compare this energy source with liquid fuel sources other than conventional petroleum or with alternative energy strategies. Other OTA assessments are addressing many of these topics.

Volume II evaluates the Federal Prototype Oil Shale Leasing Program. Both volumes were prepared in response to requests from the Senate Committee on Energy and Natural Resources. We hope they will be of value to the entire Congress when considering domestic energy policies.

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Contents

CHAPTER 1

Summary

Contents

List of Tables

List of Figures

CHAPTER 1

Summary

Summary of Findings

Technology

Two basic retorting technologies are being developed: modified in situ (MIS) for underground retorting, and aboveground retorting (AGR) for processing mined shale. These technologies are not presently ready for large-scale commercialization, but a sound R&D base exists, and they could be made ready either by modular demonstration projects or construction of pioneer plants. The MIS process is being developed on two sites and one commercial facility is planned. Aboveground retorts have been tested at up to one-tenth of full size and at least one commercial-scale retort is planned in conjunction with an MIS demonstration. There are no firm plans for testing other above--ground retorts, although several companies have shown interest. One process would be tested if a lease were provided for the Department of Energy (DOE) facility at Anvil Points, Colo. With financial incentives, two others could be tested on private lands. A multimineral aboveground process awaits the availability of Federal land, either through land exchange or limited leasing. Two true in situ (TIS) processes are being developed with DOE cost sharing, but are only at preliminary stages. Underground mining would also benefit from additional research, development, and demonstration. No major technical problems are anticipated either for open pit mining or for the conventional room-and-pillar method of underground mining. Minor uncertainties remain in the upgrading and refining area.

Economics

An oil shale industry could benefit the Nation's economy and security, but would also entail several economic risks. For example, a 400,000-barrel-per-day (bbl/d) industry established by 1990 would reduce expenditures for imported oil by $4.2 billion per year and expand regional employment, but would lead to increases in local inflation for certain goods, services, and property. The establishment of a l-rnillion-bbl/d industry by 1990 could save more than $10 billion per year in charges for imported oil and would substantially increase local employment; however, the risks associated with overextended design and construction capacity, insufficient equipment manufacturing capability, and possible inefficiency from tight construction schedules could cause damaging cost overruns. Severe regional inflation could be expected for land and housing as well as for other goods and services.

Shale oil may be price competitive with foreign crude, but when expected real rates of return on investment are 12 percent or less, the commercialization of the industry could still be impeded by uncertainties and risks. Among these are cost estimates for constructing the facilities, the future price of oil, regulations, and competition with lower cost investments of similar risk in conventional oil or other alternatives. To establish a 200,000-bbl/d (or larger) industry within 10 years would require financial incentives. The most effective would be production tax credits, purchase agreements, and price supports. The smaller firms may need loan guarantees. The net cost of an effectively designed and administered incentives program could range from $0.60 to $1.40/bbl* of shale oil syncrude** produced. Financial incentives alone may not spur development because alternative investments with a greater return for an equivalent level of risk could compete for the available capital.

The Government also could build its own commercial-scale or modular plants, but at

*Present barrel equivalent over 20 years at lo-percent discount rate.

**A synthetic crude oil produced by adding hydrogen to crude shale oil. Shale oil syncrude is a high-quality material, comparable with the best grades of conventional crude.

much higher cost. A Government effort to construct and supervise demonstration modules (9,000 to 12,000 bbl/d each) would provide technological information that could resolve some hitherto unanswered questions about the implications of oil shale development. It might also reduce the initial costs of industry development. However, the Government's experience in designing, financing, and operating facilities could be sufficiently dissimilar to that of possible private operators to make the information inapplicable. Government efforts also probably would lessen the commercial and R&D interest of the business community.

Resource Acquisition*

A 400,000-bbl/d production of shale oil could be achieved by 1990 without extensive leasing of additional Federal land if subsidies are provided so that two presently active projects are completed, three suspended projects are resumed, and a new project on private land is initiated. If these financial incentives are not provided, then additional Federal leasing will probably be necessary if it is desired to achieve this level of production. To produce 1 million bbl/d by Iwo would require leasing, land exchanges, and substantially greater subsidies.

Environment

Air and water quality, topography, wildlife, and the health and safety of the workers will be affected by the development of an oil shale industry. Many effects will be similar to those caused by any type of mineral development, but the scale of operations, their concentration in a relatively small geographic area, and the nature of the wastes will present some unique challenges. Many of the impacts will be regulated by State and Federal laws. The developers plan to comply by using control technologies from other industries. While there is reason to believe that the methods can be made to work, they have not been tested in commercial-scale oil shale plants because none exist.

The potential leaching of waste disposal areas and in situ retorts after the plants are abandoned is a major concern. If it occurs, the leachates could degrade the water quality in the Colorado River system, a vital water resource in the Southwest. Such "nonpoint" wastewater discharges are neither well understood nor well regulated, although the Clean Water Act provides a regulatory framework. Techniques for preventing leaching need to be demonstrated on a commercial scale. It will be necessary to test a variety of development technologies to assure adequate control of a large industry.

The Clean Air Act is the only existing environmental law that could prevent the creation of a large industry. It could limit production in Colorado to 400,000 bbl/d, although additional capacity could be installed in Utah. The procedures for obtaining environmental permits can take several years. Although unexpected regulatory delays should not preclude the establishment of an individual project, they could lead to cost overruns and might prevent the deployment of a large industry.

Water Availability

A 500,000-bbl/d" industry would increase by about 1.5 percent the water demands projected for the Upper Colorado River Basin in the year 2000. Surplus surface water could be available to support this industry until at least 2025, after which water scarcities may limit all regional growth. Severe shortages could be experienced as much as 20 years sooner if the region develops more rapidly than expected. Surface water scarcity may lead to intensified ground water development, to a shift in the economic base, or to importation of water from other areas. Any large oil shale industry will need new reservoirs and diversion projects. Their environmental effects, though small overall, will be

*On May 27, 1980, the Department of the Interior (DOI) announced it will lease up to four new tracts under the Prototype Program and will begin preparations for a new permanent leasing program.

substantial in the areas where they are built. The use of water for a 2-million-bbl/d oil shale industry, while increasing regional income by several billion dollars per year, would cause losses of about $25 million per year to farming and hydroelectric power generation. States that will not directly share in the increased regional income will experience some of these losses.

Socioeconomic

Oil shale development will change the communities in the sparsely populated oil shale region both socially and economically. Growth problems arising from the simultaneous development of oil shale and other energy resources are likely to be more difficult to solve than those from shale development alone. There is a potential for adverse effects, whose severity will depend on where, when, and how rapidly the plants are built, and on how well the communities are prepared to cope with the growth. The communities could accommodate the growth accompanying an industry of up to 200,000 bbl/d by 1990 if presently planned improvements and expansions are completed. Social and personal distress will occur unless active measures are taken for their prevention. A l-million-bbl/d industry could not be accommodated without major Government involvement and massive mitigation programs. The participation of Federal, State, and local agencies, the public, and the developers would be essential to minimize the adverse living conditions that would inevitably arise.

Background

Oil shale deposits are found on all inhabited continents. Those in Colorado, Utah, and Wyoming contain both a solid hydrocarbon (kerogen) that can be converted to crude shale oil by heating, and sodium minerals that can be used in air pollution control, in glassmaking, and to produce aluminum. Deposits of somewhat different chemical composition and geology are found elsewhere. Those in some foreign countries (Scotland, Spain, Australia) have been the sites of very small-scale industries in the past. Other countries (Brazil, the U. S. S. R., the People's Republic of China) either have such industries or are building them.

The deposits of the Green River formation are found in northwestern Colorado, southwestern Wyoming, and northeastern Utah. (See figure 1.) The Federal Government owns about 70 percent of the land, which contains close to 80 percent of the oil shale and nearly all of the associated sodium minerals. Private parties, Indian tribes, and the three States share the rest. Large deposits are also found throughout the Midwestern and Eastern States. Because of their richness and accessibility, however, the Green River shales are the ones most likely to be developed on a large scale in the near future.

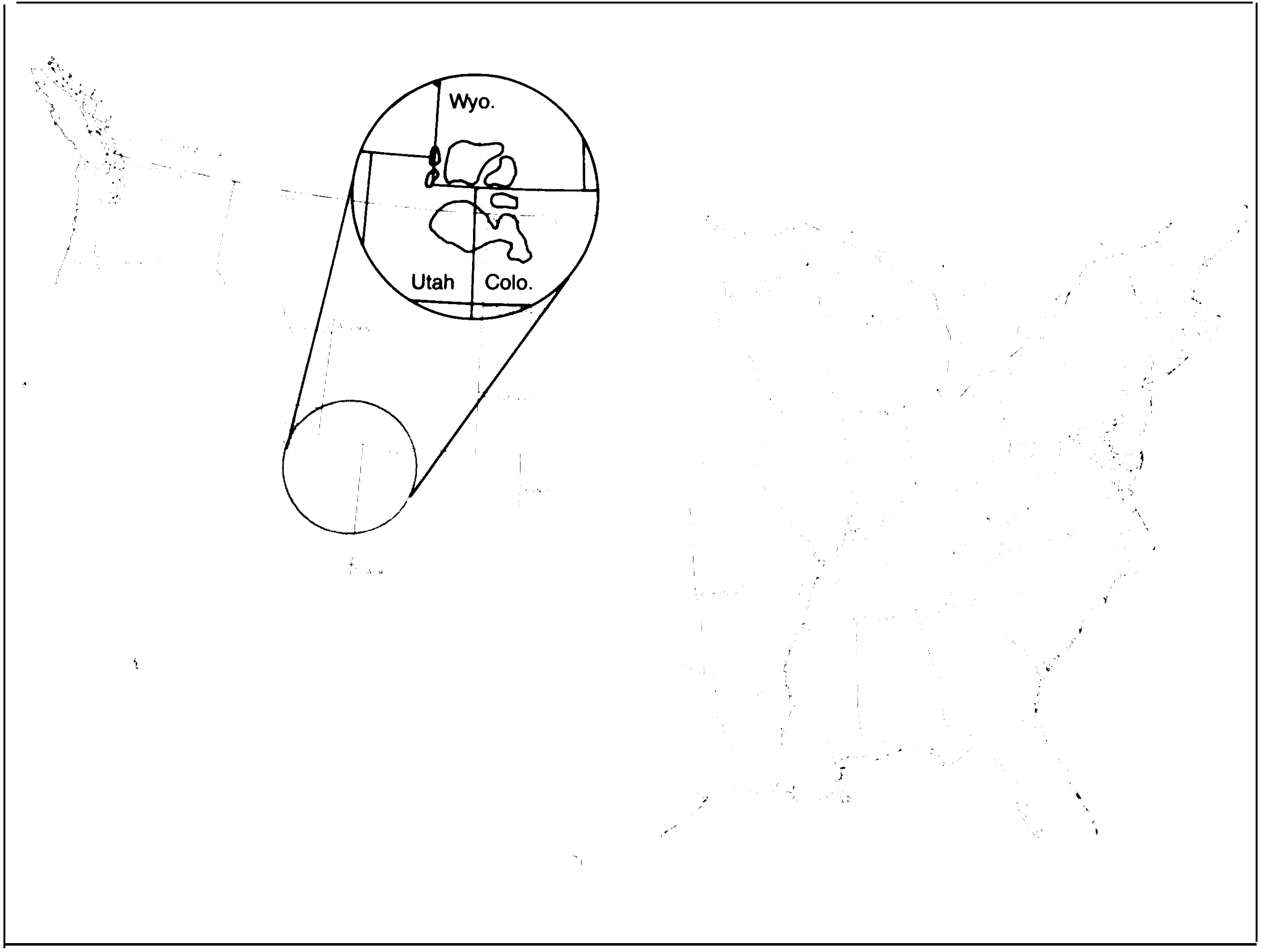
The formation has been divided into several distinct geological basins. (See figure 2.) The richest and most thoroughly explored deposits occur in Colorado's Piceance basin. The resources of Utah's Uinta basin are, in general, of somewhat poorer quality. The Wyoming deposits are relatively inferior and often intermingled with rock that contains no organic matter. Overall, the deposits contain the equivalent of over 8 trillion bbl of crude shale oil. However, only a few hundred billion barrels could be recovered economically with existing technology.

In general, the oil shale region is rugged country, with elevations ranging from 4,300 to 9,000 ft above sea level. The climate is dry, and the weather is strongly influenced by the topography. Although the soils are generally thin and dry, they support diverse plant communities and over 300 species of animals, including the largest migratory deer herd in North America and several threatened or endangered species.

Air quality is generally excellent, but high concentrations of hydrocarbons* (possibly from vegetation) and windblown dust are occasionally encountered, and thermal inver-

"Organic chemicals that contain only hydrogen and carbon.

Figure 1.—The Western Oil Shale Region



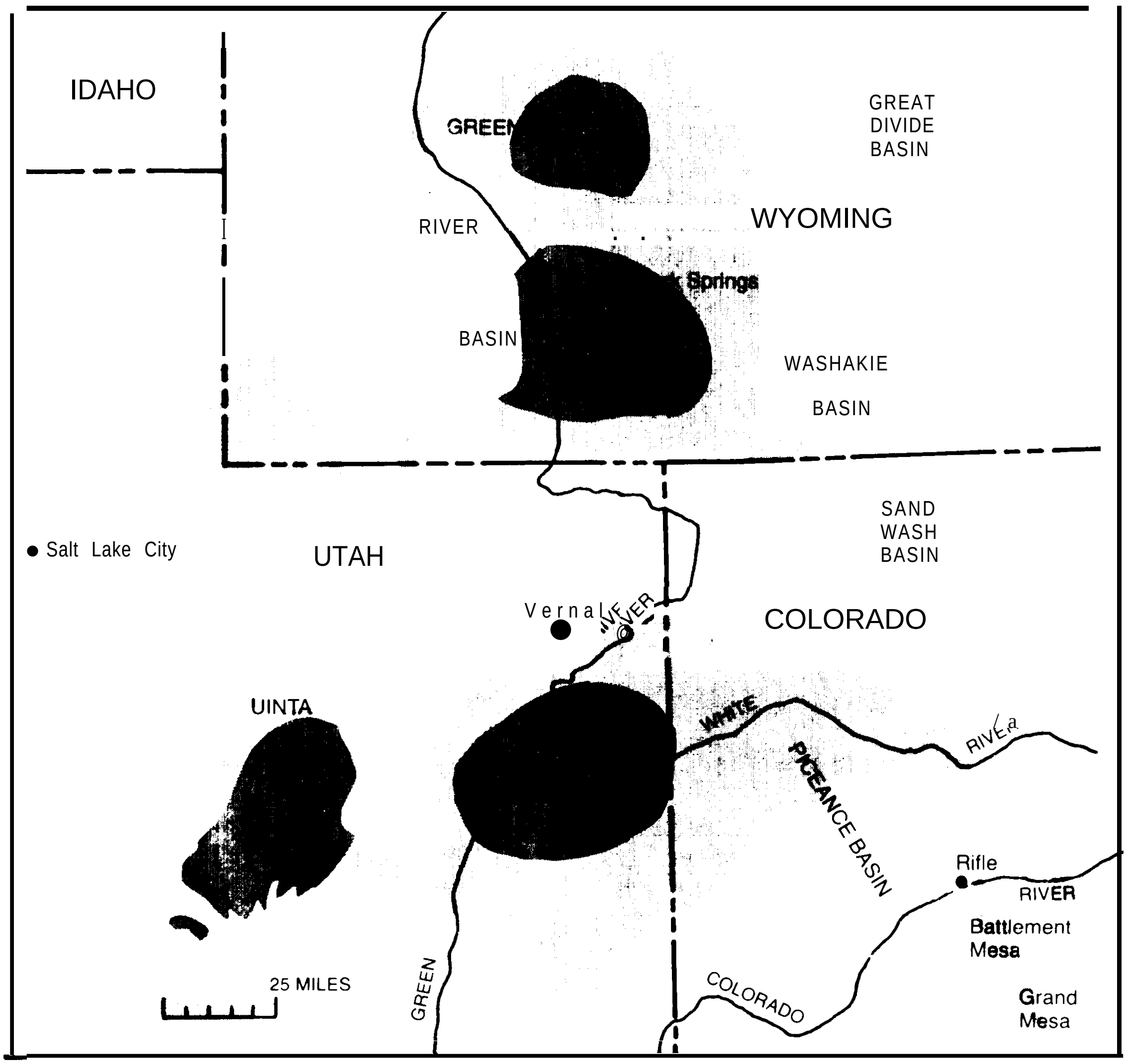
SOURCE *The National Atlas*, Department of the Interior

sions are frequent. Water quality in the surface stream-s is good to excellent in the upper reaches but much poorer downstream because of the discharges from naturally saline streams, irrigated fields, and towns and mineral development sites. The quality of the water in the extensive ground water aquifers* also varies widely. Some contain only saline brines; others contain potable water, although it does not, in general, satisfy drinking water standards.

The population is approximately 120,000—about 3 persons per square mile. Only four towns in the shale region have populations over 5,000: Grand Junction and Craig in Colorado, Vernal in Utah, and Rock Springs in Wyoming. The economy is based on agriculture, minerals, tourism, and recreation. Coal, oil, and gas development is increasing rapidly. The oil shale resources are also receiving considerable attention.

*An aquifer is an underground formation containing water.

Figure 2.—Oil Shale Deposits of the Green River Formation



EXPLANATION

Area underlain by the Green River Formatlon ın which the 011 shale ıs unappraised or low grade

Area underlain by 011 shale more than 10 feet thick, which yields 25 gallons or more 011 per ton of shale

SOURCE D C Duncan and V E Swanson, *Organic-Rich Shales of the United States and Wodd Land Areas,* U S Geological Survey Circular 523, 1965

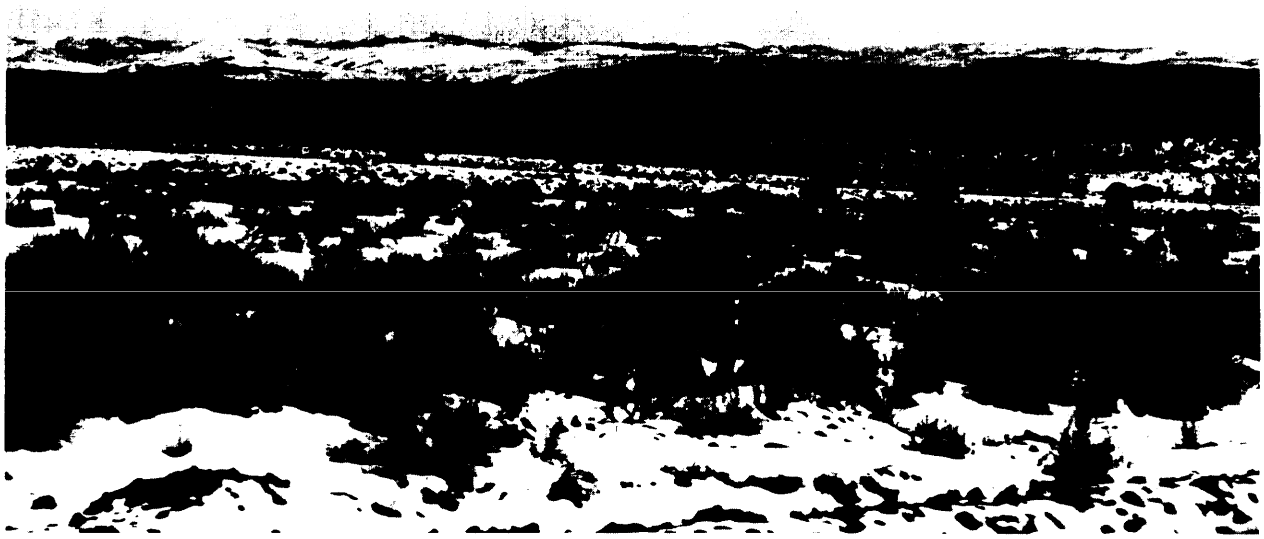


Photo credit George Wallerstein

Central Piceance basin, Colo.

Establishing an Oil Shale Industry: Perspectives and Tradeoffs

The Objectives for Development

The ultimate decision as to whether, how, and to what extent to develop oil shale will be political. Diverse groups with disparate preferences for particular types and rates of development will influence the decision. Some of the objectives of the different groups are discussed below.

To position the industry for rapid deployment.—The advocates of this objective believe the industry should be ready to expand rapidly. They acknowledge that more information and experience are needed if production is to be expanded in times of national need. Many techniques and sites would have to be evaluated in order to answer the remaining questions. Supporters favor policies expanding technical, economic, and environmental R&D, which should include demonstration plants to evaluate a full spectrum of technologies. Incentives and additional Federal land might be employed to encourage private sector experiments. All programs would be designed to maximize information generation.

To maximize energy supplies.—This objective has both economic and national security implications. Its pursuit would lead to the rapid development of a large industry. The benefits that might accrue include reduced import reliance, improved balance of payments, stimulation of private investment, increased employment, and lower energy costs over the long term. Policy responses favored by supporters of this objective emphasize encouragement of the industry and removal of the restraints on its establishment. Included might be leasing programs, substantial incentives, direct Government involvement in production, and the waiving of environmental laws.

To minimize Federal promotion.—This objective is supported by those who oppose governmental interference with private enterprise, and by those who stress that oil shale should not be promoted at the expense of other energy resources. They believe the industry should develop in response to market pressures and opportunities without active Government support or participation. Policies furthering this objective emphasize technical and environmental R&D and testing to provide a basis for developing regulations and for comparing oil shale with other energy alternatives. Planning for future mobilization programs would be carried out; leasing, land exchanges, and incentives programs would not.

To maximize ultimate environmental information and protection.—Advocates of this objective emphasize the desirability of maintaining an ecological balance. They also believe that oil shale should not be promoted more than other energy sources that could be less harmful to the environment. They would phase development to evaluate its potential impacts and to design and test controls, Information on environmental effects and control strategies would be acquired for all technologies that might be used in a commercial industry. Policies would emphasize enforcement of existing regulations, siting of plants to minimize potential impacts, monitoring and R&D to provide guidance for new regulations, and public education and participation.

To maximize the integrity of the social environment .—Supporters of this objective emphasize personal and community needs. They believe it essential that growth management be well planned and coordinated, and that development proceed at a gradual pace. Policies stress involving the region's residents in managing growth, structuring incentive and leasing programs to avoid excessive growth rates in the communities, funding community improvements and planning efforts, and allocating responsibilities for impact mitigation among the developers and the Federal, State, and local governments.

To achieve an efficient and cost-effective energy supply system.—Supporters of this objective emphasize the importance of providing a mix of energy alternatives with the best overall ratio of costs to benefits. They stress the need for positioning the industry and its technologies for long-term profitable operations so that any future expansions could be financed with internally generated resources. The related objectives of efficient development of the resource and balanced environmental and social protection are also emphasized. The pace of development would allow thorough evaluation of the technologies so that the elements of production (including land, labor, capital, water, and energy) could be used most efficiently if a large-scale industry were created. Policies would focus on incentives that leave intact some degree of managerial risk, on thorough testing of diverse technologies and sites, and on advanced R&D and demonstration to provide a basis for comparing oil shale with its alternatives. The policies would not require a commitment of funds and resources to the exclusion of other potential energy sources.

* * *

The Government, in preparing its oil shale policies, must consider all of these, as well as well as other objectives. For example, the Government owns rich oil shale deposits and is responsible for protecting the Nation from interruptions in energy supplies; this would encourage the rapid development of public lands. On the other hand, the public trust requires that these lands be developed efficiently, with equitable returns for the use of the public's resources, and with fair treatment of the affected groups and regions. This mandate would lead to a moderate pace of development. Finally, the Government is required by law to protect the environment and to consider the socioeconomic consequences of its major actions. These mandates require carefully managed development.

Depending on which objectives are emphasized, a number of future industries can be postulated. The following section evaluates the relative degree to which each of four production targets could be expected to attain the objectives for development, given a construction deadline of 1990.

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Attainment of the Objectives

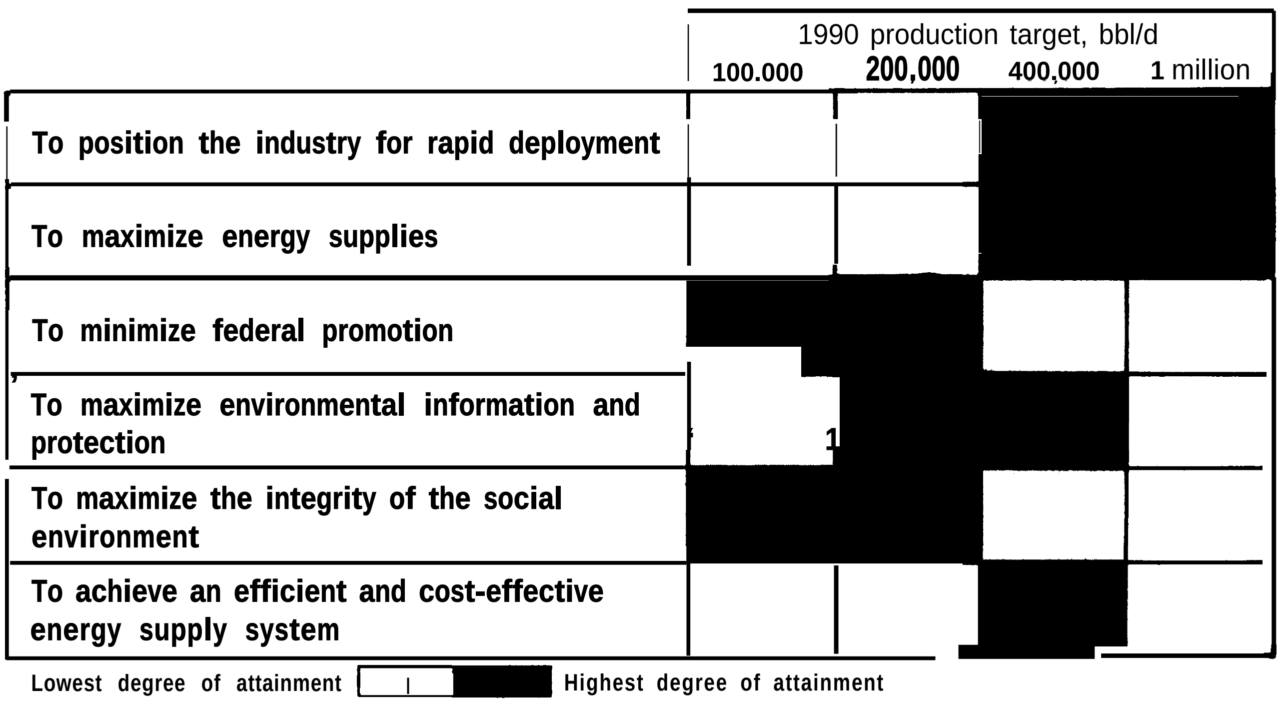
OTA analyzed four production targets for 1990: 100,000 bbl/d, 200,000 bbl/d, 400,000 bbl/d, and 1 million bbl/d. Strategies to reach the targets would entail substantially different requirements, consequences, and policy responses. Regardless of the strategy, tradeoffs among objectives are inevitable. This is indicated in figure 3, where the production goals are rated according to the relative degree to which they are expected to attain the objectives for development. The following illustrates how attainment varies with the size of the industry.

To position the industry for rapid deployment.—The 400,000-bbl/d industry is given the highest rating because a wide variety of technologies and sites would be evaluated and substantial technical, environmental, and economic information would be obtained; all of which would place the industry in a good position for rapid scaleup. The l-million-bbl/d goal is rated next since production at this level would constitute a major industry; further rapid deployment could then follow. It is rated lower than the 400,000-bbl/d industry because its accelerated construction schedule would preclude precommercial experiments and would probably result in less technically efficient plants. The other goals are rated lower because fewer processes could be evaluated.

To maximize energy supplies.—The benefits, and thus the ratings, are proportional to the production rate.

To minimize Federal promotion.—The 100,000-bbl/d target is rated highest because it could be achieved by completing the presently active projects. The 200,000-bbl/d goal probably would require some incentives, and the 400,000-bbl/d goal would require incentives, a small land exchange, and the short-term leasing of a Federal R&D facility in Colorado for a demonstration project. The l-mil-

Figure 3.—The Relative Degree to Which the Production Targets Would Attain the Objectives for Development



SOURCE Office of Technology Assessment

lion-bbl/d goal would require much stronger subsidies, additional long-term leasing of public land, permitting modifications, variances, and extensive Federal involvement in growth management.

To maximize ultimate environmental information and protection.—The quantity of pollutants and wastes generated will increase as the rate of production increases. Establishing a l-million-bbl/d industry in 10 years would cause the most disturbance per unit of production because there would not be enough time to improve the control technologies, The 100,000 -bbl/d goal is also given a low rating because the limited number of technologies tested would provide neither extensive information on impacts nor guidance for the improvement of controls and regulations. The 400,000-bbl/d target would meet the needs for information and testing of control technologies but would incur a greater environmental risk per unit of production than 200,000 bbl/d. The latter would maximize the attainment of this objective.

To maximize the integrity of the social environment.—The 100,000-bbl/d target is rated high because it should be within the physical capacities of the communities. A 200,000-bbl/d industry would strain the ability of the towns to absorb the number of expected new residents; the amount of stress would depend on the location of the development. Adjusting to the growth associated with a 400,000-bbl/d industry would be possible if the plantsites were dispersed in Utah and Colorado, if plant construction were phased, and if preparations for the construction of new towns were started at once; but boomtown effects would most probably accompany the growth. A l-million-bbl/d industry would require coordinated growth management strategies and extensive financial outlays. Severe social disruption could ensue.

To achieve an efficient and cost-effective energy supply system.—The 400,000-bbl/d target has the highest rating because it would provide a balance of information generation and of process development and demonstration. The 100,000- and 200,000-bbl/d targets are rated lower because only a few technologies and sites would be tested. The l-million-bbl/d industry is also rated low because its deployment strategy would use many of the elements of production poorly. Furthermore, the plants might not generate sufficient profit capital for subsequent expansion.

An illustration of the need for tradeoffs among objectives can be seen at the l-million-bbl/d level. This choice has high attainment of the positioning and energy production objectives (e.g., it would displace about 16 percent of the imported oil and reduce the balance of payments significantly); however, reaching the target requires tradeoffs in all the other areas (for example, it would violate the Clean Air Act).

Constraints

OTA analyzed the requirements for achieving each of the production goals by 1990, given the present state of knowledge and the current regulatory structure. The factors identified as hindering or even preventing reaching the goals are shown in table 1. The constraints judged to be "moderate" will hamper but not necessarily preclude development; those judged to be "critical" could become severe barriers. When it was inconclusive whether or to what extent certain factors would impede development, they were called "possible" constraints.

Table 1.–Constraints to Implementing Four Production Targets

	1990 production target, bbl/d			
	100,000	200,000	400,000	1 million
Possible deterring factors	Severity of impediment			
Technological				
Technological readiness ... ., ...	None	None	None	Critical
Economic and financial				
Availability of private capital ...	None	None	None	Moderate
Marketability of the shale 011 . . .	Possible	Possible	Possible	Possible
Investor participation. .	None	Possible	Possible	Possible
Institutional				
Availability of land.	None	None	Possible	Critical
Permitting procedures	None	None	Possible	Critical
Major-pipeline capacity .	None	None	None	Critical
Design and construction services	None	None	Moderate	Critical
Equipment availability	None	None	Moderate	Critical
Environmental				
Compliance with environmental regulations. .	None	None	Possible	Critical
Water availability				
Availability of surplus surface water. .	None	None	None	Possible
Adequacy of existing supply systems	None	None	Critical	Critical
Socioeconomic				
Adequacy of community facilities and services .	None	Moderate	Moderate	Critical

SOURCE Office of Technology Assessment

Issues and Policy Options

Technology

Oil shale contains a solid hydrocarbon called kerogen that when heated (retorted) yields combustible gases, shale oil, and a solid residue called spent, retorted, or processed shale. Crude shale oil can be obtained by either aboveground or in situ (in place) processing. In aboveground processing, the shale is mined and then heated in retorting vessels. In a TIS* process, a deposit is first fractured by explosives and then retorted underground. TIS is at present a primitive technology, although R&D and field tests are being conducted. MIS* is a more advanced in situ method in which a portion of the deposit is mined and the rest is shattered (rubbled) by explosives and retorted underground. The mined portion can either be retorted on the surface or discarded as waste. The crude shale oil can be burned as a boiler fuel, or it can be converted into a synthetic crude oil (syncrude) by adding hydrogen. The syncrude can also be burned as boiler fuel, or it can be converted to petrochemicals or refined like most conventional crudes. It is better as a source of jet fuel, diesel fuel, and the other heavier distillates than of gasoline. (The processing steps for an AGR system are shown in figure 4.)

*TIS = true in situ; MIS = modified in situ.

Issues

1 What are the advantages and disadvantages of different mining and processing methods?

Open pit mining allows large-scale, economical development and maximizes the recovery of the resource. Its application, however, is limited to a few areas in the Piceance basin and to several in the Uinta basin. Alterations to the surface of the land are substantial, and the stripped overburden must be disposed of along with the processing wastes. Open pit mining of oil shale has never been tested. The technique is highly developed with other minerals, however, and few technical problems are anticipated.

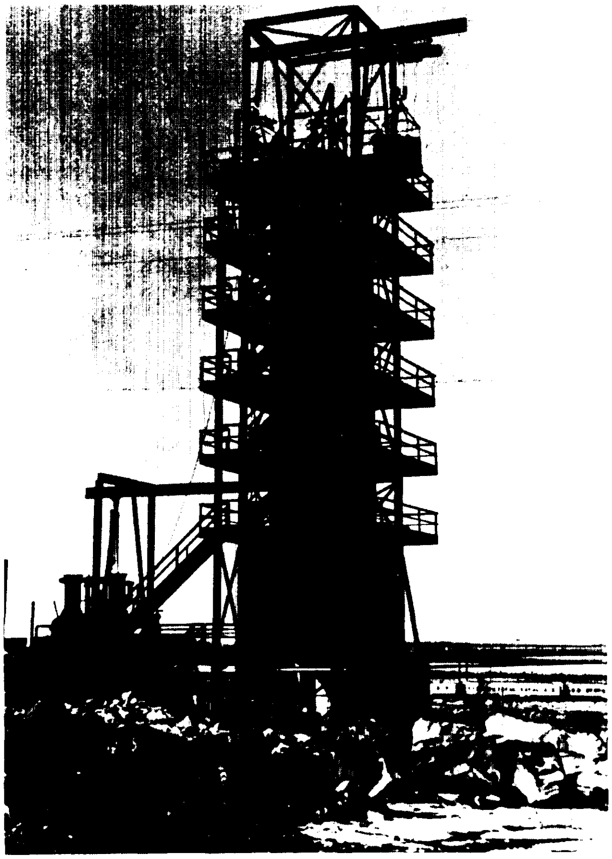


Photo credit *Departmenf of Energy*

Department of Energy's batch retort pilot test plant, Laramie, Wyo.

Underground mining, which has been tested in four mines in the Piceance basin, is more generally applicable. The Piceance mines, however, were relatively small and were located on the southern fringe. Mining conditions in other areas are considerably different. Underground mining is especially affected by the physical properties of the ore and by the presence of ground water. In general, it is more costly than open pit mining, and resource recovery is lower.

The advantages of TIS processing are that mining is not required, spent shale is not produced on the surface, and the surface facilities needed are minimal. Its principal disadvantages are that the technology is not well advanced, that it is applicable only to deposits that are not deeply buried, that oil recoveries are lower than by other methods, and that the retorted shale is left underground where it may be leached by ground water,

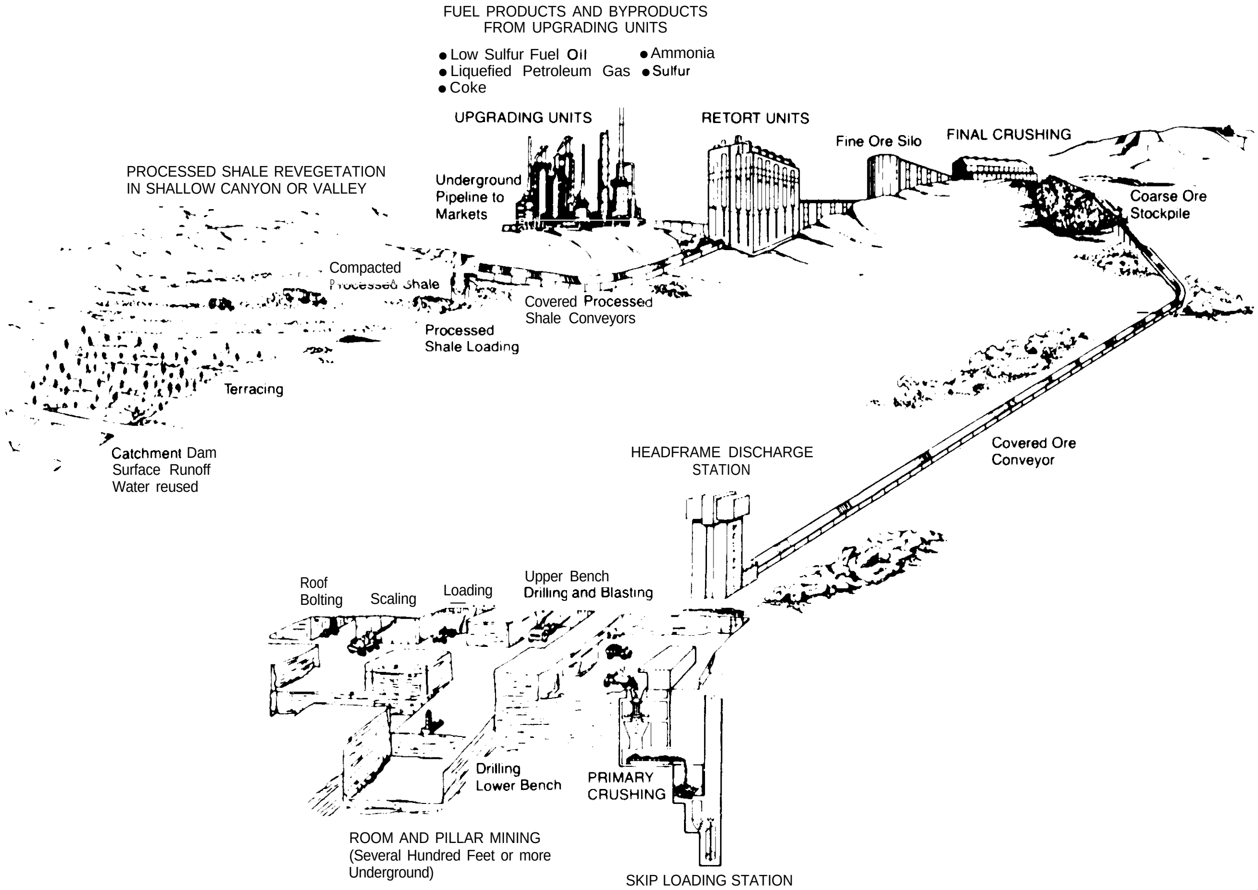
The MIS process requires mining 20 to 40 percent of the deposit to be retorted, and involves more facilities and waste disposal on the surface. More oil is recovered per ton of rock processed than with TIS, but less than with aboveground processing. Oil recovery per acre is probably higher with MIS than with a combination of underground mining and aboveground processing, but lower than with surface mining and aboveground processing. The principal advantage of above-ground processing is its high oil recovery. Its principal disadvantage is that it requires large mining and waste disposal operations and substantial surface facilities.

2 Are the technologies ready for large-scale applications?

The commercial-scale deployment of the critical retorting processes, at their present developmental stage, would entail appreciable risks of both technological and economic failure. All the components of an oil shale project must function together, which means that building a large-scale project is risky. Even though some of the other components, like the upgrading and refining processes, are highly advanced, the oil shale processes are not.

More than 30 years of R&D by governmental and private organizations has provided a basis for commercialization tests. Two above-ground retorts have been tested for several months at production rates approaching 1,000 bbl/d, about one-tenth of the size of commercial modules. Others, like the Paraho retort, have been tested at rates of a few hundred barrels per day. These experiments have produced a total of about 500,000 bbl of shale oil—the equivalent of 10 days' production from a 50,000bbl/d commercial plant. Additional testing, especially of the TIS process, is needed before a major industry can be established with a reasonable level of confidence. The MIS process is being developed on three sites in the Piceance basin, and the re-

Figure 4.—The Components of an Underground Mining and Aboveground Retorting Oil Shale Complex



SOURCE: C-b Shale Oil Project, ***Detailed*** Development ***Plan and Related Materials,*** Ashland 011, Inc., and Shell Oil Co., February 1976, p. 1.24

suits of this work should assist in determining its applicability to other areas.

3 What are the major areas of uncertainty?

The effects of shale stability and strength on mine design, on safety, and on resource recovery from underground mines are presently unclear. The effects that large inflows of ground water would have on efficiency are also not determined. Many uncertainties exist with respect to the feasibility and environmental impacts of TIS processing. The major questions about MIS concern its applicability to very rich or deeply buried shales, use of the large quantities of retort gas that are produced, and the somewhat lower oil recovery efficiencies. With AGR, the effects of scaleup on the performance and reliability of the retorts themselves and on their associated equipment (pollution controls, product recovery devices, and materials-handling equipment) are unknown.

4 What can be done to reduce the uncertainties?

TIS will require extensive evaluation, including theoretical, laboratory, and field studies, before its commercial potential can be determined. Some of the uncertain aspects of MIS and AGR processing could also be resolved with small-scale R&D programs. However, demonstration projects will be needed to accurately determine the performance, reliability, and costs of the various development systems under commercial operating conditions. At a minimum, the retorting systems could be demonstrated by the construction and operation of modular retorts—the smallest production units that would be used in a commercial operation. The module for an MIS process might be a single retort with a capacity of several hundred barrels a day, or a cluster of retorts producing several thousand. An AGR processing module might produce 10,000 bbl/d. (A commercial plant might contain five or six of these modules.) Other technologies, such as open pit mining, may necessitate a substantially larger degree of scaleup, perhaps to a full-scale commercial plant. The retorting technologies could also be demonstrated in full-scale "pioneer" plants, as proposed by Colony Development.

Policy Options

- R&D funding.—R&D programs could be conducted by Government agencies or by the private sector, with or without Federal participation. Federal programs could be implemented through the congressional budgetary process by adjusting the appropriations for DOE and other executive branch agencies, by providing additional appropriations earmarked for oil shale R&D, or by passing legislation specifically for R&D for oil shale technologies.
- Demonstration programs.—Government ownership of demonstration plants would maximize its intervention and expense, but would also provide it with the largest amount of information, This would, however, discourage independent industry programs. Funding by the private sector alone would minimize Government involvement and expense, but the developers might not be willing to invest in a timely manner and share information. Cost sharing of the projects would entail intermediate costs to the public and intermediate levels of information. Modular demonstration projects would require a smaller total capital investment than a commercial plant, but they would cost much more per barrel of oil produced. The projects could be structured in several ways.
  - —A single module on a single site would have the lowest total cost but the highest per barrel cost. The information would be useful only to the process and the site evaluated.
  - —Several modules on a single site would have higher total costs but the costs per module and per barrel would be lower. A full-scale commercial plant, incorporating several technologies, could be simulated.
  - —Single modules on several sites would have even higher costs. Unit costs would be similar to those for the single module/single site option. Several sites and processes could be evaluated.
  - —Several modules on several sites, the equivalent of a pioneer commercial industry, would be the most costly but would generate the maximum amount of information and experience.

Economics and Finances

An oil shale plant will be very costly and the oil will be expensive. Trends in world oil prices suggest that shale oil may be competitive, both now and in the foreseeable future. On the other hand, the long-term profitability of the industry could be impeded by future pricing strategies for competing fuels, by inaccuracies in the current cost estimates for constructing facilities, and by risks that regulatory problems or litigation could delay or bar a project's completion. The following discussion deals with oil shale's economic aspects and with some possible economic policies. All costs and prices are expressed in third-quarter 1979 dollars.

Issues

1 What are the economic and energy-supply benefits of oil shale development?

The output from a 400,000-bbl/d industry would approximate the petroleum requirements of the Department of Defense or would satisfy about 70 percent of the demand for liquid fuels in the Rocky Mountain States. A l-million-bbl/d industry could provide about 20 percent of the liquid fuels currently consumed in the entire Midwest, including 60 percent of the jet fuel, diesel fuel, and distillate heating oil. The amount of output would replace about 16 percent of the current imported oil requirement. At $32/bbl, this would reduce expenditures for imported oil by about $10 billion per year (about 56 percent of the balance-of-payments deficit in 1979). * The effects of this industry on world oil prices cannot be accurately predicted. For illustration, if prices were depressed by 1 percent, then expenditures for foreign oil would be reduced by an additional $900 million per year. Employment in the oil shale region would increase dramatically if an industry of any appreciable size were established.

2 What are the negative economic effects of establishing the industry?

During its construction by 1990, a l-million-bbl/d industry would cause a very small, but perceptible, increase in the national rate of inflation. In the longer term, this impact would be offset by improvements in the balance of payments. If the industry were emphasized at the expense of less costly alternatives, the long-term inflationary effects, through increased energy costs, might be greater. Inflationary impacts on the oil shale region would be significant for a 200,000-bbl/d industry, substantial for 400,000 bbl/d, and severe for 1 million bbl/d, Costs of labor and housing would be most affected.

*Posted prices of some foreign crudes currently exceed $32/bbl.

3 How much will oil shale facilities cost?

According to the current cost estimates, to complete a 50, 000-bbl/d” syncrude project by 1990 would require a capital investment of about $1.7 billion. The economic and financial requirements of the four production targets are indicated in table 2, together with their requirements for water and labor. A 1-million-bbl/d industry (approximately 20 projects) would cost about $35 billion, unless cost overruns resulted from regulatory delays, accelerated construction schedules, or attempts to build many of the projects simultaneously, Establishing this industry by 1990 could cost as much as $45 billion.

About 70 percent of the capital investment would probably come from corporate equity; the rest would be borrowed. The annual debt requirement for a l-million-bbl/d industry would constitute no more than 4 percent of annual business investment, and should not significantly strain U.S. private sector lending capabilities.

4 Is oil shale competitive?

Estimates of a breakeven price for shale oil are highly dependent on assumptions, including the real rate of return required on investment, capital costs, operating costs, annual real escalations of operating costs, productive life of the resource base, and the effective tax rate for developers. OTA's computer simulations indicate that prices of $48 and $62/bbl (in 1979 dollars) of shale oil syncrude would be required to achieve real, aftertax rates of return of 12 and 15 percent, respectively. (See table 3.)

OTA's assumptions are more conservative (less optimistic) than those of many developers who believe that syncrude breakeven price estimates are $6 to $9/bbl below those used by OTA. OTA based its analysis, however, on the most recent cost estimates for those technologies having advanced engineering designs, and the results are believed to represent accurately the present economic

Table 2.–Requirements for the Production Targets

Resource	100,000	200,000	400,000	1 million
	1990 production target, bbl/d			
	Requirements			
Institutional				
Design and construction services, % of 1978 U.S. capacity needed each year	Minimal	Minimal	12	***35***
Plant equipment, % of 1978 U.S capacity needed each year	Minimal	Minimal	6-12	15-30
Economic and financial[a]				
Loans. $ billion .,	$0.9-1.35	***$1,8-26***	***$3.6-42***	$90-135
Equity, $ billion	2,1-3,15	***4,2-59***	***8.4-98***	21.0 -31,5
Total, $ billion . .	3.0-4.5	6.0-85	12,0-140	30,0 -45.0
Annual, $ billion[b] . .	06-0.9	1.2-1,7	2.4-2,8	6.0-9.0
Water availability				
Water, acre-ft/yr[c]	***9,800-24,600***	19,600-49,200	***39,200-98,400***	100,000-250,000
Socioeconomic				
Workers ., .,	**5,600**	8,800-11,200	***17,600-22,400***	44,000-56,000
New residents requiring housing and community services ., .,	**23,000**	41,200-47,200	***82,000-95,000***	118,000-236,000

[a]Third quarter 1979 dollars
[b]Maximum annual requirements for a 5 year construction period
[c]Assumes 4 9001012 300 acre ft/yr for production of 50 000 bbl/d of shale 011 syncrude
[d]Assumes 1200 Construction workers and 1600 operators per 50 000-bbl/d plant Multipliers used for total increase = 25 x (construction workers) + 55 x (operators) Ranges reflect adjustments In construction work forces assuming phasing of plant construction

SOURCE Office of Technology Assessment

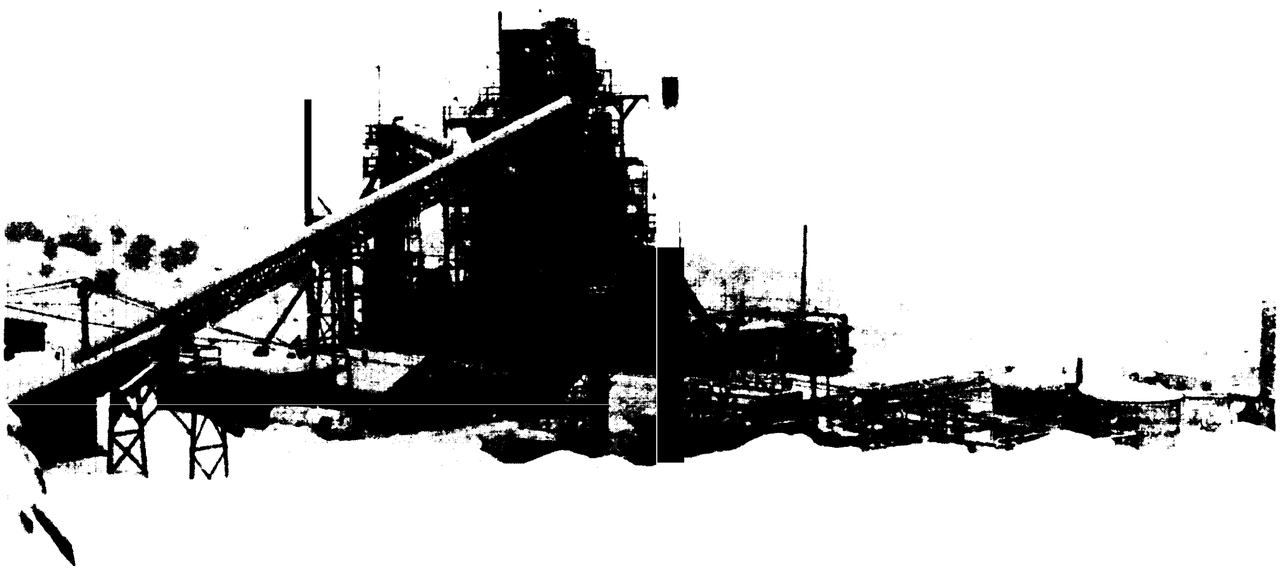


Photo credit OTA staff

Oil shale retort plant at Anvil Points, Colo.

Table 3.–Subsidy Effect and Not Cost to the Government of Possible Oil Shale Incentives[a]

(12-percent rate of return on invested capital)

Incentive	Total expected profit ($ million)	Change in expected profit ($ million)	Probability of loss	Total expected cost to Government ($ million)	Breakeven price ($/bbl)
Construction grant (50%)	$707	$487	0.00	$494	$3400
Construction grant (33%)	542	321	0.00	327	38.70
Low-interest loan (70%)	497	277	0.00	453	43.40
Production tax credit ($3)	414	194	0.01	252	42.60
Price support ($55)	363	142	0,01	172	NA
Increased depletion allowance (27%)	360	140	0.05	197	45,70
Increased investment tax credit (20%)	299	79	0.05	87	45.80
Accelerated depreciation (5 years) ., ...	296	76	0.05	79	46.00
Purchase agreement ($55) . . .	231	11	0.03	0	NA
None . .	220	0	0.09	0	48.20

(15-percent rate of return on invested capital)

Incentive	Total expected profit ($ million)	Change in expected profit ($ million)	Probability of loss	Total expected cost to Government ($ million)	Breakeven price ($/bbl)
Construction grant (50%) ., ., .,	$281	$477	0.00	$494	$40.60
Construction grant (33%)	119	315	0.19	327	47,70
Low-interest loan (70%) .,	81	277	0.23	453	54.70
Production tax credit ($3) ., .,	-61	135	0.63	252	56.10
Price support ($55) ., ., ., ., ., : :	-88	108	0.77	172	NA
Increased depletion allowance (27%) ., . .	-110	86	0.75	197	57.20
Increased investment tax credit (20%) ... .,	-131	65	0.77	87	58.80
Accelerated depreciation (5 years) .,	-127	69	0.76	79	58.90
Purchase agreement ($55) ., ., ., ., ., .,	-150	46	0.92	0	NA
None ., ., ., ., ., ..., .,	-196	0	0.93	0	61.70

[a] The calculations assume a $35/bbl price for conventional premium crude that escalates at a real rate of 3 percent per year Thus, the predicted $48/bbl breakeven price for the f 2-percent discount rate will be reached in t 1 years, or In the fifth year of production Therefore, m narrow economic terms, 011 shale plants starting construction now which assume a 12-percent discount rate will be profitable over the life of the project without subsidy (See discussion especially ch 6. for caveats concerning this Conclusion) The calculations are for a 50 000-bbl/d plant costing $1 7 billion All monetary values are in 1979 dollars

SOURCE Resource Planning Associates Inc Washington D C

position of shale oil. If OTA's cost estimates proved correct and a 12-percent rate of return were sufficient to attract industry investment, Government incentives might not be required to foster shale oil development. Similarly, if OTA has overestimated the costs and required rate of return, this conclusion would still hold. On the other hand, if the uncertainties discussed below should come to pass and/or a rate of return higher than 12 percent is required to attract capital, subsidies or other public policy actions would be required to encourage development.

Several uncertainties bear on forecasts of competitiveness. Although OTA's analysis attempted to capture them, the following ones cannot be completely incorporated in a quantitative analysis:

- Unreliable cost estimates.—There are no cost data for commercial-size plants because none have been built. Cost estimates for projects have traditionally been unstable, rising by more than 400 percent between 1973 and 1978. The current range of estimates, based on preliminary engineering designs and experience with other industries, is believed to be more accurate, although the possibility of significant errors remains,
- Regulatory disincentives.— Projects may be delayed or precluded by procedures for obtaining permits, by siting or process changes necessitated by regulations or litigation, or by future regulations that cannot be met economically. Unexpected delays would contribute to cost overruns.

- Uncertain future world oil prices.—Present prices are high, and rising. There is a possibility, however, that future price changes may be less significant than commonly forecast, or that they could be sufficiently unstable to add appreciably to the risks of oil shale development.
- Cost overruns because of competition with other projects.—Individual projects could be completed in 5 to 7 years (10 years if preliminary demonstration tests were conducted for the technologies). A 400,000-bbl/d industry could probably be put in place by 1990 without severe cost overruns if the various plants' construction were coordinated and phased. However, the 20 or so projects needed for 1 million bbl/d by 1990 would face delays and cost overruns because of the large demands for equipment, labor, and construction services.

These uncertainties make any forecast of breakeven prices unreliable. At the same time, they may induce developers to seek higher rates of return for their shale investments. For example, a 15-percent real rate of return, which would be substantially greater than that required for more conventional investments, would increase the price of shale oil syncrude by $14/bbl (to about $62/bbl) and thus would make it noncompetitive, without subsidy, with the forecast prices of foreign oil.

The rate of return issue.—In addition to the interactions between the uncertainties and required rate of return, there is another important interrelationship. It pertains to the flow of private capital given the rates of return for potential alternative investments. There has been much confusion over why the estimated costs of shale oil always have been higher than the actual costs of conventional oil, even after the sustained high price rises of the 1970's. As discussed above (and in ch. 6), the effects of both increasingly detailed engineering cost estimates and of inflation on construction and capital equipment costs have contributed significantly to the rising estimates of the cost for a barrel of shale oil.

Alternative investment possibilities also critically affect shale oil's competitiveness. Shale oil is tied to conventional oil in two ways. First, it is a substitute in the marketplace, and therefore must be price competitive. Second, the companies that are potential oil shale developers are the same ones that produce or refine petroleum, or are potential developers of other synthetic fuels. The profitability of shale oil must be "competitive" in the sense of selling at a price that competes with conventional oil while permitting a reasonable rate of return. A company with a finite amount of capital is most likely to invest in those projects that offer the highest rate of return at a given level of risk.

Price increases over the past 7 years have dramatically increased the profitability of both domestic and foreign petroleum development. As a consequence, companies may choose to invest in petroleum so long as it has a similar rate of return and does not entail the extensive uncertainties of oil shale. It follows that public policies to encourage oil shale development must address making its risks and rates of return comparable to those of petroleum.

Oil shale investments at 12- or 15-percent rates of return are not likely to displace investments that have lower costs, lower risks, and higher rates of return, even if shale oil has a competitive price. The incentives summarized in this chapter and discussed in detail in chapter 6 primarily address making shale oil price competitive. They will not necessarily assure that it will compete successfully with alternative investments. Fewer opportunities in the future for investment in conventional petroleum projects will tend to increase interest in oil shale investments. These considerations of price, cost, and rate of return also apply to other synthetic and alternate energy industries. To the extent that subsidies or other policy actions encourage shale development alone, these other energy investment alternatives are put at at relative disadvantage.

5 Which incentives would be most effective?

OTA analyzed 10 possible incentives on the basis of 6 economic and financial criteria. (See table 4.) Price supports, purchase agreements, and production tax credits appear to have the most overall economic merit. Debt guarantees or low-interest loans, however, will probably be necessary to encourage the participation of smaller firms. All incentives programs would have to be properly administered to be effective, and should be removed when no longer needed.

6 What would incentives programs cost?

The total net cost of subsidizing a 50,000-bbl/d plant with one of the more effective subsidies could range from $200 million to $400 million. (See table 3.) This cost would be spread over about 22 years, and would range from $0.60 to $1.40/bbl of oil produced. It is determined by:

- the size and timing of the outflows from the Treasury,
- the size and timing of the increased taxes paid by the developers, and
- the discount rate assumed for Government expenditures. *

It is not necessarily true that the least costly incentive would be the best choice. Firms with different corporate circumstances will prefer different incentives because they must avert different risks. It would be cost effective to offer a choice of incentives (e.g., grants and low-interest loans to smaller firms, tax credits to larger firms with bigger tax liabilities) to encourage participation by a variety of firms.

7 What other economic factors could affect the establishment of an industry?

Attempts to establish a large industry quickly could be impeded by the capacity of existing major pipeline systems leading to Midwest markets and by shortages in design and construction services and plant equipment. These factors should not be major problems for industries of up to 400,000 bbl/d.

*The Office of Management and Budget uses a discount rate of 10 percent per year to compare the cost effectiveness of Government programs.

Policy Options for Financial Support

Financial support could be provided either by incentives to private industry or by direct Government ownership or participation.

Incentives to private industry .—Incentive programs could be structured for a high level of risk reduction with relatively small net costs and administrative burdens. The proper incentives would share the risks associated with creating the projects, but would leave some of the managerial risks intact. This would help establish the industry but would allow market risks and opportunities to govern its development.

A possible disadvantage of incentives would be that the Government could not directly control the pace of the industry's growth unless extensive encouragement were provided. On the other hand, direct Government control is likely to discourage participation by private firms and could incur the risk of managerial inefficiency. Also, with reliance on incentives, the Government would not have direct access to the types of technical and economic information that might be needed to structure future oil shale policies. * Incentives legislation could include requirements for disclosure of proprietary information and for specific test programs, but such requirements would discourage industrial participation. Information could also be obtained through licensing arrangements with the owners of the technologies.

Direct Government participation or ownership. —A Government-owned industry might be desirable in a crisis situation. OTA did not analyze this option in detail because of its extremely high cost to the public. The

*In its May 27, 1980, oil shale policy announcement, DOI indicated it would seek Memoranda of Understanding and other formal documents to expand its ability to obtain performance information.

Table 4.–Evaluation of Potential Financial Incentives for Oil Shale Development

	Effect of incentive on program objectives			Extent to which incentive meets policy guidelines			
						Promotion of competition	
Incentive	Subsidy effect	Risk-sharing effect	Financing effect	Promotion of economic efficiency	Minimization of administrative burden	Effect on firms	Firm preferences
1. Production tax credit ($3/bbl)	Strong, subsidizes product price	Moderate, shares risk associated with price uncertainty (if tax credit varies with product price)	Slight, Improves project economics	Slight adverse effect, distorts product price	Minimal administrative burden	Benefits firms with large tax liability and strong financial capability	Supported by relatively large firms,
2. Investment tax credit (additional 10%)	Strong, subsidizes Investment cost	Moderate; shares risk associated with Investment cost uncertainty	Slight; improves project economics	Moderate adverse effect; distorts input costs, favors capital-lntenswe technologies	Minimal administrative burden	Benefits firms with large tax liability and strong financial capability	Supported very strongly by most firms; however, firms that would not be able to use the investment tax credit do not favor its enactment
3. Price supper	Strong; subsidizes product price (if contract price is higher than market price)	Moderate: shares risk associated with price uncertainty	Moderate; improves borrowing capability	Slight adverse effect, distorts product price	Moderate administrative burden	Benefits all firms except those with very weak financial capability	Moderately supported by a wide range of firms
4. Loan guarantee	Slight; subsidizes Investment cost	Moderate; shares risk of project failure	Strong: improves borrowing capability	Slight adverse effect; distorts input costs: favors capital-intensive technologies	Moderate administrative burden	Benefits firms with weak financial capability	Supported by firms with limited debt capacity
5. Subsidized interest loan (70% debt at 3% below market rate)	Slight; subsidizes investment cost	Moderate; shares risk of project failure	Strong; Government provides capital	Slight adverse effect; distorts input costs; favors capital-lntenswe technologies	Moderate administrative burden	Benefits firms with weak financial capability	Supported by firms with limited debt capacity
6. Purchase agreements	Strong; but less than price supports	Strong; shares risk of price uncertainty	Moderate; improves borrowing capability	Slight adverse effect; distorts product price	Moderate (normally more than price supports)	Benefits all firms but those with very weak financial capability	Moderate, but less than for price supports
7 Block grant (33 & 50% of plant cost)	Strong; neutral subsidy	None	Strong; Government provides capital	No adverse effect	Moderate administrative burden	Benefits all firms	Supported by firms in widely varying financial circumstances
8 Government participation	Slight	Strong, shares all project risks	Moderate; reduces firm's capital requirement	No adverse effect on firm decisions; however, active Government involvement may lead to inefficiency	Major adminstrative burden	Benefits firms that are very averse to risk (e. g., smaller, less well-financed firms)	Little support
9 Accelerated depredation (5 years)	Moderate: subsidizes investment cost; maximum subsidy effect is limited by Federal corporate income tax rate and interaction with the depletion allowance	Moderate; shares risk associated with Investment cost uncertainty	Slight; Improves project economics	Moderate adverse effect, distorts input costs, favors capital-intensive technologies	Minimal administrative burden	Benefits firms with large tax liabilities and strong financial capability	Supported by large, Integrated 011 companies
10. Percentage depletion allowance (27%)	Moderate: subsidizes product price; value of subsidy increases as the need for the subsidy decreases	None; Increases risk associated with price uncertainty	Slight; improves project economics	Moderate adverse effect, distorts product price in a variable and undesirable manner	Minimal administrative burden	Benefits firms with large tax liabilities and strong financial capability	Not supported

SOURCE Resource Planning Associates Inc

remaining option is Federal participation in demonstration programs for the purpose of obtaining and disseminating information. This could provide a better assessment of the public's oil shale resources, allow for the participation of firms lacking oil shale land or proprietary technologies, permit the thorough testing of environmental controls, and facilitate regulation of the industry. *

The Government could become a part owner of the project by sharing the capital and operating costs with industry. The consequences would be similar to those resulting from the construction grant option, except that the Government would share all of the risks and benefits. Almost without exception, potential developers believe that active Government participation would increase managerial complexity and inefficiency. Administrative burdens would be high.

The Government could also contract for the construction of several modular plants it would then operate, either alone or through contracts. It would then be in a position to obtain information on technical feasibility, project economics, and the relative merits of different processes. This might be of assistance in evaluating future policies towards oil shale development, in disseminating technical information, and in improving understanding of the value of publicly owned oil shale resources. The facility could later be scrapped or sold to a private operator. This option would provide the Government with information and experience. The cost, however, would be much higher than that of incentives to private developers.

Considering that the technologies to be tested are proprietary, it is by no means clear that the Government would have the legal right to publish all this information. In addition, its experience in designing, financing, managing, and obtaining permits for an oil shale plant may not resemble that of private industry. Thus, the information acquired might be of little use to subsequent private developers. Environmental information gathered in this way would not entail such problems. Furthermore, most of the information secured through Government ownership could be made available as a condition of granting private financial incentives.

Government intervention is likely to discourage private developers from undertaking their own modular development and R&D initiatives, because programs of this kind tend to reduce the benefits that a particular firm could obtain from its own R&D or modular testing. Finally, the patenting and licensing of technologies make definite provision for dissemination of technical information on both gratis and fee terms to possible users of the processes.

Policy Options for Services, Equipment, and Pipelines

Training programs could alleviate the shortage of design and construction personnel, whose skills could be used later in the operating facility. Developers normally try to avoid equipment shortages by identifying items with long delivery times and ordering them early. Developers who coordinated efforts to standardize equipment could reduce their problems with specially fabricated items. However, such coordination could be impeded by developers' unwillingness to share their process information and by antitrust laws. The Government could reduce or eliminate tariffs and quotas on imported equipment. Domestic suppliers would resist this action. Shortages in pipeline capacity could be reduced only by building more pipelines. The Government could provide aid by expediting the review and approval of the numerous permit applications that would be required.

Resource Acquisition

The oil shale resources are owned by the Federal and State governments, by Indian tribes, and by private firms. (See figure 5.) Overall, the Government owns about 70 percent of the land surface, which overlies about 80 percent of the resources. About 20,000

*Various types of demonstration programs are discussed in the section on technological policies.

acres (less than 1 percent) of the Federal land has been leased to private firms. It may be necessary to involve more Federal land in order to test certain technologies, or to establish a large industry rapidly.

Issues

1 Could the private land support 1arge-scale development?

The private lands are extensive, but it is unlikely that a large industry will be sited on them until the processing technologies have been proven to be economic. As shown in figure 6, the private lands in the Piceance basin generally lie along the southern fringe where the deposits are comparatively thin and lean, and are sometimes mixed with layers of barren rock. Development would be more costly than on the Federal land to the north, where the deposits are more than 1,000 ft thick and yield more oil per ton. In addition, the privately owned resources contain no large deposits of sodium minerals and they are, in general, too deeply buried for economical open pit mining. The large sodium mineral deposits and the shallow oil shale beds are on Federal land.

There are some tracts, Colony and Union, for example, that contain commercially attractive rich deposits. These firms have been developing retorting technologies for about 20 years, and projects with a total capacity of about 150,000 bbl/d have been proposed for their tracts. These projects have been suspended, however, pending a more favorable economic and regulatory climate. The tracts owned by Getty, Standard Oil of California, and others contain resources of comparable quality, but no projects have been announced for any of these private lands. In part, this reflects the technological positions of the landowners who do not own advanced retorting technologies. They may plan to license the processes of the other companies, once these have been demonstrated.

2 What production is expected from the Federal lease tracts?

Production from the two Federal Prototype Program lease tracts that are presently active could reach 133,000 bbl/d by 1987. However, only the lessees of Colorado tract C-b are committed to commercial-scale production (57,000 bbl/d). Four other leases were offered in 1973, but those in Wyoming were not sold and those in Utah are suspended until the Supreme Court decides who owns the land. * The potential production from the Utah tracts (100,000 bbl/d) is not assured.

3 What other projects have been proposed or are presently active?

Tosco is proceeding at a slow pace in response to the diligence requirements of a State lease in Utah. Geokinetics, Inc., and Equity Oil are conducting small-scale R&D projects under cost-sharing arrangements with DOE. Occidental Oil Shale is conducting large-scale tests of its MIS process under a similar arrangement. Paraho Development is attempting to extend its lease for DOE's research facility at Anvil Points, Colo., and to obtain funding for a modular demonstration program. Superior Oil Co. has proposed a land exchange to develop a multimineral process in Colorado, and EXXON Corp. has proposed to exchange its scattered holdings for a single tract of Federal land in the Piceance basin.** DOE and the Department of Defense are preparing a plan to develop Naval Oil Shale Reserve (NOSR) 1, near the Anvil Points site. If the current R&D is successful, if the land exchanges are consummated, and if favorable economic conditions exist, the total production from these projects could exceed 250,000 bbl/d.

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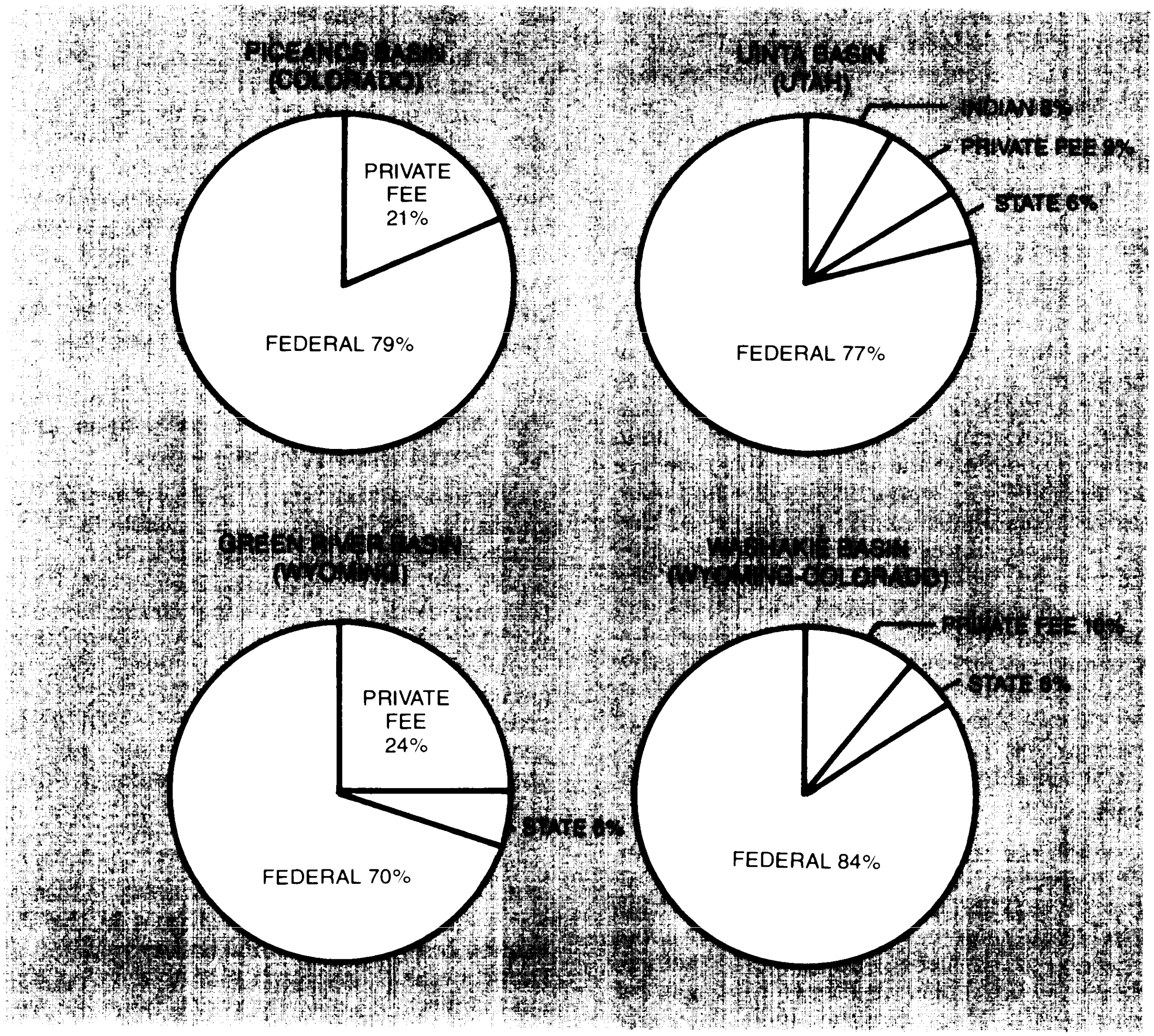
*On May 19, 1980, the U.S. Supreme Court reversed the lower court decisions and held that the Secretary of the Interior could reject Utah's applications for oil shale lands (*Andrus* v. Utah, No. 78-1522).

**The Bureau of Land Management recently denied Superior's initial proposal. Negotiations are continuing.

Figure 5.—Ownership of the Oil Shale Lands of the Green River Formation



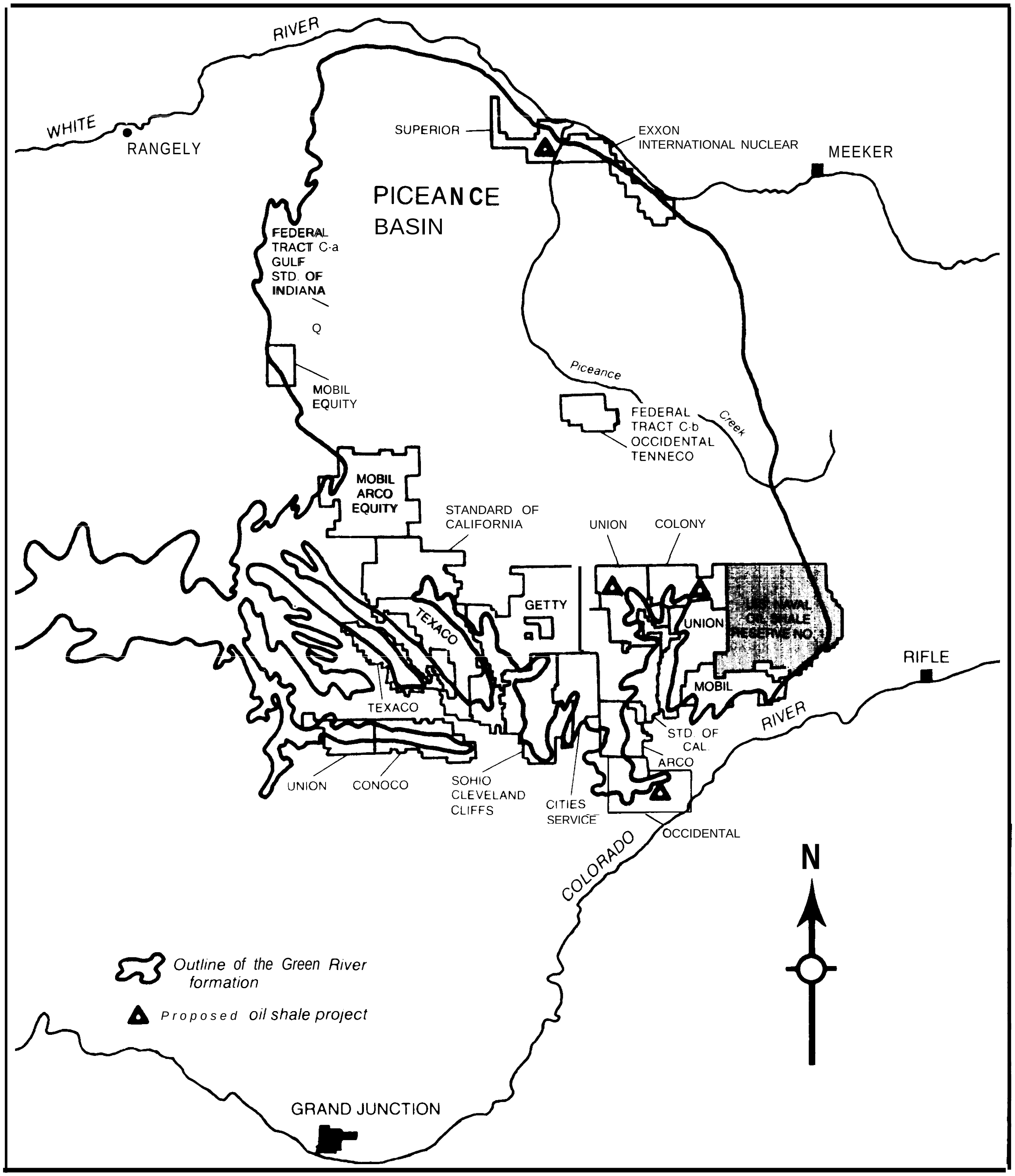
SOURCE *Map of the Major Oil Shale Ho/dregs—Colorado, Wyoming, Utah,* Denver, Colo Cameron Engineers, Inc , January 1978

4 Will more Federal land be needed to initiate an oil shale industry?

The need for more land will depend on whether a large industry is to be created rapidly, on the prevailing prices for imported oil, on whether financial incentives are provided, and on whether specific processing technologies are to be tested. Different amounts of shale oil that might result from various Government actions are indicated in table 5. An industry producing at least 60,000 bbl/d could emerge without additional Federal actions. A 360,000-bbl/d industry might result if incentives were provided to encourage Colony and Union to resume their projects. * An industry

*The incentives would have to be carefully structured to achieve this result. See the section on economic and financial policies for a discussion of incentives programs.

Figure 6.— Privately Owned Tracts in the Piceance basin



SOURCE *Map of the Major Oil Shale Holdings-Colorado, Wyoming, Utah*, Denver, Colo Cameron Engineers, Inc , January 1978

P h P V C

b 5 E m d Sh O P d b 990 R p V d A

Federal action	Case 1	2	3	4	5	6	7	8
None	x							
Incentives for first-generation developers[a]		x	x	x	x	x		
Testsites for modular retorts[b]			x	x	x	x	x	x
Resolution of ownership issues on Utah tracts[c]				x	x	x	x	x
Offtract land use[d]					x	x	x	x
Proposed land exchanges						x	x	x
Incentives for second-generation developers (or Improved economics)							x	x
Naval 011 Shale Reserves or expanded Prototype Program or permanent leasing								x
Production, bbl/d	60,000-[f]185,000	360,000	390,000	490,000	560,000	620,000	850,000	1,000,000

[a]Assumes the entry of one as yet unannounced developer
[b]Includes the proposed Superior Oil land exchange and a leasing of Anvil Points by Paraho Development A 30 000-bbl/d production increment Irom Government-sponsored modular lest retorts could occur at any point in the first 400000 bbl/d of production
[c]Resumption of the tract U-a/ U-b project may also depend on the availability of incentives and on other Improvements in project economics
[d]For waste disposal from the open pit mine that was originally proPosed for tract C a
[e]Includes the proposed Superior 011 and EXXON land exchanges
[f]Only 57000 bbl/d is firmly committed

SOURCE Office of Technology Assessment

approaching 400,000 bbl/d could be realized if incentives were provided and small tracts of Federal land were available for retort test programs. A multimineral lease or land exchange (such as proposed by Superior) and continuation of the Paraho lease at Anvil Points are alternatives. If the Utah lease tracts resume development, a production of 500,000 bbl/d might be possible. If the tract C-a lessees returned to the original open pit mining concept, production could reach 560,000 bbl/d. (This would require permission to site processing facilities and to dispose of the solid wastes outside of the tract boundaries.) Adding the EXXON land exchange might increase production to 620,000 bbl/d. Unless economic conditions became very favorable, a much stronger set of incentives would be needed to spur development of the "second generation" tracts—those near the fringe of the Piceance basin. All of these conditions, plus additional leasing or development of the NOSR in Colorado, would be required to reach 1 million bbl/d by 1990.

5 What are the options for making Federal land available?*

The major options are governmental development of the NOSRs, leasing, and land exchange, Leasing is allowed under the Mineral Leasing Act of 1920, as amended. The Prototype Program was structured under this Act. Land exchanges such as those proposed by Superior and EXXON are authorized by the Federal Land Policy and Management Act of 1976 (FLPMA).

6 What are their advantages and disadvantages?

The NOSRs contain poorer quality oil shale than the Federal holdings in the central Piceance basin. NOSR 1 in Colorado, however, is large enough to support production of 200,000 bbl/d for at least 20 years. One drawback is that this reserve is located near the private lands that may be developed, and environmental and socioeconomic effects would be concentrated if it were developed concurrently. Any program for developing the reserves (whether by a Government-owned corporation, leasing, or cooperative agreement with industry) could be structured to yield valuable information, but would also add a level of administrative overhead,

Leasing has several advantages. Informational requirements and environmental stipulations can be included in the lease provisions, and the pace of development can be controlled (e.g., specifying preconstruction monitoring periods, providing favorable royalty arrangements, and including diligence requirements). Under the Mineral Leasing Act, as amended, a portion of the leasing proceeds would be returned to the affected State and could be used to mitigate the socioeconomic impacts accompanying development. A major long-term advantage would be that the Government would continue to own the land.

Additional leasing at this time also has disadvantages. It could increase environmental and socioeconomic impacts by encouraging development before these impacts are fully understood and strategies for their mitigation in place. Delaying leasing, however, while information is collected could lead to better design of a future leasing program. Furthermore, it can be argued that new leasing is unwarranted now since existing projects theoretically could yield about 400,000 bbl/d, which is sufficient to test a variety of technologies at commercial scale.

Land exchanges could improve resource management by allowing consolidation of tracts that are presently too small, or too unfavorably situated, for economical development. Under FLPMA, however, environmental stipulations, informational requirements, and developer participation in socioeconomic

*On May 27, 1980, DOI announced it will lease up to four new tracts under the Prototype Program and will begin preparations for a new permanent leasing effort. Also announced was the decision not to give special emphasis to the execution of exchanges.

impact mitigation programs could not be made conditions of any exchange.

Either lease tracts or land exchange parcels could be selected to avoid ecologically sensitive areas and to disperse socioeconomic effects.

7 What are the difficulties with leasing and land exchange?

All actions involving Federal land in the oil shale region may be affected by the unpatented mining claims that overlie most of the Federal holdings. * The claims have been a source of legal controversy since the 1920's. If they are validated by the courts, the Government could lose control of much of the oil shale land, including tracts potentially available for leasing or land exchange.

Some provisions of the Mineral Leasing Act also may inhibit industry's response to lease offerings. These provisions limit the number of leases to one per person or firm and restrict the size of a lease tract to a maximum of 5,120 acres.**

If a firm wishes to exchange its holdings for a Federal tract, the values of the lands must be within 25 percent of one another. Given the lower quality of the private oil shale lands, such equivalent values may be difficult to achieve. In addition, the evaluation and review procedures for exchanges so far have been time consuming. (The Superior proposal has been in the review stage since 1973.) The experiences of Superior and Colony were the first attempts to use, for oil shale lands, the exchange authority under FLPMA. Colony did not immediately request expedited treatment. Inadequate information in Superior's initial request may have been partly responsible for the delay in evaluating its request.

*On June 2, 1980, the U.S. Supreme Court ruled in favor of two groups of unpatented claimholders in Colorado. It is too early to determine the effects of this action on other unpatented claims. Andrus v. *Shell Oil* Co. (No. 78-1815, June 2, 1980).

**In its May 27, 1980, decision paper, DOI stated that " would seek legislation to remove the statutory acreage limitations on lease size, and to permit holding a maximum of four leases nationwide and two per State.

Policy Options

- Amend the Mineral Leasing Act of **1920.** —The Act could be amended to increase the acreage limitations, or to set the size of the tract according to the recoverable resources it contained. This might allow more economies of scale, thereby improving economic feasibility. It might also allow the inclusion of a suitable waste disposal site within a tract's boundaries, thus avoiding the need for separate offtract disposal while still providing adequate shale resources for sustained, large-scale operations. The number of leases per person or firm could also be increased. This might encourage firms that do not own oil shale lands because it would allow them to apply experience obtained on one lease tract to another while the first was still operating. However, the number participating in the leasing program could be reduced if a few firms acquired all of the leases. One possibility would be to increase the number but limit it to one lease per State. This might encourage a firm to develop a process in the richer deposits in Colorado and then apply it to the poorer quality resources in Utah or Wyoming.
- Amend FLPMA.—FLPMA could be amended to allow the inclusion of conditions (such as environmental stipulations and diligence requirements) in oil shale land exchange agreements. This would improve the Government's control over the exchanged parcel, but could discourage private participation.
- Allow offsite land use for lease tracts. —Legislation could be passed to allow a lessee to use land outside of the boundaries of a lease tract for facility siting and waste disposal. * This might permit larger, more economical operations (including perhaps an open pit mine) and would maximize resource recovery on the tract, but could inhibit subsequent development of the offtract areas.

*DOI indicated in its May 1980 announcement that it would propose such a legislative change.

- Lease additional tracts under the Prototype Program.—There is no statutory limitation on the number of tracts that could be leased under the Prototype Program. However, DOI originally committed to leasing no more than six. Because two of the original tracts were not leased, offering two new ones might be justified, provided that the technologies to be tested were different from the processes being developed on the existing tracts. (One of the primary goals of the Prototype Program is to obtain information about a variety of technologies.) Leasing more than two more tracts, or leasing for the purpose of expanding near-term shale oil production, would be opposed by critics of rapid oil shale development. Leasing could begin sooner than under a new leasing program, if some of the potential lease tracts previously nominated were offered. A supplemental environmental impact statement (EIS) would be required. Construction on the tracts could probably not begin until 1985 and production no sooner than 1990.
- Lease only for testing of multimineral extraction. *—Multimineral extraction, wherein shale oil is obtained along with other commercially valuable minerals such as nahcolite and dawsonite, has been receiving increased attention. Potential developers argue that obtaining the associated minerals would substantially increase the profitability of the venture, The only suitable land for multimineral experimentation is federally owned.
- Initiate a new, permanent leasing program.—An advantage would be that more production than is possible under the present Prototype Program could be achieved. A full EIS and a new set of leasing regulations would be needed. Without the information to be acquired by completing the present Prototype Program projects, it might be difficult to prepare an accurate environmental assessment and to structure comprehensive leasing regulations. Production could probably not begin until after 1990. Abandonment of the Prototype Program would be implied, which might engender opposition.
- Expedite land exchanges.—No regulations governing land exchanges have been promulgated under FLPMA. Standardized and objective procedures could significantly expedite the process. The review and approval procedures could also be improved by, for example, setting up a task force within DOI specifically for oil shale proposals,
- Government development.—The Government could develop the NOSRs. Unless this were done by leasing to private developers, it would involve competition with private industry, and would encounter political opposition. It would also be costly; the public would have to pay the full cost of the facilities, and that might discourage independent experiments by private firms. The option would be helpful in obtaining information for developing policies and regulations for the industry, but the information might not be useful to private developers when evaluating their investment alternatives. This is because of the discrepancy between Government and private developers' experience in financing and operating facilities. Some of the information is being acquired in the present Prototype Program. It could also be obtained in additional leasing programs or through licensing arrangements with the owners of the technologies.
- Continuation of present policies.—Continuation of present policies concerning offsite disposal, lease limitations, and land exchange procedures (without additional leasing) would help protect the social and physical environments. It would preclude commercial development beyond that presently envisioned on the four lease tracts and the three to five private holdings that could support commercial operations. By limiting future leasing and land exchanges, shale oil production could not exceed 300,000 to 400,000 bbl/d and the adverse impacts of a larger industry would be

*DOI will offer at least one multimineral tract in its renewed Prototype Program.

avoided. The gathering and evaluation of information would enhance understanding of the environmental consequences of development prior to further commercialization, and the pace would provide leadtime for the communities to prepare for growth. Given the long period needed to construct facilities, however, this option would restrict the contribution shale oil could make in the near term to the Nation's liquid fuel supply. The option also would tend to discourage further corporate interest and could delay the testing of a variety of technologies,

Environment

Oil shale facilities, like other mineral operations, will emit pollutants and produce large amounts of solid wastes. The severity of the environmental impacts will depend on the scale and duration of the operations, on the kinds of development technologies used, and on the efficiency of the control strategies. The plants must be designed and operated in compliance with environmental laws. The developers plan to achieve compliance largely through use of control technologies applied successfully in other industries. There appears to be little reason to believe that the proposed controls cannot be made to work, but they have not yet been tested for extended 'periods with the wastes produced during oil shale processing

Issues

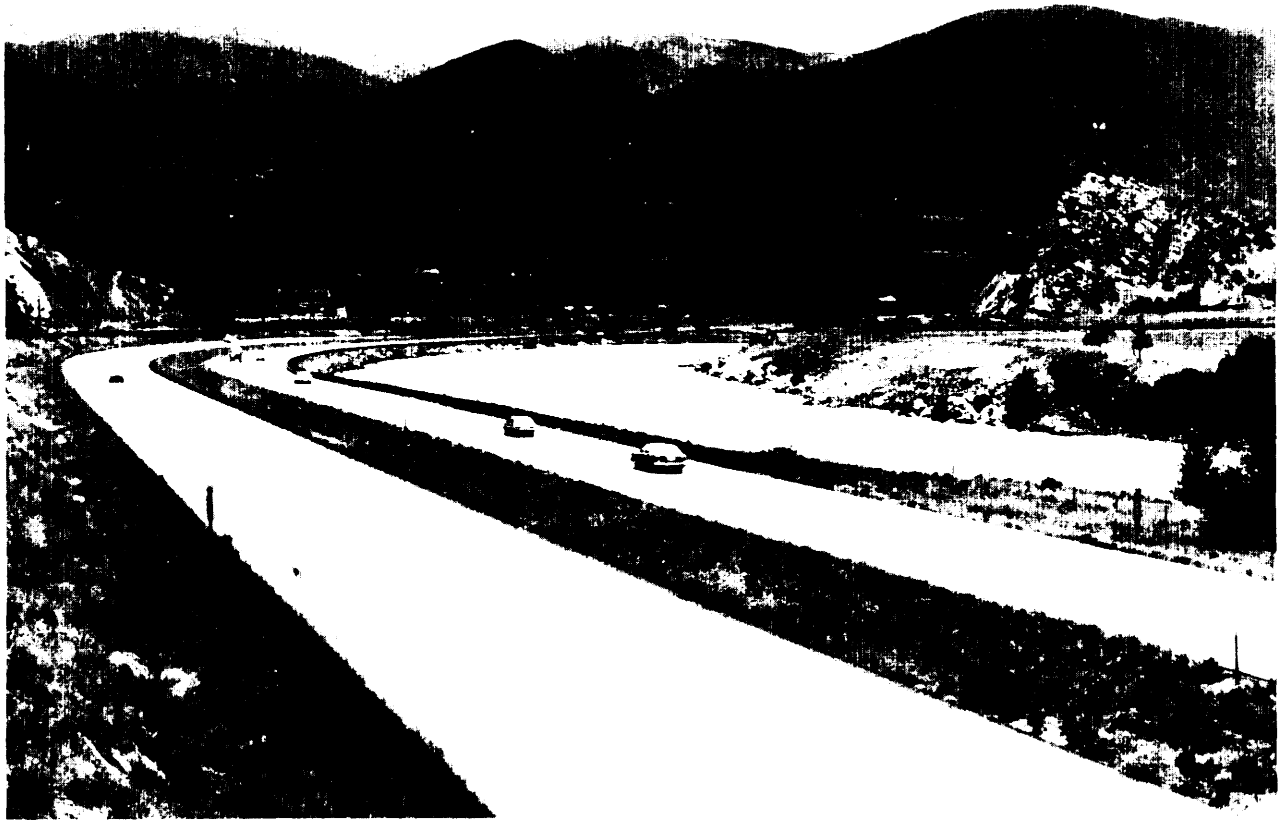
1 How will oil shale development affect the environment?

The air in the oil shale region is relatively unpolluted and, even if the best available control technologies are used, a large industry will affect visibility and air quality not only near the facilities but also in nearby parks and wilderness areas. These impacts will be regulated under the Clean Air Act.

Water quality is a major concern in the region. Oil shale operations could pollute the water by accidental leaks and spills, by point-source wastewater discharges, and by nonpoint discharges, such as runoff and leaching of waste disposal areas and ground water leaching of in situ retorts. Unless the pollution is properly controlled, aquatic biota and water for irrigation, recreation, and drinking could be adversely affected. Point-source discharges are well regulated under the Clean Water Act; developers plan to discharge no processing wastewater to surface streams, although they may discharge ground water during the early stages of development. Standards for injecting wastewaters into ground water aquifers are being promulgated under the Safe Drinking Water Act; developers do not plan to inject any wastewaters, but may reinject the ground water extracted during mining. Most of the wastewaters will be treated for reuse within the facility. Untreatable wastes will be sent to solid-waste disposal areas. As mentioned, these areas have the potential for nonpoint discharges that are neither well understood nor well regulated at present, although a framework for their regulation has been established under the Clean Water Act and the Resource Conservation and Recovery Act.

The extent to which development will affect the land will be determined by the location of the tract; the scale, type, and combination of processing technologies used; and the duration of the operations. Land conditions (largely topographic changes from mining and waste disposal) and wildlife will be affected. The facilities must comply with the State laws that govern land reclamation and waste disposal, which in some ways are less stringent than the Federal laws governing reclamation of land disturbed by coal mining. Appropriate methods must be used to prevent the large quantities of solid wastes from polluting the air with fugitive dust and the water with runoff and leachates.

Many of the occupational safety and health hazards will be similar to those of hard-rock mining, mineral processing, and the refining of conventional petroleum. Workers might, however, be exposed to unique hazards be-



Phofo credit OTA staff

Colorado River flowing along Interstate 70

cause of the physical and chemical characteristics of the shale and its derivatives, the types of development technologies employed, and the scale of the operations. To protect workers from these hazards, the developers will have to comply with the Occupational Safety and Health Act and the Mine Safety and Health Act. Specific practices will have to be developed as the industry grows. This may be difficult if the growth is too rapid.

2 What are the major uncertainties with respect to the impacts of the industry?

Although extensive work has been undertaken on pollution control technologies and mitigating strategies and on procedures to protect the safety and health of the workers, uncertainties remain. For example, it is not known whether conventional methods could treat all of the process wastewaters to discharge standards, should this become necessary or desirable in the water-short region. Nor is it known whether the proposed reclamation techniques will adequately protect the waste disposal areas from leaching. Were significant leaching to occur, it could have severe effects on the region's water quality. The stability of revegetated spent shale piles will remain uncertain for many years, and the effectiveness of strategies proposed for controlling the leaching of in situ retorts is unknown.

Worker fatalities and injuries have been rare in the industry to date, but oil shale has been mined and processed only for experimental purposes, and at rates that are insignificant compared with commercial-scale operations. Predictions of a safe working environment have yet to be verified under conditions of sustained large-scale production.

The rates and characteristics of atmospheric emissions have not been firmly defined, and their dispersion patterns cannot be accurately predicted because modeling methods are not yet adequate for the irregular terrain and complex meteorology of the oil shale region.

Laboratory studies, computer simulations, and pilot-scale test programs could clear up some of these uncertainties (such as dispersion behavior and wastewater treatment). Others (such as the efficacies of waste disposal practices) may need extensive test programs involving commercial-scale modules or plants.

3 What potential impacts are not presently well regulated?

New Source Performance Standards for air and water pollution control have not yet been developed, although the regulatory framework exists and they will be forthcoming as experience is gained with the operations. Standards for hazardous air pollutants and visibility will be promulgated by the end of 1981. It does not appear, however, that the hazardous substances to be covered by these regulations will be generated in significant quantities by oil shale operations. Nonpoint sources of water pollution are not presently well regulated. Performance standards for land reclamation that are specific to oil shale have not yet been developed. Standards developed for coal under the Surface Mining and Reclamation Act are not entirely suitable for oil shale because of the significant differences that exist in geology, topography, waste characteristics, and other factors. A regulatory framework similar to that in the Act could be used for developing oil shale standards.

Environmental monitoring is presently required on private lands to assure compliance with State and Federal regulations. The requirements, however, are not so strict as those under the Prototype Leasing Program. Environmental groups believe that the same conditions should apply to both private lands and Federal lease tracts. This, they believe, would provide better information about the environmental impacts from the technologies operating on private holdings, and would allow comparison with the effects from the Federal lands. Furthermore, since one purpose of the Prototype Program is to obtain information about a variety of technologies, additional monitoring of the private lands might provide these data. As a result, the need for additional Federal leasing might be reduced.

Developers using private lands oppose this action and claim that existing requirements are more than sufficient to monitor the effects of their projects. They also point out that additional monitoring is done voluntarily, and assert that some of the tests required on the lease tracts are of limited or dubious value.

4 How much will pollution control cost?

Air pollution control is estimated to cost approximately $0.90 to $1.15/bbl of syncrude produced. Water pollution control is estimated to cost about $0.25 to $1.25/bbl of syncrude, assuming the water is treated for reuse within the facilities. Land reclamation will cost about $4,000 to $l0,000/acre disturbed, or about $0.01 to $0.04/bbl of syncrude. The total cost, which may vary significantly with the location of a project, with the nature of the operation, and with other factors, might be about $1.00 to $2.50/bbl (1.6 to 2.4 cents/gal) of oil produced. Although substantial, the cost should not preclude the establishment of an industry since it would have only a small effect on the product price.

5 Will the size of the industry be limited by existing environmental regulations?

Existing regulations for water quality, land use, and worker health and safety do not appear to be obstacles. However, the industry's capacity will probably be limited by air quality standards governing the prevention of significant deterioration (PSD). These specify the maximum increase in the concentrations of sulfur dioxide and particulate that can occur in any area, Under the Clean Air Act, the oil shale region has been designated a Class II area, where some additional pollution and industrial growth are allowed. Class I areas, where the air quality is more strictly regulated, however, are nearby. One of these, the Flat Tops Wilderness, is less than 40 miles from the edge of the Piceance basin, where most of the near-term development is likely to take place. A preliminary dispersion modeling study by the Environmental Protection Agency (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, if the plants were dispersed. Additional capacity could be installed in the Uinta basin, which is at least 95 miles from Flat Tops. A l-million-bbl/d industry could probably not be accommodated, because at least half of its capacity would have to be located in the Piceance basin.

The lack of commercially available plant species that are adaptable to the oil shale region also could impose a temporary restriction on the industry's land reclamation efforts. If commercial growers were to expand their production to keep ahead of the needs, this problem could be solved.

6 Will the industry be limited by the procedures for obtaining environmental permits?

Of the more than 100 permits required for construction and operation of an oil shale facility, about 10—the major environmental permits—require substantial commitments of time and resources. It may take as long as 2 years after the start of baseline monitoring programs to obtain these permits, with an additional minimum of 9 to 24 months required if an EIS needed. * If the regulatory agencies need additional technical information, or if agency personnel are overloaded with work, the process may even take longer. Although the permitting process is lengthy, it should not preclude the establishment of an individual project. Particularly if many projects begin simultaneously, agency overloads could delay them all, thus causing cost overruns. This should not limit the size of the industry, but it might prevent a large industry from being established rapidly.

*A statement may take much longer. The programmatic EIS for the Prototype Leasing Program required 4 years. Preparing the draft EIS for the proposed Superior land exchange required 2 years. The EIS for extending Paraho's Anvil Points lease is in its fifth revision, after more than 2 years.

Policy Options for Air Quality Management

- Increase information.—More R&D could be conducted on air pollutants, their effects, and their controls. Studies of the dispersion behavior of oil shale emissions, for example, would lead to a better understanding of the long-range consequences of these emissions on ambient air quality. This, in turn, would provide guidance for plant siting to reduce air quality deterioration. Options include the evolution of existing R&D programs in EPA and DOE, their expansion by redistributing or increasing appropriations, and the passage of legislation specifically for air quality studies. R&D should be coordinated with any demonstration projects that are conducted. Data from these projects could help in setting performance standards for pollution control.

- Change the standards.—The emissions standards for oil shale facilities have not yet been set because of a lack of information about the nature of the operations, The estimated limit of 400,000 bbl/d in the Piceance basin is based on estimates of the emissions that would occur if the best currently available control technologies were applied. EPA could set stricter emissions standards that would reduce air pollution and, if the standards could be met, would also allow more production. If the plant emissions were cut in half, for example, up to 800,000 bbl/d could be installed in the Piceance basin, and more in Utah. This option would entail much higher control costs, and it might not be technologically achievable.

Another option would be to redesignate the oil shale region from Class II to Class III. This would allow greater degradation of air quality (the extent of which cannot be accurately predicted in the absence of reliable regional modeling studies) while allowing more production. However, it would not remove the limits imposed by nearby Class I areas, which at present appear to be controlling.

- Amend the Clean Air Act.—There are three options for amending the Act. Each deals with the restriction posed by the PSD standards.

  At present, EPA distributes PSD permits to developers on a first-come, first-served basis. The Act could be changed to require a coordinated strategy for facility siting that would maximize production while maintaining air quality at regulated levels. EPA could allocate portions of the PSD increments based on its own analysis of needs and impacts, or it could consult with all of the potential developers in an attempt to evolve an optimum distribution. (An amendment would be required to avoid impediments to such cooperation under the antitrust laws.) Distributing the PSD increment among the maximum number of facilities would amount to an implicit tightening of the emissions restrictions, which would add to the costs of air pollution control.

  The Act could be amended to exempt the developers from maintaining the air quality of the nearby Class I areas, while adhering to Class II standards in the oil shale region. The maximum size of the industry would be limited, because the developers would still have to comply with the region's standards. Alternatively, if this action were coupled with a redesignation of the oil shale region to Class III, there could be, at the cost of increased pollution in all areas, at least twice as much production as is presently possible. (The Class III standards allow twice as much pollution as Class II.)

  Finally, the Act could be amended to exempt the developers from air quality regulations in both the oil shale area and the nearby Class I areas. This would allow high levels of production, again at the cost of increased pollution over a large area. This action would encounter significant political and legal resistance.

Policy Options for Water Quality Management

- Increase information.—More R&D could be conducted to develop and demonstrate methods for treating the process wastewaters to meet discharge standards. Although not a part of current developer plans, such treatment could provide additional water resources for the water-short region. Additional attention could also be given to preventing leaching of waste disposal areas and in situ retorts. Policy actions would be similar to those for air quality R&D. Alternatively, requirements for developing strategies for dealing with the long-term effects on water quality could be added to leases for Federal land. (The lessees in the current Prototype Leasing Program are required to develop and demonstrate both reclamation methods and procedures that will prevent the leaching of in situ retorts.)
- Develop regulatory procedures and standards.—Promulgating standards in the areas that are not presently well regulated would reduce the uncertainty that future regulations could preclude profitable operations. Under the present approach, regulations evolve as the industry and its control technologies develop. This introduces uncertainty, but allows the standards to be set with a knowledge of the technical and economic limitations. As an alternative, standards could 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 the uncertainty, but the standards would have to be carefully established to assure that they were both adequate to

protect the environment and attainable at reasonable cost.

- Ensure the long-term management of waste disposal sites and in situ retorts.—These locations may require monitoring and maintenance for many years after the projects are completed. Long-term management could be regulated, for example, under the Resource Conservation and Recovery Act, which allows EPA to set standards for the management of hazardous materials, including mining and processing wastes. (Spent oil shale has not been classified as a hazardous waste, but EPA has suggested that it may be given a special classification because of the large volumes that will be produced.) Alternatively, the developers could be required to guarantee such management by incorporating appropriate provisions in leasing regulations.

Policy Options for Occupational Health and Safety

- Increase information.—R&D could be conducted on the cancer risks associated with processing oil shale and shale oil. This work should take advantage of the extensive, but often conflicting, prior work and should be coordinated with ongoing studies. Policy actions would be similar to those for air quality R&D.
- Undertake health surveillance,-A central registry of health records would facilitate the identification of hazards and the development of protective methods. It could be located in a regional medical center, with or without the active participation of Federal agencies. Funds could be provided by the Government, by the States, by labor organizations, or by the developers.
- Develop exposure standards.—As information about potential chemical health hazards is analyzed, the National Institute of Occupational Safety and Health, the Occupational Safety and Health Administration, and the Mine Safety and Health Administration could address the necessity for exposure standards.

Policy Options for Land Reclamation

- Increase information.—R&D and field testing could be conducted on reclamation methods and the selection of plant species for revegetation. This work would help set reclamation performance standards for the oil shale industry. Policy actions would be similar to those for air quality R&D. Additionally, the developers could continue to be required in future leasing programs to develop viable reclamation methods (currently required of participants in the Prototype Leasing Program).
- Establish Federal reclamation standards.—Legislation could be introduced to provide standards that are appropriate to the conditions in the oil shale region and to the types of disturbance that will occur with development. The standards should be ecologically sound, economically achievable, and consistent with the public's goals for postmining land use. Consideration should be given to the relative merits of alternative control strategies and environmental performance standards necessary to reduce erosion and leaching and to allow more efficient use of the land for wildlife, grazing, or other purposes.
- Expand the production of seeds and plant materials.—This might avoid a possible delay in reclamation programs. It could be done by providing appropriations to the Federal plant materials centers and by expanding the cooperative programs between these centers and commercial suppliers.
- Protect the wildlife and their habitats. —Lease tracts and land exchange parcels could be chosen to minimize disruption of ecologically fragile areas. This would require extensive, site-specific characterization studies in advance of leasing or exchange. These studies would be expensive and time consuming, but they could ultimately expedite subsequent actions by reducing the duration of the baseline monitoring period that might be required of de-

velopers. (Provisions for wildlife maintenance were included in the leases for the Prototype Program.)

Policy Options for Monitoring and for Permitting Procedures

Increase information.—Additional environmental monitoring of developments on private lands could be required. This would entail changing existing laws and regulations. Its advantages include gathering comparable information for both private holdings and Federal lease tracts. The new information might reduce the need for leasing more Federal tracts to test technologies not being used by the Prototype Program lessees. Its disadvantages include the possibility of litigation. It would also increase expenses for developers using private holdings,

Further study of the permitting procedures could help to design more efficient ones while maintaining a high level of environmental protection. The studies could be conducted by the regulatory agencies or by the General Accounting Office.

- Increase agency resources.—Increasing personnel and financial resources would allow the agencies to improve their response capabilities and increase their assistance to State and local regulators. Coordination of the expanded resources would also be needed.
- Improve coordination among the agencies and between the agencies and the public.-Coordinated reviews could be conducted to reduce jurisdictional overlaps, paperwork, and workloads. It might be necessary to mandate coordination to assure its effectiveness. Another approach would be to establish a regionwide environmental monitoring system to determine baseline conditions for all areas to be affected by oil shale projects. This might reduce the duration and the cost of the monitoring programs now required of permit applicants. Site-specific studies and monitoring would still be needed for certain data. Another option would be to improve the coordination of public participation in agency decisionmaking processes. This might help reduce confrontations, although it could lead to an expanded perception of risks and thus to stronger opposition.
- Clarify the regulations and the permitting process.— Simplifying the procedures would have the advantage of retaining the laws and their protection while making it easier to comply with them. Problems could arise if procedures were changed while applications were in process. Another approach would be to establish detailed, standardized specifications for permit applications. (EPA is doing this for the PSD process.) This would reduce, but not eliminate, delays. Fully standardized forms are probably not practical.
- Expedite the permitting procedure.—An authority (such as the Energy Mobilization Board) could be established with power to make regulatory decisions if the agencies do not do so within a set period. This would provide a single point of contact between the developer and the regulatory system, but it would add to the bureaucracy and increase controversy. Another possibility would be to limit the period of litigation for permitting actions, as was done in the case of the Trans-Alaska oil pipeline.
- “Grandfather” oil shale projects.—Plants under construction, or already operating, could be exempted from future regulations. (This concept is embodied in the Energy Mobilization Board legislation.) This would remove many regulatory uncertainties, but would reduce environmental protection. Some environmental laws already contain “grandfather” clauses.
- Waive existing environmental laws.—This would remove virtually all of the problems and delays associated with permitting. However, it would have serious political, environmental, and social ramifications. The allocations of the waivers would be highly controversial. The extent to which such action would speed the deployment of an oil shale industry is unclear.

Water Availability

Oil shale development will affect the hydrologic basins of the Green River, the White River, and the Colorado River mainstem in Colorado. These basins are located within the semiarid Upper Colorado River Basin, which includes the Colorado River and its tributaries north of Lee Ferry, Ariz. (See figure 7.) The river system is one of the most important in the Southwest, It serves approximately 15 million people, and its waters are critical resources for towns, farming, industry and mining, energy development, recreation, and the environment. In the past, natural flows along with water storage and diversion projects have generally been adequate. However, because the region is developing, water supplies are beginning to be strained, and at some point in the future a scarcity of water may limit further growth.

Issues

1 What are the water needs of an oil shale industry?

Depending on the technologies used, producing 50,000 bbl/d of shale oil syncrude would consume 4,800 to 12,300 acre-ft/yr of water for mining, processing, waste disposal, land reclamation, municipal growth, and power generation. This is the equivalent of from 2. I to 5.2 bbl of water consumed per barrel of oil produced. A l-million-bbl/d industry using a mix of technologies might require 170,000 acre-ft/yr. This is slightly more than 1 percent of the virgin flow* of the Colorado River at Lee Ferry, or 5 percent of the water consumed in the Upper Basin at present. * *

‘Virgin flow is the flow that would occur in the absence of human-related activities.

**For comparison, irrigated agriculture along the White River and the Colorado River consumes about 549.000 acre-ft/yr to produce 3 percent of Colorado”s crop production. This is equivalent to the water needs of a 3.2-m illion-bbl/d oil shale industry.

2 Is there enough surface water available to support a large industry without curtailing other uses?

Surplus surface water will be available to supply an industry of at least 500,000 bbl/d through the year 2000 if:

- additional reservoirs and pipelines are built;

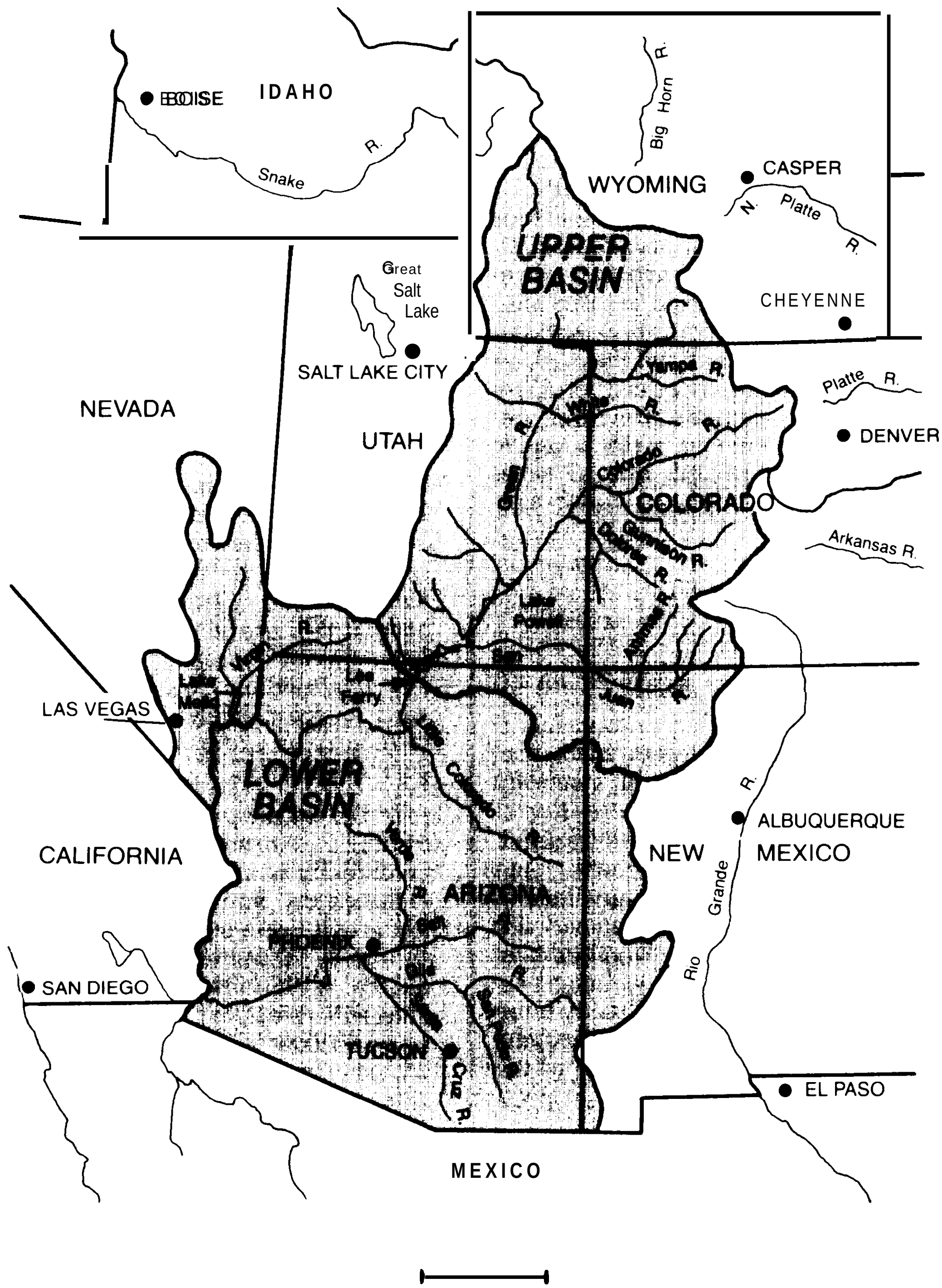
  and
- demand for other uses increases no faster than the States” high growth rate projections;

  and
- average virgin flows of the Colorado River do not decrease below the 1930-74 average (13.8 million acre-ft/yr).

Otherwise, surface water supplies would not be adequate for this level of production unless other uses were curtailed, interstate and international delivery obligations as presently interpreted by the Government were not met, or other sources of water were developed. If the reservoirs and pipelines are built, flows do not decrease, and the region develops at a medium rate (which the States regard as more likely), there should be sufficient surplus water to support an industry of over 2 million bbl/d through 2000.

In the longer term, surface water may not be adequate to sustain growth. Surplus water availability is much less assured after 2000. If the rivers’ flows do not decrease, and if a low growth rate prevails, demand will exceed supply by 2027 even without an oil shale industry. With a medium growth rate, the surplus will disappear by 2013. A high growth rate will consume the surplus by 2007, again without any oil shale development. This is a potentially serious problem for the region, and its implications for oil shale development are controversial. On the one side, it is argued that there is no surplus surface water and this should preclude the establishment of an industry. On the other side, it is maintained that the facilities in a major industry could function for much of their economic lifetimes without significantly interfering

Figure 7.—The Upper and Lower Colorado River Basins



SOURCE: C. W Stockton and G. C Jacoby, "Long-Term Surface-Water Supply and Streamflow Trends in the UPper Colorado River Basin Based on Tree-Ring Analyses," *Lake Powell Research Project Bulletin No. 18,* March 1976, p. 2.

with other users, and in any case would use relatively little water. (A l-million-bbl/d industry would accelerate the point of critical water shortage by about 3 years if only surface water were used.)

In any event, the analysis of future water availability is clouded by the uncertain demand schedules of other users and by a long-standing legal conflict between the Upper and Lower Basin States. It is not clear how much water is legally available to the Upper Basin and therefore to the oil shale region, For example, the calculations presented above assume that 750,000 acre-ft/yr is sent from the Upper Basin to Mexico to satisfy a national delivery obligation incurred under the Mexican Water Treaty of 1944-45. The Upper Basin States maintain that they are not responsible for this obligation and that the water should be freed for their use. (The quantity of water in question is equivalent to the water needs of a 4.4-million-bbl/d oil shale industry.) The region's water problems cannot be solved, however, simply by reallocating surface water supplies from the Lower Basin States, where water is an equally critical resource. Rather, if growth is to be sustained in both basins, it may be necessary to increase net supplies by more efficient municipal, industrial, and agricultural use; or to increase gross supplies by importing water from other hydrologic basins or possibly by weather modification. All of these options would be expensive, will involve environmental impacts, and could encounter legal, political, and institutional opposition.

3 Will the costs of obtaining water limit the size of the oil shale industry?

Although water is expensive in the West, the costs of water development will be a small fraction of the costs of producing shale oil and therefore should not limit development. The costs of the most expensive water supply option, importation from other hydrologic basins, could exceed $1/bbl of shale oil produced. Other supplies would cost less than $0.50/bbl. This includes the amortized costs of reservoir and pipeline construction plus the cost of treating the water to industrial standards. Development of high-quality ground water would be least expensive, but would be limited to specific areas.

4 Will the use of water for oil shale development affect irrigated agriculture?

The effects on farming should be relatively small, especially when compared with those caused by competition for labor and by the purchase of farmlands for municipal growth. Farm production in the Colorado portion of the Upper Basin would be reduced if rights to irrigation water were sold to oil shale developers, but the present developers do not plan to purchase irrigation water in significant quantities. In the longer term, if water shortages occur, the industry may have to purchase water, thus displacing farm production. The water laws of all three States allow the transfer of rights between willing sellers and purchasers.

5 Will developing water resources for oil shale have severe environmental impacts?

The environmental impacts will include reduced stream flows, increased salinity in the river system, and land alterations as a consequence of constructing reservoirs and diversion facilities. These should be small on the Upper Basin as a whole, but could be large in some areas, especially where reservoirs will be built. Fish habitats and recreational activities along the White River are expected to be the most severely affected. Environmental impacts on the Lower Basin States should not be substantial.

6 What will be the economic effects of developing water resources for oil shale?

The economic losses from decreased flows and increased salinity could reach $25 million per year for a 2-million-bbl/d industry.

g d m d h C d R V

These would include the effects of increases in salinity on farming and of reductions in river flows on farming and hydroelectric power production. (It is assumed that the developers do not purchase irrigation water.) The positive effects of the same industry would include a gain of several billion dollars per year in regional income. A simple comparison of the relative gains and losses should be made with caution, however, because some of the adverse effects would occur in areas that will not enjoy the benefits. For example, some of the impacts on farming will be experienced in the Lower Basin.

Policy Options

- Development of a water management system.—The U.S. Bureau of Reclamation (USBR)* and individual developers and other users have conducted preliminary water management studies. No systematic basinwide evaluation of water management alternatives, however, has compared water supply options with respect to their water and energy efficiency, their costs and benefits, and their environmental and social effects. Such an assessment, involving Federal, State, and local governments; regional energy developers; other users; and the general public, may be an appropriate prelude to actions to construct new water storage and diversion projects. It could be especially useful in evaluating and coordinating such controversial options as importation of water. Funding could be provided by DOI, DOE, or other agencies. USBR or the Colorado River Compact Commission could manage the study.
- Financing and building new reservoirs.—New reservoirs will be needed if a large industry is to be established. These could be provided through two mechanisms, First, Congress could appropriate funds for those water projects that have already been authorized under the Colorado River Storage Project Act. (At least one of these, the West

*Now the Water Power Resources Service,

Divide project, may be suitable for supplying water to oil shale facilities in Colorado.) Second, legislation could be passed specifying both the construction and funding of water projects not now authorized for the region, Alternatively, a State organization or the oil shale developers themselves could finance and build the water storage. A commitment to the facilities would simplify planning for the oil shale industry and for other regional growth as well. The facilities would be expensive, and their construction might be resisted especially if general tax revenues were used for this purpose.

- Minimizing reservoir and diversion siting problems.—The siting, construction, and operation of reservoirs and diversion projects could be affected by the Endangered Species Act, the National Wild and Scenic Rivers Act, and the Wilderness Act. Problems could be avoided if Congress directed that the Federal agencies complete a survey of endangered species in the area (including the designation of critical habitats, if any are found), identify the stream reaches that will be included in the Wild and Scenic Rivers System, and designate the areas to be included in the National Wilderness Preservation System. The storage and diversion facilities could then be sited to minimize interference with these areas. The environmental surveys in particular could be time-consuming and expensive, and expediting the selection processes might involve departing from the purposes of the respective Acts.
- Make water available for oil shale.—Congress could take steps to assure that water was supplied to oil shale facilities from Federal reservoirs, both the existing ones and any new ones that might be built, This policy would have to be carefully implemented to avoid interfering with other users and with the water management policies of the affected States,

  The Government could also provide water from Federal reserved rights. Because of legal restrictions on the use of water from Federal reservations, the only potential source appears to be the NOSRs in Colorado and Utah. The States might resist allocating this water to an oil shale industry. For example, the use of water from NOSR 1 is in the early stages of litigation in Colorado.
- Supply water through interbasin diversions.—Water shortages in the Upper Basin could be reduced by importing water from other hydrologic basins. Options include transporting water directly to the oil shale region; or to satisfy all or part of the delivery obligation to Mexico; or to supply water to the cities in Colorado's Front Range Urban Corridor (to replace the water that is presently obtained from the oil shale region). All of these options could release sufficient water to support a large industry as well as allowing other types of regional growth. However, they all would be expensive. Furthermore, the study of diversions into the Colorado River Basin is banned by Federal statute until 1988, This ban would have to be lifted before the option of supplying water directly to the oil shale region could proceed. The other alternatives might not be impeded.
- Encourage more efficient use of water.—Financial and technical assistance could be provided to encourage municipal, agricultural, and industrial water conservation practices. Likely targets would be agriculture, powerplants, the oil shale facilities in the development region itself, and the cities on the eastern slope of the Rocky Mountains that import water from the region, Large quantities of water could be saved, although at substantial cost. The implementation of these policies could encounter resistance. Augmentation methods such as weather modification could be tried but would entail environmental, legal, and institutional problems.

Socioeconomics

The oil shale region in which near-term development is likely to occur is a 3,200 mi^2

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rural area, sparsely populated and with limited transportation. (See figure 8.) In northwestern Colorado, about a dozen towns in three counties are likely to be substantially affected. * The population of one of these counties could increase by as much as sevenfold if a 500,000-bbl/d industry were established and other energy industries expanded. (See figure 9.) The benefits of this growth could include increased employment, higher wages, a broader tax base, community improvements, and stimulation of other businesses. Among the negative consequences could be a severe housing shortage, strain on public services and facilities, symptoms of social stress such as increased crime, and private-sector dislocations such as small-business failures. Even if the growth is reasonably well controlled, some residents may perceive a deterioration in their quality of life. The term "modern boomtown" has been used to describe communities that have experienced these kinds of growth-related negative impacts.

The region is presently growing and has experienced some adverse effects, although local officials are confident that their communities can deal with additional development. The oil shale developers have been responsive to the social effects of the industry's expansion. A sense of increased community identity and pride is already evident, and is considered by some as a positive consequence of oil shale development. Whether the communities will continue to deal successfully with their growth, or be overwhelmed by it, will depend on a number of factors. Among these are:

- the absolute numbers and abruptness of the population influx;
- the attitudes of both long-term residents and newcomers;
- past experiences with boom and bust cycles;
- the ability of local political structures to prepare for population growth; and
- the availability of assistance—financial and other—for mitigation of impacts.

*This summary refers primarily to Colorado. Utah and Wyoming are discussed in ch. 10.

Issues

1 How many people can the region absorb?

Between 1985 and 1990, the physical facilities of the small communities in Garfield and Rio Blanco Counties that will be most affected by oil shale development should be able to accommodate up to 35,000 people. This assumes presently planned improvements and expansions (including the construction of Battlement Mesa, a new town) can be completed. (See table 6.) This capacity, which is an increase of 250 percent over the present population, is compatible with the growth that will accompany completion of the two presently active oil shale projects (they could produce 133,000 bbl/d). The growth accompanying an industry of up to 200,000 bbl/d could be accommodated if the construction were phased and if some of the new people lived in adjacent Mesa County. If additional projects were sited in Utah, the industry could reach 300,000 bbl/d. Major efforts would be neces-

Table 6.–Actual and Projected Population and Estimated Capacity of Oil Shale Communities in Colorado

Location[a]	Population 1977 census[b]	1980 projected[c]	1985-90 capacity[d]
Garfield County			
Rifle	2,244	4,362	10,000
Silt	859	1,211	2,800
New Castle	543	831	1,000
Grand Valley	377	589	3,000
Battlement Mesa[e]	–	198	2,500
Other	–	—	1,700
Subtotal[f]	4,023	7,191	21,000
Rio Blanco County			
Meeker	1,848	2,779	6,000
Rangely	1,871	2,223	6,000
Other	1,381	1,542	2,000
Subtotal	5,100	6,544	14,000
Total	9,123	13,735	35,000

[a]Does not include Mesa or Moffat Counties both of which are more distant from the area Of development
[b]Actuals from a special U S census
[c]End-of-the-year projections by the Colorado West Area Council of Governments
[d]Estimated by OTA from various planning and needs assessments documents, assumes completion of currently planned projects (e g housing, waler and sewer system expansions street and road Improvements, etc)
[e]A new town; construction anticipated to begin in the early 1980 s
[f]Includes only the immediate 011 shale vicinity

SOURCE Off Ice of Technology Assessment

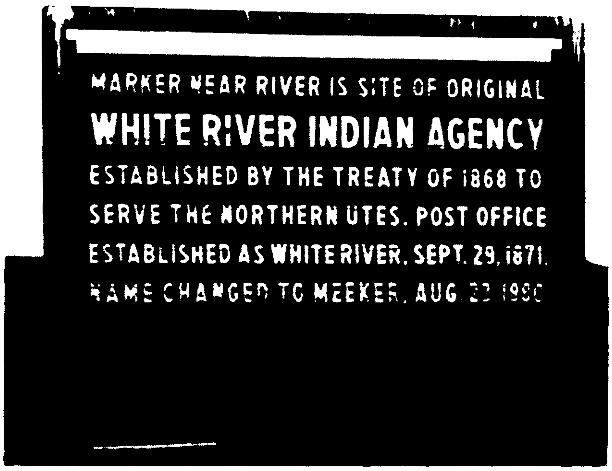


Photo credit OTA staff

Marker indicating original site of the Northern Ute Indian Reservation near Meeker, Colo.

sary to assist the small communities in Utah if sudden, rapid growth accompanied industry expansion. * In Colorado, additional growth could be accommodated if some of the presently planned facilities for workers and their families were constructed quickly. For example, according to current schedules, Battlement Mesa will house 1,500 residents in its first phase of development (ultimate plans call for a maximum of 7,000 units for 21,000 people). If construction were accelerated, more could be housed in a shorter period of time.

The Colorado communities expect to be able to assimilate more residents because they have been preparing for an oil shale industry for nearly 10 years. Local interests have participated in broadly structured task forces that assist in planning and managing growth. The industry has supported these groups. It also has aided local governments, has adopted programs to reduce negative impacts, and has invested in housing and in the land for Battlement Mesa. The communities have been developing municipal facilities and services. New housing is being built, businesses expanded, and health care extended. The State has appropriated more than $40 million for over 75 projects, and the Federal Government has contributed technical assistance. These efforts have prepared the towns for a reasonable number of new residents.

2 Will oil shale development cause community disruption?

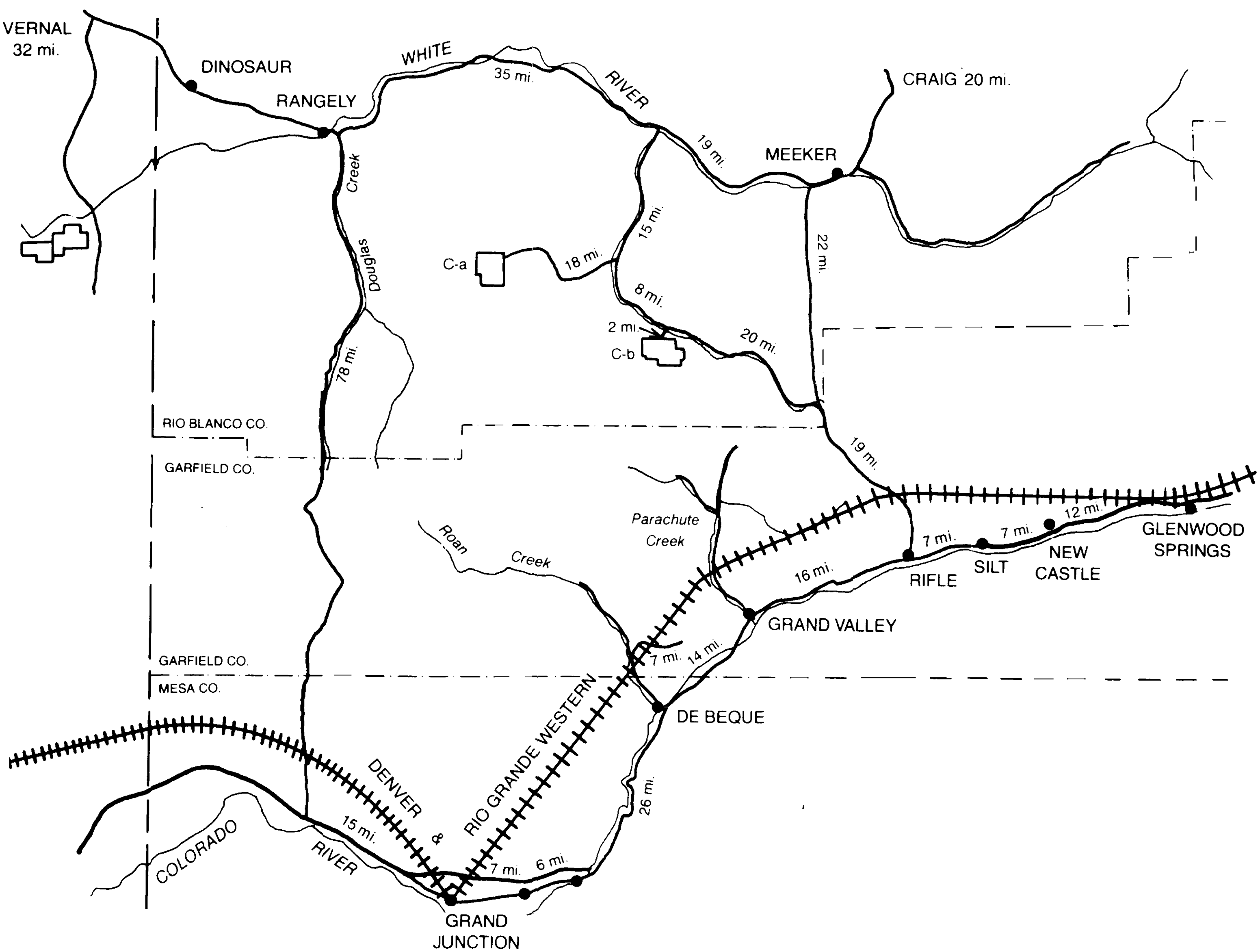
Not enough is known about the causes of boomtowns to be able to predict the exact threshold beyond which oil shale development would lead to serious impacts. However, establishing a l-million-bbl/d industry by 1990 would exceed the capacity of all of the communities, and stressful living conditions would be inevitable. It is known that the possibility of disruption will be influenced by the location of the growth, by the total number of newcomers, by the rapidity with which they arrive, and by the ability of the communities to prepare for the influx. Some towns in Wyoming have successfully accommodated expanded coal development, while others that have experienced the same kinds of growth, and have had access to the same preventive programs, have suffered for long periods. The social and economic problems accompanying oil shale growth could be aggravated if development is concurrent with expansions in other industries. The region is already experiencing some rapid growth, particularly from coal mining.

3 What role can industry play in dealing with the socioeconomic consequences of oil shale development?

Industry has contributed financial and technical assistance to the growth management effort. The Mineral Leasing Act of 1920 allows the affected States to share in the pro ceeds from leasing programs; Colorado received nearly $74 million as its share of the bonus payments for Federal tracts C-a and

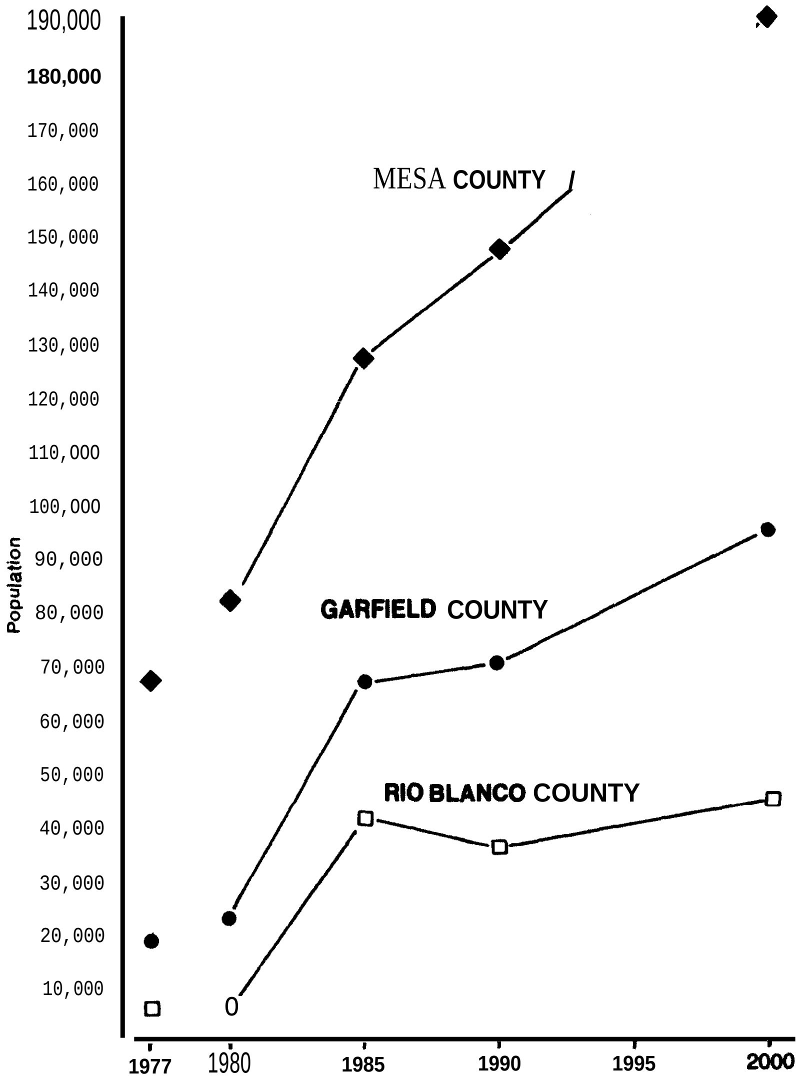
*Planning for oil shale impacts in Utah has not been as extensive as in Colorado for a number of reasons. Most important is that mitigation funds from a major source (the State's share of bonus and lease payments under the Mineral Leasing Act) have been held in escrow pending settlement of the ownership questions.

Figure 8.—The Communities in the Colorado Oil Shale Region



SOURCE: Oil Shale Tract C-b Socio-Economic Assessment, 1976, Vol. II.

Figure 9.—Projected Growth of Counties in Northwestern Colorado From Oil Shale Development, 1980-2000



1977-actual population from special U.S. census
1980-2000—projections assume oil shale development with a production level of 500,000 BPD by 1990 and 750,000 BPD by 1995 combined with other energy industry (e.g., coal, electric generation, oil & gas) expansion.

SOURCE: Colorado West Area Council of Governments.

C-b. From this fund has come the $40 million for community improvements in Colorado's oil shale area. The lessees and other developers have contributed additional money and support for planning efforts and other improvements. If more projects are initiated by leasing, more funds will become available. If, on the other hand, the new projects are on private land or on land-exchange parcels, developer participation will be voluntary.

It is in the developers' best interest to participate. The benefits of such involvement are illustrated by the experience of the Missouri Basin Power Cooperative in installing a powerplant on the Laramie River in Wyoming. The developer invested $21 million in mitigation efforts through grants and revenue guarantees to towns, counties, and public agencies; by inkind services; with bond guarantees; and with other types of assistance. The company believes that it saved about $50 million in project costs by reducing employee turnover and avoiding construction delays. Furthermore, all but about $3 million of the initial outlay will be recovered. Ultimately, the amount spent for mitigation may be less than 1 percent of the total cost of the plant.

4 What role can the Federal Government play?

The region should be able to accommodate growth from the presently active projects, and no new Federal initiatives appear to be needed unless an industry larger than 200,000 bbl/d is desired before 1990. Although some towns and counties have experienced problems in obtaining funds for specific improvements, the existing growth management mechanisms have been successful to date. They involve a cooperative effort among local citizens; municipal and county governments; regional, State, and Federal agencies; the oil shale developers; and other energy industries. These efforts must not be interrupted if the communities are to continue to be able to deal with their growth problems.

Increased Federal involvement will be required if production of over 200,000 bbl/d is attempted before 1990. In this case, a coordinated growth management strategy would be required to ensure that financing was available for building houses, that public facilities and services could be provided, that basic needs could be met, and that a reasonably stable work force could be maintained for the industry. Many Federal, State, local, and private organizations, operating in many areas and at all levels, would have to be involved to cope with sustained, rapid growth.

Policy Options

The courts have affirmed that, under the National Environmental Policy Act of 1969, the Federal Government must examine the social impacts of its major actions. The problems accompanying recent expansion of energy industries have led to a call for more Federal involvement. The extent and nature of this involvement, however, are controversial. On the one side it is argued that socioeconomic changes are the inevitable results of industrial development and are, at most, State and local problems. On the other side the position is taken that national energy requirements are the root causes of negative impacts and, for reasons of equity, active Federal participation in their amelioration is appropriate. Some examples of Federal assistance programs arising from the latter position are the Coastal Zone Management Act Amendments of 1976, which are directed at communities experiencing impacts from oil and gas development on the Outer Continental Shelf, and the Powerplant and Industrial Fuel Use Act of 1978, which established the Impacted Area Development Assistance Program (the sec. 601 program) to aid areas affected by coal and uranium development.

With respect to the socioeconomic problems of oil shale development, there are three policy options available. These options could be considered in bills that deal with the effects of all types of energy development; or they could be considered along with the impacts of similar energy forms (e.g., synthetic fuels); or they could be treated solely as the consequences of oil shale development.

- Continuation of present policies.—Federal assistance could continue to emphasize technical and financial aid. Revenues channeled through established programs would be the major mechanism, but other programs not now designed to deal specifically with impact mitigation could be redirected to assist the communities. Congressional action would primarily involve continuing or increasing appropriations.
- Increased growth management involvement. —New emphasis could be given to increased regulation. For example, social and economic effects could be made criteria for selecting Federal tracts to be offered in leasing programs, Alternatively, mandatory participation of the lessees in mitigation efforts could be included in the lease terms. Greater Federal involvement in monitoring and in technical assistance is another possibility. Congressional action could include amending existing laws, passing new legislation, or exercising oversight powers.
- Extension of impact mitigation programs. —Existing programs could be expanded or new ones adopted. Amendments to extend the assistance provided by the Powerplant and Industrial Fuel Use Act of 1978 are currently under consideration by Congress. * Among their features are the authorization of grants, loans, loan guarantees, and payment of interest on loans. An expediting process for providing assistance through current Federal programs is proposed, as is an interagency council to coordinate Federal efforts. This assistance is directed to the effects of major energy developments, which could include oil shale.

*S. 1699.

CHAPTER 2

Introduction

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Introduction

At the request of the Senate Energy and Natural Resources Committee, OTA has studied the history and status of efforts to develop the oil shale resources in Colorado, Utah, and Wyoming. The Committee's request called for a complete assessment of shale oil recovery technology in general and of the current Federal Prototype Oil Shale Leasing Program in particular.

The remaining chapters of this volume deal with the general context of oil shale development, The following subjects are discussed,

- Chapter 3— "Constraints to Oil Shale Commercialization: Policy Options to Address These Constraints' '—describes some alternative objectives that might be pursued to control the growth of the industry. Four development scenarios are used as a framework for identifying the obstacles that might inhibit or preclude the establishment of industries of various sizes before 1990, (This analysis is based largely on information contained in the subsequent chapters.) The congressional policies that might be directed to these obstacles are then discussed. Given these obstacles and policies, the relative degree to which each scenario would attain each objective for development is then described.
- Chapter 4—''Background"-describe the oil shale region, discusses the resources, outlines the processes for extracting shale oil and other materials, and summarizes the history and status of development efforts in the United States and abroad.
- Chapter 5—" Technologies ''—describes the mining and processing methods that could be employed to recover shale oil and to refine it to finished fuels. The advantages and disadvantages of the various processes are presented and their status summarized. Research, development, and demonstration needs are identified, and some possible Government policies are discussed.
- Chapter 6— "Economic and Financial Considerations"- deals with the costs of recovering shale oil and with the risks that inhibit oil shale projects. These risks include the absence of certainty about the capital cost estimates for commercial plants, the future of conventional oil prices and their impact on shale oil prospects, and the adequacy of U.S. equipment manufacturing and construction and design capacity for rapid deployment of a large industry. The need for Government subsidies is evaluated. A number of financial incentives are examined for their influence on the breakeven price for syncrude from shale oil, the probability of project financial loss, and the net cost to the Government. No explicit attempt has been made to compare the economics of shale oil with that of other synthetic fuels nor with possibilities such as conservation or solar energy. Such a comparison is outside the scope and mandate of the present study. The chapter assumes that the commercial prospects of shale oil will continue to be determined until the end of this century by its cost and price relationship with conventional oil.
- Chapter 7—''Resource Acquisition"'—discusses the characteristics of the oil shale lands that are owned by the Federal Government and by private parties. The possible need for involving additional Federal land is related to the level of shale oil production that is desired, and to the provision of other types of encouragement, such as subsidies, The principal mechanisms for providing such land —leasing and land exchange—are described and evaluated.
- Chapter 8—''Environmental Considerations"—discusses the implications of de-

velopment for the environment and for the workers. Separate discussions are provided for the potential effects on air quality, water quality, land characteristics, and the health and safety of the workers. In each case the legal framework governing the effects is described, the potential impacts of development are discussed, the proposed control technologies are evaluated, and the areas of uncertainty are identified. A discussion is also included of the procedures that control the issuance of environmental permits for oil shale projects. Possible governmental policy responses are discussed for each area of concern.

- Chapter 9—"Water Availability"-deals with the implications of oil shale development for the region's scarce water supply. The water resources themselves are described, and the institutional framework that governs their allocation is discussed. Water requirements of conventional users are projected to the year 2000 and compared with the physical resources to determine if surplus water might be available to support an oil shale industry. Mechanisms and policies for making additional water available are discussed.
- Chapter 10—"Socioeconomic Aspects"—deals with the effects of development on the small, rural communities that characterize the oil shale region. The population increases that might accompany development are estimated, and the abilities of the communities to accommodate this growth are evaluated, The nature of the potential impacts is discussed and possible policy responses are presented.

Volume II presents a history of the current Federal Prototype Oil Shale Leasing Program, together with an analysis of a prior leasing attempt which, although unsuccessful, affected the character and conduct of the Prototype Program. The problems encountered in the Program since its inception are discussed, and the status of development on the lease tracts is described, The ability of the Program to achieve its original objectives is evaluated.

Each aspect of this assessment is based on recent publications, on contractor reports prepared for OTA, and on the independent investigations of the project staff. The results are current as of February 1980. It is important to note that the oil shale situation is in a state of flux and that new developments may significantly alter the status and outlook of the industry and affect the accuracy of any conclusions presented herein.

CHAPTER 3

Constraints to Oil Shale Commercialization: Policy Options to Address These Constraints

Contents

ListofTables

List of Figures

CHAPTER 3

Constraints to Oil Shale Commercialization: Policy Options to Address These Constraints

Introduction

This chapter describes the requirements for establishing an oil shale industry by 1990, discusses potential constraints to its establishment, and presents policy options to address them, The effects of oil shale development on the physical, social, and economic environments are discussed in this chapter only to the extent that they are obstructions to development, Not all of these effects hinder development, and those not judged to be barriers are not included here, For instance, filling a canyon with spent shale constitutes an irrevocable alteration to the locale's appearance; but does not, by itself, bar development.

The many important issues not identified as constraints are summarized in chapter 1 and dealt with at length in the subsequent chapters. Comprehensive analyses are presented of the economics of oil shale development (ch. 6), and of the effects production could have on the air, land, water, worker health and safety (ch. 8), on regional water availability (ch. 9), and on the social and economic structure of the region's communities (ch. 10). As the next section explains, these considerations all bear on decisions about the future of oil shale, even though they may not be discussed here as barriers to its development.

This chapter is organized as follows:

- Alternative objectives for development are identified. To provide a framework for analysis, production scenarios are presented that might result from pursuing different combinations of these objectives.
- The requirements for investment capital, water, labor, and a favorable combination of marketability and land availability are summarized for the production targets of the scenarios.
- The constraints to achieving the targets are identified.
- Some policies for dealing with the constraints are discussed.
- Given the requirements, constraints, and policies, the scenarios are evaluated with respect to the relative degree they could attain each of the objectives for development.

Approaches to Development

Possible Objectives

Whether, how, and to what extent an oil shale industry should be developed will ultimately be a political decision. The past efforts of diverse groups—Government agencies, private firms, public-interest advocates, and environmental conservationists—to influence public policy on behalf of their goals will undoubtedly continue, These interests have different perceptions about the relative importance of certain basic values. The preferences they show for particular types and rates of development reflect these differences. Some of the varied, and often competing, objectives for development are discussed below.

To position the industry for rapid deployment.—The supporters of this objective acknowledge that more information is needed about oiI shale technologies if production is to be expanded rapidly in times of national need. Many techniques and sites would be required to answer most of the remaining questions about the technical, economic, and environmental implications of full-scale development. Demonstration plants to allow the evaluation of a full spectrum of technologies would be needed. Incentives and additional Federal land might be made available to encourage private sector experiments. All programs would be designed to maximize information generation. Growing international tensions, with the consequent potential for severe disruptions in oil supplies, provide a rationale for this objective.

To maximize domestic energy supplies.—This objective emphasizes the rapid development of a large industry, and has both economic and national security implications. The benefits include reduced reliance on oil imports, improved balance of payments, stimulation of private capital investment, increased employment, and lower energy costs over the long term. Policies supporting this objective emphasize the encouragement of the oil shale industry and the removal of restraints on its establishment. Among these policies might be additional Federal leasing, substantial economic incentives, waiving of environmental laws, and direct Government involvement in the production of shale oil.

To minimize Federal promotion.—This objective is supported by those who oppose Government involvement in the free market and with private enterprise. Other supporters stress that oil shale should not be promoted at the expense of other energy sources. In both cases, the advocates believe the industry should develop in response to traditional market pressures and opportunities and without the active financial participation or support of the Government. Policies that relate to this objective emphasize R&D, with particular attention to technological and environmental uncertainties; this would provide a basis for comparing oil shale with other energy alternatives and for developing regulations. Planning for future programs to mobilize the industry would be carried out; programs such as leasing, land exchanges, and financial incentives would not.

To maximize ultimate environmental information and protection.—The desirability of maintaining the existing environmental quality of the oil shale region and its environs is emphasized by the supporters of this objective. They also believe that oil shale should not be promoted more than other potential energy sources that could be less harmful to the environment. They would prefer that development proceed slowly, if at all, until its potential impacts have been determined and control strategies designed and thoroughly tested. The policies in this case would emphasize the enforcement of existing environmental regulations, the siting of any new plants to minimize their impacts, continued monitoring and R&D to provide information for the promulgation of new regulations, and public education and participation in decisions.

To maximize the integrity of the social environment.-This objective emphasizes personal and community needs. Its supporters would prefer to see a slow but steady developmental pace in order to avoid the potentially disruptive effects of too-rapid growth. Well-planned and coordinated growth management is essential to meet this objective. Policies would stress the involvement of local residents in the growth management process, efforts to avoid exceeding the growth capacities of the communities, the funding of needed community improvements, and the allocation of responsibilities for both growth management and impact mitigation among the oil shale developers, and the local, State, and Federal governments.

To achieve an efficient and cost-effective energy supply system.—Supporters of this objective emphasize the importance of providing a mix of energy alternatives with the best overall ratio of costs to benefits. They stress the need to position the industry and its technologies for long-term profitable operations. Future expansions could then be supported with internally generated financing. The related objectives of efficient development of the resource and balanced environmental and social protection are also emphasized. The proposed pace of development would allow thorough evaluation of the technologies so that the elements of production (land, labor, capital, water, energy, and incremental environmental changes) could be used most efficiently if a large-scale industry were created. Policies would give attention to incentives that left intact a degree of managerial risk, to thorough testing of diverse technologies and sites, and to advanced R&D that would provide a basis for comparing oil shale with its alternatives. These policies would not require a commitment of funds and resources to the exclusion of other potential energy sources.

Possible Futures

The Government, in preparing its policies for oil shale development, is bound to consider and weigh along with others, all of the objectives discussed above. For example, the Government is responsible for protecting the Nation from external threats of interruptions in the supply of essential raw materials like petroleum. This responsibility, when coupled with the Government's ownership of the richest oil shale deposits, would tend to encourage the rapid development of public lands. On the other hand, the public trust requires that these resources be developed with good management practices, with minimum waste and inefficiency, and with equitable treatment of the affected groups and regions. This mandate would lead to a moderate pace of development. Furthermore, the Government is required by its own laws to protect the environment of the oil shale region and to consider the socioeconomic consequences of each of its major actions. These mandates would lead to slow, carefully managed development.

Depending. on the emphasis given to the various development objectives, a number of future industries could be postulated, from none at all, to the production of several million barrels of shale oil per day. Four scenarios, based largely on shale oil production targets for 1990, will be considered as a framework for evaluating the requirements, the effects, and the policy implications of development. These are:

Scenario	Production target of shale oil (bbl/d)
1	100,000
2	200,000
3	400,000
4	1,000,000

Requirements for Development

In order to proceed, each project will need:

- land,
- water,
- adequate mining and processing technologies,
- access to markets,
- a favorable economic outlook,
- investment capital,
- compliance with environmental regulations,
- design and construction services,
- equipment and construction materials,
- construction and operating labor, and
- housing and community services.

The requirements of the scenarios for design and construction services, equipment, capital, water, and labor are shown in table 7. Also shown are the numbers of new residents who will have to be accommodated by the region's communities. Water requirements increase directly with the level of production because the amount each plant will need is independent of the others. Ranges are given because different technologies having different water requirements could be used. Because of the assumptions made about the phasing of construction, the labor requirements do not always increase directly with the level of production. In addition, whereas scenario 4 produces 2.5 times more oil than scenario 3, it requires from 2.5 to 4 times more capital. This cost escalation is attributable to the large demands for labor, materials, and equipment for 1 million bbl/d.

Table 7.–Requirements for the Production Scenarios

Resource	Requirements			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Institutional				
Design and construction services, % of 1978 U.S. capacity needed each year	Minimal	Minimal	12	35
Plant equipment, % of 1978 U S. capacity needed each year	Minimal	Minimal	6-12	15-30
Economic and financial[a]				
Loans, $ billion	$09-1.35	$1,8-2,6	$36-4.2	$90-135
Equity, $ billion	2.1-315	4.2-5.9	84-9,8	21.0-31 5
Total, $ billion	30-4,5	6.0-8,5	12,0 -14,0	30,0 -45.0
Annual, $ billion[b]	06-0,9	1.2-1 7	24-2.8	6.0-9,0
Water availability				
Water, acre-ft/yr[c]	9,800-24,600	19,600-49,200	39,200-98,400	100,000-250,000
Socioeconomic				
Workers.	5,600	8,800-11,200	17,600-22,400	44,000-56,000
New residents requiring housing and community services	23,000	41,200-47,200	82,000-95,000	118,000-236,000

[a] Third-quarter 1979 dollars
[b] Maximum annual requirements for a 5-year construction period
[c] Assumes 4900.12300 acre-ft/ yr for production of 50000 bbl/d Of shale oil syncrude
[d] Assumes 1200 construction workers and 1600 operators per 50000-bbl/d plant Multipliers used for total Increase = 2 5× (constructionworkers) + 5.5× (operators) Ranges reflect adjustments In construction work forces assuming phasing of plant construction

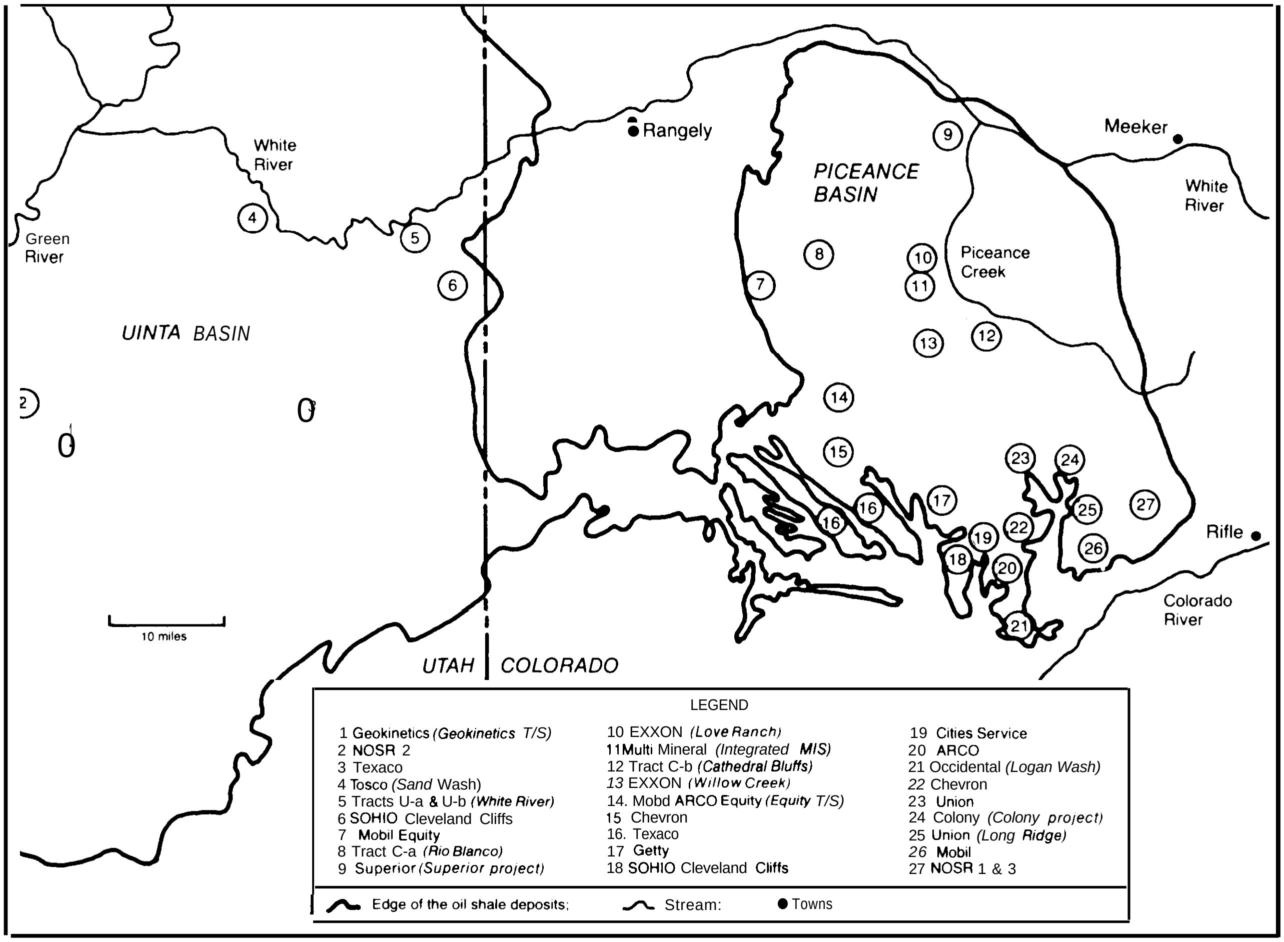
SOURCE Office of Technology Assessment

All projects share certain critical requirements that do not appear in the table. First, permits will have to be obtained. Their number and nature will depend on the project's location, on the technologies used, and on whether the site is privately owned or is controlled by either the Federal Government or a State. In order to obtain the necessary permits, the firm will have to demonstrate its ability to comply with the regulations promulgated under the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act, and other laws. Second, each developer must have a transportation system to move the products and byproducts to markets. Third, a project must be economically feasible. That is, market conditions must appear favorable based on reliable cost estimates, contractor services and equipment must be available at reasonable costs, compliance with existing and future regulations must be possible, and the permitting process must not unduly delay a facility's construction and operation. Finally, the developer must have land—either public, private, or a combination of both.

The interrelationship between the requirements for land, marketability, and a conducive regulatory environment can be illustrated by considering how some projects might be combined to achieve the production goals of the scenarios. The locations of tracts on which projects could be sited are shown in figure 10. The ownership of the tracts and the status of their development are shown in table 8. Many other tracts exist that could be developed, thus the list of possible sites in table 8 is far from complete. It does not include any tracts in Wyoming, for example, because no large-scale projects have been proposed for that State. The only State-owned land shown is the tract leased for the Sand Wash project. Utah has additional land that could be leased. Also, the federally owned tracts shown total only about 160,000 acres—roughly 3 percent of the public's oil shale land in Colorado and Utah.

In table 9, potential projects on these tracts are combined in alternative ways to reach the production targets of the scenarios. The projects are assigned to four categories: active projects, suspended projects, projects needing additional Federal land, and projects on other private tracts. Three alternatives are shown for scenarios 1 and 2. The first alternative represents the completion and possible extension of presently active projects. In the second, it is assumed that two presently active projects are canceled, leaving a production shortfall. This is eliminated

Figure 10.—Some Present and Potential Oil Shale Development Sites in Colorado and Utah



SOURCE Office of Technology Assessment

by the reactivation of presently suspended projects in response to substantial improvements in the economic and regulatory climate. In the third alternative, the shortfall is eliminated by the commitment of additional Federal land. Only two alternatives are shown for scenarios 3 and 4. The first incorporates the completion and extension of present projects and the development of new projects on private land, in response to favorable economic and regulatory conditions. The second alternative assumes that less favorable conditions exist, but that Federal land is made available.

In structuring the alternatives it has been postulated that the more advanced projects will respond to improved conditions before the less advanced. However, it should be understood that the industry patterns shown are in part arbitrary, and probably extreme in some cases. For example, the scenario 4 alternatives require either new projects on private land or new Federal tracts. In reality, an industry created under this scenario would more likely involve both types of land. Also, the combinations of projects shown are only illustrative; they do-not represent the recommendations of specific developers, technologies, projects, sites, or policies.

Table 8.–Some Potential Oil Shale Development Sites in Colorado and Utah

Site	Location	Ownership	Developer	Project title	Status	Announced production target[b]
1	Utah	State	Geokinetics	Geokinetics TIS	Small-scale field tests underway of TIS method	At least 2,000 bbl/d
2	Utah	Federal[a]	Navy/DOE	NOSR 2	No development,	None
3	Utah	Private	Texaco	None	No development,	None
4	Utah	State	Tosco	Sand Wash	Baseline monitoring and mine planning underway,	50,000 bbl/d
5	Utah	Federal[c]	Phillips/Sundeco/ SOHIO (tracts U-a & U-b)	White River	Suspended pending resolution of land-ownership issue.	100,000 bbl/d
6	Utah	Private	SOHIO/Cleveland Cliffs	None	No development,	None
7	Colorado	Private	Mobil/Equity	None	No development,	None
8	Colorado	Federal[c]	Standard of Indiana/Gulf (tract C-a)	Rio Blanco	Preparing for MIS retort demonstration,	76,000 bbl/d
9	Colorado	Private	Superior Oil	Superior	Suspended pending approval of land exchange proposal.	11,500 bbl/d
10	Colorado	Federal	EXXON	Love Ranch	Proposal submitted for land exchange,	60,000 bbl/d
11	Colorado	Federal	Multi Mineral	Integrated MIS	Negotiations begun for use of USBM mine shaft	,50,000 bbl/d
12	Colorado	Federal[c]	Occidental/Tenneco (tract C-b)	Cathedral Bluffs	Preparing for MIS retort demonstration.	57,000 bbl/d
13	Colorado	Federal	EXXON	Willow Creek	Proposal submitted for land exchange,	None
14	Colorado	Private	Mobil/ARCO/Equity	BX	Small-scale field tests underway of Equity's TIS method,	None
15	Colorado	Private	Chevron	None	No development.	None
16	Colorado	Private	Texaco	None	No development.	None
17	Colorado	Private	Getty	None	No development.	None
18	Colorado	Private	SOHIO/Cleveland Cliffs	None	No development,	None
19	Colorado	Private	Cities Service	None	No development,	None
20	Colorado	Private	ARCO	None	No development,	None
21	Colorado	Private	Occidental	Logan Wash	Small-scale field tests of Oxy's MIS technique. Results will support Cathedral Bluffs project.	Few hundred bbl/d
22	Colorado	Private	Chevron	None	No development.	None
23	Colorado	Private	Union	None	No development,	None
24	Colorado	Private	Colony Development	Colony	Suspended because of economic and regulatory uncertainty,	46,000 bbl/d
25	Colorado	Private	Union	Long Ridge	Suspended because of economic and regulatory uncertainty,	75,000-150,000 bbl/d
26	Colorado	Private	Mobil	None	No development,	None
27	Colorado	Federal[a]	Navy/DOE	NOSR 1 & 3	Development management plan being prepared,	None

[a]Naval Oil Shale Reserve
[b]Based on developers preliminary plans
[c]Leased under the Federal Prototype 011 Shale Leasing Program

SOURCE Office of Technology Assessment

Constraints to Development

The factors that will hinder or even prevent reaching the production goals of the OTA scenarios are shown in table 10. They were identified by analyzing the scenario requirements, given the present state of knowledge and the current regulatory structure. Constraints judged to be "moderate" will hamper, but not necessarily preclude, development; those judged to be "critical" could become major barriers. When it was inconclusive whether or to what extent certain factors would impede development, they were called "possible" constraints. Only those that could be addressed by Federal action are shown.

Each potential constraint is important by itself, but the combined effect that more than one might have on a scenario's realization should also be considered. Thus, a moderate restriction on the availability of land together with one on permitting could preclude investor participation. Similarly, an inadequate community water supply for the workers and their families coupled with a moderate restriction on the availability of water for a project could become a critical constraint.

Table 9. –Some Production Alternatives for the Scenarios (barrels of shale oil per day)

	Scenario 1 alternatives			Scenario 2 alternates			Scenario 3 alternatives		Scenario 4 alternates	
Possible projects	1-A	1-B	1-C	2-A	2-B	2-C	3-A	3-B	4-A	4-B
Active projects										
Rio Blanco	76,000	—	—	76,000	—	—	76,000	150,000[a]	76,000	150,000[a]
Cathedral Bluffs	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	100,000
Sand Wash	50,000	—	—	50,000	—	—	50,000		50,000	50,000
Geokinetics	2,000	2,000	2,000	17000	2,000	2,000	21,000	2,000	20,000	40,000
Equity BX	—	—	—		—	.		-		
Suspended projects										
Union Long Ridge		41,000	:	—	141,000	—	150,000	—	150,000	150,000
Colony	—			—		—	46,000		46,000	46,000
White River	—	—			—	—	—		100,000	100,000
Projects needing more Federal land										
Superior		—	11,500		—	11,500	—	11,500	—	11,500
Multi Mineral	—	—		—	—	50,000		50,000	—	50,000
EXXON Love Ranch		—			—	60,000		60,000		60,000
EXXON Willow Creek			29,500		—					
NOSR 1	—	—		—	—	19,500	—	69,500	—	242,000
NOSR 2					—		—			
New lease tracts	—	—			—		—		—	
Other private tracts	—	—		—	—		—	—	501,000	–
Total	185,000	100,000	100,000	200,000	200.000	200,000	400,000	400,000	1,000,000	1,000,000

[a]Possibly involving open pit mining and offtract waste disposal

SOURCE Office of Technology Assessment

Table 10.–Constraints to Implementing Four Production Targets

	1990 production target, bbl/d			
	100,000	200,000	400,000	1 million
Possible deterring factors	Severity of Impediment			
Technological				
Technological readiness	None	None	None	Critical
Economic and financial				
Availability of private capital	None	None	None	Moderate
Marketability of the shale oil	Possible	Possible	Possible	Possible
Investor participation	None	Possible	Possible	Possible
Institutional				
Availability of land	None	None	Possible	Critical
Permitting procedures	None	None	Possible	Critical
Major- pipeline capacity	None	None	None	Critical
Design and construction services	None	None	Moderate	Critical
Equipment availability	None	None	Moderate	Critical
Environmental				
Compliance with environmental regulations.	None	None	Possible	Critical
Water availability				
Availability of surplus surface water	None	None	None	Possible
Adequacy of existing supply systems	None	None	Critical	Critical
Socioeconomic				
Adequacy of community facilities and services	None	Moderate	Moderate	Critical

SOURCE Office of Technology Assessment

Technological

Technological readiness will not hinder the first three scenarios because the relatively slow pace of their development will allow normal scaleup practices to be followed. Scenario 4 presents a different case. To achieve its goals, the construction of almost all plants will have to be started before 1984, which does not allow sufficient time either to undertake much preliminary experimentation, or to gain experience by modular demonstration or by the operation of pioneer facilities. In addition, the necessity to standardize the plant designs could have a number of unfortunate consequences. Among these could be that erroneous equipment specifications and other design flaws would be duplicated, and plant components would be unreliable and short-lived. Unanticipated environmental problems caused by the failure of pollution control systems could delay the projects, increase their costs, and have severe ecological consequences. Unreliability and less than optimum performance could prevent some plants from ever operating at their design capacity.

Economic and Financial

For a project to be economically viable and attract investors, it needs to have a favorable combination of market conditions, of construction and operating costs, and of resources such as land, water, and workers. The necessary permits must also be readily obtainable. Tradeoffs are possible. Thus, if adequate resources are available, and permits obtainable without undue expenditure of time and money, then somewhat less favorable market conditions might be acceptable.

Until late in 1979, it was assumed that sizable subsidies would be needed to offset unfavorable market conditions. However, in January 1980, developers estimated that they could profitably market shale oil syncrude at $35 to $40/bbl. * The present selling price for similar high-quality crudes is within this range (e.g., Wyoming Sweet sold in January of 1980 for a posted price of around $35/bbl). The "spot" or noncontract prices for these crudes are considerably higher ($40 to $52/bbl). Industry sources and petroleum economists expect the world price of crude to continue advancing in the future. Consequently, in a narrow economic sense shale oil appears to have reached parity with conventional crude.

*Whether shale oil requires subsidy for profitable marketing depends in part on the discount rate developers are assumed to require in order to proceed. See table 12.

The situation calls into question the need for financial incentives for the oil shale industry. This assumes, however, that market conditions continue to improve, and that institutional barriers (e.g., regulations, permitting requirements, and land availability) do not preclude development. Such could be the case if the developers responded to normal market pressures and opportunities. If, however, high levels of production must be achieved within a relatively short time, then Government support will probably be required to reduce the remaining risks associated with oil shale development. The most important of these risks are:

- Present capital and operating cost estimates for oil shale plants could substantially underestimate actual costs. No commercial facility has ever been built, and most of the existing engineering design estimates are preliminary. Estimates for the costs of building plants have consistently increased much faster than the rate of general inflation.
- Uncertainties in the regulatory or permitting process, or changes in the regulations after a plant was built, could jeopardize a project's economics or even preclude its development.
- Future petroleum prices might not allow shale oil to be profitably marketed once the plants were built. Since developers do not know precisely what their production or construction costs will be, the uncertainty of future prices for shale oil's primary competitor is a crucial risk.

Investor participation is not considered to be a problem for scenario 1, and the financial community will be able to supply the necessary capital for scenarios 1, 2, and 3. The financial requirements of scenario 4 will strain the Nation's resources of investment capital only slightly or moderately. However, it is questionable whether investors would be willing to risk participating in scenarios 2, 3, and 4 because of such factors as the uncertainties in world oil prices, the existence of institutional barriers, and the doubtful future of Government policies. "Possible" obstacles are shown for these scenarios.

Institutional

Land

The availability of land is not expected to be a problem with scenarios 1 and 2 because potential developers already have access to sufficient private and public lands to achieve the relatively modest production goals. It could, however, cause some problems for scenario 3, particularly if multimineral recovery or open pit mining were to be tested, It will be a critical obstacle for scenario 4. The production target (1 million bbl/d) will require about 15 to 20 plants each on a tract of approximately 5,000 acres, or a smaller number of larger operations, probably including some open pit mines. It is doubtful that private holdings are either large enough or contain enough rich oil shale to support this many projects by 1990.

Permitting Procedures

As a production target increases in size, so will the number of permits that must be obtained from the many different Government agencies. If many projects are involved, these agencies are likely to be overwhelmed by the sheer number of applications that must be reviewed, revised, and approved, The evaluation process could become more lengthy and complicated, which would increase the risk of delays in project schedules. Financial losses to the developers would be the outcome. Alternatively, if the agencies bypassed certain review steps in order to expedite the permitting process, design problems could slip by that would subsequently need to be corrected, introducing additional delays; or, if not caught, would result in environmental damage. Regulatory changes during the development of the projects could mandate unanticipated, and possibly uneconomical, process modifications that could have more easily been made during the design phase. These factors are likely to discourage some developers in scenario 3; they would severely impede reaching the targets of scenario 4.

Pipelines

Under the first three scenarios, the existing system of major pipelines should be adequate to convey the shale oil to nearby markets as well as to more distant ones in the Rocky Mountain region. Only relatively small pipeline spurs, plus some truck and rail transport, will be needed to supplement the system. The system will not be adequate for scenario 4, and new pipelines will be needed to provide access to markets in the Midwest,

Design and Construction Services

Only about 20 architectural, engineering, and design firms in the United States have the capacity to design and build an oil shale facility. The projects that would be needed for scenario 3 would require about 12 percent of their capacity; those in scenario 4 about 35 percent. If other industrial expansion competes for their services, the availability of these firms could delay the attainment of both scenarios. Contracting with foreign firms could be a short-term solution. In the longer term, as domestic firms expanded and smaller companies merged, the necessary array of technical expertise would become available. If the projects were to be completed before the 1990 deadline, however, these adjustments would have to take place in the early 1980's, which may not be possible. In any case, the demand for design and construction services would escalate project costs, especially in scenario 4.

Equipment

Scenario 3 will require between 6 and 12 percent of the U.S. production of valves, compressors, heat exchangers, pressure vessels, and other industrial equipment. If there were shortages, scenario 4, which will need 15 to 30 percent, could be severely hampered by project delays and cost escalations. Deficiencies in equipment supplies and design and construction services could escalate project costs by as much as 50 percent. *

Environmental

Although harm to the air, water, and land would certainly increase as the industry expanded, existing regulations for water quality, land use, and worker health and safety do not appear, at present, to be obstacles under any of the scenarios. This observation is based only on the results of laboratory tests, engineering design studies, and experience with small-scale plants. Therefore, it is not possible to accurately evaluate large-scale operations with respect to the efficacies of their control systems, the characteristics of their ultimate emissions streams, the consequences of the scaleup necessary to build them, and thus their effects on the environment. It is not known whether the industry will be able to meet, in the future, permitting standards and regulations for environmental protection.

The same types of uncertainties also apply to air quality. Recent studies, however, indicate that even when the best available control technologies are used, production capacity will be limited by the standards for prevention of significant deterioration (PSD). These were promulgated under the Clean Air Act, and specify the maximum allowable increases in the ambient concentrations of sulfur dioxide and particulate for any area.

The oil shale region has been designated as a Class II area, i.e., some additional air pollution and moderate industrial growth are allowed. There are also Class I areas nearby, where the air quality must be kept virtually unchanged. These could be affected by oil shale operations. One of these, the Flat Tops Wilderness, is less than 40 miles from the edge of the Piceance basin, and about 95 miles from the eastern edge of the Uinta basin. A preliminary regional modeling study undertaken by the Environmental Protection Agency (EPA) has indicated that by carefully siting the plants in the Piceance basin, an industry of up to 400,000 bbl/d could probably be controlled to satisfy the PSD standards for Flat Tops. The standards might hinder scenario 3 if all the capacity were concentrated in the eastern Piceance basin, but this is unlikely. It is more probable that some projects will be sited in the Uinta basin. Thus the scenario's goal could probably be achieved. Under scenario 4, air quality deterioration would be sufficiently large that compliance would not be possible because at least half of the capacity (500,000 bbl/d) would be located in the Piceance basin.

Water Resources

The availability of surplus surface water for large-scale oil shale development depends on the rate of regional growth holding to the medium levels anticipated by the States, and the long-term average flow of the Colorado River remaining at or very near the levels that have obtained since 1930. If there are higher rates of regional growth, or if the river's flows decrease by a few percent, production could be limited to about 500,000 bbl/d unless water were diverted from other users. Shortages of surface water, which could hinder scenario 4, could be offset by developing ground water, by purchasing surface water from other users, or by importing water from other areas. However, these strategies could encounter institutional obstacles. For example, importation of water is presently banned by Federal statutes, and ground water could be developed only if the rights of surface water users were protected.

All of the scenarios will require additional reservoirs to assure year-round water sup-

*Such increases occurred in process plant construction during the period from 1973 to 1975. See ch. 6.

plies. In many cases, these will be small and located at the plantsites. However, a large industry will need new reservoirs if the projects, and all other users, are to have adequate water supplies, The existing reservoirs will not be adequate for scenarios 3 and 4, and new storage will have to be built in the basins of the White River and the Colorado River mainstem. Reservoir siting could be restricted on some streams by their designation as wild and scenic rivers, or by the presence of rare and endangered species.

All of the scenarios will require diversion projects to carry water from the streams and reservoirs to the oil shale plants. Their construction would also come under environmental laws.

Socioeconomic

Social and economic obstacles will arise if the communities are unable to adapt to the growth caused by shale development, These obstacles have two aspects, The first relates to the physical ability of the towns to provide adequate housing, facilities, and services. The second involves the effects of local living conditions on workers and other residents. Even when physical facilities are adequate, the way of life can be unpleasant. In some Western and Great Plains communities where large and rapid growth has accompanied energy industry construction, living conditions have become so intolerable that workers and their families have simply left. The consequences for the projects of this labor turnover were construction delays, cost overruns, and poor workmanship.

Communities in the oil shale region are preparing for additional growth. In Colorado, for example, the State government, and the oil shale counties and municipalities—with the support and cooperation of industry—have been preparing for increased development for nearly 10 years. Consequently, the region is awaiting expanded oil shale development, and is prepared to absorb a moderate number of new residents. Assuming there are no breakdowns from boomtown stresses, and that presently planned facilities (such as the new town of Battlement Mesa) can be built, the region could accommodate up to 35,000 people between 1985 and 1990. (See table 11.) More could be incorporated if preparations were begun at once. The established communities could expand and new towns could be constructed, provided that financing were available, regulatory actions could be taken in a timely fashion, and the political and administrative atmosphere were favorable. However, if community and individual stress became too great and social institutions faltered, not even the total of 35,000 residents could be absorbed without disruption.

Although some social stress can be anticipated, the area should be able to deal with the growth associated with scenario 1. Scenario 2 could probably be accommodated if project construction were phased, and if some projects were developed in Utah. Severe problems would accompany the growth expected for scenario 3, and the growth for scenario 4 would greatly exceed the capaci-

Table 11 .–Actual and Projected Population and Estimated Capacity of Oil Shale Communities in Colorado

	Population		
Location[a]	1977 census[b]	1980 projected	1985-90 capacity[d]
Garfield County			
Rifle .	2,244	4,362	10,000
Silt :	859	1,211	2,800
New Castle	543	831	1,000
Grand Valley. ~ ~	377	589	3,000
Battlement Mesa[e] ~	—	198	2,500
Other ~ ~	–	–	1,700
Subtotal [f]. .,	4,023	7,191	21,000
Rio Blanco County			
Meeker	1,848	2,779	6,000
Rangely ...	1,871	2,223	6,000
Other. .	1,381	1,542	2,000
Subtotal	5,100	6,544	14,000
Total . , , . .	9,123	13,735	35,000

[a]Does not include Mesa or Moffat Counties both of which are more distant from the area of development

[b]Actuals from a special U S census

[c]End-of-the year projections by the Colorado West Area Council of Governments

[d]Estimated by OTA from various planning and needs assessment documents assumes completion of currently planned projects (e g housing waler and sewer system expansions street and road Improvements etc)

[e]A new town Construction anticipated to begin in the early 1980 s

[f]Includes only the immediate oil shale vicinity

SOURCE Off Ice of Technology Assessment

ties of the communities. Not only would the existing towns have to double or triple in size, but several new ones would have to be established. Disruption from social and psychological stress would be inevitable for scenario 4, and there is little doubt that adverse living conditions would prevent the realization of its production goal.

Policy Considerations

Some possible Federal policy responses to the constraints that would inhibit or preclude the expansion of the oil shale industry are discussed in this section. Other issues and impacts that have not been identified as constraints are dealt with in the subsequent chapters and summarized in chapter 1. Some examples are the efficacies, over the long term, of the proposed solid waste disposal practices, and the consequences of decreases in the flows of the Colorado River system.

Technology

Accelerated research, development, and demonstration would be needed to remove the technological barriers to scenario 4. The following programs might be considered.

R&D Policy Options

Some of the remaining technical questions could be answered in small-scale R&D programs. These could be conducted by Government agencies or by the private sector, with or without Federal participation. If Federal involvement is desired, the R&D programs could be implemented through the congressional budgetary process by adjusting the appropriations for the Department of Energy and other executive branch agencies, by providing additional appropriations earmarked for oil shale R&D, or by passing new legislation specifically for R&D on oil shale technologies.

Demonstration Options

In general, potential developers would prefer to follow conventional engineering practice, and to approach commercialization through a sequence of increasingly larger production units. Union, Colony, and Paraho have progressed through this sequence to the semiworks scale of operation—about one-tenth of commercial module scale. Larger demonstration projects will be needed to accurately determine the performance, reliability, and costs of processing technologies under commercial operating conditions. For Union and Paraho, the next step is a modular demonstration facility that would incorporate only one retort. Although costing several hundred million dollars, this facility would provide the necessary experience and the technical and economic data to decide whether to commit much larger sums to commercial plants. Rio Blanco and Cathedral Bluffs are also following the modular demonstration path. Colony regards the pioneer commercial plant as more suitable for demonstrating the TOSCO II technology.

As discussed in the section on economic and financial policies, whether the Federal Government plays an active role in funding and operating the demonstration projects will strongly influence the balance that is achieved between information generation and dissemination, timing of development, and cost to the Treasury. There are four possible structures for demonstration programs. In all cases, the net cost of the program will depend on where the facilities are sited. If the site could be subsequently developed for commercial production (e.g., a private tract, a potential lease tract, or a candidate for land exchange), the facility would have substantial resale value. Otherwise, it would have only scrap value.

A single module on a single site.—This option would provide comprehensive information about one process on one site. Either underground or surface mining experiments could be performed, but probably not both. The costs would be small overall but large on a per-barrel basis, because there would be no economies of scale. Some of the mined shale could be wasted because the single retort might not be able to process all of it economically.

Several modules on a single site.—This program might consist of an MIS operation coupled with a Union retort for the coarse portion of the mined oil shale and a TOSCO II for the fine portion. As with the single-module option, either surface or underground mining could be tested, or possibly both if the plant had sufficient production capacity. The total costs would be larger than for the single-module program, but unit costs would be much lower. For example, a three-module demonstration plant would cost about twice as much as a single-module facility; a six-module plant about four times as much. Different technologies could be combined to maximize resource utilization, and detailed information could be obtained for each. However, all of the information would be applicable to only one site. If many modules were tested, the demonstration project would be equivalent to a pioneer commercial plant, except that a true pioneer operation would probably not use such a wide variety of technologies.

Single modules on several sites.—Several technologies might be demonstrated, each at a separate location. For example, an underground mine could be combined with a TOSCO II retort on one site; a surface mine with a Paraho retort at another. Total costs would be large, as would unit costs, which would be comparable with those of the single-module/single-site option. The principal advantage would be that different site characteristics, mining methods, and processing technologies could be studied in one program.

Several modules on several sites.—For each site, a combination of mining and processing methods could be selected that would be appropriate for the site's characteristics and the nature of its oil shale deposits. The maximum amount of information would thus be acquired in exchange for the maximum amount of investment. Each project would resemble the several-module/single-site option; the collection would constitute a pioneer commercial-scale industry.

Economic and Financial

Continuing uncertainties over eventual plant costs, along with present regulatory deterrents, may mean that financial incentives will be needed. Government action to allow easier access to public oil shale land, or to remove regulatory impediments, could reduce this need. If, however, assuring the production for scenarios 3 or 4 by 1990 is a major objective, then financial incentives should be seriously considered. They would be particularly important in meeting the goals of scenario 4, because the rapid deployment of a large number of projects within 10 years is likely to create cost overruns and jeopardize project economics.

Government Financial Support

Several types of Government financial supports are discussed below. These are basically of two kinds: incentives to private industry, and direct Government ownership or participation.

Incentives to industry.—An effective incentive must avert one or more economic risks. It should also be cost-effective: its cost to the Government should be low and its subsidy effect high. It should promote, or at least not impede, efficient investment and production decisions, and should encourage competition. It should facilitate access to capital. It should entail small administrative and bureaucratic costs. Finally, it should be phased out as market conditions improve and risks are reduced. The following analysis assumes that only temporary incentives will be required for the first generation of oil shale facilities. If this assumption proves incorrect, the implications of subsidizing the industry should be reevaluated; permanent subsidies are a very different economic proposition from temporary ones.

OTA analyzed 10 possible economic incentives. These differ with respect to the criteria described above and also with respect to whether the Government provides the incentive before or after production begins. The latter option is desirable because the Government could phase in the subsidy disbursement. Production incentives (those applied after production begins) limit the Government's financial exposure and risk. The use of production subsidies alone, however, may encourage only large corporations with exceptional debt capacity.

The net cost to the Government of a particular incentive can directly reflect the extent of its subsidy effect, but the relationship is not necessarily linear: some incentives definitely provide more subsidy at a lower cost to the Treasury than others. (See table 12.) It is also important to note that the corporate, financial, technical, and fiscal circumstances of the potential developers will show considerable differences. Consequently, it is unlikely that any single "best" incentive will be revealed. However, some are clearly superior to others from the viewpoints of both the Government and developers. An optimal policy might be to provide a variety of incentives of approximately equal dollar value, and to allow each company to choose the one that is most appropriate to its particular circumstances. The implications of each of the incentives follow. *

- Construction grant. —The Government provides a direct grant to cover a prespecified percentage of total construction costs.

*Full discussion is found inch. 6.

Table 12.–Subsidy Effect and Net Cost to the Government of Possible Oil Shale Incentives'

(12-percent rate of return on invested capital)

Incentive	Total expected profit ($ million)	Change in expected profit ($ million)	Probability of loss	Total expected cost to Government ($ million)	Breakeven price ($/bbl)
Construction grant (50%)	$707	$487	000	$494	$34.00
Construction grant (33%)	542	321	0.00	327	38.70
Low-interest loan (70%)	497	277	0,00	453	43,40
Production tax credit ($3)	414	194	0,01	252	42,60
Price support ($55)	363	142	0.01	172	NA
Increased depletion allowance (27%)	360	140	0.05	197	4570
Increased Investment tax credit (20%)	299	79	0.05	87	4580
Accelerated depreciation (5 years)	296	76	0.05	79	46,00
Purchase agreement ($55)	231	11	0.03	0	NA
None	220	0	009	0	4820

(15-percent rate of return on invested capital)

Incentive	Total expected profit ($ million)	Change in expected profit ($ million)	Probability of loss	Total expected cost to Government ($ million)	Breakeven price ($/bbl)
Construction grant (50%)	$281	$477	0.00	$494	$4060
Construction grant (33%)	119	315	0.19	327	47,70
Low-Interest loan	81	277	0.23	453	5470
Production tax credit ($3)	-61	135	063	252	56.10
Price support ($55)	-88	108	077	172	NA
Increased depletion allowance (27%)	-110	86	0.75	197	57.20
Increased Investment tax credit (20%)	-131	65	0.77	87	58,80
Accelerated depreciation (5 years)	– 127	69	0.76	79	5890
Purchase agreement ($55)	-150	46	092	0	NA
None	-196	0	093	0	61.70

[a]The calculations assume a $35/bbl price for conventional premium crude that escalates at a real rate of 3 percent per year Thus the predicted $48/bbl breakeven price for the 12-percent discount rate 'Will be reached in 11 years or in the fifth year of production Therefore in narrow economic terms 011 shale plants starting construction now which assume a 12-percent discount rate will be profitable over the life of the project without subsidy (See discussion for caveats concerning this conclusion) The calculations are for a 50,000 -bbl/d plant costing $17 billion All monetary values are in 1979 dollars

SOURCE Resource Planning Associates Inc Washington O C

(OTA analyzed both 50- and 33-percent grants.) This incentive has a strong effect on project financing. It benefits all developers, and does not distort investment or production decisions. However, it would impose large administrative burdens on both the Government and industry. There would be no assurance that production would occur even with the grants. Large initial lump-sum payments would be required rather than phased-in treasury disbursements. The subsidy would probably be politically unpopular.

- Production tax credit.—The developer is allowed a credit against corporate income taxes for each barrel of shale oil produced. (A $3 credit per bbl of crude shale oil was analyzed.) This incentive provides a strong subsidy effect, and moderately shares investment cost uncertainty. It imposes minimal administrative burdens. It only slightly improves project financing, however, and entails some distortion of product price, It most strongly affects firms that have large tax liabilities, and its net cost to the Government is high compared with other possible incentives. It is widely supported by potential developers.
- Price support.—A minimum price for shale oil is guaranteed for a long enough period to allow developers to recover their capital. (OTA analyzed a minimum price of $55/bbl of shale oil syncrude-the Government would pay the difference if the market price were lower.) This incentive has a very strong effect on project economics. It removes most of the risk of price fluctuations in foreign oil. On the other hand, it does not prevent shale oil from being sold in the private market if prices there are higher than the supported price. With present and projected world oil prices, it is very possible that no Government purchases would be necessary. In this case, the Government would gain income since the developers would pay taxes on their production. This incentive limits the Government's financial exposure—a highly desirable feature. * Its availability would also help developers obtain project financing.

  Price supports would benefit all firms. However, they might not be sufficient for firms with limited debt capacity (i.e., firms that could not borrow the required capital), especially if they were considering costly commercial-size plants. The administrative burden would range from slight to moderate. This subsidy is supported by a variety of potential developers. Its characteristics make it attractive to both developers and the Government.
- Purchase agreement.—A developer contracts with the Government to sell shale oil at a specified price that is usually somewhat above the expected market price. (OTA's analysis assumed a price of $55/bbl in constant 1979 dollars.) This incentive is similar to a price support except that the developer must sell the oil to the Government; he does not have the option of selling it in the open market. Purchase agreements increase profitability to a lesser extent because the firm does not benefit if the market price is above the contract price. On the other hand, the Government shares in both the risks and the potential benefits of shale oil production. Consequently, the average cost to the Government is somewhat lower than with a price support. Purchase agreements limit the possibility of loss, but also reduce the likelihood of large profits. They are less popular with industry than are price supports. The administrative costs are also higher than those of price supports, but their severity can be controlled, to some extent, by the manner in which the subsidy is constructed.
- Low-interest loan.—The developer borrows a specified percentage of capital costs from the Government at an interest rate below the prevailing market rate. (OTA's analysis assumed 70-percent fi-

*As indicated in table 12, the net cost to the Government of providing such an incentive—even if developers chose to sell to the Government-would be low relative to most other incentives, nancing at 3 percentage points below the market rate.) This incentive requires the Government to share significantly in the risk of project failure, and it has a marked effect on a developer's ability to obtain financing, but it tends to distort input costs, and to bias investment decisions in favor of capital-intensive technologies. It also imposes large administrative burdens. This type of subsidy is usually designed to provide the greatest benefits to firms with weak financial capability. In practice, however, it is difficult to deny loans to strong firms.

- Debt guarantees.—The Government agrees to pay back a loan if the developer defaults. With this insurance, a firm can usually obtain lower interest rates. Usually, only a fraction of the total loan is insured, and the borrower is required to pay a premium for the insurance. This incentive only slightly subsidizes the investment, but it provides maximum sharing of the risk of project failure. It considerably eases borrowing problems. Loan guarantees primarily benefit financially weak firms. They distort input cost, and they bias investment decisions toward capital-intensive technologies. They also impose a significant administrative burden. Perhaps the most obvious drawback is the uncertain financial exposure of the Government. The Government's costs would be zero if no plants failed, but huge if even a few failures occurred. The Government has had considerable experience with debt insurance programs during the last 15 years, and the fees paid by firms for the protection have, in sum, yielded it net income. If the participation of small- and medium-sized firms is desired, then either debt guarantees or low-interest loans will probably be necessary.
- Investment tax credit (10 percent), accelerated depreciation (5 years), and increased depletion allowance.—None of these would be likely to have a major impact on oil shale development. Their incentive characteristics are discussed in chapter 6.

Direct Government Participation or Ownership

The Government could share the capital and operating costs with industry, and thereby become a part owner of the project. The consequences would be similar to the construction grant option, except that the Government would share all of the risks and benefits. Almost without exception, potential developers believe that active Government participation would increase managerial complexity and inefficiency. Administrative burdens would be very high.

The Government could also contract for the construction of several modular plants it would then operate, either alone or through contracts. It could thus conduct operations to obtain accurate information on technical feasibility, project economics, and the relative merits of different processes. This would be of assistance in evaluating its future policies towards oil shale, in disseminating technical information, and in improving its understanding of the value of its oil shale resources. After enough information had been obtained, the facility could be scrapped or sold to a private operator. This policy would provide the Government with information and experience, but the cost would be much higher than that of incentives to private developers.

Because industrial partners would insist on some protection of proprietary information, the Government would probably not be able to disseminate all project data as it chose. In addition, its experience in designing, financing, managing, and obtaining permits for an oil shale plant may not resemble that of private industry. Thus, the information acquired may be of only limited use to subsequent private developers.

Most of the information secured through Government ownership could be made available as a condition of granting private financial incentives. Furthermore, this kind of Government intervention is likely to discourage private developers from undertaking their own modular development and R&D programs. Government programs of this kind tend to reduce the benefits that a particular firm could obtain from R&D or modular testing. Finally, when patenting and licensing technologies, definite provision is made for the dissemination of technical information on both gratis and fee terms to possible users of the processes,

Institutional

Use of Federal Land*

The Federal Government owns over 70 percent of the oil shale lands and nearly 80 percent of the best shale resources. Essentially all of the large deposits of nahcolite and dawsonite** in the Piceance basin are federally owned. No permanent leasing program exists for these lands, and the current Prototype Oil Shale Leasing Program is limited to no more than six tracts of 5,120 acres each. To date, four tracts have been leased: Utah tracts U-a and U-b (the White River project) and Colorado tracts C-a (Rio Blanco) and C-b (Cathedral Bluffs). The other two tracts were proposed for Wyoming, but no bids were received when their leases were offered in 1974. Development is proceeding on the Colorado tracts, but the ones in Utah have been stalled by litigation between the State and the Federal Government. ***

*On May *27, 1980* the Department of the Interior (DOI) announced several oil shale decisions. Up to four new tracts will be leased under the Prototype Program and preparations started for a permanent leasing program. At least one multimineral tract will be included in the renewed Prototype Program. Land exchanges will not be given special emphasis, and no decision will be made to settle mining claims until the Supreme Court rules on *Andrus* v. *Shell Oil* (the oil shale mining discovery standard case). [NOTE: This case was decided on June 2, 1980. No. 78-1815.] The administration will propose to Congress legislation to give DOI the authority to grant leases bigger than the present statutory limitation of 5,120 acres, to provide for off-lease disposal of shale and siting of facilities, and to allow the holding of a maximum of 4 leases nationwide and 2 per State.

**Nahcolite is a mineral containing sodium; dawsonite contains aluminum.

***On May 19, 1980, the U.S. Supreme Court reversed the lower court decisions and held that the Secretary of the Interior could reject Utah's applications for oil shale lands as school land indemnity selections (*Andrus* v. Utah, No. 78-1522).

Additional Federal land would not be needed to achieve the goal of scenario 1, nor to reach that of scenario 2 if economic conditions favored oil shale development. The goal of scenario 3 could also be met without more Federal land if regulatory and economic uncertainties were sufficiently reduced to encourage Tosco, Colony, Union, and Rio Blanco to continue their commercialization programs. On the other hand, implementation of scenario 4 would require a highly favorable economic and regulatory climate (probably including Federal subsidies), or the use of additional Federal land, or both. In any of the scenarios, more public land may be required if large-scale multimineral recovery processes or open pit mining are to be tested in the near future.

The land could be leased, exchanged for private land, or developed by the Government. All three options may be affected by the fact that much of the best Federal oil shale land is subject to unpatented mining claims by private parties. The validity of some of these claims will be determined by the Supreme Court in 1980. If the Court's ruling favors the claimants, much less Federal land may be available for disposition.

Leasing.—Under the Mineral Leasing Act of 1920, the Department of the Interior (DOI) has the authority to lease public oil shale lands to private developers. The Act limits the number of leases to one per person or firm, and restricts the maximum size of a single tract to 5,120 acres (8 mi^2). Individuals and firms are allowed to hold shares in several leases, but the total area covered by these shares cannot exceed 5,120 acres.

Whether the acreage limitation will impede development will depend on the location of the tract and on the types of development technologies to be employed. It might preclude large-scale operations in the thinner, leaner deposits in Wyoming. However, a 5,120-acre tract in the relatively rich areas of the Piceance and Uinta basins could easily support a commercial-scale operation over its economic lifetime. On the other hand, if a very large facility were desired, the acreage limitation could impede efficient resource development, especially if surface mining were to be used. If the entire tract were suitable for surface mining, the need to dispose of mining and processing wastes within the tract boundaries would reduce overall resource recovery, and might allow only relatively inefficient development. One solution would be to include in the tract an area (such as a dry canyon) that contains no oil shale resources but that could be used for waste disposal. This option would not require amending the Leasing Act, but it could complicate mining operations and would reduce the value of the tract to the private sector. Another option would be to allow disposal in similar areas outside the tract boundaries, as was originally proposed for tract C-a, but this would require amending the Federal Land Policy and Management Act of 1976 (FLPMA).

The argument in favor of limiting the number of leases per individual or firm is that it prevents a small number of entrepreneurs from cornering the lease market. The argument against the restriction is that it prevents a developer from acquiring experience and technical information on one tract and then applying it to another while the first is still operating. The latter position is valid for potential developers who do not have their own oil shale land, but not for those whose privately owned tracts could be developed commercially if the company could acquire the necessary expertise in the richer deposits on public land. The options are to increase the number of leases allowed to two or three per company or individual, regardless of the locations of the tracts; or to allow one lease per developer per State. The latter would allow a developer to obtain experience with the richer oil shales in Colorado, for example, which could then be applied in Utah or Wyoming. Potential developers prefer the first option because the shales in Utah and Wyoming are much poorer than those in Colorado. Both options would require amending the Mineral Leasing Act.

If additional leasing is desired, it could be carried out either in a new, permanent leasing program, or as part of the Prototype Program. Opportunities exist for leasing at least two additional tracts within the Prototype Program because of the two Wyoming leases that were not purchased during the 1974 offering. No congressional action would be required to extend the Prototype Program, but its extension would constitute a major Federal action. Therefore, a supplementary environmental impact statement (EIS) would be required. Its preparation could take from 1 to 2 years.

Nomination of the tracts and preparation of leasing regulations could add several months to a year to the front end of the schedule. Unless the preliminary steps were expedited, the leases could probably not be sold until about 1983. If the leases were similar to those for the existing Prototype tracts, a 2-year environmental monitoring program would be mandated before site development could proceed. Thus, the first construction work could not begin until about 1985. If a commercial plant were built without a preliminary demonstration phase, commercial production could start in about 1990. With a demonstration phase, commercial production could not begin before 1992 or 1993.

The timespan could be reduced somewhat by offering the tracts that were considered in the mid-1970's as replacements for the Wyoming tracts. The nomination process was completed for these tracts, and work was begun on a supplemental EIS. They were originally selected as sites for in situ operations, and to offer them now for this type of development would be inconsistent with one of the Program's major goals, which was to test a variety of processing technologies. (Both of the active Prototype tracts are being developed by in situ techniques.) If they were also suitable for aboveground processing, their use in the program extension would shorten the commercialization schedule by about a year.

The other leasing option would be a new, permanent leasing program that would be independent of the Prototype Program and therefore not restricted by its six-tract limit. Implementing this option would take longer than extending the Prototype Program, because of the need to prepare new leasing regulations and an entirely new EIS. No congressional action would be required, unless the program were to be coupled with an incentives package or with amendments to the Mineral Leasing Act.

The adoption of a new leasing program would imply the abandonment of another objective of the Prototype Program, namely to obtain the technical, economic, and environmental information needed to design a permanent leasing program. For a variety of reasons, the Prototype Program has not yet provided this information. (See vol. II.) Its abandonment would engender political opposition from the individuals and groups that criticize oil shale development, especially where public land is involved.

Land exchange.—Private interests own several million acres of oil shale land. Of the approximately 400,000 acres of privately owned land in Colorado, at least 170,000 acres contain beds that are at least 10 ft deep with a potential yield of 25 gal/ton, It has been estimated that the total potential oil yield from these richer tracts is at least 80 billion bbl. However, much of the privately held land is located on the fringes of the oil shale basins, and contains thinner, leaner deposits than does the adjacent Federal land, Furthermore, many of the private tracts are in small, noncontiguous parcels (mainly former homesteads and small mining claims) that cannot be economically developed. Private oil shale development would be encouraged if these lands were exchanged for more economically attractive Federal tracts.

There are essentially two land exchange options. The first involves "blocking up' scattered or oddly shaped private tracts by exchanging some of them for adjacent Federal lands. (Superior Oil Co. proposed such an exchange for its tract near the northern edge of the Piceance basin.) The second option involves the exchange of large privately owned parcels for equivalent Federal tracts, perhaps in an area that is more suitable for a specific development method.

Both options are allowed by FLPMA. Under FLPMA, the Government may exchange public land for private land, provided that the exchange is in the public interest and that the properties involved are within 25 percent of equal value. The difference can be made up with cash. The major problem with exchanges under FLPMA is that the procedures are time-consuming, complex, and costly. Several Federal agencies must be involved in estimating the relative values of the tracts in question and in determining whether the exchange is in the public interest. An EIS may be needed; its preparation could take as long as 2 years. The overall process, including review, evaluation, and approval by the agencies plus a period for public comment, can take even more time.

There are several ways to improve the exchange process. One would be to streamline the review procedures, perhaps by setting up a task force within DOI to deal with exchange proposals involving oil shale lands. Another option would be for DOI to nominate Federal tracts, to characterize their environments, and to evaluate their resources, even if no exchange proposals had been received from private parties. With this advance preparation, the exchange process would be shortened, and the Government would be able to control the location of the future oil shale plants. Both options would be costly and would enlarge the bureaucracy. Additional appropriations, and possibly authorizing legislation, would have to be provided by Congress.

A third option would be to exchange private land for Federal land that is adjacent to State-owned tracts. The mix of private and State land could then be developed under a State-controlled leasing program. This option would be most applicable to the Uinta basin, where the State's extensive holdings are intermingled with Federal and private tracts.

Government development.—The Government could also develop its own oil shale lands. Two likely tracts are the 40,000-acre Naval Oil Shale Reserve 1 (NOSR 1) in Colorado and the 90,000-acre NOSR 2 in Utah. (The resources on NOSR 2 are of much poorer quality.) These sites could be developed either with a Government-owned corporation, or through a cost-sharing arrangement with industry. The advantages and disadvantages of different types of Government participation are discussed in the section on economic and financial policies.

Permitting Procedures

Developers view the costs and potential risks of the present regulatory process as one of two primary impediments to development. Reaching the production goals of scenarios 1 and 2 will probably not require expediting the permitting process, but it will be needed to meet the goals of scenario 3, and is even more important for scenario 4. One or more of the following actions could speed up the process: require regulatory agencies to make decisions in a specified period of time; "grandfather" projects under development to make new laws and regulations inapplicable to them; create an energy board or authority with the power to overrule Federal regulatory decisions; or limit litigation as was done with the Alaskan oil pipeline. The first two options are likely to be a part of the powers of the Energy Mobilization Board.

Another possibility would be for regulatory agencies themselves to take the lead in simplifying their own permitting procedures. This could be done by the imposition of internal time limits on the period of review, and could be combined with an arrangement whereby developers applied for a package of related permits. This would consolidate the number of permits required, and eliminate some of the existing permit duplication. EPA Region VIII appears to be adopting these procedures, although it is not clear whether and to what extent they will actually expedite the permitting process.

Pipelines

A major pipeline would have to be built to ship most of the l-million-bbl/d target of scenario 4 because existing pipelines to Wyoming and Midwestern refineries are inadequate. Its construction could require access across Federal land and eminent domain rights to private land, as well as extensive regulatory actions and EISs. Congressional action might be needed to facilitate such a project.

Design and Construction Services and Equipment

To achieve the goals of scenario 4, Federal assistance might be needed to deal with scarcities of heavy equipment and limited design and construction services. The following policies might be developed:

- Training programs could be set up for construction workers to provide a skilled work force when construction begins.
- Equipment with long delivery times could be identified and supplies increased by either expanding existing capacity, stimulating additional capacity, or encouraging early orders.
- Tariffs and quotas on imported equipment could be reduced or eliminated.
- Federally sponsored R&D programs could address the technical questions of scaling up to commercial-sized facilities.
- Developers, local governmental units, related industries, concerned interest groups, and appropriate Federal agencies could be encouraged to coordinate their efforts. This would help avoid construction delays,
- Standardization of plant designs could be used to reduce complexity and simplify construction.

Environmental

Air Quality

The PSD standards promulgated under the Clean Air Act could hinder scenario 3 and will, with current "best available control technologies, " prevent achieving scenario 4. Policy options for addressing these obstacles include:

- Coordinate the issuance of PSD permits.— This option would not alter the PSD regulations nor relax air quality standards, but would change the methods for issuing the PSD permits that are needed before construction of the plants can begin. Rather than issuing the permits on a first-come first-served basis, EPA would encourage all prospective developers to coordinate their development plans before applying for their permits. The goal would be a siting pattern that maximized production while complying with air quality standards. This might relieve some of the siting difficulties envisioned for the Piceance basin as a result of its proximity to the Flat Tops Wilderness area. The implementation of this type of option, however, could be complicated by factors such as antitrust laws.

- Redesignate the oil shale region from Class 11 to Class III.—This option would be initiated at the State level, with a requirement for final approval from EPA. The criteria that would have to be satisfied include:
  —the Governors of Colorado, Utah, or Wyoming must specifically approve the redesignation after consultation with legislators, and with final approval of local government units representing a majority of the residents of the area to be redesignated, and
  —the redesignation must not lead to pollution in excess of allowable increments in any other areas.

  This option would allow greater degradation of air quality, but would permit more industrial development. While it would appear that with such an option there could be about twice as much oil shale development as presently possible, there would still be limitations owing to nearby Class I areas. With this option it is expected that the production target of scenario 3 could be achieved, but not that of scenario 4.
- Amend the Clean Air Act.—This congressional option would exempt the oil shale region from compliance with certain provisions of the Act. Under this option Congress might direct EPA and the States to redesignate the oil shale region from a Class 11 to a Class III area, and to exempt the developers from maintaining the visibility and air quality of nearby Class I areas. This would remove both the major uncertainties surrounding the siting of facilities within the resource region itself and any siting barriers connected with the degradation of the Class I areas. Such an option should allow achievement of the scenario 4 production goal at the cost of increased air pollution in the oil shale and nearby regions.

Environmental R&D

The public and private sectors have carried out extensive work on the environmental impacts of oil shale development and on pollution control technologies to reduce these impacts. Yet many questions remain about the effects that a commercial-size industry would have both on the physical environment and on worker health and safety. It is essential, therefore, that R&D keep pace with the industry's development. The information generated would also assist regulatory agencies to develop emission and effluent standards for the industry.

Options at the Federal level for improving technical information include improved coordination of R&D among executive branch agencies, increased appropriations for oil shale R&D, the use of existing national commissions (e.g., the National Commission on Air Quality) and the passage of legislation specifically directed to R&D on the environmental impacts of oil shale technologies. (Environmental R&D needs are discussed in ch. 8 and summarized in ch. I.)

Water Resources

Policy options for removing obstacles associated with water resources are discussed below.

Financing and Building New Reservoirs

Major new reservoirs will be needed for scenarios 3 and 4 to ensure that the water needs of oil shale developers as well as all other users can be satisfied. They could be financed and built by the Federal Government, by State organizations, or by the developers. The options for Federal involvement are discussed below. (Those for the States and the developers are discussed inch. 9.)

Congress could provide for the construction and financing of new water projects through two mechanisms. First, funds could be appropriated for a projector projects that have already been authorized. Several have already been evaluated by the Water and Power Resources Service (WPRS), * and their construction approved. Actual construction cannot not be started until they are funded. However, not all of these projects have been evaluated for their suitability to supply water for oil shale development, and some projects may not be optimally located to serve oil shale plants. A second option would be to pass legislation that would specify both the construction and funding of new, but not previously authorized, Federal water projects. Unless language were included to expedite construction, these projects would require a long review process. They could, however, be designed and sited as water sources for oil shale (as well as other possible uses). An example would be constructing irrigation reservoirs with additional capacity for oil shale requirements.

Under either option, DOI, through WPRS, could operate these reservoirs in accordance with State water law. Their costs could be recovered over the operating life of the facilities from revenues generated by selling water to oil shale developers and other users, in accordance with authorizing legislation.

The Siting of Reservoirs and Direct Flow Diversions

The construction of new reservoirs and direct flow diversions (e.g., pipelines) might be hampered, delayed, or even disallowed under provisions of the Endangered Species Act, the National Wild and Scenic Rivers Act, and the Wilderness Act. Potential problems could be reduced by the following mechanisms.

- Identifying endangered or threatened species.—Two federally designated rare and endangered fish species, the humpback chub and the Colorado River squawfish, have already been found in the waters of the oil shale region, and additional species requiring protection may be found during future studies. The Endangered Species Act may be interpreted as restricting activities that might affect the critical habitats of such species, although no critical habitat has been declared for the squawfish or humpback chub. Knowing the approximate location of the critical habitats of endangered species would be helpful if it were decided to establish an oil shale industry because the timely siting of reservoirs and direct flow diversions could be affected by agency interpretations involving instream flows. Should construction of these facilities begin before the critical areas were identified, there could be opposition to their completion, and water supplies from a particular reach of a river could be delayed or interrupted. If the locations of all designated critical habitats were identified by DOI and the required biological opinions obtained, the facilities could be sited to minimize interference and delay.

  Alternatively, Congress could designate such reservoirs to be in the national interest, and could allow their construction in spite of the effect this might have on endangered species.

- Designating wild and scenic rivers and wilderness areas.—To date, no rivers in the oil shale region have been designated for inclusion in the Wild and Scenic Rivers System; however, several within the basins of the Colorado River mainstem are being considered, Diversions of water from specific stream reaches could be affected if they are set aside. An early designation of the eligible rivers would assist in the planning for future shale oil production. Given this information, direct flow diversions could be sited downstream from the por-

*Formerly the U.S. Bureau of Reclamation (USBR).

tions designated as wild or scenic. This would avoid a direct conflict within a given river stretch but could add to the water supply costs. (Supply costs are discussed in detail inch. 9.)

To date, four areas in the basins of the White River and the Colorado River mainstem have been designated under the Wilderness Act. Other areas are being considered pursuant to the Roadless Area Review and Evaluation II (RARE II) program. * New reservoirs would not be permitted in the designated areas. A complete listing of wilderness areas that might be considered in the near future would allow potential developers to locate their water storage facilities elsewhere. Alternatively, Congress could specifically exclude rivers and/or new areas in the oil shale region from designation as wild and scenic rivers or wilderness areas.

Federal Sources of Water for Oil Shale Development

Congress, under its constitutional powers, could make water available from Federal water projects, or potentially from the reserved rights doctrine. (See ch, 9.) If Congress decides that water from congressionally funded projects should be made available for oil shale development, then any legislation enacted should provide that the term "industrial use or purpose" includes the use of water for oil shale development,** Congress could also amend the authorizing legislation for those projects from which water for oil shale development might be sought, to permit the use of their water for this purpose. The objective of this action would be to overcome any administrative reluctance to permit the use of water for oil shale development under an authorization that did not specifically mention oil shale,

The power of Congress over reserved waters is more limited than its power over waters in congressionally funded projects. Water rights covered by the reserved right doctrine must be used "in furtherance of the purpose of the reservation. " For this reason, Federal water rights do not seem to be likely sources for oil shale development, except perhaps in the case of lands set aside for the Naval Oil Shale Reserves. This question, however, is in the early stages of litigation.

Interbasin Diversion

Interbasin diversion is a technically feasible although costly option for bringing additional water to the oil shale region, There are also serious political obstacles to this alternative. The Reclamation Safety of Dams Act of 1978, amending the Colorado River Basin Project Act, prohibits the Secretary of the Interior from studying the importation of water into the Colorado River Basin until 1988. If it were decided to pursue this option as a means of supplying water to an oil shale industry coming online in 1990, this prohibition would have to be lifted.

Interbasin transfers could be used to relieve the water problems of the oil shale region in several ways, Water could be transferred directly to the oil shale region, either exclusively for oil shale development or for all users. Alternatively, the water needs of Colorado's eastern slope cities, presently being supplied in part from the Upper Colorado River Basin, could be met from other hydrologic basins. The water presently being exported from the Upper Basin then could be used for oil shale development. In a third application of interbasin transfers, all or a portion of the 750,000 acre-ft/yr presently being supplied to Mexico by the Upper Basin States under the Mexican Water Treaty of 1944-45, could be taken from another hydrological

*The Forest Service, in its RARE 11 program, is evaluating over 66 million acres of land to determine their suitability for designation as wilderness, During the period of initial evaluation, and up to final recommendation by Congress, these lands will be in some form of restrictive management.

**A Memorandum of Understanding ex ists between DOI and the State of Colorado with respect to the use of water from existing or authorized U.S. Bureau of Reclamation (now WPRS) projects, The State desires that the water not be changed from agricultural, municipal, or light industrial uses to energy product ion (including oil shale] that are inconsistent with State policies. Under this memorandum, the State will review any applications to redistribute water from conventional uses to energy production. The memorandum could be superseded bv direct congressional directives of overriding national importance.

basin (perhaps the Mississippi basin). The water thus freed in the Upper Basin could be assigned in part to oil shale development (750,000 acre-ft/yr would be sufficient for a 3-million- to 7.5-million-bbl/d shale oil industry).

The Allocation of Water Resources

If Congress were to pass legislation encouraging the development of an oil shale industry, it might wish to address the issue of how the necessary water would be supplied and how oil shale legislation might affect water allocation.

Water in the oil shale region is presently distributed by a complex framework of interstate and interregional compacts, State and Federal laws, Supreme Court decisions, an international treaty, and administrative decisions. Within the Western States, water rights are apportioned by the States to competing users according to a doctrine of prior appropriation under which water rights are a form of property separate from the land.

Oil shale developers presently hold extensive, but largely junior (i.e., low priority) surface water rights. Therefore, if water shortages were to occur, existing developer supplies could be interrupted. More reliable supplies may be provided through development of ground water not tributary to the surface, purchase of the consumptive portion of irrigation rights during the irrigation season, purchase of surplus water from Federal reservoirs, or importation of water from more distant hydrological basins. (The last two options have been discussed above). A discussion of the amount of water needed for oil shale development is presented in detail in chapter 9.

If control over the water supply for oil shale is to be left to the States, then Congress should probably so specify that decision in oil shale legislation to avoid any question of the preemption of State water laws. Legislation that would confirm preservation to the States of the same power over water for oil shale as they have over other water supplies should require the developer to comply with State procedures in securing a water supply, and provide that the established State appropriation system has the same authority to grant, deny, or place conditions on a water right and permit as would prevail in the absence of the legislation.

If Congress were to attempt to remove the water supply for oil shale production from the control of the State, strong legal and political resistance would ensue. Such resistance could delay oil shale development.

Socioeconomic

The social and economic effects of oil shale development are not unique to the resource being produced or to the technologies involved. Rather, they derive from an influx of people, regardless of the cause. In this respect, they are similar to the effects of growth in other energy industries, such as coal or oil and gas. Before looking at specific policy options for the effects of oil shale development, the perspective from which they are viewed and the role of the Federal Government in impact mitigation must be considered.

Congress can view socioeconomic impacts from one of three policy perspectives:

- As part of the consequences of all kinds of energy development.—In recent sessions, Congress has considered bills that would provide assistance to communities faced with problems from the growth of many different energy industries, and programs for oil shale could be included in such legislation.
- As an aspect of specific energy initiatives.—Proposed amendments to the Powerplant and Industrial Fuel Use Act of 1978 are illustrative of this more limited approach. These amendments are directed to the adverse effects of major energy developments, which could include oil shale. They authorize grants, loans, loan guarantees, and payments of interest on loans; and propose an expediting process for present Federal pro-

grams as well as an interagency council to coordinate Federal impact assistance.
- As the result of oil shale development alone.—In this case, specific language dealing with socioeconomic effects could be included in bills providing for the development of oil shale resources.

The ways in which Congress deals with the impacts will depend on which perspective is adopted.

Policy decisions must also consider the role of the Federal Government in impact mitigation. Assistance in coping with the consequences of growth is not expected in the usual course of economic development. Recently, domestic energy development has become an exception when the distinction has been drawn between effects that can be handled by local communities—i.e., those that can be considered a normal adjunct of development, and those that cannot be readily solved with local resources—boomtown problems. The extent and nature of Federal involvement in impact mitigation is highly controversial. On the one side, it is argued that social and economic difficulties are State and local problems that should be viewed as the inevitable consequences of industrial growth, and thus the Federal Government need not be involved with their amelioration. On the other side, the position is taken that national energy requirements are the root causes of impacts, therefore a Federal role is appropriate. Several Western States propose that for reasons of equity, the national goal of accelerated domestic energy production requires direct Federal participation in alleviating negative impacts. This question about the Federal role must be faced before decisions can be made about appropriate Federal actions for dealing with the impacts of oil shale development.

No new Federal initiatives appear to be needed for scenarios 1 and 2, as long as the existing mechanisms are effective. Several requirements must be met, however:

- both Federal and State actions must support already established growth management processes;
- efforts to improve the delivery of Federal programs should continue;
- State appropriations from funds designated to assist the oil shale communities will be necessary; and
- support services, such as technical assistance to the local governments, should not be reduced.

Increased Federal participation will be needed if the region is to accommodate the growth anticipated under scenarios 3 and 4. Several kinds of support could be given. One option would be to provide additional financing for expanding the communities and for planning and establishing new ones. Another would be to create Federal programs to solve problems for which local groups have neither the time nor the resources. For instance, difficulties may arise from inequities in the distribution of revenues among States. These could be evaluated, and Federal actions taken for their correction. Such problems will occur if the workers for Utah developments choose to live in Colorado; Utah will gain tax revenues from the plants but Colorado will have to pay for the consequences of increased growth in its rural areas. Yet another option would be to expand Federal R&D efforts. As an example, it would be valuable to have estimates of the maximum rate at which the communities could grow without experiencing severe disruption. These estimates could be used by policymakers to adjust the timing and location of additional Federal oil shale leases to take into account socioeconomic impacts.

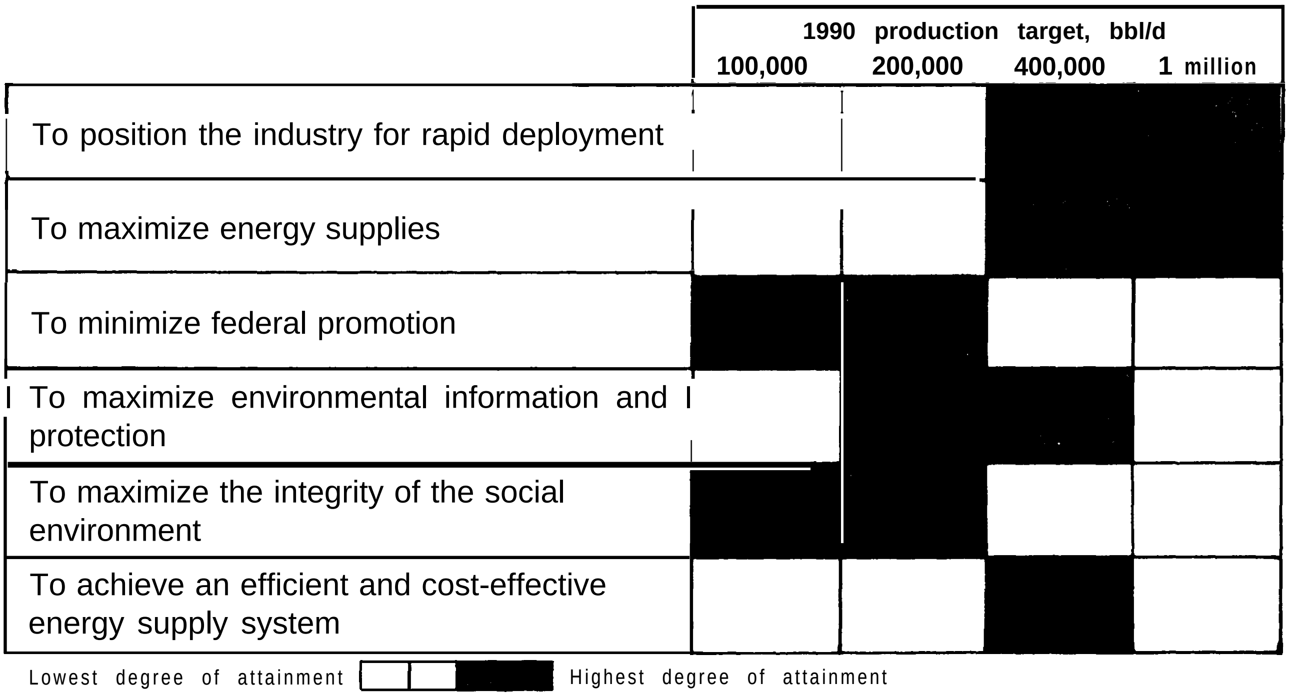
Which of the options would be best will depend on the success of local preparations and on the nature and timing of new development. If the industry grows slowly, Federal participation might be limited to R&D and other supporting activities. If it expands rapidly, substantial direct financial support and active growth management efforts will be needed. For example, a coordinated strategy will be required to cope with the growth that would accompany the production of 1 million bbl/d, as envisioned by scenario 4; and the responsibilities would have to be shared by Federal, State, regional, and local governmental units as well as by all private sectors. Extensive Federal participation would be unavoidable. One option would be to create a new Federal regional authority, for the impacts will extend into Utah and Wyoming. The powers granted to such an authority would depend on the degree of coordination and cooperation between the public and private sectors, and on the severity of the negative impacts. For instance, construction of new homes, apartments, and other living facilities will have to be financed. This will involve private parties like lending institutions, and possibly the oil shale developers. But where private capital is insufficient, the Federal or State governments will have to step in. Housing is only one sector where the needs can be expected to outstrip the resources, and where combined efforts to meet them will be essential. Many agencies, operating in many areas and at all levels, would have to be involved to cope with the growth that would accompany the establishment of a l-million-bbl/d industry by 1990.

Scenario Evaluation

As has been shown for the four scenarios, different development strategies entail substantially different requirements, consequences, and Federal actions. Regardless of the strategy selected, tradeoffs among objectives and requirements are inevitable. This is indicated in figure 11, where the scenarios are rated according to the relative degrees to which they are expected to attain the objectives for development. The following summarizes how the attainment of each objective varies with the production goals.

- To position the industry for rapid deployment.—The 400,000-bbl/d industry is given the highest rating because a wide variety of technologies and sites would be evaluated and substantial technical, environmental, and economic information would be obtained; all of which would place the industry in a good position for rapid scale-up. The l-million-bbl/d goal is rated next since production at this level would constitute a major industry; further rapid deployment could then follow. It is rated lower than the 400,000-bbl/d" scenario because its accelerated construction schedule would preclude valuable precommercial experiments and would probably not result in the most technically efficient plants. The other goals are rated lower because fewer processes could be evaluated.
- To maximize energy supplies.—The benefits, and thus the ratings, are proportional to the production rate.
- To minimize Federal promotion.—The 100,000-bbl/d target is rated highest because it could be achieved by completing the presently active projects. The 200,000-bbl/d goal probably would require some incentives, and the 400,000-bbl/d" one would require incentives, a small land exchange, and the short-term leasing of a Federal R&D facility in Colorado for a demonstration project. The l-million-bbl/d target would require much stronger subsidies, additional leasing of public land for a longer period, permitting modifications, variances, and extensive Federal involvement in growth management.
- To maximize ultimate environmental information and protection.—The quantity of pollutants and wastes generated will increase in proportion to the rate of production. Establishing a l-million-bbl/d industry in 10 years would cause the most disturbance per unit of production because there would not be enough time to improve the control technologies. The 100,000-bbl/d industry is also given a low rating because the limited number of technologies tested would provide neither extensive information on impacts nor guidance for the improvement of controls and regulations. The 400,000-bbl/d target would meet the needs for information and testing of control technologies but would incur a greater environmental risk per unit of production than

Figure 11 .—The Relative Degree to Which the Production Targets Would Attain the Objectives for Development



SOURCE Off Ice of Technology Assessment

200,000 bbl/d. The latter would maximize the attainment of this objective.

- To maximize the integrity of the social environment. —The 100,000-bbl/d target is rated high because this level of growth should be within the physical capacities of the communities. The 200,000-bbl/d" goal would create some strain in the ability of the towns to absorb the number of expected new residents; the degree of stress would depend on the location of the development. Adjusting to the growth associated with a 400,000 -bbl/d industry would be possible if the plantsites were dispersed in Utah and Colorado, if plant construction were phased, and if preparations for the construction of new towns were started at once; but there would be a high probability that boomtown effects would accompany this level of growth. A l-million-bbl/d industry would require coordinated growth management strategies and extensive financial outlays. Severe social disruption could be anticipated.

- To achieve an efficient and cost-effective energy supply system.—The 400,000-bbl/d target has the highest rating because, among other factors, it would provide a balance of information generation and process development and demonstration. The 100,000- and 200,000-bbl/d targets are rated lower because only a few technologies and sites would be tested. The l-million-bbl/d industry is also rated low because its deployment strategy would poorly utilize many of the elements of production. Furthermore, the plants might not generate sufficient profit capital for subsequent expansion.

An illustration of the need for tradeoffs between objectives can be seen at the l-million-bbl/d level. This choice has high attainment of the positioning and energy production objectives (e.g., it would displace about 16 percent of the imported oil and reduce the balance of payments significantly). However, reaching the target requires tradeoffs in all the other areas. (For example, it would violate the Clean Air Act.)

CHAPTER 4

Background

Contents

List of Tables

List of Figures

CHAPTER 4
Background

Introduction

The United States has obtained energy for human comfort, security, and productivity from a variety of sources over the past 200 years. The availability of energy was instrumental in its transformation from a largely agricultural society until the late 18th century to a major industrial power in the 20th.

During all of the 18th century and early 19th, human muscles and those of beasts of burden did most of the useful work. Throughout this period, wood was the primary fuel, supplemented by relatively small amounts of coal, coal oil, whale oil, mechanical energy from falling water, and kerosene derived from natural petroleum seeps. By the middle of the 19th century, coal had become the chief fuel and dominated the Nation's energy supply system for about a hundred years. Petroleum-based fuels and natural gas entered the picture after 1859, the year in which the first commercial oil well was drilled in Pennsylvania. The use of petroleum grew rapidly. It was further accelerated by the arrival of the automobile age in the early 1900's. Natural gas, which was originally burned or vented as a waste product from oil wells, became a major fuel for domestic, commercial, and industrial heating by the end of World War II.

By the middle of the 20th century, oil and gas had become the leading sources of energy in the United States, having displaced coal because of their convenience. In 1972, according to the Department of Energy (DOE), the Nation's economy consumed approximately 72 Quads of energy from primary sources, * of which approximately 46 percent was obtained from petroleum, 32 percent from natural gas, and 17 percent from coal. Relatively small amounts were supplied by hydroelectric dams, nuclear powerplants, geothermal sources, biomass, and other energy resources. Wood, once the principal energy source for the Nation, was used largely by some lumber mills and wood-processing facilities.

*One Quad equals 1 quadrillion (101 Btu. A primary energy source is one that may be converted to another form prior to end use. Coal burned for power genera t ion is an example.

The Need for a New Energy Supply System

In 1973, Arab oil exporting nations instituted an embargo against the United States and other nations that supported Israel. Reduced petroleum availability was followed by a recession that lasted through 1974 and into 1975. As a consequence, energy consumption declined slightly, bottoming out at about 71 Quads in 1975. By 1976, energy demand had returned to its 1973 level of about 74.5 Quads/yr. It has continued to rise, although somewhat less rapidly than prior to the embargo.

In 1978, approximately 78 Quads of energy were consumed in the United States—the equivalent of 13.4 billion bbl of fuel oil. Energy supply patterns had altered slightly since 1972. In 1978, petroleum supplied about 48 percent of the energy, natural gas about 25 percent, and coal about 18 percent. Geothermal and biomass use had increased substantially, but these resources, together with nuclear and hydropower, still provided only about 9 percent of the Nation's energy.

It is likely that energy consumption will continue to rise until conservation strategies are adopted by all sectors of the economy. If historical growth trends for energy consumption are followed, the annual energy consumption will reach 135 Quads by the year 2000-the equivalent of over 23 billion bbl of fuel oil per year or nearly twice the 1978 consumption. Actual consumption should be considerably lower, because energy demand is now growing more slowly than in the past. Conservation should slow it down further.

Several implications may be drawn from this discussion. First, the United States consumes enormous amounts of energy. (The 1978 consumption was equivalent to over 2,500 gal of fuel oil per citizen per year,) Second, energy demand will continue to rise in the near future. Third, the Nation runs on fossil fuel, with petroleum satisfying nearly 50 percent of the total energy demand.

This last implication is crucial because it appears that the United States no longer has adequate petroleum reserves of its own. New petroleum discoveries peaked in the 1950's. Domestic oil production followed suit in about 1970, except for the fields in Alaska and on the Continental Shelf. Domestic discoveries are increasing, at present, because of higher oil prices, but it is unlikely that sufficient U.S. reserves exist to provide secure supplies beyond the end of the 20th century. Because of the inability of domestic petroleum development to keep pace with growing demands for liquid fuels, the United States has become increasingly dependent on imported oil. In 1978, the United States imported nearly 24 percent of its total energy supply and nearly 45 percent of its requirement for crude oil and refined petroleum products. A barrel of imported petroleum now costs five to six times as much as it did in 1972.

The short-term reliability of imported oil supplies is very uncertain, as exemplified by disruptions arising from the Suez crisis of 1956, the Arab-Israeli War of 1967, the Arab oil embargos of 1973 and 1974, and the present Iranian situation. Long-term reliability is also questionable because worldwide oil production is expected to peak within the next few decades and to decline rapidly thereafter. Eventually, it may be impossible to import oil at any price.

Growing reliance on increasingly scarce and expensive energy imports has had many adverse effects. Some of the economic impacts (such as balance-of-payments deficits) can be quantified with some degree of precision. Other, less tangible effects (such as threats to national security and the social and economic impacts of supply disruptions), although more difficult to quantify may prove to be much more significant. It has become apparent that an energy supply system needs to be evolved that is more appropriate to the Nation's present and projected needs and internal resources. Just as wood was displaced by coal, coal by domestic petroleum and gas, and domestic petroleum by imported oil, it appears that imported energy must be replaced by new sources of domestic energy.

An initial step in developing a new energy supply system should involve formulating a comprehensive policy that reduces demand through conservation, increases availability from domestic resources, and restricts imports. Conservation must be an important element of any such policy. However, there are limits to the savings that can be accomplished through conservation. Thus, it appears that it will be necessary to develop new energy resources. Potential sources include additional reserves of conventional oil and gas, enhanced oil recovery, expanded coal development, solar-thermal and photovoltaics, wind energy, tidal energy, ocean thermal gradients, increased nuclear fission for power generation, nuclear fusion, biomass combustion, and the recovery of synthetic liquid and gaseous fuels by the conversion of coal, tar sands, biomass, and oil shale. The challenge is to derive optimal combinations of these sources which, when coupled with conservation and restricted imports, will provide sufficient energy for future economic growth and development, while simultaneously protecting the Nation's physical and social environments.

The Purpose and Organization of This Chapter

As noted in the Introduction to this report, this assessment is concerned with only one of the Nation's energy supply opportunities, oil shale—specifically with deposits in the Green River formation of Colorado, Utah, and Wyoming. Although the oil shale literature is extensive, the information is inadequate concerning certain environmental, socioeconomic, technological, and financial aspects of oil shale development. However, the assessment's overall analysis has been facilitated by the extensive body of background information acquired during the Nation's long but sporadic involvement with oil shale as an energy resource. The purpose of this chapter is to organize this background information into a supporting framework for the detailed analyses found in subsequent chapters. The following subjects are discussed:

- the location and extent of the oil shale resources of the United States and foreign nations;
- the characteristics of the resource region in Colorado, Utah, and Wyoming, including brief descriptions of the geography, the geology, the climate, and the physical and social environments;
- the potential applications for materials derived from the Green River oil shales, including oil, fuel gases, minerals, and spent shale; and
- the history and status of development efforts in the United States and other countries, with emphasis on the efforts currently underway in the Green River formation.

Oil Shale Resources

The Genesis of Oil Shale

Oil shale is a sedimentary rock that contains organic matter, which although not appreciably soluble in conventional petroleum solvents can be converted to soluble liquids by heating. Oil shale was formed in the distant past by the simultaneous deposition of mineral silt and organic debris on lakebeds and sea bottoms. As the raw materials accumulated, heat and pressure transformed them into a stable mixture of inorganic minerals and solidified organic sludge. The formation processes that yielded petroleum, tar sands, and coal were conceptually similar, but differed with respect to key physical and chemical conditions. In oil shale, these conditions resulted in the formation of chemical bonds between individual organic molecules. The large size of the molecules formed by this bonding prevents them from dissolving in normal solvents. When heated in processes known as pyrolysis and destructive distillation, the bonds rupture forming smaller liquid or gaseous molecules. These can then be separated from the inorganic matrix, which remains behind as the spent shale waste product.

Photo credit Department of the Interior

Oil shale sample showing layers of organic composition

Worldwide Deposits

Oil shale deposits have been found on all of the inhabited continents. The extent of the worldwide resources cannot be accurately determined, but it appears to be very large indeed. In 1965, the U.S. Geological Survey

(USGS) estimated that the world's oil shale deposits comprised over 4 quadrillion tons, having a total potential shale oil yield of over 2 quadrillion bbl. If all of this oil were extracted and distributed among the world's residents, each person would receive about 600,000 bbl. However, the spent shale waste would cover the entire surface of the world, land areas and oceans included, to a depth of about 10 ft.

The deposits in Asia contain the largest amount of potential shale oil resources, over 700 trillion bbl; Africa is second, with nearly 500 trillion bbl; North America contains over 300 trillion bbl; South America (principally Brazil) about 250 trillion bbl; Europe has about 170 trillion bbl; and Australia and New Zealand together have only about 120 trillion bbl.

Many of the world's deposits have been subjected to commercial-scale development at various times in the past. Those in Scotland, France, Germany, Australia, Sweden, Spain, and South Africa are of historical interest because of the industries that once flourished in those countries. The deposits in Estonia, Manchuria, Brazil, and Morocco are of current interest because they are the sites of present or projected commercial development.

Deposits in the United States

Overview

The oil shale deposits in the United States are shown in figure 12, and their theoretical shale oil yields are given in table 13. The deposits in the Green River formation in Colorado, Utah, and Wyoming are particularly noteworthy because they contain the largest concentration of potential shale oil in the world. Because deposits in the Central and Eastern United States underlie a larger area, they appear more impressive on maps than do those of the Green River. However, they contain less than half the oil shale in the Green River formation, and do not yield as much oil on a unit basis because of a lower proportion of hydrogen to carbon in their organic component.

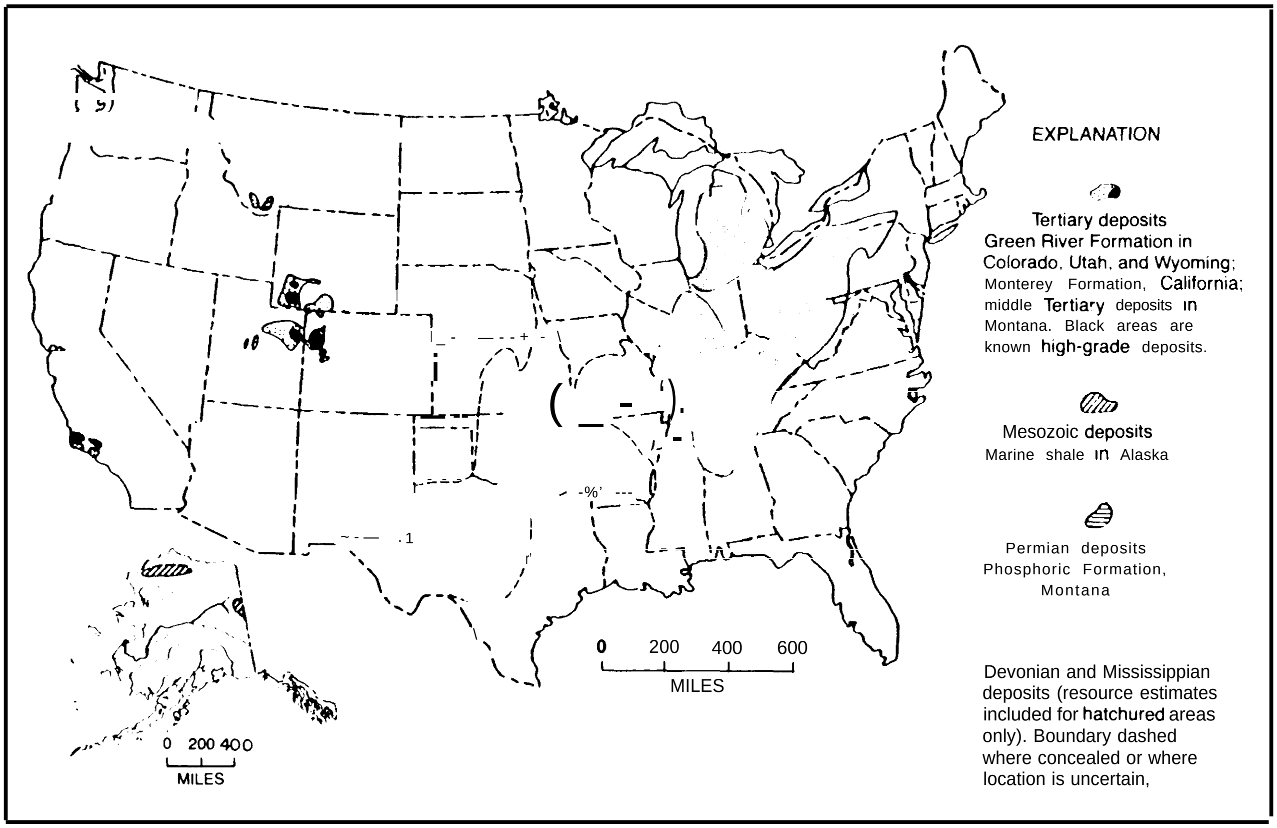
Some of the eastern shales have attracted interest because of the natural gas resources locked within the shale formations. DOE is presently supporting a research and development (R&D) program to evaluate the potential of eastern shales for producing this fuel, with special attention given to stimulating gas production from the Devonian shales that occur in and around eastern Ohio and the western part of West Virginia. The Antrim shales in southern Michigan are also being investigated as potential sources of synthetic pipeline gas, which would be obtained by underground gasification methods. DOE is also investigating the Chattanooga oil shales in Tennessee and Kentucky. In addition to their organic component these shales contain low-grade uranium and thorium ores. But they do not appear to have much commercial potential because the beds are thin and unfavorably located, and ore concentrations are very low.

The Green River Formation

The Green River formation is a geologic entity underlying some 34,000 mi^2 of terrain in northwestern Colorado, southwestern Wyoming, and northeastern Utah. (See figure 13.) The formation has been divided into several distinct geologic basins. The Green River, Great Divide, and Washakie basins occur primarily in Wyoming. Together with the Sand Wash basin in northern Colorado, these basins underlie about 14,000 mi^2. About 35 million years ago they were occupied by a single large and long-lasting freshwater lake.

The Uinta basin in northeastern Utah and northwestern Colorado and the Piceance basin in Colorado underlie about 20,000 mi^2 of terrain, and were once occupied by a second freshwater lake. Most of Colorado's Piceance basin lies north of the Colorado River, but it includes oil shale deposits within Battlement Mesa and Grand Mesa on the south side of the river. Colorado oil shale also occurs in the Sand Wash basin, which is north of the Piceance basin near the Wyoming border.

Figure 12.—Oil Shale Deposits of the United States



SOURCE D C Duncan and V E Swanson, *Organic-Rich Shales of the United States and World Land Areas,* U S Geological Survey Circular 523, 1965

Table 13.–Potential Shale Oil in Place in the Oil Shale Deposits of the United States (billions of barrels)

	Range of shale oil yields, gallons per ton		
Location	5- 10[a]	10- 25[a]	25- 100[a]
Colorado, Utah, and Wyoming (the Green River formation)	4,000	2,800	1,200
Central and Eastern States (Includes Antrim, Chattanooga, Devonian, and other shales)	2,000	1,000	(?)
Alaska	Large	200	250
Other deposits	134,000	22,500	(7)
Total	140,000+	26,000	2,000(?)

[a]Order of magnitude estimate Includes known deposits extrapolation and interpolation of known deposits and anticipated deposits

Data from D C Duncan and V E Swanson *Organic-Rich Shales of the United States and World Land Areas* U S Geological Survey Circular 523 1965

Oil shale resources have been found under some 17,000 mi^2, or 11 million acres, of the basins of the Green River formation. The principal deposits are found in the Piceance, Uinta, Green River, and Washakie basins. These areas, and in particular the Piceance basin, are among the most intensely explored geologic regions in the United States. The U.S. Bureau of Mines (USBM), USGS, and private industry have drilled hundreds of exploratory coreholes into the basin rocks. The earliest of USBM's efforts took place during World War H. As a result, there is a considerable body of geological information about some areas of the deposits. Other deposits, particularly near the fringes of the Uinta basin and the basins in Wyoming, are still largely unexplored.

To comprehend the potential value of the oil shale in the Green River formation, it is necessary to distinguish among deposits, resources, and reserves. A deposit is simply a natural accumulation. A resource is a naturally occurring substance with properties

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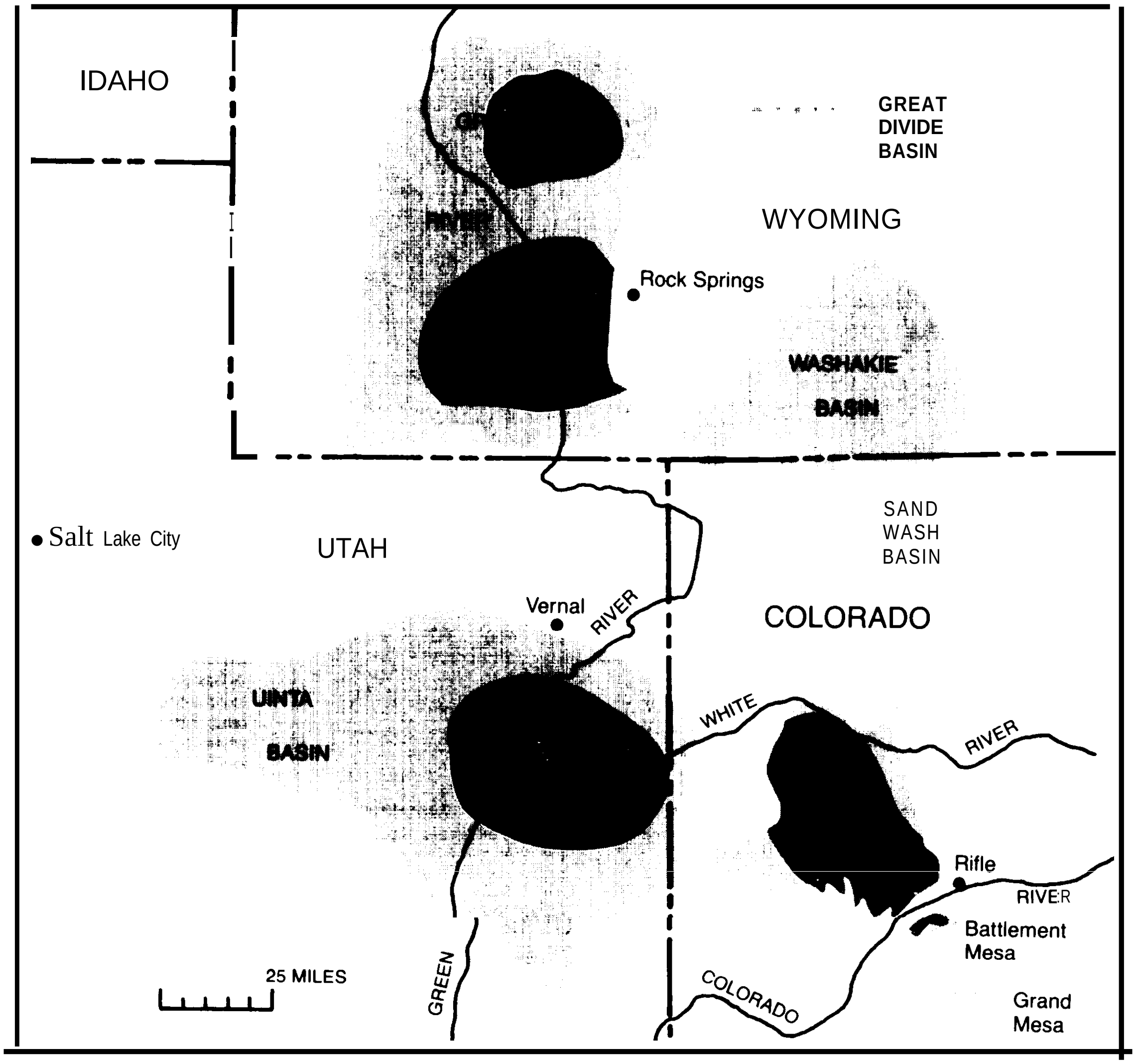
Figure 13.—Oil Shale Deposits of the Green River Formation



EXPLANATION

Area underlain by the Green River Formation in which the oil shale is unappraised or low grade.

Area underlain by oil shale more than 10 feet thick, which yields 25 gallons or more oil per ton of shale.

SOURCE D C Duncan and V E Swanson, *Organic-Rich Shales of the United States and Wodd Land Areas,* U S Geological Survey Circular 523, 1965

that can be put to use. A reserve is the equivalent of money in the bank. All of the rocks in the Green River formation occur in deposits. Some of the deposits are also resources because they contain sufficient oil shale, which when properly manipulated can yield useful fuels to warrant being considered for commercial development. However, if the cost of extracting fuels from the resource is greater than the value of the fuels obtained, the resource is not a reserve. Reserves exist only when the resource can be extracted and processed to yield products that can be marketed at a profit.

The total oil shale deposits of the Green River formation contain, in place, * the equivalent of over 8 trillion bbl of crude shale oil, including all rocks that would yield from 5 to 100 gal/ton of oil on destructive distillation. However, many of these deposits are too thin, too deeply buried, or too low in oil yield to be included in a survey of oil shale resources, because it would not be economically feasible to develop them.

In table 14, the quality of the Green River shale is evaluated according to thickness and potential oil yield. Only deposits that yield at least 15 gal/ton and are at least 15 ft thick are considered even marginally attractive. This group includes shales containing as much as 1.4 trillion bbl of shale oil in place. The high-grade shales are further defined as shale beds that are at least 100 ft thick that would yield at least 30 gal/ton. Their in-place oil content is an additional 0.4 trillion bbl, for a total shale oil resource of about 1.8 trillion bbl, in place.

The extent of the oil shale reserves cannot be determined at present. Resources can be regarded as reserves only when processes for developing them appear to be economically feasible. This has yet to be demonstrated for oil shale processes. However, several attempts have been made to delineate particular Green River resources that would present a greater potential for profitable extraction. In 1972, the National Petroleum Council (NPC) used published geological data to classify the shale beds according to thickness and richness, accessibility to underground mining, and the extent to which they had been explored. A summary of the results appears in table 15. Data are presented for four classes of oil shale resources. Classes 1 and 2 were considered economically attractive for existing aboveground recovery technologies. They include only the more favorably located and better defined shale beds, which are at least 30 ft thick and would yield at least 30 gal/ton. These two classes contain about 130 billion bbl of shale oil, in place. The shales in class 3 might also be economically attractive, but they are less well-defined, and their unfavorable locations could hinder commercial development. Class 3 shales contain about 186 billion bbl. The bulk of the Green River resources are in class 4, which includes lower grade, poorly defined, and unfavorably located deposits. Class 4 shales contain nearly 1.5 trillion bbl. Some of the deposits in classes 3 and 4 may be suitable only for in situ processing.

The total estimate shown in table 15 (about 1.8 trillion bbl) agrees well with the total shown in table 14. However, the higher quality resources in the first three classes contain only 315 billion bbl, which is about 2 percent of the total estimated. The potential yield of these deposits can be estimated by taking into consideration the inevitable losses that would occur during mining and processing. Conventional underground mining methods can recover from 60 to 70 percent of the oil shale in a mining zone; large-scale aboveground mining can recover about 90 percent. Processing the mined ore in aboveground retorts recovers approximately 90 to 100 percent of the oil that would be recovered if the shale were dis-

*The term "in place" is used to indicate the quantity of oil that would be created if the shale were retorted. As noted, oil shale deposits contain essentially no oil as such.

Table 14.–Potential Shale Oil in Place in the Green River Formation: Colorado, Utah, and Wyoming (billions of barrels)

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

SOURCE W C Culbertson and J K Pitman 011 Shale in *United States Mineral Resources* U S Geological Survey Professional Paper 8?0 1973 pp 497503

Table 15.–Potential Shale Oil Resources of the Green River Formation (billions of barrels)

Location	Resource class[a] 1	2	3	4	Total
Piceance basin (Colorado)	34	83	167	916	1,200
Uinta basin (Utah and Colorado)	–	12	15	294	321
Wyoming basins	–	–	4	256	260
Totals	34	95	186	1,466	1,781

a 1 Deposits at least 30 ft thick and averaging 35 gal/ton
2 Deposits sat least 30 ft thick and averaging 30 gal/ton
3 Deposits similar to classes 1 and 2 but less well defined and not as favorabley located
4 Poorly defined deposits ranging down to 15 gal/ton

SOURCE An Initial Appraisal by the 011 Shale Task Group 1971-1985 *U S Energy Outlook—An Interim Report*, The National Petroleum Council, Washington D C 1972

tilled under carefully controlled laboratory conditions. If it is assumed that about 60 percent of the oil in the shale deposits could be recovered, the resources in classes 1 through 3 could yield 189 billion bbl of crude shale oil.

The projected yield of 189 billion bbl of shale oil is only a small fraction of the total potential yield estimated—1.8 trillion bbl. It is very small compared with the total in-place shale oil content of the Green River deposits (some 8 trillion bbl). To put the figure in a meaningful perspective, the United States consumed about 6.5 billion bbl of crude petroleum in 1978, of which about 2.8 billion bbl of crude oil and refined products were imported. At the 1978 consumption levels, the higher quality Green River resources have the potential to supply all of the Nation's crude oil needs for 29 years or to replace imports for nearly 68 years. Looked at another way, the resources in the first three classes could sustain a l-million-bbl/d shale oil industry for over 500 years. The class 1 resources in Colorado's Piceance basin alone could supply it for nearly 56 years.

With existing data, a preliminary evaluation of the Green River resources can be made with respect to their promise of commercial development, but the actual reserve value is still highly uncertain. It is likely that some of the deposits could not be developed without unacceptably damaging the environment. It is also possible that some favorably located resources could not be developed because of particular geotechnical characteristics (such as highly fractured ore zones or the presence of excessive amounts of ground water) that were not considered in NPC's analysis. In any case, the economic aspects of development are not well-understood because large-scale technologies have not as yet been built and operated. As previously observed, the key criterion in estimating reserves is economic feasibility.

If all the above factors were given careful consideration, it is possible that actual reserves would be very small. On the other hand, it is also possible that an evaluation of the potential of known resources for in situ processing along with additional exploration and research, could increase the reserve estimate. There are deficiencies in the NPC estimate that largely reflect the current status of technical and geological knowledge. For example, over 75 percent of the Uinta basin deposits were placed in class 4 because they have not been as thoroughly explored as those of the Piceance basin. The analysis also downgraded deposits that are not well-suited to mining and aboveground retorting but might be ideal for underground processing. If the survey were revised in the light of present knowledge, it is possible that the reserve estimate would be substantially increased.

Description of the Oil Shale Resource Region

Location

The oil shale deposits of the Green River formation underlie about 17,000 mi^2 of terrain in northwestern Colorado, northeastern Utah, and southwestern Wyoming. * Major settlements in the area and major tributaries that drain the region's watershed into the Colorado River system are shown in figure 14.

Topography and Geology

At the time of their deposition, the oil shale basins probably resembled the fairly uniform topography of continuous lakebeds. Tectonic upheavals have since elevated them, and substantial erosion by wind and water have altered their terrain. Today, most of the oil shale region is very rugged country. The topography of both the Uinta and Piceance basins is typified by rolling plateaus, cliffs, and canyons. The elevation ranges from approximately 4,300 ft above sea level along the Green River in the Uinta basin to more than 9,000 ft at a point near the southeastern edge of the Piceance basin. This irregular topography strongly influences such characteristics as climate, air motion and dispersion patterns, and the duration of the growing season.

The various mountain systems surrounding the area of the Green River formation are shown in figure 15, and the general topographic relief of the Piceance basin north of the Colorado River in figure 16. This figure does not show Battlement Mesa and Grand Mesa, which lie to the south of the Colorado River. These are part of the Piceance structural basin, but the characteristics of their oil shale resources are not well known.

The main part of the Piceance basin is bounded by the White River on the north, by the Grand Hogback on the east, by the Roan Cliffs on the south, and by Douglas Creek and the Cathedral Bluffs on the west. Within the basin are topographically high areas such as the Roan Plateau, which is relatively flat but severely eroded by stream courses.

The southern escarpments (steep cliffs) that overlook the valleys of the Colorado and Green Rivers are the most spectacular features of both the Piceance and Uinta basins. At several locations these sheer cliffs rise to heights of 4,000 ft above the adjacent river valleys. They are nearly continuous for a distance of some Z00 miles from the intersection of the Roan Cliffs with the Grand Hogback near Rifle along the Cathedral Bluffs on the western side of the Piceance basin, to the intersection of the Book Cliffs with the Wasatch Plateau at the western tip of the Uinta basin.

Escarpments along tributary canyons are similarly impressive. The topography along one stretch of Parachute Creek in the Piceance basin is depicted in figure 17. * At the location shown, the maximum elevation is approximately 8,100 ft above sea level at the ridge of the escarpment, and the minimum elevation is about 6,100 ft in the adjacent bed of Parachute Creek. The topography in other tributary canyons is similar. For example, the Roan Creek Valley (near the southern edge of the Piceance basin) is more than 30 miles long and from 2,000 to 3,000 ft deep. The Federal oil shale lease tracts are located in less eroded areas of the basin, and their topographic relief is much less dramatic. On tract C-a, for example, the average difference in elevation between valley floors and nearby ridge tops is only about 300 to 600 ft.

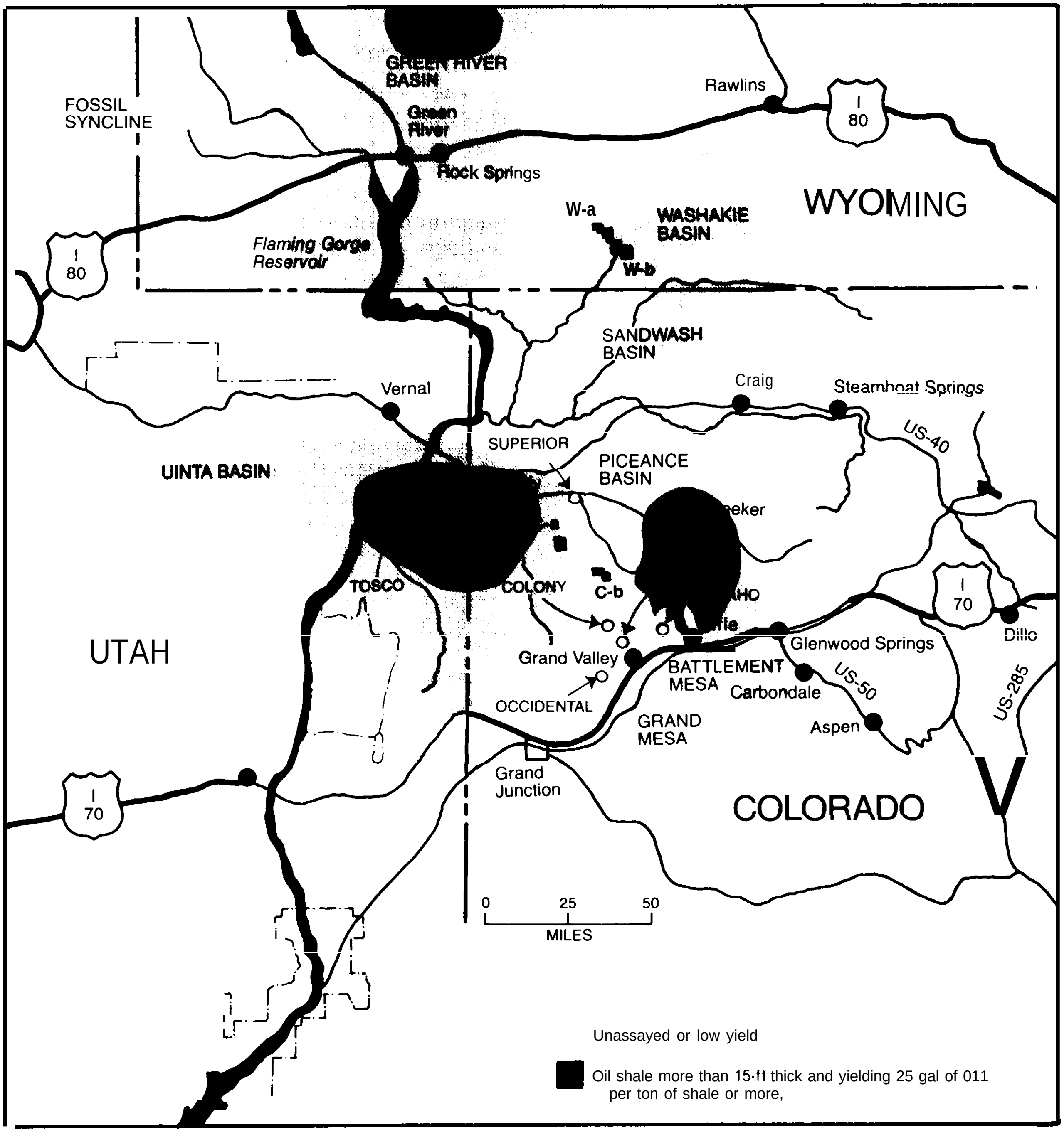
Figure 18 is an idealized cross section of the Piceance basin that shows the stratigraphic relationships between the various structural members of the Green River formation, the overlying Uinta formation, and the underlying Wasatch formation.** The bound-

*This area is slightly larger than Vermont and New Hampshire combined.

*The Parachute Creek valley was the site of two oil shale development projects in the 1950's and 1960's, and additional projects are currently being considered for the same locations.

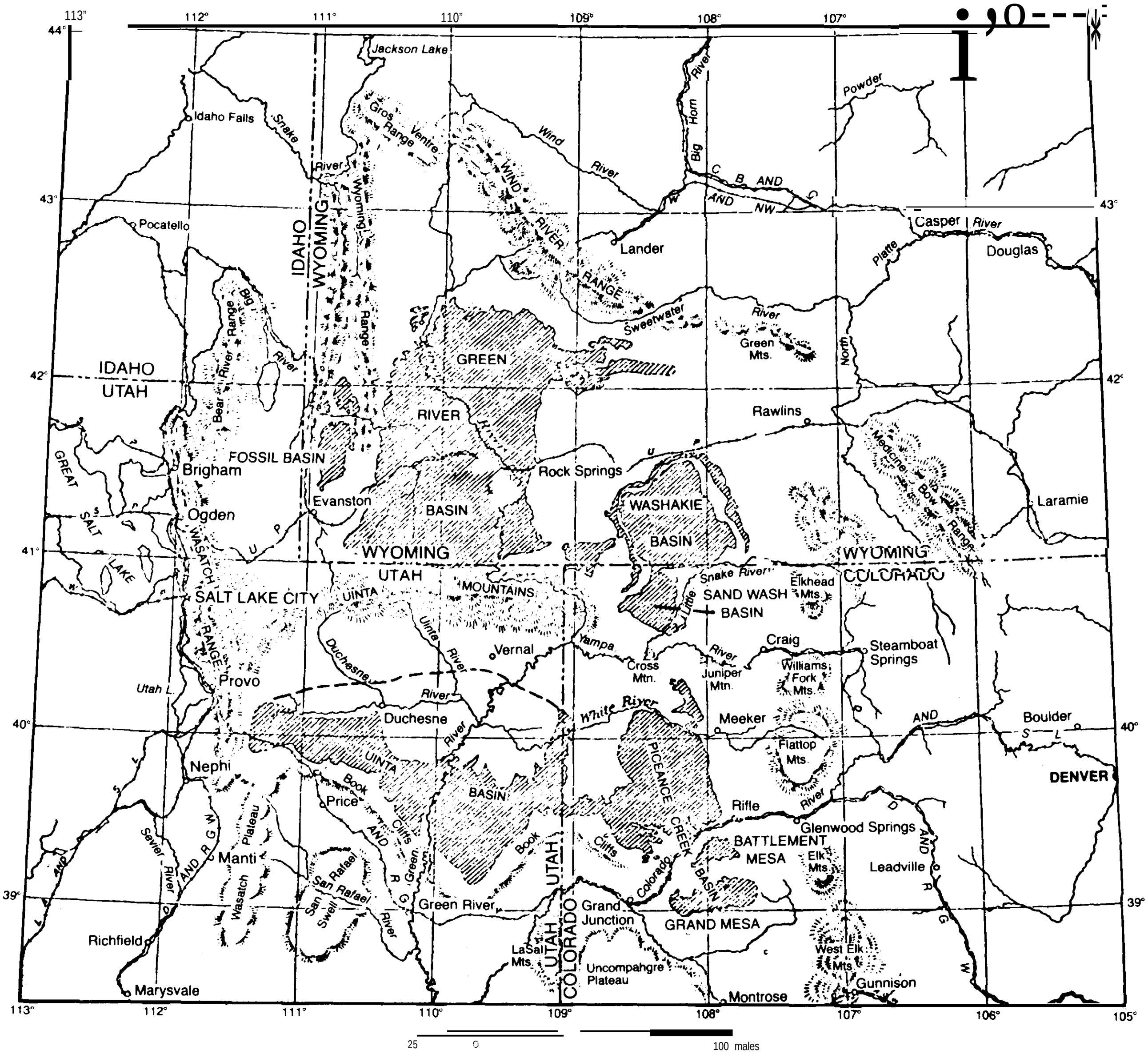
**The Uinta formation was previously called the Evacuation Creek member of the Green River formation in this area. See: C. W. Keighin, "Resource Appraisal of Oil Shale in the Green River Formation, Piceance Creek Basin, Colorado, " Quarterly *of* the *Colorado School of* Mines, vol. 70, No. 3, July 1975, pp. 57-68.

Figure 14.—The Oil Shale Resource Region of the Green River Formation: Colorado, Utah, and Wyoming



SOURCE. E DiSante, "A Look at 011 Shale–What's It All About," *Shale Country Magazine,* vol 1, No 1, January 1975, p 7

Figure 15.—Major Mountain Systems in the Vicinity of the Green River Formation

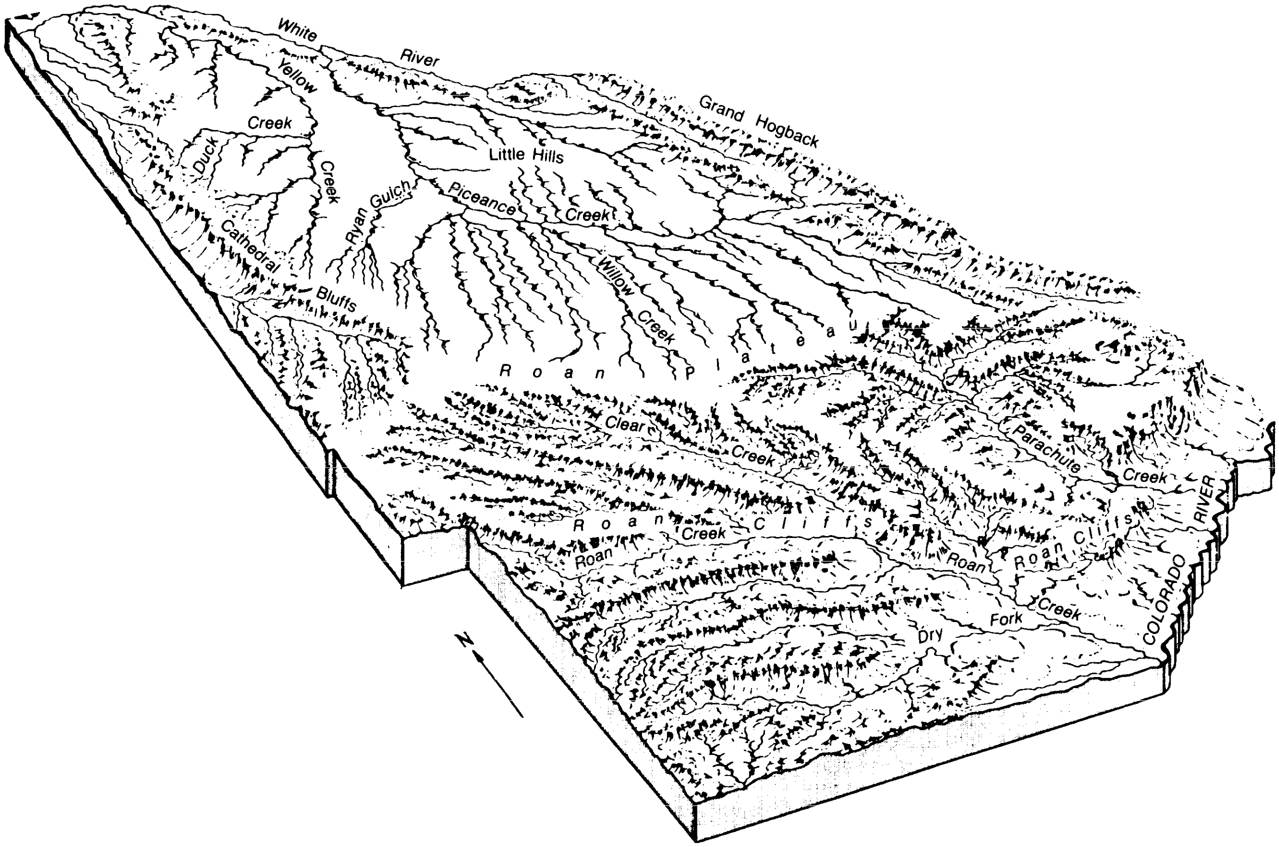


SOURCE U S Department of the Interior, *Final Environmental Statement for the Prototype Oil Shale Leasing Program,* GPO stock No *2400-00785,* 1973, p II-2

aries of these members, which are visible along Parachute Creek, were shown in figure 17. The Green River formation is about 3,000 ft thick near the center of the basin.

The top strata of the section comprise the Uinta formation, which underlies the surfaces of high plateaus in the Piceance basin. The Uinta is largely barren sandstone and siltstone with some interbedded oil shale. Below the Uinta, at a depth of 500 to 1,000 ft, is the Parachute Creek member of the Green River formation, which is almost entirely oil shale marlstone with occasional beds of volcanic material (tuff) and sandstone. Near the basin's depositional center, the Parachute Creek member contains scattered deposits of the minerals dawsonite, nahcolite, and halite. Dawsonite, which contains aluminum, is occasionally found in thin layers between the oil

Figure 16.—Topographic Relief of the Piceance Basin, Colo.



SOURCE Golder Associates, Inc., *Water Management in Oil Shale Mining*, September 1977, NTIS No PB-276 086, p 73

shale beds. More commonly it occurs as microscopic crystals disseminated throughout the oil shale. Nahcolite is sodium bicarbonate. It is a source of soda ash, a raw material for glassmaking, and may also be used to remove sulfur dioxide from stack gases. Halite is sodium chloride, from which table salt is made. The Parachute Creek member also includes the Mahogany Zone, which contains oil shale yielding up to 70 gal/ton. Below the Mahogany Zone, near the center of the basin, is a region from which soluble sodium salts have been leached out by the ground water flows and which now contains saline ground water. Near the bottom of the Parachute Creek member is the "saline zone," which contains high concentrations of nahcolite and other sodium salts that have not been leached.

The lower extremities of the Garden Gulch and Douglas Creek members, which underlie the Parachute Creek member, roughly coincide with the bottom of the ancient lake on which the raw materials for the Green River oil shales accumulated. The upper 200 to 300 ft of the Garden Gulch member contain clay beds and deposits of shale having an appreciable organic content. ' The Garden Gulch shales are true shales in that their primary inorganic components are aluminum-containing illite clays, unlike the oil shales of Parachute Creek, which are primarily composed of dolomite (calcium and magnesium carbonate) rocks. Below the Douglas Creek member is the Wasatch formation, which is largely barren sandstone and mudstone. The Wasatch rocks generally form valley floors throughout much of the Piceance basin. They

Figure 17.— Stratigraphy and Landform Units Along Parachute Creek, Piceance Basin, Colo.

LANDFORM UNITS

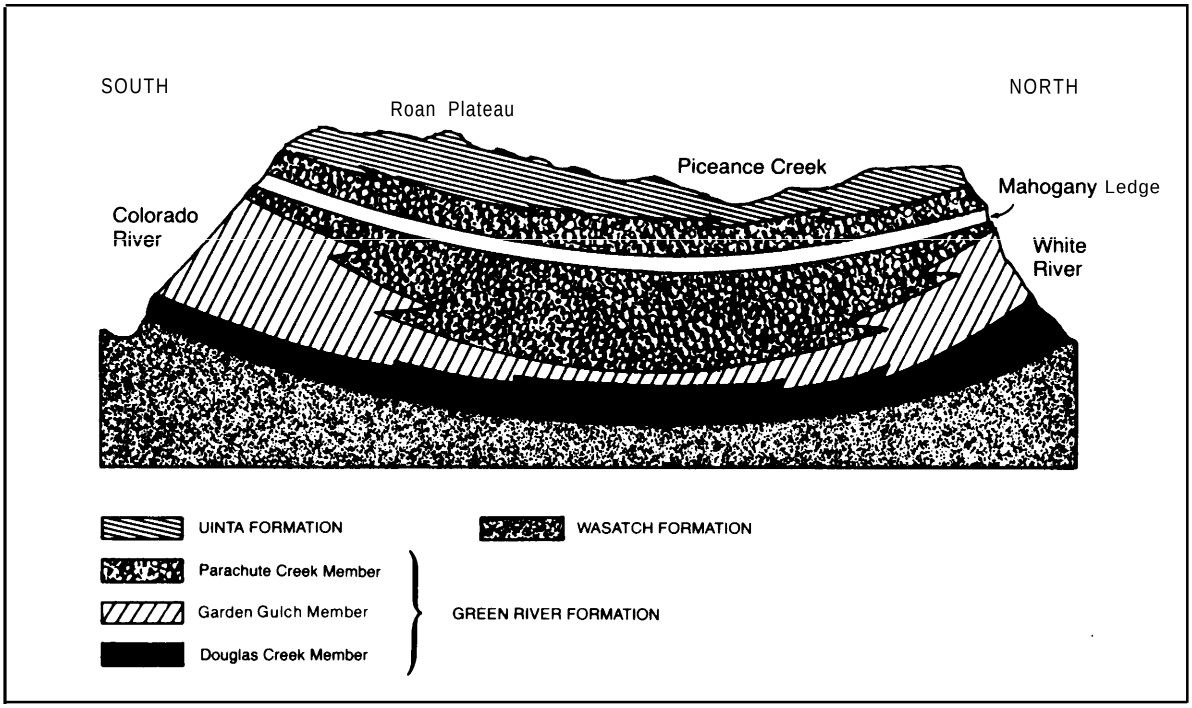
I—CLIFFS (ESCARPMENT)
2—MID-SLOPES
3—SLIP AND ROCKFALL TERRAIN (TALUS)
4—WASATCH FOOTSLOPES
5-ALLUVIAL FAN
6-CHANNEL LAND

STRATIGRAPHY

UINTA FORMATION
GREEN RIVER FORMATION
Tgp--PARACHUTE CREEK MEMBER
Tgg—GARDEN GULCH MEMBER
Tgd—DOUGLAS CREEK MEMBER
WASATCH FORMATION

SOURCE Bureau of Land Management, *Draft Environmental Statement for Proposed Development of Oil Shale Resources by the Colony Development Operation In Colorado* U S Department of the Interior, 1975 p III-101

Figure 18.— Idealized Cross Section of the Piceance Basin, Colo.



SOURCE Bureau of Land Management, *Draft Environmental Statement for* Proposed Development *of Oil Shale* Resources *by the Colony Development Operation in Colorado,* U S. Department of the Interior, 1975, p 111.13

do not contain any oil shale of commercial interest.

Variations in the properties of the various strata have had significant effects on the topographic relief of the region. The Uinta formation sandstones cover the oil shale deposits over much of the Piceance basin. Over the past several million years, outcrops of the Uinta rocks have weathered considerably. The organic-rich oil shale zones of the underlying Parachute Creek member, however, have been much more resistant to weathering. The Mahogany Zone of the Parachute Creek member is an outstanding example. It is from 10 to 225 ft thick, contains oil shale that has, in general, a high organic content, and underlies an area of more than 1,200 mi^2 in the Piceance basin. It also extends into the neighboring Uinta basin. * Oil shale beds immediately above and below the Mahogany Zone are lower in organic content and less resistant to weathering. Where the zone outcrops along tributary canyons, its richer shales have resisted erosion, but the leaner surrounding shales have not. Consequently, the outcropping fringe of the zone is often highly visible as an overhanging prominence known as the Mahogany Ledge, which appears in most areas as a dark band along the escarpment, as shown near the top of figure 17.

Gradual deterioration of the ledge has resulted in rockfalls and the formation of talus (debris) slopes between the bottom of the ledge and the river valley below. Such slopes were indicated in figure 17 as slip and rockfall terrain. They are steep and unstable, particularly if naturally or artificially undercut. Because talus slopes are naturally unstable and lack sufficient permanent topsoil, they do not provide favorable growing conditions for most types of vegetation. However, varying amounts and kinds of vegetation can grow on some slopes depending on their aspect and

*Green River oil shale has a laminar appearance because of variations in the organic content of adjacent strata. Polished sections of the richer beds resemble mahogany wood. Most oil shale projects in the near term will be focused on the rich shales of the Mahogany Zone. The other potential source of rich oil shale, the Garden Gulch member, is probably too deep for near-term commercial development.

the available moisture. The north-facing slopes generally have fairly abundant vegetation; the south-facing slopes much less.

Climate and Meteorology

Climate

The climate of the oil shale region is classified on the whole as semiarid to arid. Annual precipitation varies from approximately 7 inches in the Wyoming plains to approximately 24 inches in the high plateaus of the Piceance basin. Most of this occurs as snowfall, Snowpack, which commonly exceeds 30 inches on protected slopes, provides surface runoff during the spring. Summer and fall are usually dry, but there are short, heavy thunderstorms occasionally during the late summer months. These can cause flash flooding in low-lying areas, Relative humidity is generally low to moderate, with high evaporation rates throughout the region. Because of the region's abundant sunshine, most valley floors and south-facing slopes are usually not covered with snow during winter,

Average temperatures are generally moderate, but maximum daytime temperatures can reach 100° F (38° C) at lower elevations during midsummer, and winter temperatures may drop to – 40° F (–40° C) at higher elevations. The number of frost-free days varies from 50 at higher elevations to 125 at lower elevations. The limited rainfall and low relative humidity coupled with the short growing season restrict the agricultural use of tillable areas. Some forage crops are produced along the tributary valleys within the basins, but most food crops are grown outside of the basin along major rivers where adequate irrigation water is available.

Meteorology

The meteorology of the oil shale region in Colorado is typified by year-round gradient winds from the west that are interrupted only by the passage of frontal systems. Migratory low-pressure systems are frequently deflected around the entire region by the Sierra Nevadas to the west and the Rocky Mountains to the east, Stagnant high-pressure cells sometimes persist for days over the basins, their passage blocked by the surrounding high mountains. Adjacent mountain ranges also contribute to the region's dry climate. Moist air from the Gulf of Mexico is blocked by the Rocky Mountains, while moist air from the Pacific is blocked by the Sierra Nevadas. Flows from both directions lose most of their moisture before reaching the oil shale area. The frequent presence of dry, high-pressure air cells over the basins causes an abundance of clear sunny days with light winds and large differences between daytime and nighttime temperatures.

Air Patterns

Localized wind patterns and other meteorological conditions are very sensitive to topography and elevation. For example, in the Piceance basin, shielding by the Cathedral Bluffs, the gentle downward slope of the basin to the northeast quadrant and the existence of deep gullies, effectively channel surface wind flows and decouple them from the prevailing gradient winds. The shielding effect is provided by the sheer escarpment of the Cathedral Bluffs and Roan Cliffs along the southern and western edges of the basin. When prevailing winds encounter the bluffs they must rise approximately 3,000 ft to clear the upper ridges. The rising air increases in speed and generates turbulent eddies whose duration is enhanced by the downward slope of the basin's upper surface. The shielding of the escarpments combined with the basin's downslope minimizes the effect of gradient winds on surface wind patterns except along very high ridges and plateaus. Airflows in the Colorado River valley, in tributary canyons, and along the valleys and low hills atop the Roan Plateau are almost entirely determined by local topography. They follow a drainage-wind pattern and are nearly independent of the behavior of prevailing gradient winds aloft.

The Mountain-Valley Breeze System

The predominance of drainage-wind patterns is exemplified by the mountain-valley breeze system that has been observed on both Federal oil shale lease tracts in Colorado. The phenomenon is characterized by gentle down-valley air flows beginning around sunset and prevailing for about 10 hours in winter, followed by gentle up-valley flows starting at midmorning. On clear nights, when the upper atmosphere is stable, layers of dense, cold air form near ground level. Any cold air that enters the valley along adjacent slopes will tend to flow downslope into the stagnant cold layer. In the early morning, sunlight gradually warms the surrounding slopes. The cold air then disperses and flows upslope to become entrained in the prevailing gradient winds. At various times during the day and night, circular flow patterns and eddies may prevail within the valley, but they will not carry air from the valley unless gradient winds along the upper ridges are quite strong.’

Thermal Inversions and Their Implications

The mountain-valley breeze system often causes a layer of cold stagnant air to form below a layer of warm air—a thermal inversion. Such inversions exacerbate air pollution problems. There is little air transport out of the cold layer, and pollutants emitted near ground level will tend to accumulate there. Inversions are usually broken by surface heating during the daylight hours, but under certain adverse conditions they may prevail for several days. Valleys with broad floors are especially susceptible, particularly after a snowfall. Snow cover reflects sunlight and inhibits the warming of the stagnant layer during the day, thus reducing the upward flow of warm air that is essential to disruption of the inversion. At night, the exposed snow surface enhances the downward flow of air from the valley ridges, thus increasing the thickness of the inversion layer.

Studies have shown that Grand Junction, Colo., which is located outside of the oil shale basins, experiences one of the highest inversion frequencies in the United States. The inversions occur most frequently during the winter and persist over 50 percent of the time in the fall and winter months. Inversions might be expected to occur less frequently on the slopes and plateaus of the Piceance basin. However, it has been predicted that inversion episodes lasting from 3 to 6 days could occur at least once a year over the entire region.[3] Recent investigations performed on the Federal lease tracts have concluded that the pollutant dispersion potential of the basin is good when contaminated air is released above the higher plateaus, and relatively poor when fumes are released into the valleys. The same studies have predicted that trapping inversions, * such as are associated with the mountain-valley breeze system, should seldom persist longer than 24 hours.

Plants and Animals

The Green River formation underlies a large area. Its soil characteristics show considerable variation over this area. In combination with climate, meteorology, and topography, soil characteristics largely determine the types of plant communities that can be supported. These, in turn, influence the diverse animal species that feed directly or indirectly on them.

Plants

The vegetation of the region is highly diverse, and its makeup is strongly affected by elevation. Most of the broader stream valleys in the region contain fertile alluvial (floodplain) soils that support relatively luxuriant growths of cottonwood, shrubs, and other species. In contrast, the surfaces of steep slopes and some upper plateaus are bare rocks and ledges with little or no soil development. Vegetation is often absent or at best quite sparse in such areas, especially in some plateaus in Utah and Wyoming and in the Piceance basin where the saline rocks of the

*A trapping inversion is one that traps contaminated air regardless of the temperature at which the contaminants are released from their source.

Garden Gulch member are exposed, Some gently sloping upland areas contain thin and poorly developed soils with occasional localized strips of alluvium. Plant cover in these locations varies from very sparse in the poorer areas to relatively abundant over the alluvial deposits. In general, the extent of vegetation is strongly influenced by aspect. South-facing slopes have much less vegetation because their greater exposure to sunlight accelerates the evaporation of critical moisture.

In the high plains of southwestern Wyoming, soils are usually thin and dry, and vegetation is predominantly saltbrush-greasewood and related shrubs. There are limited areas of Douglas fir forests and mountain mahogany woodlands in the northern fringes of the Green River and Washakie basins. Soils are somewhat thicker in the Uinta basin, but the arid climate inhibits plant growth except along the valleys of the major rivers, Saltbrush-greasewood and other shrubs dominate, but there are occasional stands of mountain mahogany, oak shrub, pine, and fir.

In the Piceance basin, shrublands and woodlands also dominate, and forestlands are sparse. Shrubland plants consist primarily of mixed shrubs on moist soils at higher elevations and sagebrush, which dominates in all dry soils. Woodlands occur in thinner soils at lower elevations, and are dominated by pinyon pine and juniper, except where grazing and other disruptions have allowed intrusions of brushes and grasses. Forests are primarily cottonwood along streams at lower elevations, and Douglas fir and aspen on northern and eastern slopes at higher elevations,

Overall, plant life in the Green River formation area is less abundant than in other regions that have ample rainfall and less rugged terrain. However, the area contains diverse plant communities that are well adapted to their environment. Some of the communities in the Piceance basin were studied by the developers of Federal lease tracts C-a and C-b as part of the baseline-monitoring function required for the preparation of detailed development plans. The baseline studies included a census of existing plant species and a determination of the structural characteristics and successional status of plant communities. The results of these studies provide an indication of the diversity of plant life in the vicinity of proposed oil shale development sites.

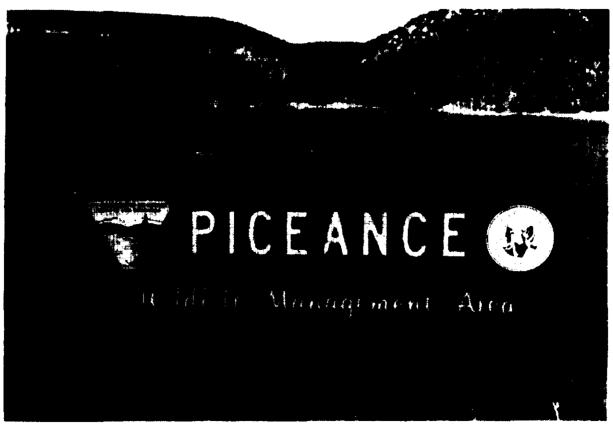
The plants identified on tract C-a included 5 types of trees, 36 shrub species, and 168 herbaceous species, of which 44 were classified as grass or grass-like. One of the plants, dragon milkvetch, is on the Smithsonian Institution’s list of endangered plant species. However, the species is not considered threatened in Colorado.’ On tract C-b, 37 types of trees, shrubs, and vines were identified, together with 137 species of herbs. Vegetation community types included pinyon-juniper woodlands and rangelands, upland and valley sagebrush, Douglas fir forests and aspen woodlands, mixed mountain shrublands, marshes, riparian areas, agricultural fields, mountain grasslands and communities dominated by bunchgrass, Great Basin wild rye, rabbitbush, greasewood, and annual wild plants. No threatened or endangered plant species were found on tract C-b or on tracts U-a and U-b, [5] Colony Development{ has reported the presence of two endangered plant species (yellow columbine and milkvetch) and one threatened plant species (sullivantia) along the valley of Parachute Creek.[6]

Animals

Many types of mammals, cold-blooded vertebrates, birds, invertebrates, and aquatic systems exist throughout the oil shale regions. The diversity of vertebrates is among the highest in the United States, a result of the highly diversified habitats of woodland, grassy shrubland, and high desert that characterize the area. In Colorado’s Piceance basin, for example, more than **300** species of birds, reptiles, mammals, and amphibians have been found or are believed to exist. Similar numbers of animal species have been reported in other geologic basins of the Green River formation. ’ Because of the relatively low rainfall, wildlife of the region are highly dependent on the stream systems and the riparian habitats of their environs.

COLORADO'S PICEANCE BASIN

The Piceance basin is Colorado's most important mule deer range. It is the principal wintering ground for the White River herd, the largest nonmigratory deer herd in North America. Its size has been estimated at approximately 100,000 head.[8] The northeast corner of the basin normally supports the highest deer concentrations in winter, and the entire basin is considered to be a deer range in the summer. Antelope are also found there, but are primarily restricted to the northern edge. Limited numbers of elk live in the general area of the basin and especially on the upper plateaus. A few mountain lions roam over it, largely in pursuit of migrating deer herds and sheep flocks, and a few black bear are found at higher elevations in the southern part. Coyotes and bobcats are regarded as abundant, but there has been no detailed census of these predators. There may be as many as 150 to 200 cottontail rabbits per square mile, and both snowshoe hares and pine squirrels are found in the Douglas fir forests of the high plateaus. Other mammals present include yellow-bellied marmots, prairie dogs, ground squirrels, porcupines, chipmunks, red foxes, raccoons, badgers, and skunks, and from 150 to 250 wild horses range throughout the entire area. The avian species found in this basin include sage grouse, partridge (stocked), pheasants, mallards and other ducks, mourning doves, pigeons, golden and bald eagles, and many other species of migratory waterfowl, shorebirds, songbirds, hawks, eagles, and vultures. Fish species include trout, suckers, and minnews.[8]



Phofo credit *OTA staff*

UTAH'S UINTA BASIN

Utah's Uinta basin is more primitive and isolated than the Piceance basin. It has been described as an ideal natural faunal habitat. '() Parts of the basin are utilized by mule deer herds as winter feeding areas, and small numbers of elk are also present in restricted areas. Transplanted antelope have become established and appear to be flourishing. Bears have been reported in the area but are considered scarce. Mountain lions also range over the basin, but their numbers are unknown. Other mammal species include coyotes, porcupine, bobcat, muskrat, beaver, mink, rabbits and hares, and others. The Bureau of Land Management (BLM) has estimated that about 130 head of wild horse inhabit Utah's oil shale lands. Most bird species found in the Piceance basin are also found in the Uinta basin. Fish live in the clear headwaiters of various tributaries but are less abundant in the heavily silted lower reaches of most rivers and streams.[11]

WYOMING'S BASINS

Over 300 animal species have been identified in Wyoming's Green River and Washakie basins. Of the larger mammals, elk and moose are believed to inhabit the parts of Wyoming that encompass the oil shale regions. Relatively few elk and moose live in the oil shale basins per se, but black bear and lions have been observed. The basins also contain important antelope ranges and habitats. Sizable numbers of wild horses live in the Washakie basin and winter in the highlands where prevailing winds sweep the heavy snowfalls from grazing areas. Several species of grouse, ptarmigan, partridge, wild turkey, pheasant, ducks, and geese have also been observed in the general vicinity of the oil shale lands. Tributaries support several trout varieties including the Colorado River cutthroat, and some of the better trout habitats are located within the oil shale area. 12

ENDANGERED SPECIES

In compiling an inventory of animal species, the tract C-a lessees recorded sightings of both peregrine falcons, listed as an endangered species by the U.S. Department of the Interior (DOI), and prairie falcons, a fully protected species, The number of peregrine falcons was estimated at from one to four. No falcon nesting sites were found in the 170 mi^2 survey area. It is unlikely that falcons would nest within the tract boundaries because of the absence of large cliff faces (their preferred nesting location) and the scarcity of water. Approximately 30 greater sandhill cranes, endangered species in Colorado, were observed in the study area, but no nesting sites were discovered within a 20-mile radius of the tract. The tract and its environs may serve as staging and foraging areas for the birds during their annual migrations, but the area does not contain any important crane habitats.[13]

The environmental reconnaissance on tract C-b did not reveal any rare, endangered, threatened, or protected animal species. However, a prairie falcon was sighted outside of the tract boundaries.[14] Environmental surveys for Colony Development revealed no endangered or threatened species within the tract boundaries.[15] BLM's environmental statement for the Colony program lists several species of concern that might be present in the general area. These include the southern bald eagle, the prairie and peregrine falcons, the humpback chub, the Colorado squawfish, the Colorado cutthroat trout, the bonytail sucker, the black-footed ferret, and the ferruginous hawk.[16]

Air and Water Quality and Economic Base

Regional air and water quality, and their potential alterations because of oil shale development, are discussed in chapter 8. The region's economic base, and the impacts it might experience during the development of an oil shale industry, are discussed in chapter 10.

Air Quality

In general, air quality is excellent throughout most of the region because of the region's rural character and lack of industrialization and urban development. Ambient concentrations of sulfur dioxide, nitrogen oxides, hydrogen sulfide, and carbon monoxide are very low compared with more densely populated areas in the three oil shale States. In both the Piceance and Uinta basins, however, there are occasionally high ambient concentrations of nonmethane hydrocarbons, particulate, and ozone, The hydrocarbons are apparently emitted in aerosol form by sagebrush and other vegetation, because their concentrations vary with the growing seasons for these plants. Windstorms and passing automobile traffic on unpaved roads both contribute to high particulate concentrations. Haze is occasionally observed in the valley of the Colorado River and in the canyons of its tributaries. It has not been determined whether this haze is caused by photochemical smog or by a combination of suspended particulate and local humidity. In general, the area is free from man-induced odors.[17]

Air quality problems may be encountered in the future because of the region's peculiar meteorological conditions. As discussed previously, the predominance of the mountain-valley breeze system coupled with high altitudes and the effects of surrounding mountain ranges on gradient winds aloft, leads to frequent thermal inversions, especially during winter. To date, such inversions have been offensive only near the larger population centers outside of the oil shale basins, such as Grand Junction. However, inversion-related air pollution is likely to become more severe as the region develops, regardless of whether such growth is associated with the creation of an oil shale industry or expansions in other activities. The potential for inversions may preclude siting processing plants in canyons and other low-lying areas, thus, limiting them to higher areas such as the Roan Plateau of the Piceance basin.

Water Quality

Water quality in the region is highly variable. It is good to excellent in most of the upstream reaches of major tributaries such as the Colorado River, but significantly poorer in the downstream reaches. The gradual deterioration is caused by discharges from numerous point and nonpoint sources. About half of the increase in salinity is related to the discharge of naturally saline streams into the river system. The rest is generally related to the concentration of human activities, such as urban areas, mineral development sites, and irrigated farmlands.

A twentyfold increase in salinity has been noted in the Colorado River between its headwaiters and Imperial Dam in Arizona.[18] Salinity is of special concern because the Colorado River system is important to the entire Southwest. Irrigated agriculture causes most of the human-related salinity effects through salt loading (picking up soluble salts from field soils) and salt concentration (the evaporation and transpiration of relatively pure water in irrigation canals and fields).

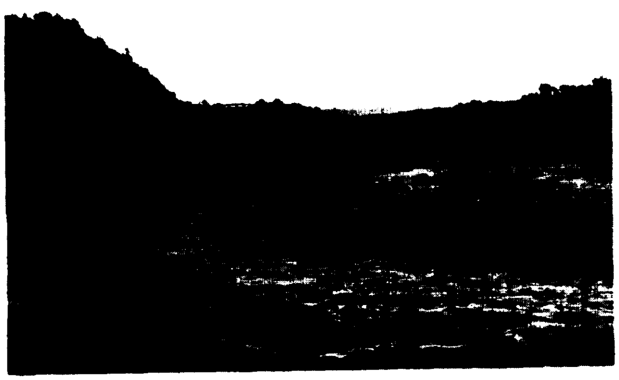


Photo credit OTA *staff*

White River near Meeker, Colo.

Surface streams within the oil shale basins also show wide variations in water quality. In Piceance Creek, for example, the concentration of dissolved solids range from less than 400 mg/1 in the upper reaches to over 5,000 mg/1 at the discharge point into the White River.[19] Dissolved solids in Yellow Creek in the Piceance basin range from about 700 to 3,000 mg/1. Water quality deteriorates in the downstream direction because of natural surface runoff, agricultural return flows, and the discharge of saline ground water from aquifers in the Green River and Uinta formations. As described in chapters 8 and 9, ground water quality in the aquifers of the Piceance basin varies enormously, from a low of less than 250 mg/1 in the purer waters of the upper aquifer above the Mahogany Zone to over 63,000 mg/1 in the highly saline brines of the lower aquifer in the northern portions of the basin. In general, the ground water from all the aquifers in the Piceance basin does not satisfy the drinking-water standards of the U.S. Public Health Service. There are particular problems with respect to dissolved solids, fluoride, and barium concentrations.[20]

The quality of surface streams and ground water in the Uinta basin shows similar extreme variability. The concentration of total dissolved solids in the Uinta basin ground water aquifers range from 350 mg/1 (which is considered potable water) to 72,000 mg/1 (which is considered brine). In the Wyoming oil shale basins, surface streams have dissolved solids concentrations from 150 to 855 mg/1, while concentrations in ground water range from about 450 to 7,000 mg/l.[21]

Population

The population density over the entire oil shale resource region is low, averaging about 3 persons per square mile. The densities in many areas are even lower. For example, when the oil shale resources of a 2,500 mi^2 area of the Uinta basin were mapped in 1967, 250 people lived in the entire area, with 200 of them living in the town of Bonanza. The average population density of the area was therefore about 0.1 persons per square mile.[22]

The population of the entire Green River formation region is approximately 120,000. About 62 percent live in Colorado, 17 percent in Utah, and 21 percent in Wyoming. The major communities are Grand Junction, Rifle, Meeker, Craig, and Rangely in Colorado; Vernal in Utah; and Green River and Rock Springs in Wyoming, Grand Junction, the largest Colorado town, has a population of approximately 24,000, Vernal 'has about **6,200**, and Rock Springs about 28,000, The region's present economy is based on agriculture (crop raising and sheep and cattle ranching), minerals production (oil, gas, uranium, trona, and coal), and tourism and recreation.[23,24,25]

Oil Shale Products and Their Potential Applications

The Nature of Oil Shale

Green River oil shale is not a shale nor does it contain appreciable amounts of liquid oil. The shale portion is actually a marlstone, and its principal constituents are dolomite, calcite, and quartz. In contrast, true shales are composed largely of silicate clays. They have a finely stratified or laminated structure and tend to fracture along individual bedding planes. Oil shale also has a stratified appearance and tends to fracture in a similar matter, particularly when organic matter is present in low concentrations. These properties led early investigators to believe that the Green River oil shales were true shales. However, the appearance and fracture properties of Green River shale arise from variations in the concentrations of organic matter it contains, and not to any great extent from the characteristics of the inorganic component,

Most of the organic component is a solid material called kerogen, from the Greek words for waxmaking, that is insoluble in most standard petroleum solvents. About 10 percent of the organic component is a solid substance called bitumen that can be dissolved in certain solvents.

Kerogen is composed of carbon and hydrogen molecules cross-linked together by sulfur and oxygen atoms to form relatively large three-dimensional macromolecules with molecular weights of about 3,000. These macromolecules are embedded within the finer grained inorganic or mineral matrix of the oil shale rock. This organic continuous phase gives kerogen-rich oil shale most of its physical strength and stability. When the organic matrix is removed from very rich oil shale, the mineral residue has little cohesive strength and is easily crushed to a fine powder,

Kerogen Pyrolysis

When kerogen is heated above 400" F (200° C), chemical bonds between and within the individual organic molecules are ruptured, forming smaller molecules. Most of these can be readily isolated from the mineral material as liquid and gaseous products. Some of the organic coproducts of kerogen decomposition remain trapped within the inorganic material as a coke-like residue.

A chemical change produced by heat is called pyrolysis, This process can also be called destructive distillation, when an organic substance is broken down by heat and the products are distilled off, leaving a residue. When pyrolysis is carried out in a vessel called a retort, the process is called retorting. Oil shale retorts may vary in size from laboratory-size Fischer assay* units used to estimate the potential oil yield of oil shale rocks, to commercial-sized vessels that can process 10,000 tons of raw oil shale per day, to in situ retorts containing several hundred thousand tons of rock.

When kerogen is pyrolyzed, three combustible products are formed: vaporized oil, which can be condensed by cooling; a gaseous mixture containing hydrogen, oxides of carbon, hydrogen sulfide, and hydrocarbon

*In a Fischer assay, small samples of crushed oil shale are heated to 9320 F (500° C] under carefully controlled conditions. The oil yield by this method is the standard measure of oil shale quality.

gases such as methane; and a coke-like solid residue that remains behind in the retort.

The relative proportions of oil, gases, and coke largely depend on the pyrolysis temperature and atmospheric conditions in the retort, and to a lesser extent on the organic content of the raw shale. The product yields from a typical Green River oil shale pyrolyzed at 932° F (500° C) according to the standard Fischer assay technique are summarized in table 16. As indicated, the raw shale contained about 17 percent organic matter by weight and yielded about 27 gal/ton. Oil was the largest decomposition product. It comprised 63 percent of the organic matter originally present in the shale, Noncondensible gases comprised 15 percent, and the carbon residue about 13 percent. The balance of hydrogen and oxygen content of the organic matter was transformed to water vapor by the pyrolysis process.

Table 16.–Composition and Pyrolysis Products of Typical Colorado Oil Shale[a]

Mineral constituents

Mineral	Weight percent of minerals
Dolomite	32
Calcite	16
Quartz	15
Illite	19
Low-albite	10
Adularia	6
Pyrite	1
Acalcime	1
Total	100

Ultimate analysis of organic constituent

Element	Weight percent of organics
Carbon	765
Hydrogen	103
Nitrogen	25
Sulfur	1.2
Oxygen	9.5
Total	1000

Yields from Fischer assay Pyrolysis

Decomposition product	Weight percent of organic constituent in raw shale	Weight percent of total raw shale
Oil	63	10,4
Noncondensable gas	15	2.5
Fixed-carbon residue	13	2.2
Water vapor	9	1.4
Total	100	16,5

[a]Pyrolyzed by the standard Fischer assay procedure at 932° F 011 yield = ?6 7 gal/ton

SOURCE T A Sladek Recent Trends in 011 Shale–Pad 1 History Nature and Reserves *Mineral Industries f3u/e/in* vol 17 No 6 November 1974 pp 4-5

Each of the three main products of kerogen decomposition is a potential source of energy. Crude shale oil can be burned directly as a fuel or it can be refined to produce fuels similar to those obtained from conventional petroleum crude oils. As discussed in chapter 6, the physical and chemical properties of crude shale oil differ from those of conventional crude, thus presenting some refining challenges. However, shale oil can yield high-quality finished fuels such as gasoline and jet fuel.

The composition and properties of the off-gas from kerogen pyrolysis vary tremendously with the nature of the pyrolysis process. Gas from the Fischer retort typically has a heating value comparable to that of natural gas. Such high-quality gas could be used as plant fuel in the oil shale facility, or it could be pipelined to other areas for commercial or industrial applications. In contrast, gases from commercial directly heated retorts are highly diluted with carbon dioxide (from combustion and from the decomposition of carbonate minerals) and nitrogen. They have only about one-tenth the heating value of natural gas. Such gases could be useful within the oil shale facility but they could not be transported economically over any significant distance, nor could they be upgraded to higher heating values at reasonable cost. Surplus retort gases could become valuable byproducts if they were burned for power generation. Some developers plan to do this.

The coke residue is also a potential source of energy, but it is a very poor solid fuel compared with coal or with the raw shale itself. (A typical shale coke from the Fischer retort has a heating value of about 250 Btu/lb; most quality coals have heating values of about 12,000 Btu/lb.) Transportation of the coke residue for offsite combustion would not be practical because of its high content of inert mineral matter. Any energy values will have to be recovered within the oil shale facility either by burning the residue in the retorts or by converting its carbonaceous component to fuel gas. If the latter approach is followed, the gas may be consumed within the plant, upgraded for external sale, or burned onsite for power generation.

As indicated in table 16, inorganic minerals comprise approximately 80 percent of raw Green River oil shale. These minerals remain as part of the coke residue after the oil and gas products are removed. The properties of this retorted or spent shale vary with the type of retorting procedure used. Indirectly heated retorts produce a carbonaceous spent shale, while directly heated retorts produce a shale that is essentially stripped of carbon. The indirectly heated TOSCO II retort, for example, produces a spent shale resembling black talcum powder. The directly heated Union "A" retort produces a gray decarbonized spent shale resembling coal ash and clinkers.

Spent shale will be produced in enormous quantities by an oil shale industry of any significant size. Some potential uses exist for the spent shale produced by aboveground retorts. With in situ processing, the spent shale remains underground, and the only option for byproduct recovery is by means of a leaching process. Spent shale on the surface could be converted to cement or building materials, but the output from a single commercial-size facility will far exceed the market demand for such material. Nearly all of the spent shale will have to be disposed of as a waste material, and such disposal will have to be done either on or very near the plantsite. Spent shale disposal is the source of much of the environmental controversy surrounding oil shale development as discussed in chapter 8.

Associated Minerals

In addition to kerogen, some deposits in the Green River formation contain several sodium-bearing minerals that could be commercially valuabIe. These include nahcolite, dawsonite, and trona. Nahcolite (sodium bicarbonate) is chemically identical to commercial baking soda. As mentioned previously, it occurs in scattered deposits near the depositional center of the Piceance basin and is found in high concentrations near the bottom of the Parachute Creek member. Nahcolite may be processed to yield soda ash, a common raw material for glass production, and its ability to adsorb sulfurous gases may be of use in scrubbing sulfur compounds from powerplant stack gases.

Dawsonite (dihydroxy sodium aluminum carbonate) is a potential source of alumina, which can be converted to aluminum. As indicated previously, dawsonite is found as disseminated crystals and crystalline planes in the Parachute Creek member. Occurrences of both nahcolite and dawsonite are very extensive in this basin. A survey of mineral resources in the basin by USGS estimated that 1 mi^2 of terrain in the soda-mineral region overlies 1 billion bbl of potential shale oil in place, 130 million tons of nahcolite with a potential soda ash yield of 82 million tons, and sufficient dawsonite to produce 42 million tons of alumina. By comparison, the bauxite deposits in the rest of the United States contain the equivalent of only about 30 million tons of alumina.[26]

Trona is a hydrated mixture of sodium carbonate and sodium bicarbonate. It is also a source of soda ash for glass production, and is presently being mined for this purpose in Sweetwater County, Wyo. Unlike nahcolite and dawsonite, trona does not always occur in intimate association with oil shale, and its commercial development could take place either with or without the related development of hydrocarbon resources. The existing facilities in Sweetwater County do not recover shale oil. Projected plans for multiminerals operations, such as those of Superior Oil and the Multi Minerals Corp., call for the simultaneous production of shale oil, soda ash, and alumina.[27 28]

Both of these projects depend on acquiring access to Federal land through land exchanges or leasing. No privately owned tracts contain sufficient quantities of dawsonite and nahcolite for their development to be economically attractive. Some sodium leases have been issued for oil shale land, but these exclude the development of the associated oil shale.

The History of Oil Shale Development

Useful hydrocarbons have been extracted from oil shale for many years. In the 14th century, Austrian and Swiss oil shales were pyrolyzed to yield "petro oleum, " or "rock oil. " This was subsequently processed to yield an ointment called Icthyol, a name derived from the Greek words for fish-oil, in reference to the fossilized fish remains frequently encountered in the marine oil shales of central Europe.[29] In 1694, England issued patent No. 33 for a retorting process that was claimed to produce "oyle from a kinde of stone. "[30]

In 1859, the first commercial oil well was drilled in Pennsylvania. Prior to that year, at least 50 commercial plants existed along the Atlantic seaboard of the United States for extracting fuel oil from oil shales.]' Also in 1859, the first commercial oil shale retort began operating in Scotland. It started an industry that lasted for over 100 years.

In 1874, workers on the transcontinental rail line found that rocks picked up from excavations along the Green River in Wyoming ignited when used to protect campfires from the night winds. The March 1874 issue of Scientific American noted that the railroad superintendent :[32]

> . . . has caused analyses and experiments to be made with this substance which proves to be a shale rock rich in mineral oils. The oil can be produced in abundant quantities, say 35 gallons to the ton of rock. The oil thus obtained is of excellent quality.

The rocks of interest were pieces of oil shale from the Green River formation.

The use of oil shale as a fuel resource thus predates the large-scale use of conventional petroleum by several centuries. In the past 150 years, commercial industries have existed in Scotland, France, Germany, Spain, South Africa, Australia, and the United States. At present, industries exist or are being started in Estonia, the People's Republic of China, Brazil, and perhaps the United States. The following section describes the history of foreign and U.S. development efforts and defines the status of present industries around the world.

Scotland

Scottish oil shales occur in seams from 4 to 14 ft thick yielding approximately 22 gal/ton. Reserves were originally estimated to contain about 600 million bbl. The first retorting plant was built in 1859. Its economic viability was immediately threatened by the rapid development of conventional petroleum that followed the drilling of the first commercial oil well. The production of shale oil and valuable byproducts such as waxes, ammonia, pyridines, * ammonium sulfate, and building materials enabled the Scottish industry to survive for over 100 years despite the high cost of the oil in comparison with conventional crude oil. At its peak, the industry involved about 140 different companies and processed about 3.3 million ton/yr of oil shale. In 1919, the companies were consolidated into a single corporation that subsequently became a subsidiary of the predecessor of British Petroleum. The industry was subsidized by the British Government with tax credits and other incentives, but competition from cheap petroleum forced the last plant to close in 1962.

Sweden

Typical Swedish oil shales are about 50 ft thick and yield from 6 to 15 gal/ton. The total resource is estimated to be about 2.5 billion bbl of shale oil in place. The Swedish oil shale industry began in the 1920's, with the largest operations near the city of Kvarntorp. These facilities featured two types of aboveground retorts and a unique type of in situ process in which the deposits were pyrolyzed with electric heaters. The industry reached a maximum capacity of 2 million tons of oil shale per year (6,000 ton/d) and produced as much as

*Nitrogen-containing organic solvents also used to synthesize other useful products.

550,000 bbl/yr of crude shale oil. Because of the limited quantity of high-quality reserves, and price competition from petroleum crude, the industry ceased operation in 1966.

France

French resources total about 500 million bbl of shale oil in place. They are of medium quality and yield from 10 to 24 gal/ton. They are more properly called bituminous shales, rather than oil shales, because they contain inclusions of asphaltic compounds. The French industry began in 1840 and continued intermittently until 1957. Its maximum throughput was 0,5 million ton/yr of shale, attained in 1950. For most of its existence, the industry was protected from competition with foreign oil by excise taxes and import duties.

Spain

The best Spanish resources yield from 30 to 36 gal/ton. Reserves have been estimated at about 280 million bbl of oil in place. The Spanish industry began in 1922 using retorts similar to those that had been developed in Scotland. Maximum throughput for these units was 220 ton/d, reached in 1947. In 1955, new retorts from Scotland were installed. In 1960, the enlarged industry processed 1 million tons, supplying more than half of Spain's requirement of lubricating oil, Obsolete processing technology and high operating costs forced the industry to cease operation in 1966.

Germany

German resources are estimated to contain only about 2 million bbl of shale oil in place. Oil yields average only 12 gal/ton. German shales were developed as early as 1857, and several retorts were operated in the 1930's. A major development effort was initiated during World War II in response to wartime fuel shortages. The German industry used two types of aboveground retorts and one in situ process. A plant with about 30 Lurgi above--ground retorts was operated from 1947 to 1949. In 1961, a plant was built in the town of Dotterhausen that burns finely crushed oil shale in a fluidized-bed combustor. The heat of combustion is used for power generation, and the spent shale product is used to make cement. The plant is the only active oil shale facility in West Germany.

South Africa

Very rich deposits are found in South Africa. Oil yields reach 100 gal/ton, with an average of 55 gal/ton, and the deposits are located just beneath coalbeds. South African shale oil production began in 1935, and the industry attained a maximum throughput of 800 ton/d in the 1950's, with a corresponding shale oil production of 800 bbl/d. The industry was located in the country's interior, and although it was not directly subsidized by the government, its economic viability was enhanced by the high cost of transporting competing petroleum from the seacoast ports to interior markets in the vicinity of the plants. The richer deposits were eventually depleted, and the industry ceased operations in 1962,

Australia

Oil shale deposits are found throughout Australia. Those of New South Wales and Tasmania have been developed commercially. Total reserves are estimated at 270 million bbl of shale oil in place. Most of the deposits are very rich, with oil yields as high as 180 gal/ton. Shale oil production in New South Wales began in 1862, and by 1892, about 100,000 tons of shale were being processed each year. The Australian Government began subsidizing the industry in 1917, but production ceased in 1925. Production of Tasmanian shale oil began in 1910 and ceased in 1935. In the interim, about 41,000 tons of oil shale were processed, and 85,000 bbl of shale oil were produced.

Production was resumed in New South Wales early in World War II under the direction of the Australian Government. By 1947, annual throughput reached 330,000 tons, and about 100,000 bbl of shale-derived gasoline were produced annually. The production was equivalent to about 3 percent of Australia's gasoline consumption. The plant was closed in 1952 because of resource depletion, high operating costs, and competition from conventional petroleum.

United States

As indicated previously, the U.S. oil shale industry was an important part of the Nation's energy economy before the first oil well was drilled. At least 50 commercial plants for extraction of fuel oil from eastern oil shales existed prior to 1859. The industry disappeared shortly after commercial petroleum production began.

Between 1915 and 1920, supplies of domestic crude fell below demand, and oil imports increased, especially from new oilfields in Mexico. USGS indicated at that time that the United States had only a 9-year reserve of petroleum in the ground and that the outlook for new discoveries was not good. At about the same time, USGS announced that large fuel resources were contained in the oil shales of the Green River formation. When combined with predictions of forthcoming fuel shortages, the announcement triggered an oil shale boom. Some 30,000 mining claims were filed on Federal lands, and about 200 companies were formed to develop the resource. Retort development programs were initiated at several locations, and at least 25 retorting processes were advanced to the pilot-plant stage. Total shale oil production was negligible, but interest was at an all-time high. The boom ended abruptly with the discovery of large oilfields in eastern Texas. Oil prices dropped to a few cents per barrel, and interest in oil shale development essentially disappeared.

Little R&D was conducted in the United States until World War II. In 1944, out of concern for the hazards of imported energy, Congress passed the Synthetic Liquid Fuels Act, which authorized USBM to establish a liquid fuel supply from domestic oil shale. USBM began a comprehensive R&D program that has continued to the present day, although oversight authority was transferred to the Energy Research and Development Administration in 1974 and to its successor, DOE, in 1978.

One of USBM's most significant early acts was the establishment of a research facility at Anvil Points on the Naval Oil Shale Reserve near Rifle, Colo. Between 1944 and 1956, the Anvil Points facility was used for mining studies that led to the application of the room-and-pillar technique of underground mining. The gas combustion retort, the predecessor of modern directly heated retorts, was also developed during this period. In 1964, the facility was leased by the Colorado School of Mines Research Foundation, and was the site of a 4-year development program in which the gas combustion retort was evaluated and improved by a consortium of six major oil companies: Mobil, Humble, Continental, Pan American, Phillips, and Sinclair.

In 1973, the facility was leased by Development Engineering, Inc. (DEI), which operated it for 5 years during which the Paraho retorting process was developed. This is an improved version of the gas combustion retort. DEI then used the facility to produce over 100,000 bbl of shale oil for refining studies, and has recently proposed to use Anvil Points for further development work, including the construction and operation of a commercial-size module of the Paraho retort.

Between 1963 and 1968, DOI evolved a leasing proposal that was intended to encourage private development of the Federal oil shale lands in the Green River formation. The program failed to attract private participation. However, it gave rise to the current Federal Prototype Oil Shale Leasing Program, which was conceived in 1969 and promulgated in 1974 with the sale of leases to four tracts in Colorado and Utah. The histories of these leasing programs are presented in volume II of this report. The status of development efforts on the Federal lease tracts is described in the last section of this chapter.

In addition to these activities on Federal lands, private companies have also engaged in exploration and R&D programs on their own lands, The companies that have been most heavily involved are: Union Oil, Occidental Petroleum and its subsidiary Occidental Oil Shale, Inc.; Superior Oil Co.; and the Colony Development Operation group, which has included Tosco, Atlantic Richfield, Cleveland Cliffs Iron Co., and Ashland Oil Co. The activities of these companies, and others that are presently involved in oil shale development, are summarized in the following section, together with a status report on the industries in other countries.

Status of Foreign Oil Shale Industries

Morocco

Oil shale is found in Morocco at Timahdit, in the Middle Atlas mountains, and at Tarfaya, on the Atlantic coast in the southern part of the country. Other, smaller deposits have also been found. Most of the development efforts involve the Timahdit deposits, which contain an estimated 4 billion to 9 billion bbl of shale oil in a seam that is as much as 350 ft thick. The Moroccan Government is actively investigating aboveground retorting, direct combustion of oil shale for power generation, and modified in situ processing technologies.

Soviet Union

The principal reserves of the U.S.S.R. are in the Baltic Basin, with additional deposits in the Ukranian S.S.R. and the Central Asian Republics. The latter resources have been little explored and are not being developed; most development activity is centered on the "kukersite" oil shales in the Baltic basin. The total Baltic resource is estimated to be about 21 billion tons, with about 11.3 billion tons regarded as having commercial potential. About 8.4 billion tons occur in the Estonian S. S. R., with about 2.9 billion tons in the Leningrad area. The Estonian shales occur in beds about 10 ft thick and are buried beneath 30 to 130 ft of overburden. They are of good quality, yielding about 50 gal/ton.

The Estonian deposits were first developed in the 1920's after the State achieved independence from Finland. In 1939, about 1.7 million tons were processed. About 60 percent of the shale was retorted to obtain fuel oil; the rest was burned directly for process heat and power generation. During World War II, the area was occupied by Germany, and the shale oil produced during this period was refined to obtain illuminating oil and bunker fuel oil for the German navy. When the Estonian S.S.R. was created, the German-built plants were expanded to provide fuel gas for the cities of Tallinn and Leningrad. Shale oil and petrochemicals were also produced, but most of the shale mined was burned as a boiler fuel for power generation.

In 1970, about 14 million tons were mined. The present goal is to expand production to 54 million ton/yr. About 75 percent of the present production is burned under boilers to supply about 90 percent of Estonia's electrical needs. The rest is retorted to produce fuel oil, gasoline, fuel gas, and chemicals.

The Soviet industry is estimated to have mined about 560 million tons of kukersite between 1945 and 1975. As noted, only one-fourth of the mined shale is retorted. If all of the shale had been converted to oil, the average production rate would have been about 67,000 bbl/d, slightly more than would be produced by a single commercial-scale oil shale facility in the United States. The present target of 54 million ton/yr is equivalent to about 200,000 bbl/d.

Two types of large-scale retorts are used: the Kiviter gas generator which is similar to the gas combustion and Paraho directly heated retorts; and the Galoter retort which uses spent shale as a heat carrier and is remarkably similar to the TOSCO II indirectly heated design. At present, the largest Kiviter retort has a capacity of about 1,000 ton/d, about one-tenth the size of retorts planned for U.S. plants. The largest Galoter unit has a capacity of about 500 ton/d. A 3,30()-ton/d unit is under construction. *

People's Republic of China

Oil shale is found near Fushun in Manchuria, and near Maoming in the Province of Kwantung. The Manchuria deposits occur in 450-ft-thick seams and overlie thick coal seams. The shale is mined by open pit methods, together with the coal, Oil yields average only about 15 gal/ton. The deposits were first developed by the Japanese when they invaded Manchuria during World War II. About 1.3 million bbl of shale oil were recovered during the war through use of retorts similar to the gas combustion design. Most of the oil was refined into fuel oil for the Japanese navy. During the Korean war, production was expanded to about 50,000 bbl/d. Byproducts included chemical fertilizer from the nitrogen in the shale oil and cement from the spent shale. Additional shale was mined, mixed with coal, and burned directly for power generation.

During the past decade, the capacity of the Manchuria industry has remained fairly constant, but six retorting plants have been built in the Kwantung Province. The total production from the Chinese plants is unknown, but it is unlikely to be more than about 50,000 to 70,000 bbl/d. About two-thirds of the oil is refined, the rest is burned directly for power generation.

Brazil

Brazil has very large deposits which could contain as much as 3 trillion bbl of potential shale oil. The largest deposits of commercial interest are those of the Irati formation, which begins in the State of Sao Paulo and extends southward in an S-shaped curve for a distance of about 1,000 miles to the border with Uruguay. Irati shale yields about 20 gal/ton on retorting, which is comparable to a medium grade of Green River shale.

Small retorts have been used intermittently in Brazil since 1862. Early operations produced illuminating gases for home use. Retorting was discontinued in 1946 but resumed in the 1950's under control of the national government. In 1970, a 2,200-ton/d" demonstration retorting plant was completed at Sao Mateus do Sul in the State of Parana. The plant has operated on an experimental basis. The Petrosix retorting process is used. It was developed by the engineering staff of Petrobras, the national oil company, with the assistance of Cameron Engineers, a U.S. engineering firm. Little information has been released about the demonstration but, given the properties of the Irati shale and assuming high oil recoveries from the retort, the plant could produce about 1,000 bbl/d of shale oil, eve. a million cubic feet of high-Btu gas per day, and about 15 ton/d of elemental sulfur.

At present, Petrobras is attempting to raise about $1.5 billion to build a commercial-size plant with a capacity of about 45,000 bbl/d. The plant would be sited near the present demonstration facility. About 20 Petrosix retorts would be used. Current plans call for a 25,000-bbl/d operation by 1983, with subsequent expansion to full capacity by 1985. The deposits in the immediate vicinity of the plantsite could supply the full-size facility for about 30 years. Two additional plants of similar size are contemplated for the State of Rio Grande do Sul, which is south of the demonstration plant.

Brazil's enduring interest in oil shale development is related to its oil-import problem. It consumes about a million barrels of crude oil per day, of which about 960,000 bbl/d are imported. The net drain of the national economy is about $11 billion per year, which contributes to a net deficit in the balance of international payments of about $1.55 billion. It is difficult to track the effect of this deficit in an economy with a 60-percent annual inflation rate, but the currency drain to purchase im-

*For additional information on retorting technologies see ch. 5.

ported oil is estimated to be equivalent to about 6 percent of the nation's gross national product (GNP). If the United States spent the same proportion of its GNP on imported oil, about 15 million bbl/d would be imported, or nearly twice the present rate.

Status of U.S. Oil Shale Projects

The characteristics and status of 11 projects that are at least at the stage of field testing in the Green River shales are summarized in table 17. The list does not include several relatively new projects (such as Multi Mineral Corp. 's project for extraction of oil, nahcolite, and alumina from deeply buried deposits in the Piceance basin) or projects that are being conducted in the eastern shales. It also does not include the numerous theoretical investigations and laboratory-scale experiments that are being conducted by Federal and State agencies and private companies.

Two of the projects—Rio Blanco and Cathedral Bluffs—are actively proceeding towards commercial-scale operations on Federal lease tracts in Colorado. The White River project is also on a Federal lease tract, but it is inactive at present because of legal uncertainties.* Tosco's Sand Wash project is Proceeding towards commercialization at a relatively leisurely pace to maintain compliance with the due-diligence provisions of the Utah leases. Three projects—Logan Wash, Geokinetics, and BX—are of an experimental nature and are being partially funded by DOE. The four other projects—Colony, Union, Superior, and Paraho—are aimed towards ultimate commercial-scale operations but are inactive at present for a variety of reasons, principally economic.

*The Rio Blanco, Cathedral Bluffs, and White River projects are parts of the Federal Prototype Oil Shale Leasing Program, which is discussed in vol. II of this report.

Table 17.–Status of Major U.S. Oil Shale Projects

Project	Location	Proposed technology	Production target (barrels per day)	Status summary
Rio Blanco Oil Shale Co.: Gulf, Standard of Indiana	Federal lease tract C-a, Colorado	MIS[a] and Lurgi-Ruhrgas aboveground retorts	76,000 (1987)	Shaft sinking for MIS module development. Designing Lurgi-Ruhrgas module, PSD[b] permit obtained for 1,000 bbl/d.
Cathedral Bluffs 011 Shale project: Occidental Oil Shale: Tenneco	Federal lease tract C-b; Colorado	Occidental MIS	57,000 (1986)	Shaft sinking for MIS module development, Process development work being done at Logan Wash, PSD permit obtained for 5,000 bbl/d.
White River Shale project: Sundeco; Philips; SOHIO	Federal lease tracts U-a and U-b; Utah	Paraho aboveground retorts	100,000	Inactive because of litigation between Utah, the Federal Government, and private claimants over landownership
Colony Development Operation: ARCO; Tosco	Colony Dow West property ;Colorado	TOSCO II aboveground retorts	46,000	Inactive pending improved economic conditions. PSD permit obtained for 46,000 bbl/d.
Long Ridge project: Union 011 of California	Union property; Colorado	Union "B" aboveground retort	9,000	Inactive pending improved economic conditions. PSD permit obtained for 9,000 bbl/d.
Superior Oil Co.	Superior property; Colorado	Superior aboveground retort	11,500 plus nahcolite, soda ash, and alumina	Inactive pending BLM approval of land exchange proposal. PSD permit obtained for 11,500 bbl/d.
Sand Wash project: Tosco	State-leased land; Utah	TOSCO II aboveground retorts	50,000	Site evaluation and feasibility studies underway. Lease terms require $8 million investment by 1985,
Paraho Development Corp.	Anvil Points: Colorado	Paraho aboveground retorts	7,000	Inactive following completion of pilot plant and semiworks testing. Seeking Federal and private funding for a modular demonstration program,
Logan Wash project, Occidental Oil Shale: DOE	D. A. Shale property; Colorado	Occidental MIS	500	Two commercial-size MIS retorts planned for 1980 m support of the tract C-b project. PSD permit obtained for 1,000 bbl/d,
Geokinetics, Inc., DOE	State-leased land, Utah	Horizontal-burn true in situ	2,000 (1982)	Continuation of field experiments, About 5,000 bbl have been produced to date.
BX 0il Shale project Equity 0il Co. ; DOE	Equity property; Colorado	True in situ retorting with superheated steam (Equity process)	Unknown	Steam injection begun and will continue for about 2 years. Oil production expected in 1980. Production rate has not been predicted

[a] Modified in situ processing
[b] Prevention of significant deterioration—an air quality permit that must be obtained before construction can begin (See ch 8)

SOURCE Off Ice of Technology Assessment

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CHAPTER 5
Technology

Contents

List of Tables

List of Figures

CHAPTER 5
Technology

Introduction

The mining and processing technologies that can be used to convert kerogen, the organic component of oil shale, into marketable fuels are discussed in this chapter. The characteristics of these technologies will influence the effects that an oil shale industry will have on the physical environment, and their technological readiness will affect the rate at which an industry can be established. The following subjects are discussed:

- the general types of processing methods and their major unit operations;
- the mining methods that could be used to remove oil shale from the ground and prepare it for aboveground processing;
- the generic types of retorting methods that could be used to convert the oil shale to liquid and gaseous fuels;
- the upgrading and refining methods that could be used to convert crude shale oil to finished products;
- the potential markets for shale-derived fuels;
- the technological readiness of the major steps in the oil shale conversion system;
- the uncertainties and the research and development (R&D) needs that are associated with each major unit operation; and
- the policies available to the Government for dealing with the uncertainties,

Summary of Findings

Oil shale contains a solid hydrocarbon called kerogen that when heated (retorted) yields combustible gases, crude shale oil, and a solid residue called spent, retorted, or processed shale. Crude shale oil can be obtained by either aboveground or in situ (in place) processing. In aboveground retorting (AGR), the shale is mined and then heated in retorting vessels. In a true in situ (TIS) process, a deposit is first fractured by explosives and then retorted underground. In modified in situ (MIS) processing, a portion of the deposit is mined and the rest is shattered (rubbled) by explosives and retorted underground. The crude shale oil can be burned directly as boiler fuel, or it can be converted into a synthetic crude oil (syncrude) by adding hydrogen. The syncrude can also be burned as boiler fuel, or it can be converted to petrochemicals or refined to obtain finished fuels. Some of OTA's major findings concerning these mining and processing technologies are:

- Limited areas of the oil shale deposits may be amenable to open pit mining. This technique has never been tested with oil shale but it is well-advanced with other minerals. More oil shale experience has been acquired with underground mining, particularly room-and-pillar mining, and preparing MIS retorts. Although uncertainties remain, the mining technologies should advance rapidly if presently active projects continue and suspended ones resume.

- TIS is presently a very primitive process, although R&D and field tests are being conducted. The principal advantages of TIS are that mining is not needed and surface disturbance from facility siting and waste disposal is minimized. The principal disadvantages are a low level of technological readiness, low recovery of the shale oil, and a potential for surface subsidence and leaching of the spent shale by ground water.

- MIS is a more advanced in situ method. It is being further developed on two lease tracts and a privately owned site. The Department of Energy (DOE) is providing substantial R&D support. The principal advantages of MIS are that large deposits can be retorted, oil recoveries per acre affected are high, and relatively few surface facilities are required. However, some mining and some disposal of solid wastes on the surface are required, and the oil recovery per unit of ore processed is low relative to AGR methods. The burned-out MIS retorts have a potential for ground water pollution.

- AGR also has a medium level of technological readiness. Three retorts have been tested for several months at rates approaching one-tenth the capacity of commercial-size modules. Others are still at the laboratory or pilot-plant stages. The principal advantage of AGR processing is high oil recovery per unit of ore processed. However, with some mining methods, oil recoveries per acre may be lower than with MIS. Surface disturbance is highest with AGR because of the extensive surface facilities, and because large quantities of solid waste are generated.

- The physical and chemical properties of crude shale oil differ from those of many conventional crudes. However, depending on the nature of the upgrading techniques applied, the syncrude can be a premium-quality refinery feedstock, comparable with the best grades of conventional crude. Shale oil is a better source of jet fuel, diesel fuel, and distillate heating oil than it is of gasoline. Although some technical questions remain, the upgrading and refining processes are well-advanced. Refining shale oil may cost from $0.25 to $2.00 more per bbl than refining some of the poorer grades of domestic crude.

- The initial output from the pioneer oil shale industry will probably be marketed near the oil shale region. Once the industry is established, the shale oil will probably be used as boiler fuel or refined in the Rocky Mountain States. A large industry will most likely supply oil to Midwest markets. A 1-million-bbl/d industry could completely displace the quantities of jet, diesel, and distillate heating fuels that are presently obtained from foreign sources in the entire Midwest.

- With the present technical status of the critical retorting processes, deploying a major oil shale industry would entail appreciable risks of technological and economic failure. Although much R&D has been conducted, and development is proceeding, the total amount of shale oil produced to date is equivalent to only 10 days of production from a single 50,000-bbl/d plant. Because of its primitive status, much basic and applied R&D is needed for the TIS method. The MIS approach and some of the AGR processes are ready for the next stage of development—either modular retort demonstrations or pioneer commercial-scale plants. Such demonstrations would be costly, but they would substantially reduce the risks associated with the much larger capital investments needed to create an industry,

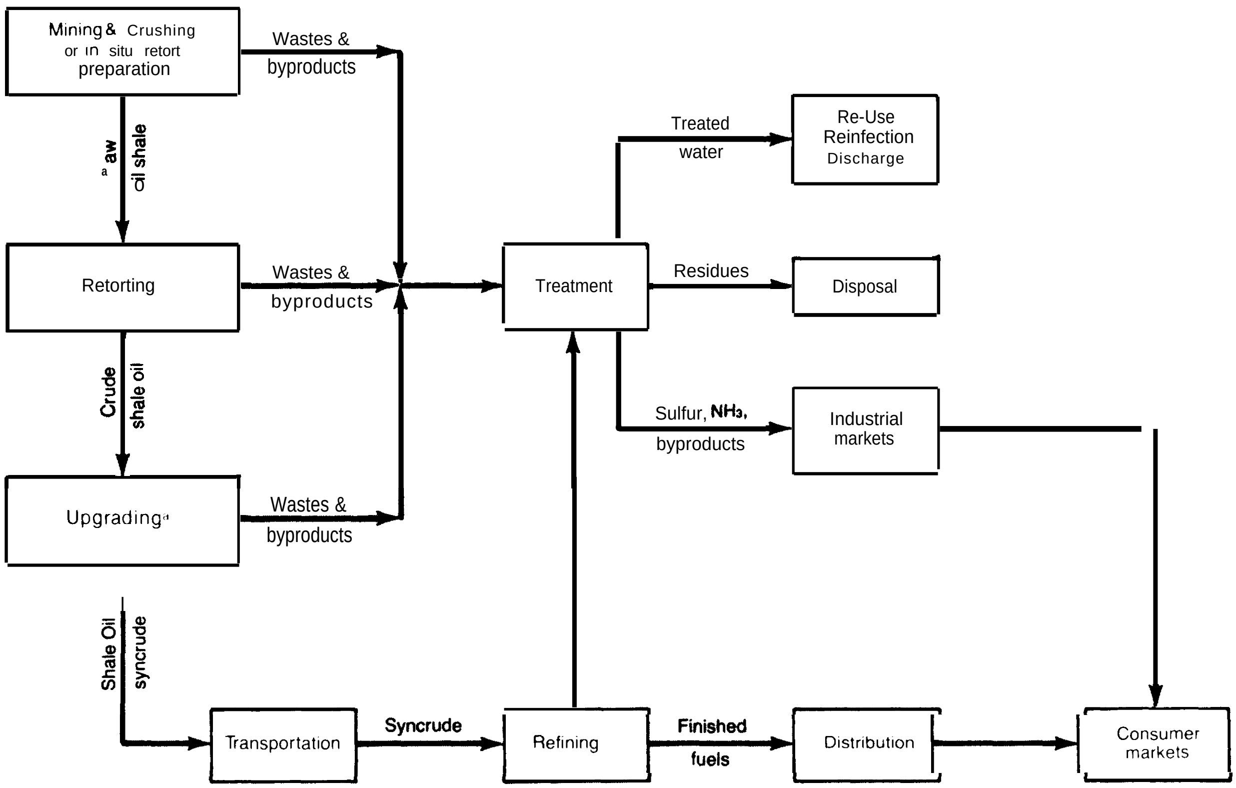
An Overview of Oil Shale Processing

Converting shale in the ground to finished fuels and other products for consumer markets involves a series of processing steps. Their number and nature are determined by the desired mix of products and byproducts and by the generic approach that is followed in developing the resource. The alternative approaches are:

- TIS processes in which the shale is left underground, and is heated by injecting hot fluids;
- MIS processes in which a portion of the shale deposit is mined out, and the rest is broken with explosives to create a highly permeable zone through which hot fluids can be circulated; and
- AGR processes in which the shale is mined, crushed, and heated in vessels near the minesite.

Figure 19 is a flow sheet for the steps common to all three options. How the steps would be integrated in an AGR facility is shown in figure 20. In the first step, the oil shale is mined and crushed for aboveground processing, or the deposit is fractured and rubbled for in situ processing. The main product is

Figure 19.– Oil Shale Utilization



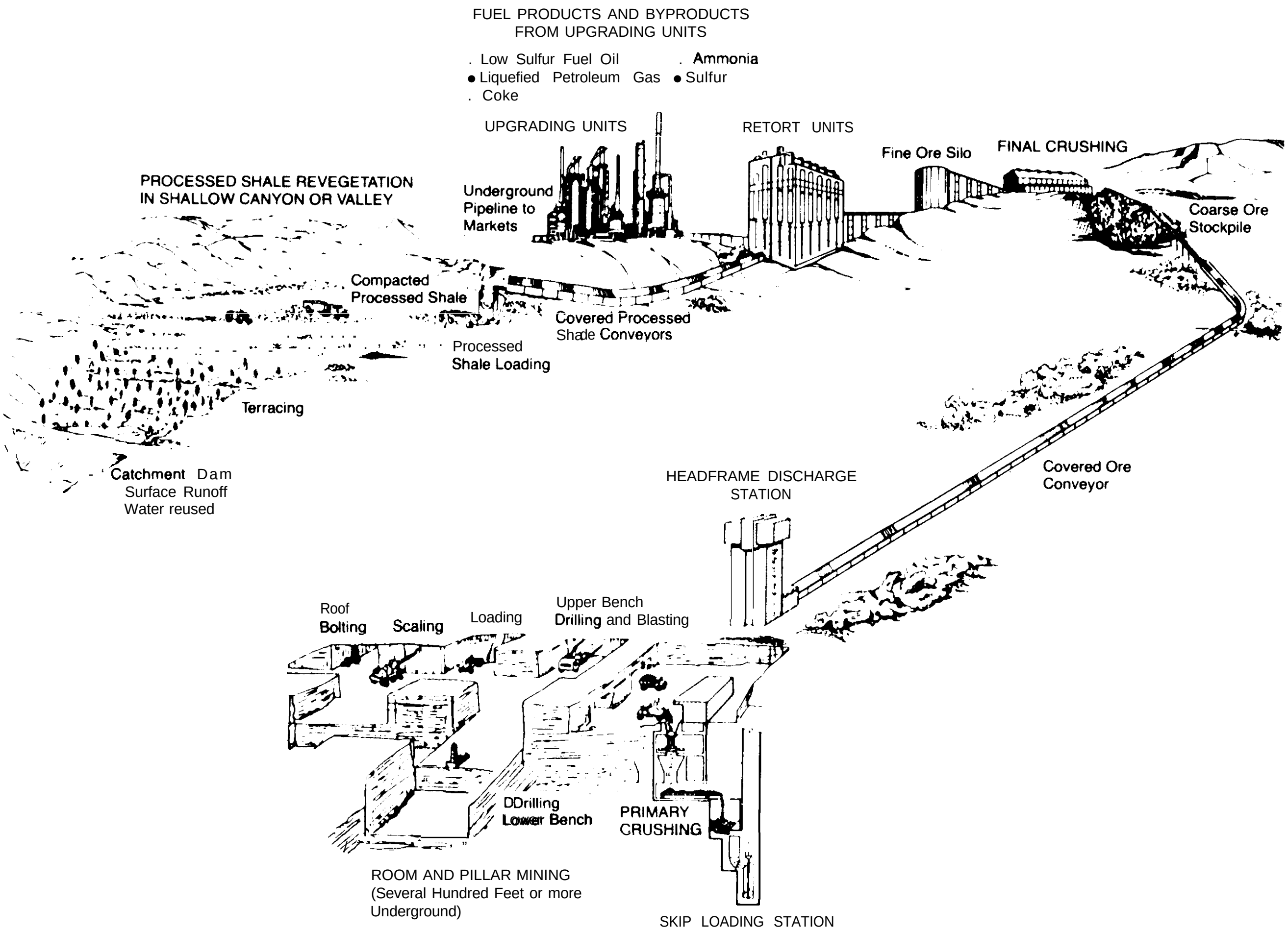
aMay not be needed for some in situ methods

SOURCE Off Ice of Technology Assessment

raw oil shale with a particle size appropriate for rapid heat transfer. Nahcolite ore can be one of the various byproducts from this step. Dust and contaminated water are among its wastes, In the retorting step, the raw oil shale is heated to pyrolysis temperatures (about 1,000° F (535° C)) to obtain crude shale oil. Other products are the spent shale residue, pyrolysis gases, carbon dioxide, contaminated water, and in some cases additional nahcolite and dawsonite ore. The crude shale oil may be sent to an upgrading section in which it is physically and chemically modified to improve its transportation properties, to remove nitrogen and sulfur, and to increase its hydrogen content. (Crude shale oils from some in situ processes may not need upgrading before transportation.) Contaminated air and water, and in some units refinery coke, are the wastes produced along with gases that contain sulfur and nitrogen compounds. Depending on the extent of the treatment, the upgraded product—shale oil syncrude-can be a high-quality refinery feedstock, comparable with the best grades of conventional crude. In the refining step, which may be conducted either onsite or offsite, hydrogen is added to convert the syncrude to finished fuels such as gasoline, diesel fuel, and jet fuel. The syncrude, or the crude shale oil, could also be used directly as boiler fuel. After refining, the fuels are distributed to consumer markets. Refining also produces waste gases and various contaminated condensates.

To protect the environment, contaminated water must be treated for reuse in the oil shale facility, for reinfection into the ground water aquifer source, or for discharge into

Figure 20.—The Components of an Underground Mining and Aboveground Retorting Oil Shale Complex



SOURCE C b Shale 01 I Project *Detailed Development Plan and Related Materials* Ashland 011, Inc and Shell 011 Co , February 1976, p 1-24

surface streams. Contaminated air and process gases must be purified to meet Federal and State air pollution standards before they can be discharged to the atmosphere. The waste gases from retorting, upgrading, and refining are potential sources of ammonia (for fertilizer and other uses) and sulfur (for sulfuric acid and many other materials). These can be recovered during the treatment steps and sold to industrial processors. In some portions of the Green River formation, the solid residues from mining and retorting will contain nahcolite (which can be used to produce soda ash and for stack gas scrubbing) and dawsonite (a source of aluminum metal). In any case, spent shale from above--ground processing must be moistened, compacted, and revegetated to prevent erosion and leaching. Retorted shale in in situ retorts, and spent shale from surface operations that is backfilled into underground openings, must be protected from leaching by ground water.

This chapter deals with the processing technologies used in mining, retorting, upgrading, and refining. Technologies for treating air, water, and solid wastes are discussed in chapter 8.

Oil Shale Mining

Both MIS and AGR require mining. In the case of AGR, the mined shale is conveyed to retorts where it is processed to recover shale oil. With MIS, the shale may also be retorted aboveground, or it may be discarded on the surface as a solid waste.

Green River oil shale deposits are characterized by their extreme thickness and by their extensiveness. The richer shale zones in the Piceance basin, for example, are more than a thousand feet thick, in places, and are continuous over an area of 1,200 mi^2. Deposits of this nature could be amenable to either surface mining (strip or open pit) or to underground mining methods (such as room and pillar), depending on topographical features, accessibility, overburden thickness, presence of ground water in the mining zone, and many other factors. Surface mining may be feasible for very thick oil shale zones that are not deeply buried, especially if their average oil yield is not high, Because of the thickness of the overburden, only a limited area of the Piceance basin and somewhat more of the Uinta basin and the Wyoming basins is amenable to surface mining. In other areas, streams have eroded gulleys and canyons through the shale beds, exposing some of the richer shale zones. Shale that outcrops in these areas, plus the shale in all deeply buried beds, will probably be extracted by underground mining,

Despite the high price of crude oil, oil shale is a lean ore compared with many ores that contain valuable metals. Economies of scale encourage massive mining installations, regardless of the mining method selected. A prospective developer once characterized commercial-scale oil shale mines as "prodigious, " because it connotated a larger size than "giant.'" A sense of this can be conveyed by comparing their capacities with those of more conventional mines. At present, the largest surface mine in the United States is Kennecott Copper's Bingham Canyon pit in Utah, which produces about 110,000 ton/d of copper ore. The largest underground mine is the San Manuel copper mine in Arizona, which yields about 50,000 ton/d of ore, About 70,000 ton/d of 30 gal/ton oil shale would have to be mined to support a single 50,000-bbl/d plant that used aboveground retorts. * This mine would be substantially larger than the San Manuel mine. A 400,000-bbl/d industry of aboveground retorts would have to mine about 560,000 ton/d—the equivalent of 5 Bingham Canyon pits or 11 San Manuel mines. If the same industry used only MIS, about 230,000 to 460,000 ton/d would have to be mined—the equivalent of four to seven San Manuel mines. ** Some of the mining techniques that could be used to achieve these levels of production are described below.

Surface Mining

The two principal types of surface mining —open pit and strip— both have been widely used to develop coal seams and deposits of many other minerals. Their technical aspects are fairly well-understood for these minerals. However, their feasibilities and effects vary with the nature of the ore body. Neither technique has yet been applied to the oil shales of the Green River formation.

Surface mining is economically attractive for large, low-grade ore deposits because it permits high recovery of the resource and allows sufficient space for very large and efficient mining equipment. An open pit mine could recover almost 90 percent of the oil shale in a very thick deposit. Strip mining could provide even higher recoveries. In contrast, underground mining would recover less than 60 percent. One of the reasons that industry's bids on a lease for Federal tract C-a were so high was that the deposit could be

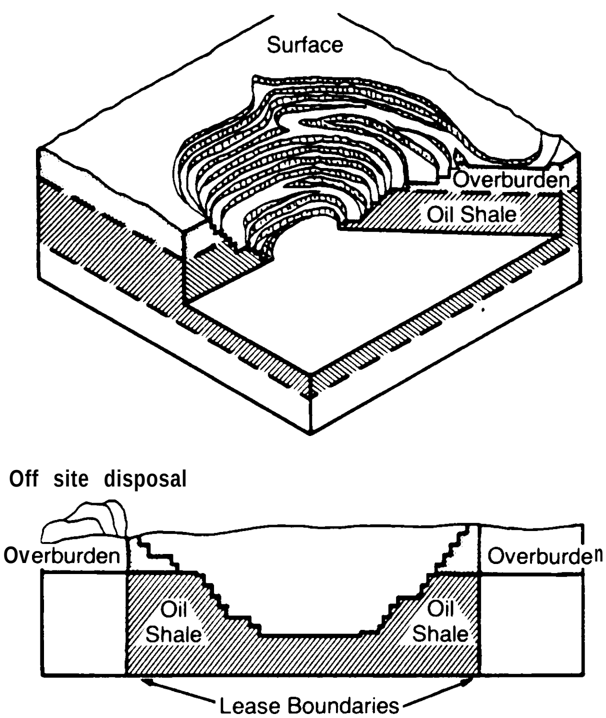
*This assumes recovery of 100 percent of Fischer assay oil, a recovery efficiency that has been achieved in tests of the TOSCO 11 technology.

**This assumes mining of 20 to 40 percent of the shale in the retort volume, and an oil recovery of 60 percent of Fischer assay.

mined by open pit methods. About five times as much shale could be recovered by open pit, which could have mined the entire deposit, than by underground room-and-pillar mining, which would have been limited to a relatively thin zone.[2]

A mature open pit mine is shown in figure 21 and the steps in its operation in figure 22. In the first step, overburden is drilled and blasted loose over a large area above the oil shale zone. The burden is carried by trucks or conveyors to an offsite disposal area. When enough burden is removed to expose the shale beds, the shale itself is drilled and blasted, and is hauled from the pit for processing in aboveground retorts. As mining proceeds, a huge hole is formed, extending from the top of the overburden to deep into the oil shale deposit. The walls of the pit are under pressure from the overburden, and must be angled outwards to transmit the pressure without collapsing.

Figure 21 .—An Open Pit Oil Shale Mine



SOURCE *Hear/rigs on Oil Shale Leasing,* Subcommittee on Minerals, Materials, and Fuels of the Senate Commitee on Interior and Insular Affairs, 94th Cong 2d sess , Mar 17, 1976, p 84

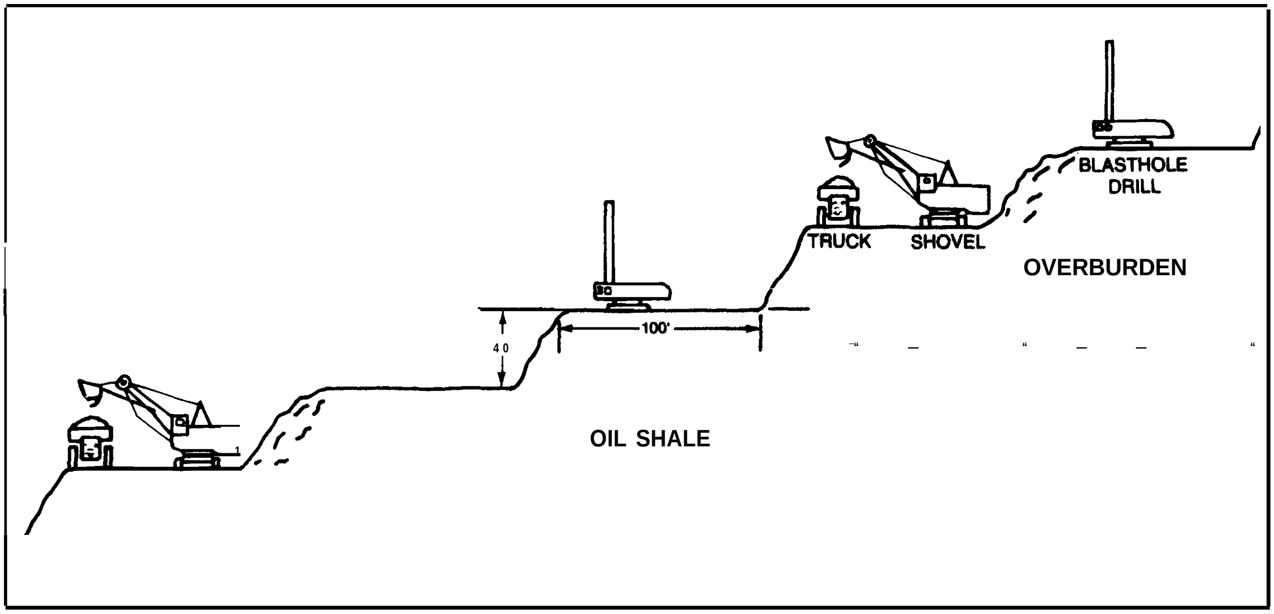
Open pit mining was originally proposed for tract C-a by the Rio Blanco Oil Shale Co., the lessee. The pit was to have started in the northwest corner of the tract, and eventually to have covered its entire surface. After a few decades, freshly removed overburden and spent shale from the aboveground retorts would have been returned to the pit as backfill. In the interim, the solid wastes would have been disposed of on a highland to the northeast of the tract boundaries. This concept was abandoned when the Department of the Interior (DOI) refused to allow offtract waste disposal. Rio Blanco later switched to MIS techniques because the alternative—underground mining—would have reduced resource recovery and threatened profitable operations. * At present, there are no plans for any open pit mines, although Rio Blanco may reconsider its original plan if offsite disposal were allowed.[3]

In strip mining, overburden is removed with a dragline—a massive type of scraper shovel. When the dragline has filled its scoop, it pivots and dumps the burden into an adjacent mined-out area. One difference between open pit and strip mines is that in strip mining, the burden is simply cast into a nearby area; in open pit, it must be moved far from the minesite to prevent interfering with the development of the pit. Strip mining has not been proposed for any of the Green River deposits.

Surface mining of most oil shale deposits is made difficult by the great thickness of the overburden that covers them. In the center of the Piceance basin, for example, the 2,000-ft-thick oil shale zones are buried under about 1,000 ft of inert rock and very lean oil shale. This does not necessarily preclude surface mining, because the deposits are generally characterized by a favorable stripping ratio—the ratio of overburden thickness to orebody thickness. The thick beds in the center of the Piceance basin have 1 ft of overburden

*This change in plans is discussed in vol. 11,

Figure 22.—Open Pit Oil Shale Mining



SOURCE U S *Energy Outlook—An Interim Report The* National Petroleum Council Washington D C 1972

for every 2 ft of oil shale—a stripping ratio of 1:2. With coal, a stripping ratio of 10:1 is often economically acceptable. A study by the National Petroleum Council indicates that open pit mining would be favored for stripping ratios between 2:1 and 5:1, strip mining for smaller ratios, and underground mining for larger ratios than 5:1.'

However, the economic principles of coal mining should be applied with caution to oil shale. Removing 1,000 ft of overburden to recover 2,000 ft of shale might be possible in theory, but the pit's boundaries would be so extensive that it would have to be located on a very large tract. Furthermore, the large "front-end" investment in removing overburden many years in advance of retorting would probably make open pit mining of deep deposits uneconomical. Also, strip mining would not be feasible in many parts of the oil shale region, even those with favorable stripping ratios, because the dragline would have to reach to the bottom of a 3,000-ft-thick layer of overburden and oil shale. It is not clear that such a machine could be built.

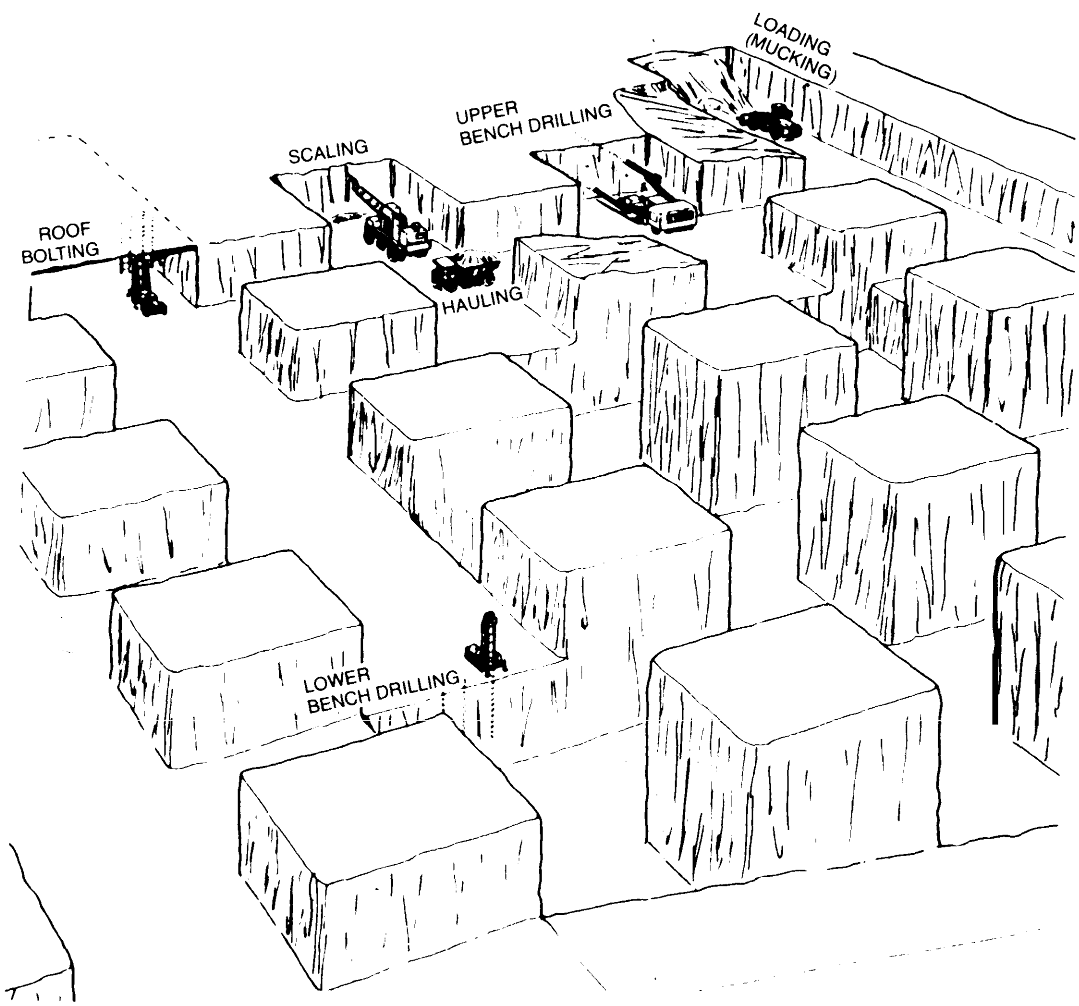
Underground Mining

Many underground mining procedures have been proposed for oil shale deposits[5-10] but to date only room-and-pillar mining and mining in support of MIS retorting have been tested at any significant scale. In room-and-pillar mining, some shale is removed to form large rooms and some is left in place, as pillars, to support the mine roof, The relative sizes of rooms and pillars are determined by the physical properties of the shale, by the thickness of the overburden, and by the height of the mine roof. Most of the deposits of commercial interest are very thick and have relatively few natural faults and fissures. The ore itself resists compression and vertical shear stresses. These properties allow the use of large rooms, and relatively little shale needs to be left as unrecoverable pillars.

The U.S. Bureau of Mines (USBM) studied underground mining of oil shale at the Anvil Points Experimental Station in the late 1940's and early 1950's.[11] The primary purpose of the mining program was to supply raw shale for the Bureau's retorting experiments, but the program was also designed to develop a safe, low-cost mining method. The room-and-pillar technique was adopted after extensive testing. From their studies, which included enlarging the rooms until the roof failed, the investigators concluded that for safe mining conditions the rooms should be 60 ft wide with pillars that are 60 ft on a side.

Many of the modern mine designs have been patterned after the USBM experimental mine. The design depicted in figure 23 is the mining plan proposed for Colony Development's 46,000-bbl/d facility in the Piceance basin. [12] The rooms are 60 ft wide; the pillars are 60 ft square; and the mine roof is 60 ft high. Mining is conducted in two 30-ft-high benches. The upper bench is mined first by drilling blastholes into the walls of a production room, and breaking the shale loose with explosives. The broken shale is carried by trucks to the crushers where it is crushed to the size range required by the TOSCO 11 aboveground retorts. The walls and the roof of the new room are then "scaled" to remove shale that was loosened by the blasting but

Figure 23.—The Colony Room-and-Pillar Mining Concept



SOURCE R W Marshall Colony Development Operation Room. and-Pillar 011 Shale Mining," *Quarterly 01 the Colorado School o/ Mines*, VOl 69, No 2 April 1974. pp 171 184 did not fall. Holes are drilled into the roof, and roof bolts are inserted to assure its integrity, thus protecting the miners from roof falls. The USBM studies indicated that roof bolts would have to be installed in the access passageways but not in areas that were actively being mined. These production rooms would be vacated long before there was any serious danger of roof falls.

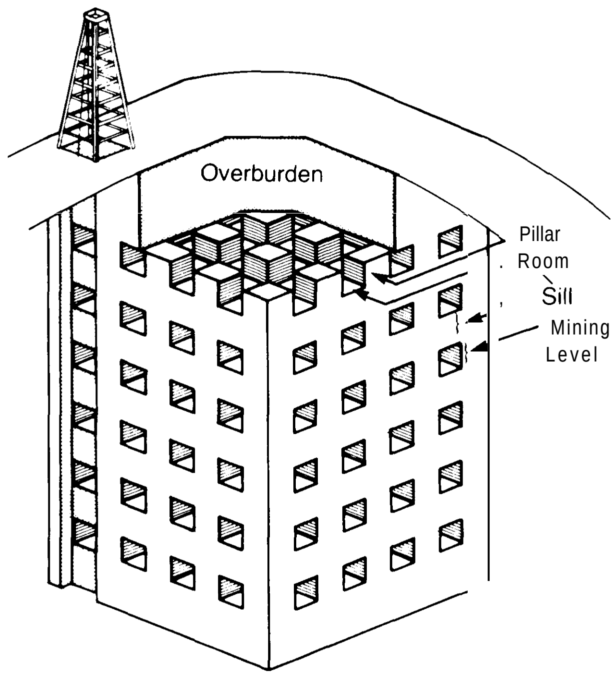
The lower bench is mined next, The sequence is similar except the blastholes are drilled into the floor of the upper bench, and additional roof bolting is not needed, The cycle of drilling, blasting, loading, scaling, and roof bolting was designed to produce about 66,000 ton/d of shale. About 60 percent of the shale in the mining zone was to be removed for processing in the aboveground retorts. The rest was to remain in the support pillars. Colony estimated that enough shale is present in the 60-ft seam to support the retorting facility for at least 20 years.

The same type of mine was proposed by the Colony partners for development of tract C-b, after considering longwall mining, long-hole blasting, continuous mining, block caving, open pit mining, in situ processing, and many other options. The major advantages of the room-and-pillar method were identified as: [13]

- it is highly flexible and can easily be modified to accommodate new conditions, new equipment, or technological advances:
- it can be highly mechanized and high overall production rates can be achieved because many areas can be mined simultaneously:
- the mine openings are relatively easy to ventilate:
- development of access passageways is also a production operation because oil shale would be removed; and
- the mine could be designed to minimize surface subsidence.

The disadvantages were the high cost of the roof support system and the relatively low recovery. In this regard, it was estimated that only 30 to 50 percent of the shale in a 75-ft-thick interval could be recovered. Higher recoveries would be possible if the pillars were subsequently mined out or if the mining were conducted on multiple levels. (See figure 24,)

Figure 24.—Room-and-Pillar Mining on Multiple Levels

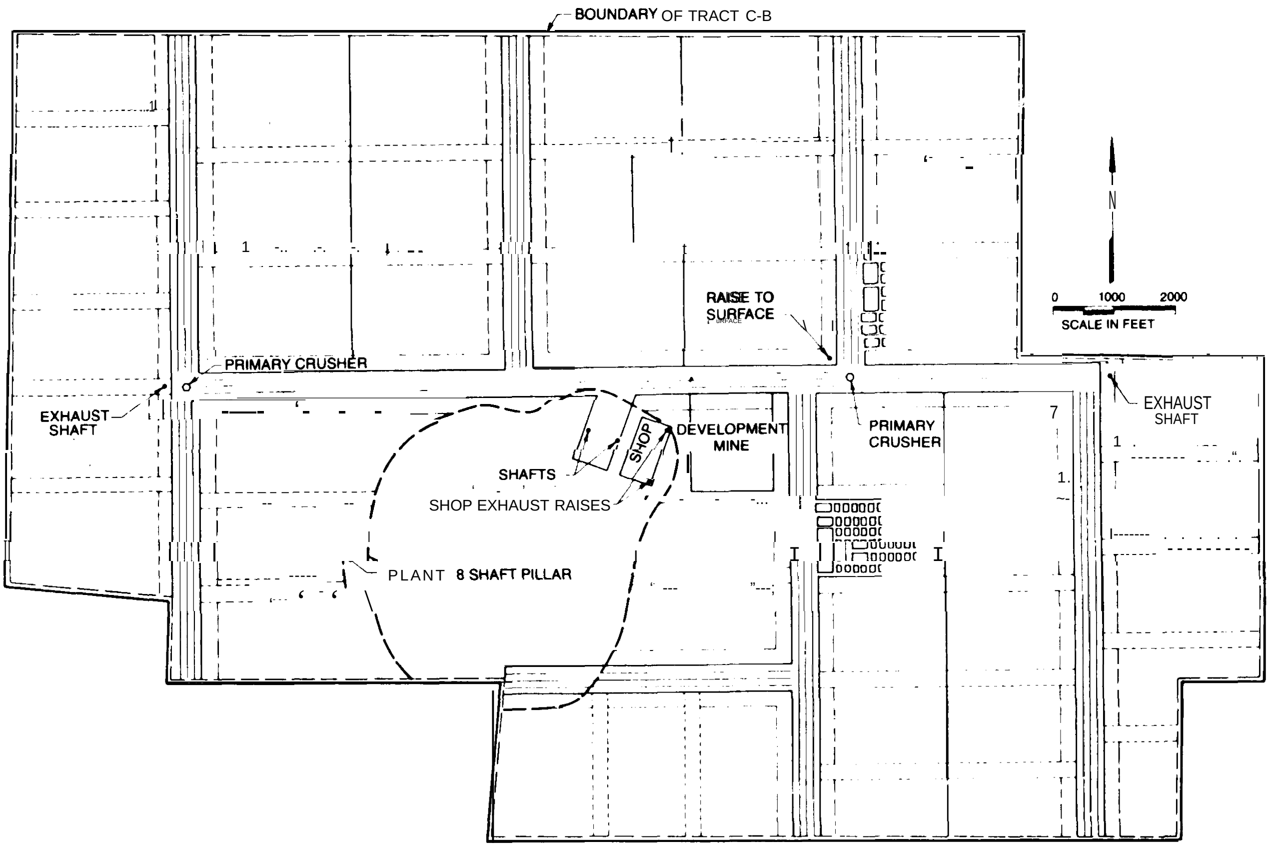


SOURCE *Hearing on Oil Shale Leasing* Subcommittee on Minerals Materials and Fuels of the Senate Committee on Interior and Insular Affairs 94th Cong 2d sess Mar 17 1976 p 83

The mine eventually would have extended under the entire surface of tract C-b, as shown in figure 25. However, the concept was abandoned when it was discovered that the shale in the mining zone was highly fractured—a condition that would have required large support pillars thus reducing resource recovery to uneconomic levels. All of the original partners subsequently withdrew from the tract, and it is now being developed by MIS methods by Occidental Oil Shale and Tenneco Oil Co.

Mining to prepare for MIS retorts is distinguished from room and pillar both by the volume of the deposit that is disturbed and by the configuration of the disturbed areas. As indicated, the underground mines both on the Colony property and on tract C-b would have been developed in a 60-ft-high mining zone;

Figure 25.—The Original Mine Development Plan for Tract C-b



SOURCE C-b Shale 011 Project, *Detailed Development Plan* and *Related Materials*, Ashland 011, Inc , and Shell 011 Co , February 1976, p IV-1 1

present plans for the MIS operations on tracts C-a and C-b call for recovering oil from the shale in a 750-ft-high zone. However, the actual mining required to support this development will take place in relatively confined areas. The mine will consist primarily of fairly small underground openings in the region in which the MIS retorts will be created, plus shafts from the surface for ventilation, drainage, passageways for the miners, and transportation of combustion air and retorting products. Some of the mining plans are discussed later in the section on MIS retorting methods.

Oil Shale Retorting

The three generic methods for recovering shale oil from oil shale deposits are described below. Brief discussions of some of the more significant R&D programs that have been conducted as part of their development are ineluded.

True In Situ

The sequential steps in TIS processing are:

1. dewatering, if the deposit occurs in a ground water area;

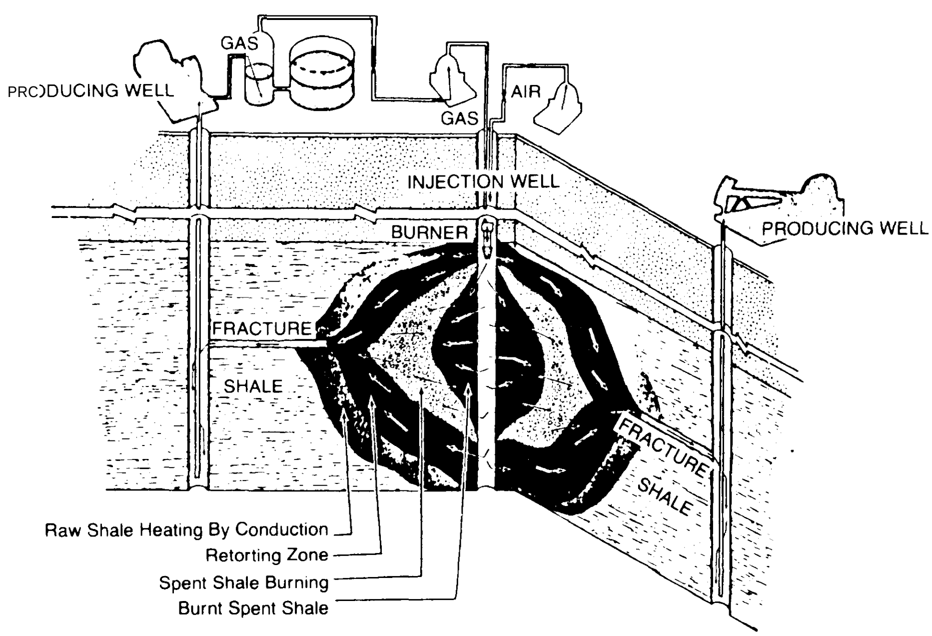
2. fracturing or rubbling if the deposit is not already permeable to fluid flow;
3. injection of a hot fluid or ignition of a portion of the bed to provide heat for pyrolysis; and
4. recovery of the oil and gases through wells.

The principles of TIS processing are illustrated in figure 26. Several types have been proposed that differ from each other with respect to the methods for preparing and heating the deposit. All use a system of injection and production wells that are drilled according to a prescribed pattern. One that is commonly used is the "five-spot" pattern in which four production wells are drilled at the corners of a square and an injection well is drilled at its center. The deposit is heated through the injection well and the products are recovered through the production wells,

For efficient TIS processing, the deposit must be highly permeable to fluid flow, which is true of portions of the Green River oil shales. A good example is the Leached Zone of the Piceance basin where ground water has dissolved salt deposits to leave large rubble-filled zones. It is estimated to contain about 550 billion bbl of shale oil in place. [14] There are interconnected fractures and voids in other areas of the formation, but these, in general, have only a very limited permeability. The permeability of most of the zones that appear to have commercial promise is essentially zero. Deposits that lie near the surface could be fractured by injecting water or explosive slurries, but mining would probably be needed to increase the permeability of deeply buried deposits. MIS or AGR processes are more appropriate for the deeper resources.

In 1961, Equity Oil Co. began developing a TIS process for the Leached Zone, which was tested in the Piceance basin between 1966 and 1968. It involved dewatering a portion of the zone followed by injecting hot natural gas. Pyrolysis gases and a small amount of oil were swept in the natural gas stream to production wells through which they were

Figure 26.—True In Situ Oil Shale Retorting



SOURCE B F Grant Retorting 011 Shale Underground—Problems and Possibilities, *Quarterly of the Colorado School of Mines VOl 59, No 3,* July 1964, p 40 pumped to the surface. The gas was separated from the oil, reheated, and reinfected into the deposit. The oil had a much lower pour point, viscosity, and nitrogen content than oils from aboveground retorts. * These favorable characteristics may have been related to the solvent properties of the natural gas, and to the absence of oxygen from the retorting zone. The quality of the retort gases was also good, partly because of their natural gas component, and partly because during retorting combustion and the decomposition of carbonate minerals were minimal. **

Process development was not pursued because too much of the natural gas was lost in the unconfined formation. In 1968, Atlantic Richfield Co. (ARCO) purchased an interest in the process and resumed its development. In 1971, a revised concept was announced in which superheated steam, rather than natural gas, was to be used to heat the deposits. In 1977, DOE contracted with Equity to test the concept in a 50()-f t-thick seam in the Leached Zone of the Piceance basin. The seam underlies about 0.7 acre of surface, and contains about 700,000 bbl of oil in place. It has been estimated that as much as 300,000 bbl could be recovered over a 2-year period, with about half of the oil produced in the first 7 months. 's Steam injection has begun at the site, and will continue through 1981. No detailed estimates have yet been released of production rates or retorting efficiency. If the process proves to be technically and economically feasible, it could be applied in portions of both the Piceance and the Uinta basins.

At present, no work is being done in slightly fractured formations, but much research is being performed to develop methods for increasing their permeability by enlarging natural fractures and creating new ones. Some of the fracturing techniques used have been chemical explosives, electricity, and injecting high-pressure air and water. These methods have been used to enhance recovery of conventional petroleum; oil shale fracturing poses a similar problem. Nuclear explosives were also proposed in the 1960's, but were not tested because of their potential for harming the environment, A nuclear test—Project Rio Blanco—was conducted in the Piceance basin to fracture sand formations containing natural gas. The test failed.

The earliest TIS work was by Sinclair Oil Co., between 1953 and 1966. A thin section of shale in the Mahogany Zone of the Piceance basin was fractured by injecting air. The bed was ignited, although with difficulty, and a small quantity of shale oil was collected before the hot shale swelled and sealed the fractures. After additional tests, Sinclair concluded that the zone's limited permeability would not permit profitable operations. *

Research on TIS processing began at USBM in the early 1960's. In 1974, the programs and personnel were transferred to the Energy Research and Development Administration, and in 1978, they moved to DOE. The R&D programs have included laboratory experiments, computer simulations, pilot-plant studies, and field tests. Among the latter were tests of electrical, hydraulic, and explosive fracturing and combustion retorting near Rock Springs, Wyo. These revealed some of the problems associated with the TIS approach. In one early test, for example, after inert gas at about 1,300° F (7050 C) was pumped into a fractured formation for a period of 2 weeks, about 1 gal of shale oil was recovered. In another experiment in a zone that contained 7,800 bbl of shale oil in place, it was estimated that only 60 bbl of the close to 1,000 bbl that were released were actually recovered.

Low oil recoveries are often associated with TIS processing because of the large im-

*These properties have economic significance. Pour point is the lowest temperature at which oil will flow. Oils with high pour points are hard to transport because they solidify at normal ambient temperatures. Viscosity is a measure of a fluid 's resistance to flow. Oils with high viscosity are expensive to pump. Reducing the high nitrogen content of most crude shale oils consumes hydrogen, which is costly.

**Both of these processes produce carbon dioxide, which is a major constituent of gases produced by some above-ground retorts.

*The results of a mathematical simulation indicated that about 18 years of continuous steam injections would be required to heat the shale to pyrolysis temperatures within a 30-ft radius of a fracture.

permeable blocks of shale in the fractured formation. These cannot be fully retorted in a reasonable length of time. Irregular fracturing patterns that can cause the heat carrier to bypass large sections of the deposit are another problem. Oil shale that is located in the bypassed regions will not be retorted, And, even if all of the shale in a fractured area were retorted, much of the oil would not reach the production wells, but would remain trapped in the pores of the spent shale or would diffuse beyond the production wells, to be lost in surrounding areas.

To develop methods for improving recovery, an extensive R&D program has been conducted at the Federal research center in Laramie, Wyo. Aboveground batch retorts with capacities of both 10 and 150 tons of shale have been used to simulate in situ retorting, but under more controlled conditions than exist underground. Oil recoveries of up to 67 percent have been achieved, and an experiment in a "controlled-state" retort achieved 95-percent oil recovery. *

In 1976 and 1977, the program was expanded to include field tests of different fracturing and retorting techniques under cost-sharing contracts with Equity Oil, Talley - Frac, Inc., and Geokinetics, Inc.** The Equity program has been described. The Talley-Frac program was terminated after the fracturing method failed. The Geokinetics process uses a fracturing technique called surface uplift in which an explosive is injected into several wells and detonated to fracture the shale and make it permeable to fluid flow, The shale is ignited by injecting air and burning fuel gas through one well. It is pyrolyzed by the heat that sweeps through the bed in the gas stream, Oil and gases are pumped to the surface through outlying production wells. It is hoped that the technical feasibility of the process can be demonstrated for thin deposits that are covered by less than 100 ft of overburden. It has been estimated that there are at least 6 billion bbl of shale oil in place in this type of deposit. It is common in the Uinta basin,[16]) and at present, would be most economically developed by strip mining.

Geokinetics has been investigating the surface uplift approach since 1973, and is presently burning its 20th retort in Utah. The largest retort prior to 1979 measured 130 ft by 180 ft by 30 ft thick. A retort about 200 ft on a side and 30 ft thick will be required to demonstrate the technical feasibility of the process. By 1982, DOE and Geokinetics hope to have developed a commercial-scale operation with a production capacity of 2,000 bbl/d.[17]

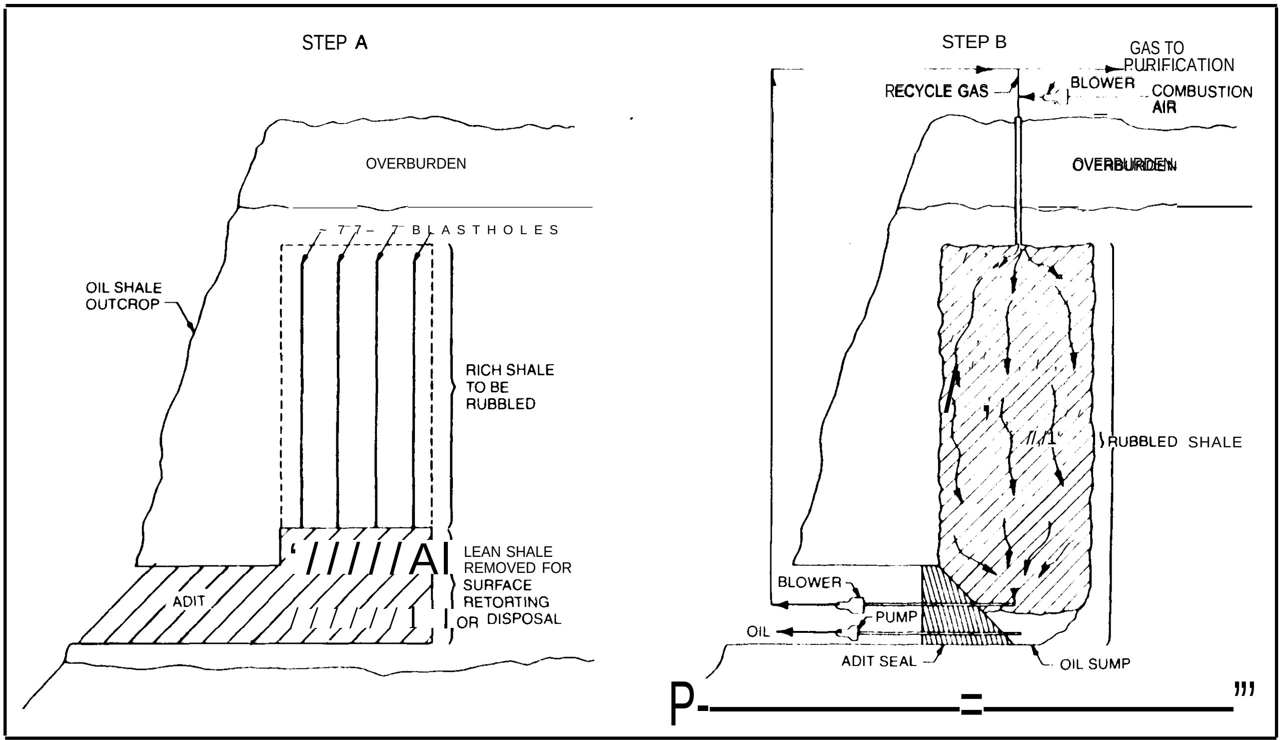
Modified In Situ

In MIS processing, the permeability of oil shale deposits is increased by mining some shale from the deposit and then blasting the remainder into the void thus created. The two-step process is depicted in figure 27. In the first step, a tunnel is dug to the bottom of an oil shale bed, and enough shale is removed to create a room with the same cross-sectional area as the future retort. Holes are drilled through the roof of the room to the desired height of the retort. They are packed with explosives that are detonated in the second step. A chimney-shaped underground retort filled with broken shale results. The access tunnel is then sealed, an injection hole is drilled from the surface (or from a higher mining level) to the top of the rubble pile. The pile is ignited by injecting air and burning fuel gas, and heat from the combustion of the top layers is carried downward in the gas stream. The lower layers are pyrolyzed, and the oil vapors are swept down the retort to a sump at the bottom from which they are pumped to the surface. The burning zone moves slowly down the retort, fueled by the residual carbon in the retorted layers. When the zone reaches the bottom of the retort, the flow of air is stopped, causing combustion to cease.

*The large retorts resemble the classic Nevada-Texas-Utah (NTU) retort that is described later in this chapter. Because of the higher percentage of void volume in the rubble, these retorts provided better simulations of MIS processing than of '1'1S. The controlled-state retort was much smaller and was equipped for better cent rol of retorting renditions.

**Tbe procurement also included a contract with Occidental Oil Shale, Inc., to develop its MIS process, which is discussed in the next section.

Figure 27. —Modified In Situ Retorting



SOURCE T A Sladek Recent Trends in 011 Shale — Part 2 Mining and Shale 011 Extraction Processes *Mineral Industries Bulletin* VOl 18 No 1 January 1975, p 18

Photo credit OTA staff

Head frame at tract C-a

Occidental Oil Shale, Inc., a subsidiary of Occidental Petroleum (Oxy) has demonstrated the MIS process, [18] Oxy's work began in 1972 on the D. A. Shale property along Logan Wash—a private tract on the southern fringe of the Piceance basin about 50 miles northeast of Grand Junction, Colo. To date, six retorts have been burned at the site, with varying degrees of success. The first retort was about 32 ft on each side and 70 ft high. About 60 percent (1,200 bbl) of the shale oil in place was recovered, comparable to the best results from USBM's experiments at Laramie, The next two retorts were slightly larger, and performed similarly, The fourth retort was of nearly commercial size—120 ft on each side and 270 ft high. It contained about 32 times as much shale as the first retort and yielded about 25 times as much oil. The fifth was the same size but was designed for a much lower void volume. The rubbling step did not evenly distribute the void volume, and the performance was poor. Only 40 percent of the oil was recovered. The burning of retort 6 began in 1978, but the sill pillar—the layer of unbroken shale that caps a retort—collapsed into the rubble pile. Operations were disturbed while the top was resealed, but retorting was eventually completed, and about 40 percent of the oil was recovered. DOE will share the costs of retorts 7 and 8, which are scheduled for 1980 and 1981,

The oil shale at the Logan Wash site is not considered to be of commercial quality because of its low kerogen content. In 1976, Oxy acquired access to the higher quality resources of tract C-b by exchanging its technical knowledge for a half interest in the lease. In 1978, Ashland Oil Co., Oxy's partner in the C-b Shale Oil Venture, withdrew and left Oxy in full charge. In 1979, Tenneco Oil Co. purchased a half interest in the lease for $110 million and is proceeding to develop the tract in cooperation with Oxy, If present plans are followed, Oxy's technology could be used to produce about 57,000 bbl/d by 1985.

Oxy's technique uses a vertical burn configuration— that is, the combustion zone progresses vertically through the shale bed. It is also theoretically possible to advance the burn front horizontally, in much the same way as it is done in TIS processing. A crude version of this approach was implemented in Germany during World War II, when a few MIS retorts were created by digging tunnels into oil shale deposits and then collapsing their walls into the void volume. These operations were short-lived because oil recoveries were extremely low, and they were very hard to control.[19]

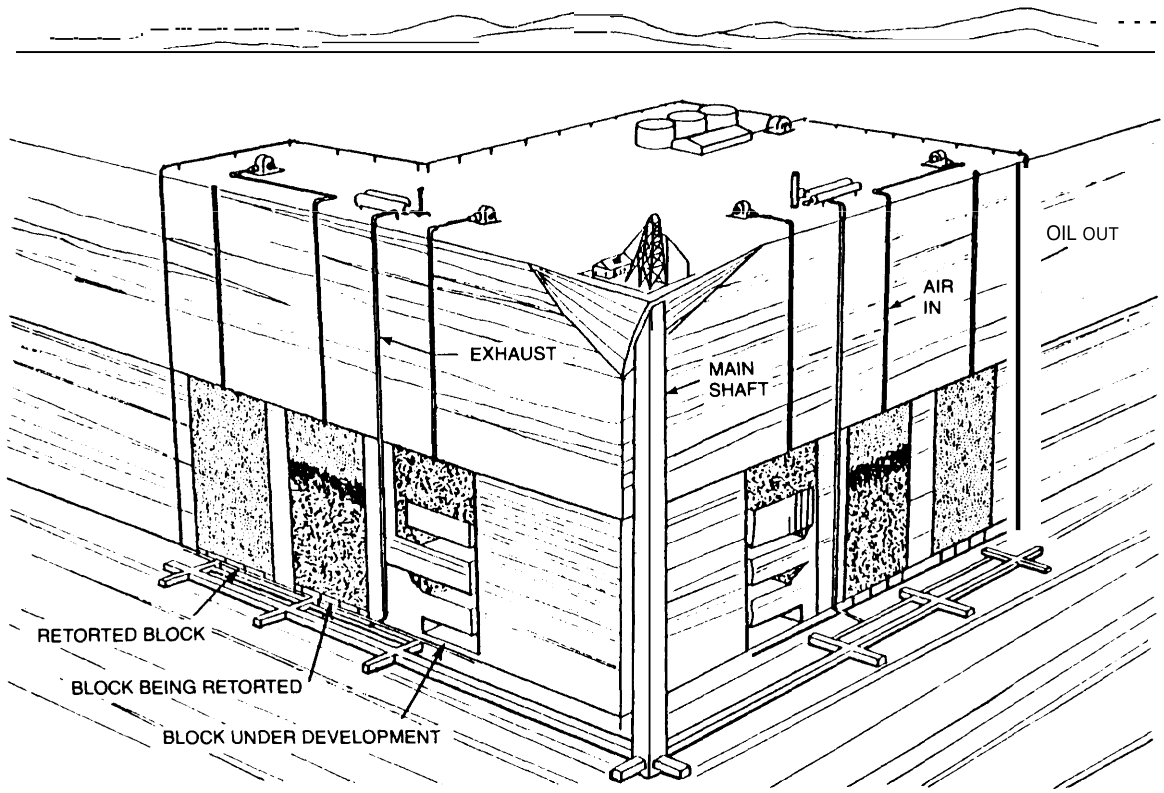
Horizontal MIS might be practical if a technique could be developed to remove large sections of oil shale strata. One possibility is to use solution mining: the injection of fluids into the formation to dissolve soluble salts from among the oil shale layers, The result would be a honeycomb pattern of voids that could then be distributed throughout the area to be retorted by injecting and detonating an explosive slurry. This method would be limited to areas like the Leached Zone or the Saline Zone that contain significant concentrations of soluble salts. Other methods, such as longwall mining or mechanical underreaming, could be used in other areas. It might be possible to operate mechanical underreaming machines by remote control from the surface, thus reducing or even eliminating the need for miners to work underground. None of these approaches has been tested in any oil shale deposit.

Other MIS techniques that use vertical-burn patterns have also been developed. For example, the firm of Fenix and Scisson designed two systems for underground mining, rubbling, and retorting in the vertical mode.[z,)] To date, they have been tested only with a computer model. DOE'S Lawrence Livermore Laboratory has also developed an MIS technique called rubble in situ extraction (RISE) with the aid of computer simulation and laboratory experiments in pilot-scale above--ground retorts.[21-23] (See figure 28.) Several levels are mined, and a portion of the deposit is removed at each. The remaining shale is broken with explosives. Sufficient broken shale is then removed so that there is a total void volume of 20 percent in the retort area. The rubble is then ignited at the top, and retorting proceeds as in the Oxy system.

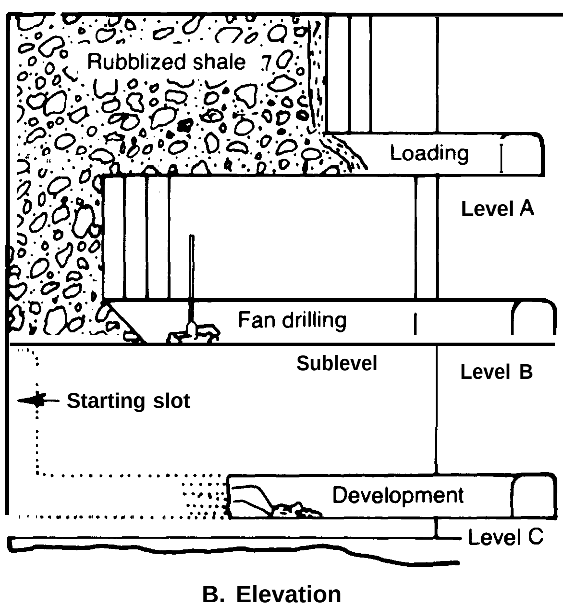
The RISE approach was originally proposed by Rio Blanco Oil Shale Co. for tract C-a, but the firm is now going ahead with its own process, which has benefited from technical information acquired under a licensing arrangement with Oxy. Livermore's modeling studies and laboratory experiments are continuing.

The initial plans for developing tract C-a by MIS methods are shown in figure 29. They would have involved five precommercial retorts of increasing size. The present plan, which was adopted after purchase of Oxy's MIS technology, is shown in figure 30. In the new development plan, a small pilot retort (retort "O") will be followed by two demonstration retorts of increasing size. The largest (retort "2") will be close to commercial scale. Several options of different size are being considered for retort 2, with one option a retort with dimensions 60 ft by 150 ft by 400 ft high, The method by which the shale is rub-

Figure 28.—The RISE Method of MIS Oil Shale Retorting



A. Isometric

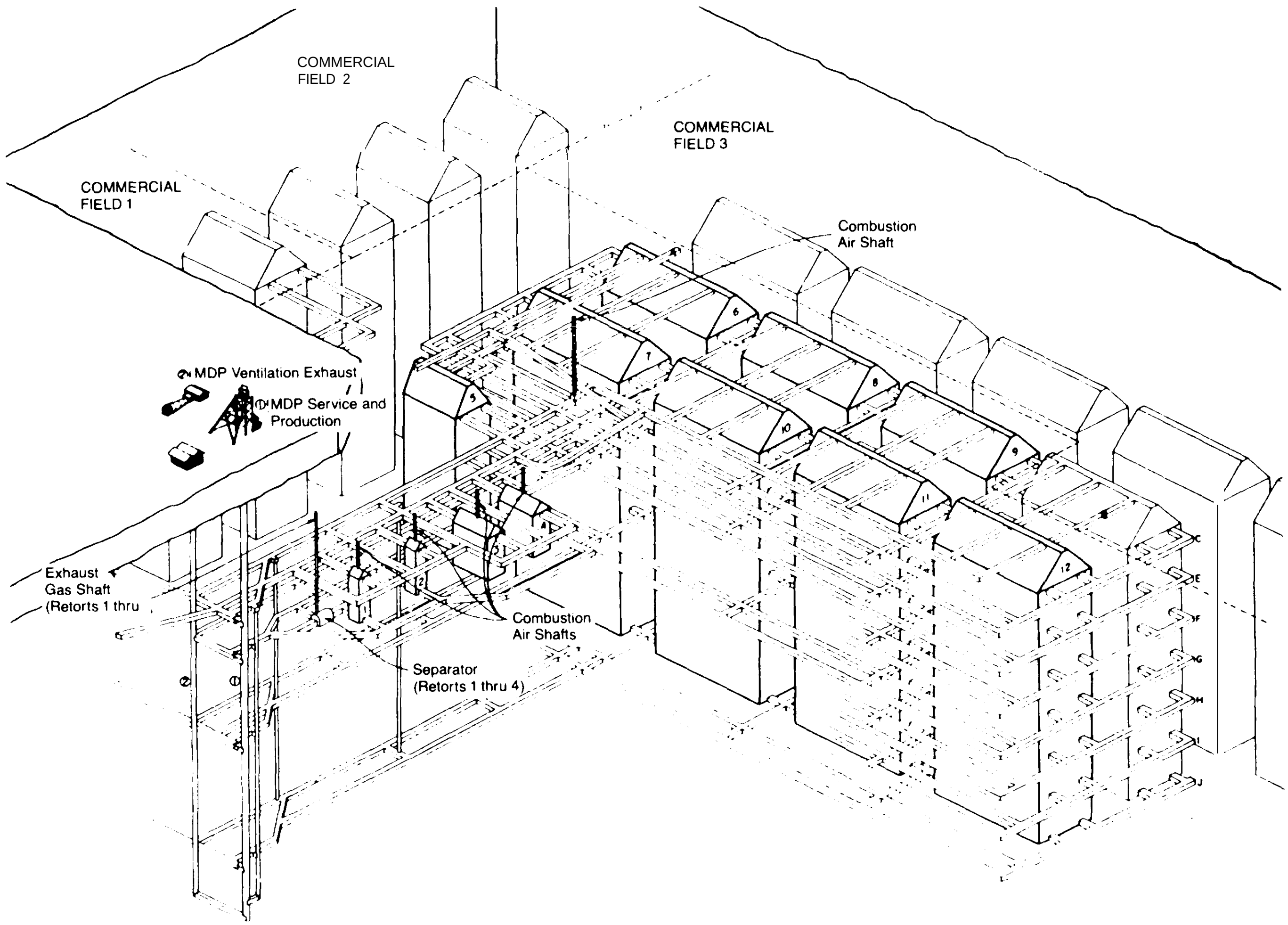


B. Elevation

Development proceeds simultaneously on several levels. At each level, horizontal drifts are driven the full width of the retort block, and a vertical slot is bored to provide void volume for blasting. About 200/. of the broken shale is removed after each blasting operation. The rest is left in the retort volume.

SOURCES: 01/ *Shale Retorting Technology,* prepared for OTA by Cameron Engineers, Inc., 1978; and C. K. Jee, et al., ***Review** and **Analysis of** Oil Shale **Technology—Volume 3. Modified In Situ Technology,*** report prepared for the U.S Department of Energy by Booz-Allen & Hamilton, Inc , under contract No, EX-76-C-01-2343, August 1977, p. 6.

Figure 29.— Initial Modular MIS Retort Development Plan for Tract C-a

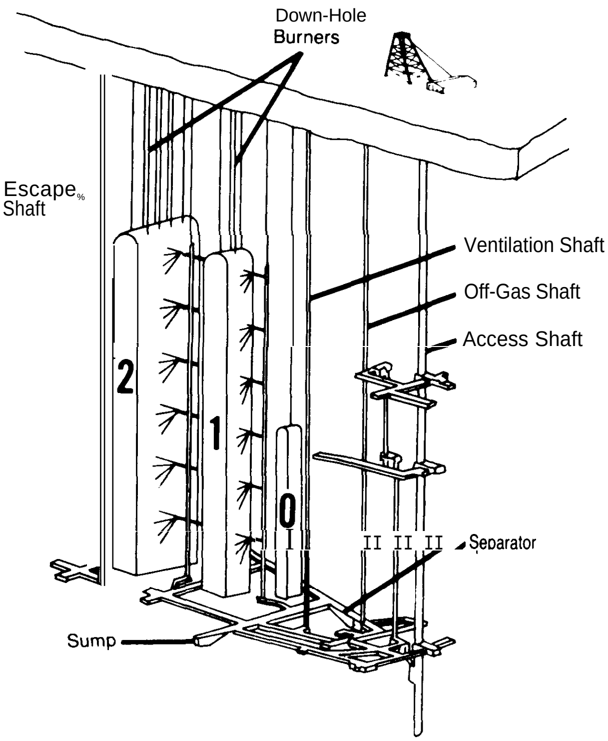


SOURCE Rio Blanco 011 Shale Project Revised *Detailed Development Plan Tract* C a Gulf 011 Corp and Standard 011 Co (Indiana), May 1977 P 1-2-5

bled, and the fraction of the shale that is mined from each retort area are two of the major differences between the Rio Blanco approach and Oxy's technique. Oxy has tested several rubbling methods, including drilling blastholes up from a room at the bottom of the retort, drilling down from the top, and boring a central shaft the full length of the retort and then blasting the surrounding shale into the shaft. In Rio Blanco's approach, a room will be created at the bottom of the future retort, blastholes will be drilled from the surface into the roof of the room, and explosives will be detonated sequentially at different levels, The shale above the room will thereby be blasted loose in layers, with each layer of rubble falling to the bottom of the retort volume before the next higher layer is blasted. Through this technique, Rio Blanco hopes to obtain uniform size distribution in the rubble. This is believed to be a key technical requirement for efficient MIS retorting. Rio Blanco also proposes to mine twice the volume (40 v. 20 percent) as is contemplated by Oxy.

Another MIS method that is still being designed is the integrated in situ technology proposed by Multi Mineral Corp. for recovering shale oil, nahcolite, alumina, and soda ash from oil shale deposits in the Saline Zone of the Piceance basin. This zone underlies the Leached Zone, is relatively free from ground

Figure 30.— Present MIS Retort Development Plan for Tract C-a

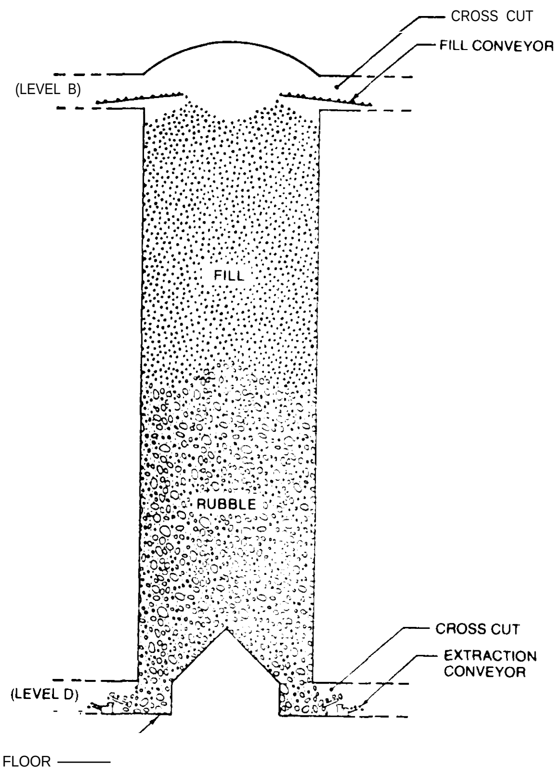


SOURCE The Pace Co Consultants and Engineers Inc *Cameron Synthetic Fuels Report* vol 16 No 3 September 1979 p 28

water, and contains extensive resources of nahcolite and dawsonite in addition to oil shale. Development is hindered because the zone is deeply buried (about 2,000 ft) below the surface of the basin. To reduce the costs of its R&D program, Multi Mineral has proposed to use an 8-ft-diameter shaft that was drilled by USBM in 1978 through the Leached Zone and into the Saline Zone. In the first phase, mining and mine safety methods will be tested, and about 8,000 tons of nahcolite and 11,000 bbl of shale oil will be produced. The nahcolite will be used for stack-gas scrubbing tests in a powerplant. In the second phase, a retorting module will be used to produce up to 3,000 ton/d of nahcolite, 10,000 bbl/d of shale oil, 200 ton/d of alumina, and 3,000 ton/d of soda ash. The modular retort and the access shafts and drifts are shown in figure 31, If technical and economic feasibility is indicated during the test program, Multi Mineral would proceed to a commercial-scale facility that would produce 50,000 bbl/d of shale oil, 10,000 ton/d of nahcolite, 1,000 ton/d of alumina, and 20,000 ton/d of soda ash.

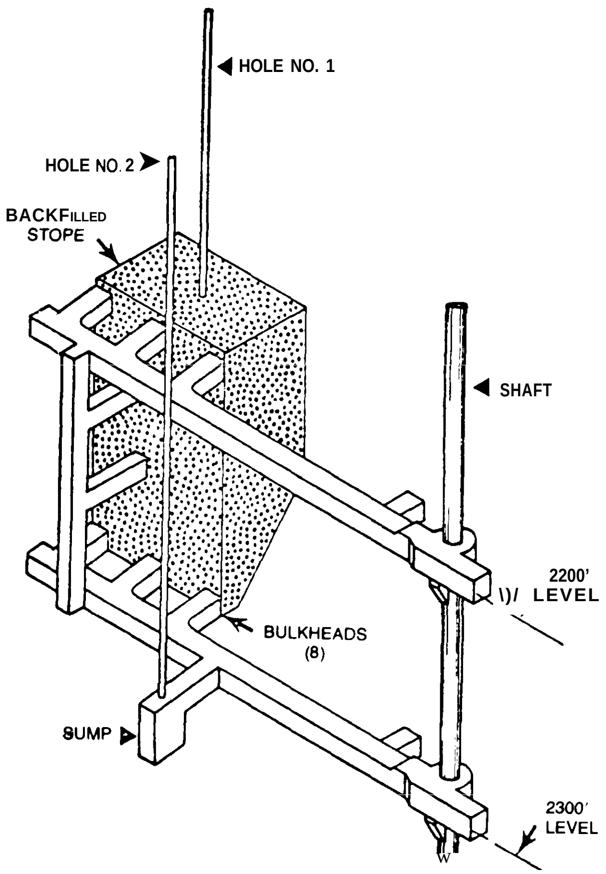
The Multi Mineral approach resembles the RISE technique in that mining and rubbling are conducted at several levels along the height of the retort, It departs from RISE in that, after rubbling, the broken shale in the retort is removed from the bottom, crushed and screened, and returned to the top in a continuous operation. This part of the retort development plan is shown in figure 32. The rubbled shale will contain free nahcolite and

Figure 31 .— Retort Development Plan for the Multi Mineral MIS Concept



SOURCE B Weichman, *Saline Zone Oil Shale Development by the Integrated In Situ Process* Multi Mineral Corp Houston Tex December 1979. p 9

Figure 32.— Preparation of a Multi Mineral MIS Retort



SOURCE B Weichman *Saline Zone Oil Shale Development by the Integrated In Situ* Process Multi Mineral Corp Houston Tex December 1979 p 15

nahcolite that is still associated with the large blocks of shale. Crushing will liberate most of the associated nahcolite, and screening will separate it from the shale particles. The shale will be backfilled to the top of the retort; the nahcolite is transported to the surface for processing. The result would be a retort that is filled with uniformly sized oil shale particles. With this configuration, Multi Mineral hopes to avoid the channeling and bypassing problems that may occur in TIS and MIS processing.

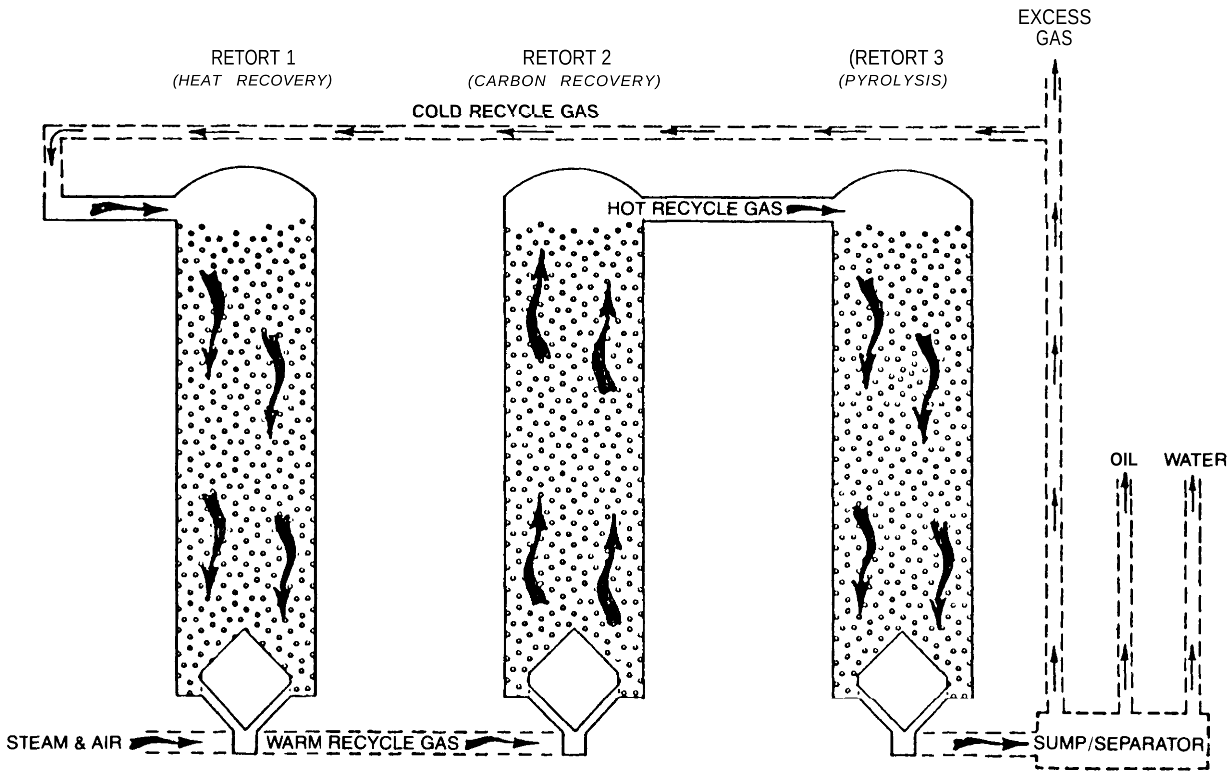
In a commercial-scale facility, the retorts would be operated in sets of three, as shown in figure 33, In retort 3, the oil shale is being pyrolyzed by injecting hot gases to produce shale oil (which is removed to the surface), residual carbon, and soda ash and aluminum oxide—the products of the thermal decomposition of dawsonite. The last three products remain in the retort rubble. In retort 2, the residual carbon is being gasified by injecting a mixture of steam and air. The heat from the gasification reaction is carried to retort 3. In retort 1, the hot gasified shale is being cooled by passage of cold recycle gas. The heat thus recovered is conveyed to retort 2. After the shale in retort 1 is cooled, the soda ash and the aluminum oxide can be leached out with water. The leachate is then pumped to the surface and processed to recover its mineral values.

Temperature control is the key to the entire operation. Oil alone could be recovered with a combustion-type method, such as Oxy's, but because of the high temperatures, the decomposition of the dawsonite would produce compounds insoluble in water. The gas-recycle heating method would avoid this problem by maintaining lower retorting temperatures. The operation also depends on the ability of explosive rubbling techniques to produce broken shale that can be fed to conventional crushing equipment. Overall, the method is very interesting because of its potential for simultaneously recovering fuel and minerals from deposits that may not be accessible with any other approach. However, too little is known about the various steps to permit a thorough evaluation at this time.

Aboveground Retorting

Hundreds of retorts have been invented in the 600-year history of oil shale development. Most were never brought to the processing stage but some were tested using laboratory-scale equipment, and a few at pilot-plant and semiworks scales. None has been tested at a scale suitable for modern commercial operations. This section summarizes the technical aspects of seven retorting systems that offer the promise of being applicable in the near future. One obsolete technology that is the basis for several of the modern systems is also discussed.

Figure 33.—A Set of Multi Mineral MIS Retorts



SOURCE B Weichman, *Saline Zone" Oil Shale Development by the Integrated In Situ Process,* Multi Mineral Corp , Houston, Tex December 1979, p 11

Although aboveground retorts differ widely with respect to many technical details and operating characteristics, they can be grouped into four classes:

- Class 1: Heat is transferred by conduction through the retort wall. The Pumpherston retorts used in Scotland, Spain, and Australia were of this class, as is the Fischer assay retort that was developed in the 1920's. It is a laboratory device for estimating potential shale oil yields. Its oil yield is the standard to which the retorting efficiencies of all other retorts are compared. Because conduction heating is very slow, no modern industrial retorts are in class 1.
- Class 2: Heat is transferred by flowing gases generated within the retort by combustion of carbonaceous retorted shale and pyrolysis gases. Retorts in this class are also called directly heated. They include the Nevada-Texas-Utah (NTU) and Paraho direct processes described below, and also USBM's gas combustion retort and the Union "A" retort. Class 2 retorts produce a spent shale low in residual carbon and low-Btu retort gas. Their thermal efficiencies are high because energy is recovered from the retorted shale. However, recovery efficiencies are relatively low—about 80 to 90 percent of Fischer assay.
- Class 3: Heat is transferred by gases that are heated outside of the retort vessel. Retorts in this class are also called indirectly heated. They include the Paraho indirect, Petrosix, Union "B," and Superior retorts discussed below, and also the Union SGR and SGR-3, the obsolete Royster design, the Soviet Kiviter, the Texaco catalytic hydrotort, and others. These retorts produce a carbonaceous

spent shale and a high-Btu gas. Thermal efficiencies are relatively low because energy is not recovered from the residual carbon, but oil recovery efficiencies are high, from 90 to over 100 percent of Fischer assay.

- Class 4: Heat is transferred by mixing hot solid particles with the oil shale. They include the TOSCO II and Lurgi-Ruhrgas retorts described below, and also the Soviet Galoter retort. Class 4 retorts achieve high oil yields (about 100 percent of Fischer assay) and produce a high-Btu gas. The spent shale may or may not contain carbon, and thermal efficiencies vary, depending on whether the spent shale is used as the heat carrier. The retorts are sometimes referred to as indirectly heated, as in class 3, because they also lack internal combustion, and produce a similar gas product.

Several other conversion methods have been developed that cannot easily be placed in these classes. These include microwave heating, bacterial degradation, gasification, and circulation of hot solids slurries. Although some of these processes have potentially valuable characteristics, they will not be discussed in this section because they have not yet been proposed for near-term commercial application.

The Nevada-Texas-Utah Retort

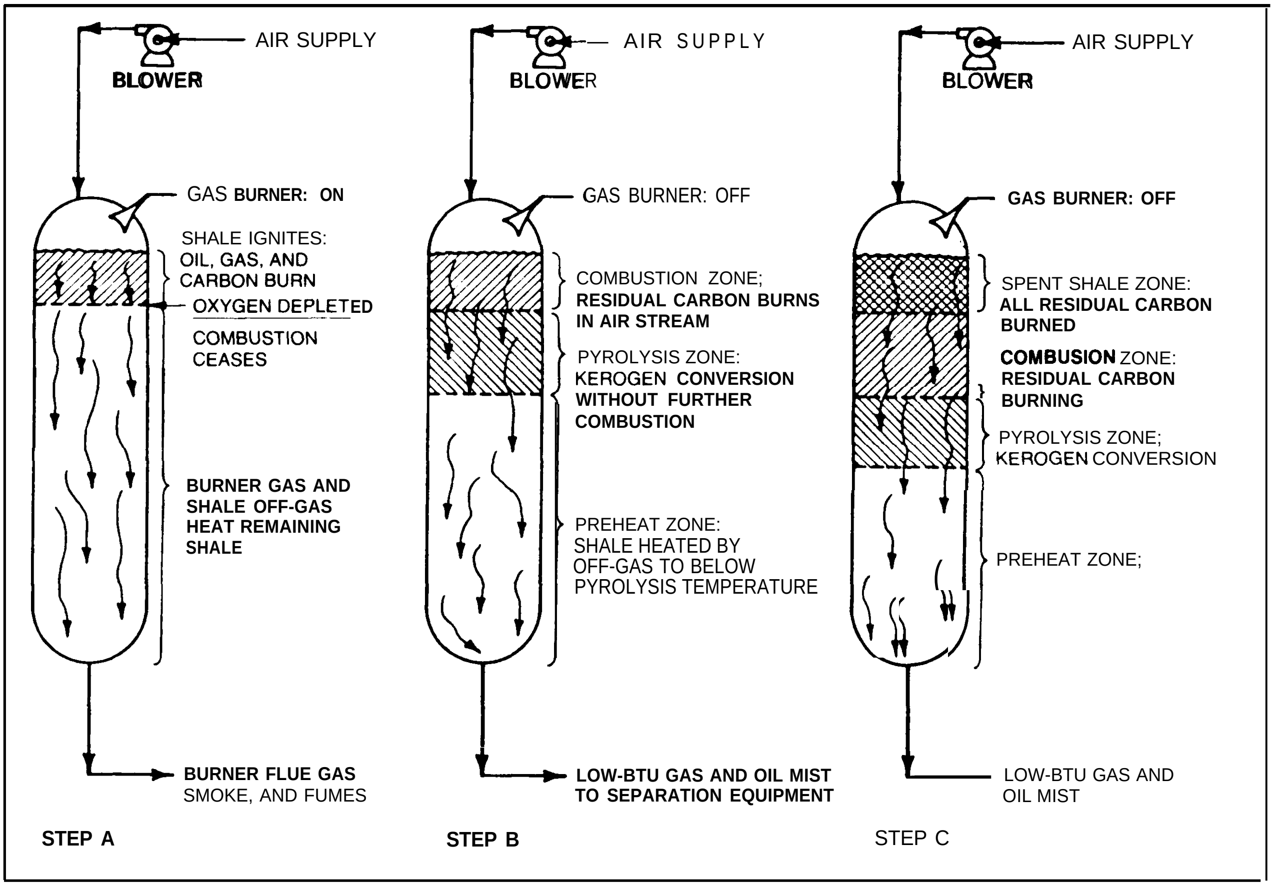
The NTU retort is a modified downdraft gas producer similar to units used in the 19th century to produce low-Btu gas from coal. It is a vertical steel cylinder, lined with refractory brick and equipped with an air supply pipe at the top and an exhaust pipe at the bottom. The top may be opened for charging a batch of shale; the bottom for discharging the spent shale after retorting. The unit was developed and tested for oil shale processing by the NTU Co. in California in 1925, and was also tested by USBM at Rifle, Colo., from 1925 to 1929. Two units with nominal capacities of 40 tons of raw shale were built and operated by USBM at Rifle between 1946 and 1951. They produced more than 12,000 bbl of shale oil. Three units that were operated in Australia during World War 11 produced nearly 500,000 bbl. As noted previously, USBM used two units to simulate in situ retorting.

The operating sequence for the NTU retort is shown in figure 34. The unit is loaded with crushed oil shale and sealed. The gas burner is lighted, and air is blown in. Once the top of the shale bed is burning (step A), the fuel gas is shut off but the air supply continues. As the air flows through the burning layer, it is heated to approximately 1,500° F (815° C). This hot gas heats the shale in the lower layers and induces the pyrolysis of the kerogen. The oil and gases produced are swept down through the cooler portions of the bed to the exhaust port (step B). The solid product from the conversion of the kerogen (residual carbon) remains on the spent shale and is consumed as the combustion zone moves down the retort, providing fuel for additional combustion and thereby heat for additional pyrolysis. When all the carbon is burned from the upper layers of the bed, the four zones shown in step C are formed. The top layer contains burned and decarbonized spent shale. The second layer is burning, releasing heat for pyrolysis in the third layer. In the bottom layer, the shale is being heated but is not yet at pyrolysis temperatures.

As time passes, the top layer expands downward and the lower three zones move uniformly down the retort. When the leading edge of the combustion zone reaches the exhaust port, oil production ceases, air injection stops, and the retort is emptied. The dumping of spent shale ash from the 40-ton NTU at Laramie is shown in figure 35. The entire cycle, from ignition to dumping, takes about 40 hours.

NTU retorts are simple to operate, and require no external fuel except for small amounts of gas to start the retorting. They can process a wide variety of shales with oil recoveries ranging from 60 to 90 percent of Fischer assay. They are unsuitable for modern commercial applications because they are batch units with high labor costs and small capacities. Over 600 150-ton retorts

Figure 34.—The Operation of an NTU Retort



SOURCE T A Sladek. Recent Trends ın 011 Shale– Part 2 Mining and Shale 011 Extract Ion Processes, *Mineral Industrial Bulletin* vol 18 No 1 January 1975 p 5

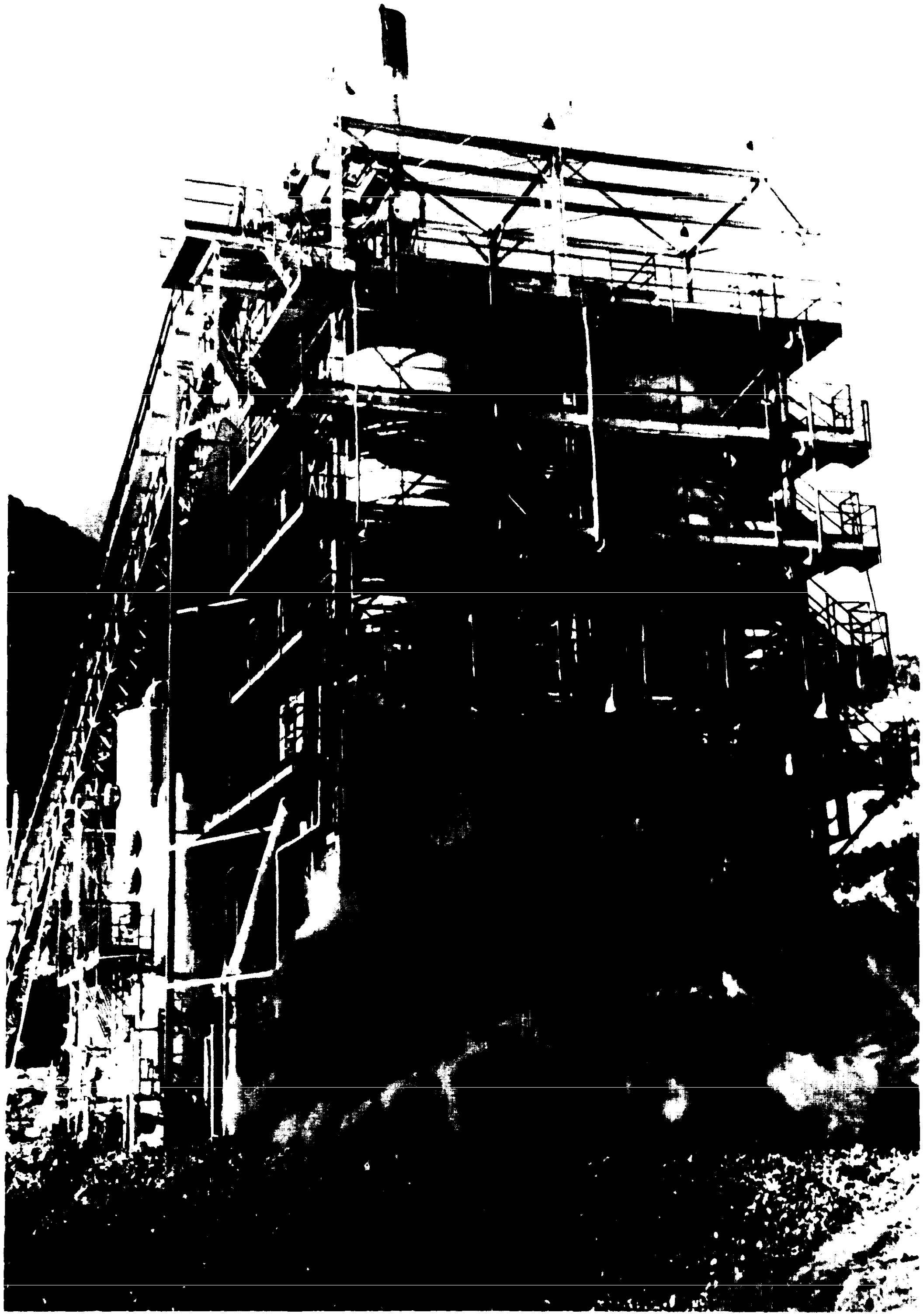
would be needed to produce 50,000 bbl/d of crude shale oil. In contrast, plants using some of the continuous technologies described below would require only about six retorts for the same production capacity.

The Paraho Direct and Indirect Retorts

An NTU retort becomes a Paraho direct retort when it is turned upside down, made continuous, and mechanically modified. The Paraho retorts are based on USBM's gas combustion retort which, in turn, evolved from the NTU retorts tested at Anvil Points in the late 1940's. The gas combustion process was tested in 6-, 10-, and 25-ton/d units by USBM between 1949 and 1955, and by a consortium of six oil companies between 1964 and 1968. The Paraho direct retort is similar in design to the gas combustion technology but it is more likely to be commercialized. It was developed by Development Engineering, Inc., (DEI) in the late 1960's, and was tested for limestone calcining in three cement kilns in South Dakota and Texas. Each kiln had a capacity of 330 ton/d and was comparable to the largest gas combustion retort tested by the six oil companies.

After verifying the solids-flow characteristics of the Paraho technology in the limestone kilns, DEI leased the Anvil Points site from the Federal Government in May 1972, and began a 5-year program to develop the technology for oil shale processing. Funding was obtained from a consortium of 17 energy companies and engineering firms. In return for a contribution of $500,000, each company

Figure 35.— Discharging Spent Shale Ash From a 40-Ton NTU Retort



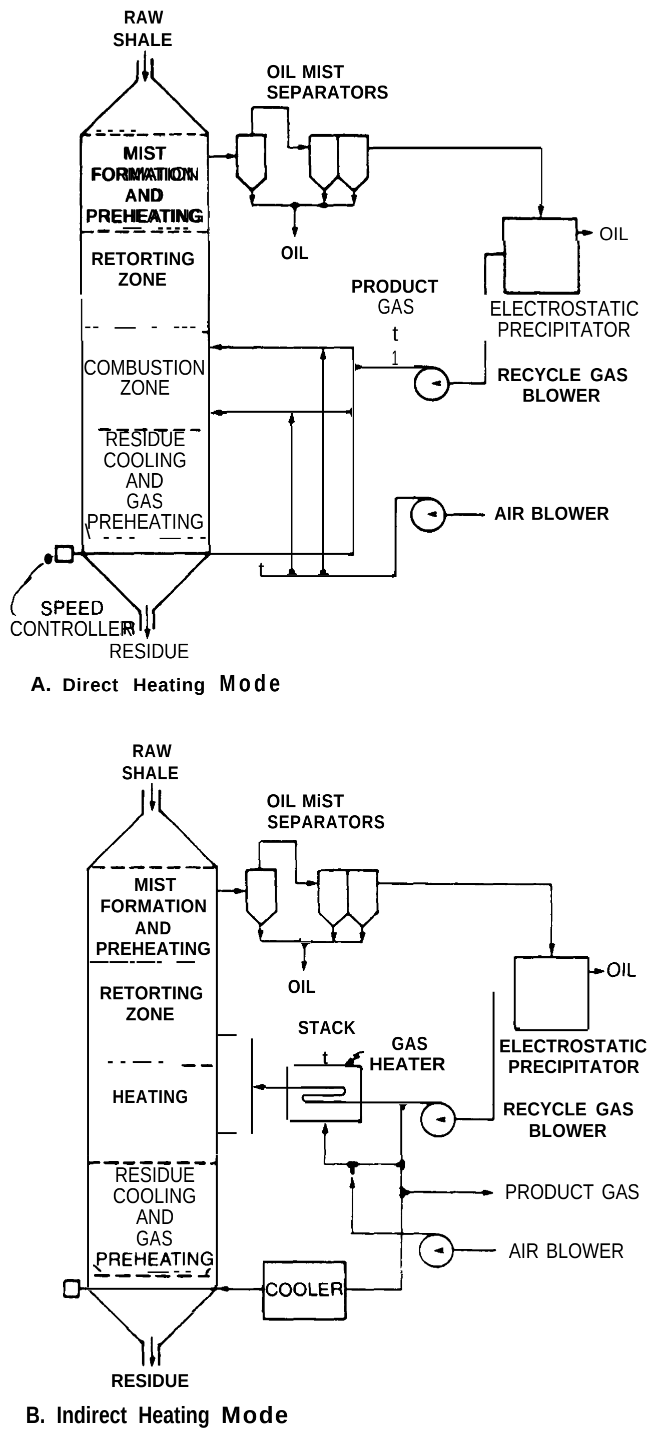
SOURCE U S Department of Energy

was guaranteed a favorable royalty arrangement in any subsequent commercial application of DEI's technology. The Paraho Development Corp. was formed to manage the project. * Two retorts, a pilot-scale unit 4.5 ft in diameter and 60 ft high and a semiworks unit 10.5 ft in diameter and 70 ft high, were installed and tested after August 1973. They were used to produce over 100,000 bbl of crude shale oil, some of which was used for refining and end-use experiments by DOE and the Department of Defense. Maximum throughput rates reached about 400 ton/d in the semiworks unit. Both direct and indirect heating modes were tested.

The Paraho retort is shown in figure 36, and the Anvil Points semiworks unit in figure 37. In its direct mode, the retort is very similar to the older gas combustion design. However, significant differences exist in the shale feeding mechanism, in the gas distributors, and in the discharge grate. During operation, raw shale is fed to the retort through a rotating distributor at the top. It descends as a moving bed along the vertical axis of the retort. As it moves, it is heated to pyrolysis temperatures by a rising stream of hot combustion gases. The oil and gas produced are swept up through the bed to collecting tubes and out of the retort to product separation equipment. The retorted shale retains the residual carbon. As the shale approaches the burner bars, the carbon is ignited and gives off the heat required for pyrolyzing additional raw shale. Passing beyond the burner bars, the shale is cooled in a stream of recycle gas and exits the bottom of the retort through the discharge grate. It is then moistened and sent to disposal.

The retort may also be operated as a class 3 retort. The configuration would resemble directly heated operations except that air would not be injected and the offgas steam would be split into four parts after oil separation. One part would be the net product gas. Another would be sent through a reheating furnace and then reinfected into the middle of

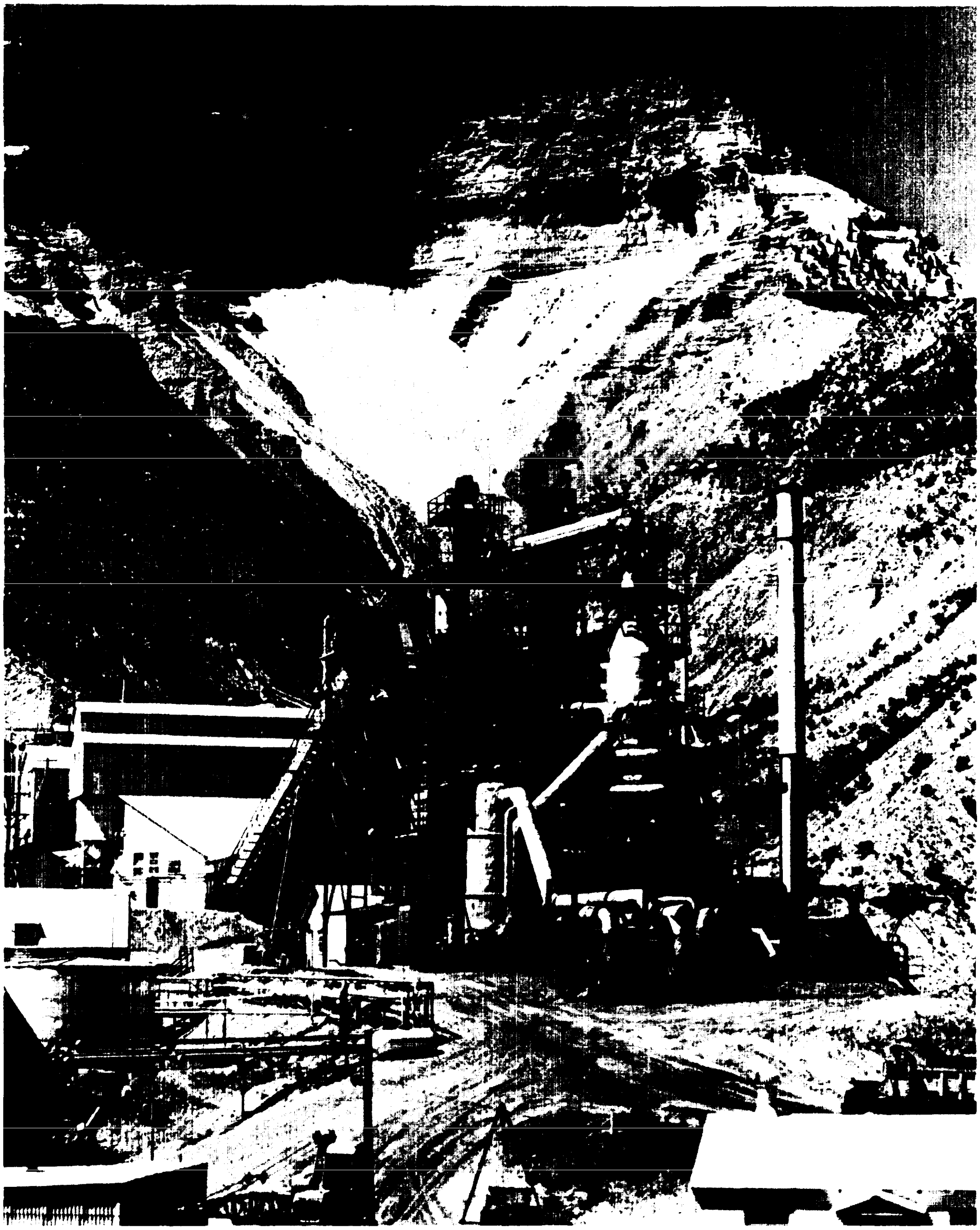
Figure 36.—The Paraho Oil Shale Retorting System



SOURCE C C Shih, et al *Technological Overview Reports for Eight Shale Oil Recovery Processes* report prepared for the U S Environmental Protection Agency by TRW under contract No EPA-600/7-79-075 March 1979, pp 20 and 23

*"Paraho" is from the Portuguese words "para homen"—for mankind.

Figure 37.—The Paraho Semiworks Unit at Anvil Points, Colo.



SOURCE Paraho Development Corp

the retort. A third would not be reheated but would be reinfected through the bottom of the retort to cool the shale before discharge. The fourth would be used for fuel in the reheating furnace. All heat for kerogen pyrolysis would be provided by the reinfected gases, and no combustion would occur in the retort vessel itself.

To date, the Paraho retorting technology has been tested at about one-twentieth of the size that would be used in commercial plants. Paraho would like to test a full-size module producing about 7,300 bbl/d at Anvil Points, and has submitted a proposal to DOE for such a program. Both direct and indirect heating modes would be tested. Permission has been obtained from the Department of the Navy to use large quantities of shale from the Naval Oil Shale Reserves for the program. An environmental impact statement (EIS) is being prepared for the project. Paraho has responded to a DOE Program Opportunity Notice for a $15 million engineering design study of modular oil shale retorting, and would base the design of the Anvil Points module on results of the study. Outcome of the procurement has not yet been announced.

The Petrosix Indirectly Heated Retort

The Petrosix process was developed for the Brazilian Government by Petrobras, the national oil company, with the assistance of Cameron and Jones, Inc., a U.S. engineering firm, Russell Cameron, later president of Cameron Engineers, worked on the gas combustion program at Anvil Points, as did John Jones, later president of Paraho. The system is depicted in figure 38. Figure 39 is a photograph of the demonstration retort that has been built and tested in Brazil. The retort is 18 ft in diameter, and has a capacity of 2,200 ton/d of Irati oil shale. It was built in 1972, and tested intermittently until quite recently. In 1975, a U.S. patent was issued for the process, A 50,000-bbl/d plant is planned by the Brazilian Government, to be developed in a two-stage project. The first stage would involve construction of a 25,000-bbl/d facility about 5 miles from the site of the demonstration plant near the city of Sao Mateus do Sul in the State of Parana. In the second stage, the full commercial plant would be built on the same site, to include 20 Petrosix units, each about 33 ft in diameter. Brazil is not committed to either stage, but if financing is obtained in 1980, the first stage could be completed by 1983 and the second by 1985. In addition to the shale oil, the plant would also produce sulfur and liquefied petroleum gases. Preliminary plans are also being prepared for two additional commercial-scale plants south of the present demonstration plant in the State of Rio Grande do Sul.

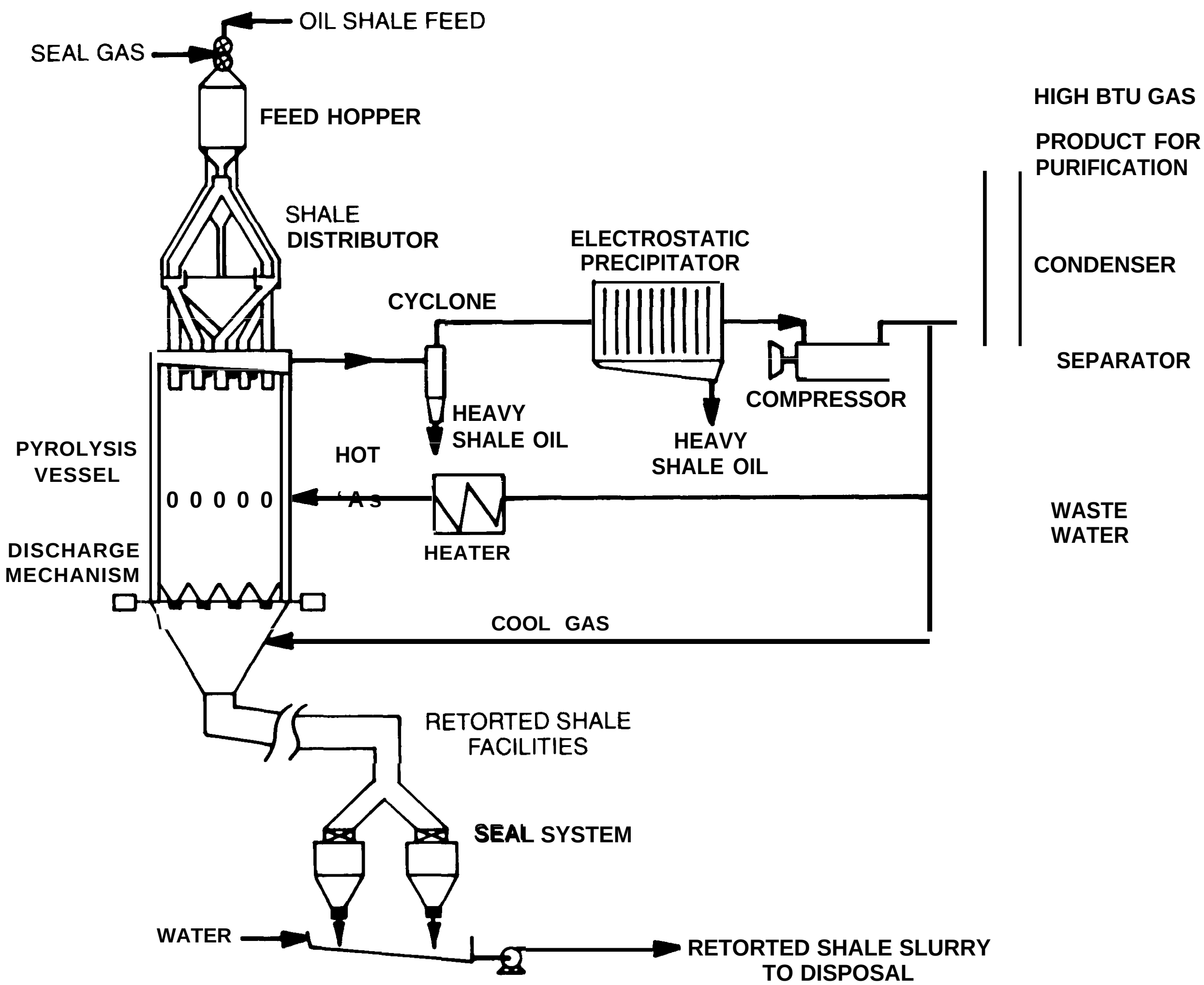
Except for mechanical differences, the Petrosix retort is very similar to the Paraho indirect retort described above. This similarity is not surprising in view of the shared engineering heritage of the two systems. One operational difference is that the Petrosix spent shale is discharged into a water bath and pumped in a slurry to a disposal pond. Paraho shale is discharged dry, with only a little water added prior to disposal.

Little information has been released about the demonstration program. Oil characteristics have been described, but these have little relevance to the processing of Green River shale. It can be predicted that the retort should have high oil recovery efficiencies and produce a retort gas with high heating value. The spent shale would be carbonaceous. In the demonstration plant, recovery of energy from the spent shale was not possible because of the slurry disposal method. In any commercial plant, it is possible that the shale would be burned in a separate unit to produce heat for pyrolysis.

The Union "B' Indirectly Heated Retort

The Union "B" retort is a class 3 retort that evolved from the Union "A," a class 2 retort, by the Union Oil Co. of California. Two other systems, the SGR and SGR-3, have also been proposed by Union, Union describes them all as continuous, underfeed, countercurrent retorts. The "B" has not been field tested, but the "A" was tested in Colorado in the 1950's

Figure 38.—The Petrosix Oil Shale Retorting System



SOURCE *Oil Shale Refer//ng Technology,* prepared for OTA by Cameron Engineers, Inc , 1978

at up to 1,200 ton/d. Figure 40 is a sketch of the Union "B" design. It incorporates most of the design features of the "A."

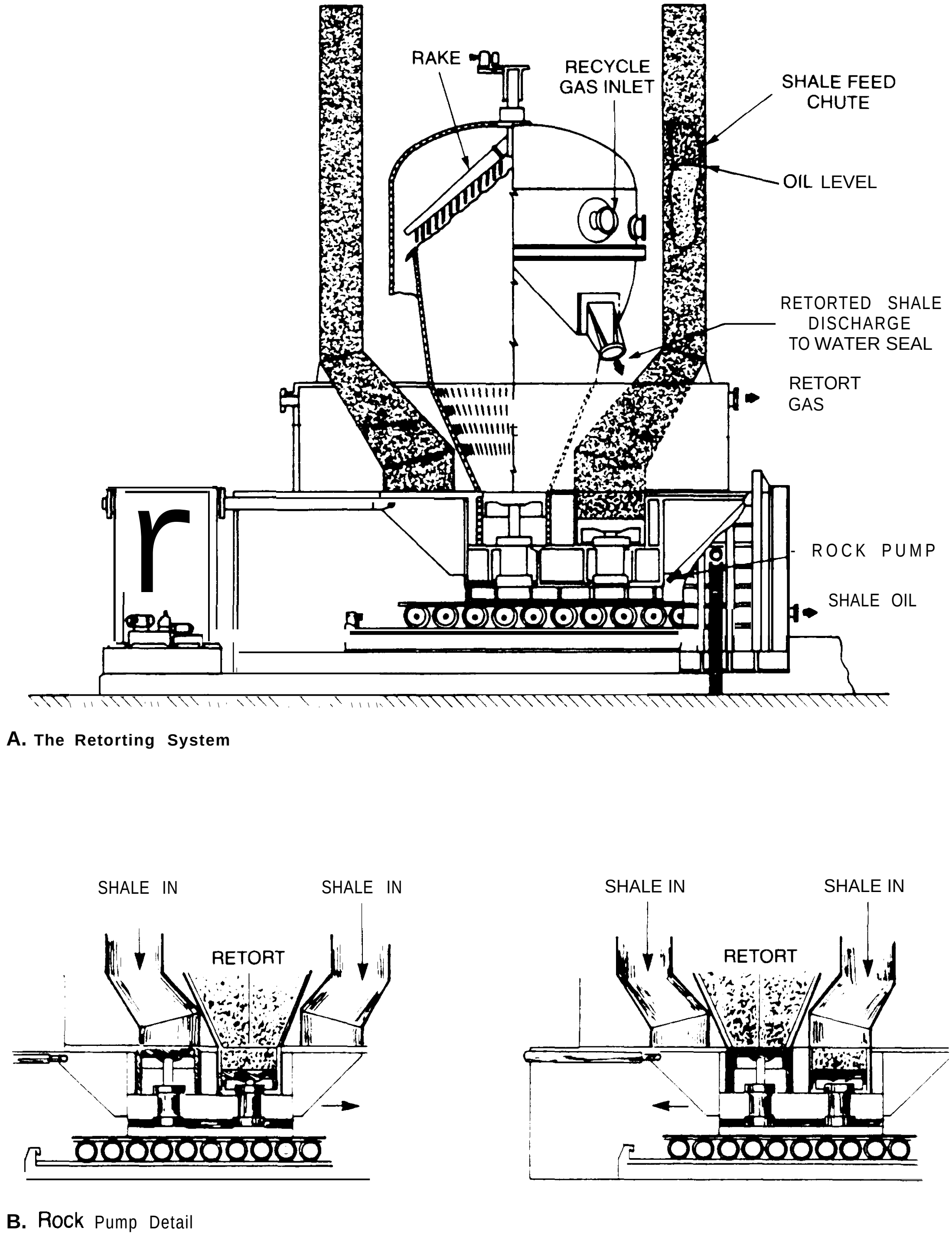
During operation, shale is fed through the bottom of the inverted-cone vessel. The retorting process thereafter resembles that of a continuous NTU retort. Hot gases enter the top of the retort and pass down through the rising bed, causing kerogen pyrolysis. Shale oil and gas flow down through the bed. The oil accumulates in a pool at the bottom, which seals the retort and acts as a settling basin for entrained shale fines. Oil and gas are withdrawn from the top of the pool. The gases are split into three streams. One is reheated and reinfected to induce additional kerogen pyrolysis; one is used as fuel in the reheating furnace; and one is the net product. The shale is discharged from the top of the retort and falls into a water bath in the retorted shale cooler. From there it is conveyed to disposal.

The key to all of Union's retorting systems is the solids pump that is used to move the oil shale through the retort. In the "B" design, the solids pump is mounted on a movable carriage and is immersed in the shale oil pool.

Figure 39.—The Petrosix Demonstration Plant, Sao Mateus do Sul, Brazil

SOURCE Cameron Engineers, Inc

Figure 40.—The Union Oil "B" Retorting Process



SOURCE *Oil Shale Retorting Technology,* prepared for OTA by Cameron Engineers Inc .1978

The pump consists of two hydraulic assemblies that act in sequence. (See figure 40.) While the cylinder of one assembly is filling with oil shale, the other is charging a batch of shale into the bottom of the retort. When this operation is completed, the carriage moves horizontally on rails until the full cylinder is under the retort entrance. A piston then moves the oil shale in this cylinder upwards into the retort, while the other fills with fresh shale from the other feed chute. The carriage then returns to its original position and the process is repeated.

The "B" achieves high oil yields, and the retort gas has a high heating value, although much of it is consumed in the reheating furnace. The mechanical nature of the rock pump is troublesome because its moving parts would be subject to wear during operation. However, the pump is immersed in the shale oil pool, which should provide adequate lubrication. Union appears to be satisfied with its reliability.

In 1976, Union announced plans to build a demonstration plant on its private land in Colorado. The "B" retort was to be used to produce 7,000 bbl/d of shale oil from 10,000 ton/d of oil shale. Later, the announced capacity was increased to 9,000 bbl/d. The demonstration plant, called the Long Ridge project, would be the first step towards a 75,000-bbl/d commercial-scale plant. Air quality permits have been obtained for the modular plant, which could be completed before 1985. Construction has not begun because Union is awaiting financial incentives from the Federal Government.

The Superior Oil Indirectly Heated Retort

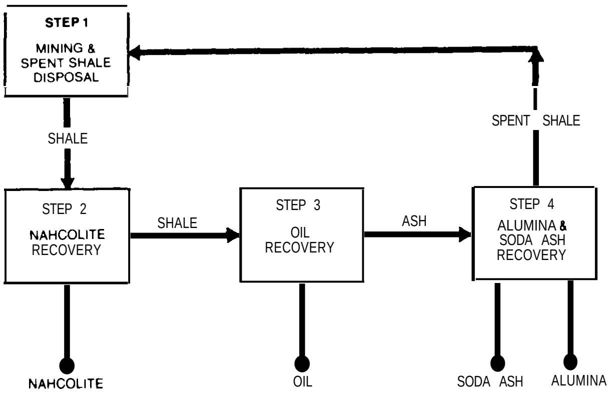
The Superior retort is unique among the aboveground retorts discussed in this section because it is designed for recovery of sodium-bearing minerals in addition to shale oil. As discussed in chapter 4, the minerals nahcolite and dawsonite occur in substantial quantities in portions of the Piceance basin. They are potential sources of sodium bicarbonate, soda ash, and aluminum.

A block diagram for the Superior approach is shown in figure 41. In step 1, the mined oil shale is crushed to pieces smaller than 8 inches and screened. About 85 to 90 percent of the nahcolite in the shale is in the form of distinct, highly friable nodular inclusions that become a fine powder during the crushing operation. This is screened from the coarser shale in step 2. The shale is then further crushed to smaller than 3 inches and is fed in step 3 to a doughnut-shaped traveling-grate retort, which includes sequential stages for heating, retorting, burning, cooling, and discharging the oil shale feed. The retort is sketched in figure 42. In the heating section, oil is recovered by passing hot gases through the moving bed. In the carbon recovery section, process heat is recovered by burning the residual carbon. In the cooling section, inert gases are blown through the bed of spent shale, cooling the shale and heating the gases for use in the heating section. After discharge, the cooled spent shale is sent to other units in which alumina is recovered from calcined dawsonite and soda ash from calcined nahcolite. The alumina is shipped to offsite aluminum refineries; the soda ash to glass plants; and the nahcolite to refineries and powerplants for use as a stack-gas scrubbing agent.

Superior chose the traveling-grate retort because it allows close temperature control, important to maintaining dawsonite's solubility during the burning stage. Similar, simpler devices have been used to sinter iron ore for steelmaking and to roast lead and zinc sulfides. Superior's process has been tested for oil shale in pilot plants in Denver and Cleveland. A commercial-scale plant would consume 20,000 ton/d of oil shale to produce 10,000 to 15,000 bbl/d of shale oil, 3,500 to 5,000 ton/d of nahcolite, 500 to 800 ton/d of alumina, and 1,200 to 1,600 ton/d of soda ash.

In the early 1970's, Superior proposed to build a commercial-size demonstration plant on its 7,000-acre tract in the northern Piceance Basin. The deposit was to be developed by deep room-and-pillar mining on several levels. The single retort was to produce

Figure 41 .— Block Diagram for the Superior Multi Mineral Concept



SOURCE 01/ *Shale Retorting Technology,* prepared for OTA by Cameron Engineers, Inc .1978

11,500 bbl/d of shale oil, plus the byproducts described above. Although the tract's resources are extensive, its L-shaped configuration does not favor large-scale development. Superior therefore proposed to exchange portions of the tract for adjacent land controlled by the Bureau of Land Management (BLM). Approval was delayed by BLM review and by preparation of an EIS, a draft of which was recently released. In February 1980, BLM denied the exchange because the two tracts involved were not considered to have equivalent value. The decision is open to review.

The TOSCO H Indirectly Heated Retort

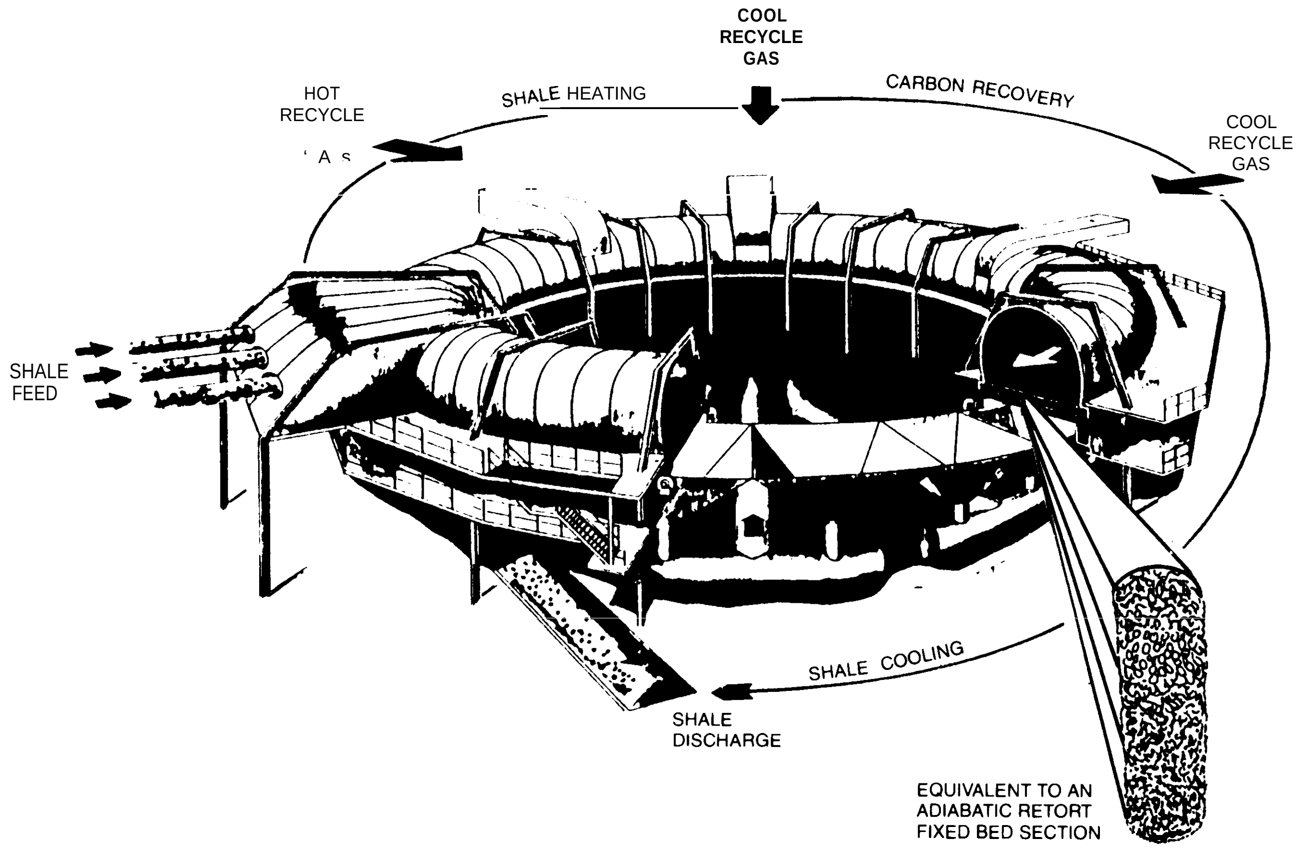
The TOSCO II is a class 4 retort in which hot ceramic balls carry heat to finely crushed oil shale, It is a refinement of the Aspeco process developed by a Swedish inventor. Patent rights were purchased by The Oil Shale Corp. (later Tosco) in 1952. Early development work was performed by the Denver Research Institute, including testing of a 24-ton/d pilot plant. In 1964 Tosco, Standard Oil Co. of Ohio (SOHIO), and Cleveland Cliffs Iron Co. formed Colony Development, a joint venture company, to commercialize the TOSCO II technology. Between 1965 and 1967, the group operated a 1,000-ton/d semiworks plant on its land near Grand Valley, Colo., next to the site of Union's semiworks operations. In 1968, Colony prepared a preliminary engineering design and cost estimate for a commercial-scale plant that would contain six TOSCO II retorts, and convert 66,000 ton/d of oil shale into about 46,000 bbl/d of shale oil. In 1969, ARCO joined Colony, and a second semiworks program began to test scaleup procedures and to evaluate environmental controls. The program continued until April 1972. Between 1965 and 1972 the semiworks plant converted 220,000 tons of oil shale into 180,000 bbl of shale oil.

In 1974, the 1968 cost estimate, which had been updated in 1971, was further revised to incorporate operating data from the latter part of the semiworks program and to account for additional pollution controls. The resulting cost estimate was about three times as large as the previous estimate. This cost escalation raised doubts about commercial feasibility, and the project was postponed indefinitely. SOHIO and Cleveland Cliffs subsequently withdrew from the Colony group.

Early in 1974, Tosco, ARCO, Ashland, and Shell purchased a lease for tract C-b from the Federal Government. Initial development plans for the tract involved a plant similar to that proposed for Colony's private tract. These plans were also affected by the cost escalations, and in 1976 suspension of operations on tract C-b was granted by the Government. In 1977 Tosco and ARCO withdrew from the tract. Shell withdrew in 1977. Ashland, the remaining partner, teamed with Oxy to develop the tract using MIS techniques.

Colony's semiworks retort, which is about one-tenth of commercial scale, is shown in figure 43. The TOSCO II retorting system is sketched in figure 44. Raw shale is crushed smaller than one-half inch and enters the system through pneumatic lift pipes in which the shale is elevated by hot gas streams and preheated to about 500" F (260° C). The shale then enters the retort, a heated ball mill, and contacts a separate stream of hot ceramic balls. As the shale and balls mix, the shale is heated to about 950°F (510°C), causing retorting to take place. Oil vapors and gases are withdrawn. The oil is condensed in a fraction-

Figure 42.—The Superior Oil Shale Retort



SOURCE. *Oil Shale Retorting Technology*, prepared for OTA by Cameron Engineers, Inc , 1978 (after Arthur G McKee & Co)

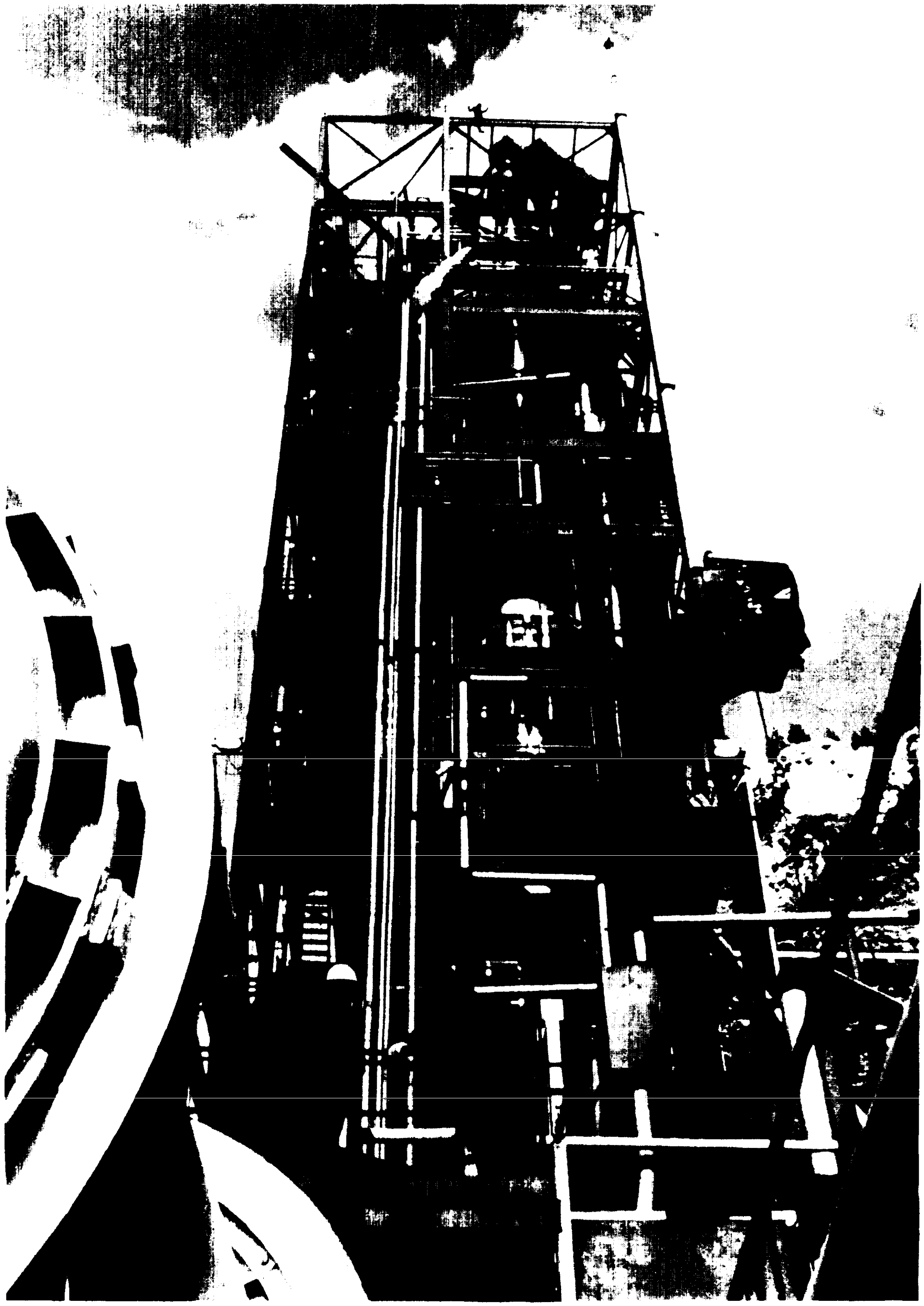
ator. Some of the gases are burned in a heater to reheat the ceramic balls to about 1,2000 F (650° C). At the retort exit, the retorted shale and the cooled ceramic balls pass over a trommel, a perforated rotating separation drum. The shale, which has been thoroughly crushed during retorting, falls through holes in the trommel. It is cooled and sent to disposal. The larger balls pass over the trommel and are sent to the ball heater.

Oil yields exceeding 100 percent of Fischer assay have been reported for the TOSCO II technology. However, overall thermal efficiencies are low because energy is not recovered from spent shale carbon, and much of the product gas is consumed in the ball heater. Tosco has patented processes to burn the retorted shale as fuel for the ball heater, thus increasing energy recovery, and freeing the valuable retort gases for other uses.

The retort's chief disadvantages are its mechanical complexity and large number of moving parts. The ceramic balls are consumed over time. The need for a fine feed size results in crushing costs that are higher than those of systems that can handle coarser feeds. On the other hand, all crushing operations produce some fine shale that could be screened from the feed to coarse-shale retorts and converted in auxiliary TOSCO II units. Disposal of TOSCO II spent shale presents some problems because it is very finely divided and contains carbon.

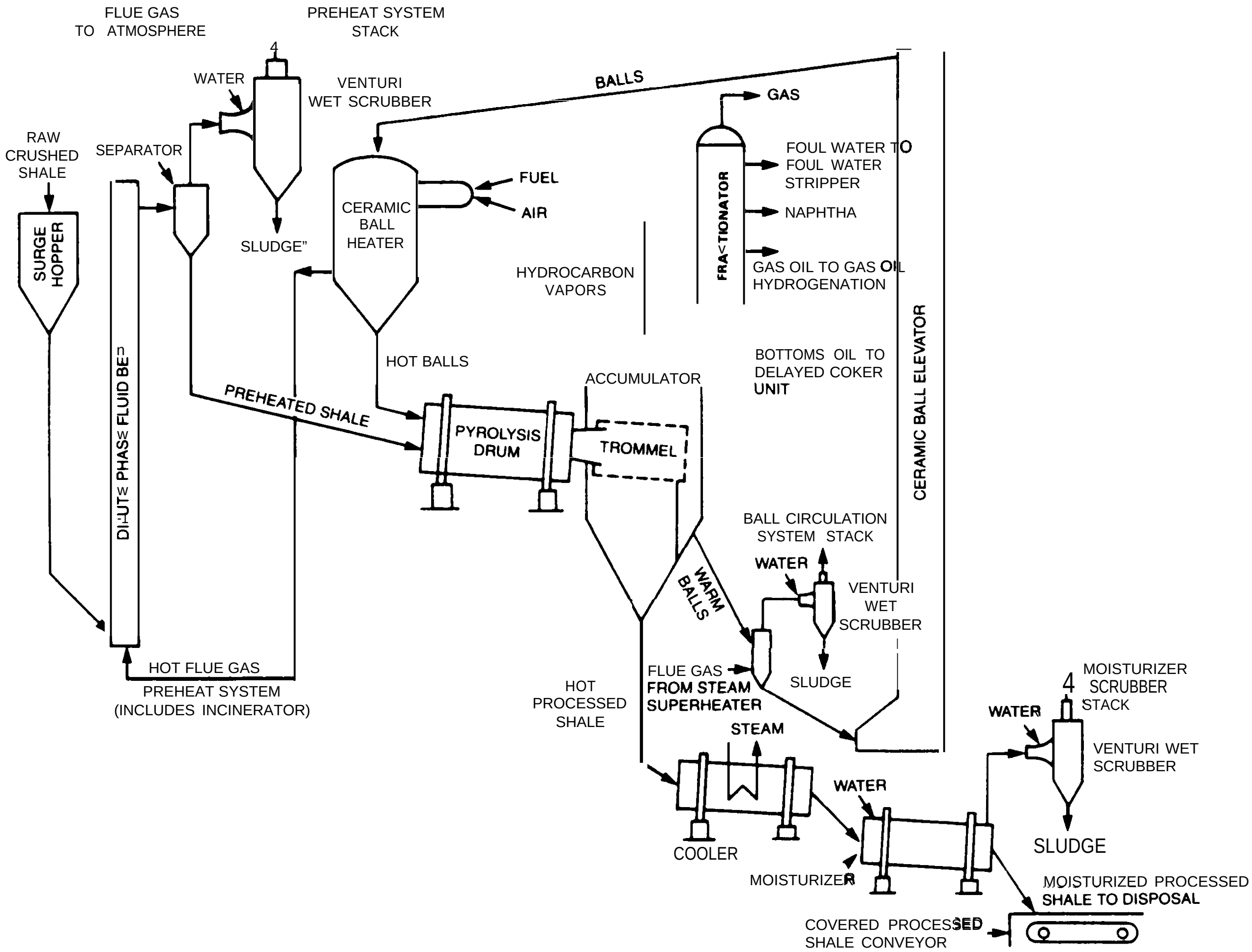
At present Tosco is participating in two projects that are committed to its proprietary

Figure 43. — The Colony Semiworks Test Facility Near Grand Valley, Colo.



SOURCE Colony Development Corp

Figure 44.—The TOSCO II Oil Shale Retorting System



SOURCE *Oil Shale Retorting Technology*, prepared for OTA by Cameron Engineers, Inc , 1978.

retorting technology. The Colony project has been mentioned previously. The other venture, the Sand Wash project, is being developed on 14,000 acres of land in the Uinta Basin leased from the State of Utah. Unlike the Colony project, which has been suspended pending resolution of economic uncertainties, Sand Wash is proceeding towards commercialization in compliance with the due diligence requirements of the State leases. A plant similar to the proposed Colony facility is contemplated, but no schedule has been announced for its construction. At present, work consists of monitoring the environment, and preparing to sink a mine shaft.

The Lurgi-Ruhrgas Indirectly Heated Retort

The Lurgi-Ruhrgas retorting system uses a class 4 retort in which hot retorted shale carries pyrolysis heat to oil shale. The process was developed jointly by Ruhrgas A. G. and Lurgi Gesellschaft fur Warmetechnik m. b. H., two West German firms that have been involved in synfuels production for decades. The process was developed in the 1950's for low-temperature coal carbonization. A 20-ton/d pilot plant was built in West Germany, to test a variety of coals, oil shales, and petroleum oils. European shales were tested in the late 1960's, and Colorado oil shale in

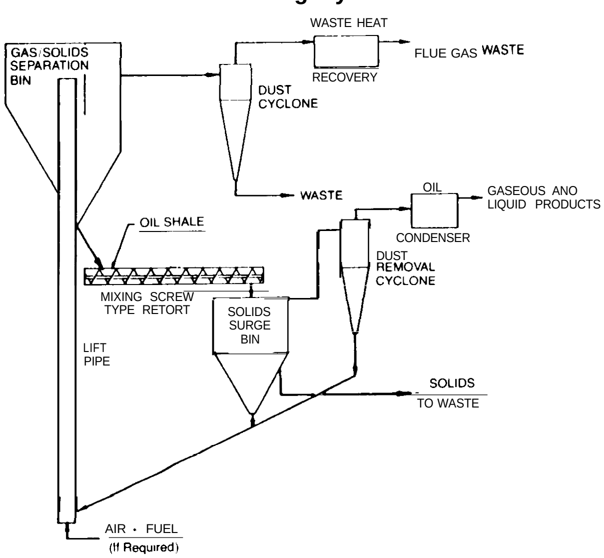
1972. The plant has since been scrapped but smaller retorts are available.

Coal processing plants using the Lurgi-Ruhrgas technique have been built in Japan, West Germany, England, and Argentina. There are also two Yugoslavian plants, each built in 1963, with a capacity of 850 ton/d of brown coal. The Japanese plant is also of commercial size, and uses the process to crack petroleum oils to olefins. No large-scale oil shale plants have yet been built.

The retorting system is shown in figure 45. Finely crushed oil shale is mixed with hot retorted oil shale in a mechanical mixer that resembles a conventional screw conveyor. Retorting takes place in the mixer, and gas and shale oil vapors are withdrawn. Dust is removed from these products in a cyclone separator and oil is separated from the gas by condensation. Retorted shale leaves the mixer and is sent to a lift pipe where it is heated to about 1, 100° F (5950 C) in a burning mixture of fuel gas and air. The hot retorted shale is then sent back to the mixer, and the process is repeated.

High oil yields have been reported for the retort, and the product gas is of high quality.

Figure 45.—The Lurgi-Ruhrgas Oil Shale Retorting System



SOURCE *Oil Shale Retorting Technology,* prepared for OTA by Cameron Engineers Inc 1978

Except for the mixer, the process is mechanically simple and has few moving parts. It should be capable of processing most oil shales, if they are crushed to a fine size. The two major problems with the system appear to be accumulation of dust in the transfer lines and dust entrainment in the oil. Dusty crude oil is not a severe problem because the dust is concentrated in the low-value residual product when the oil is subsequently refined. As with the TOSCO II process, requirements for a fine feed material will result in high crushing costs. These costs would be partially offset by the ability to process the fine fraction from any crushing process, including those used to prepare shale for coarse-shale retorts.

In 1972, Lurgi proposed to develop its retorting technologies with Colorado oil shale. The program was not funded, but Lurgi's interest in commercializing the technique has continued. In recent years Lurgi has been working with Dravo Corp. to interest U.S. firms in using the technology. At present, at least one company—Rio Blanco—has obtained a license to investigate the use of Lurgi-Ruhrgas retorts. Present plans call for constructing a modular Lurgi-Ruhrgas retort that will be close to commercial size (2,200 ton/d). It will be used to retort the shale that will be mined during the preparation of MIS retorts on tract C-a.

Advantages and Disadvantages of the Processing Options

The greatest advantage of TIS processing is that mining is not required, and spent shale is not produced on the surface. The technical, economic, and environmental problems associated with above-ground waste disposal are thereby avoided. MIS does involve mining and aboveground waste disposal, although to a lesser extent than with AGR. However, the MIS waste is either overburden or raw oil shale. Both materials are found naturally exposed on the surfaces of deeper canyons in the oil shale basins. Although raw shale has low concentrations of the soluble salts, it does contain soluble organic materials that could

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be leached from the disposal piles. It should be noted that the presence of spent shale underground has the potential to cause environmental problems because soluble salts could be leached by ground water. Therefore, environmental controls will also be needed for TIS and MIS methods.

Surface Facilities

TIS has another theoretical advantage in that the required surface facilities are minimal, consisting only of wells, pumps, gas cleaning and product recovery systems, oil storage, and a few other peripheral units. These facilities would probably resemble those for processing of crude oil and natural gas. MIS requires more facilities to support the mine and the waste disposal program. Aboveground processing, which uses the largest number of facilities, causes the most surface disruption.

Oil Recovery

The advantage of AGR is that the conditions within the retorts can be controlled to achieve very high oil recoveries—approaching or even in some cases exceeding the yields achieved with Fischer assay retorts. Retorting efficiencies are usually lower for MIS processing and much lower for TIS because of the difficulty in obtaining a uniform distribution of broken shale and void volume, which in turn, makes it difficult to maintain uniform burn fronts and leads to channeling and bypassing of the heat-carrier gases. The few estimates of the retorting efficiencies of TIS operations that have been published have not been encouraging. (USBM achieved recoveries of 2 to 4 percent in its field tests.) MIS retorting has not exceeded 60-percent recovery of the potential oil in the shale within the retorts. It is expected that yields from MIS retorts could be increased by injecting steam or hydrocarbon gases (as is done in Equity's TIS process), but it is doubtful that recoveries can reach those of carefully controlled above--ground retorts. On the other hand, the present low efficiencies of MIS operations are partially compensated for by their ability to convert very large sections of an oil shale deposit, by their ability to process shale of a lower grade than would be practical for AGR, and by their lower cost of preparing the shale for retorting.

It is difficult to compare overall recoveries from MIS and AGR without making numerous assumptions about the operating characteristics of both systems. To make a rough comparison, it could be assumed that AGR (with room-and-pillar mining) and MIS were to be applied to two 30()-f t-thick deposits with identical physical characteristics. The net recoveries from several development options are summarized in table 18. The highest recovery (100 percent) is for full-subsidence mining in conjunction with AGR processing. It should be noted that full-subsidence mining, for either MIS processing or AGR, would result in extensive surface disturbance and could increase risks to the miners. Subsidence mining has never been tested in oil shale. Its potential for surface disturbance could be reduced by backfilling the mined-out areas with spent shale from surface processing, The retorted shale in burned-out MIS retorts would also reduce the severity of subsidence.

The three generic approaches to oil shale processing also have various other advantages and disadvantages with respect to water needs, environmental effects, financial requirements, and social and economic impacts. These aspects are discussed in the respective chapters of this report.

Table 18.–Overall Shale Oil Recoveries for Several Processing Options

Case	First-stage retorting technology	First-stage mining method	Second-stage processing	Overall shale oil recovery[a]
1	AGR	Conventional room-and-pillar mining on three levels 60-ft rooms, 60-ft barrier and sill pillars.	None	36%
2	MIS	Conventional MIS mining. 40% of shale left behind in barrier pillars 20% of the disturbed shale is removed to the surface to provide void volume in the retorts	None	29%
3	MIS	As in case 2	AGR processing of the mined shale	41%,
4	AGR	As in case 1	Barrier and sill pillars collapsed and retorted by MIS	74%
5	MIS	Full subsidence b	None	48%
6	MIS	Full subsidence b	AGR processing of the mined shale	68%
7	AGR	Full subsidence b	None.	100%

[a]Assuming AGR recovers 100 percent of the potential 011 in the shale retorted MIS assumed to recover 60 percent of the potential 011
[b]Entire deposit is mined

SOURCE Off Ice of Technology Assessment

Properties of Crude Shale Oil

Crude shale oil (also called raw shale oil, retort oil, or simply shale oil) is the liquid oil product recovered directly from the offgas stream of an oil shale retort. Synthetic crude oil (syncrude) results when crude shale oil is hydrogenated. In general, crude shale oil resembles conventional petroleum in that it is composed primarily of long-chain hydrocarbon molecules with boiling points that span roughly the same range as those of typical petroleum crudes. The three principal differences between crude shale oil and conventional crude are a higher olefin content (because of the high temperatures used in oil shale pyrolysis), higher concentrations of oxygen and nitrogen (derived from oil shale kerogen), and, in many cases, higher pour point and viscosity,

The physical and chemical properties of crude shale oil are affected by the conditions under which the oil was produced. Some retorting processes subject it to relatively high temperatures, which may cause thermal cracking and thus produce an oil with a lower average molecular weight. In other processes (such as directly heated retorting) some of the lighter components of the oil are incinerated during retorting. The result is a heavier final product. Others may produce lighter products because of refluxing (cyclic vaporization and condensation] of the oil within the retort. One of the most important factors is the condensing temperature within the retorting system—the temperature at which the oil product is separated from the retort gases, The lower this temperature, the higher the concentration of low molecular weight compounds in the product oil,

The properties of crude shale oil from several aboveground and MIS retorting processes are listed in table 19.[24] It is important to note that the oils that are characterized were produced in small-scale test runs under conditions that may not be representative of those that will be encountered in other areas, and with larger processing systems. The oils from commercial-scale facilities in other parts of the oil shale region may have properties that are quite different,

The properties of the oil produced by different AGR processes vary widely, but the differences between these oils and the in situ oils are much more significant. In situ oils are generally much lighter, as indicated by their higher yields of material with relatively low boiling points, and would produce more low-boiling product (such as gasoline) and less high-boiling product (such as residual oil). In general, the low yields of residuum make shale oils attractive as refinery feedstocks in comparison with many of the heavy conven-

Table 19.—Properties of Crude Shale Oil From Various Retorting Processes

Retort	Aboveground processes												In situ processes				
	Fischer assay	N U			Gas combustion		OSCO		Union Oil		Paraho direct		Occidental oil shale			USBM	
									A'	B'							
Retort, weight percent																	
Carbon, weight %	84 59	—	84.61	84.58	83.92	—	85.1	—	84.0	84.80	84.90	—	84.86	—	—	84.60	—
Hydrogen, weight %	11.53	—	11.40	11.76	11.36	—	11.6	—	12.0	11.61	11.50	—	11.80	—	—	12.08	—
Oxygen, weight %	—	—	1.10	—	1.67	—	0.8	—	0.9	0.90	1.40	—	1.13	—	—	1.18	—
Nitrogen, weight %	1.96	2.20	2.10	1.77	2.14	2.12	1.9	1.85	2.0	1.74	2.19	2.00	1.50	—		1.55	1.41
Sulfur, weight %	0.61	0.92	0.79	0.76	0.70	0.68	0.9	0.67	0.9	0.81	0.61	0.71	0.71	—	—	0.59	0.72
Carbon/hydrogen ratio	7.34	—	7.42	7.19	7.39	—	7.34	—	7.0	7.30	7.38	—	7.19	—	—	7.00	—
Gravity, °API	—	19.4	20.3	25.2	9.8	2'	21.2	—	18.6	22.7	19.3	—	25	—	24.3	28.4	28.4
Specific gravity	0.92						0.93	0.93	—	0.81	0.94	0.94	0.90	—	—	0.89	—
Pour point, °F	80	80	90	70	84	85	80	—	80	60	85	—	40	—	65	40	40
Arsenic, p/m[a]							—	—	—	—	19.6	—	—	—	—	—	—
Nickel, p/m	—	—	—	—	6.4	—	6	—	6	—	2.5	—	—	—	—	—	—
Iron, p/m	—	—	—	—	108	—	00	—	55	—	71.2	—	—	—	—	—	—
Vanadium, p/m	—	—	—	—	6.	—	3	—	1.5	—	0.37	—	—	—	—	—	—
Distillation, volume %																	
5 @ °F	—				378	445	200	—	390	—	—	—	—	400	405	—	61
10 @ °F	326	493	—	—	438	497	275	360	465	400	520	530	440	460	—	382	620
20 @ °F	430	560	—	—	529	589	410	480	565	—	600	610	—	520	—	405	648
30 @ °F	518				607	668	500	600	640	—	680	680	600	570	600	—	666
40 @ °F	—				678	742	620	690	710	—	750	745	—	620	—	343[b]	681
50 @ °F	655	670	—	—	743	808	700	780	775	731	810	805	700	680	—	375[b]	699
60 @ °F	685	692	—	—	805	865	775	860	830	—	840	860	—	715	—	415[b]	732
70 @ °F	705	—	—	—	865	918	850	935	980	—	—	910	770	765	—	464[b]	768
80 @ °F	—	—	—	—	935	984	920	1,020	—	960	—	980	—	82	830	528[b]	809
90 @ °F	—	—	—	—	1,030	1,065	—	—	—	—	—	1,040	920	91	—	—	867
95 @ °F	—	—	—	—	1,099	—	—	—	—	—	—	—	—	05	1,000	—	914

[a]Parts per million. [b]Vacuum distillation at 40 mm of mercury. All other results are from atmospheric distillation.

SOURCE: Office of Technology Assessment.

tional crudes that are currently being processed in the United States. For example, in situ oil from Oxy's MIS process contains 1 to 4 percent of material with a boiling range of over 1,000° F (5350 C), compared with 20 percent for crude from Alaska's North Slope, and 18 percent for Arabian Light crude.[25 26] Other foreign crudes, such as Kuwait and Arabian Heavy, contain even larger residuum fractions. Oils from some AGR processes contain as much as 30 percent of residuum which, although higher than the contents of in situ crudes, is substantially lower than that for many conventional crudes.

Coal-derived liquids are often regarded as alternatives to shale oil feedstocks. However, syncrudes from coal have a much higher yield of gasoline and low-boiling distillates than shale oil, with little or no material boiling at temperatures above 850° to 1,000° F (4550 to 535° C), The coal liquids would be well-suited for gasoline production because their higher concentrations of lower boiling constituents when refined would yield the desired light naphtha fractions. Shale oil, on the other hand, has a much higher concentration of high-boiling compounds, and would favor production of middle distillates (such as diesel fuel and jet fuels) rather than naphtha, Shale oil and coal-derived syncrudes should, therefore, be regarded not as a competitive or substitutable feedstocks but rather as complementary feedstocks, with each yielding a different major fuel product from an equivalent amount of refining.

Among the negative characteristics of most crude shale oils are high pour point, high viscosity, and high concentrations of arsenic and other heavy metals and of nitrogen. The pour point and viscosity are of economic importance because transporting viscous oil that has a high pour point is difficult and costly, thus suggesting the need for pretreatment prior to marketing. * As shown in table 19, in situ oils with their relatively low pour points and viscosities could be marketed without pretreatment but they would retain their high nitrogen contents. This would reduce their value as refinery feedstocks and boiler fuels.

High concentrations of arsenic and other metals are a disadvantage because they poison refining catalysts, especially in hydrogenation units. They must be removed prior to catalytic processing, and a variety of physical and chemical methods have been developed for this purpose.[28 29] It should be noted that the concentrations of heavy metals in crude shale oil will vary with the location of the deposit from which the oil is recovered. Oils from some sites may be relatively free of such contaminants.

* Some conventional crudes have comparably high pour points. For example, the Altamont crude from Utah has a pour point Of about 100° F (35° C).

Shale Oil Refining

Shale oil has been successfully refined in oil shale operations in Sweden, Scotland, Australia, West Germany, the U. S. S. R., and other countries, although on a relatively small scale and under unusual economic conditions. In the United States, the initial refining research was conducted by USBM at the Petroleum and Oil Shale Experiment Station at Laramie, Wyo. It was coordinated with the early development of the gas combustion retort at Anvil Points, Colo. The results of this work, plus the findings of other investigators, allowed a preliminary assessment to be made of the economic aspects of shale oil utilization, and justified continued efforts aimed at its recovery. In recent years, refining R&D has been revived because refiners now consider the availability of shale oil to be a distinct possibility. There is also a need to perform more precise and up-to-date economic analyses.

To date, refining studies have been conducted on the upgrading of crude shale oil to a transportable product, and on the total refining of shale oil into finished fuels. The difference between these operations lies in the nature of the desired final product. As discussed previously, some crude shale oils have pour points and viscosities that make transporting them difficult and expensive. In some situations, economic considerations may dictate that the crude shale oil be partially refined (upgraded) near the retorting site to improve its transportation characteristics. In other instances, a developer may desire to obtain a complete array of finished fuels from an integrated processing facility located near the minesite. In this case, a total-refining facility would be considered rather than a more simple upgrading plant.

To date, upgrading experiments have been carried out largely at the bench scale, and in relatively small pilot plants. Theoretical studies and computer modeling have also been used to evaluate the expected performance of three types of upgrading processes: thermal, catalytic, and additive. Thermal processes include visbreaking (a relatively mild treatment) and coking (a severe treatment). Mild thermal treatment will reduce pour point and viscosity, but the oil will retain its initial amounts of nitrogen and sulfur. In contrast, severe thermal treatment reduces pour point, viscosity, and sulfur content and also causes the nitrogen compounds to concentrate in the heavier products. The properties of the lighter products will thus be considerably improved.

In catalytic processes, the shale oil is reacted with hydrogen in the presence of a catalyst. Viscosity is reduced, and the nitrogen and sulfur are converted to ammonia and hydrogen sulfide gases that can be recovered as byproducts. In additive processes, blending agents are added that reduce the pour point and allow the crude to be transported by pipeline. Such pour point depressants have been added in several instances with success, but the technique is not yet highly developed.

Total refining studies have focused either on the needs of existing refineries that would have to be modified for processing shale oil, or on those of newly built facilities that could be designed specifically for shale oil feedstocks. These studies differ in their approach to the analysis of refining requirements. Studies of existing refineries must consider the equipment that is in place, and must allow for the limited flexibility of this equipment for processing a feedstock that is different from the one for which the refinery was designed. Studies of specially built refineries, in contrast, need not be biased in this manner, and can draw upon any processing technique that is available within the refining industry. However, both types of studies must make assumptions about feedstock characteristics and desired product mixes. These will vary with the location of the refinery, the nature of the market it serves, and the type of retorting facility that supplies its feedstocks. The optimal refining conditions for one set of assumptions will probably not be applicable to another set. For example, a refining method to maximize gasoline production from TOSCO II shale oil would not maximize diesel fuel production from Oxy's in situ oil.

Numerous computer studies and bench-scale refining investigations have been conducted for a wide range of shale oil feedstocks and operating conditions. The results of these studies can be extrapolated, with some degree of caution, to predict the performance of commercial-scale refineries. However, refining tests both in pilot plants and in commercial-scale facilities, because of much higher costs, have focused on only a few feedstocks, and have been conducted for particular sets of operating constraints. In general, each large-scale study has dealt only with oil from aboveground retorts or with oil from in situ operations, but usually not with both types of feedstocks. The conclusions of all studies are highly dependent on the combination of feedstock and refining conditions assumed. Caution must be used when applying the results to different conditions.

Shale Oil Upgrading Processes

The treatment techniques that can be used to improve the transportation properties of crude shale oil are briefly described below.

Visbreaking

This technique involves heating the crude shale oil to approximately 900° to 980° F (480° to 525° C) and holding it at this temperature range for from several seconds to several minutes. The product is then cooled, and the gases evolved during the heating are removed. There is little reduction in the contents of nitrogen, sulfur, and oxygen. Therefore, the principal improvements are reductions in pour point and viscosity. This technique is simple but energy-intensive. It could reduce the pour point of crude shale oil from about 850 F to about 400 F (300 to 40 C).[30]

Coking

This process involves heating the oil to about 900° to 980° F (480° to 525° C) and then charging it into a vessel in which thermal decomposition occurs. If the vessel is a coke drum, the process is called delayed coking. The coke—the solid product from thermal decomposition—is allowed to accumulate until it fills about two-thirds of the drum's volume. The feed is then switched to another drum while the coke is cleaned out of the first one.

In the fluid coking process, hot oil is charged into a vessel that contains a fluidized bed of coke particles. The particles become coated with oil, which then decomposes to yield gases and another layer of coke. The gases are withdrawn from the vessel. The coke is also withdrawn continuously, at a rate sufficient to maintain an active stock of coke within the bed.

The flexicoking process, developed by EXXON, combines conventional fluid coking with gasification of the product coke. The advantage is that energy is recovered from the coke. The process is used in the refining industry, but tests would have to be performed to determine if it would be suitable for the coking characteristics of crude shale oil.

Catalytic Hydrogenation

In these processes, the crude shale oil is reacted with hydrogen in the presence of a catalyst. The sulfur in the oil is converted to hydrogen sulfide, the nitrogen to ammonia, the oxygen to water, the olefin hydrocarbons to their paraffin equivalents, * and long-chain molecules to smaller molecules. The hydrogenation reactions can take place in a fixed-bed reactor through which a mixture of oil vapors and hydrogen is passed, in a fluidized-bed reactor, or in an ebulliating-bed reactor. The latter technique is being promoted by Hydrocarbon Research, Inc., as the H-Oil process. Plants in several foreign nations have successfully used it for heavy petroleum feedstocks and for residuum fractions from a variety of crudes. In this process, a mixture is injected into the bottom of a reactor at a high enough velocity to cause catalyst ebulliation (a boiling motion). This movement reduces the possibility that the bed will become plugged by coke and by the liquid tars that are formed during the coking process. It also allows spent catalyst and coke to be removed, and fresh catalyst to be added, so as to keep the bed actively stocked.

Catalytic hydrogenation produces upgraded products of the highest quality, but it is relatively expensive. The use of fixed-bed reactors would probably be confined to the treatment of streams from an initial fractionation step; fluid-bed or ebulliating-bed processes could be used for either fractionator products or for the whole shale oil.

*Olefins are unsaturated (lower ratio of hydrogen to carbon) hydrocarbon compounds having at least one double bond. They are the source of synthetic polymers such as polyethylene and polypropylene used in the manufacture of fibers and other materials. Paraffins are saturated hydrocarbons (equal ratio of hydrogen to carbon) having only single bonds. Methane, ethane, propane, and butane are some of the paraffin hydrocarbons.

Additives

Chemicals may also be added to crude shale oil to improve its transportation properties. Pour point depressants have been successful in some instances, but this does not mean that they would always work. A chemical that is suitable for one type of oil may not work at all with oil from another retorting process. Furthermore, pour point depressants are disadvantageous because they only change the physical characteristics of the oil and not its chemical properties. Thus, their cost can be offset only if they save transportation costs.

Conventional petroleum crudes are other potential blending agents. Since shale oil (at least in Colorado) will be produced in an area that also contains petroleum reserves, and even active crude oilfields, the possibility exists that the light petroleum crudes could be mixed with crude shale oil to form a transportable blend. The feasibility of this concept is unclear because, in general, the blend would not be as valuable as a refinery feedstock on a per-unit basis as would the petroleum alone. However, the decrease in unit value would be offset by the increased volume. In the case of a refinery that does not have a reliable supply of crude, this could be a significant advantage.

Total Refining Processes

The three primary factors that affect the design of a refining system are:

- the characteristics of the crude shale oil feedstock;
- the desired mix of finished products; and
- the constraints imposed by the equipment and operating practices of the proposed refinery.

The first factor probably will have the lowest effect because, except for the higher nitrogen and arsenic contents, the characteristics of crude shale oil are not widely different from those of conventional petroleum. The second factor—the product mix—is much more significant. This is evidenced by the changes that have occurred in the proposed configurations of shale oil refineries since the 1950's: the earlier studies placed much more emphasis on gasoline production. For example, early designs by USBM called for the extensive use of middle-distillate cracking and reforming to yield gasoline, The ratio of gasoline to distillate yields was nearly 3 to 1.[31] Most of the refinery configurations that have been proposed more recently indicate a gasoline-to-distillate ratio of about 1 to 4."

The third factor—equipment and operating constraints—has become increasingly important in recent years. The modifications to convert a conventional refinery to shale oil feedstocks might not be economically justifiable unless the refiner could be assured of an adequate supply of shale oil. The economic desirability of building a refinery specifically for shale oil would be thoroughly scrutinized. Modular retorts, or even a few pioneer commercial plants, would not produce enough shale oil in the mid-term to justify a new refinery unless the refiner was assured that the operations would continue until his investment cost could be recovered. For this reason, the most recent studies have stressed modifying existing facilities to make them suitable for processing shale oil, rather than building new ones. In some cases, this entails only minor changes to installed equipment, in others, the adaptation of an existing facility by adding new units.

The basic unit operations in crude oil refining are:

- coking,
- hydrotreating,
- distillation,
- hydrocracking,
- catalytic cracking, and
- reforming.

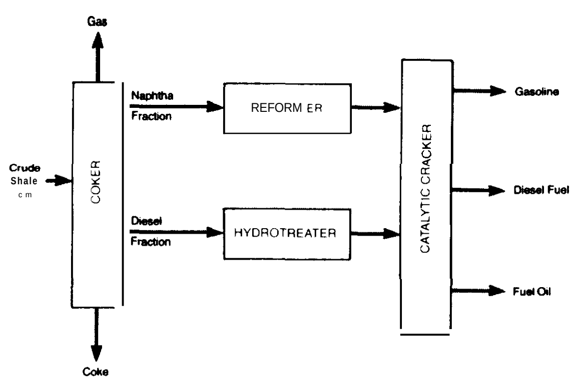
The various refining schemes that have been proposed for shale oil cannot easily be generalized because, depending on both the desired product mix and the possible operating conditions, many configurations could be designed that would achieve the same results. The one selected will largely depend on the availability of equipment and the individual economics of the particular refinery.

One significant difference among the various configurations described in the literature is the relative arrangement of distillation and thermal or catalytic treatment. Two general approaches have been investigated:

1. distillation of the whole crude into its components, then catalytic or thermal treatment; or
2. catalytic or thermal treatment of the whole crude, then distillation.

In the first approach the properties of the finished products are better controlled. In the second, the net load on successive processing units is reduced, and, in general, the overall yield of high-value hydrocarbon products is increased. Most of the refining research to date has been focused on the second approach. Three versions are shown schematically in figures 46 through **48.** The scheme in

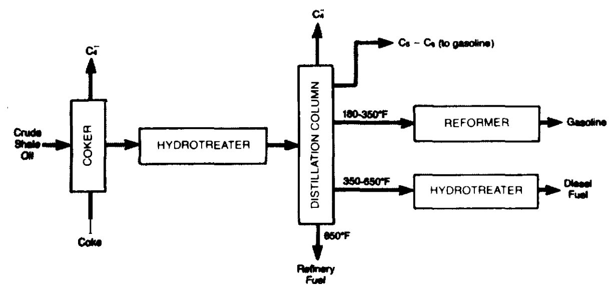
Figure 46.— Refining Scheme Used by the U.S. Bureau of Mines to Maximize Gasoline Production From Shale Oil



SOURCE G L Baughman, *The Refining and Marketing of Crude Shale Oil*

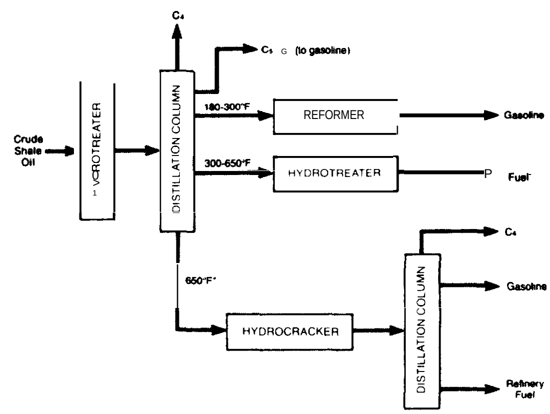
figure **46,** which was used by USBM at Anvil Points in the late 1940's,[33] had a gasoline-to-distillate ratio of 3 to 1. Figure 47, a configuration that was investigated by Chevron U.S.A. during pilot-plant runs on Paraho shale oil,[34] had a gasoline-to-distillate ratio of 1 to 4. Both of these systems used an initial coking step to upgrade the feedstock and to supply a product stream more easily refinable into finished fuels. The disadvantage of coking is that there might not be a ready market for coke in the vicinity of the refinery, particularly if it were located in the oil shale region.

Figure 47. —Refining Scheme Employing Coking Before an Initial Fractionation, Used by Chevron U.S.A. in Refining Experiments



SOURCE G L Baughman *The Refining and Marketing of Crude Shale Oil*

Figure 48.— Refining Scheme Employing Initial Hydrotreating, Used by Chevron U.S.A. in Refining Experiments



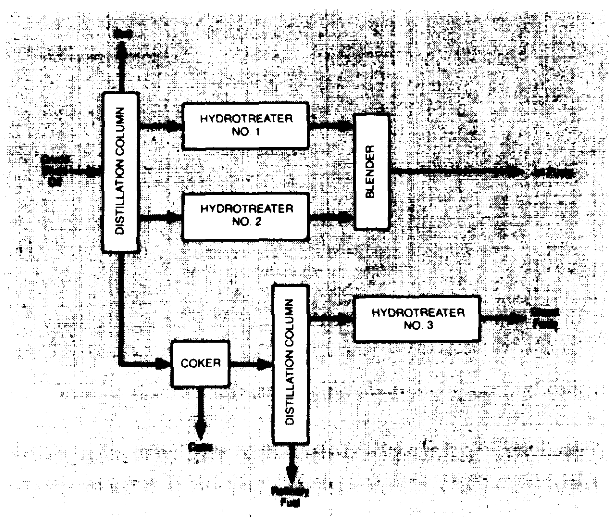
SOURCE G L Baughman, *The Refining and Marketing of Crude Shale Oil*

Another refining scheme that was investigated by Chevron is shown in figure 47. It uses a fixed-bed catalytic hydrotreater to upgrade the shale oil before distillation. No coke is produced because most of the heavier components of the crude shale oil are upgraded into lighter and more valuable liquid fuels during the hydrogenation process. This method may be more costly than the coking approach, but that can only be determined by operating experience and evaluating the economics.

Chevron also investigated the possibility of substituting a fluidized catalytic cracker for the hydrocracker in figure 48. A similar approach was used by SOHIO in processing 85,000 bbl of Paraho shale oil at its Toledo refinery.[35] The chief difference between the SOHIO runs and the Chevron experiments is that SOHIO used an acid/clay treatment to upgrade the distillation products into jet fuel and marine diesel fuel for military applications. The residuum fraction from the column was used for fuel in the refinery.

The approach in which the crude oil is fractionated before hydrogenation or other treatment is shown in figure 49. This scheme

Figure 49.— Refining Scheme Employing Initial Fractionation, Used by SOHIO in Prerefining Studies



SOURCE. G L Baughman. *The Refining and Market/rig of Crude Shale Oil*

was used by SOHIO during the prerefining studies carried out before 10,000 bbl of Paraho shale oil were refined at the Gary Western refinery in Fruita, Colo.[36] During the actual refinery run, a combination coker/fractionator was used rather than the separate units shown in the diagram.

The shale oil must also be treated to remove excess amounts of water, ash, and heavy metals such as arsenic. Water must be removed because it can cause cavitation in pumps and explosions in processing units. Ash, or particulate matter, must be removed to prevent its deposition in pipes, heat exchangers, and catalyst beds. Recent studies have shown that heating the crude oil to about 165° F (75° C) then letting it stand for about 6 hours allows the water and solid matter to separate from the oil. As noted, arsenic and other metals poison the hydrotreating catalysts. A variety of processes have been developed for their removal; consequently, their presence no longer presents a technical problem. ARCO has patented several catalytic techniques and methods for heat treating the oil in the presence of hydrogen. Recent studies by Chevron U.S.A. have shown that an alumina guard bed preceding the hydrotreater will effectively remove both arsenic and iron from shale oil.[39]

The quantity and quality of the fuels produced will be determined by both the configuration of the equipment and the operating conditions used in the refining step. The fuels produced by USBM at Anvil Points in the 1940's were quite satisfactory.'" However, some of the fuels from the Gary Western refining run in 1975 failed to meet certain military specifications, principally those for stability.[41] This has been attributed to the application of refining techniques unsuitable for shale oil feedstocks, specifically inadequate hydrogenation. Subsequent refining tests at SOHIO's Toledo refinery show that, with appropriate refining, fuels can be produced that are of superior quality and that can meet all applicable specifications.[42]

Cost of Upgrading and Refining

The most recent estimates of the cost of upgrading crude shale oil to a transportable refinery feedstock have been prepared by Chevron U.S.A.[43] The retorting complex that was considered had a capacity of 100,000 bbl/d. Conventional hydrotreating was the upgrading technique evaluated. Chevron considered two possible locations for the upgrading facility: a newly built unit at the retorting site; and a unit to be added to an existing refinery at some distance from the retorts. In both cases, the estimated cost for upgrading 1 bbl of crude shale oil was $6.50, in first-quarter 1978 dollars. The product would be a high-quality syncrude suitable as feedstock for most refineries in the United States.

It is more difficult to estimate the costs of the total-refining option for converting crude shale oil into finished fuels. This is because in addition to the properties of the crude oil consideration must be given to the location of potential refinery sites, the availability of refining equipment, the proximity and stability of potential markets, the ease of product distribution, and other factors. Chevron considered some of these in its analysis of refining costs, although in a relatively generalized manner. Three total-refining options and two refining capacities and refinery locations were considered. For a l00,000-bbl/d refinery located in an urban area in the Rocky Mountains (e.g., Denver), the refining cost was estimated to range from $8.00 to $10.00/bbl of crude shale oil. For a 50,000-bbl/d refinery located in a remote area of the Rocky Mountains (e.g., near the retorting facility), the refining cost would be approximately $10.00 to $12.00/bbl.* These are somewhat higher than the costs for refining a high-quality conventional crude oil because of the additional amounts of hydrogen that would be needed to reduce the nitrogen content of the shale oil crude.

Another study compared the cost of shale oil refining with those of refining Wyoming sour crude oil and Alaskan crude. It was assumed that a refinery in the Rocky Mountain region was modified for these feedstocks. The increased costs to refine crude shale oil, rather than the other crudes, was in the range of $0.25 to $2.00/bbl.[44 45]

*Costs are in first-quarter 1978 dollars.

Markets for Shale Oil

Crude shale oil has three major potential uses: as a boiler fuel, as a refinery feedstock, and as a feedstock for producing petrochemicals, The output from a mature oil shale industry will probably be used for all three purposes. However, the relative importance of the three markets will change with time as the industry develops. In the mid-1980's, when shale oil first becomes available in significant amounts, its most likely use will be as boiler fuel, with only a small quantity directed to nearby refineries that could be modified to accommodate the feedstock without large capital expenditures. As more shale oil becomes available, its use as a refinery feedstock will increase as conventional petroleum becomes scarcer. At a later date, when the market for boiler fuels declines, shale oil will begin to be used for petrochemical production.

Shale Oil as a Boiler Fuel

Shale oil will most likely first be used as a boiler fuel because of the relatively small capital investments and very short leadtimes that would be required. Because of Government regulation, the current trend in the utility industry is to replace oil- and gas-fired boilers with coal-fired units, thus freeing the natural gas for domestic consumers. In some areas, it will be a two-stage transition, with the gas first replaced by oil, and the oil later by coal. During the transition, there maybe a market for about 50,000 to 80,000 bbl/d of crude shale oil near the oil shale region. In addition, the refining industry has a small but significant demand for boiler fuel because refineries are also changing from natural gas to oil. Therefore, refineries located near the oil shale region are likely to be near-term shale oil customers. In the long run, the largest market for shale oil boiler fuel is likely to be in the Great Lakes States. Transportation distances will probably preclude its use in the other two major markets for boiler fuels—the east and west coasts.

Shale Oil as a Refinery Feedstock

There has been relatively little research on the refining of crude shale oil because building an oil shale plant takes about 5 to 7 years, whereas a refinery operator can evaluate a new potential feedstock in a few days, develop a feasible refining strategy within a matter of weeks, conduct the necessary pilot-plant refining studies in a few months, and modify the refinery to accommodate the new feedstock in less than 3 years. Thus, neither the developer nor the refiner has any inducement to study shale oil refining until they are sure that the oil will, in fact, be forthcoming.

Another reason is that until quite recently, shale oil was not considered a highly desirable refinery feedstock. During the 1950's and 1960's, the refining industry tended to maximize gasoline yields at the expense of middle and heavy distillates. Because shale oil is a good source of heavier distillates, not of gasoline, it was not highly regarded. However, most projections indicate that gasoline demand will peak in the early 1980's and then decline slightly, even though total demand for refined products will continue to grow.[46] This will be the result of the increasing efficiencies of gasoline engines in automobiles and of a greater use of diesel engines in automobiles and light trucks. Also, because the current supplies of conventional petroleum are becoming more like shale oil with respect to their distillate yields, the refining industry is being forced to adopt techniques that would be equally suitable for shale oil.

For these reasons, shale oil's desirability is increasing, and its potential availability as a premium feedstock has encouraged the refining studies that have been conducted by Chevron and other organizations. These studies have dealt with four general types of refining facilities:

1. a new refinery just for shale oil;
2. a new refinery for a mix of shale oil and conventional crude;
3. an existing refinery modified for, and dedicated to, shale oil; and
4. an existing refinery processing a mix of shale oil and conventional crude.

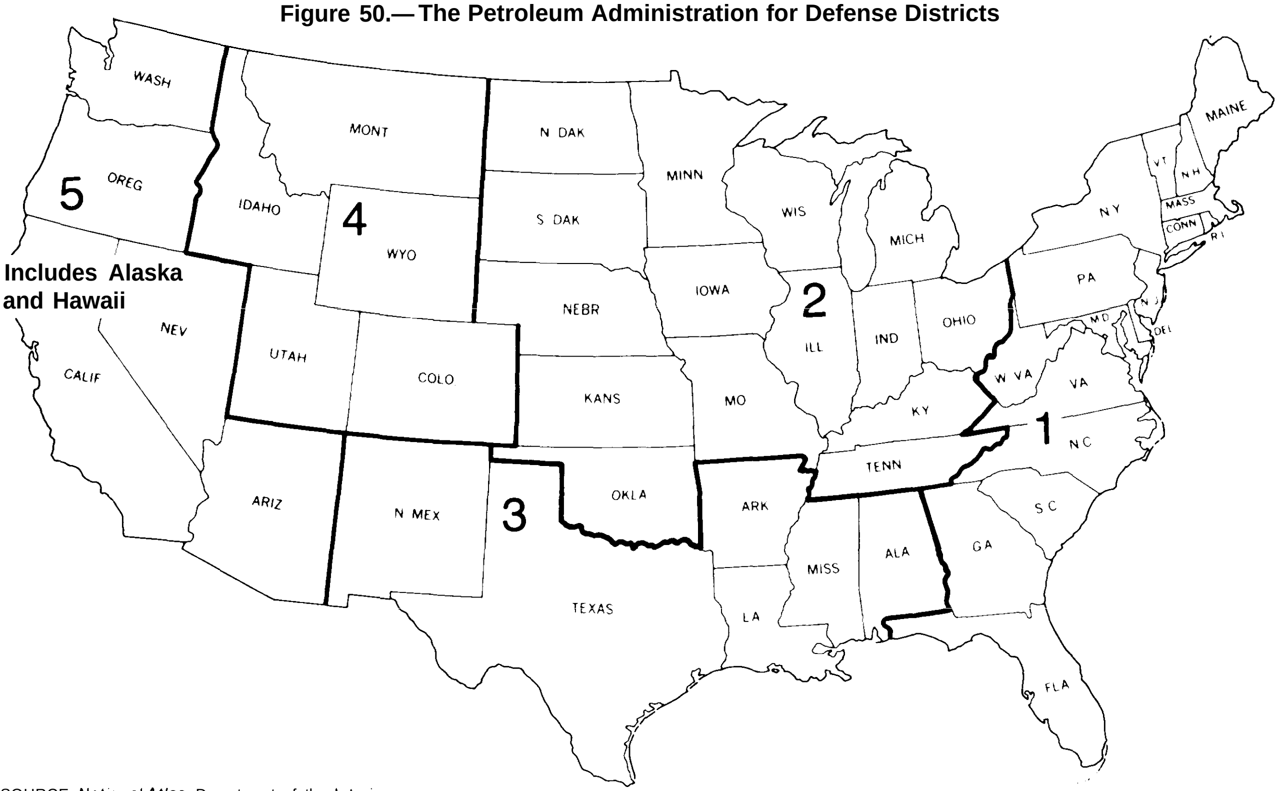
The first two approaches are precluded for the foreseeable future because, as long as refined products continue to be imported, the United States will have excess refining capacity. At least through the 1980's, shale oil will most likely be refined in existing refineries, either by itself or as a blend with conventional petroleum,

The shale oil produced by demonstration facilities will probably be processed in local refineries* or in more distant refineries owned and operated by the energy companies that participate in the oil shale programs. The much larger output from a commercialize industry will be more widely distributed; thus it will have to compete with other feedstocks, at least regionally. Recent studies have indicated that the Midwest is the most likely market area for large quantities of shale oil. This includes the States in the Petroleum Administration for Defense District 2 (PADD 2), as shown in figure 50. There will be secondary effects in other districts, as a consequence of the supplies of shale-derived fuels in PADD 2, because the conventional petroleum that it displaces will become available for use elsewhere.

The quantitative impact on the supply situation in PADD 2 can be determined by refering to table 20, which indicates how the district's supplies of finished fuels were divided among domestic and foreign sources in 1978. As shown, the district consumed about 518,000 bbl/d of medium and heavy distillates (jet fuels, diesel fuel, and distillate fuel oil) from foreign sources. According to Chevron's

*These could include the Gary Western refinery in Fruita, Colo., the Little America refinery in Rawlins, Wyo., the Chevron refinery in Salt Lake City, Utah, and others.

Figure 50.— The Petroleum Administration for Defense Districts



SOURCE *National Atlas*, Department of the Interior

Table 20.–Supply of Finished Petroleum Products in PADDs 2, 3, and 4 in 1978 (thousand bbl/d)[a]

	PADD 2 Midwest			PADD 3 Texas and New Mexico			PADD 4. Rocky Mountains		
	Foreign sources	Domestic sources	Total	Foreign sources	Domestic sources	Total	Foreign sources	Domestic sources	Total
Gasoline.	976	1,540	2,516	422	604	1,026	33	219	252
Light ends	224	236	460	276	388	664	12	25	37
Jet fuel	81	131	212	50	71	121	7	29	36
Kerosine	17	27	44	19	27	46	0	2	2
Distillate fuel oil	420	672	1,092	194	279	473	13	113	126
Residual fuel 011	150	173	323	237	340	577	4	38	42
Petrochemical feedstocks.	18	26	44	211	298	509	0	1	1
Special naphthas and still gas	60	98	158	114	165	279	2	14	16
Others	138	232	370	102	146	248	4	31	35
Total	2,084	3,135	5,219	1,625	2,318	3.943	75	472	547

[a]PADD = Petroleum Administraton for Defense District

SOURCE G L Baughman *The Refining and Marketing of Crude Shale 01/*

studies, refining will convert about 74 percent of a crude shale oil feedstock to similar distillates." A l-million-bbl/d industry would yield about 740,000 bbl/d of medium and heavy distillates. If it were marketed in PADD 2, this production would completely displace the foreign supplies and free an additional 222,000 bbl/d of the fuels for use in other districts. The same size industry would produce about 170,000 bbl/d of gasoline, which would be equivalent to about 17 percent of the district's gasoline currently obtained from foreign sources.

An alternative marketing strategy would be to sell the output from a major shale oil industry in PADD 4—the Rocky Mountain region—and to supply any surplus fuels to adjacent districts such as PADD 2 or PADD 3 (Texas and New Mexico). As shown in table 20, the Rocky Mountain district consumes relatively little distillate fuel (about 20,000 bbl/d) from foreign sources. A l-million-bbl/d shale oil industry could easily displace this entire supply. The surplus production (about 720,000 bbl/d) could displace about 95 percent of the supply of foreign-derived distillates in both PADD 2 and PADD 3. The gasoline derived from the shale oil could supply about 67 percent of the total gasoline demand in the Rocky Mountain States.

As indicated previously, the capabilities of the refineries in the Midwest and the Rocky Mountain States will strongly affect the willingness of the refiners to accept shale oil feedstocks. In some cases, shale oil could not be accommodated without significant investments of capital. However, the receptivity of refiners to shale oil will also be influenced by the reliability of other feedstocks such as foreign petroleum. The area in which the supplies of crude are most uncertain is the northern tier of States, which includes Montana, North and South Dakota, Minnesota, and Wisconsin. These States have historically depended on refinery feedstocks from Canada, but, in recent years, a significant reduction in these supplies has led the refiners in this area to look elsewhere. The result has been the present interest in building a pipeline to transport crude from Alaska and from foreign nations into the area. An alternative—a pipeline from the oil shale region—could also be built as the oil shale industry developed.

The area that covers Iowa, Missouri, Illinois, Indiana, Michigan, and Ohio also does not have an adequate indigenous supply of crude. However, unlike the northern tier, these States have good pipeline systems with adequate access to both foreign and domestic crude supplies. The feasibility of marketing shale oil in this area will largely be determined by the cost differential between it and other crude supplies and by the differences in the reliability of its supply versus that of foreign crude. Recent marketing studies have identified several large refineries in this area that, with only minor modifications would be able to handle crude shale oil. [48] Furthermore, some of the refineries only have access to the heavier petroleum crudes at present, and their production is being limited by their capacity to process the large quantities of residuum from the distillation of these fuels. Shale oil, with its relatively small yield of bottoms fractions, would help alleviate this problem.

Shale Oil as a Petrochemical Feedstock

Three principal factors must be considered in evaluating the suitability of shale oil supplies for producing petrochemicals:

- the yields of petrochemicals from shale oil feedstocks;
- the ability of existing and future petrochemical plants to process the shale oil; and
- the logistics of supplying the shale oil to the plants.

Because shale oil is produced by pyrolysis, its olefin content is approximately 12 percent, which is appreciably higher than conventional crudes. Together with its fairly high hydrogen content, these characteristics make shale oil, and its hydrogenated derivatives, appropriate feedstocks for petrochemical production.” 50 Steam pyrolysis has been used to process crude shale oil, and the yields of olefin products have been comparable with those from many conventional crudes. Shale oil syncrudes, with even higher olefin yields, are considered to be premium petrochemical feedstocks. These conclusions are based on laboratory studies under carefully controlled conditions. The feasibility of marketing shale oil to the petrochemical industry depends on the ability to replicate these conditions in commercial chemical plants.

Historically, the primary feedstock for petrochemical plants has been natural gas liquids from the gulf coast. Because crude shale oil is quite different from these liquids, it would be difficult to switch traditionally designed petrochemical plants to shale oil. However, the production of domestic natural gas and its associated liquids is declining, and the petrochemical industry is shifting to heavier feedstocks such as naphtha and gas oils. The supplies of these feedstocks are uncertain and irregular. The availability of naphtha has been affected by a growing demand for its use as a gasoline blending agent in response to the phasing out of tetraethyl lead. Gas oils are also being used more frequently for home heating fuels, which causes seasonal variations in their availability. Because of these supply uncertainties, new petrochemical plants are being designed to be highly flexible with respect to feedstocks. As using heavier feedstocks becomes more common in the industry, shale oil may become a highly regarded raw material.

The use of shale oil for petrochemical production is hampered by the distance between the oil shale region and the petrochemical plants. While refineries and oil-fired boilers are distributed fairly uniformly across the United States, the petrochemical industry is concentrated on the gulf coast. This concentration will continue into the foreseeable future. Therefore, it will be necessary to either move the shale oil to the coast, or to build a new petrochemical complex in the Rocky Mountain region. In the latter case, the half-finished products from the new plant would still have to be transported to the coast for final conversion to commercial chemicals. The former approach is more likely but is impeded by the lack of a product pipeline system between the oil shale region and the gulf coast, and by the high cost of alternative modes of transportation.

In summary, tests have shown that crude shale oil and its derivatives could be used to produce petrochemicals. However, these materials cannot be considered to be viable feedstocks in the near future because existing chemical plants are generally unable to process them and there is ‘no economical transportation link between the oil shale region and the existing petrochemical plants.

Issues and Uncertainties

The technological readiness of the major mining and processing alternatives is summarized in table 21. Estimated degrees of readiness are shown as judged by DOI in 1968,[51] and as they appear under present conditions. There are significant differences between the two evaluations because much R&D work has been conducted in the interim, and because two new processing methods—MIS retorting and concurrent recovery of associated minerals—have since entered the picture. As shown, room-and-pillar, open pit, and MIS mining methods are regarded as reasonably well-understood. Open pit mining has not been tested with Green River shales, but it is highly developed for other minerals such as copper and iron ores. It was evaluated on paper for application to the shales on tract C-a. Some highly relevent experience has been obtained from the operation of large-scale lignite (a form of coal) mines in West Germany.[52] In these operations, the lignite is covered by 900 ft of overburden, and stripping operations will soon extend to 1,600 ft. This is comparable to the oil shale deposits, which are covered by a maximum of about 1,800 ft of overburden.

Nevertheless, uncertainties remain with respect to the effects of shale stability and strength on mine design, mine safety, and resource recovery. The effects of large inflows of ground water, such as have been encountered on tract C-a, could pose severe operational difficulties, especially with underground mines. In all mines, the logistics associated with moving many thousands of tons of raw material and solid wastes could present some formidable problems. Materials-handling systems exist that could be applied, but they have yet to be tested in commercial oil shale operations.

Table 21 .–Technological Readiness of Oil Shale Mining, Retorting, and Refining Technologies

	Technological readiness			
Unit operation	In 1968	In 1979	Developments in the Interim	Remaining areas of uncertainty
Mining				
Room and pillar	Medium	Medium	Mine design studies. Experience of Colony, Mobil, and the six-company program at Anvil Points	Rock mechanics Ground water Deep shales Logistics.
M I S	Unknown	Medium	Oxy experience at Logan Wash Mine design studies.	Rock mechanics Ground water Deep shales Logistics
Open pit	Low	Medium	Established procedure for other minerals Large-scale mines in West Germany. Mine design studies for tract C-a,	Rock mechanics Logistics Reclamation
Other	Low	Low	Mine design studies No field experience	All areas
Retorting				
Aboveground	Medium	Medium	Pilot studies for Lurgi-Ruhrgas Semiworks programs by Colony and Paraho Detailed designs by Colony and Union.	Effects of scaleup on stream factor and recovery. Characteristics of emissions streams Reliability of peripheral equipment Materials handling.
T I S	Low	Low	Field work and lab tests by USBM. Field tests by Equity, Geoknetics, and Talley-Frac. National lab support	Stream factor and recovery. Characteristics of emissions streams Rock mechanics Deep shales.
M I S	Unknown	Medium	Oxy experience, Design studies for tracts C-a and C-b. DOE and USBM design studies Modeling and lab support by national laboratories.	Effects of scaleup on stream factor and recovery Characteristics of emissions streams Reliability of peripheral equipment Use of low-Btu gas Rich shales. Mixed shales, Fracturing Rock mechanics Deep shales,
Multimineral	Unknown	Medium	Pilot plant studies by Superior USBM lab tests of product recovery methods. Nahcolite scrubbing tests.	Effects of scaleup on stream factor and recovery Characteristics of emissions streams Reliability of peripheral equipment, Materials handling Integration of recovery steps Underground waste disposal Marketability of byproduct minerals.
Upgrading and refining.	High	High	Studies and refinery runs by SOHIO/Paraho, Chevron, and others. Marketing analyses by Oxy and DOE.	Effects of retorting conditions on crude characteristics Cost effectiveness of alternate processes Use of pour point depressants Effects of metals

SOURCE Office of Technology Assessment

AGR is regarded as having a medium level of readiness, as it was in 1968. The understanding of its technical aspects has been improved since then by field tests in the Piceance basin, but the largest tests conducted to date have been at the semiworks scale—about one-tenth of commercial size. Their results do not permit accurate cost projections for commercial-scale plants. Particular problems are noted with respect to the effect of scaling up the semiworks design to commercial size. The on-stream factor—the fraction of the time that the retorts could be expected to operate at design capacity—is unknown. The reliability of some associated systems (emissions controls, product recovery devices, materials-handling equipment) is also questionable.

Although understanding has increased since 1968, TIS must still be regarded as being in the conceptual stage. Many uncertainties remain, especially with respect to economics and environmental effects.

MIS retorting, a new concept since 1968, has advanced to a medium level of technological readiness, approaching that of above--ground retorts. This progress is largely a result of Oxy's development efforts in Colorado, but additional understanding has been obtained through simulations by USBM, DOE, and the national laboratories, most notably the Lawrence Livermore and Los Alamos Laboratories. The remaining uncertainties are similar to those for aboveground retorts, except the materials-handling problems may be less substantial with MIS methods. The major uncertainties relate to the use of the large quantities of low-Btu retort gas for power generation and to the application of the technique to very rich or very deep shales.

The multimineral concept was also largely unknown in 1968, although the presence of sodium minerals was recognized. At present, the aboveground system of Superior Oil is regarded as having medium technological readiness. Its uncertainties are much the same as for other AGR methods, with the addition of the potential difficulties with integrating the systems for recovering mineral byproducts with those for recovering oil and gas. The marketability of the nahcolite, soda ash, and alumina has also not been well-established. The MIS concept proposed by Multi Mineral Corp. is not specifically evaluated in the table. It would share the same uncertainties as conventional MIS, with additional potential problems introduced by the need to evacuate a large underground retort, and because the oil shale resource is deeply buried.

Upgrading and refining systems were given a high rating in 1968, which has been improved by additional study. No major problems are anticipated, although more needs to be known about the feasibility of using pour point depressants, the effects of retorting conditions on the characteristics of the crude oil, and the effects of metals (such as arsenic) on refining catalysts. The major uncertainty in the distribution area—the existence of an adequate pipeline system to the most likely markets—is not directly related to the nature of the refining technology and is therefore not indicated.

It should be noted that mining and retorting (the major subprocesses having only medium levels of technological advancement) require only about 35 percent of the capital investment that is needed to establish an AGR complex. The remaining 65 percent is distributed among upgrading units, byproduct recovery systems, utilities, sidewalks, and other well-established items. Yet developers hesitate to commit themselves to oil shale plants. The reasons given are an uncertain regulatory climate, an uncertain future for the price of conventional petroleum, and the fact that all of the components of a facility must work as designed—not just the well-established ones. With the present state of technological knowledge, it is not clear that an oil shale plant would perform as desired, nor that the oil would be sufficiently cheap to compete with its currently designated competitor—imported petroleum. Even though the future of oil shale looks brighter, few companies are willing to build large-scale plants immediately. They prefer to follow conventional engineering practice by proceeding to an intermediate step—the so-called modular demonstration retort.

The modular retort is the smallest unit that would be used in commercial practice, A commercial-size oil shale facility would use several of these retorts in parallel to obtain the desired production rate. The capacity of a module varies with the developer. For Oxy, a modular MIS retort might have a capacity of only a few hundred barrels per day of shale oil; a commercial facility would have several dozen of these retorts operating simultaneously in modular clusters, each producing several thousand barrels per day. A modular Lurgi-Ruhrgas retort would have a capacity of about 2,200 bbl/d. One or two such units might suffice for the mined shale from an MIS operation; a facility that used only AGR might need a dozen comparable units. A commercial-sized plant that used Paraho retorting might have seven or eight individual retorts, each producing 7,300 bbl/d. A comparable plant might use seven Union “B” retorts, each producing about 9,000 bbl/d. Colony prefers to bypass the modular demonstration phase and to proceed directly to a commercial-size facility, claiming that the TOSCO 11 technology is ready to be scaled up to such a capacity for demonstration purposes.

Regardless of these differences, the several “next steps” that are proposed by the developer’s have two points in common: the production units must be large enough to simulate actual commercial practice, and the equipment must be operated long enough to obtain reliable data on its performance under a complete spectrum of operating conditions.

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R&D Needs and Present Programs

R&D Needs

Mining

Room-and-pillar mining and mining in support of MIS operations have been tested with oil shale, and an extensive body of information has been assembled. To date, however, all of the field tests have been conducted in one area—the southern fringe of the Piceance basin. In each case, the deposit was reached through an outcrop along a stream course. The limited area in which mining tests have been conducted is unfortunate because the characteristics of deposits in other areas are quite different. They may be more or less favorable to mine development. For example, there is little ground water in the southern fringe. In contrast, the deposits on tracts C-a and C-b, nearer the basin's center, lie within ground water aquifers, and the inflow of water into the mine shafts has been a problem on tract C-a. Similar problems were encountered at the USBM shaft in the northern part of the basin. Work on this site was also impeded by the presence of highly fractured zones, which are not common on the southern fringe.

Similar surprises could be avoided in future projects if the suitability of the candidate mining techniques for developing deposits throughout the oil shale region were better understood, especially in these areas where near-term development is likely. This information could be obtained through coring and rock mechanics studies, mathematical simulation, and experimental mining. Field testing of mining methods would be expensive, although overall costs could be minimized through developing a single site that could be used to test many mining alternatives. A single shaft or adit, for example, could be used to test room and pillar, longwall, block caving, and other methods. It should be noted that open pit mining, because of the necessity for costly and large-scale operations, would probably not be amenable to testing in a limited field program.

TIS Retorting

TIS is the most primitive of the processing methods. It has some potentially valuable features but these cannot be evaluated because of a lack of information. The potential impacts on surface characteristics and ground water quality are especially unclear. The R&D needs include:

- development of less expensive drilling techniques;
- development of efficient and cost-effective fracturing and rubbling techniques;
- development of methods for determining the success of a rubbling program through, for example, surveys of the permeability increase that has been achieved;
- development of ignition methods and of methods for maintaining a uniform burn front;
- study of the effects of heat-carrier composition, rate of injection, and temperature on product recovery;
- study of the effects of creep* on retort stability and product recovery;
- determination of the effects of ground water infiltration on retorting; and
- evaluation of the long-term potential for surface subsidence.

Valuable information is being obtained in the Equity and Geokinetics projects, but these results are applicable only to specific types of oil shale deposits—the Equity process to shale in the Leached Zone; the Geokinetics method to thin, shallow beds. Additional field work in other types of deposits would aid in evaluating the potential of TIS methods for large-scale production. To minimize the cost and duration of these tests, they could be supplemented with initial theoretical studies and laboratory programs.

*Creep is the gradual change in the shape of a solid object induced by prolonged exposure to stress or high temperatures.

MIS Retorting

MIS is more highly developed, but more testing is needed before its potential application to other areas of the Green River formation can be determined. The R&D needs are similar to those for TIS. They are:

- the development of better rubbling techniques;
- the development of improved remote sensing procedures for permeability, fluid flow, and temperature;
- the development of methods for creating and maintaining a better burn front;
- evaluation of the effects of heat-carrier characteristics;
- evaluation of the effects of creep and subsidence; and
- examination of the effects of ground water infiltration, retort geometry, and particle-size distribution.

Many of these needs will be addressed in the MIS programs on tracts C-a and C-b and the USBM shaft.

Aboveground Retorting

Several candidate retorting processes have been tested in Colorado, but only for relatively short periods, and in small-scale facilities, More R&D is needed, and particular emphasis should be given to:

- evaluating the effects of scaleup on the flow patterns of solids and fluids within the retort vessel;
- determining the reliability and effectiveness of peripheral equipment such as solids-handling systems, pollution controls, and product separators;
- examining the effects of heat-carrier characteristics on product recovery and equipment reliability; and
- determining the reliability of mechanical components such as Union's rock pump; Tosco's retort vessel, separation trommel, and ball elevator; the Lurgi-Ruhrgas screw conveyor; and the raw shale distributors and spent shale discharge grates of all retorts that use gas as a heat carrier.

Some of these needs could be addressed by further laboratory-scale and semiworks testing. Others could be estimated by theoretical calculations and modeling. All of them and especially the need for reliability studies, will eventually have to be addressed in full-scale retorting modules, either alone or as part of a commercial-size complex.

Upgrading, Refining, and Distribution

Because crude shale oil is sufficiently similar to conventional petroleum crude, no substantial problems are anticipated in the refining area. R&D on the effects of heavy metals on refining catalysts and of retorting conditions on oil properties could be conducted in the laboratory, provided that retorts were operating that could supply a product resembling the crude oil that will be produced in commercial operations,

In the upgrading area, the major need is related to the feasibility of using chemical additives to depress the pour point of crude shale oil. The necessary R&D could be conducted in the laboratory or in a pilot refinery, again assuming the availability of a representative crude shale oil.

R&D is also needed to determine the optimum distribution pattern for the finished fuels, which will vary with the size of the industry, the location of the facilities, the need for various fuels and feedstocks, and the availability of a transportation system. R&D is needed to determine optimal plans for likely combinations of these factors. Work has begun in this area, and more work could be conducted at relatively low cost, since it is theoretical rather than experimental in nature. However, it will not be possible to define an optimum pattern for the actual future industry until the sites of the production facilities are designated.

The System

All manufacturing and processing plants potentially suffer from a lack of systems reliability. Because of the scale of operations and the need for the coordinated performance of many components, it is certainly possible that oil shale plants will have significant problems. On the other hand, they may not be more severe than in other, more conventional industries. R&D programs, such as mathematical simulations and industrial engineering studies, would help to eliminate some of the uncertainties regarding the expected performance and reliability of oil shale systems. Basic data on the lifetimes of equipment, operating characteristics, and other factors could be obtained from those minerals processing and refining plants that oil shale facilities will resemble. However, because of the unique character of oil shale operations, predictions from these studies will be tentative. It will only be possible to define performance characteristics after large-scale oil shale plants are operated at their maximum production capacities.

Present Programs

Some of the current R&D programs for individual retorting technologies were described previously. An effort that has not been discussed in detail is DOE's integrated research, development, and demonstration program for oil shale.[53] Its major objective is to provide the private sector with the technical, economic, and environmental information needed to proceed with the construction of pioneer commercial plants. Its specific goals are:

- by *mid-1981:* to provide technical designs, cost data, and environmental information for construction and operation of at least one AGR module;
- by 1982: to design at least one commercial-size MIS retort that could be used on the Federal lease tracts or in other locations; and
- by 1985 to 1990: to remove the remaining technical uncertainties that impede commercial-scale use of the alternate technologies in the various types of oil shale deposits.

In situ processing has been given the major emphasis throughout the program, and much of the technical R&D will be conducted in the "Moon Shot" project that will address the second goal. Initial support of AGR will focus on designing the retort module and on surface and underground mines to support single plants and an industry of 1 million to 3 million bbl/d. The decision to proceed with construction of AGR modules will be determined by the economic outlook for shale oil in mid-1980. DOE will consider a cost-shared program if industry has not announced firm plans to proceed without Federal participation. The program will also include resource characterization studies that will help to delineate the portions of the oil shale basins where the different types of development technologies would be most applicable. Other studies will include assessments of air, water, land, and socioeconomic impacts; of occupational safety and health; and of methods for increasing the efficiency of water use.

These efforts should substantially advance the understanding of the technological aspects of oil shale development. The budget of over $387 million for fiscal years 1980 through 1984 should be adequate to address most of the R&D needs identified in the previous section. This budget includes about $126 million for developing and operating a commercial-scale MIS retort, and half of the estimated $200 million cost of an AGR module.[54]

The demonstration facilities are especially important to the acquisition of firm engineering and economic data. Unfortunately, only one in situ technology and one aboveground retort will be tested, and it will be difficult to evaluate fully the effects of resource characteristics on the feasibility of alternate mining methods.

Policy Options

R&D

Some of the remaining technical uncertainties could be alleviated with additional small-scale R&D programs. These could be conducted by Government agencies or by the private sector, with or without Federal participation. If full or partial Federal control is desired, the programs could be implemented through the congressional budgetary process by adjusting the appropriations for DOE and other executive branch agencies, by providing additional appropriations earmarked for oil shale R&D, or by passing new legislation specifically for R&D on oil shale technologies.

Demonstration

Full-scale demonstrations will be needed to accurately determine the performance, reliability, and costs of development systems under commercial operating conditions. In general, potential developers would prefer to follow conventional engineering practice and approach commercialization through a sequence of increasingly larger production units. Union, Colony, and Paraho have progressed through this sequence to the semiworks scale of operation—about one-tenth of commercial size.

If this conservative approach were continued, the next step would be a modular demonstration facility. Although such a plant would cost several hundred million dollars, it would provide the experience and the technical and economic data needed to decide on the commitment of much larger sums to commercial-scale operation. Union has expressed its preference for this path; Rio Blanco and Cathedral Bluffs are following it. Colony regards a pioneer commercial plant as the best facility for proving the TOSCO II technology.

The two general approaches to funding such demonstration programs are discussed below. Selecting an option will depend on the desired balance between information generation and dissemination, Federal involvement, timing of development, and cost.

Private Funding

If left alone, the industry would develop in response to normal market pressures and opportunities, and the Government's expense and involvement would be minimized. However, the Government would not be assured of access to the technical, economic, and environmental information that it needs to formulate future policies and programs, although some of this information could be obtained through third-party reviewers or through licensing arrangements. Another disadvantage is that industry may not risk even the relatively modest investment of a modular program until economic and regulatory conditions clearly favor development. For example, Union and Colony have announced that they will not proceed until Federal incentives are provided and regulatory impediments removed. Industry may eventually proceed, but perhaps not in time for the resource to contribute substantially to the Nation's fuel supplies within the next decade.

Government Support

The alternatives are full Government funding of demonstration facilities, indirect funding through incentives to industry, and a sharing of the costs with industry. The options are discussed in detail in chapter 6 and summarized in chapter 3. In brief, Federal ownership would provide the Government with the maximum amount of experience and information. It would also maximize Government intervention and the commitment of public funds, and it might discourage private developers from proceeding with independent demonstrations. Also, industry and Government would design, finance, and operate a demonstration project in very dissimilar ways. The Federal experience with a Government-owned facility may have little relevance to the problems that would be encountered by a private developer with the same production goal, The Government's experience would therefore provide little guidance for evaluating oil shale as a private investment opportunity.

Incentives programs could involve tax credits, purchase agreements, price supports, or other types of support, either singly or in combination. They could be structured to encourage the participation of specific types of firms and could be combined with regulatory changes, and possibly land exchanges or additional leasing, to control both the growth and the nature of the ultimate commercial industry. They would cost less than Government ownership. They would also tend to provide the Government with less information and with no operating experience. However, disclosure requirements could be inserted into the leases or the incentives legislation as a prerequisite for project eligibility y.

The cost sharing of demonstration facilities would entail intermediate expenditures of public funds and intermediate levels of information. The receptivity of industry to such proposals would depend on how much the Government would intervene in designing and operating the projects. If industry responded, the Federal investment that would be needed for a single Government-owned plant could be spread over several projects, thereby increasing the total amount of information generated.

Program Alternatives

Demonstration will require designing, building, and operating full-size production units, either as separate modules or incorporated in pioneer plants.

A single module on a single site.—This option would provide comprehensive information about one process on one site. Either underground or surface mining experiments could be performed, but probably not both. The costs would be small overall but large on a per-barrel basis, because there would be no economies of scale. Some of the shale mined could be wasted because the single retort might not be able to process all of it economically. If the site could subsequently be developed for commercial production (e. g., a private tract, a potential lease tract, or a candidate for land exchange), the facility would have substantial resale value. Otherwise, it would be valuable only as scrap.

Several modules on a single site.—This program might consist of an MIS operation, coupled with a Union retort for the coarse portion of the mined oil shale and a TOSCO II for the fines. As with the single-module option, either surface or underground mining could be tested, depending on the site, or possibly both if the plant had a sufficiently large production capacity. The total costs would be larger than for the single-module program, but unit costs would be lower. For example, a three-module demonstration plant would cost about 2. I times as much as a single-module facility; a six-module plant about 3.7 times as much. Different technologies could be combined to maximize resource utilization, and detailed information could be obtained for each. However, all of the information would be applicable to only one site. If many modules were tested, the demonstration project would be equivalent to a pioneer commercial plant, except that a true pioneer operation would probably not use such a wide variety of technologies.

Single modules on several sites.—Several technologies might be demonstrated, each at a separate location. For example, an underground mine could be combined with a TOSCO II retort on one site; a surface mine with a Paraho retort at another. Total costs could be large, as would unit costs, which would be comparable with those of the single-module/single-site option. The principal advantage would be that different site characteristics, processing technologies, and mining methods could be studied in one comprehensive program.

Several modules on several sites.—For each site, a mix of mining and processing methods would be selected that would be most appropriate for the characteristics of the site and the nature of its oil shale deposits. The maximum amount of information would thus be acquired, in exchange for the maximum amount of investment. Each project would resemble the several-module/single-site option; the collection would constitute a pioneer commercial-scale industry.

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CHAPTER 6

Economic and Financial Considerations

Contents

List of Tables

List of Figures

CHAPTER 6

Economic and Financial Considerations

Introduction

The loss of oil imports from Iran coupled with large OPEC price increases during 1979 once more emphasized the vulnerability of the United States to its continued dependence on imported oil. Rapidly escalating world oil prices combined with uncertain supplies and dwindling domestic reserves have seriously affected the balance of payments, the rate of inflation, and the general health of the economy. While expert opinions may differ about prices in the immediate future, they agree that supplies will remain uncertain and prices will continue to rise. The recently renewed interest in shale oil (and other synthetic fuels) as contributors to the domestic fuel supply has arisen in response to these uncertainties.

The present debate over the proper economic policy to pursue with respect to oil shale development centers around the following:

- the potential it may have for alleviating the Nation's energy-supply problems;
- the financial, environmental, and socioeconomic costs and risks that could be encountered in developing an oil shale industry;
- a comparison of its benefits and costs with those of other energy strategies such as conservation, solar, increased direct use of coal, other synthetic fuels, expanded domestic exploration and production, or continued reliance on foreign oil:
- the implications of both alternative production goals and the rate at which the industry is established for maximizing the benefits and minimizing the costs and risks of commercialization;
- the relative advantages and disadvantages of different financial mechanisms for achieving various production levels and minimizing private and Government risk; and
- the major commercial and institutional risks and obstacles that currently hamper commercial development, which of these can be predicted, and in which cases is information insufficient to adequately evaluate policy options.

Considering the amount of capital that would need to be invested and profitably returned over long periods of time, a rational and informed choice about the commercial production of shale oil (or any synthetic fuel) requires making reasonably confident estimates of the following factors and relationships:

- the required capital and operating costs for various levels of shale oil production, and a comparison of these costs with those for alternative strategies for obtaining equivalent benefits;
- the future effect of OPEC pricing policies;
- the corporate perceptions of specific risks and deterrents that currently inhibit private commercialization;
- the subsidies and incentives that would most effectively, and at least cost, sufficiently reduce uncertainty to promote development; and
- the temporary or permanent subsidies that would be required to maintain an industry.

These are all complex issues open to a variety of interpretations. Several of these questions may be unanswerable at this time with the information available.

The Nature of the Investigations

This chapter reports the results of the following analyses:

- The capital and operating costs have been estimated for commercial-size facilities in third-quarter 1979 dollars. This has been done for both surface retorting and modified in situ (MIS) technologies. The total costs of various production levels have been calculated for industries based on both generic technologies. The accuracy of current cost estimates has been evaluated in the light of the prior unreliability of such projections, and an attempt has been made to disaggregate the factors responsible for the escalating cost estimates for these facilities.
- The effect of uncertain prices for OPEC crude on shale oil commercialization has been examined, a variety of projections for these prices evaluated, and a probable rate of increase for future real prices described.
- OTA has undertaken extensive qualitative and quantitative examinations of the relative effectiveness and outcomes of various possible financial incentives for stimulating commercial development. These were based on independently conducted mathematical simulations of industry economics, as well as on extensive discussions with private consultants, Government financial administrators, and industry representatives.
- The relative advantages and the merits of several different strategies, development schedules, and production targets have been examined with respect to their comparative costs, risks, and benefits.
- A detailed study has been carried out of the impact on capital availability and pricing of oil shale development at several levels of production. The investigation indicates the probable impacts that alternative levels of oil shale production will have on the cost and availability of capital, both for the U.S. energy sector and the economy as a whole, given a variety of different growth and demand characteristics for investment capital, This examination also considers the relative impact that different Federal incentives will have on capital markets.
- The effect of various levels and paces of oil shale development on the level of employment, the balance of payments, the rate of inflation, and Federal tax generation,

Summary of Major Findings

The major conclusions of OTA's economic analysis of the oil shale industry are as follows:

- The commercialization of oil shale has been generally impeded in the past by several uncertainties. Among the most important are large and unreliable plant capital cost estimates, the insufficient number of high-grade private oil shale tracts plus limited access to Federal oil shale lands, uncertainty about present and future environmental regulations, and uncertainty over future prices for oil.
- It is likely, given current market conditions, resource availability, and the regulatory climate that without additional Federal action a shale oil production capacity of 100,000 bbl/d will be online by 1990-92. It is probable, given similar conditions, that the production of 200,000 bbl/d by that date will require financial incentives, direct Government participation, or major changes in the regulatory environment of the industry. The same would be even more the case for a 400,000 -bbl/d industry. Furthermore, the deployment of this size industry by 1990 could require additional land ex-

changes or Federal leases. The deployment of a 1-million-bbl/d industry by the same date would require aggressive action in all of these areas.

- Given recent increases in the price of oil, the potential marketability of shale oil improved substantially during late 1979 and early 1980. In narrow economic terms, the production of shale oil may be price competitive with foreign crude at this time. However, this conclusion is subject to several critical limitations, It assumes that current capital and operating cost estimates are within 20 percent of actual costs, that the price for oil will continue to rise throughout the rest of this century by at least a real 3 percent per year, and that developers require a real discount rate of no more than 12 percent. (The economics of shale oil and its potential selling price are extremely sensitive to the discount rate assumed by the developers.)

- If financial incentives to private industry are to be employed, production tax credits, purchase agreements, and price supports have the most economic merit based on a variety of criteria. However, it should be noted that the subsidy effect of purchase agreements and price supports are dependent on the contract price that is set. Consequently, the success of these two incentives will depend on how they are constructed and administered. Small and moderate firms will require some kind of front-end subsidy if they are to significantly participate in oil shale development. If such participation is an important goal of Government policy, debt guarantees or debt insurance are probably the most efficient vehicles.

- The deployment of a 400,000-bbl/d industry by 1990 would begin to markedly strain the capacity of U.S. manufacturers to supply heavy equipment to developers. To deploy a 1-million-bbl/d industry by that time would use between 15 and 30 percent of current U.S. annual production of this equipment. There would be a similar strain on the capacity of large integrated architectural/engineering firms capable of undertaking major process plant construction.

- Existing capital markets and lending institutions are able to supply sufficient capital for even the rapid development of a large industry (1-million-bbl/d by 1990) without significant perturbations,

- Oil shale development would provide a number of economic benefits such as contributions to the national fuel supply and direct substitution for foreign oil imports. A production of 500,000 bbl/d would reduce the balance-of-payments deficit by about $5 billion current dollars if the price of foreign crude were $31/bbl.

- Oil shale development, even at high rates of deployment, would have an insignificant impact on national prices and rates of employment. However, the production of even 200,000 bbl/d by 1990 would noticeably increase local rents, land prices, and labor costs. Even moderate developmental rates would favorably affect local employment levels and this effect would extend to the region with the deployment of a 400,000-bbl/d industry by 1990.

Development, Commercialization, and Deployment’

In this assessment, the term commercialiuation is used to designate the process by which private industry adopts a technology for commercial use after most of the technical uncertainties affecting its economic feasibility have been resolved. In the United States, commercialization of new technologies is primarily undertaken by private firms without direct Federal intervention. Nevertheless, during the past decade the amount of direct Government involvement has risen sharply. If Congress and the administration decide to stimulate the commercialization of oil shale, it will be necessary for their attention to be focused on the period between the time when the major technical problems have been solved and the time when the technology is commercially self-sufficient—the initial phase. Once a decision about the advisability of intervention has been made, the question then is how the commercialization of the initial phase can best be accomplished.

Government sponsored development programs consist primarily of research and development (R&D) to solve the technical problems of a process. Thus far, such programs for oil shale have been directed to developing specific techniques for mining, retorting, rubbling (in MIS processing), removing of impurities, and hydrotreating the shale oil.

Commercialization, in which a technology is adopted and made economically viable by private industry, involves the resolution of the institutional and economic deterrents that affect profitability. Efforts by the Government to promote commercialization assume that the adoption by private industry of a process, which is temporarily not commercially viable, will be expedited. The rationale is that such assistance will enable an industry to become self-sufficient and profitable without further subsidy. A Government-sponsored deployment program differs from one to promote commercialization in that it does not assume that an industry will ultimately be self-sufficient or that incentives are temporary. The deployment of the synthetic rubber industry during World War II is a well-known example of such a program. In this case the industry subsequently became profitable without subsidy, but this was not the main objective of the program.

Both deployment programs and commercialization support for synthetic fuel plants have been proposed. Although they have similar goals, these strategies imply very dissimilar relationships between Government and industry. Deployment programs are governmentally controlled. The function of private firms is restricted to advising, constructing, and, in some instances, operating the facilities. Private corporations provide services for a fee to the Government, which buys the products and services and retains ultimate authority over the planning and the pacing. Commercialization, on the other hand, implies that the private sector makes the final decisions about adopting a technology.

The Rationales for Federal Intervention

From an economic point of view, Government involvement in commercialization may be justifiable when private industry declines to undertake an enterprise that meets major social needs or benefits society. The penalty for governmental inaction may take the form of a forgone social benefit, such as a decrease in national security because of insufficient domestic suppies of oil, or of increased costs to society, such as environmental damage because of inadequate regulation. Society would also have to pay if, as a consequence of the Government's failure to intervene, the price of a resource increased at a later time.

The deliberate stimulation of a significant level of oil shale production could be expected to have a number of social benefits. It would help reduce dependence on foreign oil. It would position the United States several years closer to the deployment of a major shale oil industry should this be made necessary by future political or economic events. Stimulated production might also have a moderating effect on oil price increases, although it is not clear what level of production would be needed for this to happen.

Private industry declines to invest in an enterprise when it lacks confidence in the prospects for profitability. Higher expected profits are required of very risky projects than of more certain ones. Three types of risk for oil shale are discussed in this chapter:

1. the possibility that capital and operating cost estimates may seriously underestimate a project's cost and thus jeopardize its profitability or that the technology will not perform as planned,
2. the possibility that world oil prices may fluctuate in such a way that product marketability will be interrupted at some point in the time period required to recoup the initial investment, and
3. the possibility that regulatory delays or a change in environmental standards may adversely affect project economics.

If the Government is already intervening in such a way as to penalize a new technology, the private sector may be discouraged from pursuing it, despite its usefulness. For example, the regulation of the prices of domestic petroleum and natural gas that is now being phased out undoubtedly penalized oil shale development.

It is widely believed in oil shale industry circles that the overall impact of Government policy (e.g., regulations, permitting processes, preferential treatment of conventional petroleum, and limitation of access to shale resources on Federal land) has been one of the most important impediments to oil shale development,

A variety of groups and individuals oppose Government stimulation of the oil shale industry (or other industries) because they believe that the free play of market forces will make much more efficient and productive market decisions than will any federally inspired stimulation program. Those sharing this perspective argue that favorable alteration of oil shale economics by the Government will inhibit the use of the most efficient energy sources, encourage less efficient management of the industry itself, increase the cost of energy, and foster continued dependence on fossil fuels. However, those who would allow the market to decide whether shale oil should be produced, also tend to argue that taxes on developers, restrictions on resource acquisition, and regulatory constraints should also be radically reduced.

It does not necessarily follow from the failure of market mechanisms to promote commercialization that the Government will or can do it better. Government intervention is justified only if its benefits (appropriately computed) are greater than its actual real costs. Since the choice is not between efficient markets and inefficient Government or efficient Government and inefficient markets, but rather between inefficient markets and inefficient Government, the question is which will be more effective in a particular situation.

Impediments to the Commercialization of Oil Shale*

The successful commercialization of a new technology ultimately depends on its profitability. Commercialization will not take place, despite Government encouragement, if developers are unable to obtain a return on their investment commensurate with returns available to them from other investments. Consequently, in determining the proper course to pursue with respect to oil shale development, the Government needs to give careful consideration to the prospects for profitable operation. An industry that requires permanent subsidies is a different economic proposition from one that needs them only for the first commercial-size facilities. There are three types of factors that influence self-sufficient profitable operation: technical, economic, and institutional.

Technical uncertainties primarily refer to the difficulties associated with scaling up a new process from pilot to commercial size. This usually involves solving technical problems that could adversely affect operation and thus increase the risk of financial loss, e.g., a component may be required to perform beyond the capacity of available equipment, or existing mining techniques may be inadequate for the scale of commercial-size operations. With MIS technologies, the need to properly rubble shale in order to achieve necessary burn characteristics (and thus a high rate of shale oil recovery) is such a technical problem. With surface retorting, an example would be scale-up of 10 to 20 times of complex reaction systems handling massive quantities of solids.

Economic uncertainties are different for those technologies that produce a substitute for an older product than they are for those that produce primarily new products. The economic risks associated with shale oil center around whether it can be produced and sold with sufficient profitability to compete with conventional crude. Uncertainty about capital and operating costs has continually beset corporate decisionmaking with respect to oil shale commercialization. In addition, developers are unable to accurately predict shale oil's marketing potential because of uncertainty over future prices for OPEC crude. The recovery cost of most world oil is unquestionably far lower than that of shale oil, and will remain so over the life of a first-generation shale oil facility. Oil price increases have begun to make shale oil very attractive. However, since these prices are, in part, set by a cartel and bear little relation to the cost of production, there is no certainty that they will continue to rise in real terms. *

Commercial shale oil facilities producing 50,000 bbl/d require investments of around $1.5 billion (third quarter 1979 dollars). In order to recoup this investment, they will have to function profitably for 10 to 15 years. Given the 4 or 5 years such plants take to become operational, it is clear that even the largest private developers would want to be confident about the trend of international prices over the next 15 years in order to undertake commercial operations.

Institutional uncertainties occur because all technologies and economic activities take place within an institutional context that can act to facilitate or impede their commercialization. The extent to which this happens depends on the extent to which the technology and its costs create conflicts over basic values or the use of scarce resources. At issue is whether the aggregate impact of Government policies such as leasing arrangements, taxes, incentives, and environmental regulations would be applied more or less favorably to oil shale development than they would be to other forms of energy. Clearly, Government policy does not treat all energy sources "neutrally."

*Many analysts believe that the OPEC cartel has lost much of its power to set prices and that OPEC price decisions are now following rather than preceding market trends. Recent evidence of market prices rising above OPEC-established prices supports this belief. So does the outcome of the December 1979 OPEC meetings,

Although not as severe as the polarization that has been taking place over nuclear power, the debate over the development of oil shale and other synthetic fuels is significant. Proponents of solar power and conservation continue to oppose fossil-based synthetic fuels because their development supposedly diverts funds from the pursuit of "soft" energy strategies and discourages conservation. Environmental groups oppose development because of the possible deleterious effects on air, water, and land. Fiscal conservatives oppose Federal intervention on the grounds that Government money should not be used to subsidize private development. Although it has been argued that the populace of the oil shale region is generally in favor of development, local communities are concerned about the impact that these facilities might have on their quality of life and the local environment.

Developers believe, virtually without exception, that delays and costs associated with the permitting process are a major disincentive to oil shale investment. They argue further that the possibility of new or more strict regulations in the future is a severe impediment to development. The imposition of new regulatory rules or standards after a plant is in construction or operation could require extensive and costly modification of the facility's design or operation. These expenses could seriously harm a project's economics, and in extreme cases force the suspension of operations. The need to compensate for significant regulatory risks and disincentives is one of the primary arguments used to justify Federal subsidies.

To understand the prospects for successful commercialization, it should be recognized that many of the technical, economic, and institutional impediments are interdependent. In general, the potential for successful commercialization is limited by the margins available to accommodate a technology to these impediments without encountering barriers. Thus, if the relative economic advantage of a process is very large, then extensive adjustments to environmental standards can be made without reaching an economic barrier. When a process has relatively low technical performance requirements, it may be possible to reduce economic or institutional barriers by upgrading technical performance. However, if technical performance goals are high, production costs are close to or exceed the selling price for competitive products, and institutional barriers are restrictive, then the technology will encounter serious difficulties. Under these conditions, the usual response of industry would be to postpone commercial commitment while waiting for technical improvements, reduced institutional barriers, or improved market prices for the product.

Technical problems can be reduced through further R&D. Economic uncertainty can be averted through some form of subsidy. Institutional barriers can be minimized through altering administrative or regulatory rules and timetables.

Although other considerations are extremely important (e.g., overall cost to the Government, financial exposure, and administrative burden), the risks presented in commercializing a particular industry must be seen, at least in part, from the point of view of present and potential developers. The success of any Government program to stimulate the commercialization of a new technology depends, to a large degree, on the extent to which the policy incorporates the developers own perceptions of the risks, benefits, and uncertainties associated with production.

Surface oil shale technologies are comparatively well-understood with only a few remaining technical uncertainties. They are, in fact, very much the same today as they were 20 years ago, and present little room in which to maneuver with respect to changing their scale of operations or improving their performance. For example, there is apparently no alternative to large-scale mining and the disposal of sizable quantities of spent shale. In real terms, these technologies are unlikely to become significantly less costly than they are now. Thus, the possibility of technical tradeoffs from the technology itself is reduced, and the improvement of overall commercial prospects must come through the reduction of economic and institutional barriers.

Risks, Uncertainties, and Impediments Associated With Oil Shale Development

The commercialization of oil shale faces three primary economic risks and uncertainties:

- the uncertainty over the costs of building and operating commercial facilities;
- the risk of unfavorable recovery-cost differentials relative to conventional crude (except possibly those from such frontier areas as Outer Continental Shelf development); and
- the uncertain future selling prices of world oil.

These are compounded by the partial connection between the costs of oil shale facilities and the rising price of energy,

There are three additional uncertainties related to the carrying capacity and response of the institutional systems within which the oil shale industry operates that could seriously affect the economics of the industry. They are:

- the possibility (under conditions of rapid large-scale deployment) of bottlenecks and shortages of equipment, architectural and engineering construction capacity, and trained manpower for constructing and operating facilities;
- the possible scarcity of available and reasonably priced investment capital during the period of construction; and

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- the potentially unfavorable effects of present or future Federal and State regulatory policies on commercial development.

Plant Capital Cost Estimates

A 50,000-bbl/d oil shale facility would require a capital investment of around $1.5 billion in 1979 dollars. Operating costs are estimated by industry at $8 to $13/bbl of crude shale oil processed, exclusive of capital recovery. Such an investment would be undertaken cautiously even if the estimates of capital and operating costs for oil shale plants were known to be accurate. However, during the past 10 years, capital cost estimates have increased much more rapidly than has the general rate of inflation, and still do not appear to be totally reliable. The experience of Colony Development is illustrative but not exceptional. Its direct capital cost estimates for a 43,000-bbl/d facility increased from $225 million in 1972 to $1.3 billion in early 1979, and were $1.7 billion in February 1980. (See table 22.)

Cost escalations of this magnitude are not unusual for large, capital-intensive facilities involving complex novel technologies. As demonstrated by experience with light water reactors, many coal gasification plants, Canadian tar sands, and various weapons systems, cost estimates are likely to rise rapidly as a process advances from initial to definitive engineering designs. Also, as with similar projects, oil shale development is highly vulnerable to changes in the cost of capital and labor. These costs have increased more rapidly in recent years than the composite rate of inflation. In addition, oil shale development will be particularly subject to regulatory requirements, permitting procedures, and possible environmental litigation that could delay or arrest construction and substantially add to costs.

A number of hypotheses have been offered to explain these cost estimate increases. Some argue that since the historically most accurate method of estimating the price of shale oil is simply to add $5 to the price of imported oil, oil shale companies are exaggerating their costs in order either to prepare the market for high selling prices or to get large governmental subsidies. This charge has its basis in the observation that the rise in shale oil cost estimates has paralleled foreign oil prices, and seems to increase each time the Government gives serious consideration to industry subsidies, Neither this nor any other investigation has produced evidence that cost increases are contrived, Most of the variations in cost increases and estimated prices for oil shale can be explained by examining four significant variables:

- increases in the general rate of inflation,
- escalations in the real costs of plant construction.

Table 22.–Cost Estimates for Oil Shale Processing Plants[a]

Time of estimate	Estimated cost $ million	Data source	Scope and detail of estimate
1968	$ 138	Department of the Interior	Initial
1968	144	The 011 Shale Corp	Initial
1970	250	National Petroleum Council	Initial
1973	280	Department of the Interior	Initial
1973	250-300	Colony Development Operation	Initial
Early 1974	400-500	Colony Development Operation	Detailed (early version)
Late 1974	850-900	Colony Development Operation	Detailed
1976	960	The Oil Shale Corp.	Update
1977	1,050	The Oil Shale Corp.	Update
1979	1,350	OTA	Update
1980	1,700	The 011 Shale Corp.	Update

[a]Plants use underground mining and above-ground retorting to produce approximately 50000 bbl/d Of shale 011 syncrude

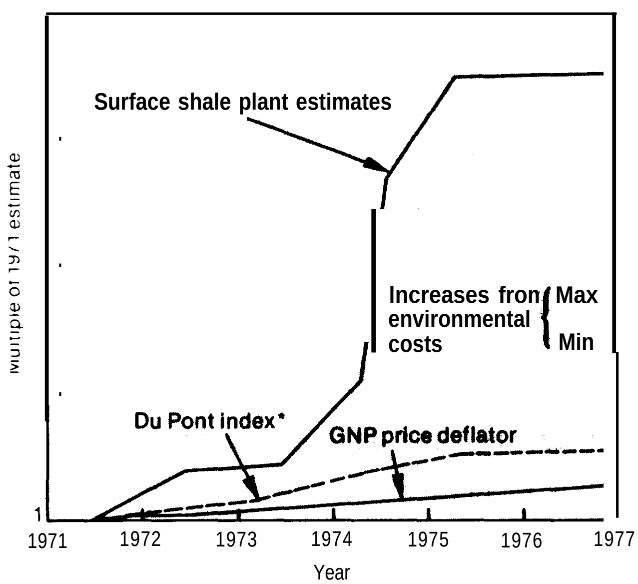
SOURCE Office of Technology Assessment

- more stringent environmental standards for oil shale operations, and
- increases in estimates as a consequence of more complete and detailed knowledge of a facility's actual design,

Increases in the General Rate of Inflation

Many developers believe that chronic inflation during the last 10 years has been the primary cause of the exceptional cost escalations. Although inflation rates were very high between 1972 and 1976, this view is apparently incorrect. For oil shale developers facing nominal rather than adjusted real prices, the overall impact of dollar inflation would appear quite large. The rate of general price inflation also tends to drive up the interest rates on construction loans. However, as shown in figure 51, during the period from 1972 to 1977, not more than 12 percent or approximately $100 million of the cost estimate increases were due to changes in the general price index. The rate of general inflation is important because of the way it affects the perceptions of developers. The factors that influence relative price changes are, however, considerably more significant.

Figure 51 .—Increases in Capital Cost Estimates



*Dupont index This index gives the gradient of change for Industrial process plant costs Although not entirely appropriate for 011 shale plants, it is the best available index However it probably somewhat understates plant cost escalations

SOURCE Edward W Merrow *Constraints on the Commercialization of Oil Shale* 2293 DOE September 1978

Escalations of Plant Costs

Large plants are vulnerable during periods of extreme inflation when the demand for necessary equipment and services rises sharply relative to their supply. Such a period existed in 1974. From mid-1973 to 1975 the general price index increased in excess of 20 percent, but chemical industry equipment increased by approximately 70 percent, and certain key items such as compressors and heat exchangers increased by almost 100 percent. It was during this period that the cost estimate for the Colony oil shale plant approximately doubled.

The effects of severe sectoral inflation on project costs are even greater than those suggested by the above numbers, which are based on list prices that are often discounted. Discounts are eliminated as industry inflation accelerates.

In a crash program for synthetic fuels, there will almost certainly be real cost escalations and overruns. The first few plants committed could contract for a significant part of the available U.S. manufacturing capacity for key items such as valves, pumps, compressors, and pressure vessels. As additional plants reach the procurement stage, equipment suppliers would be forced to quote longer and longer delivery times. These entail higher price contingencies for contractors to cover unknown increases in supplier costs, and can have a devastating impact on large capital projects. Almost half the total per-barrel cost of synthetic fuels is estimated to be solely the carrying cost of the capital investment. project owners will, therefore, be willing to bid up the prices for essential equipment in order to save time. A single week's delay could increase costs by millions of dollars.

Because of the potential for extreme sectoral inflation, costs could increase dramatically in a crash program. Building 20 plants could cost considerably more than twice the cost of building 10 plants. Any savings in design costs by building duplicate plants would be wiped out by cost increases. Plant construction costs during an all-out crash program are likely to increase in real terms by 50 percent or more.[3]

Increases Due to Environmental Regulations

The environmental legislation passed during the late 1960's and early 1970's, along with the provision of substantial enforcement power to the Environmental Protection Agency, altered the context in which large-scale industrial development may now take place. Without question, this legislation, which has been paralleled by similar State laws, has been and will continue to be very costly to industry. It is not possible, however, to accurately ascertain what the actual costs of meeting these standards are, because the costs are both direct and indirect. Most estimates usually include only the former cost category. Cost estimates for meeting some of the standards are discussed in detail in chapter 8.

In 1978, the RAND Corp. estimated that the direct costs of pollution control technologies for oil shale developers ranged between 6.5 and 15 percent of total capital costs. These were primarily for eliminating hydrocarbons, particulate, and hydrogen sulfide from the retorting process, and for dust control and spent shale disposal. By assuming a zero value for environmental costs in 1971, RAND goes on to estimate that between 8 and 20 percent of the increases in estimated capital costs or $65 million to $165 million between 1971 and 1978 were caused by environmental factors.

These estimates do not include the possible indirect environmental costs that might occur because of:

- necessary siting changes,
- alterations of mining plans,
- disruption of construction schedules,
- less efficient facility operation, and
- costs of potential litigation.

Each of the above can have enormous impacts on plant economics; delays occurring late in the construction stage are particularly costly. A 6-month delay in the middle of construction could add more than $100 million to costs. Additional environmental equipment can substantially reduce reliability and the on-stream factor, * if operations must cease when environmental equipment fails. A reduction in the on-stream factor of 5 percent will increase the required selling price of the product by 7 percent. A construction delay such as might be caused by environmental litigation can be extremely costly after ground has been broken. The costly delays and disruptions described here will probably characterize only a fraction of the projects undertaken. Nevertheless, they constitute a significant risk that must be included by developers in their contingency plans.

Environmental regulations add to developers' estimates of uncertainty and risk. The uncertainty is over how present regulations will be interpreted, administered, and enforced; and the risk derives from the possibility of future regulations. Rather than making an attempt to predict with some degree of accuracy what might be the indirect effects of environmental standards on plant economics, developers have increased the size of their estimates as a hedge against uncertainty, based on their informal sense of general risk. Although environmental regulations have significantly augmented industry's capital cost estimates, they nonetheless are responsible for less than than 20 percent of the overall cost estimate escalations since 1971.

The Learning Curve for New Plant Design

The escalations due to improved knowledge about costs, as a consequence of more complete engineering designs, appear to be responsible for the largest increases in capi-

*The on-stream factor is the proportion of operating days per year.

tal cost estimates. Between 40 and 50 percent of the estimated increases between 1971 and 1977 were of this kind.

Forecasting the costs of constructing a commercial facility for a new technology is normally based on a series of engineering design estimates, each of which is presumably more detailed and accurate than the previous one. There are four types of such estimates. They start with initial estimates, which are “back of the envelope” predictions that give only a rough indication of eventual costs; proceed through the preliminary design estimate in which the plant’s subsystem flows are defined, but component subprocesses are not defined; continue with the detailed design in which estimates are prepared for specific materials and components; and end with the final design estimate in which precise costs for all materials, components, and labor are pulled together. The final design estimate should accurately locate the cost of immediate construction to between plus or minus [usually plus) 15 percent of the eventual cost.

The cost of preparing a final engineering design estimate for a commercial-size oil shale facility is between $12 million and $20 million. To date, only detailed design estimates have actually been carried out. The intention of this iterative estimation process is to provide continually better design forecasts based on continually more precise technical data derived from increasingly larger developmental tests, As the designs become more complete and the technical data improve, the costs become clearer.

The cost estimate escalations that took place between 1973 and 1976 occurred, in part, because prior to the middle of 1974, no final or detailed engineering design estimates had ever been prepared. Colony Oil Shale Development Corp. ’s detailed design estimate represented an 80-percent increase over the preliminary design estimate made 10 months earlier. The subsequent experience of other developers with their more detailed designs was similar,

Cost estimation increases are by no means limited to oil shale facilities. Similar increases have characterized the development of coal gasification, coal liquefaction, Canadian tar sands, light water nuclear reactors, and a variety of new weapons systems. However, several characteristics of oil shale plants present particular design and estimation problems. First, such plants are highly site specific. The costs of transporting, mining, handling, and disposing of shale all depend on the nature of a site’s topography, geology, and surrounding terrain. Second, the estimation of oil shale plant costs requires an array of engineering, architectural, economic, and technical skills possessed by only a few architectural and engineering firms.

The reliability, or on-stream factor, for the plant after it is constructed, figures significantly in the eventual cost of production. Cost estimates compute the cost of building the plant, and then assume that it will be on-stream about 90 percent of the time. There is a high probability, however, that pioneer plants will not operate as planned for some time, or until such time as additional investments are made to correct their problems. For this reason, companies tend to build only those designs that are known to work, even though new but untried approaches may promise appreciable savings.

As technical data improve and developers complete more detailed design estimates, the gradient for real cost escalations will level off. It is probable, but not certain, that current cost estimates are fairly realistic and that there will be no further substantial increases, other than normal inflation. However, no commercial-sized facilities have been built, and cost estimates are unlikely to become stabilized without industry experience in constructing and operating such facilities.

Uncertain Future Prices of World Crude

The market price of premium grades of conventional crude oil is a major determinant of the highest possible profitable selling prices for syncrude from shale. Therefore, present and future prices for conventional crude are among the basic factors that will condition the economic viability of the oil shale industry. A developer who commits $1.4 billion to $1. i' billion to a shale oil plant with a very long payback period must be reasonably confident that the market value of the product will exceed its production costs. Uncertain future prices of international oil prevent firms from accurately predicting market values for shale oil. Since the Arab oil embargo of 1973-74, the actions of the OPEC cartel and high international demand have pushed the price of world oil far above recovery costs.

Between September of 1979 and February of 1980 the prices of world oil increased by over 30 percent. In March of 1980, the posted prices of the premium grades of conventional crude (the counterpart of upgraded shale oil) stood between $34 and $38/bbl. Their spot-market prices (e.g., for Wyoming Sweet and the best grades of Nigerian and North African oil) are currently between $40 and $52/bbl. Sweet crude oils were recently sold from the Elk Hills and Teapot Dome Petroleum Reserves for $43 and $50/bbl respectively. These increases, along with the probability of further escalations in the future, have substantially improved shale oil's economic attractiveness. The future viability of shale oil is predicated on the assumption that increases in its production costs will lag behind the rising price of world market crude. On the basis of the best current capital and operating cost estimates (compiled between November of 1979 and February of 1980), it appears that shale oil may have reached parity with conventional oil without subsidy. However, this conclusion is subject to several critical limitations.

First, this finding assumes that current capital and operating cost estimates are, in real dollar terms, within 20 percent of being accurate. Given that such projects have never been previously undertaken, still lack final engineering design estimates, and are prone to possibly severe inflation because of associated heavy equipment costs, this may be a very risky assumption.

Second, most analysts expect international oil prices to increase by 3 or 4 percent per year, over and above inflation. This will mean that the price of oil will double, in real terms, by 2000. However, because international oil prices are still set, in part, by a cartel, the future of the market cannot be predicted with any certainty. Increasing or continued high demand, decreasing world reserves, and OPEC or producer-state governmental policies directed at conserving their reserves through price rationing could result in sustained price inflation for imported oil. On the other hand, prolonged recession in the industrial West or reduced international demand could limit oil price increases in the future. Recent events strongly indicate that OPEC's capacity to set international oil prices has been substantially weakened. Nevertheless, the play of market forces is still likely to maintain upward pressure on prices. In any event, future incremental price increases are not likely to be regular. Instead, temporary periods of oversupply and soft markets are likely to alternate with shortfalls and high demand. Therefore, short periods of stable prices will probably alternate with rapid price increases.

Finally, the question of whether present and future oil prices will allow profitable selling prices for shale oil without subsidy depends on the discount rate that firms are assumed to require in order to undertake development. The average real aftertax returns on investment of U.S. industrial firms is generally between 6 and 10 percent. Given the risks associated with a pioneering industry, oil shale developers will require a larger profit than that obtained from less risky projects. Industry sources generally maintain that this would mean a real aftertax expected profit of between 12 and 15 percent. Break-even selling prices for shale oil are extremely sensitive to the discount rate, which at 12 percent would make shale oil competitive with conventional petroleum according to OTA's analysis. However, if developers require a is-percent rate of return to undertake investment, then subsidies will probably still be necessary.

Choosing Goals for Oil Shale Development

The Federal Government has a variety of options available to stimulate oil shale development. In order of increasing Government involvement, these include:

- continuing present policies and providing no additional incentives;
- encouraging precommercial modular plants;
- building and operating a number of Government-owned modules;
- encouraging a few commercial-sized plants; and
- deploying a major industry.

Each option differs with respect to the cost to the Treasury, the level of shale oil production, the risks of cost overruns and inefficiency, and the impacts on the physical and social environments. They also vary with respect to the extent and types of financial incentives that would be most effective.

There are two major policy goals to be met by an oil shale industry. One is to deploy enough production capacity to answer the remaining uncertainties related to economic and technological feasibility and environmental impacts, The other is to quickly displace foreign oil imports.

Information Base Goal

Because no oil shale process has as yet been commercialized, the economics, technical operability, and environmental impacts of each of the processes are still not fully known. If the most promising processes were operated at either the precommercial modular scale or at commercial capacity many questions could be answered and comparisons among the various processes would be possible, Operating experience could be acquired by providing incentives to industry, by operation of Government-controlled modular test facilities, or through some combination of both. A1though some questions could be answered by research, a moderate development and production program would reliably answer most of the remaining technical, economic, and environmental questions. It would also facilitate the selection of the most feasible oil shale and synthetic fuel technologies available today; provide information for rational decisions regarding oil shale commercialization; and put the United States several years closer to full-scale production capacity.

A modest program for stimulating the construction of a limited number of commercial or modular facilities would be less likely to fail, Such a strategy reserves judgment concerning the ultimate extent of development until the processes have been tested. This has the advantage of allowing policymakers to evaluate commercial results and consider alternatives for further reduction of oil imports prior to contracting for additional facilities, and should improve the chances of ultimately establishing a self-sufficient oil shale industry. It should be noted, however, that the information base strategy tends to ignore the fact that technology is not static but is continually changing, By gathering data on "today's" processes, this approach may ignore possible (probable) future process developments. It is possible that complete information could be obtained on several processes in the next 10 years only to discover that a new process may be more productive. Should policy be to repeat the cycle and obtain more information, or to build the obsolete plant? From an economic standpoint the choice is not a simple one.

In the absence of time limitations, the overdemand for scarce capacity in construction companies, in skilled labor, in plant materials, and in architectural engineering firms would be reduced or even avoided. When these are placed in short supply, costs escalate, the quality of design is lowered, and fewer plants may be constructed.

ICF in a recent study for the Budget Committee of the U.S. Senate[4] summarized the benefits of proceeding with development in a two-phased strategy by maintaining that such an approach would:

- be an effective symbolic action showing the seriousness with which the United States intends to reduce energy imports;
- provide the opportunity through follow-on stages of development to reduce energy imports directly through shale oil production, while maintaining the option to consider more cost-effective ways of import reduction; and
- provide the flexibility that has been found to be critical in advancing new technologies to a commercially viable stage.

An information base strategy initially followed by review and possible subsequent additions, as discussed in this chapter, has also been suggested by the RAND Corp., ICF, Cameron Engineers, Booz-Allen, and the Congressional Budget Office. It assumes that the principal goals are to create a viable industry, minimize the cost to the taxpayer, and maximize the efficient use of capital.

If, however, the primary goal is to reduce dependence on foreign oil by 1990, then the extensive development of a large oil shale industry might be more advisable. Economic analysts have examined whether producing additional oil shale (or other synthetic fuels) is more cost-effective than alternative approaches such as conservation. Their analyses depend on the assumption that the desirability of synthetic fuels is chiefly a matter of price rather than availability. Another OPEC oil embargo could change this assumption.

Foreign Oil Displacement Goal

If present trends continue, the United States could import around 12 million bbl/d of oil by 1990. It is beyond the scope of this report to examine whether this import dependence could be reduced to the President's target of 8.5 million bbl/d through conservation, synfuel production, and conversion from oil to coal. To estimate the desirability of the contribution that shale oil could make to reducing import reliance requires examining: 1) how cost-effective shale oil development is compared with other energy strategies in achieving import reductions; 2) whether the costs and risks of a crash program to develop a large industry outweigh its potential benefits and whether such a program would achieve its production goals; and 3) if a rapid development strategy would have unacceptable environmental costs.

Establishing a large industry to replace foreign oil would have both positive and negative effects. On the positive side, the economy and national security would benefit from a reduction in oil imports; and in the oil shale region, employment would rise and an increased tax base would provide revenues for community development. On the negative side, such a program would be extremely costly. It would necessitate investing in numerous plants, each with a capital cost of around $1.5 billion. Technologically inferior processes might be used because of insufficient time for supporting technical R&D, and the accelerated construction schedule could lead to cost overruns and managerial inefficiency. (The use of a "technologically inferior" process could, however, be compensated by the inflation savings; a better process built 10 years later would probably cost much more in real terms because of inflation of plant costs.) Capital availability for other economic sectors could be restricted. It is also questionable that mining and processing equipment could be supplied within the construction time frame. Furthermore, it is possible that the lack of supporting environmental R&D could lead to a conflict with environmental standards. On balance, the socioeconomic effects could well be more negative than positive.

There is general agreement among the engineering and construction firms contacted by OTA that a program to establish a large oil shale industry (over 500,000 bbl/d by 1990) would entail sizable cost overruns because of high inflation in critical supply industries. It would also impose severe time constraints on a developer's operations. Contractual agreements for these facilities would have to begin immediately and continue under conditions of tight scheduling for the next 8 to 12 years. Various studies of the consequences of Federal funding to stimulate the commercial adoption of new technologies, including the 1976 study by the RAND Corp.,[5] report that subjection to severe time constraints has rarely resulted in the establishment of a viable industry. Furthermore, a rapid development effort would probably require the commercial operation of facilities before the technologies and their economics were fully understood.

A major Government effort to establish an industry based on a new technology under time constraints does not allow sufficient time to review progress, make cost-benefit tradeoffs, and modify plans in response to new knowledge, When a pressing national emergency requires a crash program, the resultant inefficiencies entailed by these restrictions may be justified. However, when the primary purpose is to establish a self-sufficient industry, crash programs should be avoided.

A Comparison of Alternative Financial Incentives

Before oil from domestic shale can significantly supplant imported supplies, any development program must take into account the major technological, environmental/regulatory, and economic uncertainties that discourage private firms from undertaking such investments. To overcome these uncertainties, Congress is contemplating implementing an incentive program that would share in the risks or subsidize the economics of oil shale development. In evaluating alternative incentives and their probable effects on oil shale development, the reactions and preferences of developers must be taken into consideration.

In conducting this analysis, 10 alternative incentive structures were examined:

- Construction grant. The Government provides a direct grant to cover a prespecified percentage of total construction costs, both a 50- and 33-percent construction grant were analyzed.
- Production tax credit. The developer receives a tax credit for each barrel of shale oil produced, a $3/bbl credit computed on shale oil prior to upgrading was analyzed.
- Low-interest loan. The Government lends the developer a prespecified percentage of capital costs at an interest rate below the prevailing market rate; the analysis assumed 70-percent Government financing at 3 percentage points below the market rate.
- Price support. With this incentive, the Government guarantees the developer a certain price for shale oil; the analysis assumed $55/bbl of hydrogen-upgraded syncrude (hydrotreated shale oil). If the market price for the product falls below the guaranteed price, the Government would make up the difference.
- Purchase agreement. The developer contracts with the Government to sell shale oil at a price higher than the prevailing market price; the analysis assumed a price of $55/bbl of upgraded product.
- Increased depletion allowance. The developer is allowed to claim a 27-percent depletion allowance (at present it is 15 percent).
- Increased investment tax credit. The developer can claim an additional investment tax credit of 10 percent,
- Accelerated depreciation. The firm is allowed to depreciate its investment over 5 years.
- Loan guarantee. The Government would agree to pay off a loan in the event that the firm defaults on its loan: the firm would typically receive a lower interest rate than that prevailing in capital markets.
- Government participation. The Government would become an equity participant in an oil shale project.

To evaluate how effectively the different incentives will promote the development of a viable oil shale industry, each was analyzed in relation to three fundamental objectives of the congressional incentive program. * These objectives are:

- Subsidizing the economics of shale oil production. The mechanism by which each incentive affects the perceived economics of oil shale development and how well it functions as a subsidy was analyzed.
- Sharing in project risks. The extent to which each incentive allows the Government to share in the risks of oil shale development, and the extent to which it reduces the variance of the present value of the aftertax income from a project was analyzed. To conduct this analysis, a project risk was assigned for four specific categories: the risk of unsuccessful project completion, which stems largely from technological and regulatory uncertainties; the risk associated with uncertain investment costs; the risk associated with uncertain operating costs; and the risk associated with uncertain future prices for oil from shale.
- Facilitating access to capital. The extent to which each incentive would sufficiently induce capital markets to lend the large sums of money that will be required to develop an oil shale industry was examined. This consideration is particularly important for understanding which types of firms would benefit from specific incentives (i.e., whether an incentive will benefit less well-capitalized firms or those with limited ability to incur debt).

Once it was determined how well each incentive met each of the program's objectives, it was examined in the context of two important policy guidelines:

- Efficient use of the Nation economic resources. To make efficient investment decisions,** oil shale developers should pay the same prices for resources (i.e., land, labor, capital, and materials) that are paid by firms engaged in other production activities in the general economy (i.e., the prices paid should equal the value of these resources in alternative uses). Similarly, the price received for the shale oil by producers should equal its value to the economy. This will be the marginal price of crude oil, because upgraded shale oil and crude oil are almost equally substitutable. Therefore, OTA analyzed the extent, if any, to which each incentive would interfere with developers' perceptions of the market prices of the productive resources consumed in shale oil production or the market price for the final product.
- Minimal administrative burden. The cost of administering an incentive program represents a loss to the economy that falls on the public and private sectors alike. In addition, the administrative burden affects the time required to implement a program as well as its overall effectiveness. Therefore, OTA analyzed the administrative requirements for each of the incentives.

Finally, the analysis was structured to assist Congress in developing an incentive program to meet a third policy guideline: to promote a healthy state of competition in the industry, Because of the potential multiplicity of objectives for an incentive program, and the variety of types of firms involved, it is probably necessary that the incentive program consist of a package of incentives. This should allow firms in differing financial, technical, and tax circumstances all to benefit.

To clarify the competitive implications of a program consisting of a combination of incentives, the kinds of firms that would most benefit from each incentive were identified based on the analyses of the incentives, a review of industry statements, and discussions with industry representatives. Specific examples of firm preferences for the different incentives have been documented. The effects of the various incentives on the program objectives and the policy guidelines are sum-

*Congress, before designing an incentive program, should specify the relative emphasis to be placed on each objective.

**This definition of efficiency is in the somewhat narrower sense of its use in economics.

marized in table 23. The rank-order preferences of different shale oil developers for the various financial incentives are summarized in table 24. In order to make a comparison of the incentives and evaluate their contributions to the objectives of the total program and the policy guidelines, a computerized simulation model developed by Professors Wallace Tyner (Purdue University) and Robert Kalter (Cornell University]" was used to test and measure each of them against the case in which no incentive is offered. The present calculations with the Kalter-Tyner model were prepared for OTA by Resource Planning Associates, Washington, D.C. A complete description of the simulation model, its capabilities, limitations, and how it was employed can be found in appendix B. Using the model, it was possible to estimate the following four variables (for all but the production tax credit and loan incentives):

- Expected profit. Expected economic profit is defined as expected return in excess of a company's minimum required aftertax return on its oil shale investment. * OTA calculated both expected profit and the change in expected profit relative to the no-incentive case.
- Risk. The risk of the investment refers both to the probability of the investment resulting in an economic loss (i. e., earning less than the minimum required rate of return), and to the degree of variation in possible profit outcomes, OTA measured this variation in absolute terms (i.e., the ratio of change in expected profit to standard deviation of expected profits).
- Breakeven price. The breakeven price is the constant price for hydrotreated** shale oil at which it would just earn its minimum required rate of return.
- Cost to the Government. The expected cost to the Government of providing the incentive is the gross subsidy to the firm less increased tax payments to the Government. * An incentive increases tax receipts if the present value of the tax payments is larger with the incentive than if an equal investment was made without the incentive. OTA estimated both the actual cost to the Government and the ratio of the change in expected profit to cost.

With these computations, the way in which a firm's marginal tax rate** (and, for a low-interest loan, its cost of borrowed funds) influenced expected profits was assessed, and the sensitivity of expected profits to different discount rates (defined as the minimum rate of return necessary to induce private development) was determined,

The numerical results of this analysis, which are summarized in tables 25 and 26, were calculated using the best available data for the cost of commercial oil shale facilities. They thus provide a reasonable approximation of the magnitude of the probable effects of each of the incentives. While these outcomes would not be expected for the operation of an actual facility, they would be for the average operations of a number of facilities. Because of the uncertainties inherent in the estimation, the most useful application of these quantitative results is for establishing comparisons among the incentives.

Congress is currently considering 10 major kinds of incentives to be included in a domestic oil shale development program. The analysis of the specific effects of each of these on the three program objectives and the three policy guidelines is summarized below. The discussion also includes a quantitative evacuation of the impact on expected profits, on

*Profit was measured as the sum of each year's cash flows, discounted using the company's minimum required aftertax rate of return as a discount rate (see app. B).

**In hydrotreatment the physical properties of raw shale oil are improved by adding hydrogen and removing nitrogen and sulfur. The product is often referred to as syncrude.

*Government cost was calculated in present value terms as was private profit. Net cost for each year (i. e., subsidy less increased tax revenues) was discounted at the Government's discount rate (assumed to be 10 percent in real terms). The resulting present value calculations were summed for all years.

**The marginal tax rate is the rate at which income from an additional investment (e. g., an oil shale facility) is taxed by the Government. For most firms, this is 46 percent. However, a firm with excess tax deductions or credits from other operations would apply the excess to the oil shale investment, thereby reducing its marginal tax rate.

Table 23.–Evaluation of Potential Financial Incentives for Oil Shale Development

	Effect of incentive on program objectives			Extent to which incentive meets policy guidelines			
						Promotion of competition	
Incentive	Subsidy effect	Risk-sharmg effect	Financing effect	Promotion of economic efficiency	Minimization of administrative burden	Effect on firms	Firm preferences
1 Production tax credit ($3/bbl)	Strong, subsidizes product price	Moderate, shares risk associated with price uncertainty (If tax credit varies with product price)	Slight, improves project economics	Slight adverse effect, distorts product price	Minimal administrative burden	Benefits firms with large tax liability and strong financial capability	Supported by relatively large firms
2 Investment tax credit (additional lo%)	Strong, subsidizes investment cost	Moderate: shares risk associated with Investment cost uncertainty	Slight, Improves project economics	Moderate adverse effect; distorts input costs, favors capital-intensive technologies	Minimal administrative burden	Benefits firms with large tax liability and strong financial capability	Supported very strongly by most firms; however, firms that would not be able to use the investment tax credit do not favor its enactment
3. Price supper	Strong, subsidizes product price (If contract price is higher than market price)	Moderate; shares risk associated with price uncertainty	Moderate; improves borrowing capability	Slight adverse effect, distorts product price	Moderate administrative burden	Benefits all firms except those with very weak financial capability	Moderately supported by a wide range of firms
4 Loan guarantee	Slight, subsidizes Investment cost	Moderate, shares risk of project failure	Strong; improves borrowing capability	Slight adverse effect; distorts input costs: favors capital-Intenswe technologies	Moderate administrative burden	Benefits firms with weak financial capability	Supported by firms with limited debt capacity
5 Subsidized Interest loan (70% debt at 3% below market rate)	Slight; subsidizes Investment cost	Moderate: shares risk of project failure	Strong, Government provides capital	Slight adverse effect; distorts input costs, favors capital-intensive technologies	Moderate administrative burden	Benefits firms with weak financial capability	Supported by firms with limited debt capacity
6. Purchase agreements	Strong, but less than price supports	Strong: shares risk of price uncertainty	Moderate; improves financial capability	Slight adverse effect, distorts product price supports)	Moderate (normally more than price supports)	Benefits all birms but those with very weak financial capability	Moderate, but less than for price supports
7. Block grant (33 & 50% of plant cost)	Strong, neutral subsidy	None	Strong; Government provides capital	No adverse effect	Moderate administrative burden	Benefits all firms	Supported by firms in widely varying financial circumstances
8. Government participation	Slight	Strong, shares all project risks	Moderate, reduces firm's capital requirement	No adverse effect on firm decisions; however, active Government Involvement may lead to inefficiency	Major adminstrative burden	Benefits firms that are very averse to risk (e. g., smaller, less well-financed firms)	Little support
9 Accelerated depredation (5 years)	Moderate, subsidizes Investment cost, maximum subsidy effeet is limited by Federal corporate income tax rate and interaction with the depletion allowance	Moderate, shares risk associated with Investment cost uncertainty	Slight, improves project economics	Moderate adverse effect, distorts input costs, favors capital-Intenswe technologies	Minimal administrative burden	Benefits firms with large tax liabilities and strong financial capability	Supported by large, integrated oil companies
10 Percentage depletion allowance (27%)	Moderate, subsidizes product price, value of subsidy Increases as the need for the subsidy decreases	None, Increases risk associated with price uncertainty	Slight, improves project economics	Moderate adverse effect, distorts product price in a variable and undesirable manner	Minimal administrative burden	Benefits firms with large tax liabilities and strong financial capability	Not supported

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Table 24. –Summary of Companies Ordinal Preferences for Incentives

Company	Produc - tion tax credit	invest - ment tax credit	Price guarantee/ purchase agreement	Loan guarantee	Low- Interest loan	Block grant	Accelerated depredation	Government participation	Liberalizing leasing and land management terms	Percentage depletion
Union 0il	2	1	3	4	4	—	—			.
Colony project										
Tosco	2	3	4	1	1		3	.	—	
ARCO	1	2	3	4	—	—	—	—		—
Superior	2	1	3	1	1		—	—	1	—
Occidental	2	4	3	1	1	—	—	—	—	
RIO Blanco project										
Gulf	1	2	3	—	—	3	2			—
Standard (Indiana)	4	2		5	5	3	1		—	—
SOHIO Natural Resources	4	5	3	2	2	1	—	1	—	—
EXXON	—	—	—	—	—	—	—	—	1	—
Standard (California)	3	1	4	—	—	—	2		—	—
Conoco	3	1	4	—		—	2	—	—	—

NOTE No company indicated any preference for the percentage dei)letlon Incentlve
Rank orcered by preference 1 = most preferred elc

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Table 25.–Subsidy Effect and Net Cost to the Government of Possible Oil Shale Incentives' (12-percent rate of return on invested capital[b])

Incentive	**Total expected profit**[c] (**$ million**)	Change in expected profit (**$** million)	Standard deviation[d] ($ million)	Ratio of change in expected profit to standard deviation	Probability of loss	**Breakeven price ($)**	Total expected cost to Government (**$** million)	Ratio of change in expected profit to Government cost
Construction grant (50%)	$707	$487	$205	2,4	0.00	$34.00	$494	98
Construction grant (33%)	542	321	210	1 5	0.00	38,70	327	98
Low-interest loan (700/0)	497	277	219	1 3	0 0 0	43.40	453	61
Production tax credit ($3)	414	194	219	0,9	001	42.60	252	77
Price support ($55)	363	42	171	0.8	001	NA	172	.83
Increased depletion allowance (27%)	360	40	247	0 5	0,05	45.70	197	71
Increased Investment tax credit (20%)	299	79	216	0.4	0.05	45.80	87	90
Accelerated depredation (5 years)	296	76	215	0 4	0,05	46.00	79	96
Purchase agreement ($55)	231	11	126	0 1	0,03	NA	0	NA
None	220	0	219	0.0	0.09	48.20	0	NA

[a] All monetary values are in constant 1 979 dollars
[b] With 12 percent annual inflation a 12 percent real discount rate is approximately a 24-percent nominal aftertax rate of return The calculations assume a $35/bbl Price for conventional Premium crude that escalates at a real rate of 3 percent per year Thus the predicted $48/bbl breakeven price for the 12-percent discount rate will be reached In 11 years or in the fifth year of production Therefore in narrow economic terms 011 shale plants starting construction now which assume a 12-percent discount rate will be profitable over the hfe of the project without subsidy (See discussion for caveats concerning this conclusion) The calculations are for a 50 000-bbl d plant costing $1 7 billion
[c] Expected profit is the return in excess of a 12 percent discounted cash flow rate of return on investment
[d] Standard deviation is a measure of the dispersion of possible profit outcomes around expected profit

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firm risk reduction, on breakeven prices, and on the cost to the Government.

Production Tax Credit

In the 96th Congress (1979), the Senate Finance Committee approved a production tax credit for alternative forms of energy. Under this proposal, producers of shale oil would receive a $3/bbl credit on Federal income taxes. Projects operating after April 20, 1977, and in production between 1979 and 2000, would be eligible. The $3/bbl credit would be defined in real terms; that is, the credit would increase with inflation. This proposed credit will be phased out on a sliding scale as the price of imported oil increases.

Table 26.–Subsidy Effect and Net Cost to the Government of Possible Oil Shale Incentives' (I S-percent rate of return on invested capital[b])

Incentive	Total expected profit[c] ($ million)	Change in expected profit ($ million)	Standard deviation ($ million)	Ratio of change in expected profit to standard deviation	Probability of loss	Breakeven price ($)	Total expected cost to Government ($ million)	Ratio of change in expected profit to Government cost
Construction grant (50%) .	**$281**	$477	$135	3 5	0.00	$40.60	$494	96
Construction grant (33%)	**119**	315	140	2,2	0 1 9	47.70	327	96
Low-interest loan (70%)	**81**	277	153	1.8	0 2 3	54.70	453	61
Production tax credit ($3)	**-61**	135	153	0,9	0 6 3	58.30	252	.54
Price support ($55). ., ...	**-88**	108	122	0 9	0.77	NA	172	63
Increased depletion allowance (27%) .	-110	86	170	0.5	0,75	57.20	197	44
Increased Investment tax credit (20%),	**-131**	65	150	0,4	0.77	58.80	87	75
Accelerated deprecation (5 years) .	**-127**	69	149	0.5	0 7 6	58.90	79	87
Purchase agreement ($55).	**-150**	46	102	0,4	0 9 2	NA	0	NA
None. . . .,	**-196**	0	153	0.0	0.93	61.70	0	NA

[a]All monetar,values are in constant 1979 dollars
[b]With 12-percent annual inflation a 15-percent real discount rate is approximately a 27-percent nominal aftertax rate of return
[c]Expected profit is the return in excess Of a 15-percent discounted cashflow rate of return on investment
[d]Standard deviation is a measure of (he dispersion of possible profit outcomes around expected profit

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This tax credit will strongly subsidize the production of shale oil. By reducing a firm's tax liability, it effectively increases the unit product price by an amount equal to the tax credit per unit of production (i.e., per barrel) divided by 1 minus the firm's Federal corporate income tax rate. For example, if a company's tax rate is 46 percent, a $3/bbl credit becomes an effective price boost of $5.60. At current imported oil price averages of $35/bbl, the effective price with the credit would be $42.60. This price boost could substantially improve a project's economics by creating a higher aftertax cash flow throughout its producing life, and a higher return on investment.

Although the production tax credit does not share in the risks of project noncompletion or price and cost uncertainties, it would decrease the risk of incurring a loss by improving project economics. Therefore, it may slightly improve the ability of firms to acquire capital financing. However, this tax credit alone would not encourage financial institutions to lend to a financially less secure oil shale developer.

A production tax credit has a function similar to a price guarantee. Depending on lender expectations about investment and operating costs and the resultant project profitability, it may provide a sufficient asset base against which firms may borrow for project financing. However, it will not assist project financing as strongly as a purchase guarantee or a debt guarantee.

The production tax credit also can enhance economic efficiency, because it does not distort a firm's perception of the market prices for the economy's productive resources (i.e., land, labor, capital, and materials), that are consumed in development and production. Moreover, if subsidizing oil shale development meets national objectives, this tax credit with a sliding-scale phaseout can be used by firms as a baseline for making their decisions. To promote efficient investment and production decisions, the price subsidy afforded by the tax credit should reflect the premium society is willing to pay to encourage the development of oil shale resources.

Because it works through the existing tax framework, implementing a production tax credit should be relatively straightforward, necessitating little or no administrative overhead. The chief administrative policies would be to define a reference price for determining the value of the credit, to set an inflation adjustment formula, and to develop a mechanism for ensuring that firms accurately report the amount of shale oil produced. (However, reliance on tax-based incentives would tend to reduce the Government's control over production levels.)

Large, integrated oil companies will most readily benefit from this incentive (i.e., those firms having both a sufficient Federal income tax liability to use the credit and a strong ability to raise debt). Moreover, in trying to secure a competitive advantage in the oil shale development industry, those firms that have already undertaken investment in oil shale, and that can accept exposure to the risks of project noncompletion and investment and production cost uncertainties, may favor production tax credits over all other incentives,

The production tax credit is supported by most of the larger firms involved in oil shale activities. The Atlantic Richfield Co. (ARCO), Gulf, Union, and Occidental, all companies with current oil shale investments, rank it either first or second in their incentives preference lists. However, Standard of Indiana, which is Gulf's partner in Rio Blanco, ranks it last, preferring incentives that deal with the front-end investment uncertainties. Chevron, which is just starting its oil shale development activities, directly opposes it in favor of an investment tax credit that addresses the investment cost risks, which Chevron feels are considerable, (See table 24.)

In calculating the quantitative effect of this incentive, the unit value of the subsidy (established as $3/bbl of unrefined shale oil) was multiplied by the entire annual output; that product was then subtracted from the income tax obligation for each year of production. * The results indicate that the $3/bbl tax credit ranks fourth, behind the 50- and 33-percent construction grants and the low-interest loan, in its tendency to increase profitability and reduce the risk of loss. In addition, because obtaining the tax credit is simpler administratively than obtaining a grant, it might be preferred by some firms.

*In OTA's analysis, the tax credit was calculated on shale oil output prior to hydrotreating. Because of processing losses, the output of hydrotreated oil is 12 to 15 percent lower.

Expected Profit

In comparison with no incentive, the $3/bbl tax credit would increase the expected profit of the 50,000-bbl/d facility by $194 million. This increase was the fourth highest of the incentives tested. With the tax credit, the expected profit of such a facility would be $392 million, more than enough to induce its development. Moreover, this tax credit would retain its high ranking irrespective of a firm's marginal tax rate, unless it has excess tax credits (i. e., the tax credit expires before the firm has earned enough income to offset it). Although some firms might hold excess tax credits at the outset of production, few, if any, would hold them over the entire lifetime of a project, given the eventual large annual income that can be expected, Therefore, an excess credit situation would be likely to exist for no more than a few years of the tax credit's duration which could be short or long depending on the phase-out provisions.

The production tax credit is highly sensitive to the discount rate, however, because the subsidy is spread over a project's entire lifetime, In fact, over the range of rates tested, this incentive is one of the most sensitive to the discount rate: averaged over the discount rates, each percentage point drop in the discount rate resulted in a $20 million increase in expected profit.

Risk

Because the production tax credit does not reduce the variation in possible future prices and costs, it does not reduce the overall variation in possible profit outcomes. However, it significantly reduces financial risk because it boosts the expected profit. For this reason, the production tax credit ranks fourth behind both construction grants and the low-interest loan in reducing the probability of loss in the variation in profit relative to the change in expected profit.

Breakeven Price

In the absence of an incentive, the breakeven price was $48.20/bbl of hydrotreated product, with the production credit it was $5.60 less, or $42.60/bbl. This price ranks third behind the breakeven prices for 50- and 33-percent construction grants and the low-interest loans; nonetheless, it is still within the commercially feasible range, given the average discounted price of oil—$53.00/bbl—over the production period.

Cost to the Government

The cost to the Government is commensurate with the credit's strong effect on profitability. Overall, it is the fourth most costly incentive, ranking below the 33- and 50-percent construction grants and the low-interest loan. Moreover, the production tax credit is one of the least cost-effective (as measured by the ratio of change in expected profit to Government cost). It ranks below most of the other incentives, including construction grants. However, it offers two advantages over construction grants. First, the cost to the Government would be spread more evenly over time; the production tax credit would require about $49 million per year over a 20-year production lifetime, compared with $170 million per year over a 5-year construction period for the 50-percent grant. Second, it would be much easier to administer for both oil shale developers and the Government. Developers would simply file for the credit on their tax return, thus making the Government audit of production records straightforward.

Construction Grant

Under a construction grant program, the Government transfers a sum of money to a firm undertaking an oil shale development project. In return, the firm must only fulfill its obligation to undertake the project within some period of time. The size of the grant would be some prespecified fraction of the investment costs. Alternatively, the Government could hold the inverse of a bonus-bid lease auction (i.e., firms could bid the amount required to operate a project capable of producing a specified quantity of shale oil). In this case, with sufficient competition, firms would bid on an amount equivalent to the negative expected present value of their projected aftertax income. Instead of bidding a bonus to be paid to the Government, they would bid a bonus to be received from the Government. Those bidding the lowest bonuses, up to some aggregate bonus payout from the Government, would receive the awards.

A construction grant would make it possible for otherwise uneconomic projects to have a profitable, positive expected present value of aftertax income. The immediate effect of a grant will be to facilitate capital acquisition because less funds probably will be needed from external sources.* In addition, over the life of the project, there will presumably be lower debt repayment requirements. A construction grant reduces the uncertainty over investment costs but not over operating costs or product prices. Thus, depending on its size, a construction grant may significantly reduce the risk of project failure. Moreover, it may reduce the amount of external financing needed, and because it improves project economics, it enables the firm to borrow. However, it does not create an asset on the firm's balance sheet, and will thus provide no assurance to lenders of a firm's ability to meet its debt repayment obligations.**

The construction grant is not economically efficient since it affects a firm's perception of its investment costs, creating a bias in favor of more capital-intensive projects. Moreover, once the plant is constructed, output decisions will be based on the market price of oil rather than the strategic value of domestically produced synthetic fuel. Finally, the construction grant will be costly to administer

*A construction grant program should not be confused with a loan program or a program to facilitate financing. To assist financing, the Government should consider a direct-loan or loan-guarantee program.

**Unless a grant is to be paid at a future date and a firm borrows against it in the short term.

and may result in project delays if not processed expeditiously.

There will be problems in deciding the size of grants without an auction. A firm can refuse the project if the grant is too small, If the grant is too large, on the other hand, the firm would receive excess economic rent* from the project at society's expense. To minimize the cost to the Government, the grant should equal the absolute value of the negative expected economic rent on the project (plus, for a risk-averse firm, any risk premium).**

Second, even if the Government uses an auction to distribute grants, firms will probably collect excess rents at the expense of society. The grant program shares none of the risks of oil shale development. If these risks are as substantial as currently expected, firms may require large risk premiums in their bonuses to ensure against economic loss. Although necessary and efficient from a firm's perspective, the risk premium represents an excessive transfer of income from the public to the private sector. Also, unless competition is high and firms have equal access to technical information, bids will not be driven down to the level of the negative expected economic rent. In this case, firms may strategically bid more than this figure in an attempt to receive higher than the risk-free required rate of return for undertaking the project.

The administrative requirements associated with this incentive could delay implementation of an efficient program for several years. The construction grant is a neutral subsidy; all firms should be able to use it. They may, however, dislike the grant on ideological grounds. Those that are more risk-averse will be at a competitive disadvantage in acquiring grants in an auction (i. e., their requirement for higher risk premiums will reduce the probability of winning a grant).

*Excess economic rent here indicates a situation where the developer has recovered more subsidy than would have been required to under take the project.

**A risk premium is the additional margin of profit required by a firm in order to undertake development.

Construction grants are supported by firms of widely varying size and financial condition. In addition to those with more limited debt capacity, two financially strong companies, Gulf and Standard of Indiana, also support this incentive. Gulf supports only limited grants; its partner in the Rio Blanco development, Standard of Indiana, supports front-end cash construction grants for up to 25 percent of project investment to help offset the heavy initial capital requirements of early projects. (See table 24.)

The effects of grants of 50 and 33 percent of plant cost (estimated to average $1.7 billion including upgrading) were analyzed, assuming that the cost would be incurred over a period of 6 years and that the Government would pay its percentage of each year's cost at the end of the year in which the cost was incurred.

On purely economic grounds, construction grants would be ranked highly by oil shale firms. Compared with the other incentives, the 50-percent grant would offer the greatest increase in expected profit, the greatest decline in risk of loss, and the lowest breakeven price. The 33-percent grant also compares well, ranking second in its effect on profitability, ability to lessen the probability of loss, and breakeven price. For the Government, however, construction grants would be among the most costly incentives.

Expected Profit

In the simulations, (see table 25) the 50-percent construction grant yielded an expected profit of $707 million. When compared with an expected profit of $220 million when no incentive was employed this represents a gain of $487 million, the largest of any incentive tested. The 33-percent grant, although ranking second behind the 50-percent grant, resulted in $321 million in expected profit. Both grant levels would therefore be more than adequate to induce private development of the 50,000-bbl/d oil shale facility.

In assessing the effect of a construction grant on profitability, an analysis was made of its sensitivity to a firm's marginal tax rate and discount rate. An individual firm's marginal tax rate was found to strongly influence the grant's effectiveness: the higher the rate, the lower the value of the incentive to the firm. Because the grant reduces the amount of investment that is depreciated against corporate income tax, the developer has a higher taxable income as a result of this subsidy. In analyzing this incentive, the highest marginal tax rate (46 percent) was used in the calculations; the value of the grants for firms with lower marginal tax rates would therefore be greater than that stated in this report.

It was found that the effect of construction grants on profitability, however, would depend only slightly on the level of the discount rate. The results were calculated using a 12-percent discount rate, * but the expected increase in profit stemming from construction grants changes very little with discount rates of 10 and 15 percent. This is because the subsidy is concentrated in the construction phase, thus is discounted over relatively few years.

Risk

Because the Government shares so large a portion of cost, construction grants have a very pronounced effect on risk reduction. For the representative facility, the probability of loss dropped from 9 percent with no incentive to O percent with both the 50- and 33-percent grants. Thus, these grants rank highest in reducing the risk of loss. In addition, the construction grants result in the greatest reduction in the variation of profit outcomes (as measured by standard deviation) relative to change in expected profit.

Breakeven Price

The 50-percent construction grant also has the lowest breakeven price, $34,00/bbl of premium syncrude, compared with $48.20/bbl when no incentive was offered. The 33-percent grant results in the second lowest breakeven price, $38.70/bbl. Either price would place the shale oil facility in the commercially viable range. Given an initial oil price of $35/bbl, and the expectation that the price will rise over time (at 3 percent per year in real terms), the price of oil at the start of production in 1986 would be $42/bbl. It is more meaningful, however, to compare the breakeven price with a composite price of oil over the production lifetime—$53.00/bbl.* Because the breakeven prices with both the 50- and 33-percent grants are less than this amount, the project would be viable.

Cost to the Government

Construction grants of 50 and 33 percent would be among the most costly to the Government. In the simulations, the gross cost to the Government for the 50-percent grant was $170 million per year for each of the 5 years of construction. The net cost, however, depends on the marginal tax rate of the recipient. Because the grant would reduce the amount of investment subject to depreciation, the Government would recover about one-third of the gross subsidy paid to firms with a 46-percent marginal tax rate, through increased income tax payments. With this tax rate, the net cost to the Government for the 50-percent grant was higher than any other incentive—$494 million** and third highest for the 33-percent grant. However, the construction grants are the most cost-effective, as measured by the ratio of change in expected profit to Government cost. The net cost figures, however, do not include administrative costs, which could be significant.

To guard against cost overloading, the Government would have to establish precise accounting guidelines and be prepared to audit all grant recipients. Furthermore, the grant

*On the basis of studies showing that the real, aftertax return for U.S. business averages from 5 to 10 percent, the 12-percent rate was selected as representative. It reflects the risk involved in oil shale investment compared with that of the average investment.

*The composite price is a constant price, which when substituted for the escalating market price, does not change the profit calculations (see app. A).

**All Government costs are calculated in present value terms using a lo-percent real discount rate. This is the rate adopted by the Office of Management and Budget (OMB) for evaluating Government programs. (See OMB'S Circular A-95.)

application procedure would tend to be time-consuming for both the Government (complex auditing procedures would be required) and the applicant, (a well-documented application would be required). Alternatively, the Government could simply offer to award $400 million ($80 million per year for 5 years) to any company that is willing to build a 50,000-bbl/d plant, the only stipulations being that the plant must be completed and operated.

Low-Interest Loan

The effects of a low-interest loan are similar to those of a debt guarantee. Its primary purpose is to assist firms in financing the large capital outlays required for oil shale projects. Those that otherwise would be unable to raise sufficient capital would benefit most from this incentive.

With a low-interest loan incentive, the Government lends money directly to firms at a lower interest rate than would be provided by private lenders. The money may be obtained from general funds, designated taxes (e.g., the extra-profits tax currently being considered in Congress), or through a Government-financing authority (similar to the Federal National Mortgage Assistance Program).

A low-interest loan and a loan guarantee would have similar effects on project economics. Both would reduce the interest cost of debt; as a result, the firm would have a lower payout obligation and higher cash flow over the life of the project. A low-interest loan program could have a significant effect on project economics. It provides access to capital for firms that otherwise could not borrow in capital markets or that must borrow at very high rates.

Its risk-sharing features are identical to those of the loan-guarantee program. As the direct lender, the Government shares the risks of project failure and default on debt repayment. The equity owners of the development firm remain exposed to the risks of project failure and loss of capital. With the low-interest loan program there is only minor sharing in the risk of investment cost uncertainty and none in the risks of operating cost and product price uncertainty. Because the Government lends directly to the firms, a subsidized interest loan facilitates direct access to capital for financially weaker firms.

The effects on economic efficiency parallel those of a loan guarantee. The reduced interest rate serves as a capital subsidy, thus, it may favor relatively capital-intensive technologies. The primary effect on efficiency is to encourage participation of a greater number of firms in oil shale development projects. If increased competition leads to the testing and development of a wider variety of technologies, future production costs for shale oil may be lowered.

Because the low-interest loan incentive requires discretionary review and approval of loan applications, it will be time-consuming and laborious to administer. Delays in implementing an effective program may be encountered.

The firms that will most benefit from a low-interest loan program will be relatively weak financially with limited access to capital markets. If the Government were to make debt available to all firms at less than market rates (i.e., rather than at the AAA rate), all, independent of financial condition, could presumably benefit from the incentive. Like loan-guarantee incentives, low-interest loan incentives are preferred by companies with limited debt capacity because they need subsidized interest loans to raise project capital.

This type of loan could be structured in a variety of ways. A loan for 70 percent of construction costs was analyzed. It was assumed that loan funds would be made available during the years the construction costs would be incurred (e.g., if construction takes 5 years, funds would be dispersed over the 5-year period at the rate of 70 percent of each year's cost per year. It was further assumed that the developer would begin repayment at the end of the first year of production, that the loan would be issued at an interest rate of 3 percentage points below the prevailing market rate (e.g., 9-percent nominal interest on the loan when the market rate is 12 percent), and that amortization would occur over a 20-year period.

A low-interest Government loan would be a very effective incentive, ranking close behind the 33-percent construction grant and production tax credit in its effect on profitability. It would act to significantly reduce the risk of incurring a loss. However, it might be the most costly to the Government; as such, it could be less cost-effective than other high-ranking incentives.

Expected Profit

The subsidized interest loan resulted in an expected profit of $497 million compared with $220 million with no incentive. This $277 million increase is less than the increases induced by the 50- and 33-percent construction grants but more than the $3/bbl production tax credit. The size of the increase, however, depends on both the marginal tax rate for individual firms and the access those firms have to capital markets. For a firm with a 46-percent marginal tax rate, the 3-percent before-tax difference between the Government's interest rate and a firm's borrowing rate becomes a 1.5-percent aftertax difference, because interest payments are deductible. The aftertax spread would be 2 percent for a firm with a 3-percent marginal tax rate. Hence, the lower the marginal tax rate, the more the loan is worth. In addition, the higher the rate of interest on alternative sources of debt financing, the more the loan is worth. Because different firms may have different borrowing rates, they might value the Government loan higher or lower than the value OTA has computed.

Risk

The low-interest loan does not affect the degree of variation in possible profit outcomes, because it does not reduce the variation in future costs or prices. However, it does significantly reduce the risk of loss; with the loan the probability of earning less than 12-percent return was 0.00, but it was 0.09 when no incentive was offered. Moreover, the loan is effective in reducing the degree of variation in profit relative to expected profit, but to a lesser degree than the construction grants and production tax credit.

Breakeven Price

The low-interest loan resulted in a breakeven price for premium grade synthetic crude from shale oil ($43.40/bbl) that is only slightly higher than the price resulting from the production tax credit ($42.60/bbl). However, it is well below the price prevailing when there is no incentive ($48.20/bbl), and lower than the average expected market price over the production period ($53.00/bbl).

Cost to the Government

The low-interest loan costs the Government more than any other incentive except the 50-percent grant. It also results in the lowest change in profit per dollar cost. The gross outlay for the 70-percent loan is actually larger than that for the 50-percent construction grant because both are computed on the same construction costs. Loan repayments after the completion of the construction phase would also be higher than the increased tax receipts under the 50-percent grant program. However, because the subsequent receipts are discounted more heavily than the initial outlay, the net cost to the Government in present value terms would be almost as great for the 70-percent loan as for the 50-percent grant. Moreover, it actually could be higher than has been calculated, because some firms might default on the loan. *

Purchase Agreement

In a purchase agreement, the Government signs a long-term contract with a prospective

*These conclusions are extremely sensitive to the choice of Government discount rate. If Government cash flows were discounted at a rate of less than 10 percent, the loan would cost less. For example, at a 5-percent real discount rate, the cost to the Government is $2OI million compared with $453 million when the discount rate is 10 percent.

oil shale developer to purchase some quantity of shale oil or hydrotreated syncrude at a contract price (either in nominal or real terms). The Government may set the contract price directly, negotiate it with firms, or invite contract price bids. If the contract price is negotiated or set by competition, the Government can selectively apply the incentive to the most efficient firms by granting the purchase agreement to firms bidding the lowest contract prices. The Government can always control the number of firms using the subsidy by limiting the number of projects and the quantity of shale oil production covered in guaranteed price contracts.

The purchase agreement incentive and the production tax credit subsidize shale oil production by providing (presumably) a higher price to developers than they would receive in the open market. Higher prices will benefit a firm over the life of the project, or until the specified quantity of shale oil has been purchased.

The purchase agreement reduces project risk stemming from the uncertainty over future oil prices. Because the product price is essentially fixed, the Government bears all the risk of price variations. However, this incentive does not share in the risks of project noncompletion or investment and operating cost uncertainties,

It does offer some security to lenders, and may provide a sufficient asset base for firms to borrow against. As a result, the prospects for project financing are improved for firms with limited ability to raise debt. Like the production tax credit, the purchase agreement also has distinct economic efficiency advantages. It does not distort the prices of resource inputs and thus encourages firms to utilize efficiently the Nation's economic resources. In addition, it does not arbitrarily favor any development technologies based on differences in capital intensity or required construction time. Because it works through the product price mechanism, the extent of the subsidy for shale oil is readily apparent, and, in theory, should be set at a level that reflects the social benefit of domestic shale oil production. Finally, when combined with a competitive bid mechanism, the purchase agreement also subsidizes only the most efficient firms.

Despite its advantage for economic efficiency, this incentive imposes significant burdens on administrative efficiency. The Government must determine the amount of shale oil to be subsidized and the contract price, and it must manage a system for allocating the price contracts. If competitive bidding is used to allocate contracts and set contract prices, managing the auction is another major administrative requirement. Moreover, because the mechanisms are less familiar to industry than for such other incentives as the tax credit, they will impose higher costs on firms attempting to use and benefit from them. Although purchase agreements entail a considerable amount of administrative burden, its type and extent are strongly dependent on the particular mechanisms employed.

According to this analysis, all firms except those with very weak financial ability should be able to benefit from purchase agreements. Unlike the tax credit, a firm's ability to use this incentive is not limited by the size of its Federal tax liabilities. To some degree, those that have not yet invested in oil shale development and are strongly averse to the risk of investment cost uncertainty may find this incentive less attractive than the investment tax credit and the loan guarantee.

Expected Profit

In the simulations, a purchase agreement of $55/bbl resulted in an expected profit of $231 million compared with $220 million with no incentive. The $11 million gain in profitability ranks behind gains achieved with all the other incentives tested. The effect on profitability is less than that of the $55/bbl price support, because with the price support a firm benefits when the price exceeds $55/bbl (this occurs in the ninth year of production, assuming a 3-percent annual price increase). The subsidy effect of purchase agreements (and also price supports) is tied to the contract price. At such price, the purchase would cost the Government nothing. However, its subsidy effect is also low. The use of a higher contract price would have substantially increased its incentive impact.

Risk

Because it eliminates all variations in possible future prices, the purchase agreement results in a large reduction (25 percent) in variations in possible profits. However, it does not reduce the probability of loss as much as the price support, because a company cannot benefit from upward variations in price above the purchase agreement price.

Breakeven Price

Because this incentive establishes a minimum price above the breakeven price when no incentive exists, there is no meaningful breakeven price under the price support or the purchase agreement.

Cost to the Government

At no direct cost, the purchase agreement was the least costly incentive for the Government. Government costs are incurred from the first year of production until the market price equals or exceeds the fixed purchase agreement price, If the market price increases over time, the cost to the Government declines, and if the market price exceeds the fixed price, the Government will regain part of its subsidy through low-cost purchases of shale oil. It can also recapture part of the subsidy through the increased taxes that result from a developer's larger taxable income. In analyzing this incentive, a high marginal tax rate for the company was assumed; the cost to the Government would be higher than calculated here if the company had a lower marginal rate.

Price Support

A price support is currently being considered in several proposals before Congress. It is similar to a purchase agreement, except that the Government does not take title to the shale oil; it simply pays the difference between the support price and the prevailing free-market price. If the free-market price exceeds the contract price, the Government pays nothing. The price support, like the purchase agreement and the production tax credit, subsidizes shale oil production since it is presumed to have a probability of being higher than the market price of imported oil.

The effects on project risk and efficiency of the price support are similar to those of the purchase agreement: it reduces the risk of oil price uncertainty, it improves access to debt capital, and it improves project economics. Like the purchase agreement, the price support entails significant administrative costs. However, in general, those associated with price supports are lower than those for purchase agreements.

Expected Profit

In the simulations (see table 25), a $55/bbl price support resulted in an expected profit of $363 million, which is more than enough to induce a profit-maximizing firm to undertake an investment in oil shale. The level of profit presents a gain of $142 million over the case in which no incentive is offered, placing the price support midway in the ranking.

As with most of the other incentives, the expected profit for individual firms using the price support will depend on their marginal tax rates. The price support will be worth less to firms with high marginal tax rates than to those with low marginal tax rates, because the subsidized price increases taxable income.

Expected profit is also very sensitive to a firm's discount rate, because the price support begins only after the start of production and continues for a number of years. The expected profit gain under this incentive varies more with changes in the discount rate than it does with a construction grant. On the other hand, the price support represents a relatively larger sum in the early years of production (assuming increasing oil prices) compared with the constant tax credit. Thus, the $55/bbl price support is somewhat less sensitive to changes in the discount rate than is the $3/bbl production tax credit.

Risk

The price support is effective in reducing risk because it eliminates the possibility of a price for oil below the floor price. By reducing the variation in possible future oil prices, it reduces the total variation in possible profit outcomes. In the simulations, the variation in profit with the price support was reduced by over 20 percent compared with no incentive. Given this reduction and the increased expected profits, the probability of incurring a loss drops from 0.09 with no incentive to 0.01 with the $55/bbl price support. This reduction in risk is only slightly below that for construction grants, the low-interest loan, and the production tax credit. (See table 25.)

Breakeven Price

Because this incentive establishes a minimum price above the breakeven price when no incentive exists, there is no meaningful breakeven price under the price support or the purchase agreement.

Cost to the Government

The price support, which ranks fifth in its net cost to the Government, would be spread over most of the production life of the facility, with a larger share in the early period if the price of oil continues to rise. In the analysis, the net cost figure of $172 million, which accounts for the partial recovery of the gross subsidy through increased income taxes, was calculated using a 46-percent tax rate. The cost of this incentive to the Government would be higher in the event of lower marginal tax rates.

Investment Tax Credit

Several oil shale developers view the investment tax credit as one of the most desirable incentives. These firms have indicated that an additional 10- or 15-percent investment tax credit would be particularly attractive. (See table 24.)

Like the production tax credit, an investment tax credit strongly subsidizes the production of oil shale. Under current tax accounting procedures, it effectively reduces the cost of an investment by the percentage of the tax credit. That is, firms can deduct a specified percentage of their capital costs from their income tax liabilities during the first year in which the project operates. When construction is scheduled over several years, a firm's actual benefit is reduced by discounting because the tax credit is not taken until the project begins operation. The investment tax credit increases net cash flow early in the life of the project when companies often need such a boost. However, depending on the dollar value of the investment tax credit relative to a firm's tax liabilities, it may take several years to fully utilize the tax benefit if other revenues are not available on which to use the tax writeoffs.

By reducing investment costs by a specified percentage formula, the investment tax credit reduces the variance in investment cost, and allows the Government to share in the risk of capital-cost uncertainties. In the early stages of oil shale commercialization, capital-cost uncertainty will be a major source of risk,

As investment costs increase, the share paid by the Government increases in proportion to the percentage rate of the tax credit. Conversely, as investment costs decrease, the Government's share decreases. The investment tax credit does not share in the risks of project noncompletion and price and operating cost uncertainties.

Although an investment tax credit will enhance a project's profitability and return on investment, it cannot overcome the financing problems of firms with limited debt capability. Unlike the production credit, it does not induce lenders to provide the substantial amounts of capital required for oil shale development.

The effect of the investment tax credit on economic efficiency is less desirable than the production tax credit, for several reasons. First, it interferes with a firm's perception of the market prices for the resources used in oil shale development. This incentive subsidizes investment costs only, and so favors the more capital-intensive development technologies. In addition, because the value of the tax benefit decreases as the length of the construction period increases, an investment tax credit incentive favors development technologies with relatively short construction leadtimes.

Because the investment tax credit has been part of the tax structure for several years, it is particularly easy to implement. Analysis has indicated that large, integrated oil companies (i.e., firms with large tax liabilities and strong financial capabilities) will prefer and benefit most. By inference, firms that prefer an investment tax credit to a production tax credit are more averse to the risk associated with investment cost uncertainty than to the risk associated with product price uncertainty.

Expected Profit

In simulating the impact of a simple IO-percentage point increase* in the investment tax credit, it appeared unlikely that it would increase the profitability of oil shale ventures enough to induce their development. In the quantitative analysis, the hypothetical facility had expected profits of $299 million compared with $220 million without an incentive. On the basis of the effect of profitability, the increased investment tax credit ranked near the bottom, above accelerated depreciation and the purchase agreement.

The investment tax credit's effect on profitability (like the production tax credit) is not sensitive to the marginal tax rate unless a firm has excess credits at the time the increased tax credit expires. However, unlike the production tax credit, the investment credit is claimed over a short construction period rather than a long production period. Therefore, its value is relatively more sensitive to a firm's overall tax credit situation. This credit is, however, relatively insensitive to a firm's discount rate because all the tax credit would be claimed early in the life of the project and would thus be discounted over relatively few years.

*The existing investment tax credit has an additional IO-percent tax credit for energy investment, However, this credit was ignored in the calculations because it was due to expire in 1982.

Risk

The investment tax credit was found to have a slight effect on the risk of loss but virtually no effect on the variability of profit outcomes. With this incentive, the probability of a loss dropped to 0.05, the same level as the increased depletion allowance and accelerated depreciation.

Breakeven Price

At $45.80/bbl, the breakeven price of the investment tax credit was slightly higher than that of the increased depletion allowance ($45.70/bbl), and not significantly less ($2.20) than the breakeven price with no incentive.

Cost to the Government

For this incentive, the cost to the Government ($87 million) was among the lowest, ranking just above accelerated depreciation. Compared with the depletion allowance, however, the cost of the tax credit would be incurred over a shorter period of time.

Accelerated Depreciation

Accelerated depreciation for tax accounting has been discussed by several firms as a possible incentive for encouraging development projects. For example, they have suggested that oil shale investments be deducted from income over a period of 5 years instead of 10 to 15 years, as is now expected. Some firms have even suggested the possibility that the entire oil shale investment could be written off in the first year of project operation.

Accelerated depreciation functions similarly to an investment tax credit. It provides a modest subsidy for development. However, in comparison with an investment tax credit, accelerated depreciation will have a weaker, only moderate subsidy effect, which is limited by the firm's marginal income tax rate and the interaction of depreciation with depletion in tax computation procedures.

Shortening the period over which investment costs may be deducted from pretax income increases the present value of the tax deductions and, thus, will lead to a higher return on investment for a project. In addition, accelerated depreciation would improve cash flow in the early years of a project's operation when firms are often short of cash. In effect, the Government pays an increased share of the investment cost through reductions in income tax liability. The share paid is the present value of depreciation deductions multiplied by the firm's Federal income tax rate, which thereby sets a ceiling on the subsidy effect of this incentive. The maximum benefit would be obtained with an instantaneous writeoff; in this case, the share paid by the Government would be equal to 0.46 multiplied by the cost of the investment (assuming 46 percent of the firm's corporate income tax rate).

However, the subsidy effect of accelerated depreciation could be limited by the interaction of depreciation and percentage depletion in computing Federal income tax liability. Percentage depletion is a deduction from taxable income that is determined as a percentage of gross production revenue in any year. However, the maximum deduction for percentage depletion allowed in any year is 50 percent of net income after subtracting all other deductibles allowed by the Internal Revenue Code. Such deductibles include depreciation. Thus, increasing the depreciation allowance in any year would reduce the income ceiling on the depletion allowance and could reduce the deduction allowed for percentage depletion. In this case, the benefit to a firm from accelerated depreciation would be somewhat offset by the reduction in the tax benefits of percentage depletion,

Through accelerated depreciation, the Government shares in the risk stemming from the uncertainty of investment cost. In effect, it pays a percentage share of the investment costs of a project, thus reducing their variation. It has no effect on the risks stemming from the possibility of project failure and the uncertainty of production cost and price,

Accelerated depreciation will improve project economics but, by itself, is not sufficient to facilitate a firm's access to debt markets. It does not provide an asset against which firms may borrow.

Accelerated depreciation has a negative effect on economic efficiency. * It interferes with the perceived prices of the resource consumed in oil shale development. Because it functions as a capital subsidy, it will favor the more capital-intensive technologies. It will not affect the production signal provided by product price. Moreover, like the investment tax credit, accelerated depreciation does not function through an easily observable mechanism (e. g., product price). Therefore, it will be relatively difficult for society to ascertain the magnitude of the premium it is paying to develop domestic oil shale resources.

Depreciation, which is familiar in tax accounting, would probably entail a minimal administrative burden to implement.

Large, integrated firms with strong financial positions will benefit most from this incentive. Their pretax income and tax liabilities from other business activities are sufficiently high that the accelerated depreciation writeoffs can be taken as they become available. In addition, unless the accelerated depreciation is made retroactive, firms that have not yet invested in oil shale development will have a somewhat stronger preference for this incentive than firms that have made investments with a longer depreciation schedule.

'This assumes that the existing depreciation period is efficient. In actuality, depreciation probably inefficiently biases against capital-intensive projects. Shortening the depreciat ion period reduces some of this bias and hence promotes efficiency.

Expected Profits

In the simulations, the accelerated depreciation schedule induced an increase in expected profit of $76 million, which was the second lowest figure for any incentive tested.

The effect of accelerated depreciation on profitability depends greatly on the tax situation of a firm: it will benefit firms with higher marginal tax rates more than it will benefit those with lower rates. This difference arises for two reasons. First, the amount of tax savings for a given amount of depreciation is directly proportional to a firm's tax rate. Second, a firm with a high marginal tax rate and with other income-producing investments will be able to write off the depreciation against other income, whereas a firm with a low tax rate will be likely to have excess deductions. In the latter case, the increased depreciation deductions must be carried forward and are thus worth less, through discounting, than they would be if they could immediately offset taxable income.

The value of this incentive is also affected by the discount rate. The effect is slight, however, because both the tax writeoff and its timing are small. A 3-percentage point increase in the discount rate produced only a lo-percent reduction in the change in expected profits.

Risk

Accelerated depreciation was found to have little effect on the risk of oil shale investments. In the simulations, the probability of incurring a loss did not drop significantly nor did the absolute variation in possible profit outcomes. Relative to change in expected profits, the variation in profit was next to the lowest, ranking above the purchase agreement.

Breakeven Price

By analysis, the breakeven price with the 5-year depreciation incentive was found to be $46.00/bbl compared with $48.20/bbl for the 12-year depreciation. This reduction in breakeven price was the smallest of any incentive tested.

Cost to the Government

Of the incentives tested, accelerated depreciation is one of the least costly to the Government and one of the most cost-effective. In the simulations, the net cost to the Government was $79 million, and the ratio of change in expected profit to the Government was 0.96. Moreover, because the incentive is granted through the existing tax system, the cost of its administration would be negligible. (See table 25.)

Increased Depletion Allowance

An increased percentage depletion allowance has been discussed as a possible incentive for encouraging oil shale development. Firms have suggested that the percentage depletion allowance be increased to 25 or 27 percent.

The primary effect of an increased percentage depletion allowance would be to subsidize the economics of oil shale development. Specifically, increasing the depletion allowance will increase the share of production revenues that are shielded from the Federal corporate income tax. The depletion allowance, like a product-price increase, will improve a firm's cash flow throughout the producing life of a project. As a result, a firm's return on investment for a project is improved.

The depletion allowance might be assumed to be as effective an incentive as the production tax credit because both function through the price mechanism. However, it has several undesirable characteristics as a subsidy. The presumptions underlying its use as an incentive are that oil shale development is uneconomic and that the increasing (effective) product price is the appropriate vehicle for its subsidization.

To be an efficient subsidy through the price mechanism, the value of the price subsidy should decrease as the product price increases (i. e., as the need for the subsidy decreases). However, the percentage depletion allowance has the reverse effect. As the product price increases, the value of the price subsidy also increases. Conversely, as the product price decreases and the need for the subsidy increases, the value of the subsidy actually decreases. This effect will make it impossible to maintain the subsidy at a desired level.

In addition to its undesirable subsidy effects, the percentage depletion allowance has poor risk-sharing characteristics. In fact, it increases the risk associated with the uncertainty about future shale oil prices. Because the value of the price subsidy increases with the product price, this incentive magnifies the effects on a firm of changes in the product price. The variance of aftertax income increases as the percentage depletion allowance is increased. This incentive does not share in the risks either of project failure or of the uncertainties of investment and operating cost. The depletion allowance will improve project economics but will not significantly influence a firm's ability to raise debt.

The effect of the percentage depletion allowance on economic efficiency is similar to but more adverse than the production tax credit. It does not affect the prices of resource inputs. Consequently, resources should be combined in an economically efficient manner and a firm's preference for specific oil shale development technologies should not be influenced. However, in effect, it alters the price perceived by a firm and thus will influence its production and investment decisions. Moreover, the contrary manner in which the subsidy effect increases as product price increases will make it difficult for the Government to use this incentive to promote efficient decisions that reflect the social benefits of shale oil production.

Like accelerated depreciation, percentage depletion is a familiar component of the U.S. tax code, and would thus be very easy to apply. The firms that will benefit most from an increased depletion allowance will be those having large before-tax income and large tax liabilities. Moreover, by inference, firms that prefer an increased depletion allowance are relatively unconcerned about risk of future decreases in product price. Rather, they are apparently betting in favor of continued long-term increases in the price of imported oil. No firm seriously advocates this incentive. (See table 24.)

In analyzing this incentive, an increase in the depletion allowance from the current 15 to 27 percent was assumed. Such an increase would be a significantly less effective incentive than the construction grants, the production tax credit, the low-interest loan, the price support, or the purchase agreement. Compared with these other incentives, the increased depletion allowance would result in a much smaller gain in expected profits and only a slight reduction in the risk of incurring a loss.

Expected Profit

The increased depletion allowance resulted in a comparatively modest gain in expected profit—$140 million—compared with no incentive. Because firms cannot claim depletion deductions in excess of 50 percent of taxable income, increasing the depletion allowance above 27 percent does not result in significant additional expected profit.

For firms with lower marginal tax rates, the gain in expected profit would be even smaller. In the simulations, for example, the $140 million gain in profitability calculated using a 46-percent tax rate would be reduced to only $70 million if the tax rate were 23 percent. (See table 26.)

The effect of an increased depletion allowance on profitability is also more sensitive to the discount rate than any other incentive tested. This sensitivity stems from the increase in the incentive's value that accompanies the increase in the real price of oil (and hence revenues). Thus, a higher value in later years is more sensitive to discounting than a value that remains constant over time (as the production tax credit does, for example).

Risk

Although a higher depletion allowance actually increases the variation in possible profits, the gain in expected profits results in a small reduction in the probability of loss. In the simulation the 27-percent depletion allowance reduced the probability of loss to 0.05, compared with 0.09 when no incentive was employed. The increase in the variability of profit outcome occurs because profits are more sensitive to changes in future prices with the higher depletion allowance.

Breakeven Price

Although the increased depletion allowance will result in a reduced breakeven price, this reduction is likely to be small. In the simulations, the breakeven price fell from $48.20 to $45.70/bbl. (See table 25.)

Cost to the Government

The cost of this incentive to the Government is commensurate with its effect on expected profit. In the analysis, the increased depletion allowance cost $197 million, which makes it the fifth most costly incentive. Moreover, it is not a cost-effective option since it results in the second lowest ratio of change in expected profit to Government cost.

Loan Guarantee

Under a loan-guarantee incentive, which has been frequently discussed in Congress and by oil shale developers, the Government guarantees to lenders to repay a specified portion (e.g., 50 to 70 percent] of the project debt if a firm defaults on its debt payments because of the economic failure of its oil shale project. A loan guarantee would be administered selectively by a Government agency without charge or for a fee. Under a fee arrangement, a firm effectively buys an insurance contract to guarantee debt repayment,

A loan guarantee is primarily designed to facilitate project financing and, as a result, has only a limited subsidy effect on the economics of oil shale development. Indeed, the only effect on project economics is to reduce the interest rate on debt for firms with low bond ratings. Thus, over the life of a project, a firm's debt service obligation will be somewhat reduced. A loan guarantee will be of little or no value in improving project economics for firms with strong balance sheets that can borrow at low rates.

This type of incentive requires the Government to share directly in the risks both of project failure and of default by a firm on its debt obligations. However, as long as a firm's equity contribution to total project investment remains at a reasonable level (e.g., 40 percent or more), a loan guarantee does not unduly shield a firm from economic loss (i.e., the incentive does not introduce moral hazard). * In the event of default, the loan guarantee does not protect equity owners against loss. As a result, it encourages management to operate in an economically efficient manner, and provides only weak protection from the risk of investment cost uncertainty—but only if it is for a percentage share of the capital required for the project and if the firm can borrow at a lower interest rate than would otherwise be possible. A loan guarantee does not share in the risks of operating cost and product-price uncertain y.

Of all the incentives that provide for private lending, it has the strongest effect in improving the ability of firms with limited debt capability to borrow in capital markets. By guaranteeing the fulfillment of a specified portion of a firm's obligations, the loan-guarantee program provides an asset that financially weaker firms may borrow against.

Given its limited effects on project economics, a loan guarantee has relatively minor effects on efficiency. It acts as a capital subsidy and so may favor more capital-intensive technologies. It does, however, improve competition in oil shale development by removing a major barrier to entry for less well-fi-

*Moral hazard would exist if the guarantee was constructed as to eliminate so much corporate risk that project failure is encouraged.

nanced firms. Enhancement of competition may lead to testing a broader set of technologies, and in the long run may result in higher overall efficiency by reducing production costs.

This incentive will present certain administrative problems, even though the Government has previously used loan-guarantee programs. A firm's application must be selectively reviewed and approved, thus increasing the potential for delay.

The loan-guarantee incentive benefits smaller companies with an insufficient asset base to back the major debt requirements for undertaking an oil shale development project (i.e., companies with a limited capability to raise debt that would otherwise have to borrow at higher interest rates or be excluded from oil shale development). In addition, larger companies with a large asset base but also large debt (i. e., a high debt/asset ratio) may also need guarantees to embark on an oil shale project. With the increasing debt/equity ratios evident in the petroleum industry, a growing number of firms fit this description. Those with a strong balance sheet and large asset base will not benefit from a loan-guarantee program, and for competitive reasons may not prefer its implementation.

Loan guarantees tend to be preferred by firms that have limited debt capacity. Superior Oil backs them in principle, believing that they will help some companies obtain financing to get their plants started. The Oil Shale Corp. (Tosco) reported that it would need them to obtain financial backing, and SOHIO Natural Resources, a subsidiary enterprise with limited debt capability, claims it could also take advantage of them. Occidental, a considerably larger firm, advocates any and all types of loans or loan guarantees, especially nonrecourse loans. As would be expected, the largest and financially strongest companies find loan guarantees less desirable. (See table 24.)

Government Participation

Government participation has been discussed as part of several bills being considered in Congress. Although it has certain fundamental advantages if the primary purpose of an oil shale incentive program is to share risk, it would meet strong resistance on ideological grounds, and would be extremely difficult to administer. Moreover, it may lead to inefficiency in oil shale development and production activities.

A Government participation program is based on the assumption that oil shale development is economically sound but has very high risks. Because of these risks, private firms are assumed to be reluctant to undertake projects, or willing to undertake them only with the expectation of high profits on their investment to cover their risks. Government participation would provide a mechanism for it to share risks with private firms thus encouraging them to commit capital to oil shale projects.

In such a program, the Government would provide a specified share of equity. From that point on, it would simply be an equity partner in the project and would share proportionately in any project losses or profits. Depending on the terms of its agreement, the Government could either be a silent partner or participate in management decisions. The partnership could be managed through an existing agency or a separate, newly formed administrative unit (e.g., the proposed Energy Security Corporation).

Because Government participation is simply a joint venture arrangement between the Government and private firms, this incentive would not provide any significant subsidy to oil shale development. It would, however, have the strongest effect of all the incentives on the sharing of risk between public and private sectors. In this program, the Government would share in the risks associated with all project uncertainties in proportion to its percentage ownership in a project. When the project showed a loss, the Government would lose; when it showed a profit, the Government would win. Government participation would reduce a firm's exposure to economic loss. At the same time, it would decrease the potential gains for a firm. That is, the variance in a firm's expected present value of aftertax income would be proportionately reduced by the multiple $(1 - SG)^2$, where SG equals the share of Government ownership.

The extent to which Government participation would assist a firm in raising debt will depend on the terms of its involvement in a project. If the Government does not agree to guarantee a firm's project debt, its participation would have little effect on the firm's ability to borrow. Debt-financing support would still come from the firm's own asset structure. Alternatively, if the Government provided a share of project debt or guaranteed a share of project debt, a firm's debt requirements would be reduced, and loans could be more easily acquired.

A Government participation program would have essentially neutral effects on the economic efficiency of private sector investment and operating decisions. By simply creating a partnership or joint venture, the incentive neither changes cost or prices, nor provides a project subsidy. * The primary effect of this incentive on economic efficiency would be to reduce the effects of private sector risk aversion. However, economic efficiency may decrease if the Government decides to operate as an active partner in oil shale development projects. Efficiency would be reduced if Government participation, as a result of inexperience or bureaucratic interference, contributed to inefficient managerial decisions.

A Government participation program would entail the greatest administrative burden of all incentives. A new Government bureaucracy would probably have to be created to manage the program, with the likelihood of lengthy delays in getting the program to operate effectively.

OTA's analysis indicates that Government participation would most benefit firms that are relatively risk-averse, thus unable to finance an oil shale development project alone. However, because private firms may join together in partnerships, there may be no incentive for them to enter a joint venture with the Government as an active partner. If the Government adopted a silent-partner role, however, a firm could take full managerial responsibility for a project, while still receiving the risk-sharing and financial benefits of the joint venture. Such an arrangement is not usually possible with any other private partner.

All firms except one oppose the Government participation incentive, primarily because of their fears of bureaucratic inefficiencies, of support of one technology to the exclusion of another, and of administrative problems. The only advocate, SOHIO, has sought $15 million in Government appropriations to help fund its already approved full-sized module program.

The Government could also contract for the construction of several modular plants it would then operate, either alone or through contracts. It could thus conduct operations to obtain accurate information about technical feasibility, project economics, and the relative merits of different processes. This would be of assistance in evaluating its future policies toward oil shale, in disseminating technical information, and in improving its understanding of the value of its oil shale resources. After enough information had been obtained, the facility could be scrapped or sold to a private operator. This policy would provide the Government with information and experience. However, the cost would be much higher than that of incentives to private developers.

Considering that the technologies to be tested are proprietary, it is by no means clear that the Government would have the legal

*In theory, a Government participation program would be combined with a block grant program to achieve a highly effective subsidy and risk-sharing incentive program.

right to publish all of the information. In addition, its experience in designing, financing, managing, and obtaining permits for an oil shale plant may not resemble that of private industry. Thus, the information acquired may be of little use to subsequent private developers.

Most of the information secured through Government ownership could be made available as a condition of granting financial incentives to private firms. Furthermore, this kind of Government intervention is likely to discourage private developers from undertaking their own modular development and R&D programs. Government programs of this kind tend to reduce the benefits that a particular firm could obtain from R&D or modular testing. Finally, the information argument tends to disregard the fact that patented and licensed technologies make definite provision for the dissemination of technical information on both gratis and fee terms to possible users of a process.

Government Ownership Versus Incentives for Private Development

Several factors favor incentives for private development. One is the amount and timing of Government financial support. With Government ownership, Treasury funds would be used to supply front-end money during the construction period. This would involve very large initial outlays. With private ownership, incentives such as loan guarantees, purchase agreements, and production tax credits would reduce and delay budget outlays much more than would be possible with Government ownership. Furthermore, Government expenditures would be spread over the life of the project. Only the failure of a project insured by a debt guarantee would obligate the Government for more than a small fraction of plant cost. As noted previously, fee-based guarantees would reduce this risk.

Another factor favoring private development is that limited incentives would encourage more efficient operation by leaving managerial and cost risk intact. Cost-plus contracting for a Government-owned facility could not be expected to encourage efficiency. Incentives must be limited, however, because management efficiency would decline under high levels of Government subsidy.

A final factor is that private ownership and operation would develop industrial experience in designing, licensing, financing, building, and running an oil shale plant. Government ownership may not realistically simulate industrial experience. The regulatory, financing, litigation, and managerial experiences encountered by Government are usually much different from those of industry.

Constructing an oil shale plant requires committing major physical and financial resources that would become unavailable for other purposes. Under the private option, funding would be diverted from alternative private investments and consumption. The Government option would, in the absence of higher taxes or funding through revenue bonds, either raise the Federal deficit or withdraw funds from other programs.

Which Incentives Are Most Efficient and Effective?

As the above discussion of alternative financial incentives indicates, there is no single “best” subsidy. Firms in different circumstances will tend to require different kinds of incentives to avert the risks that prevent them from undertaking commercial operations. In general, all incentive programs must be properly administered in order to be effective, This is particularly true of nontax subsidies such as low-interest loans, debt guarantees, price supports, and purchase agreements. These entail much greater administrative involvement than do tax credits, accelerated depreciation, or increased depletion allowances. The absence of close supervision of nontax incentives can lead to oversubsidizing developers. On the other hand, the creation of bureaucratic mechanisms that are extremely time-consuming and complicated, or which make the acquisition of the subsidy or its level dependent on future events that the developer cannot foresee, will radically reduce the subsidy effect of the incentives.

OTA has concluded that production tax credits, purchase agreements, and price supports are the most viable subsidy mechanisms to employ if the Government decides it is necessary to provide financial incentives. The subsidy effect of the purchase agreement and price support incentives are relatively low for the contract price ($55/bbl), which was computer simulated in the present analysis. This should not detract from the qualitative merits of these incentives. Furthermore, this analysis indicates that either loan guarantees or low-interest loans will be necessary to ensure significant participation by smaller or even moderately sized firms. The high cost of providing low-interest loans suggests that debt guarantees would be the best mechanism through which to ensure this participation.

Are Financial Incentives Needed?

The rationale for providing financial incentives is that hastening the commercialization of oil shale technologies, which although not immediately viable would probably be capable of commercialization at a later date, serves the long-run economic and national interests of the United States, The assumptions underlying this argument are that capital requirements, remaining technical uncertainties, risk of cost overruns, unstable regulatory environments, and uncertainties about present or future profitable marketability indicate to developers that their capital would be more profitably employed in alternative investments. An incentive or subsidy alters the economics of commercial production by attempting to either sufficiently reduce the risk or raise the profitability to encourage development.

Whether and to what extent oil shale development will require subsidization depends on the present and anticipated future relationship between oil prices and the cost of producing shale oil. Expectations concerning these future trends involve a consideration of such factors as: the developer's confidence in the accuracy of shale oil plant cost estimates, world petroleum demand, OPEC cartel pricing decisions, the political stability of foreign oil supply, and the rate of profit a company requires to justify its investment relative to alternatives.

Assuming that developers have some confidence in their present estimates of plant costs, and that these estimates contain contingencies for regulatory delay and environmental litigation, then the primary consideration becomes the ability to market at an acceptable rate of return. Developers base their evaluation of marketing potential on the required rate of return and the feasibility of obtaining this return given the price of competing OPEC crude. Until very recently, it was accepted that the commercialization of shale oil would require some form of subsidy.

In narrow economic terms it is no longer clear that shale oil requires subsidy to compete profitably with conventional petroleum. Price hikes during the end of 1979 and the beginning of 1980 have increased average posted spot prices for foreign and domestic crudes by more than 30 percent. Wyoming Sweet and the best grades of North African crude now have posted prices of between $34 and $38/bbl. The spot-market prices for these oils are between $40 and $50/bbl.

If it is assumed that developers require no more than a 12-percent real return on their investment, and that current capital and operating cost estimates are reliable, then shale oil could probably be produced and marketed profitably without subsidy. Predicted decreases in next year's OPEC exports (3 million bbl/d) along with the expectation of continued real price increases of at least 3 percent per year, reinforce the belief that the market outlook for shale oil will continue to improve in the future. However, ruling out the need for financial incentives would be unwise for several reasons.

First, the present competitiveness of shale oil assumes realistic capital and operating cost estimates. For the reasons discussed earlier in this chapter, this is still a risky assumption, and construction and operating costs are still escalating. Since a commercial or modular facility has never been constructed or operated, scaling-up the technology will almost certainly add hitherto unforeseen costs as technical problems—even minor ones—are encountered. If it takes place in the context of commercializing or deploying a large number of synthetic fuel plants, the shortage of already scarce equipment such as valves, compressors, and heat exchangers can be expected to further inflate construction costs. World oil price increases in excess of the 3- or 4-percent real annual growth assumed by developers would push construction costs up still further.

Second, the present competitiveness of shale oil assumes that developers are willing and able to accept an anticipated real discount rate (i.e., rate of profit) of 10 or 12 percent on an inherently risky investment. Given the nature of the risk, it is questionable whether developers would be willing to undertake the investment at this rate.

Finally, shale oil's emerging competitiveness is related to recent oil price increases. If these increases contribute to recession in the industrialized West, petroleum demand can be expected to decline. This could reduce prices in real terms, thus reducing the competitiveness of shale oil. In the longer term, however, it should move to parity with conventional crude as a result of dwindling oil reserves. However, shorter term price declines could take place as they did during the years immediately following the oil embargo of 1973 to 1974.

In the consideration of appropriate incentives, this relative change in the competitiveness of shale oil implies that emphasis should be placed on the desirability of incentives that help with financing, while reducing the risk of extreme OPEC selling price reductions in real terms. Debt guarantees, price supports, and purchase agreements are most likely to provide such assistance.

Economic and Budgetary Impacts

The economic and budgetary impacts of oil shale development will depend on the production levels and speed with which they are met. Low production levels are unlikely to have significant effects on Government spending, on the national rate of inflation, on the level of national employment, or on the cost and availability of capital. To examine these impacts, four growth-related production scenarios were prepared that distinguish shale oil development by both the anticipated level of production and the required degree of Federal involvement. The rationales, the technical descriptions of the envisioned facilities, and the analytic assumptions of these scenarios are discussed in detail in chapter 3. Briefly, the scenarios are:

Scenario	Production target in bbl/d of oil by 1990
1	100,000
2	200,000
3	400,000
4	1,000,000

Industry Costs

A standard commercial oil shale facility is conventionally described as one that would produce 50,000 bbl/d, with an on-stream operating factor of 90 percent, or 329 days per year. Such a facility would actually consist of a series of integrated modular retorts (normally five or six) each with a capacity of between 8,000 and 12,000 bbl/d. No single plant is likely to produce exactly 50,000 bbl/d. At present, the plans of the Colony operators call for a commercial facility with a 45,000-bbl/d capacity, tract C-b is projected to produce 57,000 bbl/d, a 76,000-bbl/d plant is projected for tract C-a, Union Oil's ultimate intention is to build a facility with a capacity in excess of 75,000 bbl/d, and Superior and Geokinetics expect to operate commercially profitable plants with small production capacities—11,500 bbl/d and 2,000 bbl/d, respectively.

Determining the most efficient and cost-effective size for a commercial plant depends on the amount, quality, and accessibility of the shale resource on the tract, the method of mining, the type of retorting technology, and a variety of other factors that affect the cost of shale extraction, transportation, waste disposal, and refining.

Current capital cost estimates for a 50,000-bbl/d commercial-sized oil shale plant range between $1.4 billion and $1.7 billion. In general, these plants are expected to represent an approximately 20-percent economy of scale in comparison with smaller (e.g., 9,000 to 12,000 bbl/d) modular plants. A very large commercial facility of 100,000 bbl/d might represent a 10- to 15-percent economy of scale relative to a 50,000-bbl/d operation. Whether and to what extent these economies would actually be obtained would depend on the particular properties of the development site, the mining techniques used, the technology adopted, and how efficiently the projects in question were managed.

The estimated costs of industries of different sizes are presented below. These estimates assume a 30:70 ratio of debt to equity. They include the cost of hydrotreating and upgrading to premium crude quality and minor transportation costs. They do not include the cost of major pipeline construction or unit train costs for transportation out of Uinta or Piceance Basins. Estimates are in third-quarter 1979 dollars and assume a 5-year construction period for each plant.

In billions of dollars	Scenario 1 100,000 bbl/d	Scenario 2 200,000 bbl/d	Scenario 3 400,000 bbl/d	Scenario 4 1,000,000 bbl/d
Loans, ... , .,	0.9-I .35	1.8-2,6	3.6- 4.2	9.0-13.5
Equity . . . ., .	2.1-3.15	4.2-5.9	8,4- 9.8	21.0-31.5
Total ... , .	3.0-4.5	6.0-8.5	12.0-14.0	30.0-45.0
Maximum annual. , . . .	0.6-0,9	1.2-1.7	2.4-2.8	6.0-9.0

Given current estimates, an industry of 1 million bbl/d would cost roughly $30 billion in third-quarter 1979 dollars. But these estimates are unlikely to be completely accurate. Real cost escalations of 10 to 20 percent would not be unexpected under the best of circumstances. More importantly, if 1 million bbl/d are deployed over a lo-year period, capital cost increases for plant construction are inevitable. Under such circumstances, the demand for skilled labor, for pollution control equipment, for valves, for mining equipment, for compressors, for heat exchangers, and for other needed equipment will completely outstrip supply. The consequences would be large price increases for these goods and services as well as construction delays. Hyperinflation of the costs of required goods and services, equipment shortages, and consequent construction delays could easily inflate total capital costs for facilities by 30 to 50 percent in real terms. Therefore, the costs of this scenario could easily reach $45 billion.

Cost to the Government

Each of the scenarios decribed above assumes a different extent of Federal involvement in the industrialization of oil shale. The scenarios differ from each other in the amount of the target production and the degree of governmental cost and financial exposure. The cost to the Treasury is, in turn, determined by the type and magnitude of the incentives that are provided. Those that have been evaluated in this assessment vary substantially in the amount and kind of risk that they avert for the developer. They also vary with respect to their overall impact on project economics and potential company profits.

In general, the incentives considered entail costs to the Government that are directly related to their impact on a firm's expected profits. (See tables 25 and 26.) That is, sub sidy costs to the Treasury are closely correlated with their influence on overall project economics. However, the relation between the effect of incentives on a firm's profits and the cost of the incentives to the Government is not exactly linear. Some subsidies clearly provide more financial encouragement with less governmental cost and exposure than others. The real cost to the Government is determined by: 1) the gross cost of the subsidy, 2) the amount of increased tax payments due to additional production, 3) the Government's assumed discount rate (what it is assumed could be gotten if the capital were employed elsewhere), 4) the timing of the Government's payment of the incentive, and 5) the timing of a developer tax or other payback to the Government.

Calculating the cost of incentives to the Government is complicated by the difficulty in determining the first three of these factors. For example, the gross cost of the subsidy (i.e., the size of the offered subsidy) is hard to predict for several of the incentives. The number of production tax credits that might be taken by developers is not entirely predictable, nor is the extent of the financial obligation that the Government might incur under debt insurance or guarantee programs. The number of takers for price supports could vary substantially depending on how they were constructed, on the support price level, and on future shale oil market conditions.

The amount of increased tax payment that particular incentives might generate is also difficult to predict. This is because the effective tax rate that firms pay on production varies according to the circumstances of the corporation in question. The range is potentially from O to 46 percent on Federal taxes.

Finally, the calculation of these costs assumes that the Government's discount rate is known, and that the tax generation ability of alternative Government uses of the moneys is also known. Since there is considerable disagreement among economists over the assumption of what the Government discount rate should be, some uncertainty is introduced into the calculation. These calculations assume a Government discount rate of 10 percent, which is the rate suggested by OMB.

Given these difficulties, the reported costs to the Government of providing the incentives should be viewed as illustrative of the probable average cost of providing the incentive to a number of developers. It should also be remembered that these estimates do not include the administrative cost of overseeing the incentive. Several percent could be added to the cost of the incentive, in the cases of debt guarantees, purchase agreements, block grants, and low-interest loans. The costs to the Government reported in this chapter would apply only to first-generation facilities. Subsequent plants would probably require less governmental involvement and thus lower governmental costs. If the incentives included fade-out provisions as oil prices rose in real terms and shale oil became more competitive, then the Government's costs would also fall substantially for later plants—if the price of world oil continues to rise faster than the cost of building and operating shale oil facilities.

In this chapter, the cost to the Government of providing an incentive is the gross subsidy to the firm less increased tax payments to the Government. This cost was calculated in present value terms. The net cost for each year (i.e., the subsidy less tax revenues) was discounted at the Government's discount rate (i.e., 10 percent). The resulting present value calculations were summed for all years. The nature of the Government cost calculations is described in greater detail in appendix A.

Scenario 1: 100,000 bbl/d by 1990.—OTA's analysis indicates that the production of 100,000 bbl/d by 1990 will probably take place without further subsidy beyond the general purpose tax credits that are currently available to any industrial or energy developer. Consequently, this scenario would not require any additional cost to the Government.

Scenario 2: 200,000 bbl/d by 1990.—The cost to the Government of subsidizing the 200,000 bbl/d envisioned in this scenario would depend, in part, on which incentives are used to stimulate production. As is shown in table 25, the estimated cost to the Government of subsidizing a 50,000-bbl/d plant will depend on the incentives chosen. If the Government chose to provide only one of the incentives considered in this chapter, then its costs would vary between approximately $0 and $494 million in 1979 dollars. However, this range should be adjusted in several ways. First, the construction grant subsidies are so costly and politically unpopular that they should probably be dropped from consideration. Second, although the purchase agreement is a powerful incentive in theory, its impact when set at $55/bbl over the life of the project is too low to have a significant influence on project economics. Consequently, it should also be dropped from consideration.

Each of the remaining subsidies would yield substantial profits if a 12-percent discount rate is assumed. Although all but the low-interest loan will still yield a relatively small loss if a 15-percent discount rate is assumed, this is offset by the fact that the present calculations assumed a l-year construction delay. The cost of this delay is $117 million. If such a delay does not take place, then all of the incentives except the purchase agreement will provide a small profit (or small loss) in addition to the 15-percent discount rate (return on investment).

Thus, the cost of spurring the construction of a 50,000-bbl/d plant with the use of a single subsidy would be between approximately $100 million and $400 million over the life of the project. Therefore, the cost to the Government of stimulating the production of 200,000 bbl/d would be between $400 million and $1.6 billion.

If it were certain that any of the incentives included in these ranges would induce the desired level of production, the least costly subsidy would be the best choice from the Government's perspective. Unfortunately, this is not necessarily the case. As discussed previously the particular corporate and financial circumstances of individual developers vary widely with respect to the specific risks that they need or wish to avert. Therefore, their incentive needs may be quite different. Some firms may find it difficult to use tax credits. Others may be too small or weak financially to take advantage of price supports or purchase agreements. Instead, they require some kind of financing subsidy such as a low-interest loan or debt guarantee. Some form of choice among possible incentives is probably necessary in view of these differences.

If the Government provided a choice among possible incentives, then the cost of financing this scenario would probably be between $1.2 billion and $1.4 billion in 1979 dollars.

Scenario 3: 400,000 bbl/d by 1990.—0n the basis of the same assumptions that were used in the second scenario, the cost to the Government of providing a single incentive would be between $800 million and $3.2 billion in 1979 dollars. If developers were given their choice among the incentives, then the cost to the Government to stimulate this level of production would be between $2.8 billion and $3.2 billion in 1979 dollars.

Scenario 4: 1 million bbl/d by 1990.—The costs to the Government discussed below assume that almost all of this production would take place with incentives to private industry rather than through direct Government ownership. However, since the list of incentives being considered includes both a 33- and 50-percent construction grant, the following analysis captures the financial consequences of Government participation. It also assumes that an effort to deploy the industry by 1990 would put enormous strain on U.S. manufacturing capacity (e.g., valves, heat exchangers, pressure vessels, and mining equipment), or architectural-engineering schedules, and on the reservoir of skilled workers. This would delay construction timetables and produce sizable cost overruns. The precise amount of these overruns cannot be predicted.

Conversations with representatives of industry and major construction firms, plus an examination of the available literature, suggest that such cost escalations could easily reach or exceed 50 percent of the original estimates. The calculations for the total capital cost of this scenario include this assumption. It is difficult to predict the effect that such overall cost increases would have on the cost of Government subsidies, since a large part of the increases would be absorbed by the developers, Increases in the total capital costs of the target production would not translate directly into higher governmental costs, but would more likely reduce overall production because of project failures. How much the Government's costs escalated would be sensitive to the particular incentives used. They would also be affected by the degree to which hyperinflation of overall plant costs and resulting project failures reduced tax receipts.

In order to stimulate sufficient developer commitment to stand a chance of meeting the production target, firms would have to be allowed to choose the incentive that benefited them most. In which case, the total direct cost to Government would probably be between $6 billion and $7 billion. However, it is likely that project failures and construction delays would prevent the production target from being met. Consequently, the above estimate of cost to the Government would be more likely to represent a production in 1990 of 500,000 to 750,000 bbl/d rather than the full 1 million bbl/d.

It should be noted that the above calculations do not include necessary administrative costs nor do they capture all of the costs of additional refineries, piping, and transportation facilities that would be required for the third and particularly the fourth scenarios. The estimates are in present value terms and do not represent, except for the block grants, payment by the Government of a single lump sum. All the other incentives would allow phased expenditures over a number of years, thus, limiting the Government's financial obligations during any one year. Most importantly, the calculations use OMB's lo-percent discount rate, and assume that the gross amount of the subsidies would be used in some equally productive manner if it was not spent on oil shale. Assuming alternatively that these moneys were used less productively, then the real cost to the Government of the subsidies would fall substantially. For instance. the net cost to the Government of providing the low-interest loan would be $453 million if a Government discount rate of 10 percent is assumed. The cost would be $201 million if a 5-percent discount rate is assumed.

Capital Market Impacts and Financial Feasibility

The capital outlays needed to develop a sizable shale oil production capacity are immense, e.g., $30 billion to $45 billion for just a l-million-bbl/d capacity, This has led many to question the financial feasibility of private sector development and to argue that Government financial guarantees and/or direct Government participation are mandatory if there is to be significant shale oil production capacity by 1990 or even by 2000. Still others have asserted that even if the Government ensures the necessary financing, its achievement would mean severe distortions of the capital markets, namely: 1) a significant increase in capital costs (interest rates and required return on equity), which would reduce other business investment and 2) distortions in particular economic segments such as housing, due to high interest rates and the "crowding out" of mortgage financing. Yet proponents of shale oil development argue that there are significant long-run benefits to be gained.

These include capital market benefits in terms of balance of payments, of inflation, and of strength of the U.S. dollar.

Concerns

There is a clear need to address systematically the financial and economic issues of shale oil financing. Thus, it is necessary to consider: 1) the level of required financing associated with alternative rates of shale oil development, 2) the financial feasibility, 3) the capital market impact in aggregate and on particular capital market segments, 4) financial aspects of Government policy alternatives, and 5) the impact of shale oil on the balance of payments, on inflation, on the strength of the U.S. dollar, and on tax revenues.

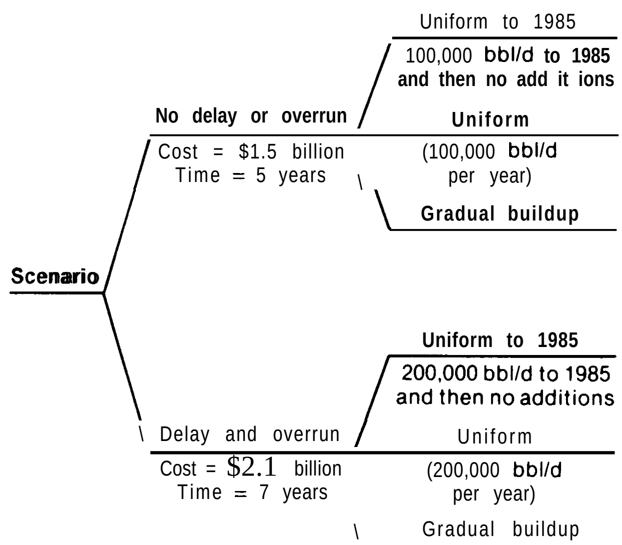
Scenario Framework

The development envisioned in either scenario 1 or 2 would not entail significant capital outlays, Thus these scenarios do not involve issues of financial feasibility and capital market distortions. Financial-economic considerations would, however, cause variations to scenario 3 (pioneer commercial industry) and scenario 4 (aggressive develop ment). Two concerns within each scenario are: the effects of delays and cost overruns and variations in the timing of development.

Delays and cost overruns.—In the absence of delays and cost overruns, it was assumed that the prototypical plant would take 5 years to build and cost $1.5 billion in 1979 dollars (the upper end of current estimates for room-and-pillar mining with surface retorting). To assess the effect of delays and cost overruns, an adverse variation was considered to be a 2-year delay and a $600 million overrun.

Alternative plant initiation schedules.—There are several ways to reach a target level for a given production capacity by 1990. One is to initiate the necessary capacity at a uniform rate, and stop adding capacity in 1985 to reflect the 5 years from initiation to completion. Another is to add plants at a uniform rate, for example, 100,000-bbl/d capacity (two prototypical plants) per year in scenario 3 and 200,000bbl/d (four prototypical plants) in scenario 4. Third and more realistic is to gradually build up the development rate from current levels to a target level of capacity additions. For each scenario, figure 52 shows the combinations of delay-overrun variations and capacity addition variations.

Figure 52.—A Summary of Variations in Each Scenario



Peak Financing Requirement

While the total capital outlay to put a shale oil industry in place may suggest financial infeasibility and the possibility of severe distortions in the capital markets, it is critical to recognize that the total is spread over a number of years. Moreover, once there is significant capacity in place, much of the cash generation is available to finance further growth, so that even a growing capacity becomes "self-financing" at some point.

The key issue of aggregate financial feasibility and capital market impact is the peak annual financing requirement. The annual financing requirements for various scenario variations* are plotted in figure 53. The peak financing requirements are summarized in table 27.

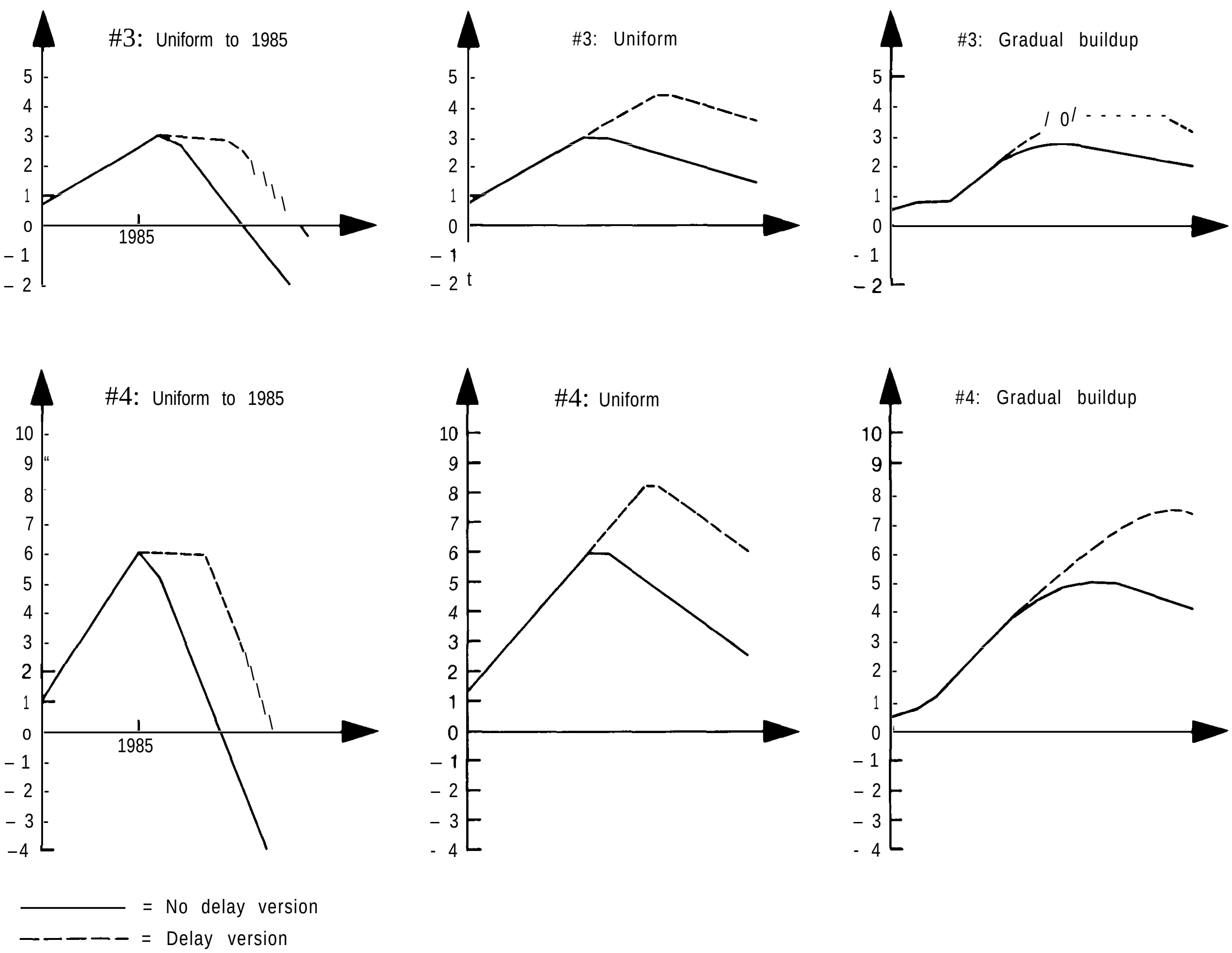
Scenario 3.—The peak annual financing requirement would be no more than $3 billion (1980 dollars) for a uniform addition of 100,000-bbl/d capacity per year with no delays and overruns. It would be no more than $4.2 billion for the delay-overrun variation.

Scenario 4.—The peak annual financing requirement would be no more than $6.0 billion for a uniform addition of 200,000-bbl/d capacity per year with no delays and overruns. It would be no more than $8.4 billion for the delay-overrun variation.

The use of the phrase "no more than" in the paragraph above reflects the fact that very conservative assumptions about cost and cash flow were used in each scenario in order to make certain that peak financing requirements are not understated.

*For more details on the scenario variations, the cost and revenue assumptions, the simulation methodology, and a detailed case-by-case development of the cash flows, see Bernell K. Stone, *Shale Oil Financing: An Assessment of Financing Requirements, Capital Market Impact, Financial Feasibility and Financial Aspects of Policy Alternatives.*

Figure 53.—Year-by-Year Financing in Billions for Various Scenarios



SOURCE Office of Technology Assessment

Table 27.–Peak Financing for Each Scenario (billions of dollars)

Version	No delay or overrun	Delay and overrun
Scenario 3		
Uniform to 1985	$3.00	$3.00
Uniform.	3.00	4.20
Gradual buildup . .	2.40	3.90
Scenario 4		
Uniform to 1985 .., ., .	6.00	6.00
Uniform.	6.00	8.40
Gradual buildup	4,95	735

SOURCE Off Ice of Technology Assessment

Aggregate Financial Feasibility

There is no significant problem of aggregate financial feasibility. Assuming that the current rate of domestic business capital investment grows at a conservative rate of 4 percent into the mid-1980's at the time of the peak financing requirement, the $6 billion would be less than 3 percent of total domestic business investment and the $8.4 billion would be less than 4 percent. *

While a figure of $6 billion to $8 billion sounds like a large annual outlay, 3 to 4 percent of net domestic business investment should cause no significant financial distortions in terms of interest rate shifts or capital market flows. This amount is well within the normal year-to-year fluctuation in domestic business investment, and a small fraction of year-to-year shifts in net domestic savings. Likewise, it is within normal shifts in capital flows from abroad. In fact, the international capital markets are now recycling many times this amount of petrodollars. Finally, it is a small fraction of the total annual mortgage financing market, where mortgage refinancing intermediaries annually recycle tens of billions. Moreover, the experience of the past 3 years has shown that thrift institutions can compete for funds at times of high interest rates when rate ceilings are lifted. Hence, this level of financing should cause no significant distortion of the housing industry.

The capital flows are well within the financial capacity of the major petroleum companies. For instance, EXXON has announced a $6.5 billion capital investment plan for 1980. A survey of the 1979 annual reports of the 18 major integrated oil companies indicates capital investment programs exceeding $50 billion per year. Moreover, cases such as the SOHIO financing of its Prudhoe Bay development, and its share of the Alaskan pipeline, indicate an ability for private enterprises with limited financial capacity to put together creative financing packages without Government assistance, when there are promising investment opportunities.

Hence, not only is there no aggregate problem of capital market capacity or distortion, but there is also no significant problem of capacity or feasibility for the private sector to provide financing as long as shale oil is a profitable investment.

A Caveat

The analysis above has looked at an aggressive development scenario in a clearly worst case for financial requirements and found no significant problem. However, it has ignored other possible sources of significant additional financing. Were shale oil financing to be only one of several Government-supported projects, each with comparable peak financing requirements in the mid-to-late

*The annual rate of business expenditures for new plant and equipment in 1979 is $174 billion ($180 billion seasonally adjusted annual rate in the fourth quarter). Hence, by the time of peak financing in the mid-1980's, business expenditures for new plant and equipment should be well over $225 billion with 4-percent annual growth, 1980's, then there is a potential problem in the sense of crowding out other domestic investment, distorting particular markets such as housing, or significantly increasing interest rates necessary to induce domestic saving and/or investment capital from abroad. While consideration of financing induced by other Government programs is beyond the scope of this report, this possibility must clearly be recognized, and an overall financial impact assessment made.

Finance Mix

Thus far the analysis has focused on the total peak financing and secondary financial effects. In general, the capital markets are very efficient at shifting funds between capital market segments. Therefore, the major macro impact depends on the amount of overall financing regardless of the particular mix. Nevertheless, there are mix issues, especially capacity to provide new equity and ability to support debt without guarantees.

The investment tax credit implies that the Federal Government automatically provides up to 20 percent of the total investment. * A scenario of further Government support of development cost beyond the investment tax credit could be an additional 20 percent for a total Government share of 40 percent. These two cases are summarized in table 28 assuming the remainder is 50-percent debt and 50-percent equity. The actual share of debt in the total financing is less, namely 40 percent and 30 percent respectively.

Table 28 shows strikingly that there should be no financing problem for the major oil companies. Both current earnings and retained earnings (earnings after dividends) are many times this amount for the 18 largest companies.

Debt capacity of the major oil companies is also more than adequate. Even if peak needs were to persist for 10 years ($32 billion), the current debt capacity would tolerate such amounts in terms of debt-equity ratios and interest coverage. Hence, for the overall energy industry, there is no significant problem of providing either debt or equity, assuming that the equity is primarily from retained earnings.

*The use of 20 percent here assumes that the extra IO-percent investment tax credit continues. Otherwise, this figure will drop to 10 percent.

Table 28.–Finance Mix

	Current Investment tax credit only		Government sharing of construction costs 20%	
	Percent	$ billions	Percent	$ billions
Government	20	1 6	40	3 2
Private debt	40	3 2	30	2 4
Private equity	40	3.2	30	2 4
Total	100	8 0	100	8 0

SOURCE Off Ice of Technology Assessment

Smaller Companies and New Equity

For smaller companies, the financing burdens can be formidable. Likewise, the magnitude of equity financing for a single commercial facility is onerous. The new equity market is not likely to provide significant venture capital for new enterprises or small companies in this area. Without Government assistance, a small company can participate only via joint ventures. However, this limitation is not unique to shale oil. Small companies cannot generally undertake billion dollar capital investments in any industry. Moreover, such companies generally lack the managerial and technical resources to undertake such ventures successfully. While financing is an obstacle for small companies, it is probably not as severe as building the organization to manage such a project.

Significant contributions to establishing a large shale oil industry should not be expected from small companies. Both technical and managerial talent and financial resources for major development reside in the large energy companies.

Secondary Financial Impacts and Benefits

In addition to the peak capital requirements and the direct impact on the capital markets, there are also a variety of secondary financial effects—balance of payments, strength of the U.S. dollar, inflation, and tax revenue (net effect on the Federal budget).

Balance of Payments and Strength of U.S. Dollar

Shale oil development has two balance-of-payment effects—the direct effect of its production and the indirect effect from its influence on the world oil price.

Direct effect.—Producing shale oil will reduce the need for imports. There should be a one-for-one substitution of shale oil for imported oil. At a $30/bbl current-dollar price for imported oil in the mid- to late 1980's, the shift in balance of payments is $5.5 billion (scenario 3 with no delay) to $7 billion (scenario 4 with delay) in 1990. It would rise to $15.5 billion (scenario 3 with no delay) to $27.0 billion (scenario 4 with delay) in 2000. These effects are summarized in table 29.

Indirect effect.—The indirect effect arises from price pressure exerted by domestic shale oil production on the price of world oil.

Table 29.–The Current Dollar Improvement in the Annual U.S. Balance-of-Payments Position Associated With Alternative Development Rate Scenarios

	Representative years		
Improved source	1990	1995	2000
Scenario 3 with no delay or cost overrun and annual capacity additions at the rate of 100,000 bbl/d			
Direct substitution (billions)[a], ..., ., .,	$5.5	$10.5	$15.5
Scenario 4 with 2-year delay and a $600 million cost overrun and uniform annual capacity additions at the rate of 200,000 bbl/d			
Direct substitution (billions)[b], ., ., ., ., .,	7,0	17.0	27.0

[a]This assumes the current dollar price of world 011 is $30/bbl in each year and corresponds to start-of-year capacity of O 5 million in 1990, 1 million in 1995, and 1 5 million in 2000 plus 50 000-bbl/d average production from phase-in of 100,000 -bbl/d capacity in each year
[b]This assumes the current dollar price of world 011 is $30/bbl in each year and corresponds to start-of-year lull production capacity of O 6. 1 6. and 26 million bbl/d respectively for 1990 1995, and 2000 plus 100000 bbl/d average production from phase-in of 200 000-bbl/d capacity in each year

SOURCE Office of Technology Assessment

For every dollar reduction in the price of world oil (at current import levels of approximately 3 billion bbl/yr), there is a $3 billion improvement in the balance of payments.

Taxes

The direct effect of any shale oil incentives can be either a reduction in taxes and/or Government payments to shale oil producers. Hence, the direct effect of incentives is to increase the Government deficit. To the extent that there is a net increase in economic activity, there are countervailing tax revenue benefits. These include: 1) the taxes paid by shale oil producers, 2) the taxes paid by suppliers to the shale oil companies, 3) the taxes paid by workers for shale oil companies, and 4) the taxes paid by workers for shale oil suppliers.

It is very difficult to assess the impact of shale oil financing on Federal tax revenue. One of the primary variables is the extent to which shale oil production and related economic activity is incremental (net new domestic production) or substitutes for other economic activity.

Estimates of the incremental Federal tax revenue are summarized in table 30. Two cases are considered—loo-percent incremental domestic production and a more plausible 50-percent incremental production. The effect is modest in 1990 due to the assumption of no taxes by the shale oil producers. However, by 2000 it rises to several billion. These figures exclude secondary activity such as incremental tax revenues due to servicing the employees and suppliers. They also do not reflect any benefits of higher employment in reducing unemployment compensation and welfare payments.

Any reduction in the Government deficit will be a long-run benefit to the capital markets to the extent that it reduces deficit financing and the associated "crowding out" of private sector financing by Government debt.

Table 30.–A Summary of Estimates of the Improvement in Federal Tax Revenue Attributable to Shale Oil Production From the Taxes Paid by Shale Oil Companies, Their Employees, Their Suppliers, and Their Suppliers' Employees

	Representative years		
	1990	1995	2000
Scenario 3–uniform 100,000-bbl/d capacity growth and no delay			
Value of annual production (billions)	$5,50	$1050	$1550
Proportion of annual production paid in taxes	15	.20	25
Net tax Improvement. 100% new activity (billions)	83	2,10	388
Net tax Improvement 50% new activity (billions)	41	1.05	1,94
Scenario 4–uniform 200,000-bbl/d capacity growth and delay			
Value of annual production (billions)	700	1700	2700
Proportion of annual production paid in taxes.	15	.20	,25
Net tax Improvement 100% new activity (billions)	1.05	3 4 0	6 7 5
Net tax Improvement. 50% new activity (billions)	.53	1 70	3.38

Notes on the lax proportions

1 The proportions used here (15 20 and 25) are developed In detail m Bernell K Stone *Shale 01l Financing An Assessment of Financing Requirements Capital Market Impact Financ/al Feasibility and Financial Aspects of Policy Alternatives* They assume a 20 percent before-tax rate of return for the companies 20 percent direct labor expense 50 percent supplier expense and 10-percent other Supplier direct labor payments are assumed to be 50 percent of supplier revenue

2 The corporate and personal tax rates used were 50 and 25 percent respectively

3 The proportions assume no corporate taxes from shale 011 producers in 1990 (due to accelerated depredation and investment lax credits) a 25 percent effective rate in 1995 and a full 50-percent rate in 2000

SOURCE Off Ice of Technology Assessment

Capital Costs: Secondary Effects

The direct effect of more capital investment is to raise capital costs. It has already been noted that this should be minor since the peak capital outlays are small as a proportion of total business investment, and would require only a modest change in saving. The various secondary financial effects (balance of payments, Government deficit, inflation) also impact capital market rates. The long-run effect of improved balance of payments, reduced inflation, and reduced deficits will be to reduce capital market rates—both interest rates and required equity returns necessary for any given level of savings. The long-run reduction should be several percentage points. Moreover, while the short-run impact of higher inflation would be adverse, the fact that capital markets are "anticipatory" (i.e., future looking) means that current rates will reflect not just current inflation but also the future improvement in inflation, balance of payments, and the budget deficit. Thus, the long-run improvements could outweigh both the short-run effect of inflation and the increased financing need. Consequently, the overall effect of shale oil on capital market rates is at worst a minor short-run increase and a clear long-run decrease.

Financial Aspects of Policy Alternatives

Impact on Peak Financing

From the viewpoint of aggregate impact, the most important Government action is that which prevents or at least minimizes delays (i.e., by removing environmental delays and licensing delays once a plant is started), thus, cost over-runs.

Impact on Private Sector Share of Peak Financing

Government subsidies in the construction and very early production stages reduce the private sector share of peak financing but not the overall impact. This is because the Government must raise its share via some combination of Government borrowing or more taxes, either of which reduces funds available for private sector financing.

General Impact of Subsidies

The overall effect of subsidies and/or risk reduction is to make investment more attractive and ensure more rapid development than would otherwise take place. Subsidies also make possible more rapid private-sector development once a basic industry is in place, i.e., beyond the 1990 period.

Government willingness to subsidize, especially via production subsidies and minimum price guarantees, sends an important message to savers and the world capital markets—namely that there will be a significant

U.S. shale oil industry with decreasing reliance on foreign oil. Hence it should reduce inflationary expectations, induce savings, induce investment from abroad, and strengthen the U.S. dollar. These policies could, therefore, have an immediate and significant beneficial effect on the domestic capital markets via their impact on future expectations.

Summary

There is no significant problem in providing peak financing requirements even for rapid shale oil development in terms of capacity of the capital markets, increases in capital costs, or reallocations from other industrial-financial sectors of the economy. Major energy companies have the capacity to provide any reasonable mix of debt and equity via retained earnings.

Long-run secondary effects on balance of payments, strength of the U.S. dollar, inflation, and the budget deficit are all favorable. The overall impact on capital markets should also be favorable, especially given that current rates will reflect future expectations about inflation and the balance of payments.

Effect on Inflation and Employment

Oil shale programs will undoubtedly be a part of a larger synthetic fuels policy. All of the legislation before Congress is concerned with the development of a synthetic fuels industry as such. The development of oil shale, were it to take place, would do so in the context of some particular array of policies concerned with such issues as conservation, oil import reduction, coal conversion, and/or increased solar power usage. Furthermore, shale oil development, like any other long-term financial commitment, will interact with Government policy and economic trends in numerous areas such as monetary policy, fiscal policy, tax policy (the windfall profits tax is particularly relevant), the characteristics of the balance of payments, and overall capital availability. To evaluate how prices and employment will be affected by oil shale development, it would be necessary to examine these effects for all of the major synthetic fuels proposals before Congress, and attempt to assess the course of the U.S. economy over the next 10 years. This task is outside the scope of this report. However, the Congressional Budget Office in its September 7, 1979 report to the Senate Budget Committee has attempted to make such an analysis.

The impacts on prices and employment nationwide of the deployment of the first scenario (100,000 bbl/d) would be insignificant. Even the realization of the second scenario (200,000 bbl/d), would have negligible effects on national inflation and employment. However, the inflationary effects of this production on the cost of the machinery and equipment necessary to the industry might be small, although discernible and could be significant, particularly on the price of labor, land, and rents, in the immediate geographical areas of development.

Even the third scenario (400,000 bbl/d) would not have an appreciable effect on national inflation rates or employment levels, It would substantially affect local prices, have an enormous positive impact on local employment, and a definable one on regional employment. Depending on the phasing of the influx of workers, the local expenditures by the developer, and the approach taken in dealing with socioeconomic impacts, the inflationary effect on land, labor, rent, and goods could be very large, particularly on land and rents. (See ch. 10.)

The prices for the machinery and equipment used for constructing the facilities would escalate sharply. It has been estimated that the construction of an industry with a 400,000-bbl/d capacity would use between 10 and 20 percent of the current U.S. manufacturing capacity for valves, pressure vessels, heat exchangers, and certain kinds of mining equipment.[6] This would clearly be inflationary for these industries. The extent would depend on the rapidity with which the industries could respond to the increased demand, how much in advance of need the equipment orders were placed, and the availability of foreign substitutes.

It is likely that the fourth scenario (1 million bbl/d by 1990) will affect the national economy somewhat differently from 1980 through 1985 than it will from 1986 through 1990. The short-run direct effect of shale oil development will be to use resources with no offsetting production. Hence, it would be clearly inflationary, although the direct inflationary impact might be offset somewhat by price pressure on world oil.

The long-run effect will be to reduce inflation because of the substitution of domestic production for imports, the pressure on the world price of oil, the improvement in the balance of payments, and the favorable impact on the Federal budget. Moreover, because capital markets set current rates on the expectation of future events, the anticipation of reduced inflation can lower current capital costs.

Simultaneously, however, this oil shale program could also exert inflationary pressure on general prices over the longer term starting in the early to middle 1980's because the high demand created by the level of investment would probably create temporary bottlenecks in various sectors of the economy, and shortages of materials and skilled labor. The net effect will tend to push up the prices of the essential elements of production.

Assuming that all other factors remain the same, the tendency will be for the inflation rate to fall by 0.05 to 0.1 percent and for the level of unemployment to rise by 0.025 to 0.05 percent during the earlier period of development. During the latter half of the decade, however, employment in the industry will grow sufficiently to very slightly reduce the national rate of unemployment (i.e., 0.015 to 0.025 percent). During this time, the tendency will be for increasingly rapid investment to exert only a small influence on the rate of inflation. It is unlikely that this impact would exceed 0.1 percent. These figures should be regarded as tendencies representing the direction of the impact—if nothing changes. Given the high probability that all things will not remain the same, these estimates should be viewed with extreme caution. One fact is, however, quite clear: oil shale development by itself will have a very small impact either on national rates of inflation or on employment.

Although the national impacts would be quite small, the local, regional, and sectoral effects would be much more substantial. Development of the magnitude envisioned in this scenario would bring many operating, professional, and construction employees into the area. This will unquestionably have an extraordinary impact on local prices, rents, and land costs, as well as on local employment. These issues are discussed in detail in chapter 10.

Construction Industry and Equipment Capacity

Current construction equipment capacity will severely hamper the ability to achieve oil shale production at the level assumed in the fourth scenario. It is apparent that limitations will be encountered in the following areas:

- the capacity of design and construction firms;
- the availability of various kinds of long leadtime equipment such as pressure vessels, valves, compressors, pumps, heat exchangers, heavy mining equipment, and alloy components;
- the capacity to move equipment to remote construction sites, and to transport shale oil by rail and pipeline to markets or refineries; and

- the availability of sufficient numbers of an adequately trained labor force to meet construction schedules.

Meeting the production targets will necessitate substantial improvements in each area. Such an expansion of capacity will require a national commitment to divert resources from other areas and uses, will create bottlenecks in other parts of the economy, and will lead to rapid inflation of costs in the relevant mining, construction, and equipment industries. In order to achieve this production goal the following annual manpower and equipment needs would have to be met.

In these projections it is assumed that approximately 20 commercial facilities having an average capacity of 50,000 bbl/d will be constructed. Most would not reach the design stage until at least 1982. Their construction is unlikely to be started until between 1983 and 1984; and will not be completed until between 1989 and 1990. Consequently, many of the projects will be designed and constructed simultaneously, thus, severely taxing the capacity of equipment suppliers and construction firms.

These projects because of their size, complexity, and the vast array of skills and expertise they require, will necessarily need to be contracted to a limited number of large architectural-engineering firms. Only a few design and construction firms have the managerial, technical, and economic experience to construct such plants. An examination of the existing capacity of such firms by Engineering News Record on April 12, 1979, indicates that of the construction firms involved in building manufacturing process facilities, only 21 contracted in 1978 for work having a total dollar value near the level of expenditure required to construct a small commercial oil shale plant—$400 million per year.[7] It can, therefore, be concluded that no more than 21 firms have the current capacity for such work. Many of these are already booked years in advance. However, workloads between now and 1985 will probably increase the number of firms that are able to undertake projects of this magnitude. There is also the possibility that by combining together, smaller firms will be able to undertake such projects.

In 1978, the construction industry contracted for $27.2 billion worth of new work, only $21.6 billion of which was industrial work. Thus, the annual construction costs of the oil shale plants that would have to be built between 1983 and 1990 to reach the million-barrel-per-day target represents 35 percent of the workload in 1978.

In particular, shortages of skilled labor can be expected during efforts to deploy an industry of this size. In 1978, there were approximately 45,000 workers in the United States having the necessary technical and professional skills (e. g., draftsmen, engineers, managers, and scientists). From 1983 to 1990, shale oil plants producing 1 million bbl/d would require 11,000 to 18,000 professional employees, which is more than 36 percent above process industry requirements in 1978. At this time, the United States has a total construction work force of around 4.5 million. During each year between 1983 and 1990, constructing the plants would require an additional 130,000 workers. The need for such a large labor force would act to hamper the deployment of an industry of this size, and would substantially inflate labor costs.

Chapter 6 References

[1]This discussion is indebted to that presented by Robert Merrow, Constraints on *the* Commercialization *of Oil Shale*, RAND Corp., 1977,

[2]This discussion in this section draws on material presented by Robert Merrow, Constraints on the Commercialization *of Oil Shale*, RAND Corp., 1977, and Synthetic *Fuels:* A Report Prepared *for* the Budget Committee *of* the U.S. Senate, 1979.

'Synthetic *Fuels:* Report by the Subcommittee on Synthetic *Fuels of* the Committee on the Budget, United States Senate, September 1979, p. 180. Statement made by Cameron Engineers.

"Synthetic *Fuels*, Report by the Subcommittee on Synthetic *Fuels of* the Committee on the Budget *of* the United States Senate, Sept. 27, 1979, pp. 46-47.

'Edward W, Merrow, Constraints on the *Commercialization of Oil Shale*, RAND Corp., September 1978, pp. 16-18.

'Wallace E, Tyner and Robert J. Kalter, "A Simulation Model for Resource Policy Evaluation, " Cornell Agricultural Economics Staff Paper, September 1977.

[7]"A Fluor Perspective on Synthetic Liquids, " Fluor Corp., 1979.

CHAPTER 7

Resource Acquisition

contents

List of Tables

List of Figures

CHAPTER 7

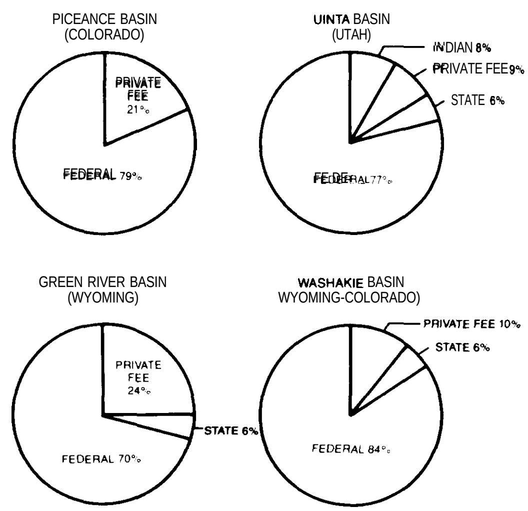
Resource Acquisition

Introduction

On May 27, 1980, the Department of the Interior (DOI) announced several oil shale decisions. Up to four new tracts will be leased under the Prototype Program and preparations started for a permanent leasing program. At least one multimineral tract will be included in the renewed Prototype Program. Land exchanges will not be given special emphasis, and no decision will be made to settle mining claims until the Supreme Court rules on Andrus v. *Shell Oil* (the oil shale mining claims discovery standard case). [Note: This case was decided on June 2,1980 (No. 78-1815).] The administration will propose to Congress legislation to give DOI the authority to grant leases bigger than the present statutory limitation of 5,120 acres, to provide for offlease disposal of shale and siting of facilities, and to allow the holding of a maximum of four leases nationwide and two per State.

The resources of the Green River formation are owned by the Federal and State governments, by Indian tribes, and by numerous private parties. (See figure 54.) Overall, the Federal Government owns about 70 percent of the land surface, which overlies about 80 percent of the resources. The Federal land contains the thickest and richest oil shale deposits and essentially all of the large deposits of sodium minerals. About 20,000 acres (less than 1 percent) of the Federal land has been allocated for private development through the Prototype Oil Shale Leasing Program. In the future, it may be necessary to involve more public land for either private or governmental development, if certain technologies are to be tested or if a large industry is to be established rapidly. Releasing this land would be affected by the laws that govern leasing and land exchange, by unpatented mining claims over most of the Federal land, and by other factors.

Figure 54.—Ownership of the Oil Shale Lands of the Green River Formation



SOURCE *Map of the Major Oil Shale Holdings —Colorado, Wyoming Utah*, Denver, Colo Cameron Engineers, Inc , January 1978

This chapter deals with the issues surrounding the use of Federal oil shale land. The following subjects are discussed:

- the possible need for committing more public land;
- leasing and land exchange programs and their problems; and
- options for involving more Federal land.

The Evolution of Leasing and Land Exchange

The legal framework that governs the use of public land for oil shale development is both complex and unsettled. It incorporates a series of laws and policies dating back two centuries that reflect conflicting philosophies about the role of the Federal Government as trustee of the public land.

The Continental Congress created the public domain from lands ceded to the new Confederation by the individual States. In 1788, the Constitution granted Congress the power to dispose of the public domain (including surface, mineral, and other rights) for the common benefit of all the States. By 1850, the public domain extended to the Pacific coast, including the oil shale lands in Colorado, Utah, and Wyoming. The Preemption Act of 1841 and the 1846 Lead Mines Statute authorized the transfer of public lands to private parties, and the Homestead Act of 1862 allowed settlement of Federal lands in the West for agricultural purposes. Some tracts along streams in the Piceance Basin were acquired by settlers under this Act. The Mining Law of 1866 declared the mineral lands of the public domain to be free to exploration and open to appropriation by those prospectors who found "lode-type" deposits on the land. "Placer" deposits were excluded under this Act but were subsequently opened to appropriation under the Placer Act of 1870. *

The Mining Law of 1872 combined, revised, and augmented the 1866 and 1870 laws, and subsequently governed disposal of all minerals that are not otherwise explicitly covered by other legislation. Prospecting was recognized as a statutory right. Upon locating a valuable mineral, a prospector could:

- stake a claim encompassing all or part of the deposit;
- develop the deposit;
- mine, process, and sell the minerals; and
- obtain ownership to the land's surface and its mineral values by paying from $2.50 to $5.00/acre, by performing about $500 worth of development work on the claim, and by carrying out at least $100 per year of "assessment" work until the time that ownership was transferred by a legal document called a patent.

*A lode deposit is confined by rock in the place where it was originally formed. Placer deposits are lode deposits that have been broken down, transported, and redeposited in alluvial sediment as a result of exposure to flowing water or ice.

The Secretary of the Department of the Interior (DOI) was given authority to enforce the provisions of the 1872 Mining Law and to oversee the filing of claims and the granting of patents. The Petroleum Placer Act of 1897 added "lands containing petroleum or other mineral oils" to those subject to the location and patenting provisions of the 1872 Mining Law. This action led to a flood of claims for oil and gas reserves, and large areas of public land were transferred to private hands as a result.

In the early 20th century, the philosophy of free exploration and occupation of the public domain came under scrutiny because of the rise of the conservation movement and concern over the dwindling supply of strategic materials, including oil. This led to two actions:

- President Theodore Roosevelt's executive withdrawals of public lands that contained coal, timber, oil, water, and other essential resources; and
- DOI's stricter enforcement of its requirements for granting of patents for mining claims.

President Roosevelt's withdrawals were protested in Congress, especially by representatives of the Western States, but Presidential authority for such withdrawals was subsequently upheld by the Supreme Court. In 1909 and 1910, President Taft withdrew the remaining public domain from appropriation by oil and gas claims. More controversy ensued, and in 1910, at President Taft's request, Congress passed the General Withdrawal Act—The Pickett Act—which authorized the President to withdraw public lands by Executive order from settlement, location, sale, or other entry. The withdrawals were to be temporary and could only be made for the purpose of evaluating the land for water powersites, irrigation, classification, or other public uses. All lands thus withdrawn would remain open for exploration, discovery, and appropriation under those provisions of the Mining Law of 1872 that applied to metalliferous (metal-bearing) ores.

In 1914, Congress severed known fuel and fertilizer mineral rights from the rights to the surface of lands appropriated for agricultural uses. The Stockraising Act of 1916 reserved to the Government all mineral rights.

The Mining Law and the other land-management laws had little effect on oil shale prior to 1916 because interest in the mineral was negligible. However, in 1914, the U.S. Geological Survey began investigating the oil shale deposits to determine their potential for yielding fuels. Publication of the results in 1916 coincided with predictions of widespread fuel shortages as a result of diminishing petroleum reserves. Based on informal representations that oil shale would be treated as a locatable mineral under the Petroleum Placer Act of 1897, more than 10,000 claims of 160 acres each were filed before 1920. Filing for oil shale claims was ended in 1920 with the passage of the Mineral Leasing Act. Also in 1920, DOI determined that oil shale had been a locatable mineral. Questions related to the valid location and maintenance of these claims became a source of contention that has endured to the present.

Leasing Programs

The Mineral Leasing Act of 1920 ended the process of claiming Federal land for petroleum, gas, coal, oil shale, phosphate, and sodium minerals. However, private firms could be given an opportunity to develop these minerals through leasing programs administered by DOI. The Secretary of the Interior was required to assess annual rentals of 50 cents per leased acre, and the maximum size of an oil shale lease tract was limited to 5,120 acres (8 mi^2). No individual or firm could hold more than this acreage under lease. * Except for these provisions, the Secretary was given broad discretionary powers to select lease tracts and to shape the terms of development leases. Five oil shale lease applications were filed with DOI after 1920. Three leases were issued, but all were subsequently canceled.

In the early 1920's, during the Harding administration, Secretary of the Interior Fall was alleged to have accepted bribes from an oil company in consideration of noncompetitive leasing of Naval Petroleum Reserve No. 3—the Teapot Dome field in Wyoming. In 1930, during the era of caution that followed the Teapot Dome scandals, DOI's Solicitor suggested that oil shale lands be withdrawn from leasing because shale oil was too expensive to produce compared with conventional petroleum, and therefore any additional leasing could only result in speculation, The suggestion was adopted by the Secretary and transmitted to President Hoover, who issued Executive Order 5327, which withdrew the oil shale lands from leasing under the Mineral Leasing Act. The order "temporarily" reserved the lands for the purpose of "investigation, examination, and classification, " as required by the Pickett Act under which it was promulgated.

Since 1930, this temporary order has been modified on a few occasions. In 1932, for example, President Hoover's Executive Order 6016 permitted oil and gas leases on the oil shale lands, and in 1935, President Roosevelt's Executive Order 7038 authorized prospecting permits and development leases for sodium-bearing minerals. The withdrawal order has also been modified from time to time to permit disposition of surface rights in limited areas. With these exceptions, it remained in effect and essentially unaltered for over 40 years, during which no oil shale leases were issued.

In 1952, President Truman issued Executive Order 10355, which authorized the Secretary of the Interior to rescind the withdrawal order. Subsequent Secretaries, however, were reluctant to exert this authority

*Shares in several leases could be held, but the total area covered by the shares could not exceed 5,120 acres.

for fear of creating the environment for a leasing scandal like Teapot Dome. DOI's hesitation was compounded by the uncertain status of unpatented mining claims on much of the Federal land and by a feeling that shale oil was not needed.

In the 1960's and early 1970's pressure from congressional delegates from Colorado, Utah, and Wyoming, and urging from State officials and the energy industry, contributed to the formulation of two different but related leasing attempts. The first was promulgated between 1964 and 1968 as part of a comprehensive oil shale program in the Johnson administration under Secretary of the Interior Stewart Udall. Secretary Udall's lease offerings failed to attract private participation. Other portions of his program were carried forward into the Nixon administration, however, where they were supplemented by the Federal Prototype Oil Shale Leasing Program under the direction of Secretaries Hickel and Morton. *

The Prototype Program officially began on June 4, 1971, when President Nixon instructed the Secretary of the Interior to expedite a leasing program that would encourage oil shale development while providing for environmental protection. On June 19, 1971, Secretary Morton announced plans for the Prototype Program and simultaneously released the preliminary environmental impact statement (EIS). In April 1972, DOI designated six tracts of about 5,120 acres each, which were offered for lease in 1974. Their locations are shown in figure 55. Dates for the sale of individual leases and other details of the Program's initiation are summarized in table 31.

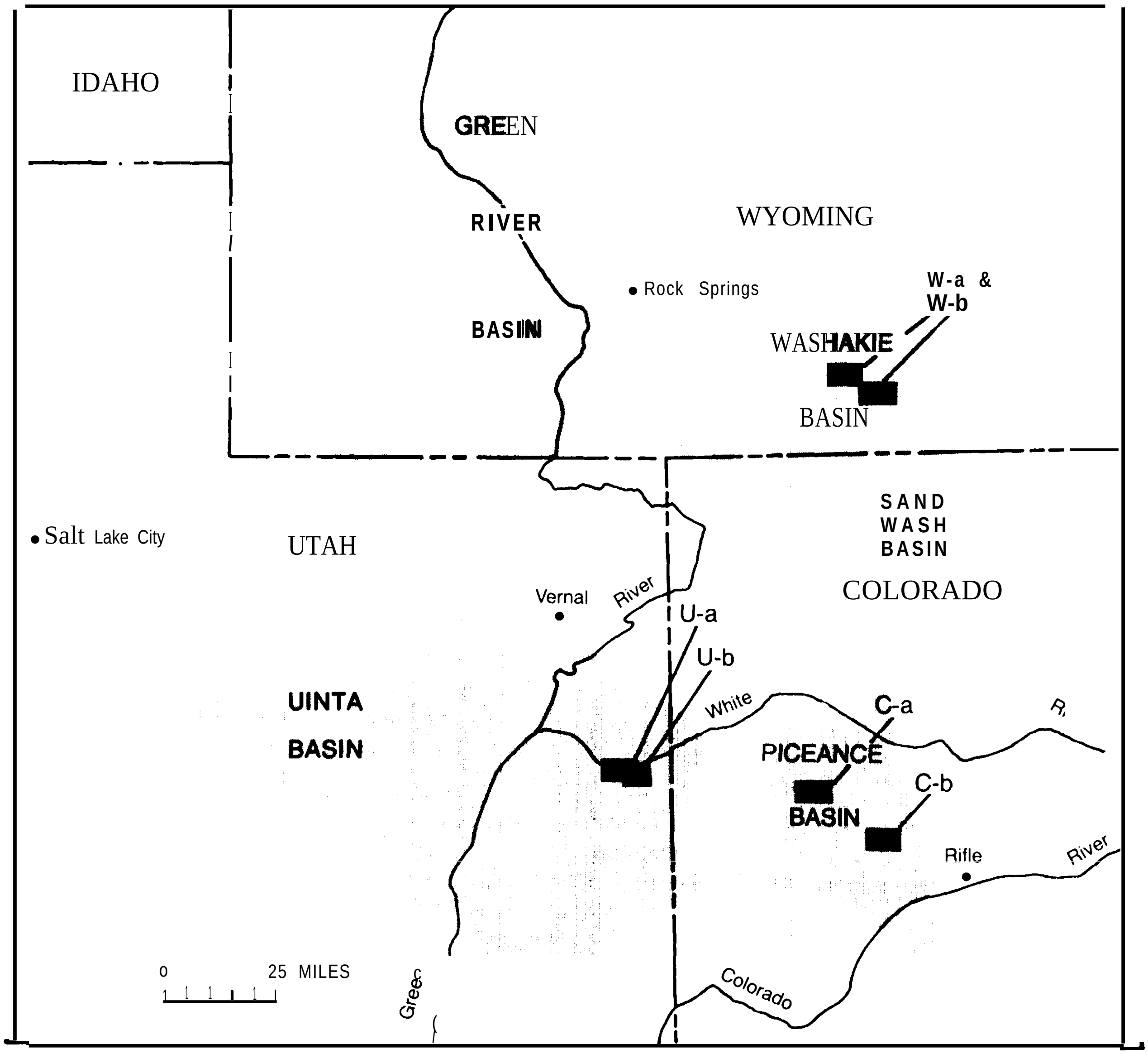
It is noteworthy that the initial development plans covered a range of technological options: underground and surface mining, aboveground and in situ retorting, and mining in ground water aquifers and in dry zones. It was estimated that the six tracts would be producing a total of 250,000 bbl/d by 1980. This goal was immediately set back because no acceptable bids were received for the in situ tracts in Wyoming. The lack of response was related to the poor quality of the Wyoming resources and to the primitive status of in situ technologies. In 1976, DOI proposed to lease two other in situ tracts in the richer Colorado shales. Several sites were investigated and a supplemental EIS was begun. The idea was abandoned in 1977 when Colorado tracts C-a and C-b switched from aboveground retorting (AGR) to modified in situ (MIS) processing. The reasons for this shift were technical problems with the fractured oil shale on tract C-b and a ban on the disposal of mining and processing wastes outside of tract C-a's boundaries. Development of both tracts was resumed after a l-year delay and both are now proceeding towards commercial operations.

Development of the Utah tracts has been stopped by legal battles between the Federal Government, the State of Utah, and private firms over ownership of the lands encompassing the tracts. There are basically two types of conflict. The first is related to the circumstances under which Utah was granted statehood. Under the Statehood Enabling Act of 1894, Utah was allowed to take title to four sections out of each township with the intent that the proceeds from their sale or use would be applied to public education. For various reasons, selection of a large number of these sections was delayed, and in some cases whole townships were made ineligible by their inclusion in Federal reservations. In lieu of sections in these townships, Utah was allowed to select other sections in other townships.

By the 1960's, Utah's stockpile of in lieu selections had reached 225,000 acres. Between September 1965 and November 1971, Utah applied for 157,225.9 acres of land in the oil shale area. Included were the present sites of lease tracts U-a and U-b. DOI declined to transfer the title to this land, and litigation ensued. To avoid delaying the Prototype Program's initiation, DOI and Utah agreed that the proceeds from the leasing of tracts U-a and U-b would be held in reserve until the

*Both leasing attempts are discussed in detail in vol. 11.

Figure 55.— Locations of the Tracts Offered for Lease Under the Prototype Program



011 shale deposits of the Green River formation

SOURCE T A Sladek, Recent Trends in Oil Shale–Part 3 Shale 011 Refining and Some Oil Shale Problems, " *Minerals Industries Bulletin*, vol 18, No 2 March 1975 p. 4

case was decided. Utah also agreed to hold the lessees to the terms of the Federal leases if the State took title. The lawsuit proceeded through the U.S. District Court and the Circuit Court, which ruled in favor of Utah, and is now in the U.S. Supreme Court, where it will be heard during the 1980 session. *

This case should not have unduly concerned the lessees because its outcome would not have affected the leasing regulations. However, the situation was complicated when a mining company applied for a prefer-

*On May 19, 1980, the U.S. Supreme Court, in a 5-4 decision, reversed the lower court decisions and held that the Secretary of the Interior could reject Utah's applications for oil shale lands as school land indemnity selections because the selected lands were grossly disparate in value to the school land grants that were lost to preemption or prior entry (*Andrus* v. *Utah*, No. 78-1 522).

Table 31 .–Tracts Offered Under the Prototype Oil Shale Leasing Program

Tract	Location	Date of sale	Winning bidder	Winning bid	Development concept
C-a	Colorado	1/8/74	Rio Blanco Oil Shale project (Gulf 011, Standard Oil of Indiana)	**$210,305,600**	Open pit mining: aboveground retorting
C-b	Colorado	2/1 2/74	C-b Shale Oil project (Atlantic Richfield, Tosco, Shell, Ashland)	117,788,000	Underground mining: aboveground retorting[a]
U-a[b]	Utah	3/1 2/74	White River Shale Oil Development (Sun 011, Phillips Petroleum)	75,596,800	Underground mining, aboveground retorting[c]
U-b[b]	Utah	4/9/74	White River Shale Oil Corp. (Sun Oil, Phillips, Standard of Ohio)	45,107,200	Underground mining; aboveground retorting
W-a	Wyoming	5/14/74	None		In situ (suggested by DOI)
W-b	Wyoming	6/11/74	None		In situ (suggested by DO I)

[a]Indirectly healed retorts (e g TOSCO II)
[b]Subsequently unified for common development
[c]Combination 01 indirectly heated and directly heated retorts (e g TOSCOII and paraho or 9as combustion)

SOURCE Office of Technology Assessment

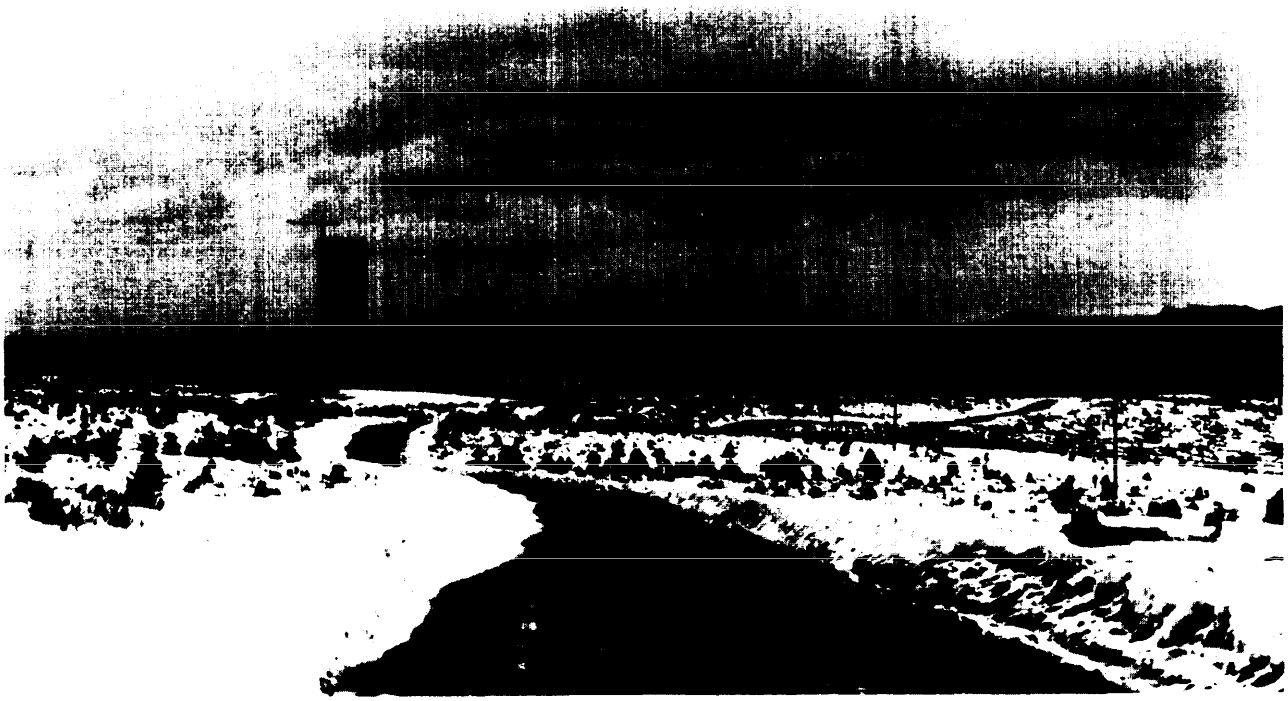


Photo credit OTA staff

Development on Federal Prototype Leasing tract C-b

ential State lease to the tract area. This might have superseded the Federal lease and therefore obviated development of the tract by the Prototype lessees. Another suit was initiated, in this instance between the mining company and the State of Utah. Proceedings have been stayed pending resolution of the in lieu litigation.

A further complication was introduced by the unpatented pre-1920 mining claims that overlie most of the Federal oil shale lands, including the Utah lease tracts. In the early 1970's, when the Prototype leases were sold, DOI was confident that the unpatented claims would be invalidated, and that the Government would retain title to the lands in question. In early 1977, however, a court decision in favor of the claimants was issued in a case involving unpatented claims in Colorado. Because this precedent could eventually have resulted in validation of the claims overlying U-a and U-b, the lessees sued for and won a suspension in the lease terms, The suspension is still in effect, pending a Supreme Court decision on the issue of unpatented claims. *

In summary, no permanent leasing program exists for the Federal oil shale lands, and under the present Prototype Program, four tracts have been leased, but two are inactive because of legal uncertainties. The other two, Colorado tracts C-a and C-b, are being developed for MIS processing, The lessees of tract C-a are also negotiating for a demonstration of the Lurgi-Ruhrgas AGR technology. If both tracts proceed to commercialization, they could produce a total of 133,000 bbl/d by 1987. With current plans, one mining technique, one in situ process, and one aboveground retort will be evaluated, Open pit mining will not be tested, nor will other in situ or AGR techniques. All of the mining will be conducted in ground water areas.

*On June 2, 1980, the U.S. Supreme Court decided in favor of the Colorado claimants (*Andrus* v. *Shell Oil*, No. 78-1815).

Land Exchanges

As discussed later, of the approximately 400,000 acres of privately owned land in Colorado, about 170,000 acres contain at least 10 ft of oil shale yielding 25 gal/ton. The total potential oil yield from these richer tracts is at least 80 billion bbl, which would support a l-million-bbl/d industry for 240 years. However, much of the privately held land is located on the fringes of the oil shale basins, and contains thinner, leaner deposits than does the adjacent Federal land. Furthermore, some of the private tracts are in small, noncontiguous parcels (mainly former homesteads and small mining claims) that could not be economically developed. Private oil shale development could be encouraged if these lands were exchanged for more economically attractive Federal tracts.

The exchanging of private mineral-bearing land for Federal land is allowed under section 206 of the Federal Land Policy and Management Act of 1976 (FLPMA). Exchanges may be consummated provided that they are in the public interest and that the properties involved are within 25 percent of equal value. The difference may be made up in cash. There are two options that would be particularly suitable for the oil shale situations. The first is the “blocking-up” of scattered or oddly shaped tracts by exchanging portions of them for adjacent Federal land, thereby creating a tract geometry that could be developed economically. Superior Oil Co. proposed such an exchange for its property in the northern Piceance basin. In this case, a stringer of Superior land that extended into the Federal holdings was to be exchanged for a parcel along the southern edge of the main body of the Superior property. EXXON Corp. has also proposed to exchange numerous small tracts along streambeds in the Piceance basin for about 10,000 acres of Federal land near the basin’s center.

The second option would involve exchanging a large block of private land on the fringe of the oil shale deposits for a substantially smaller block of Federal land in the richer, thicker areas. The Federal tract would have to be much smaller, in general, because the deposits under much of the Federal land are at least 1,000 ft thick; deposits on private tracts along the basin’s fringe are seldom more than 250 ft thick.

The Adequacy of Private Lands

Most of the privately owned lands in the Piceance and Uinta basins were acquired through the filing of mining claims for oil shale and other minerals under the Mining

Law of 1872. The provisions of the law required that the mineral be "located" by the prospector; that is, he had to sample the deposit and demonstrate, through assay, that it contained the mineral of interest. In general, the oil shales in Colorado and Utah are deeply buried and therefore not visible from the surface. However, some deposits are visible where streams have eroded through the overburden. The early prospectors obtained samples from these outcrops, assayed them, filed claims for the outcrop and for the adjacent land (which, it was inferred, also contained the mineral), and eventually obtained patents for the claimed land from the Government. Most of the original mining claims were quite small, but over the years the individual claims have been purchased by major energy companies and consolidated into much larger blocks that could be suitable for commercial development.

The locations of the larger privately owned patented or "fee" lands in the Piceance basin are shown in figure 56. * Because the oil shale deposits were first detected along the Colorado River, most of the fee lands are found in the southern part of the basin. Because of the location requirements of the 1872 Mining Law, they are generally found along streambeds. Not shown in the figure are the numerous tracts of a few hundred acres that follow the streams in the central and northern parts of the basin. These were primarily early homesteads and grazing lands, but many of them have been acquired by the energy companies. They are still used for farming and stock raising, which retains control of the water rights.

The location of the private lands has several implications for oil shale development because, although they are extensive, they are not so commercially attractive as the Federal lands to the north. There are three reasons why they are not so attractive. First, they are much thinner and contain lower concentrations of kerogen than do the deposits on Federal land. This is because the oil shale resources were created on the bed of an ancient lake by the deposition of silt and organic debris carried into the lake by rivers and streams. The lake had a bowl-shaped cross section (hence, the term "basin"), and more sedimentation occurred near its depositional centers, which lie north of the geometric center of the basin—on Federal land. The Federal deposits are therefore much thicker and, as a consequence, more amenable to large-scale development. The private lands, on the fringe of the basin corresponding to the shoreline of the ancient lake, are much thinner.

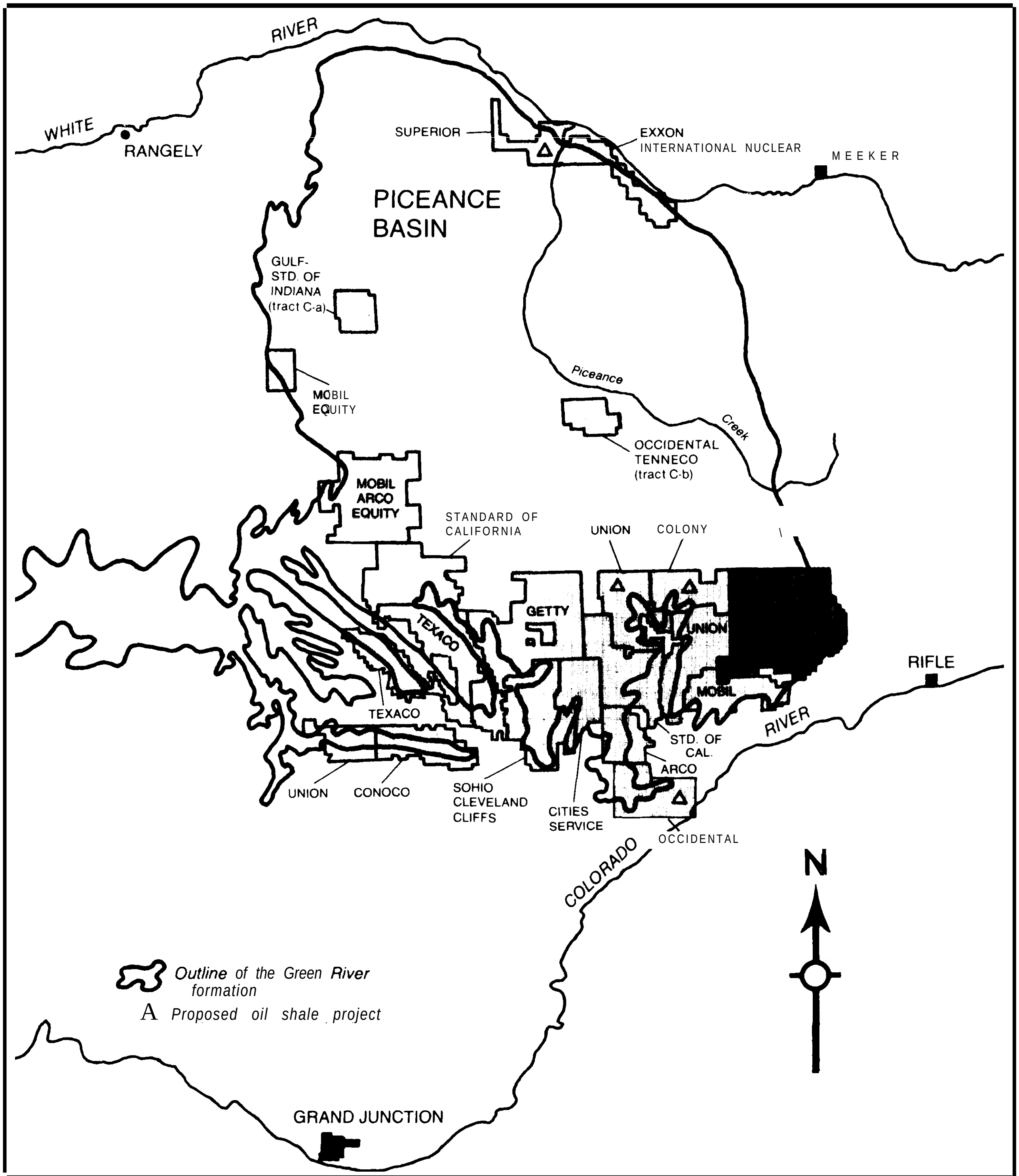
Second, because the level of water in the lake varied over time as the climate changed, the lakeshore advanced and receded. When the water level was high, organic matter was deposited over a broader area and was converted to oil shale before it could be decomposed by exposure to the air. When the water level was low, more inorganic silt was deposited, and any organic debris that was laid down near the shoreline decomposed when the shoreline receded. As a consequence, the deposits on the basin's fringe are much leaner on the average than the deposits to the north, and they occasionally are intermixed with layers of rock containing essentially no organic matter, This complicated stratigraphy reduces the average oil yield from deposits on private land, and makes them less suitable for commercial development.

The net effect of these two conditions is indicated in table 32 and illustrated in figure 57. As shown, the privately owned lands in Colorado and Utah include about 340,000 acres of deposits at least 10 ft thick that would yield at least 25 gal/ton of shale oil. The total potential yield from these deposits is about 100 billion bbl. In contrast, the Federal lands have 1.2 million acres of equivalent deposits with a potential yield of 460 billion bbl.

The third factor is that private lands contain essentially no commercially attractive deposits of nahcolite and dawsonite—the sodium minerals that are potential sources of aluminum, glass, and the chemicals used to

*The term "fee'" is derived from the Middle English word *fief:* an inheritable or heritable estate in land.

Figure 56.—Privately Owned Tracts in the Piceance Basin



SOURCE *Map of the Major Oil Shale Holdings—Colorado, Wyoming Utah*, Denver. Colo Cameron Engineers, Inc , January 1978

Table 32.–Distribution of the Oil Shale Resources in Colorado and Utah

	Ownership					
	Colorado		Utah		Total	
	Federal	Private	Federal	Private	Federal	Private
Ouantity of land (1 ,000 acres).	1,420	400	3,780	1,100	5,200	1,600
Deposits at least 10 ft thick and yielding at least 25 gal/ton (1,000 acres).	600	170	600	170	1,200	340
Potential yield of shale 011 (billion bbl).	390	80	70	20	460	100

SOURCE Adapted from *Prospects for Oil Shale Development—Colorado, Utah, and Wyoming*, Department of the Interior 1968 pp A-1 and A-2

control air pollution from flue gases. As shown in figure 58, the deposits of sodium minerals stop short of the northern edge of the major private holdings. The only significant exception is the land owned by Superior Oil Co., which lies along the northern edge of the sodium mineral resources.

Present and Potential Projects on Private Land

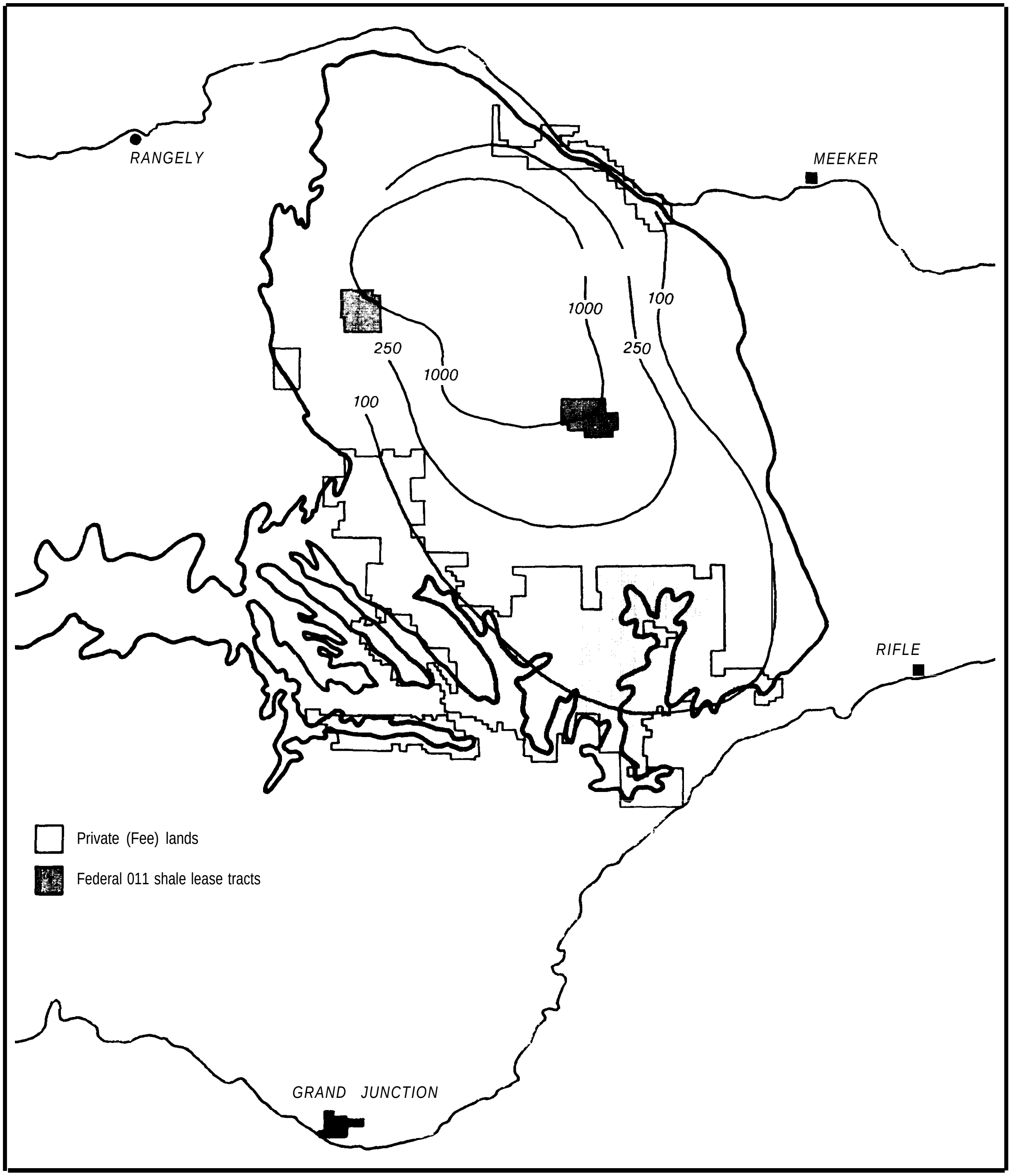
Colony Development Operation (a consortium of Tosco and Atlantic Richfield Co.) and Union Oil Co. own some of the more commercially attractive private land. The two companies have been developing retorting technologies since the 1950's and early 1960's. In the late 1960's Colony proposed to build a commercial-scale project on its property, which would use underground mining and aboveground processing in TOSCO II retorts. The project was delayed by economic uncertainties, and then resurrected in the 1970's after the Arab oil embargo. It was subsequently suspended when more detailed economic studies indicated a much higher cost for the project (and hence for its oil) than previously anticipated. The retorting process has been tested at the semiworks scale (about 1,000 ton/d), and is regarded by Colony as being ready for commercial application.

The Colony project would produce 46,000 bbl/d with six TOSCO II retorts, each processing about 10,000 ton/d of ore. Because the project would include a product pipeline across Federal land, an EIS was required. This was completed by the Bureau of Land Management (BLM) in 1977. At present, Colony has many of the major permits required to initiate the project, but it will not proceed until the economic climate is improved by further increases in oil prices or Government incentives, and until regulatory uncertainties are alleviated.[1]

Union Oil Co. began developing retorting technologies in the 1950's. It owns about 30,000 acres of land in the southern Piceance Basin, 20,000 acres of which contain oil shale. Union tested its "A" aboveground retort on this land between 1954 and 1958. Since 1974, Union has been studying a project that would use the Union "B" retort to extract 75,000 to 150,000 bbl/d of shale oil from the company's resources. The plant is to be developed with a modular stage in which a single "B" retort with a capacity of about 9,000 bbl/d will be tested. This project, the Long Ridge Experimental Shale Oil project, is in suspension until economic conditions improve sufficiently to warrant investment. A minimum requirement at present is a production tax credit of $3/bbl of shale oil produced.[2] Union has obtained all of the key environmental permits required for the modular project.

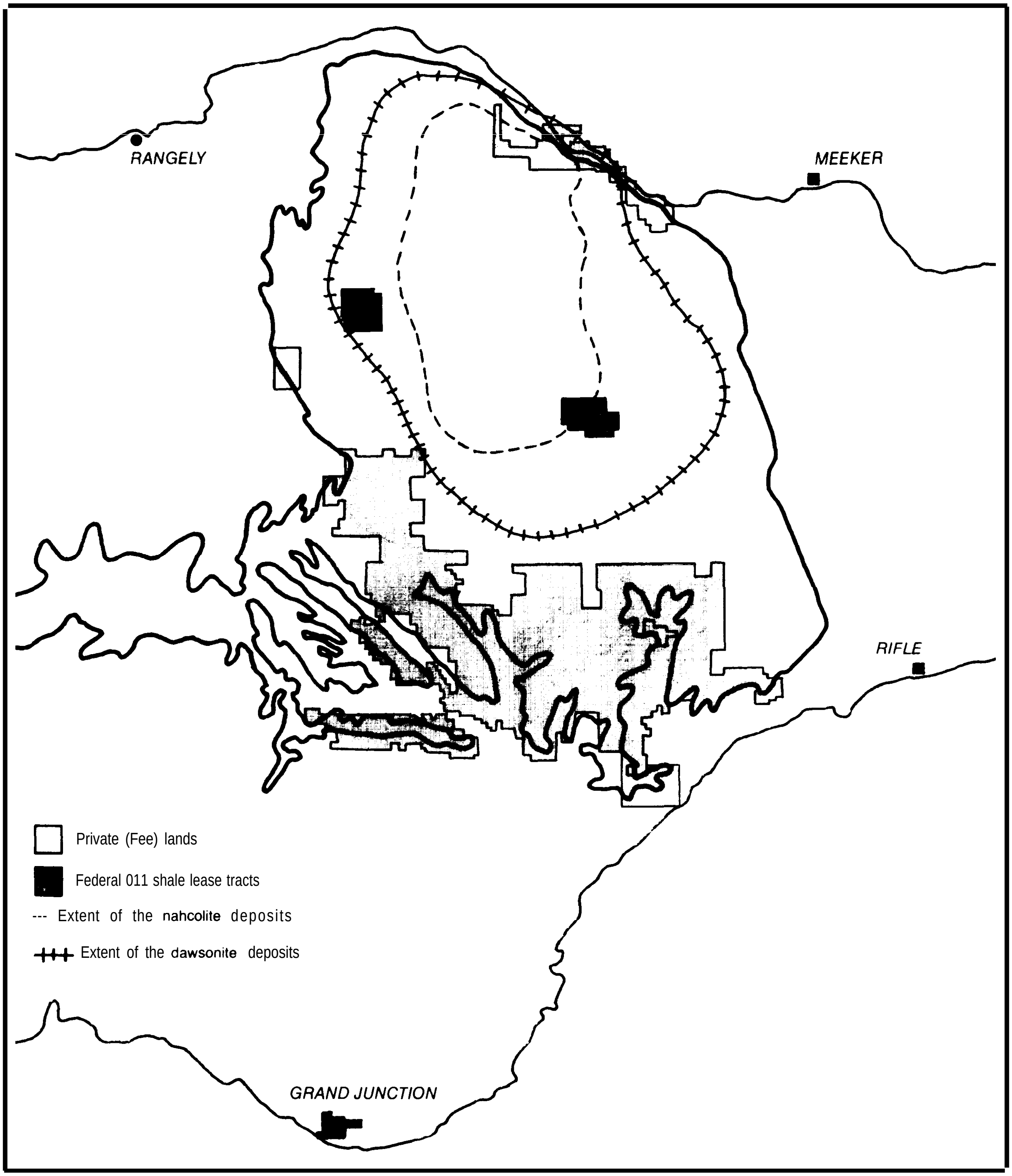
A third major oil project involving private land is the Superior project, which would involve the simultaneous recovery of shale oil, soda ash, alumina, and nahcolite from the sodium mineral deposits. As indicated previously, Superior has proposed to exchange a long, thin portion of its tract for a parcel of

Figure 57.—Thickness of the Oil Shale Deposits in the Piceance Basin That Yield at Least 25 gal/ton of Shale Oil



SOURCE Cameron Engineers, Inc

Figure 58.— Location of the Sodium Mineral Deposits in the Piceance Basin



SOURCE B Weichman, *Saline* Zone *Oil Shale and the Integrated In Situ Process*, Houston. Tex The Multi Mineral Corp , May 1979 p 17

Federal land. BLM has issued a draft EIS for the exchange, and recently completed a preliminary assessment of the value of the two tracts in question, as required by the equivalent-value provisions of FLPMA. Superior's land was found to have a significantly lower value than the Federal land to be acquired. BLM has tentatively denied the application. Superior is preparing a response to the denial and BLM's decision is open to review. If the exchange were approved, the project could produce about 11,500 bbl/d of shale oil, plus the other byproducts, from a single Superior aboveground retort. The resources on the tract could support one additional retort of the same size.

Tosco is also developing the Sand Wash project on land leased from Utah. It is in its early stages and is proceeding at a relatively slow pace. Under its leasing arrangements, Tosco is required to invest $8 million in tract development over an 8-year period. The sinking of a mine shaft has begun and will be completed in about 1982. This will be followed by an experimental mining phase lasting from 2 to 3 years.[3] Thus, by 1985, Tosco could be ready to build its retorting plant, which could ultimately have a capacity of 50,000 bbl/d. If a modular demonstration phase is included, the plant could be completed by 1995. If precommercial experiments are not conducted, as would be the case for Tosco's Colony project, the plant could be completed as early as 1990. However, this would require accelerating the experimental, design, and construction phases, which Tosco may not be willing to do in the absence of a highly favorable economic outlook. Tosco has not stated a position in regard to the types of encouragement that would be required, but as a member of the Colony Development Operation, Tosco has suggested a need for financial incentives and regulatory modifications,

Other private firms are also engaged in R&D activities on their tracts and on land leased from Utah. These projects are discussed in detail in chapter 5. The Geokinetics project, in which a true in situ (TIS) retorting technique is being developed, is the only one for which a commercial target—2,000 bbl/d—has been announced. Occidental Oil Shale is conducting experiments on its land in the extreme southern Piceance basin. However, the tests at the Logan Wash site are supporting the development of Federal lease tract C-b. The Logan Wash site has no commercial potential. Equity Oil Co. is developing another TIS process on private land in Colorado, but no production target has been announced.

If all of the presently active or suspended projects on non-Federal land proceeded to commercialization, the total production would be 280,000 to 350,000 bbl/d. However, this would require the following:

- for Union: a production tax credit;
- for Colony (and probably for Sand Wash): incentives and alleviation of regulatory uncertainties;
- for Superior: a land exchange and possibly incentives; and
- for Geokinetics: the continued support by the Department of Energy (DOE) of the company's experimental program.

There are other private tracts that have resources similar to those of Colony and Union. These include the tracts owned by Chevron (Standard Oil Co. of California), Getty Oil Co., Cities Service Corp., and others. However, no projects have been announced for any of these lands. In part, this reflects the technological positions of the other landowners—they do not own advanced retorting technologies. They may plan to license the processes of the other companies, once these have been demonstrated, or to develop their own processes once the economic viability of the oil shale industry appears assured. It appears that economic conditions would have to improve significantly in order to motivate these potential developers to complete their projects before, say, 1990. A much stronger set of incentives may be required than would be needed by Union or Colony, who already have both good technological and resource positions,

Present and Potential Projects on Federal Land

As discussed in volume II and mentioned earlier here, only two projects are actively being conducted as part of the Prototype Leasing Program. Rio Blanco Oil Shale Co. is developing tract C-a using MIS methods. A demonstration of the Lurgi-Ruhrgas above--ground retort may be included. Tract C-b is being developed as the Cathedral Bluffs Shale Oil project. Occidental's MIS technology is being used, and no plans have been announced for a concurrent demonstration of AGR technologies. The White River project on tracts U-a and U-b, which were unified for joint development, is presently in suspension pending resolution of ownership.

Paraho Development is also engaged in a project involving Federal land at the DOE research facility in Anvil Points, Colo. Anvil Points was the site of Paraho's retort development program. Paraho is attempting to extend the terms of its lease to include a modular demonstration program and to obtain funding for the project. The outlook is uncertain, because an EIS is required and none has yet been issued, despite four attempts by DOE. Paraho's management is also pursuing a production tax credit to improve the economic outlook for shale oil.

As mentioned earlier, EXXON Corp. has also proposed to exchange its scattered holdings for a single tract of Federal land in Colorado. The future of this proposal is uncertain. If Superior's land-exchange experience is regarded as typical, preparation and review of the EXXON proposal could take as long as 8 years. Four years is more likely.

DOE and the Department of Defense are preparing a management plan for developing Naval Oil Shale Reserve No. 1 (NOSR 1), which is contiguous to the Anvil Points site. This project is in the early stages, and the potential production cannot be accurately estimated. However, if all of the preliminary exploration, design work, and permitting can be completed by 1986, and if plant construction were expedited, DOE believes that NOSR 1 could be producing at least 100,000 bbl/d by 1990.

Multi Mineral Corp. has proposed to use a mine shaft on Federal land in the northern Piceance basin to develop an MIS process to recover shale oil, alumina, and nahcolite from deeply buried deposits. The shaft was drilled in 1978 by the U.S. Bureau of Mines to develop mining techniques for sodium minerals and oil shale in the saline zone. * The proposal involves a three-phase project that could lead to a 50,000-bbl/d operation.

If all of the presently active and proposed projects involving Federal land were completed, the total production could exceed 300,000 bbl/d, plus any additional production from NOSR 1. However, only 57,000 bbl/d of this production is assured, because only Cathedral Bluffs is committed to commercialization. Rio Blanco is committed only to testing its development techniques at the precommercial level—approximately 2,000 bbl/d. The decision to proceed to commercial levels of production will depend on the technical feasibility of the MIS and Lurgi-Ruhrgas methods and on the existence of a favorable economic and regulatory climate. Therefore, achieving 300,000 bbl/d from these operations is likely to require the following:

- for Cathedral Bluffs: continued technical progress and continuation of a favorable economic outlook;
- for Rio Blanco: technical progress and favorable project economics, perhaps including Federal financial incentives;
- for Paraho: extension of the terms of the Anvil Points lease and provision of a production tax credit;
- for White River: favorable resolution of the ownership dispute and possibly Federal incentives (Standard Oil Co. of Ohio (SOHIO) is a participant in the White

*The Multi Mineral technology is discussed in ch. 5. The geology and stratigraphy of the oil shale basins are discussed in ch. 4.

River project. SOHIO is also involved in the Paraho operation.); and
- for EXXON: approval of the proposed land exchange.

The potential production from tract C-a could be expanded by 75,000 bbl/d if the lessees returned to their original open pit mining plan. However, to allow maximum recovery of the oil shale resource, lands outside of the tract boundaries would have to be used for waste disposal and the siting of the processing facilities. Such off tract land use is presently banned by Federal statutes, including the acreage limitation of the Mineral Leasing Act and the provisions of FLPMA, which state:

> Nothing in this Act, or in any amendment made by this Act, shall be constructed as permitting any person to place, or allow to be placed, spent shale oil, overburden, or byproducts from the recovery of other mineral with oil shale, on any Federal land other than Federal land which has been leased for the recovery of oil shale . . .

Is More Federal Land Needed?

As discussed in chapter 6, shale oil appears to be economically competitive, based on the present and projected prices of foreign crude oil and some premium-quality domestic crudes. However, technical, economic, and regulatory risks are inhibiting potential developers from making large capital investment commitments to shale development. These uncertainties are aggravated by some of the characteristics of the private lands which, in general, are not so favorable as those of adjacent Federal lands. Furthermore, the privately owned lands contain essentially no commercially attractive deposits of sodium minerals. Assuming that these minerals could be extracted economically, they could be sold as byproducts to enhance the economic feasibility of a project. Whether more Federal land must be provided depends on:

- how much production is desired;
- how rapidly the industry is to be created;
- whether production of sodium minerals, or testing of the "multimineral" technologies used to extract them, is desired;
- how much technical, economic, and environmental information is desired to assist policymaking and the setting of environmental regulations; and
- whether financial incentives are provided that will encourage the continuation of present projects on the Federal lease tracts and also initiate projects on private lands.

The need for additional Federal land will depend strongly on the size of the industry and the pace of its creation. It will also be affected by the other Federal oil shale policies, especially those involving financial incentives. This is shown in table 33, which indicates how the industry's capacity in 1990 might be affected by different Federal actions. As shown for case 1, about 60,000 bbl/d could be achieved with no additional actions, assuming that the Cathedral Bluffs project is completed and that Geokinetics reaches its production target. If economic conditions encourage Rio Blanco to continue and Sand Wash to accelerate, production could reach 185,000 bbl/d by 1990. If incentives are added (case 2) that assure completion of these two projects, that encourage the Colony and Union projects to resume, and that also initiate a new project on private land, production would reach 360,000 bbl/d. This could be expanded in case 3 to nearly 400,000 bbl/d if the Superior land exchange is consummated (or a lease issued for the desired parcel) and test sites are provided for the Paraho and Multi Mineral processes. All three of these projects would involve providing access to additional Federal land.

If the ownership conflicts surrounding the Utah lease tracts are resolved in a manner

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Table 33.–Estimated Shale Oil Production by 1990 in Response to Various Federal Actions

Federal action	Case 1	2	3	4	5	6	7	8
None	X							
Incentives for first-generation developers		X	X	X	X	X		
Test sites for modular retorts[b]			X	X	X	X	X	X
Resolution of ownership issues on Utah tracts[c]				X	X	X	X	X
Offtract land use[d]					X	X	X	X
Proposed land exchanges						X	X	X
Incentives for second-generation developers (or improved economics)							X	X
Naval Oil Shale Reserves or expanded Prototype Program or permanent leasing								X
Production, bbl/d	60,000-185,000[f]	360,000	390,000	490,000	560,000	620,000	850,000	1,000,000

[a]Assumes the entry of one as-yet unannounced developer
[b]Includes the proposed superior 011 land exchange and a leasing of Anvil Points by Paraho Development
[c]Resumption of the tract U-a/(J-b project may also depend on the availability of Incentives and on other improvements in Protect economics
[d]For waste disposal from the open pit mme that was originally proposed for tract C-a
[e]Includes the proposed Superior 011 and EXXON land exchanges
[f]Only 59,000 bbl/d is firmly committed

SOURCE Off Ice of Technology Assessment

favoring the lessees, and if appropriate incentives are provided, the White River project could resume. This would add 100,000 bbl/d to the industry's capacity. Production could reach 560,000 bbl/d if Rio Blanco were given permission to use offtract lands and returned to its original open pit mining plan, as assumed for case 5. If the EXXON land exchange were completed (case 6), production would be increased by 60,000 bbl/d. As shown for case 7, production might be increased to 850,000 bbl/d by providing subsidies that were sufficiently attractive to encourage the participation of the "second generation" of developers—those who are not as technically advanced as Colony and Union, or who lack resources of equivalent quality. The total additional capacity indicated corresponds to about five additional major projects on private land. The Government could also become more directly involved in oil shale development by leasing additional tracts or by developing NOSR 1 (case 8). The industry's capacity in 1990 could then reach 1 million bbl/d.

In summary, reaching 200,000 bbl/d by 1990 may not require the release of substantial tracts of Federal land, if the presently active projects are technically successful and if the economic outlook remains favorable. Only 60,000 bbl/d of this capacity is assured. About 400,000 bbl/d might be achieved if effective incentives were provided and test sites allocated for retorting demonstrations. Achieving 1 million bbl/d by 1990 might require subsidies, land exchanges, permission to use offtract land for waste disposal and facility siting, and the leasing of additional tracts or the development of the Naval Oil Shale Reserves.

Policies

- **To** amend the Mineral Leasing Act of 1920.—The Act could be amended to increase the acreage limitations, or to set the size of the tract according to the recoverable resources it contained. This might allow more economies of scale, thereby improving economic feasibility. It might also allow the inclusion of a suitable waste disposal site within a tract's boundaries while still providing adequate oil shale resources for sustained, large-scale operations, thus avoiding the need for separate offtract disposal authorization. The number of leases per person or firm could also be increased. This might provide additional encouragement to firms that do not own oil shale lands because it would allow them to acquire experience on one lease tract and then apply it to another while the first was still operating. A disadvantage would be that the number of firms participating in the leasing program could be reduced if a few firms acquired all of the leases. One option would be to increase the number to one lease per State. This might encourage a firm to develop a process in the richer deposits in Colorado and then apply it to the poorer quality resources in Utah or Wyoming.

- To amend FLPMA.—FLPMA could be amended to allow including conditions (such as environmental stipulations and diligence requirements) in any oil shale land exchange agreement. This would improve the Government's control over the exchanged parcel. It might also discourage private participation.
- To allow offsite land use for lease tracts.—Legislation could be provided to allow a lessee to use land outside of the boundaries of a lease tract for facility siting and waste disposal. This might permit larger, more economical operations (including perhaps an open pit mine) and would maximize resource recovery on the tract. However, subsequent development of the offtract areas would be inhibited. (DOI estimated that Rio Blanco's offtract disposal plan would reduce resource recovery from the disposal area by about 5 percent.)
- To lease additional tracts under the Prototype Program.—There is no statutory limitation on the number of tracts that could be leased under the Prototype Program. However, DOI originally committed to leasing no more than six. Because two of the original tracts were not leased, offering two new ones might be justified, provided that the technologies to be tested were different from the processes being developed on the existing tracts. Leasing more than two more tracts, or leasing for the purpose of expanding near-term shale oil production, would encounter political opposition by the critics of rapid oil shale development. Leasing could begin sooner than under a new leasing program, if some of the potential lease tracts previously nominated were offered. A supplemental EIS would be required. Construction on the tracts could probably not begin until about 1985 and production no sooner than 1990. Consideration might be given to leasing a tract for multimineral operations, a process that is not being evaluated in any project at present. (One of the primary goals of the Prototype Program is to obtain information about a variety of technologies.)
- To initiate a new, permanent leasing program.—An advantage would be that more production could be achieved than is possible under the present Prototype Program. A full EIS and a new set of leasing regulations would be needed. Without the information to be acquired by completing the present Prototype Program projects, it might be difficult to prepare an accurate environmental assessment and to structure comprehensive leasing regulations. Production could probably not begin until after 1990. Abandonment of the Prototype Program would be implied, which might engender political opposition.
- To expedite land exchanges.—The review and approval procedures could be expedited by, for example, setting up a task force within DOI specifically for oil shale proposals.
- Government development.—The Government could develop the Naval Oil Shale Reserves. Unless this were done by leasing to private developers, it would involve competition with private industry, and would encounter political opposition. It would also be very costly because the public would have to pay the full cost of the facilities, and it might discourage independent experiments by private firms. Information useful in developing policies and regula-

tions for the industry would be obtained. However, because the Government's experience with financing and operating a facility would be substantially different from that of private developers, the information might not be useful in evaluating private investment decisions. Some of the information is being acquired in the present Prototype Program. It could also be obtained in additional leasing programs or through licensing arrangements with the owners of the technologies.

Chapter 7 References

[1]H. F. Coffer and A. Christianson, eds., *EPA Program Conference Report: Oil Shale,* EPA-600/0-79-025, July 1979, p. 90

[2]Ibid., at p. 27.

[3]Ibid.

CHAPTER 8

Environmental Considerations

Contents

List of Tables

List of Figures

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 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. 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 Ieachates 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. H 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 Supervisor 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 (SO_2), particulate, carbon monoxide (CO), ozone (0 S), lead, and nitrogen oxides (NO_x); as well as various other currently unregulated pollutants, such as silica, sulfur compounds, metals, carbon dioxide (CO_2), ammonia (NH_3), 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, SO_2, 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 SO_2 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 (H_2S), carbonyl sulfide (COS), and carbon disulfide (CS_2) 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 CS_2 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 CS_2.

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, chrome, 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 onsite pollutant production in this step will be negligible because it plans to purchase most of its electricity from offsite powerplants.

The emission of SO_2, produced in the NH_3 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,	NO,	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

[a] Table shows the level of pollutant generation, not pollutant release
[b] Room-and-pillar mining; TOSCO II retorting, scaled 1050,000 bbl/d of shale oil syncrude production
[c] Figures do not include components of the product gas and vapor stream
[d] also, equivalent of H_2S in retort gas stream

SOURCE T C Borer and J W Hand, */derr//hcal/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[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	–	–	–	–	–
Total	18,017	19,506	2,087	311	430

[a]Table shows the level of pollutant generation not pollutant release
[b]Underground mining modified in situ and TOSCO II aboveground retorting scaled to 50,000 bbl/d of shale oil syncrude
[c]Figures do not include components of the product gas and vapor stream
[d]Also, equivalent of H_2S 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[a] (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[c]	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
Total	5,100	24,030	3,500	230	210

[a]Table shows the level of pollutant generation not pollutant release
[b]Underground mining modified in situ retorting scaled to 50000 bbl/d of shale oil syncrude
[c]Figures do not include components of the product gas and vapor stream
[d]SO_2 equivalent of H_2S 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, SO_2, CO, NO_x, 0_3,, 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 1. Either type of redesignation is subject to hearings and consultations with the managers 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 major 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.

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

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 SO_2, 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 SO_2 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.

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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 Colorado's and Wyoming's standards. In addition to the standards shown for Wyoming, the State has also promulgated regulations to limit ambient concentrations of H_2S, 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)

	Ambient air quality standards					Prevention of significant deterioration standards	
						Federal	
Pollutant	Federal (primary) human health	Federal (secondary) public welfare	Wyoming[a]	Colorado[a]	Utah[a]	(Class 1)	(Class II)
SO_2							
Annual arithmetic mean. . .	***80***	None	60	80	***80***	***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	***60***	60	45	75	5	19
24-hour maximum . . .	260	***150***	150	150	260	10	37
NO_x ***(as NO_2)***							
Annual arithmetic mean.	100	100	100	100	100	None	None
Oxidants (as O_3)							
l-hour	***240***	240	160	*160*	240	None	None
CO							
8-hour maximum	10,000	10,000	10,000	10,000	10,000	None	None
l-hour maximum	**40,000**	**40,000**	**40,000**	**40,000**	**40,000**	None	None
Lead							
Quarterly .	1,5	1.5	***1,5***	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

[a]State ambient air quality standards are identical to the Federal primary standards unless printed in italics The stricter standard IS the controlling standard
[b]Not a standard, a guide to show achievement of O_3 standard
[c]Allowable Incremental change m 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 SO_2 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 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.

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

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

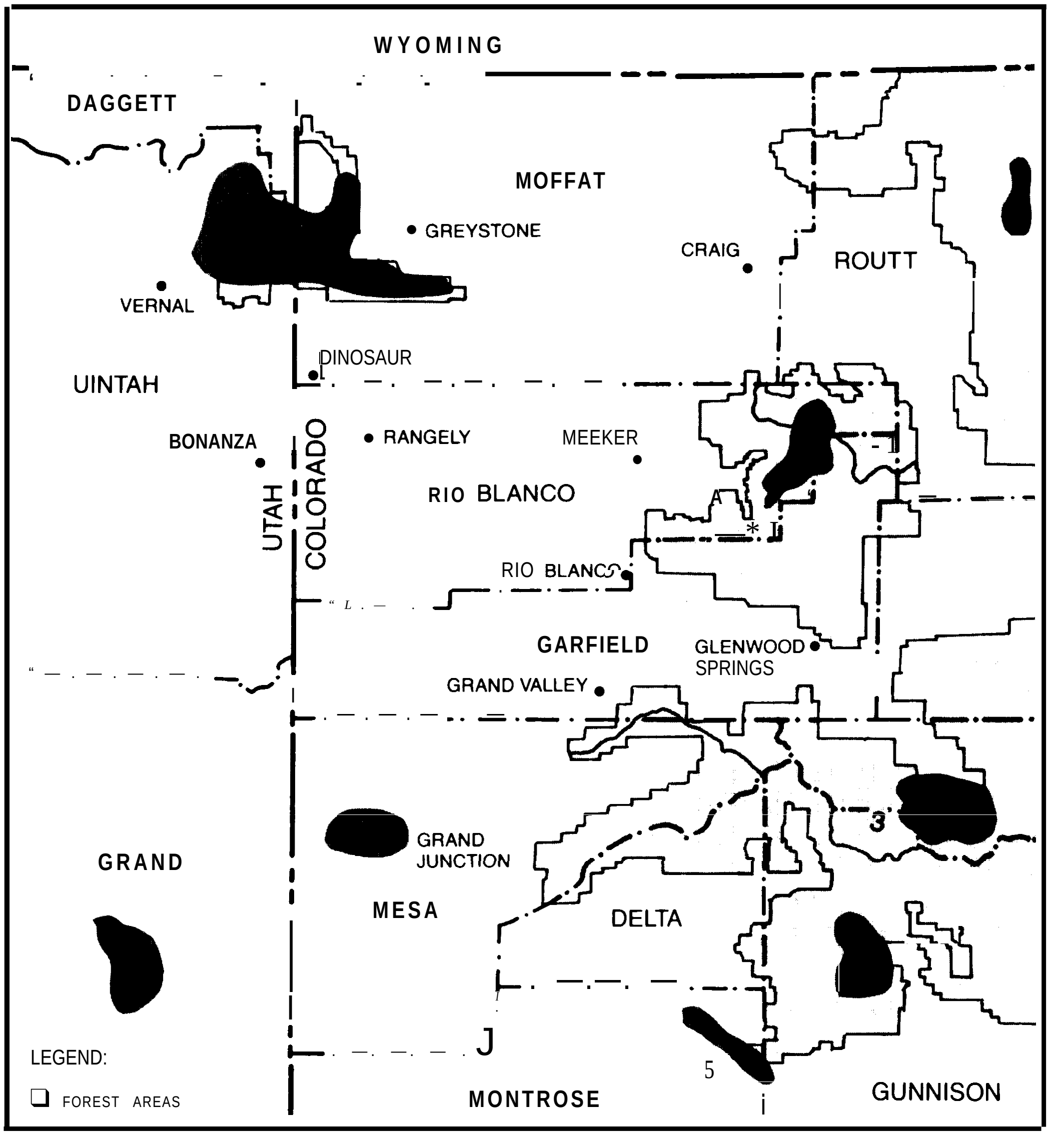
[a] EPA is presently developing Incremental standards for HC CO O_3 NO_x and Pb

SOURCE Environmental Protection Agency Work Group *Pollution Control Guidance for 01/ Shale Development Appendices to the Revised Draft* EPA Cincinnati Ohio July 1979 p 0-17

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 SO_2 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 H_2S ambient concentrations from all shale oil plants to 142 micrograms per cubic meter (142 $\mu g/m^3$ 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**
2. **Mount Zirkel Wilderness**
3. **Maroon Bells—Snowmass Wilderness**
4. **West Elk Wilderness**
5. **Black Canyon of the Gunnison Monument**
6. **Colorado National Monument**
7. **Arches National Park**
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'

Operation	Pollutant	Removal or emission standard[b]	Status
Fossil fuel fired steam generators	Particulates SO_2, NO_x	0.1 lb/m Btu 0.8 lb/m Btu for gaseous fuels; 0.3 lb/m Btu for liquid fuels	Existing
Petroleum refineries	H_2S HC	0.1 gr/scf (dry) Floating roof tanks or vapor recovery systems if true vapor pressure is between 1,5 and 11,1 lbt/in²a and reporting system only if pressure is less than 1.5 lbf/in²a	Existing
Refinery Claus sulfur recovery plants	H_2S Sulfur	0,1 gr/scf (dry) 250 p/m SO, for oxidation systems, 300 p/m total sulfur and 10 p/m H_2S for reduction systems	Existing
Gas turbines	NO_x so,	75 p/mat 15Y0 oxygen 150 p/m	Proposed for units over 10 m/ Btu per hour
Gasification plants	Sulfur HC	99,0% removal and 250 p/m total sulfur 100 p/m	Guideline
Field gas processing units	H_2S so, Sulfur	160 p/m 250 p/m for oxidation systems 300 p/m for reduction systems	Proposed

[a]Presented as a guide to what might be considered for oil shale facilities
[b]lbf/in²a = pounds per square inch absolute p/m = per million scf = standard cubic feet
[c]Standards 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.

Table 40.–EPA Standards for Best Available Air Pollution Control Technologies for Oil Shale Facilities[ab]

Pollutant	Removal requirement	Maximum emissions
Sulfur	99.0% total recovery	15 p/m H_2S (reduction systems) 250 p/m SO_2(oxidation systems)
Particulates.	99.0% from combustion gas streams 99 80/o from materials-handling gas streams Fugitive dust control	No standard
NO_x	Complete combustion	0.5lb/mBtu
CO	Complete combustion	No standard
HC	Complete combustion	No standard

[a]p m = parts per million
[b]These standards have been used in EPA s PSO 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

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, H_2S, 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 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 $S0_2$ is obtained by oxidizing part of the H_2S to $S0_2$ by burning it in air, and then mixing the combustion products with the feed stream. The $S0_2$ 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 $S0_2$. 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 cobait-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 $S0_2$ are very soluble in this liquid, and efficient conversion to sulfur results. The most important operating variable is the H_2S to $S0_2$ 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 $S0_2$, can be disposed of in ponds.

  Performance of the system is well-established, and over 99-percent $S0_2$ removal has been achieved with $S0_2$ 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 $S0_2$ 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, condensation 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, decreasing, 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 ft^3/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 H_2S control methods will work well with the low H_2S 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 $S0_2$ 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 H_2S 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 Ioading, temperature, and particle resistivity. Good removal efficiency, Low operating costs and maintenance. Good for large gas volumes. High capital cost.
H_2S		
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,
SO_2		
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 ProDosed Control of Air Pollutants kern Oil Shale Operations* prepared bv 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 design, 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 NH_3 could be included in an integrated facility, for example, not specifically for air pollution reduction but to increase plant revenues. 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 pollutant generation was summarized in tables 34 through 36,[5] DRI's hypothetical control systerns 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 SO_2 and particulate removal. Capital costs for SO_2 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 prolect[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
SO_x	99,0%	9,910	7,240	99.0%	26,210	11,187	99.0%	29,800	12,844
NO_x	(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

[a]47 000 bbl/d of shale oil syncrude [b]57 000 bbl/d of crude shale 011 [c]81000 bbl/d Of crude shale oil
[d]R..ds are paved Water sprays used for disposal areas [e]Maximum reduction achievable through adjustment of combustion conditions
[f]Low reduction requirements because of low-temperature retorting and use Of low-nitrogen fuel in combustors

SOURCE Oata adapted from Denver Research Institute *Predicted Costs of Environmental Controls for A Commercial 01/ 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,	NOx	HC	co
Mining ., ., ., . . ., ., ...	10	0	250[b]	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 +

[a]R~~m.and.pillar mining TOSCO II retorting scaled to 50000 bbl/d of shale oil syncrude production
[b]These 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,	NOx	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

[a]uflde@~Ound mining MIS and TOSCO II aboveground retorting scaled 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 Opera(/errs,* 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

[a]Underground mining MIS retorting scaled 1050000 bbl d of shale 011 syncrude production
[b]Assumes 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 I I aboveground retort	50,000 bbl/d syncrude	240	280	1,930	360	500
Rio Blanco						
MIS plus Lurgi-Ruhrgas 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, SO_2 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 subprocesses 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.

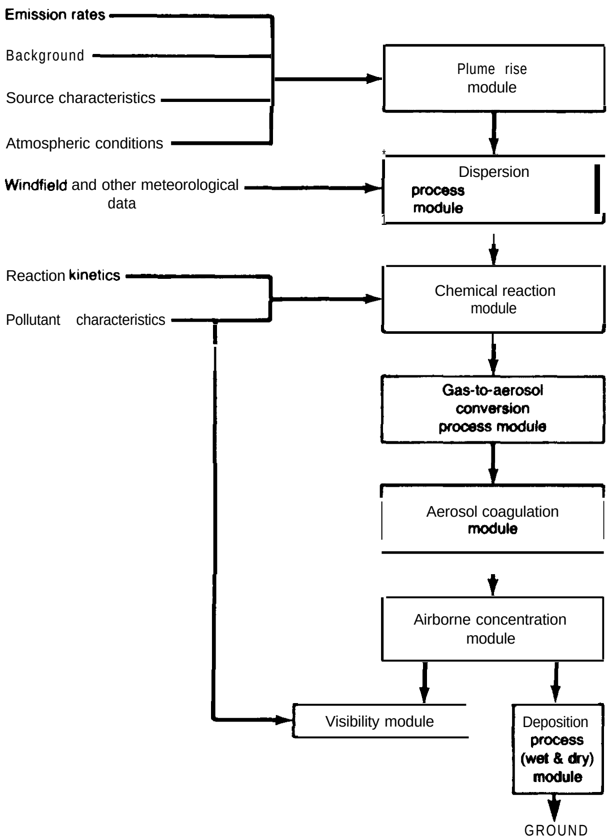
Most models incorporate a series of computational modules, as shown in figure 60. A major difference between the models lies in the manner in which the input data are manipulated and in the application of the computational modules. Usually, not all of the modules are used in any given model. Near-source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

*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.

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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-ize 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	1,806	324	829
				317	1,746	304	842
Tract C-b							
Colorado	TOSCO II	45,000	1976	267	1,634	262	776
				353	1,894	313	968
Tract C-a							
Colorado	TOSCO II	6,000	1976	26	322	112	148
		56,000		265	994	185	573
Tracts U-a and U-b							
Utah	Paraho	10,000	1976	8.4	108	0.88	68
		50,000		148	1,369	55	452

SOURCE Adapled 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 approxima te,

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, including 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.’

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

						Revised DDP (May 1977)				Original DDP(March 1976)			
		National standards		Colorado standards		Offtract ambient air		Offtract increment		Offtract ambient air		Offtract increment	
						Phase I[b]	Phase II[c]	Phase I[b]	Phase II[c]	Phase I[d]	Phase II[e]	Phase I[d]	Phase II[e]
Pollutant	Averag-ing time	NAAQS[a]	PSO increment Class II	Ambient Air	PSD Increment Category II	MIS	MIS/TOSCO II	MIS	MIS/TOSCO II	TOSCO II	Aboveground	TOSCO II	Aboveground
SO_2	Annual	80	20	80	20	84	8	32	27	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 HC[f]	3-hour	160	None	160	None	65	90	0.3	25	221	129	156	64
Lead	Quarterly	15	None	15	None	—	—	—	—	—	—	—	—
O_3	l-hour	240	None	160	None	—	—	—	—	—	—	—	—

[a]Stricter of primary and secondary standards [b]Capacity 4000 bbl/d (MIS) [c]Capacity 57000 bbl/d (MIS) + 19.000 (TOSCO II) [d]Capacity 9000 bbl/d (TOSCO II)
[e]Capacity 55800 bbl/d (TOSCO II and. e 9 .Paraho) [f]Not 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

dieted 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 SO_2, 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 SO_2 increment. Simple linear scaling would indicate that the industry would be limited to about 217,OOO bbl/d by the PSD restrictions on SO_2, 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 SO_2, because they do not allow for formation of sulfate particles from SO_2 and their subsequent deposition. Second, it is impossible for the wind to be blowing from four directions at the same time. Third, the projected SO_2 and particulate concentrations at Flat Tops were affected strongly by the Colony project, which is predicted to emit more SO_2 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 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 SO_2 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. '

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

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 SO_2, 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 capability, 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 SO_2 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 fugltive 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, O_3, 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 1 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, constraints 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 Piceance 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.

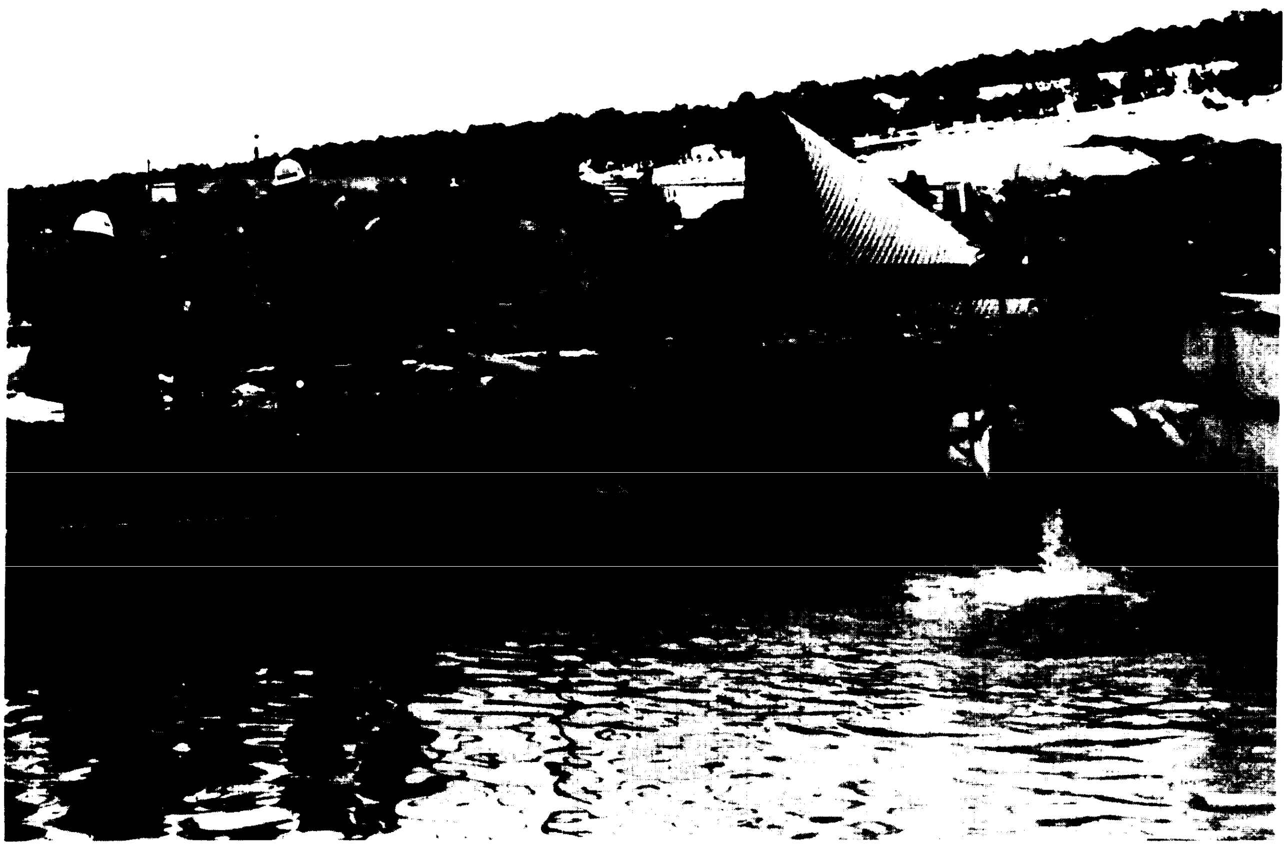
- The quality of surface and ground water resources in the oil shale region is examined.
- The applicable Federal and State water quality regulations and standards are described.
- The effects of these regulations and standards on a developing oil shale industry are analyzed.
- The pollution control 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-



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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-Ruhrgas), 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 difficult 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 reflects 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]

*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 retortinq facility			
	Aboveground direct	Aboveground indirect	MIS	MIS/ aboveground
Gas condensates				
NH_3 .	75.6	147	276	189
H_2S	0.9	2 3	1 5	1.1
CO_2	136	17.5	541	371
BOD : :	19.2	285	18,5	127
Subtotal	232	63	837	574
Retort condensates				
NH_3	(b)	(b)	3,5	2.4
H_2S. . .	(b)	(b)	–	–
CO_2	(b)	(b)	48.2	331
BOD .,	(b)	(b)	10.1	7.3
Subtotal	–	—	62	43
Upgrading condensates				
NH_3 .	134,2	1342	134,2	134,2
H_2S	58.8	58.8	58.8	58.8
CO *	1,4	1 4	1 4	1.4
BOD	3.7	3 7	3 7	3,7
Subtotal	198	198	198	198
Blowdown and waste treatment[c]				
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)	145	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)	126	12.6
Subtotal	—	—	52	52
Total,	488	295	1,171	887

[a]Tons ner stream day
[b]Assumes above-ground retorts operated at temperatures that do not Produce condensate
[c]Includes water pretreatment Above-ground plants use Colorado River wafer MIS and MIS/ above-ground plants use mme drainage waler
[d]Calcium magnesium and sodium ions
[e]Carbonate and bicarbonate ions
[f]Assumes **above-ground** retorting plants are not located in ground water areas

SOURCE Office of Technology Assessment

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 CO_2 and NH_3). 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 increase over 500 mg/1, 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/1 for dissolved solids and 250 mg/1 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,

"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, recreation, 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/1.

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[b]	0 0 6	NA	NA	0.153	0 1	0 1	0 0 6
Bicarbonate	168	241	542	601	1,470	606	540	575
Boron	NA	0088	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 0 3	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

[a]See reference list
[b]Data 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/1) to over 40,000 mg/1, A concentration of 63,000 mg/1 was reported for one sample.[36]

"I'he 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	Alluvial	Alluvial	Upper	Lower
Referenced	17	16	16	16
Ammonia	0337	NA[b]	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	0367	4 6	1 4	28
Hardness	600	NA	NA	NA
Magnesium	8 3 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

[a]See reference list [b]Data not available

SOURCE Off Ice 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.

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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 polluters. 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 the following wastewater management procedures:

- sour water stripping to reduce NH_3 and H_2S;
- 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 54.–Effluent Limitations for Petroleum Refineries Using Best Practicable Pollution Control Technology (BPT)
(pounds per 1,000 bbl of feedstock)

Effluent characteristic	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
011 and grease	60	32
Phenolic compounds	014	0068
Ammonia as N	83	38
Sulfide	0124	0056
Total chromium	O 29	017
Hexavalent chromium	0025	0011
pH	Must be within the range of 6.0 to 90	

SOURCE E R Bales and T L Thoem (eds) *Pollution Control Guidance for Oil Shale Development Appendix* Environmental Protection Agency Cincinnati Ohio July 1979 pp 9

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

	Effluent limitations	
Effluent characteristic	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	26
Chemical oxygen demand	168	134
011 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 Thoem (eds) *Pollution Control Guidance for Oil Shale Development Appendix* Environmental Protect(on Agency Cincinnati Ohio July 1979 p 0 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.

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

	Effluent Imitations	
Effluent characteristic	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
011 and grease	4.5	2.4
Phenolic compounds	0.105	0.051
Ammonia as N	8.3	3.8
Sulfide	0093	0042
Total chromium .,	0220	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 Thoem (eds) *Pollution Control Guidance for Oil Shale Development Append/x* Environmental Protection Agency Cincinnati Ohio July 1979 p 012

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

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 antidegradation 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 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 antidegradation policy.

*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 Thoem (eds) *Pollution Control Guidance for 01/ Shale Development Appendix* Environmental Protection Agenc y Cincinnati Ohio July 1979 p D 20

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

Parameters	Criteria for CW streams
Radioactive and chemical	Drinklng water standards
Settleable solids. 011, 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_5)	Less than 5 milligrams per liter
Dissolved oxygen	>6.0milligrams per liter
Temperature	Maximum 680 F

SOURCE E R Bates and T L Thoem (eds) *Pollution Control Guidance for Oh Shale Development Appendix* Environmental Pro tection 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 C_aCO_3	–	**30-130** mg/l[a]	—		—
Aluminum-total	–	0.1 mg/l	.	5.0 mg/l[b], 20.0 mg/l[a]C	5.0 mg/l[a]
Aluminum-dissolved	–	0.1 mg/l[a]	—		—
Total ammonia as N	0.5 mg/l[a]	—	—	—	—
Unionized ammonia as N	–	0,02 mg/l	—	—	—
Arsenic-total	0.01 mg/l	0.05 mg/l	—	0.1 mg/l	0.2 mg/l[d]
Barium-total	1,0 mg/l	—	—		—
Beryllium-total	–	1,1 mg/l	—	0.1 mg/l[b], 0.5 mg/l[c d]	—
Boron	1.0 mg/l[a]	—	—	0,75 mg/l[e]	5.0 mg/l[d]
Cadmium-total	0,01 mg/l	0.003 mg/l	—	O.O1[b], 0.05 mg/l[c]	0.05 mg/l[d]
Chloride-total	250 mg/l	—	—		—
Chromium-total	005 mg/l	0.3 mg/l[f]	—	0.1 mg/l[b], 1.0 mg/l[c]d	0.1 mg/l
Fecal coliform	2,000/100 ml[f]	2,000/100 ml[a]	200/100 ml	1 ,000/100 ml	1 ,000/100 ml
Color	.75 color units[a]	—	—		—
Copper-total	.1.0 mg/l	0.030 mg/l	—	**0.2** mg/l[b], 5.0 mg/l[c]	0.5 mg/l[d]
Cyanide	.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[a c]	—
Iron-dissolved	..03 mg/l	0.3 mg/l[a]	—	—	—
Lead-total	0.05 mg/l	0.03 mg/l	—	5 mg/l[b], 10 mg/l[c]f	0.1 mg/l
Manganese-total	0,05 mg/l	1,0 mg/l	—	0.2 mg/l[b], 10 mg/l[c d]	—
Manganese-dissolved	0,05 mg/l	—	—		—
Mercury-total	0,002 mg/l	0,00005 mg/l	—		0.00005 mg/l[a]
Molybdenum-total	—	—	—	0.01 mg/l[b], **0.05** mg/l[c]	0.5 mg/l
Nickel-total	–	0.1 mg/l	—	0.1 mg/l[f]	—
Nitrate-tl	10 mg/l	—	—	100 mg/l	$NO_3 + NO_2$ 100 mg/l
Dissolved oxygen	40 mg/l[f]	5.0-6.0 mg/l min.	2,0 mg/l min.	2.0 mg/l	2.0 mg/l
pH	5.0-9.0	6.5-9.0	6.5-9.0	4.5-9.0[a]	—
Phenols	0.001 mg/l	0.001 mg/l	—		—
Total PO_4-P	–	0.025 mg/l - lakes[a]	—		—
Phthalate esters	–	0.003 mg/l	—	—	—
PCB	–	0.000001 mg/l	—	—	—
Selenium-total	0.01 mg/l	0.05 mg/l	—	—	O 5 mg/l
Silver-total	0.05 mg/l	0,0001-0,0025 mg/l[g]	—		
Silver-dissolved	–	0.0001 mg/l	—		
Sodium	.270 mg/l[a h]	—	—		—
Sulfate-total	250 mg/l	—	—	—	—
TDS	500 mg/l[a]	—	—	(1)	3,000 mg/l[a]
TSS	–	25 mg/l-median[j]	—		—
H_2S (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
[a]CWA 208 recommendation only (no proposed State standard)
[b]Continuous irrigation, all soils (match WQCC proposed State standards)
[c]Short-term irrigation, neutral to alkaline fine textured soils
[d]For agricultural uses the WQCC except in a few Instances did not distinguish between irrigation and livestock uses The CWA 208 attempted 10 distinguish the differences Therefore, under livestock there are numerous differences between 208 and WQCC numbers Under irrigation the lower recommended criteria match WQCC numbers
[e]Long-term irrigation on sensitive crops
[f]Differs from proposed State standards
[g]Limiting concentration dependent on hardness
[h]Maximum concentration for a moderately restricted sodium diet
[i]Water 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
Waler that may have adverse effects on many crops and requires careful management practices f ,000-2000 mg/l
Water that can be used for tolerant plants on permeable soils with careful management practices 2,000-5000 mg/l
[j]Value represents maximum increase in ambient concentration due 10 discharge
[k]Cold 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 Thoem (eds) *Pollution Control Guidance for 01/ Shale Development Append/x*, 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 program 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
Inorganic chemicals (except fluoride)	
Arsenic	005
Barium	10
Cadmium	001
Chromium	005
Lead	005
Mercury	0002
Nitrate (as N),	100
Selenium	001
Silver . . ,	005
Fluoride	
(degrees Fahrenheit)	
53 7 and below	2 4
53.8to 583 .,	2 2
584 to 63.8	2 0
63.9 to 70,6	1.8
70.7 to 792	1 6
79 3 to 90.5	1 4
Chlorinated hydrocarbons	
Endrln	**0.0002**
Lindane	**0.004**
Methoxychlor	**0.1**
Toxaphene	**0.005**
Chlorophenoxys	
2, 4-D (2, 4-dichlorophenoxyacetic acid).	0.1
2, 4, 5-TP (Silvex)	0.01

SOURCE E R Bates and T L Thoem (eds) *Pollution Control Guidance for* 011 *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
Chloride	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	O 5 mg/l	Foaming, adverse appearance
Hydrogen sulfide	O 05 mg/l	Taste, brown stains on laundry and fixtures
Manganese	.005 mg/l	Taste, brown stains, black precipitates
Odor	3 threshold odor number	Odor
pH ., ..	65-8.5 mg/l	Corrosion below 65. 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
Zinc	5 mg/l	Taste

SOURCE E R Bates and T L Thoem (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 reinfected 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 reinfection—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 osmosis, electrodialysis, 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 CO_2 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 Retort condensate Cooling tower blowdown	Clarification Filtration
Oil and grease	Retort condensate Gas condensate Coking condensate	Gravity separation Emulsion breaking
Dissolved gases	Retort condensate Gas condensate Coking condensate	Steam stripping
Dissolved inorganics	Mine drainage Retort condensate Gas condensate Cooling tower blowdown Ion exchange regenerants	Chemical oxidation Ion exchange Reverse osmosis Adsorption Evaporation
Dissolved organics	Retort condensate Gas condensate Coking condensate Hydrotreating condensate	Solvent extraction Adsorption Biological oxidation Ultrafiltration Reverse osmosis Wet air oxidation
Trace elements and metals	Retort condensate Gas condensate	Chemical oxidation Ion exchange Adsorption
Trace organics	Retort condensate Gas condensate Upgrading condensate	Ultrafiltration Reverse osmosis Adsorption
Toxics	Retort condensate Gas condensate Upgrading condensate	Chemical oxidation Incineration
Sanitary wastes	Domestic service	Biological treatment

SOURCE R F Probstein H Gold and R E Hicks Wafer *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 elements. 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
011 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	012	0.12
Excess mine drainage	–	—	0-0.55	0-0.55
Total	$0.23	$0.25	**$0.70-1.25**	**$0.52-1.07**

[a]Plants 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

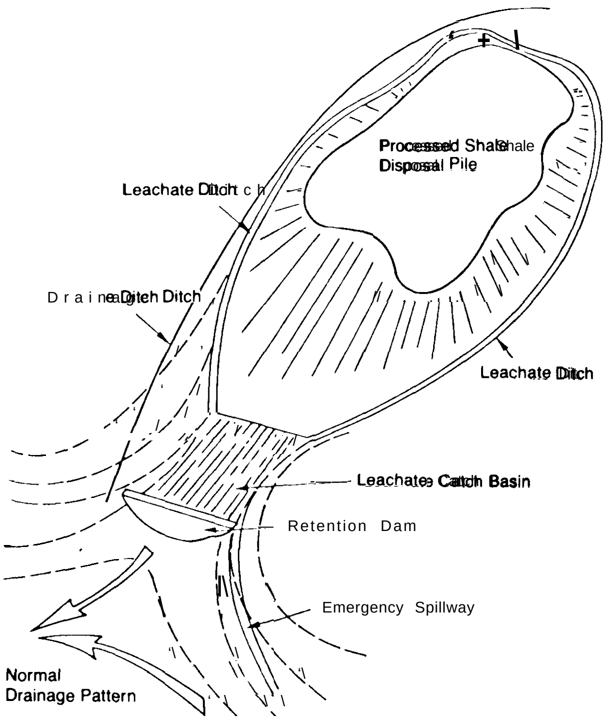
SOURCE R F Probstein, H Gold and R E Hicks, *Water Requirements, Pollution Effects and Costs of Water Supply and Treatment for the Oil Shale Industry*, prepared for OTA by Water Purification Associates, October 1979

Control of Nonpoint Sources

The major potential nonpoint sources are leachates from aboveground storage of raw or spent shale and from abandoned in situ retorts. 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 operations, 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 reinfected 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 aqui-

*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.

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 organic 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 detect 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(Al), SA(Aq)
Ammonia	M(Z)Q(o,PC)	Q	Q(Al), SA(Aq)
Arsenic.	M(Z)O(o,PC)	Q	Q(Al), SA(Aq)
Barium	—	—	(Lisa
Beryllium	Q	—	A(Al)
Bicarbonate	M(Z) Q(o,PC)	—	—
BAD.	—	Q	SA(Al), SA(Aq)
Boron	M(Z~Q(o,PC)	Q	Q(Al), SA(Aq)
Cobalt.	—	—	SA(Aq)
Color	—	—	—
COD..	Q	Q	Q(Al), SA(Aq)
Coliform, total and fecal	o	S	—
Conductivity, specific,	·	M	Q(Al)
Copper.	Q	Q	Q(Al), SA(Aq
Cyanide	Q	—	—
Dissolved oxygen	M(Z)Q(o,PC)	M	M(Al)
Fluoride	M(Z), Q(o,PC)	Q	Q(Al), SA(Aq
Hardness	—	Q	Q(Al), SA(Aq
Iron	—	Q	Q(Al), SA(Aq
Lead.	Q	Q	Q(Al), SA(Aq)
Lithium.	Q	Q	Q(Al), SA(Aq)
Magnesium,	M(Z), Q(o,PC)	Q	O(Al), SA(Aq)
Manganese,	M(Z) Q(o,PC)	Q	Q(Al), SA(Aq)
Mercury.	Q	Q	Q(Al), SA(Aq)
Molybdenum	Q	Q	Q(Al), SA(Aq)
Nickel.	—	Q	Q(Al), SA(Aq)
Nitrate	M(Z~Q(o.PC)	Q	Q(Al), SA(Aq)
Nitrogen (Kjeldahl),	M(Z), Q(o,PC)	Q	Q(Al), SA(Aq)
Odor	—	—	—
Oil and grease,	Q	Q	Q(Al), SA(Aq)
Phosphate,	M(Z~Q(o,PC)	—	—
Pesticides.	—	·	SA(Aq)
Phenol	Q	Q	A(Al), SA(Aq)
Potassium,	M(Z), Q(o,PC)	Q	Q(Al), SA(Aq)
Radiation, alpha	Q	S	SA(Al), SA(Aq
Radiation, beta	Q	S	SA(Al), SA(Aq
Sediment	M(Z), Q(o,PC)	—	—
Silica	M(Z), Q(o,PC)	—	—
Sulfate	M(Z), Q(o,PC)	0	Q(Al), SA(Aq)
Sulfide	0	—	—
Suspended solids	—	—	—
Turbidity.	—	—	—
PA,	M(Z), Q(o,PC)	M,Q	M,Q(Al)
Total dissolved solids.	M(Z), Q(o,PC)	Q	Q(Al)
Water level	—	—	MESA
Stream flow.	M(Z) Q(o,PC)	Q,SA,A	—
Water temperature	M(Z) Q(o,PC)	M,Q	M, Q(Al), SA(Aq)
Dissolved organic carbon	M(Z) Q(o,PC)	S	SA(Al), SA(Aq)

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

SOURCE E R Bales and T L Thoem (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;

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—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 nonpoint discharges. Procedures for implementation 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 uncertainty 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 rubbled 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])

*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.

In another study, postmortem examination of 30 Estonian oil shale workers who died of accidents and various other diseases[60] 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.

*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 microphage 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 respiratory 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

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

*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 H_2S, hydrogen chloride, hydrochloric acid, SO_2, 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 examined	Tumerous animals/animals exposed
Skin painting study of mice, rats, and rabbits	75	Scottish shale oils "green 011'	skin	9/100
		"blue oil'	skin	1 2/100
		"unfinished gas oil'	skin	1/50
		"lubricatmg oil	skin	3/50
Skin painting of mice	76	$CHCl_3$ extract of Scottish oil shale	skin	0/20
		Scottish shale oil	skin	6/10
Skin painting of mice	77	Shale oil	skin	1,284/10,000
Skin painting of mice	78	Shale oil	skin	(35%-90% tumerous)
		Composite petroleum control	skin	(0%-8% tumerous)
Skin painting of mice (Kettering study)	79	Crude shale oil	skin	39/40
		Hydrotreated oil	skin	5/37
		BaP control	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	0/1 2
		Powdered corn cobs (control)	lungs	6/24
Skin painting of mice (Eppley 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
Intratrachael Instillation in hamsters (Eppley 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)	27/1OO
		Saline control	(b)	0/ 100
		None (control)	(b)	0/200

[a]See reference list [b]Respiratory system

SOURCE 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 Eppley 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

[a]Parts per billion

SOURCE R M Coomes Carcinogenic Testing of 011 Shale Materials *Twelfth Oil Shale Symposium Proceedings* Golden Colo The Colorado School of Mines Press November 1979 significantly reduces its BaP content,’[(] 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 $S0_2$ 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 SO_2 and to particulate concentrations 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.

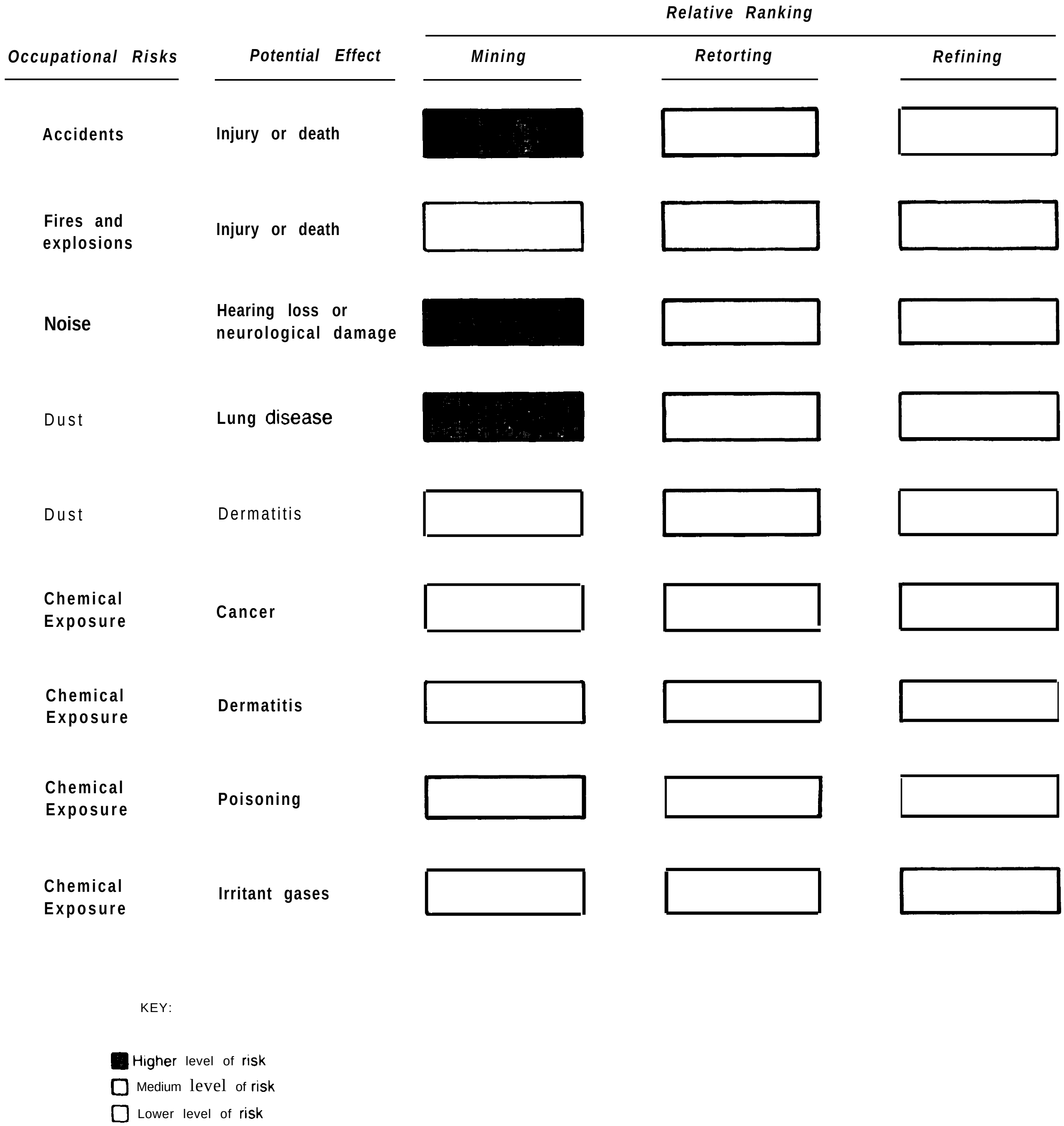
Summary of Hazards and Their Severity

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



SOURCE Off Ice 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 invesigators, 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 physical 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 premarket 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 inspections 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 registry 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 he 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 l-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 ft^3 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 disruption 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 promulgated 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.

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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 required "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 asso ciated 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-

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

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 esthetically 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

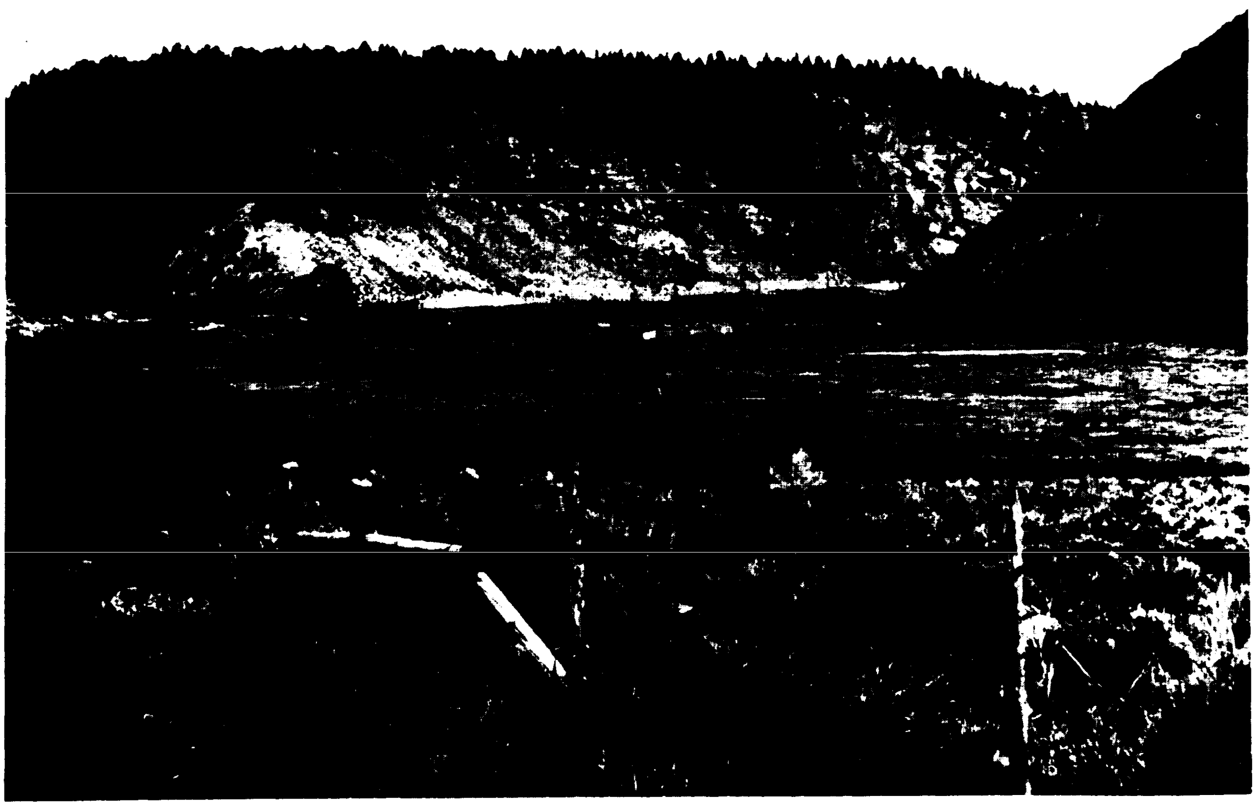

Photo credit OTA staff

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
Lurgl-Ruhrgas ., ., ., . .	Low/high	Gray	Fine/coarse	3-7	11-12

[a]Fine-textured processed shales are predominantly smaller than 2 mm while coarse-[extured processed shales are predominantly larger than 2 mm
[b]The electrical conductivity (mmho/cm) of a saturated extract prepared from spent shale particles smaller than 2 mm

SOURCE Plant Resources Institute *The free/arrrallorl 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: I (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] Hydromulch, applied at a rate of 1,500 lb/acre is one that is preferred in some studies.[10'] 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 alkinity 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 phosphorous 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 mychorrhizal only late in their establishment. There appears to be no significant effect of the seed mixture, the fer-, tilizer, 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 processed 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 pending.

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 introduced 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. '40 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 $l0,000/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[b]	100,000	250,000	1,000,000
	Required annual disposal area (acres)[c]				
	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-ftlyr
Fertilizer					
Nitrogen (80 lb/acre)	5,584-6,368 lb/yr	2,232-2,544 lb/yr	t 1,040-12,720 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)	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
w/asphalt binder (300 gal/acre)	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

[a]All numbers are approximate Actual needs will vary with aridity of the she (elevation, slope, and aspect) adapted plant species selected and soil amendments rewed
[b]Assumes 60-percent disposal in underground mine workings
[c]Assumes 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]

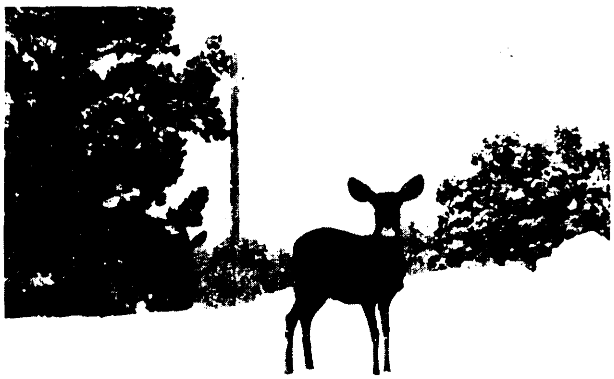

Photo credit OTA staff

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 Analysis[151] 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 encountered. 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. '5' 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 ft^2), 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 ft^2). 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 ft^2) 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 initiated[173] 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 reseeding 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 refertilization, 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 cultivating 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 workers, 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 facilit y 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 existing 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 C-a	Final programmatic Issued[a]	Yes[a]	For 1,000 bbl/d	Yes	1st phase
Cathedral Bluffs	Federal lease tract C-b	Final programmatic Issued[a]	Yes[a]	For 5,000 bbl/d	Yes	1st phase
Long Ridge (Union)	Private	Not applicable	Not applicable	For 9,000 bbl/d	Yes	Not required[b]
Colony	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

[a]Litigation proceeding over approval of the modified DDP
[b]These operations do not plan to discharge to surface streams
[c]Exchange of Federal land and pipeline right of way over BLM land requested
[d]Land exchange requested

SOURCE Office of Technology Assessment

63-898 O - 80 - 23

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 permits 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-

*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.

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 approval 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 l-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 improve 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 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 intervener 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.

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CHAPTER 9
Water Availability

Contents

List of Tables

List of Figures

CHAPTER 9
Water Availability

Introduction

The oil shale deposits are located within the Upper Colorado River Basin, which includes the Colorado River and its tributaries north of Lee Ferry, Ariz, These waters are critical resources in the semiarid region. They are used for municipal purposes, irrigated agriculture, industry and mining, energy development, and maintaining recreational, scenic, and ecological values. In the past, natural flows within the basin along with water storage and diversion projects have generally been adequate to satisfy demand. In the future, however, water resources may be taxed by rapid population growth, by accelerated mineral-resource development, and by increased recreational activities. Eventually, the availability of water may limit regional growth including the expansion of industrial developments such as oil shale.

This chapter analyzes the availability of water in the oil shale region. The following subjects are discussed:

- estimated water requirements for oil shale facilities and their related growth;
- the surface water and ground water resources of the oil shale region;
- the laws, compacts, treaties, and other documents that allocate the waters of the Colorado River system;
- the appropriation doctrine of Colorado, Utah, and Wyoming for distributing water supplies within State boundaries;
- the Federal reserved right doctrine:
- the physical availability of surface water for oil shale development;
- strategies and costs for utilizing water supplies;
- the uncertainties affecting water resource assessments;
- the impacts of water use;
- some methods for increasing water availability; and
- the policy options that might be implemented to increase the availability of water.

Summary of Findings

Surplus surface water will be available to supply an industry of at least 500,000 bbl/d through 2000 if:

- additional reservoirs and pipelines are built;

  and
- demand for other uses increases no faster than the States' high growth rate projections;

  and
- average virgin flows of the Colorado River do not decrease below the 1930-74 average (13.8 million acre-ft/yr).

Otherwise, surface water supplies would not be adequate for this level of production unless other uses were curtailed, interstate and international delivery obligations as presently interpreted by the Government were not met, or other sources of water were developed. On the other hand, if the reservoirs and pipelines are built, flows do not decrease, and the region develops at a *medium* rate (which the States regard as more likely), there should be sufficient surplus water to support an industry of over 2 million bbl/d through 2000.

In the longer term, surface water may not be adequate to sustain growth; surplus water availability is much less assured after 2000. If the river's flows do not decrease, and if a low growth rate prevails, demand will exceed supply by 2027 even without an oil shale industry. With a medium growth rate, the surplus will disappear by 2013. A high growth rate will consume the surplus by 2007, again without any oil shale development. This is a potentially serious problem for the region, and its implications for oil shale development are controversial. On the one hand it is argued that there is no surplus surface water and this should preclude the establishment of an industry. On the other hand, it it maintained that the facilities in a major industry could function for much of their economic lifetimes without significantly interfering with other users, and in any case would use relatively little water. (A 1-million-bbl/d industry would accelerate the point of critical water shortage by about 3 years if only surface water were used.)

Other findings are:

- Depending on the process used, production of 50,000 bbl/d of shale oil syncrude would consume 4,900 to 12,300 acre-ft/yr of water, including water for related municipal growth and power generation.
- A million bbl/d industry would require about 170,000 acre-ft/yr. * This would be about 1 percent of the virgin flow of the Colorado River at the boundary of the Upper Basin, about 3 percent of the water consumed at present by all users in the Upper Basin, and about 2 percent of projected consumption in 2000.
- Potential oil shale developers already own rights to substantial quantities of surface water. In 1968, for example, five companies claimed rights to enough water to produce several million bbl/d of shale oil.
- Existing developer rights would probably not assure supplies because surface water is overappropriated and oil shale rights could be interrupted during shortages. More reliable supplies could be provided through purchase of surplus water from existing Federal reservoirs, purchase of irrigation rights, ground water development, and importation of water from other hydrologic basins.
- Costs of the most expensive water supply option, importation from other basins, could exceed $0.80/bbl of shale oil produced. Other strategies would cost less than $0.50/bbl of oil. These costs include the amortized costs of reservoir and pipeline construction and the cost of treating the water to industrial standards. Development of high-quality ground water would be least expensive but would be limited to specific areas.
- All strategies that relied on surface water would require construction of new reservoirs and pipelines, principally in the White River basin in Colorado and Utah. About 180,000 to 230,000 acre-ft of new storage would be needed for a 1-million-bbl/d industry. Active capacity of existing reservoirs in the Upper Basin is about 34.7 million acre-ft. New construction for oil shale would increase storage by less than 0,6 percent.
- If a 2-million-bbl/d industry were developed, flows of the Colorado River would be reduced, and its salinity could increase by approximately 2 percent. Studies by the U.S. Water and Power Resources Service (WPRS)* and the Colorado Department of Natural Resources (DNR) indicate that the economic losses from these changes could reach $25 million per year by the year 2000–the equivalent of $0.04/bbl of oil produced.
- Sale of irrigation water to oil shale developers would reduce farm production. At present, developers do not plan to purchase such water in significant quantities. Therefore, effects on the farming industry should be small, especially compared with the effects of competition for labor and the purchase of farmlands for municipal growth.
- Studies by USBR and DNR indicate that environmental impacts of water-resource development for oil shale should be small overall on the Upper Basin but could be large in some areas. Fish habitats and recreational activities along the White River are expected to be the most severely affected. Impacts on the Lower Basin are not expected to be substantial.
- Regional development could be limited by water availability after 2000. Importation of water from other basins, conservation by municipal, agricultural, and industrial users, and possibly

* For comparison, irrigated [agriculture along the White River and the Colorado River consumes about 549,000 acre-ft/yr to produce 3 percent of Colorado's crop production. This is equivalent to the water needs of a 3. 2-million-bbl/d oil shale industry.

*Formerly the U.S. Bureau of Reclamation (USBR). For ease of reference, most citations in this chapter are to the USBR.

weather modification could make additional quantities available. The extent of the increase cannot be predicted accurately, and the strategies could be impeded by legal, institutional, and economic factors.

Analysis of Water Requirements for Oil Shale Facilities*

Introduction

Water will be used for oil shale mining and retorting, for shale oil upgrading, for revegetation and spent shale disposal, and for supplying the increased population and other related activities that will accompany the establishment of a shale oil industry. More water will be needed for final refining but this operation can be carried out at other locations. In the early years of the industry, some shale oil will probably be refined in the oil shale region and nearby in Denver and Salt Lake City. Water is also scarce in these areas. However, the refineries are presently consuming water for processing conventional petroleum. Shale oil will merely displace the conventional feedstocks, thus its refining will not add significantly to water requirements. In the long run, the output of a major industry would be refined in the Midwest where water is abundant.

Estimates of water consumption vary widely. In the following section the most recent estimates for alternative technologies on specific sites are analyzed, and then compared with estimates of regional water availability in order to identify the level of shale oil production at which water resources might limit further development.

*This analysis assumes that the quantity of water removed for a given purpose from a stream or aquifer (the water requirement) is numerically equal to the quantity made unavailable for subsequent uses (the water consumption)." This assumption is consistent with present developer plans for zero-discharge water management systems.

Process and Facility Models Analyzed

Facilities that use six retorting processes are described in table 71. The processes were selected for analysis because of their advanced development and because data have been published on their water requirements. The processes fall into three generic classes: directly heated aboveground retorting (AGR), indirectly heated AGR, and modified in situ (MIS) retorting. The facilities modeled are:

1. TOSCO 11 indirectly heated AGR,
2. Paraho directly heated AGR,

Table 71 .–Process Models for Oil Shale Facilities

Technology	Study	Reference[a]	Colorado location	Shale grade gall ton	Shale 0il capacity	Other major product	Byproducts, ton/d Coke	Sulfur	Ammonia
TOSCO II[b]	Colony	3	Davis Gulch	35	47,000 bbl/d syncrude	LPG 4,330 bbl/d	800	173	135
TOSCO II[b]	WPA/DRI	1	Davis Gulch	35	47,000 bbl/d syncrude	LPG 4,330 bbl/d	800	173	134
Paraho direct	McKee-Kunchal	4	Anvil Points	30	87,000 bbl/d syncrude	Low-Btu gas 32 billion Btu/d	650	136	290
Paraho direct	WPA/DRI	1	Anvil Points	29	*99,170* bbl/d crude	Electricity 155 mW[c]	0	132	146
Paraho Indirect	McKee-Kunchal	4	Anvil Points	30	76,000 bbl/d syncrude	Low-Btu gas 6 billion Btu/d	650	136	290
Union ' 'B' [b]	Eyring/Sutron	10	Parachute Creek	34	100,000 bbl/d syncrude	(d)		d	
Oxy MIS	Oxy	5,9	Tract C-b	24	57,000 bbl/d crude	Electricity 350 mW[e]	0	92	0
Oxy MIS	WPA/DRI	1	Tracts C-a or C-b	25	57,000 bbl/d crude	Electricity 97mW[c]	0	144	281
Oxy MIS + Lurgi	WPA/DRI	1	Tracts C-a or C-b	25	81,000 bbl/d crude	Electricity 140 mW	0	172	281

[a]See reference list at end of chapter [b]Electricity purchased 'Open cycle gas turbines [d]Data not provided [e]Combined cycle system

SOURCE R F Probstein et al Water Requirements Po i ution Effects and Costs of Water Supply and Treatment for the 011 Shale Industry report prepared for OTA by Water Purification Associates October 1979 p 4

3. Paraho indirectly heated AGR,
4. Union Oil "B" indirectly heated AGR,
5. Occidental Oil Shale's directly heated MIS retorts, and
6. a combination of directly heated MIS retorts and Lurgi-Ruhrgas indirectly heated AGR.

The water requirements of these facilities were scaled to a common basis of 50,000 bbl/d of synthetic crude oil. Thus, units for upgrading crude shale oil to a high-quality synthetic crude are included. Each facility generates sufficient electric power for its own needs, and all solid waste dumps are re-vegetated. Wastewater is recycled wherever practical, and only excess mine drainage water is discharged or reinfected. Disposing of solid wastes by slurry backfill, either to the mine or to the burned-out in situ retorts, is not included. The effects of byproduct coke, ammonia, sulfur, or gas are not evaluated. True in situ processes are not analyzed because no data are available.

With the exception of the Union "B" plant, each estimate discussed in this section is derived from a published conceptual design,[1-9] either the developer's or one that has been modified to put plant material and energy balances on a consistent basis. Although little information has been published, the Union process is considered here because plans for a plant have been announced. '() However, the data cannot be treated with the same confidence as for other processes.

A number of other studies' '-" have been completed but are not discussed in this section. Although they were based on data supplied by the developers, their conclusions did not agree because different retorting procedures, products, production rates, power supply modes, shale grades, and disposal procedures were assumed.

Water Requirements

The water requirements of the six oil shale facilities, after scaling, are summarized in table 72. As can be seen, even facilities that use similar processes (e. g., indirect AGR) require different amounts of water. However, when the requirement for each subprocess is represented as a percent of the total, there is a correlation among different plants that use similar kinds of technology, as shown in table 73. It is noteworthy that:

- Mining and dust control require considerably more water in AGR than in either MIS or MIS/AGR. This is because about

Table 72.–Water Requirements and Mine Drainage Production for 50,000-bbl/d Oil Shale Facilities (acre-ft/yr)

Retorting technology	Paraho direct		TOSCO II		Paraho Indirect	Union "B"	Oxy MIS			MIS/AGR
Study	McKee-Kunchal	WPA/DRI	Colony	WPA/DRI	McKee-Kunchal	Eyring-Sutron	Oxy 1977	Oxy 1979	WPA/DRI	WPA/DRI
Reference	4	1	3	1	4	9	5	9	1	1
Unit operation										
Mining and handling.	816	941	1,045	1,045	*934*	–	*483*	*483*	*338*	*326*
Power generation .,	665	(b)	1,233	1,233	*761*	1,233	(b)	(b)	(b)	(b)
Retorting and upgrading	2,616	2,375	5,038	3,821	3,487	1,470	9,234	2,502	3,601	3,051
Shale disposal and revegetation	1,644	1,385	3,895	3,956	4.020	3,090	2,818	1,103	1,103	1,461
Municlpal use	645	645	594	594	731	731	775	775	775	818
Net water requirements										
In acre-ft/yr .,	6,386	5,346	11,805	10,694	9,933	6,524	13,310	4,863	5,817	5,656
In bbl water/bbl 011.	271	2.27	5.02	4.53	4,22	277	5.66	2.06	2.47	2.40
Mine drainage water										
In acre-ft/yr .	(b)	(b)	(b)	(b)	(b)	(b)	6,440-16,100	4.032-6,452	12,326	8,454
In bbl water/bbl oil,	(b)	(b)	(b)	(b)	(b)	(b)	2.74-6,86	1,56-2.50	5.25	3.60

[a]See reference list at end of chapter
[b]Not applicable for projector Site analyzed

SOURCE R F Probstein et al Water Requirements Pollution Effects and Costs of Wafer Supply and Treatment for the Oil Shale Industry report prepared for OTA by Water Purification Associates October 1979 p 8

Table 73.–A Comparison of the Water Requirements of the Various Subprocesses

	Generic technology (in percent)		
Subprocess	Indirect and direct AGR	MIS/AGR	MIS
Mining and handling	9-18		4-1o
Power generation	8-12	(a	(a)
Retorting and upgrading	35-44	54	51-69
Disposal and revegetation	26-40	26	19-26
Municipal use	5-12	14	6-16

[a]Not applicable for project or site

SOURCE R F Probstein et al *Water Requirements Pollution Effects and Costs of Water Supply and Treatment for the Oil Shale Industry* report prepared for OTA by Water Purification Associates October 1979 p 9

four times as much shale is mined and handled in aboveground processing. The larger amount of material also results in high water requirements for disposal and revegetation.

- No water is needed for power generation in MIS and MIS/AGR because power will most likely be generated by burning low-Btu gases in open-cycle gas turbines that do not need to be cooled. Even if combined-cycle systems were used, very little cooling water would be needed. Cooling water is needed for AGR because solid-fuel steam-cycle systems will probably be used,
- Municipal water needs are proportional to the number of mine and plant employees. For the same output, more workers are required for MIS (about 1,800) than for AGR (about 1,400 to 1,700). It is assumed that the MIS/AGR process would require slightly more workers (about 1,900) than either technology by itself.

Retorting and upgrading require the most water. All the technologies need comparable amounts of water for upgrading, therefore, the differences among alternate technologies reflect differences in retorting efficiencies. The large differences between similar above--ground technologies result from specific operating characteristics, especially the methods for heating the retort and for disposing and reclaiming the spent shale, More water is required for indirect than for direct AGR because indirect heating has a significantly lower overall thermal efficiency,

Spent shale disposal and reclamation require large amounts of water in the TOSCO II and Paraho indirect designs (about 4,000 acre-ft/yr), while the estimate for the Paraho direct process is about 60 percent lower, Largely because of this difference, the overall requirement for Paraho direct is only about 5,900 acre-ft/yr, while the TOSCO II and Paraho indirect designs need about 10,500 acre-ft/yr or almost twice as much.

The requirements for MIS retorting and upgrading are similar to those for indirect AGR. However, because little water is needed for mining and waste disposal, overall water requirements for MIS are similar to those for direct AGR; that is, about 5,800 acre-ft/yr. For similar reasons, the requirements for MIS/AGR are similar to those for MIS alone.

It has been assumed that none of the AGR plants will produce mine drainage water. The MIS and MIS/AGR facilities, however, are assumed to produce such water in substantial quantity. This difference is not related to the technologies but rather reflects the siting assumptions made for the various plants. The MIS and MIS/AGR facilities are on tracts C-a and C-b in the ground water areas of the central Piceance basin, while the AGR operations are in drier areas along the southern fringe of the Piceance basin or the eastern portion of the Uinta basin. Mining in ground water areas produces mine drainage water that must either be used, discharged, or reinfected. The amount produced varies with location, Estimates for tract C-b range from 4,032 to 16,100 acre-f t/yr[16] and for tract C-a to at least 18,100 acre-ft/yr. [17] This water should be regarded as an alternate water resource and not as part of the process. Similar operations in other locations may not produce comparable amounts of water.

An Evaluation of Assumptions in the Estimates

Detailed breakdowns of the water required and produced by each principal operation in each model facility are shown in table 74. (Table 72 was derived from these data.)

Table 74.–Breakdown of Water Requirements and Water Production for 50,000 -bbl/d Oil Shale Facilities (acre-ft/yr)

	Paraho direct		TOSCO II		Paraho indirect	Union ' 'B'	Oxy MIS			MIS/AGR
	McKee-Kunchal	WPA/DRI	Colony	WPA/DRI	McKee[a] Kunchal	Eyring-Sutron	Oxy 1977	Oxy 1979	WPA/DRI	WPA/DRI
Water required										
Mining and ore handling	816	941	**1,045**	**1,045**	934	(a)	483	483	338	326
Power generation	832[b]	(c)	1,850[b]	1,850[d]	952[d]	1,850d	(c)	(c)	(c)	(c)
Retorting and upgrading										
Cooling tower makeup	3,849	3,854'	3,861	3,939	4,406	–	6,875[e]	**806**	4,494'	3,626[e]
Retorting	—	0	1,884	668	—	—	2,731	**3,753**	2,731	1,873
Upgrading	—	939[d]	939	939	—	—	939[d]	**939[d]**	939[d]	939
Other boiler makeup	1,224	490[e]	557	557	1,401	1 ,710[b]	985[e]	**525**	551[e]	529'
Steam and treatment loss	—	50	572	572	—	—	39	587	109	75
Service and fire water	—	69	60	60	—	—	(a)	2,111	67	60
Potable and sanitary	—	39	34	34	—	—	113	161	31	28
Disposal and reclamation										
Shale moisturizing	(c)	(c)	2.859	2,920	(c)	–	(c)	(c)	(c)	(c)
Disposal and compaction	1,664	972	428	428	—	2,870	1,208	346	346	1,239'
Revegetation		413	608	608	4,020	220	1,610	757	757	222[d]
Municlpal demand	1,61 4[b]	1,614[b]	1.485[b]	1,485°	1,829[b]	1,829b	1 ,937[b]	1 ,937[b]	1 ,937[b]	2,045[d]
Total required	9,979	9,378	16,182	15,105	13,542	8,479	16.920	12,405	12,300	10,962
Water produced										
Power generation	167d	(c)	617a	617d	191[d]	617d	(c)	(c)	(c)	(c)
Retorting and upgrading										
Cooling tower blowdown .	768	1,653e	1,240	1,319	880	(a)	625[e]	(a)	1,038[e]	907[e]
Retort condensate	127	(a)	(a)	(a)	388	240	1,243	2,419	1,243	852
Gas condensate	752	542	728	728	125	–	(a)	3,072	2,157	1,480
Upgrading condensates	540	l03[d]	103	103	618	(a)	l03[d]	103	103	103
Boiler and treatment waste	270	487[e]	557	557	309	(a)	486[e]	384	530'	513e
Service water effluent	(a)	30	27	27	(a)	(a)	(a)	241	26	27
Potable and sanitary effluent	(a)	26	26	26	(a)	(a)	(a)	161	23	20
Surface runoff'	(a)	222	188	188	(a)	(a)	(a)	(a)	201	177
Municipal effluent	969[d]	969[d]	891	891[d]	1.098[d]	1,098[d]	1, 162[d]	1, 162[d]	1, 162[d]	1,227d
Total produced	3,593	4,032	4,377	4,456	3,609	1,955	3,619	7,542	6,483	5,306
Net *consumption*										
In acre-ft/yr	6,386	5,346	11,805	10,649	9,933	6,524	13.301	4,863	5,817	5,656
In bbl water/bbl oil.	271	227	5,02	453	422	2.77	565	2.06	2.47	2,40
Mine drainage										
In acre-ft/yr	(c)	(c)	(c)	(c)	(c)	(c)	6,440-16,100	4,032-6,452	12,326	8,454[e]
In bbl water/bbl 011	(c)	(c)	(c)	(c)	(c)	(c)	2.74-6.86	1.56-2,50	525	3.60[e]

[a]Not provided [b]Includes mining and retorting [c]Not applicable [d]Estimated by OTA [e]Modified for OTA

SOURCE R F Probstein et al *Water Requirements Pollution Effects and Costs of Water Supply and Treatment for the Oil Shale Industry* report prepared for OTA by Waler Purification Associates October 1979 p 14

Paraho Direct

The two estimates for Paraho direct are reasonably consistent. However, the McKee/Kunchal water management plan is not sufficiently detailed for a thorough evaluation to be made of the differences that appear. The two designs differ principally in the mode of power generation. The McKee/Kunchal design assumed that a water-cooled steam cycle would be used; the Water Purification Associates/Denver Research Institute (WPA/DRI) design assumed that low-Btu gas would be burned in open-cycle gas turbines that require no cooling water.

The retorts are also operated differently. A higher retorting temperature is assumed in the WPA/DRI design, and the water produced during retorting is vaporized and exhausted, In the McKee/Kunchal design, lower temperatures cause partial condensation of the retort water. Also, upgrading was not considered by WPA/DRI, and it was necessary to adapt estimates from the TOSCO II plant design,

The chief uncertainty is the claim of minimal water needs for spent shale disposal. The WPA/DRI design, which was based on this claim, uses a conservative estimate of 5 percent by weight of water for compaction and a separate estimate for revegetation. The McKee/Kunchal estimate is not directly comparable because it combines compaction and revegetation. However, the total values are reasonably consistent.

Paraho's claim that proper compaction can be obtained with small water additions is based on evidence from disposing about 150 ton/d of spent shale. It is uncertain that sufficient moisture could be extracted from the atmosphere to dispose of 72,000 ton/d, the output of a 50,000-bbl/d plant.

TOSCO II

Although the Colony water management plan is very detailed, neither Colony nor WPA/DRI assumed onsite power generation. OTA's analysis assumed that about 85 MW of power would be generated by a steam-cycle system.

A principal difference between the designs is that WPA/DRI substituted a bag filter and electrostatic precipitator for Colony's venturi wet scrubbers, thereby reducing water consumption. Both designs assumed that the spent shale is moisturized to 14 percent by weight of water to allow proper compaction. For revegetation, both designs assumed an average value of 608 acre-ft/yr over the 20-year life of the plant. During the first 10 years, little revegetation would be done and water would be used only for compaction and dust control. In the second 10 years, revegetation programs would be expanded and water needs would increase.

Paraho Indirect

It is not possible to fully evaluate the Paraho indirect estimates because the McKee/Kunchal report lacks a detailed water management scheme. Compared with TOSCO H, retorting and upgrading requirements appear low. Also, the requirement for revegetation is much higher than for all other retorts. The reason given is the high carbon content of the spent shale, but this conclusion is not supported by Union's experience with similar retorted shale. The high estimates for revegetation may have been made to offset low estimates for compaction.[18]

Union Oil "B"

Because only crude data are available, judgment should be reserved on the low estimates for mining, retorting, and upgrading, The Environmental Protection Agency (EPA) recently published a considerably higher estimate for mining and processing that would lead to a total consumption more in line with estimates for other processes.[19] Unfortunately, the higher estimate cannot be verified because no background information was supplied. An older EPA document[20] provides a value for mining and processing consistent with the Eyring/Sutron estimate. The relatively large requirement for spent shale disposal is a consequence of Union's method for cooling the hot retorted shale by immersing it in water,

Occidental (Oxy) Modified In Situ

The older Oxy estimate differs significantly from the WPA/DRI design in both water requirements and water production. Oxy's requirements are higher for cooling water, for raw shale disposal, and for revegetation, It appears that these uses were deemed appropriate for disposing of excess mine drainage water. Much less water is wasted in the WPA/DRI design and in the newer Oxy plan. Also, the production of retort condensate was not estimated in the older Oxy plan. The WPA/DRI estimate (2,157 acre-ft/yr) was based on Oxy's estimates of the steam flows to the retorts. (Much more condensate would be produced if ground water entered the retorts during their operation.) WPA/DRI also assumed that the retort gases are not compressed prior to gas cleaning. This reduces the cooling water requirement, although it increases the cost of the gas cleaning equipment. The net difference (considering condensate production and cooling water reduction) is about 6,700 acre-ft/yr, which accounts for most of the discrepancy between Oxy's older plan and the WPA/DRI study. In general, the WPA/DRI results agree quite well with Oxy's current water management plan.

Modified In Situ/Aboveground Retorting

The only published water management plan for a combined facility is that of the Rio Blanco project on tract C-a. Details are not sufficient for a thorough evaluation and the plan is now obsolete because Rio Blanco has since revised its approach. The WPA/DRI model, which combines MIS with Lurgi-Ruhrgas retorts, is similar to the current plans for the tract.

The principal difference between OTA's process model and those of Rio Blanco or WPA/DRI is that OTA has assumed surface disposal of the spent shale, whereas the others assumed that the waste is returned as a slurry to the burned-out in situ retorts. In OTA's analysis, it is assumed that the vapor losses during moisturizing are the same as in underground slurry disposal. The estimates for both revegetation and upgrading were linearly scaled from the TOSCO II requirements. The accuracy limitations noted in the MIS discussion also apply here.

Municipal Use

It is assumed that the total population growth will be 5.5 times greater than the number of employees.[21] Because this large multiplier is applied to uncertain employment figures, the estimates of municipal water needs are approximate. An aggregate requirement of 175 gal/person/d has been assumed, with consumption at 40 percent of this figure, The net requirement—70 gal/person/d—is conservatively high. The average requirement for all the facilities considered is about 700 acre-ft/yr.

Mine Drainage Water

Probably the largest uncertainty of all, because it is highly site dependent, is the amount of mine drainage water produced. As noted above, estimates for the Federal lease tracts range from 6,400 to over 18,000 acre-ft/yr. This water should satisfy the processing needs of the technologies proposed for tracts C-a and C-b. However, these needs could probably not be satisified by ground water on sites along the edge of Piceance basin.

Range of Water Requirements

The most likely ranges of the quantities of water that will be consumed by the three generic technologies and by the combined plant are indicated in table 75, Also shown are the likely ranges of mine drainage water production on tracts C-a and C-b. Overall, the requirements range from 4,900 to 12,300 acre-ft/yr—the equivalent of from 2.1 to 5.2 bbl of water consumed for each barrel of oil produced. Given this range, a l-million-bbl/d industry could require from approximately 100,000 to 250,000 acre-ft/yr. Actual water requirements would be determined by the mix of technologies used. In table 76, these requirements are estimated for an industry that would result if present projects, both active and proposed, were completed. Some features of this industry are:

- Indirect AGR, the method with the highest unit water requirement, constitutes 51 percent of the total production.
- Direct AGR and MIS, which require less water, constitute only 33 percent of production. The balance is provided by MIS/AGR, which has an intermediate requirement.
- About 43 percent of the production will result from mining in ground water areas in the central and northern Pice-

Table 75.–Likely Ranges of Water Requirements and Mine Drainage Production for Oil Shale Facilities Producing 50,000 bbl/d of Shale Oil Syncrude

Technology	Average shale grade, gal/ton	Water requirements[a] Acre-ft/yr	Barrels per barrel of 011
Directly heated AGR	29-32	4,900-7,800	21-33
Indirectly heated AGR	32-35	9,400-12,300	40-52
Directly heated MIS	23-27	4,900-5.900	21-25
MIS/AGR	23-25	5,700-6,700	2.4-29
	Location	Water production	
Mine drainage water	C-a/ C-b	4,000-16,100	1 6-69

[a]Net water requirements Low end assumes higher shale grade open -cycle power systems high retort efficiency and lower waste disposal and reclamation needs High end assumes lower shale grade steam cycle or combined cycle systems low retorting efficiency and higher disposal and reclamation needs

SOURCE R F Probstein et al *Water Requirements Pollution Effects and Costs of Wafer Supply and Treatment for the Oil Shale Industry* report prepared for OTA by Water Purification Associates October 1979 p 22

Table 76.–Water Requirements for Active and Proposed Oil Shale Projects

Project	Location	Deposit	Technology	Design capacity: Barrels per day	Design capacity: Percent of total	Water requirements acre-ft/yr: For 50,000 bbl/d	Water requirements acre-ft/yr: For design capacity	Water requirements acre-ft/yr: Weighted contribution
Rio Blanco	Central Piceance basin	Wet	MIS/indirect AGR	76,000	16	6,200	9,424	992-
Cathedral Bluffs	Central Piceance basin	Wet	MIS	57.000	12	5,400	6,156	648
Long Ridge	Southern Piceance basin	Dry	Indirect AGR	75,000	16	10.850	16.275	1,736
Colony	Southern Piceance basin	Dry	Indirect AGR	46,000	10	10,850	9,982	1 085
Sand Wash	Uinta basin	Dry	Indirect AGR	50,000	10	10,850	10,850	1 085
EXXON	Central Piceance basin	Wet	Indirect AGR	60,000	13	10,850	13,020	1,411
White River	Uinta basin	Dry	Direct AGR	100,000	21	6.350	12700	1,334
Superior	Northern Piceance basin	Wet	Indirect AGR	11,500	2	10,850	2,496	217
			Total	475,500	100		80,903	8,508

SOURCE Off Ice of Technology Assessment

ance basin. These plants could obtain their process water from the aquifers in the mining zone. Surface water would not be needed.

The total production from this combination (475,000 bbl/d) would require 80,903 acre-ft/yr, On this basis, a 50,000-bbl/d plant would need about 8,500 acre-ft/yr; a l-million-bbl/d industry about 170,000 acre-ft/yr.

The following sections will use these estimates in conjunction with estimates of surplus surface water availability and other critical factors to identify the level of shale oil production at which water scarcity might restrict development. The issues section of this chapter discusses the industries that might result if a different mix of technologies were used or if ground water were developed,

Water Resources: A Physical Description

Surface water is obtained from rivers and streams; ground water from underground aquifers. In some instances, these sources are physically connected and should not be evaluated independently. For example, if the ground water supplies in most Western States were fully utilized, surface flows would decrease.

Surface Water

The Colorado River system, which includes the Colorado River and its tributaries, supplies surface water to the oil shale region. The Colorado River flows 1,440 miles from source to mouth. Its drainage area of 244,000 mi^2 includes parts of seven States and Mexice. The waters of the Colorado River system are divided between the Upper Colorado River Basin (which includes parts of Colorado, Utah, Wyoming, Arizona, and New Mexico), and the Lower Colorado River Basin (which includes parts of California, Nevada, Arizona, New Mexico, and Utah). (See figures 63 and 64.) The basins are divided at Lee Ferry, Ariz., 1 mile south of the Paria River near the border between Arizona and Utah.

Six major streams enter the Colorado River in the Upper Basin, From north to south, these are the Green, the Yampa, the White, the Gunnison, the Dolores, and the San Juan. The drainage area of the Upper Basin has been divided into a number of hydrologic subbasins, each corresponding to the watershed of a major river. Oil shale development may directly affect three of these subbasins: the Green River basin in the southeastern corner of Wyoming; the White River basin, which includes parts of western Colorado and eastern Utah; and the basin of the Colorado River mainstem in Colorado.

Water quality in these streams is highly variable. The quality in most of the upstream reaches of major tributaries is good to excellent although some smaller streams that receive discharge from saline ground water aquifers are of very poor quality. Water quality is significantly poorer in most downstream areas. The gradual deterioration is caused by flows of naturally saline streams into the river system and by man-related discharges from settlements, mineral development sites, and irrigated farmlands, Water quality and the problems it causes are discussed further in chapters 4 and 8.

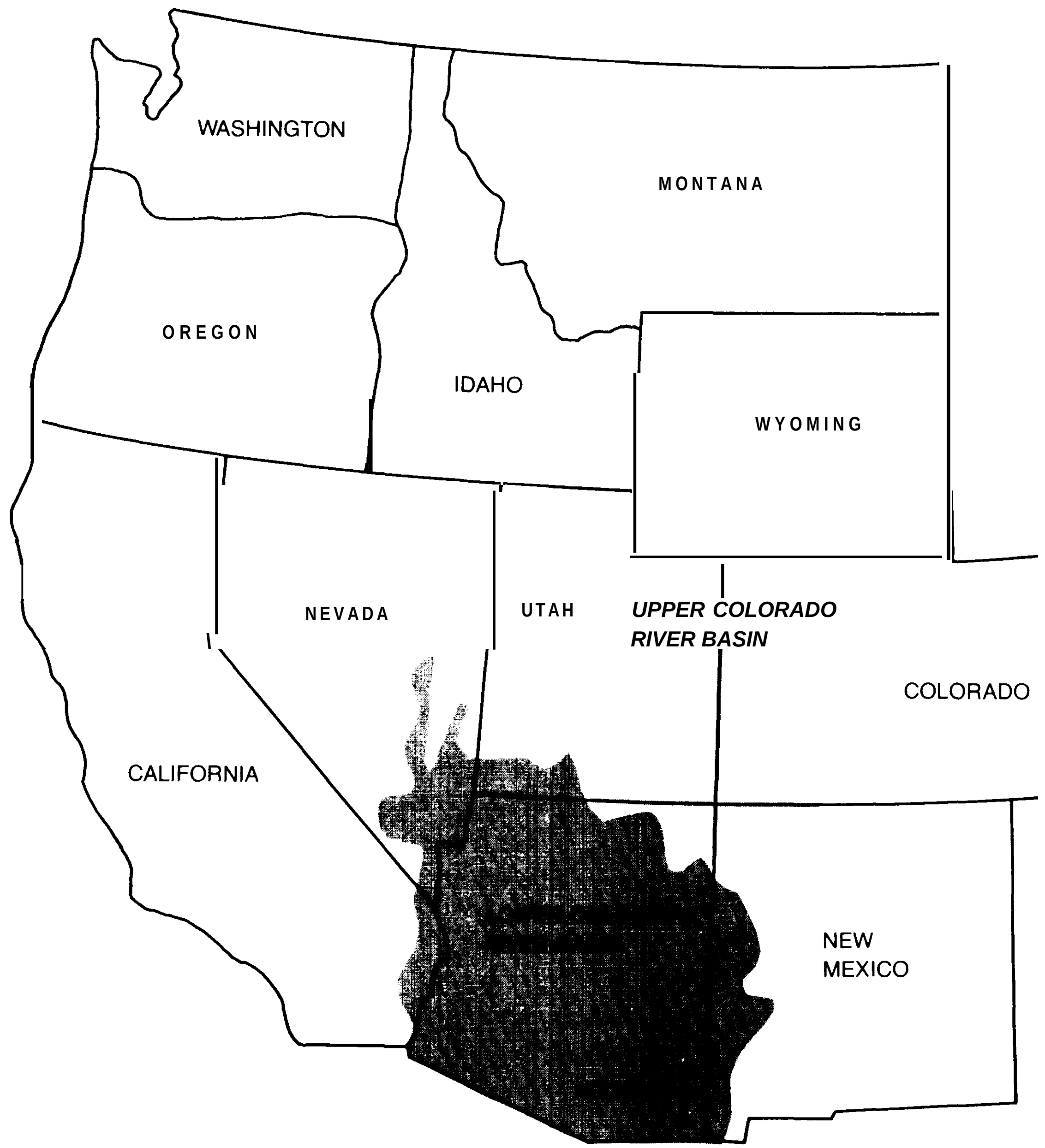
The Colorado River system drains an extensive area, but its flows are relatively small. The average annual virgin flow* at Lee Ferry was 13.8 million acre-ft/yr between

*Virgin flow is the flow that would occur in the absence of human activity. Most of the water availability analyses in this chapter deals with the 1930-74 average because of its common use in other water resources analyses. The effects of different assumptions regarding virgin flow are discussed in the issues sect ion,

Photo credit OTA staff

Upper Colorado River near Rifle, Colo.

Figure 63. —Major Hydrologic Basins of the Colorado River System

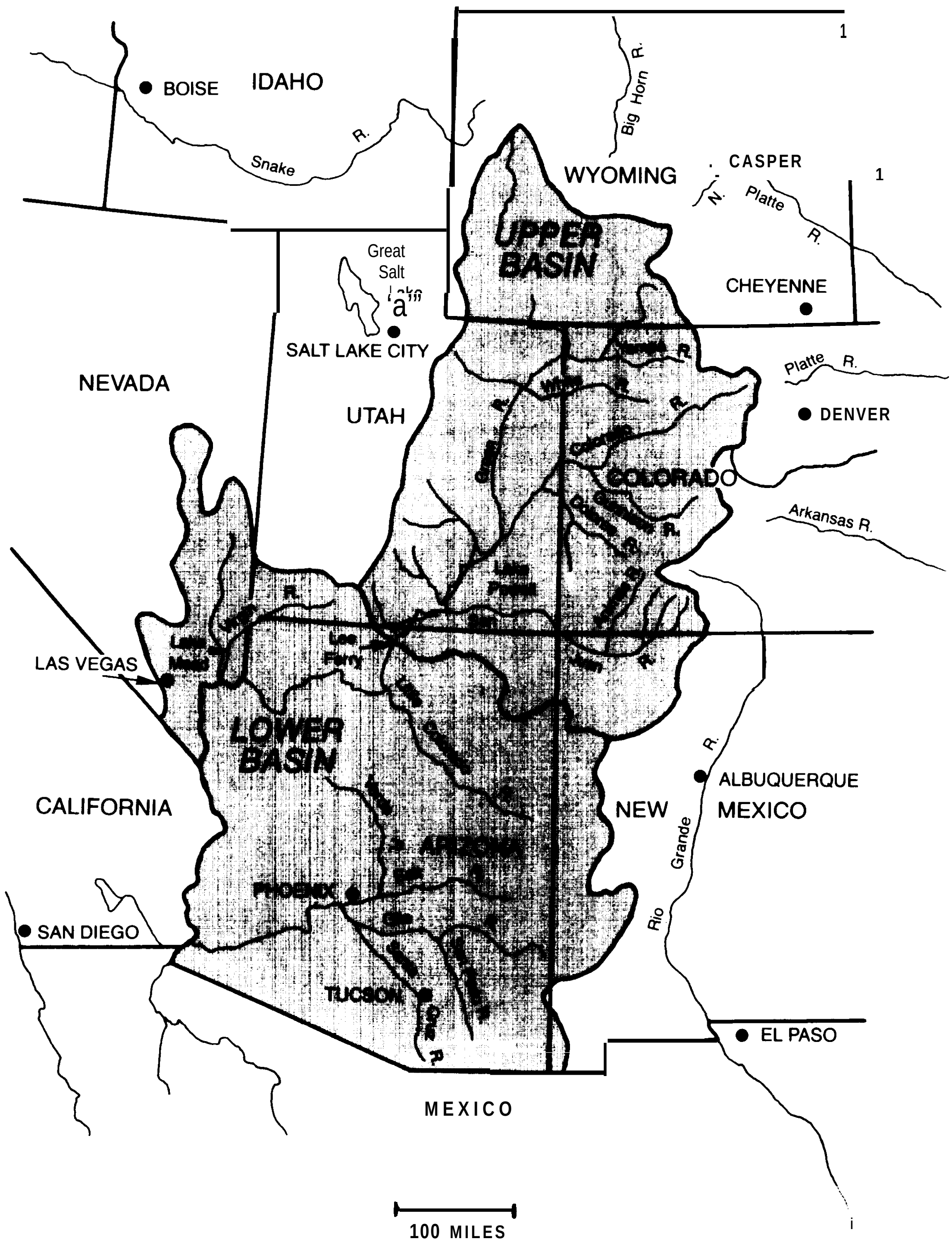


SOURCE U S Bureau of Reclamation *Critical Water Problems* Facing *the Eleven Western States—Westwide Study Volume I Main Report* NTIS No PB-263 981 Denver Colo April 1975

1930 and 1974, in contrast to about 180 million acre-ft/yr for the Columbia River and 440 million acre-ftlyr for the Mississippi River. Despite its relatively low flows, the system is one of the most important in the Southwest. It serves approximately 15 million people. Municipalities, agriculture, energy production, industry and mining, recreation, wildlife, Federal lands, and Indian reservations all compete for its waters.

Flows vary seasonally, increasing with spring snowmelts and heavy rainstorms in

Figure 64.—The Upper and Lower Colorado River Basins



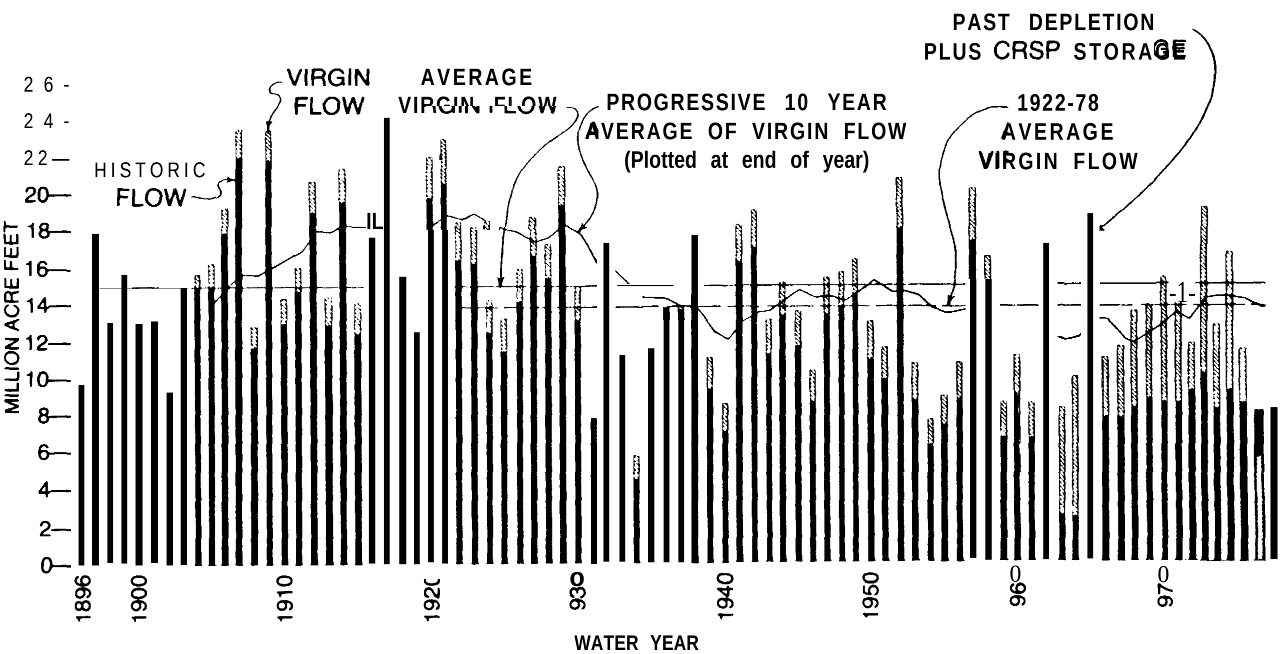
SOURCE: C. W. Stockton and G. C. Jacoby, "Long-Term Surface-Water Supply and Streamflow Trends in the Upper Colorado River Basin Based on Tree-Ring Analyses," *Lake Powell Research Project Bulletin No. 18,* March 1976, p.2

the late summer and fall and declining during the rest of the year. They also vary from year to year, as shown in figure 65. Flow records and examination of vegetation growth cycles indicate that they may also vary over a much longer period, spanning decades or even centuries. The fact that virgin flows at Lee Ferry between 1906 and 1974 averaged about 15.2 million acre-ft/yr while between 1930 and 1974 they averaged only 13.8 million acre-ft/yr is evidence of this long-term variabilit y.

The flow variations are significant because they reduce the accuracy of long-term projections of water availability. They also furnish a rationale for building reservoirs to offset seasonal fluctuations and stabilize supplies during dry years. Several reservoirs have been built in the Upper Basin for this purpose. The five largest were built by the Federal Government under the Colorado River Storage Project Act (CRSP) of 1956: Lake Powell in Arizona and Utah, Flaming Gorge in Utah and Wyoming, Fontenelle in Wyoming, Navajo in New Mexico, and the Curecanti Unit (which includes the Crystal, Morrow Point, and Blue Mesa Reservoirs) in Colorado. These projects have been completed and are now being filled, When full, the existing reservoirs will have a maximum active storage capacity of about 35 million acre-ft/yr. Lake Powell is by far the largest, and will have an active capacity of about 25 million acre-ft. Other reservoirs have been authorized by Congress but funds have not yet been appropriated for their construction. These include the Savery Pothook, Fruitland Mesa, and West Divide projects. The locations of the existing CRSP reservoirs are shown in figure 66.

Reservoirs have been effective in dampening the fluctuations in the virgin flows. This is illustrated in figure 67, which compares actual measured flows of the Colorado River at Lee Ferry with the corresponding estimates of virgin flows for the period 1953-78. The Flaming Gorge and Navajo Reservoirs began filling in 1962; Lake Powell in 1963, and Fontenelle in 1964. During prior years, actual flows varied widely, from 6 million acre-ft/yr to over 17 million acre-ft/yr. In 1962, the ac-

Figure 65.—Annual Average Virgin Flow of the Colorado River at Lee Ferry, Ariz.



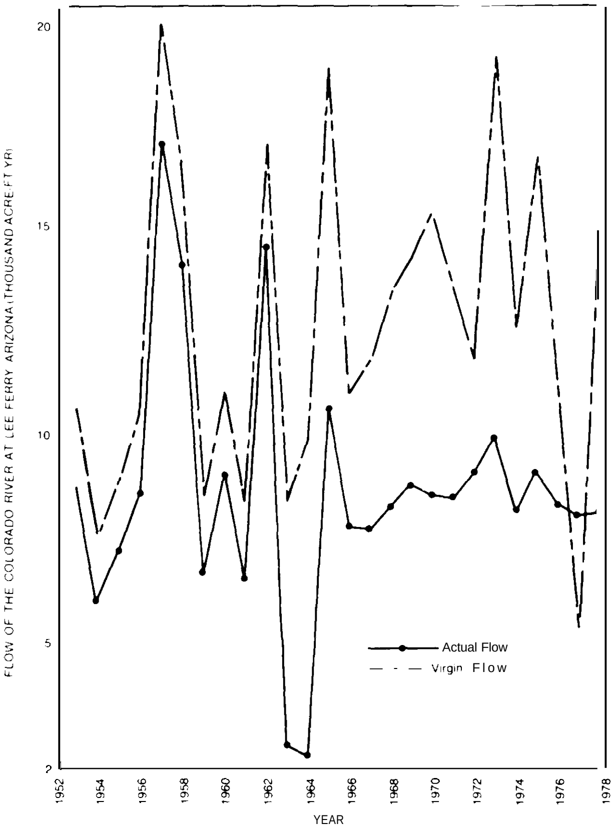
SOURCE Upper Colorado River Commission. *Thirtieth Annual Report*, Salt Lake City, Utah, Sept 30, 1978, p 44

Figure 66.— Major Dams and Reservoirs on the Colorado River and Its Tributaries

Colorado River Storage Project Act Dam and Reservoir

SOURCE Upper Colorado River Commission, *Thirtieth Annual Report,* Salt Lake City, Utah, Sept 30, 1978. p. 44

Figure 67.—Flows of the Colorado River Between 1953 and 1978



SOURCE Upper Colorado River Commission *Thirtieth Annual Report* Salt Lake City Utah, Sept 30.1978. p 44

tual flow dropped substantially, partly because of low virgin flow and partly because of the start of reservoir filling. In 1968, the actual flow approached 8 million acre-ft/yr and has remained within the range of 8.23 million to 10.14 million acre-ft/yr ever since. Between 1968 and 1978, virgin flows ranged from 5.5 million to 19.3 million acre-ft/yr. Actual flows have not yet stabilized because the reservoirs are still filling.

Ground Water

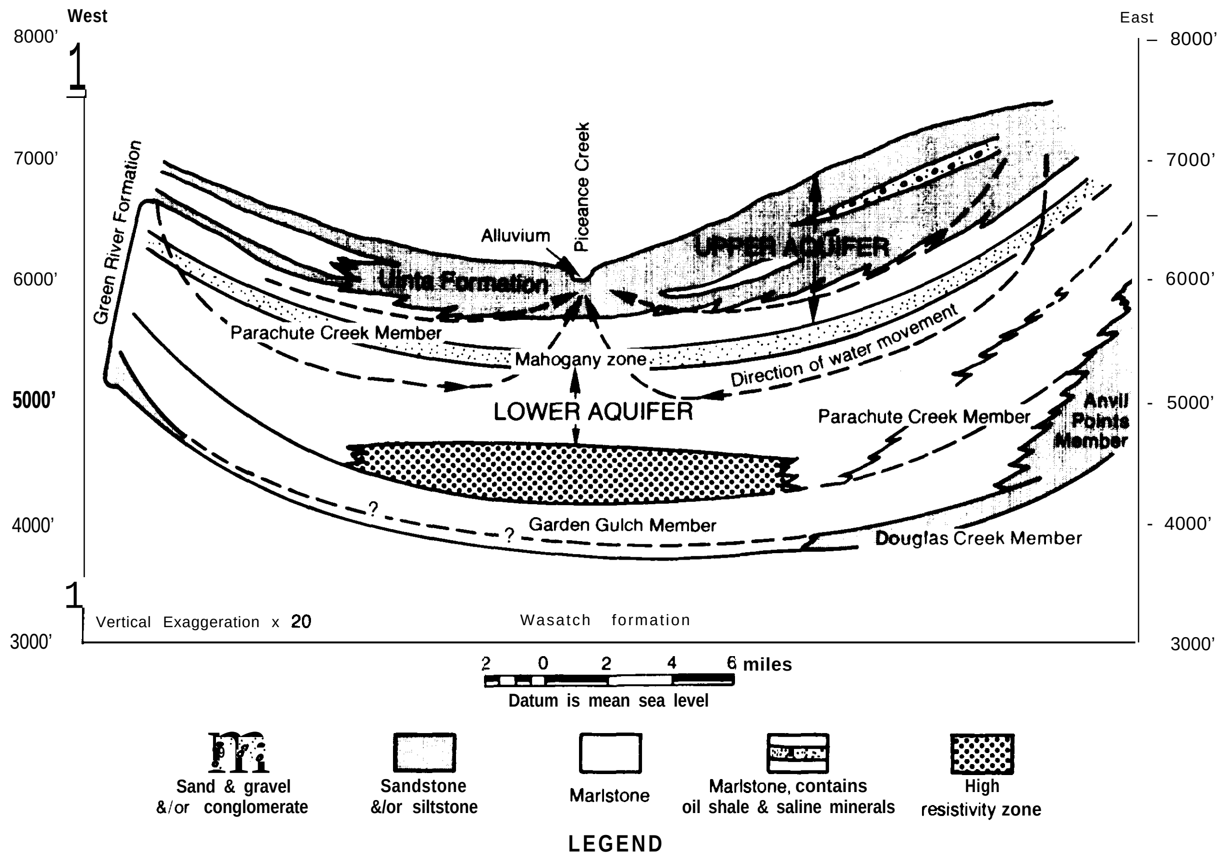
Ground water resources occur near the surface in alluvial (floodplain) aquifers and more deeply buried in bedrock aquifers. In most areas, alluvial aquifers contain relatively little water. The amount in bedrock aquifers is unknown but is though! to be very large. It has been estimated that bedrock aquifers in the Piceance basin could contain as much as 25 million acre-ft in storage. This is nearly twice the annual virgin flow of the Colorado River at Lee Ferry and is equivalent to the storage capacity of Lake Powell. The primary bedrock aquifer near Federal tracts U-a and U-b in Utah is estimated to contain at least 80,000 acre-ft.

The actual quantities of ground water that could be used for oil shale development are uncertain. The amount available is determined by the location of the aquifers relative to potential plantsites, the water quality, and physical characteristics such as the depth and the recharge rate. The physical characteristics determine the quantity of water that can be stored or extracted, the rate at which water can be added or withdrawn, and the change in water levels that will result from withdrawing a given volume of water.

The principal aquifers of the Piceance basin are located in the Uinta and Green River geologic formations. (See figure 68.) The system is characterized by two bedrock aquifers, the "upper" and the "lower," that are separated by a 100- to 200-ft-thick confining layer of rich oil shale known as the Mahogany Zone. In addition, alluvial aquifers occur in gravel, sand, and clay along the bottoms of stream and creek valleys.

The bedrock aquifers are recharged by springtime snowmelt, which replaces an estimated discharge of 26,110 acre-ft/yr. Water enters the upper aquifer along the basin margins above an altitude of 7,000 ft and moves downward through the Mahogany Zone to recharge the lower aquifer. Generally, ground water in both of these aquifers flows from the recharge areas toward the discharge areas in the north-central part of the basin. In the discharge areas water moves upward from the lower aquifer through the Mahogany Zone to the upper aquifer and is discharged both to the alluvium and by springs along the valley walls. Ultimately, the discharged ground water flows into Piceance and Yellow Creeks and then into the Colorado River system. [22]

Figure 68.— Bedrock Ground Water Aquifers in Colorado's Piceance Basin



SOURCE Department of the Interior, *Draft Environmental Statement—Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado,* Bureau of Land Management (1975), p III 34

Despite the large resources, little ground water development has taken place to date.[2] The major economic use is for watering livestock. In addition, natural seeps and springs supply water to vegetation and wildlife in many of the valley floors. Overall, relatively little water is withdrawn, and the ground water system is in hydrologic equilibrium. That is, the rates of recharge and discharge are equal and the amount of water in storage does not change significantly over time.

Allocation of the Colorado River System Waters

Because of competing demands, disputes over the proper allocation of water resources have permeated the political, social, economic, and legal histories of the seven States in the Colorado River system. As a result, a complex framework of interstate and interregional compacts, State and Federal laws, Supreme Court decisions, and international treaties has been developed to govern distribution of the system's waters. Together, the provisions of this framework comprise "the law of the river." Their interpretation is crucial to an understanding of the water availability problem.

Compacts, Treaties, and Legal Mechanisms

The Colorado River Compact of 1922

The major provisions of this compact are:

1. It divided the river system into the Upper and Lower Basins, and allocated 7.5 million acre-ft/yr to each basin for beneficial consumptive use, Authority was also given to the Lower Basin to increase its annual use by 1 million acre-ft.
2. It did not recognize a specific obligation to provide water to Mexico. However, a framework was established whereby any future obligation would be shared equally between the Upper and Lower Basins.
3. The Upper Basin was prohibited from reducing the flow at Lee Ferry to below an aggregate of 75 million acre-ft in any 10-year period. The Upper Basin was not to withhold water, nor was the Lower Basin to demand water that could not reasonably be applied to domestic and agricultural uses.

The Boulder Canyon Project Act of 1928

This Act provided for the construction of Hoover Dam and its powerplant, and for the All-American Canal. Its major provisions are:

1. It suggested a specific framework for apportioning the water supplies allocated by the compact of 1922 among the Lower Basin States of California, Arizona, and Nevada. (The States did not adopt this framework, but it was later imposed on them by the Supreme Court decision in Arizona v. California, as discussed below.)
2. It required California to reduce its annual consumption to 4,4 million acre-ft plus not more than half of the surplus water provided to the Lower Basin. (This requirement was met through the California Limitation Act of 1929.)
3. It authorized the Secretary of the Interior to investigate the feasibility of projects for irrigation, power generation, and other purposes.

The Upper Colorado River Basin Compact of 1948

In this compact, the Upper Basin States apportioned the water allocated under the compact of 1922. The negotiators recognized the problem inherent in allocating water on a strict quantity basis because of flow fluctuations from year to year. As a result, water was apportioned on a percentage basis to all States except Arizona. Major provisions of the compact are:

1. Arizona was guaranteed 50,000 acre-ft/yr, The remaining water was apportioned as follows:
   - to Colorado: 51.75 percent,
   - to New Mexico: 11.25 percent,
   - to Utah: 23.00 percent, and
   - to Wyoming: 14.00 percent,
2. It recognized that new reservoirs would be needed to assist the Upper Basin in meeting its delivery obligation to the Lower Basin. Such reservoirs, however, would increase evaporative losses from the river system as a whole, thus reducing the quantity of surplus water available to the Lower Basin. The compact provided that charges for such evaporative losses be distributed among the Upper Basin States. Each State was to be charged in proportion to the fraction of the Upper Basin's water allocation that was consumed in that State on a yearly basis, and its maximum consumptive use was to be reduced accordingly.
3. It provided for the division of water between pairs of States on a number of specific rivers. The compact did not deal with the White River, which delivers approximately 500,000 acre-ft/yr to the Utah State line and which could supply water for energy development.

Mexican Water Treaty of 1944-45

As part of negotiations over apportionment of water from the Rio Grande, Tijuana, and

Colorado Rivers, the United States guaranteed to deliver at least 1.5 million acre-ft/yr of water to Mexico. However, in times of severe drought or in the event of a failure in the delivery systems, Mexico could receive less than 1.5 million acre-ft/yr.

Colorado River Storage Project Act of 1956

This Act provided for several new storage reservoirs to assist the Upper Basin States in meeting their delivery obligation to the Lower Basin, while simultaneously increasing water consumption in the Upper Basin. The five CRSP reservoirs that have since been built were described in the earlier discussion of the fluctuating flows of the river.

The Supreme Court Decree in *Arizona v. California*

This decision (376 U.S. 340 (1964)) imposed upon the Lower Basin States the water distribution framework that had been suggested by the Boulder Canyon Project Act of 1928. The Lower Basin's water allocation of 7.5 million acre-ft/yr was to be apportioned as follows:

- to California: 4.4 million acre-ft/yr,
- to Arizona: 2.8 million acre-ft/yr, and
- to Nevada: 0.3 million acre-ft/yr.

The decree also required that approximately 1million acre-ft/yr from the allocations to California and Arizona be diverted for the five Indian tribes located along the lower Colorado River.

Colorado River Basin Project Act of 1968

This Act instructed the Secretary of the Interior to propose criteria for the coordinated long-range operation of reservoirs built under the Boulder Canyon Project Act and the CRSP Act. Criteria were subsequently established and now form the basis for operation of the reservoirs. (These operating criteria are of importance in estimating water availability in the Upper Basin States, as discussed below.) The Act also identified the Mexican Water Treaty as a national obligation, to be considered in developing any subsequent water projects. It prohibited the Secretary from studying importation of water into the Colorado River Basin until 1978. (This moratorium was subsequently extended to 1988 by the Reclamation Safety of Dams Act of 1978.)

Surface Water Allocations

Each of the above documents assumes different values for the quantity of virgin flow past Lee Ferry. They therefore differ with respect to the total amount of water to be apportioned. In general, each State can interpret the law of the river so as to maximize its water-resource position and can develop its water programs on that basis. Consequently, an analysis of the opportunities for further growth in the Upper Basin States is clouded by uncertainty, and it is not possible to predict with any exactitude the maximum size of the oil shale industry that could be accommodated.

The annual virgin flows assumed in some of these documents are shown in table 77.

Table 77.–Estimates of Surface Water Allocations to the Oil Shale States (millions of acre-ft/yr)

Source of virgin flow estimate	Virgin flow at Lee Ferry	Colorado	Utah	Wyoming	Total
Colorado River Compact of 1922 . . . ., . .	180	*5.06*	*2.25*	1.37	8.68
Mexican Water Treaty of 1944 -45...... . . .	16.2	4.12	1.83	1,12	7,07
Upper Colorado River Basin Compact of 1948. , ., .,	15,6	3.81	1.70	1.03	6.54
Colorado River Basin Project Act of 1968 . .	14.9	3.45	1.53	0,93	5.91
Average flow 1930 -74.	13.8	2.88	1,28	0.78	4.94

Assumes delivery of 823 million acre-ft/yr to Lower Basin Slates and Mexico 7500000 acre-ft/yr to Lower Basin (per 1922 compact) plus 750,000 acre-ft/yr 10 Mexico (per Mexican Waler Treaty of 1944-45) less 20 000-acre-ft/yr inflow from the Paria River below Lake Powell = 8230000 acre-ft/yr Neglects evaporative losses from Upper Basin reservoirs Assumes apportionment among the 011 shale States according to the Upper Colorado River Basin Compact *of* 1948

SOURCE Office of Technology Assessment

Also shown is the average virgin flow at Lee Ferry between 1930 and 1974. For each flow figure, the corresponding gross quantity of surface water allocated to each oil shale State is also shown. It was assumed that the Lower Basin States receive 8.23 million acre-ft/yr out of the Lake Powell Reservoir above Lee Ferry, as called for in the operating criteria prepared under the provisions of the CRSP Act of 1968. As indicated, the quantity of surface water available to the three States under the terms of the various documents could be as low as 4.94 million acre-ft/yr and as high as 8.68 million acre-ft/yr. The lower figure is more realistic for planning purposes,

Doctrine of Prior Appropriation

Introduction

The water rights policies of Colorado, Utah, and Wyoming are, in general, similar. Their respective constitutions hold that water is the property of the public, not the landholder, and that it is the State's responsibility to apportion rights to use water among competing users, Each State administers surface water rights and some ground water rights according to a doctrine of prior appropriation, This differs from the riparian doctrine that prevails in most Eastern States under which water rights are automatically the property of the owner of the land on which the water is found. Under the prior appropriation doctrine, water rights are severable from the land, and one may own water rights without owning any land whatsoever.

Surface Rights

The key elements of the doctrine of prior appropriation are: the specific types of water rights, the seniority system for determining priority of use, the preference system for distinguishing among types of water uses, options for transfer of water rights between parties, and policies for determining the abandonment of water rights.

Types of Water Rights

There are two categories of water rights: conditional and absolute. A potential user acquires a conditional water right by filing for a conditional decree from the State water courts and then proceeding diligently towards the actual use of the water. An absolute water right is created when a holder of a conditional right perfects that right by actually diverting the water and applying it to a beneficial use. Beneficial uses have been defined to include any use in which water is not wasted.

Within each category there are two types of water rights. A direct flow or diversion right permits the diversion of water from a stream followed by its immediate application. A storage right permits the impoundment of water for later application. None of the three States recognizes the right of private parties to require that sufficient stream flows be maintained for the protection of instream uses, such as rafting and fishing. However, a Colorado law permits that State to obtain water rights for sufficient flows to preserve the natural environment to a reasonable degree.

In Colorado, the water rights are adjudicated by the State Water Courts and administered by the State engineer. The right to appropriate water is limited only in that property rights of other parties cannot be impaired. A conditional right is automatically granted if the user proceeds with due diligence towards perfection of the right and if the rights of other users are not jeopardized. Neither the courts nor the executive branch of government has discretionary authority over the type, place, or quantity of use. Furthermore, the State has no power to remove a stream or any portion of its waters from appropriation. The State engineer only monitors the system to assure that rights are protected and water is not wasted.

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In Utah and Wyoming, a permit system is employed in which the right to appropriate water must be approved by the State engineer. He must consider the water rights of others, but is also allowed to consider public interest or public welfare when passing on an application for appropriation. Thus, in contrast to Colorado, the governments of Utah and Wyoming have discretionary authority to approve some uses and deny others. Use of this power has been minimal.

It is noteworthy that the continuation of conditional decrees requires only due diligence and not actual use. In the past, rights have been granted liberally by all three States and as a result, the quantities of water covered by conditional decrees far exceed the available resources. Not all of the conditional decrees have been perfected, and relatively little of the claimed water is actually being used. Consequently, surplus surface water appears to be available in the oil shale region. However, all of it has already been claimed, in part by oil shale developers. Similar situations prevail in Utah and Wyoming.

Seniority of Water Rights

The prior appropriation doctrine is based on the principle of "first-in-time, first-in-right. " Thus, the more senior (older) the water right, the higher its priority for the use of limited resources. If shortages occur, user rights that are junior in terms of the initiation date are curtailed to assure water supplies to users with more senior rights. Only when the most senior rights have been satisfied do less senior users have any rights to water.

The date of a right, assuming the appropriation goes forward diligently to completion, is the date of the first act evidencing an intent to take water for beneficial use. In general, this is the date on which the application for a conditional decree was filed. In Colorado, a State statute makes most water rights a matter of public record. Rights to surface water are established solely by the actions of individual users, but these rights are legally protected only if they are formalized by water court decrees in Colorado or by the permitting process in Utah and Wyoming.

Preference Systems

A preference system has been established in each State to apportion water among different beneficial uses during times of shortage. Under its provisions, drinking water or municipal users have first preference, agriculture is second, and industry is third. The preference system overrides the seniority system; water rights with a lower preference may be condemned in favor of a higher preferred use, even if the preferred water right is junior to the displaced right. In most cases, just compensation would be required for displaced senior water rights.

Transfer of Water Rights

Water rights are considered real property and may be sold or transferred. [24] They are conveyed by deed and may be severed from the land on which the water was originally used, In Colorado, such transfers are reviewed by the water courts and may only be denied if other users would be harmed. In Utah and Wyoming, application for transfer is made before the respective State engineer, who decides whether harm will occur to other users and also considers public interest and other factors. Sale and transfer of water rights is complicated by the need to protect junior appropriators, seasonal rights of some users, appurtenance (right-of-way) of water rights to land, and preferred use as defined by the individual States,

Abandonment of Water Rights

In all three States, absolute water rights may be partially or completely lost by abandonment. In Colorado, failure to use an absolute right for a period of 10 years constitutes prima facie evidence of abandonment. The status of water rights is reviewed periodically by the division engineer in each of the State's water divisions. In Utah and Wyoming, abandonment is defined as nonuse for a period of 5 years. Unlike Colorado, these States have no provisions for a continuing review of the status of water rights.

Ground Water Rights

In Colorado, tributary ground water (ground water that is hydrologically connected to the surface water system) is treated essentially the same as a surface flow and thus is subject to the prior appropriation doctrine. Nontributary ground water (ground water that does not reach surface streams) is divided into two categories: designated ground water basins and nondesignated ground water areas, Nontributary ground water resources in designated basins are controlled by a permit system through the State Groundwater Commission. Nontributary ground water in nondesignated ground water areas, on the other hand, is subject to prior appropriation. Permits for wells must be obtained from the State engineer, and ground water rights must be adjudicated by the water courts to assure legal protection, just as with a surface right. Small wells (less than 15 gal/rein) for livestock or domestic use have been defined by law to cause no injury and are exempt from such regulations.

In Utah, all ground water is subject to the appropriation doctrine. Rights are administered by the State engineer and permits for wells may be sold as any other water rights. In Wyoming, permits must be obtained for any ground water use. Livestock watering and domestic uses have preference over all other rights, regardless of seniority.

Federal Reserved Rights

The Federal reserved rights doctrine originated in the Supreme Court decision in Winters v. United States (207 U.S. 564 (1908)) regarding Indian water rights. It was held that when Indian reservations were established by treaty with the United States, sufficient water to supply all Indian lands was also reserved. The Court did not quantify sufficiency. Rather, it reflected the opinion that Indian reservations were created to transform a nomadic people into permanent setlers and that those people required sufficient water for irrigation.[25]

A major effect of this decision is that the vater rights set aside for Indian reservations vere interpreted to be superior to those of all ther subsequent appropriators who obtained their rights under State law, even though the Indian tribes had not yet put their rights to beneficial use. Federal rights were thus entered into the prior appropriation system of each affected State, together with 11 other applicants and appropriators.

In Arizona v. California, the Court exended the reserved right doctrine to Indian reservations created by Executive order and to other Federal reservations such as national recreation areas, wildlife refuges, and national forests. In addition, the Court addressed the question of the quantity of water reserved for Indian use. It held that water was intended to satisfy the future as well as the present needs of Indian reservations, and ruled that sufficient water would be reserved to irrigate all the practicably irrigable acreage on the reservations.[26]

A further Supreme Court decision in United States v. New Mexico (98 Sup. Ct. **3012 (1978))** attempted to resolve the uncertainty over the qualification of Federal reserved water rights for areas other than Indian reservations. The Court concluded that the doctrine applied only to the original purposes of the reservations, and that reserved water rights could not be used for other purposes.[27] For example, the rights associated with a national forest could be used for maintaining the forest and its wildlife, but not for industry, farming, or oil shale development.

While the Supreme Court has served notice that it will interpret the purpose of Federal reservations narrowly, a number of uncertainties remain concerning the quantities of water that could be claimed to serve these purposes. With regard to Indian reservations, for example, it is still uncertain how much water will be claimed, how much will be used, whether the use must take place on the reservation, and whether rights can be sold or leased for uses outside the reservation.

Physical Availability of Surface Water for Oil Shale Development

Introduction

The size of the industry that could be supported by surplus surface water is affected by the following factors:

- the long-term average virgin flow in the Colorado River system (this determines the gross quantity of water that is available);
- the compacts and other documents that constitute the law of the river (these determine how the gross water supply is allocated among the basins and States);
- the demands of other users (these consume part of the allocation to each State, the remainder is the surplus);
- the oil shale technologies employed (these determine how much water the industry would need);
- the siting of the facilities (this determines how the industry's water demands will be distributed among Colorado, Utah, and Wyoming); and
- the timing of their construction and the duration of their operation.

The final factor is particularly important. The region's surface water resources are finite, and they are not large. In the past, they have generally been adequate, when supplemented by reservoir storage, to satisfy the demands of all users. At present, there is plenty of surplus water for a very large oil shale industry, but the surplus is shrinking because of population growth (both in the Upper Basin and in the urban areas to which its waters are exported), accelerated mineral resource development, increases in irrigated agriculture, and expansions of other activities.

In the future, there may not be enough water for oil shale unless the demands of other users are partially curtailed. When this will occur is not known. If it happens before the plants are built or during their useful life, then social and economic dislocations would result. If, on the other hand, it occurs after conservation and the development of other energy sources have sufficiently diminished the demand for liquid fuels, then the disturbances caused by the temporary presence of an industry may not be overwhelming.

This section evaluates whether the surface water resources in the Upper Basin are physically adequate, and legally available, to support a large industry. Availability is analyzed for the Upper Basin as a whole, and for the hydrologic subbasins that are likely to be affected. The factors analyzed were highlighted above. Following is a summary of the assumptions made and of the sources of supporting information.

Virgin Flow

An annual average flow of 13.8 million acre-ft/yr past Lee Ferry is assumed. This is the running average between 1930 and 1974. Virgin flows have been calculated since 1896, and the 1896-1974 average is considerably higher-15.2 million acre-ft/yr. However, the natural flows (the basis of the calculated virgin flow) have been measured more accurately since 1930, and the 1930-70 average is considered a better estimate. The effects of flow fluctuations around the 13.8 million acre-ft/yr average are discussed in the issues section.

Law of the River

It is assumed that the allocation to the Upper Basin is determined by the operating criteria promulgated for CRSP reservoirs by the Department of the Interior (DOI). These criteria require a minimum discharge of 8.23 million acre-ft/yr from the Lake Powell Reservoir into the lower Colorado River. This incorporates the Lower Basin's allocation under the Colorado River Compact of 1922 (7.5 million acre-ft/yr), plus one-half of the Mexican treaty obligation (750,000 acre-ft/yr), less the contribution of the Paria River (20,000 acre-ft/yr), which discharges into the Colorado River between Lake Powell and Lee Ferry. The Upper Basin States do not agree with these criteria. The effects of other interpretations of the law of the river are discussed in the issues section.

It is also assumed that flows allocated to the Upper Basin are distributed according to the Upper Colorado River Basin Compact of 1948. As indicated previously, this compact allocated 50,000 acre-ft/yr to Arizona and, of the remainder, 51.75 percent to Colorado, 23 percent to Utah, 14 percent to Wyoming, and 11.25 percent to New Mexico,

Demands of Other Users

Section 13(a) of the Federal Nonnuclear Energy Research and Development Act of 1974 directed the U.S. Water Resources Council to assess the water requirements of emerging energy technologies and the availability of water for their commercialization. Studies were to be undertaken at the request of the Energy Research and Development Administration (ERDA), In 1977, ERDA requested three such "l3(a)" assessments, one directed to the water-resource aspects of oil shale development and coal gasification in the Upper Basin. Oversight for these projects was transferred to the Department of Energy (DOE) in 1978.

The Upper Basin 13(a) assessment was organized under the management of DNR of the State of Colorado. DNR's work has been reviewed by an interagency, intergovernmental steering committee that includes representatives of the Arizona Water Commission, the Colorado Water Conservation Board, the New Mexico Interstate Stream Commission, the Utah Division of Water Resources, the Wyoming State Engineer's Office, the U.S. Soil Conservation Service, the Department of Commerce, DOE's Denver Project Office, the Region VIII Office of the Department of Housing and Urban Development, USBR, and EPA. Technical assistance and studies were provided by USBR (hydrologic modeling), the U.S. Fish and Wildlife Service (USFWS) (fishery and recreational impacts), the U.S. Heritage Conservation and Recreation Service (recreational data), Los Alamos Scientific Laboratory (economic modeling), the U.S. Soil Conservation Service (agricultural water consumption and conservation), the U.S. Geological Survey (USGS) (water quality), and several private contractors.

Because of this broad support and review base, DNR's estimates of present and future water depletions appear to be the best available for the period between 1980 and 2000. OTA has relied on the values provided for "conventional'" (nonoil shale) depletions to define the baseline water-demand conditions under which the oil shale industry could be established. DNR"s results have also been used to evaluate water-supply options in the areas in which oil shale development is most likely to occur.

DNR projected water consumption patterns for conventional activities in 2000 based on low, medium, and high regional growth rates. The medium-growth scenario, which was based on declared plans by the various users for expanding their water needs, is considered by the States to be the most realistic. The high growth rate scenario was derived from the medium scenario by assuming that announced projects would be finished sooner than expected or would consume more water than anticipated. A few projects not considered in the medium-growth scenario are included in the high-growth scenario. The low-growth scenario was derived by assuming project delays or lower than anticipated water consumption. In this section, OTA considered only the medium growth rate. The low and high rates are considered in the issues section.

Oil Shale Technologies

It is assumed that the technology mix used by any future industry will resemble that of the projects presently active or proposed. The characteristics of this industry were described in table 76. About 51 percent of the facilities use indirectly heated AGR, 33 percent directly heated AGR and MIS, and 16 percent a combination of MIS and indirectly heated AGR. On this basis, each plant would require about 8,500 acre-ft/yr for production of 50,000 bbl/d of shale oil syncrude. The effects of other technology mixes are discussed in the issues section.

Distribution of Facilities

If the siting pattern of the present projects were extended to a major industry, 68 percent of the production would be based in Colorado, 32 percent in Utah, and none in Wyoming, Although they are of lower quality, some development of Wyoming shales may occur if a major industry is established. Therefore, it was assumed that approximately 5 percent of future production will come from Wyoming, about 70 percent from Colorado, and about 25 percent from Utah. This assumption determines which hydrologic subbasins will be impacted. It also determines how much of the production could be sustained by the extensive ground water resources of the Piceance Basin. In this section, it is assumed that all of the plants rely on surplus surface water. The possible substitution of ground water is discussed in the issues section.

Timing and Lifetime of the Projects

It is assumed that the facilities will be installed before 2000, regardless of the industry's size. As discussed in the other chapters, establishing a large industry this quickly may be difficult.

The Availability of Surface Water in the Upper Colorado River Basin

Water Consumed by Conventional Activities

At present, the following activities consume surface water in the Upper Basin:

- thermal power— for steam-electric power generation;
- agriculture— for irrigation, watering stock, and other agricultural purposes;
- wildlife and recreation—for maintenance of fish, wildlife, and recreational areas;
- minerals—for extraction, processing, and transporting ores and concentrates;
- municipal and industrial—for domestic, commercial, retail, and manufacturing facilities, including final processing of raw materials into finished products; and
- exportation— for diversion and transportation to other basins or to other areas within the Upper Colorado River Basin.

Water consumption patterns for these activities, at present and as projected to 2,000, are shown in table 78. Agriculture presently depletes nearly 71 percent of the total, water exports are the second highest category at 24 percent, and the remaining 5 percent is distributed fairly evenly among the other uses. A comparison with the year 2000 projections indicates shifts both in the absolute quantities of water consumed and in the distribution of consumption among the various activities. The following trends are indicated:

- Agricultural water consumption is projected to increase by 19 percent. However, agriculture's share of total consumption is projected to decrease to 61 percent from its present level of 71 percent.
- Thermal power's water consumption is projected to increase by a factor of 6.
- Exportation of water is projected to in-

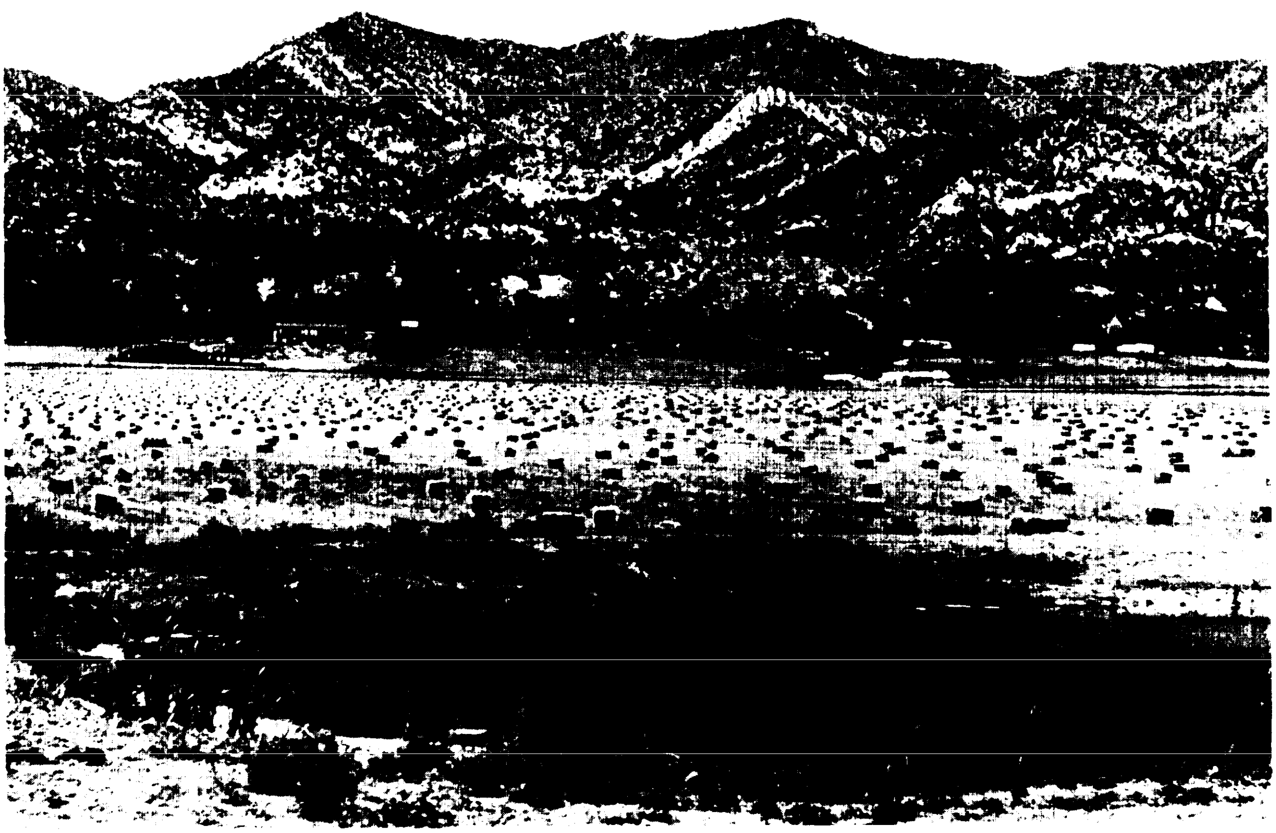

Photo credits: OTA staff

Feed for livestock consumes large amounts of the available water

Table 78.–Present and Projected Water Depletions for Activities Other Than Oil Shale Development in Colorado, Utah, and Wyoming (thousand acre-ft/yr)

	Present					Year 2000				
	Colorado	Utah	Wyoming	Total	Percent	Colorado	Utah	Wyoming	Total	Percent
Thermal power.	10	7	18	35	1,2	74	64	83	221	5,7
Agriculture	1,197	527	279	2,003	70.7	1,380	671	330	2,381	61.3
Wildlife and recreation	15	9	6	30	1,1	28	9	20	57	1,5
Minerals .,	19	12	21	52	1.8	33	12	64	109	2.8
Municipal and industrial	21	10	4	35	1,2	49	19	8	76	2.0
Exportation	541	132	7	680	24,0	757	262	22	1,041	26.7
Total	1,803	697	335	2,835	100.0	2,321	1,037	527	3,885	100,0

SOURCE Colorado Department of Natural Resources, *Upper Colorado River Region See//on 13(a) Assessment A Report to the U S Water Resources Council* draft August 1979

crease by 53 percent. The proportion of total depletions exported, however, will remain at about 25 percent.

- At present, the oil shale States together consume about 2.84 million acre-ft/yr. The total depletion would increase 37 percent to 3.89 million acre-ft/yr.

These trends are considered below in conjunction with law of the river allocations to estimate the quantities of surplus water that would be available to support additional regional growth.

Estimation of Surplus Water in the Upper Basin

Surplus water is defined as the difference between the water allocated and the total water consumption, which includes water used for beneficial purposes plus reservoir evaporative charges. * As discussed previously (see table 77), the oil shale States should be entitled to a total of 4.94 million acre-ft/yr: 2.88 million to Colorado, 1.28 million to Utah, and 0.78 million to Wyoming. In table 79, estimates are given for the quantities of surplus surface water at present and in 2000. At present, approximately 1.66 million acre-ft/yr of surplus water is available. By 2000 the surplus would be reduced to about 469,000 acre-ft/yr. These surpluses are legally available to the States. If all the present surplus were reserved for oil shale development, an industry of about 9.76 million bbl/d could be accommodated. The projected surplus in 2000 would support a 2.76-million-bbl/d industry without disrupting other users.

A more precise analysis, which considered seasonal flow fluctuations, return flows from irrigated fields, effects of fill rates, and sustained depletions on reservoir evaporation, was performed for DNR with USBR's Colorado River system simulation model. The model predicted a natural discharge from Lake Powell of 8.63 million acre-ft/yr in 2000 —400,000 acre-ft/yr more than the minimum discharge requirement, but 69,000 acre-ft/yr less than the year 2000 surplus shown in table 79. The surplus would support an oil shale industry of 2.35 million bbl/d in the Upper Basin. However, the industry's total capacity would be further reduced by the Upper Colorado River Basin Compact of 1948 that governs how water can be distributed among the individual States in the Upper Basin. The effects of this compact are indicated in table 80, where the 400,000-acre-ft/yr surplus is distributed among Colorado, Utah, Wyoming, and New Mexico according to the compact's percentage formula. As shown, the total shale oil capacity would be 2.09 million bbl/d: 1.22 million in Colorado; 541,000 in Utah; and 320,000 in Wyoming.

It is important to note that these calculations apply to average flow conditions in the Colorado River system. During dry years, natural flows out of Lake Powell might not be sufficient to satisfy the delivery requirement to the Lower Basin and might have to be aug-

*The term "reservoir evaporative charges" refers to the total amount of water that evaporates from certain reservoirs in the Upper Basin, The States are charged on a percentage basis for losses from reservoirs that are built to serve the entire Upper Basin. Evaporation from reservoirs built for a specific State are charged entirely to that State.

Table 79.–Estimation of Surplus Surface Water in Colorado, Utah, and Wyoming at Present and in 2000 (thousand acre-ft/yr)

	Present				Year 2000			
	Colorado	Utah	Wyoming	Total	Colorado	Utah	Wyoming	Total
Total water use[a]	1,803	697	335	2,835	2.321	1,037	527	3,885
Evaporation[b]	259	115	70	444	334	148	104	586
Total consumption	2,062	812	405	3,279	2,655	1.185	631	4,471
Allocatlon[c]	2,880	1,280	780	4,940	2,880	1,280	780	4,940
Surplus.	818	468	375	1,661	225	95	149	469

[a]Data from table 78
[b]Estimated charges for CRSP reservoirs Present values provided by Roland Fischer Colorado River Water Conservation District year 2000 estimates by the Colorado Department of Natura Resources
[c]Assumes 13 8 million acre-ft yr virgin flow al Lee Ferry *8 23* million acre ft yr Lake Powell discharge distribution of flows and evaporative charges per the percentage formula of the Upper Colorado River Basin Compact of 1948

SOURCE Office 01 Technology Assessment

Table 80.–Maximum Shale Oil Production Based on Surplus Surface Water in 2000[a]

Assumed virgin flow at Lee Ferry, million acre-ft/yr[b]	138
Surplus surface water available, acre-ft/yr[c]	
New Mexico	45,000
Colorado	207,000
Utah	92,000
Wyoming	56,000
Total	400,000
Shale 011 capacity, million bbl/d[d]	
Colorado	1 22
Utah	054
Wyoming	033
Total	209

[a]Assumes 823 million acre ft yr annual discharge from Lake Powell Distribution among the Upper Basin Slates according 10 the Upper Colorado River Basin Compact of 1948
[b]1930 74 annual average
[c] Based on year 2000 depletion projections fo nonoil shale users Medium growth rate scenario
[d]Based on 8 500 acre ft/yr for production 0150000 bbl d Of shale oil syncrude

SOURCE Office of Technology Assessment

mented by discharge from the Upper Basin reservoirs. As noted earlier, these were built to allow the Upper Basin States to satisfy their delivery requirements to the Lower Basin. Their active capacity is expected to be about 35 million acre-ft in 2000. If virgin flows dropped to say, 12.9 million acre-ft/yr and stayed there, * the reservoirs could offset the 0.9-million-acre-ft/yr shortfall for only about 39 years.

In summary, surplus surface water legally available to the oil shale States could support a shale industry of about 2.1 million bbl/d through 2000. This conclusion is based on one interpretation of the law of the river, one set of depletion estimates for conventional users in 2000, one assumed value of virgin flow, and an industry that employs a technology mix similar to that being developed in the present projects. If a different basis were selected, the estimated capacity of the industry could be significantly different. Some other bases are discussed in the issues section of this chapter.

*This appears to be the lower limit for long-term virgin flows in the Colorado River system. See the issues section of this chapter.

The conclusion also does not account for regional and local supply impediments that could affect facility siting and thereby determine the ultimate size of the industry. The next section evaluates water availability with respect to specific development sites within specific hydrologic basins in the oil shale area.

Water Availability in Hydrologic Basins Affected by Oil Shale Development

Oil shale development is likely to affect three hydrologic subbasins:

- the Green River basin in the southwestern corner of Wyoming, which includes the northern mainstem of the Green River and its tributaries;
- the White River basin, which encompasses the northern portion of the Piceance basin and the eastern portion of the Uinta basin, and whose tributaries include the White and Yampa Rivers to their confluence with the Green River in

eastern Utah, plus streams flowing north out of the Piceance basin into these rivers; and

- the Colorado River mainstem basin, which includes the Colorado River mainstem in Colorado, streams that flow south from the Piceance basin into the Colorado, and upstream tributaries at higher elevations.

The impacts on these subbasins can be estimated only after certain assumptions are made regarding the locations of the oil shale plants and the timing of their construction. If the trend indicated by the present oil shale projects were continued, about 40 percent of the shale oil production would come from the White River basin in Colorado, 30 percent from the Utah portion of that basin, and 25 percent from the basin of the Colorado River mainstem in Colorado. The remaining 5 percent might come from as-yet unannounced projects in Wyoming's Green River basin. The water requirements for a l-million-bbl/d industry distributed in this manner are indicated in table 81. Also shown are the water requirements for conventional uses in 2000, as projected by DNR under its medium growth rate scenario. As shown, the industry would increase the total water consumption in the three subbasins by about 10 percent. The increases in the Green River and Colorado mainstem basins would be relatively small, but water demands in the White River basin would increase by nearly 150 percent.

The Adequacy of Surface Water Resources by Hydrologic Basin

In the Green River basin, water depletions for a l-million-bbl/d oil shale industry would be approximately 8,500 acre-ft/yr. Two major Federal reservoirs within this basin, Flaming Gorge and Fontenelle, have well over 100,000 acre-ft/yr of surplus water in storage that is available for sale to industrial users such as oil shale developers. Consequently, there is more than enough water available within the basin to provide for projected growth. It is unlikely that any new reservoirs will be needed.

Oil shale development would have **a** greater effect on the White River basin. With **a** 1-million-bbl/d industry, depletions would approach 200,000 acre-ft/yr by 2000. About 60 percent would be used for oil shale. These depletions would strain the water resources of the White River because its total annual flow at the boundary of the basin is only about 568,000 acre-ft/yr, 61 percent of which occurs between April and July. Although several oil shale plants could be supplied from existing resources, new reservoirs would be needed and river flows would be substantially reduced.

According to DNR, only about 6,000 acre-ft/yr could be obtained from streams within the Piceance basin because of their low streamflows. A l-million-bbl/d industry would require an additional direct-flow diversion of 4,500 acre-ft/yr from the White River below

Table 81 .–Water Requirements by Hydrologic Subbasin for a 1-Million-bbl/d Industry in 2000

Subbasin	Water for conventional uses, acre-ft/yr[a]	Oil shale industry: Oil capacity bbl/d	Oil shale industry: Water acre-ft/yr[b]	Total water acre-ft/yr	Increase due to 011 shale, percent
White River, Colo. and Utah	80,000	700,000	119,000	199,000	149
Colorado mainstem, Colo. .	1,220,000	250,000	42,500	1,262,500	3 5
Green River, Wyo.	482,000	50,000	8,500	490,500	1 8
Total. .,	1,782,000	1,000,000	170,000	1,952,000	9.5

[a]Conventional uses include thermal power agriculture wildlife and recreation, minerals municipal and industrial and exports Estimates for the Colorado Department of Natural Resources medium growth rate scenario

[b]Based on 8 500 acre. ft/yr for production of 50000 bbl/d Of shale 011 syncrude

SOURCE Off Ice of Technology Assessment

Meeker, a reservoir with an active capacity of 60,000 acre-ft on the south fork of the White River in Colorado, and a 120,000-acre-ft reservoir on the White River mainstem in Utah. An industry of more than 2 million bbl/d would require these facilities plus a 35,000-acre-ft reservoir on the White River mainstem between Meeker and Piceance Creek, a total of 35,000 acre-ft of active capacity in several smaller reservoirs along ephemeral streams in the Piceance basin, and a reservoir of about 10,000 acre-ft/yr along Piceance Creek. All reservoirs would store spring runoff. Water from the White River would be pumped to the reservoirs in the Piceance basin during the rest of the year.

Within the Colorado mainstem basin, oil shale development would increase water depletions only slightly. However, large water demands would be imposed by the growth rates projected for other uses, especially irrigated agriculture. Reservoirs may be needed to supply both irrigation and oil shale development. DNR considered four siting schemes for reservoirs in this basin.

In the first scheme, reservoirs would be built at high elevations along tributaries like the Roaring Fork and Eagle Rivers. Springtime runoff would be trapped for release over the dry months. The released water would be recovered from the Colorado River below Rifle and pumped to the oil shale plants. The only appreciable inflows to the reservoirs would occur in the spring and large active capacities would be needed to sustain outflows during the dry seasons. Total capacities might exceed 50,000 acre-ft for a l-million-bbl/d industry.

The second scheme also involves reservoirs on upstream tributaries but at lower elevations to permit capture of agricultural return flows and of water from secondary streams. A total storage capacity of 30,000 to 50,000 acre-ft would be needed. The third scheme involves direct flow diversions from the Colorado River below Rifle, in conjunction with reservoirs on the Colorado mainstem or in side canyons in the Piceance basin. A l-million-bbl/d industry could be supplied with a 30,000-acre-ft/yr diversion and a 15,000-acre-ft reservoir. The reservoir could be located in a dry canyon because it would be supplied with pumped water from the Colorado mainstem and would not rely on local stream flows.

In the fourth scheme, 50,000 acre-ft/yr of surplus water would be purchased from existing USBR reservoirs (such as Reudi Reservoir) and pumped to the oil shale facilities. This would supply all of the water required for that portion of a l-million-bbl/d industry projected for the Colorado mainstem basin. Larger levels of production could be supported by any of the other three schemes, with reduced storage and diversion requirements.

In summary, new storage requirements for a l-million-bbl/d industry could range from 180,000 acre-ft, with reservoirs in the White River basin and no storage in the Colorado mainstem basin, to about 230,000 acre-ft for storage in both basins. The maximum storage requirements would be encountered if high-altitude reservoirs were built. Less storage would be needed if most water was obtained by direct diversions from the mainstem rivers. The additional reservoirs would increase reservoir capacity in the Upper Basin by about 0.6 percent. Evaporative losses from the new reservoirs should also be charged against the industry. Their precise magnitude would depend on the characteristics of the new reservoirs and their sites, but should add only a small percentage to each shale plant's annual water requirements.

Water Acquisition Strategies and Their Costs

The following strategies could be used either alone or in combination to supply water to oil shale facilities:

- perfection of conditional water right decrees,
- purchase of surplus water from Federal reservoirs,
- purchase of water supplies and water rights from irrigated agriculture,
- ground water development, and
- interbasin diversions.

A brief discussion of each strategy and its associated costs follows. Constraints and impacts are discussed later.

Perfection of Developer Water Rights

Description

Most potential oil shale developers have already acquired water rights. Some were obtained by direct filings through the prior appropriation system. These are now in the form of conditional decrees both for storage and for direct-flow diversions. Exact yields are not available because they are considered proprietary information by the companies. The rights are believed to be large but relatively junior. The oldest was acquired in 1949.

Other rights were purchased from irrigated agriculture. Most of these are relatively senior absolute rights that were perfected by the seller. To avoid a declaration of abandonment, some developers have allowed the sellers to continue to use the water for farming. Little information is available regarding the potential yields of these rights. However, total historic consumption, which would determine the quantities of water that could be transferred to oil shale development, could be as low as 10,000 to 20,000 acre-ft/yr.[28]

An idea of the extent of developers rights can be gotten by examining their water positions in 1968.[29] Conditional storage rights held by some potential developers at that time are tabulated below:

Developer	Storage rights, acre-ft
EXXON	122,000
Mobil	66,000
Getty Oil	53,000
Sinclair	51,500
Tosco	34,600
Total	327,100

These companies also owned conditional decrees to over 1 million acre-ft/yr of direct-flow diversions from the Colorado and White Rivers and their tributaries. Substantial rights were also held for ground water. Superior Oil, for example, held conditional decrees to over 2,400 acre-ft/yr of ground water in the Piceance basin.

The rights of the limited sampling of companies shown above could support an industry of nearly 8 million bbl/d and would be sufficient for the shale oil production levels projected for the near term.

Developers who do not presently own rights could file for new ones. In general, this option is considered undesirable because the quantity of water covered by rights issued to date already exceeds the resources of the river system. Any new rights would be junior to those of all other users and therefore the most likely for curtailment during water shortages.

Filing for new rights might be feasible for near-term development, however, because of the improbability that all of the water covered by present conditional decrees will be put to use for several decades. The long-term feasibility of this strategy is highly uncertain because supply curtailments will become more likely as regional growth proceeds. To assure supplies in the long term, new filings would have to be merged with other strategies.

costs

The costs of acquiring these kinds of rights are negligible, comprising only legal fees for recording the water claim, and for pursuing any resultant litigation, and small annual investments to demonstrate due diligence. The costs incurred by developers when they purchased their current irrigation rights are unknown but were probably small. Therefore, the costs of water supplies obtained through the prior appropriation system comprise only the costs of transporting the water from the diversion point to the oil shale site, Transportation costs are discussed later with respect to intrabasin diversions.

Purchase of Surplus Water From Federal Reservoirs

Description

Oil shale developers could also purchase surplus water from reservoirs operated by USBR and other entities. Various amounts of water are presently available from existing reservoirs in the oil shale area. As noted previously, the Flaming Gorge and Fontenelle Reservoirs in the Green River basin have sufficient surplus water for much more shale oil production than is likely to occur in the basin in the near term. This water is not being used for any purpose and could be made available to oil shale developers.

In the basins of the White River and the Colorado River mainstem, surplus water in storage is adequate for initial development. For example, Green Mountain and Reudi Reservoirs in the Colorado mainstem basin could supply about 100,000 acre-ft of surplus water, which would be sufficient for nearly 600,000 bbl/d of shale oil production. However, existing reservoirs could not support a larger industry unless other users were partially curtailed. Therefore, new reservoirs would have to be built. New pipelines would also be needed in all three basins to divert water to the oil shale plants.

costs

Reservoir construction costs are highly site-specific and are reflected in the charges for purchased water. These charges vary widely from reservoir to reservoir. Although charges for existing reservoirs are known, only rough estimates are available for new reservoirs,

Some examples of long-term contracts for water from existing USBR reservoirs are shown in table 82. As shown, charges in the late 1960's were from $7 to $11/acre-ft while previous charges were less than $1/acre-ft. The highest charge, $22.54/acre-ft in 1972, is for a small diversion from the Emery County reservoir. Because future contracts will be negotiated individually, water costs cannot be accurately predicted, although it seems unlikely that they would be much higher than $25/acre-ft.

Table 82.–Examples of the Charges for Purchasing Surplus Surface Water From U.S. Bureau of Reclamation Reservoirs

Project/reservoir	River basin	Purchaser	Year of contract	Quantity of diversion, acre-ft/yr	Unit cost, $/acre-ft
Seedskadee/Fontenelle	Green	State of Wyoming	1962	60,000	$0.40
Seedskadee/Fontenelle	Green	State of Wyoming	1974	60,000	500
Emery County	Central Utah	Utah Power & Light and others	1972	6,000	2254
Glen Canyon/Lake Powell	Colorado	Resources Co and others	1969	102,000	7.00
Glen Canyon/Lake Powell	Colorado	Salt River project	1969	40,000	7.00
Navajo	San Juan	New Mexico Public Service	1968	20,200	700
Navajo	San Juan	Utah International	1968	44,000	700
Navajo	San Juan	Southern Union Gas Co.	1968		7.00
Missouri River/Bighorn and Boysen	Yellowstone	Various	1967-71	658.000;	11,00
Boulder Canyon/Lake Mead	Lower Colorado	Colorado River Commission	1966	30,000	050

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

Some cost estimates for new reservoirs in Western Colorado are summarized in table 83. Unit construction costs in 1979 dollars vary from $120 to $740/acre-ft of storage capacity. To obtain estimates of water costs from these reservoirs, assumptions must be made about financing methods and operating characteristics of the reservoirs. A rough estimate can be made if it is assumed that storage and delivery capacities are equal, and 10 percent of construction costs are charged to water purchasers per year. Then the charges for the water would range from about $10 to about $75/acre-ft, which is substantially higher than costs from existing reservoirs.

Table 83.–Estimated Construction Costs for Proposed Reservoirs Within the Colorado River Water Conservation District

	Storage capacity, acre-ft	Construction costs, million$	Unit capital costs, $/acre-ft
Haypark , ,	20,000	$ 6 0	$300
Azure	30,000	11.4	380
Toponas, .,...,.. ,,	18,000	3,3	180
Iron Mountain,	60,000	289	480
Yoeman Park . ~ ~ ~ ~	7,000	4 9	740
Bear Wallow. .	49,000	11.9	240
Kendig, ., ., . ., ~	15,000	5.0	320
Una.	196,000	363	190
Yamcolo ,,. ,.	9,000	5.8	640
Bear, .., ,,. .	12,000	30	260
Grouse Mountain.	79,000	9.2	120
Rampart. .	12,000	4.0	350
California Park	37,000	52	140
Rangely ..,, .,, ,	55,000	112	200
Dunkley.	57,000	13,2	230
Pothook .,,	60,000	8 5	140

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

Purchase of Irrigation Rights

Description

Most oil shale developers have indicated that they plan no further purchases of irrigation rights. However, the strategy warrants discussion because large quantities of water are currently consumed by farming and the water laws allow rights to be transferred from willing sellers to willing buyers.

The feasibility of using irrigation rights for oil shale development is site specific and depends on their cost in comparison with other strategies, the proximity of irrigation diversions to potential plantsites, and the seasonal nature of irrigation rights. Transfer is unlikely in the Green River basin, for example, because adequate and inexpensive water appears to be available from existing Federal reservoirs. On the other hand, it could occur in the White River and the Colorado mainstem basins because of the limitations of existing storage capacity.

In the White River basin, irrigated agriculture consumes about 37,000 acre-ft/yr, This amount of water could supply a 250,000-bbl/d oil shale industry. If this water were transferred to oil shale, additional storage would probably be needed because of the seasonal nature of irrigation rights. These rights generally rely on direct diversions from a river, and river flows might not be sufficient during dry seasons to satisfy the oil shale water requirement.

In the basin of the Colorado River mainstem, irrigated agriculture currently consumes about 430,000 acre-ft/yr, which is much more than would be required for any projected level of oil shale development. Purchase of irrigation rights would reduce, but probably not eliminate, the need for new storage capacity. Irrigation water from the Colorado mainstem could also be diverted to oil shale facilities in the White River basin, thus reducing the need for new storage in that basin. Some new interim storage would be needed near the plantsites. In any case, new pipelines would be needed to transport water from current diversion points to the oil shale facilities.

costs

It is important to distinguish between the purchase of a specific quantity of water for use in a given year and the purchase of a water right that would authorize use in all future years. In recent years, the cost in Colorado of purchasing irrigation water for one year's use has ranged from about $10 to $25/acre-ft, which is similar to the costs of purchasing water from existing Federal reservoirs.[30] The cost of purchasing a water right for use in perpetuity, however, could range from $1,000 to $2,500 for each acre-ft/yr covered by the right.[31] If capital to purchase the right were borrowed at lo-percent interest, annual costs might range from $100 to $250/acre-ft. These costs are substantially higher than current prices for single-year diversions. The reason is that most farming could not be conducted without irrigation. Selling water rights essentially puts a farmer out of business.

Ground Water Development

Description

Ground water aquifers could be feasible water sources for oil shale development if they are favorably located relative to plantsites, if the water quality is suitable for industrial applications, and if physical characteristics (such as burial depth, storage volume, and discharge rates) are advantageous. Although knowledge is incomplete, existing data suggest that selected aquifers in the Upper Basin are worthy of consideration for some, if not all, potential oil shale facilities.

In the Piceance basin, for example, up to 25 million acre-ft is estimated to be stored in two major bedrock aquifers that are separated by rich oil shale beds. This resource is currently being used in limited amounts for livestock watering, for irrigated agriculture, and for localized domestic consumption. The water is generally high in dissolved solids and fluoride. For this reason, its use for conventional purposes will probably not increase. It is likely that an oil shale industry would be the only large-scale application for which this ground water would be suitable. * With proper pretreatment, much of it could be upgraded for such use. If this were done to the fullest extent, the aquifers could supply a 1-million-bbl/d shale oil industry for from 200 to 500 years, depending on the processing technologies used.

Less is known about ground water in the White River basin in Colorado and Utah and about Utah's water resources in general. It is known that the Uinta basin contains large artesian aquifers, one of which discharges in the vicinity of Federal lease tracts U-a and U-b. The water is not potable but could be treated for use in oil shale processing.

Because bedrock aquifers in the Piceance and Uinta basins often coincide with minable oil shale zones, ground water will be an important consideration in most development plans. Even if ground water is not intentionally developed for use as process water, it will be produced on most tracts during mine dewatering and the preparation of in situ retorts. In many locations, the water could satisfy all processing needs, In some areas, an excess will be produced that will have to be disposed of through evaporation, by reinjection, or by discharge to surface streams. Purifying excess ground water to discharge standards could be costly.

In the Piceance and Uinta basins, yields from test wells vary with location from less than 1,000 to over 4,000 acre-ft/yr. Two to four of these wells would be sufficient to satisfy the needs of an oil shale plant producing 50,000 bbl/d by directly heated AGR. Several additional wells would probably be drilled to provide backup capacity.

costs

The cost of ground water development will vary with site, with water quality, and with the water management program of the developer. In a recent study the geohydrologic characteristics of three wellsites in the Piceance basin were analyzed, and estimates were prepared of drilling capital and pumping costs.[32] For two of the sites, which had prolific water-bearing zones extending to

*Water in the upper aquifer generally contains less than 2,000 mg/l of dissolved solids, while in the lower aquifer these may range from 1,000 to 63,000 mg/l. The fluoride content is typically from 10 to 70 mg/l. Federal drinking water standards recommend a dissolved solids limit of 500 mg/l and a fluoride content of less than 1.0 mg/l.

about 1,000 ft below the surface, a minimum cost of about $30/acre-ft was estimated for delivery of 1,500 to 4,000 acre-ft/yr. The third site contained much less permeable rocks, which reduced maximum flows and thus increased costs. The estimate of the maximum flow from this well was 700 to 900 acre-ft/yr, with a minimum cost of about $90/acre-ft. In the DNR study, water costs from a well yielding 3,000 acre-ft/yr from a depth of 500 ft were estimated to be $22 to $30/acre-ft.[33] Another estimate is about $55/acre-ft for a 1,000-ft well yielding 1,500 acre-ft/yr.[34]

The costs of well drilling and pumping could, therefore, range from $20 to $60/acre-ft, assuming that aquifers occur at reasonable depths and in reasonably permeable formations. These costs are comparable to those for surface water. Ground water could offer a major economic advantage in that wells could be located near the oil shale facilities, thus avoiding transportation costs. On the other hand, the poor quality of some ground water would necessitate costly purification.

Water from some aquifers is highly saline or brackish. It would not need to be purified for use in dust control and spent shale compaction, but would have to be for use as boiler feedwater or cooling water. Purification can be quite costly. For example, treating brackish water to cooling water standards can cost from $200 to $300/acre-ft,[35] and treatment to boiler feedwater standards can cost from $650 to $ 1,000/acre-ft.[36] These high treatment costs would not be needed for all of a plant's water supply, because some requirements could be satisfied with water of any quality. If the overall water management plan of an AGR facility is considered, a brackish ground water supply would add about $250 to $530/acre-ft to the costs of water acquisition.

Thus, the overall costs of ground water development and use could range from $20 to $600/acre-ft/yr. The lower estimate corresponds to a high-quality ground water from permeable rocks at reasonable depths. The higher estimate corresponds to brackish water from relatively impermeable formations.

Interbasin Diversions

Description

Interbasin diversions move water from one major hydrologic basin to another. Exports from the Upper Basin to the cities of Colorado's Front Range Urban Corridor (Denver, Colorado Springs, etc.) are examples of interbasin diversions. Diversions could also be used in the future to increase overall water availability in the Upper Basin by relocating water from other major basins such as the Columbia River Basin or the Upper Missouri River basin.* As an illustration, diverting 1 percent of the net water supply of the State of Washington in the Columbia River Basin would provide 2 million acre-ft/yr of additional water to the oil shale area, an amount equal to two-thirds of the present water consumption in all of the Upper Basin States.

costs

Costs of interbasin diversions vary with pipeline construction and pumping costs, which in turn depend on the route, diameter, and length of the pipelines; on the number and capacity of pumping substations; and on the cost of purchased power for the pumps. These costs are highly project-specific, but, in general, decrease with pipeline throughput and increase with distance. Variations in unit costs can be illustrated by considering two alternate pipelines; one providing water to a single oil shale plant and the other supplying water to an entire industry. An oil shale plant producing 50,000 bbl/d by directly heated surface retorting would consume about 6,000 acre-ft/yr of water. This quantity could be transported to the site in an 18-inch-diameter pipe at a unit cost of about $12/acre-f t/mile. In comparison, about 240,000 acre-ft could be conveyed through a 90-inch-diameter pipeline at a unit cost of $1 .90/acre-ft/mile.[37]

*Under the CRP Act, the Secretary of the Interior was required not to undertake reconnaissance studies of any plan for the importation of water into the Colorado River Basin until 1978. The Reclamation Safety of Dams Act of 1978 extended this moratorium until Nov. **2, 1988.** Thus. no water imports from other major basins will be allowed until well after 1988, Four options illustrate typical distances and costs that might be encountered with interbasin diversion for a large oil shale industry. One option would be to bring water to the White River basin from the Oahe Reservoir on the mainstem of the Missouri River in South Dakota. The distance would be 500 to 600 miles, and the unit costs would be $950 to $1,150/acre-ft. A second alternative would be to transport water from the Missouri River at Kansas City to the John Redmond Reservoir in Kansas, then to Denver, and finally over the Rocky Mountains to the White River basin.[38] The pipeline would be about 700 miles long, and the unit transportation cost about $1,130/acre-ft. A third option would be to transport water about 800 miles from the Columbia River Basin to the White River basin. Unit costs would be about $1,520/acre-ft. A fourth possibility would be to divert water to the White River area from the Yellowstone River, a distance of approximately 400 miles, This would cost about $750/acre-ft,

In summary, interbasin transfers for a large industry would require 400- to 800-mile-long pipelines and would entail unit costs of $750 to $1,500/acre-ft. Exact costs vary widely but are, in general, quite high. To these costs must be added the purchase price of the water that is moved through the pipeline.

Intrabasin Diversions

Description

The total cost of a water supply includes the cost of acquiring the water and the cost of moving it to the oil shale facility. As indicated above, transportation costs can outweigh acquisition costs if the facility is far from the water source. The costs of transporting water acquired in the oil shale area will also be high, although less than for transfers from other major basins. The following discussion describes some of the typical intrabasin diversions that could occur within the oil shale region, and estimates the costs of moving water through such diversion systems. This cost can then be added to the purchase price of the water to obtain the overall cost of developing a given water supply.

Intrabasin diversions redistribute water within a major hydrologic basin such as the Upper Basin, They include transfers between individual subbasins such as the basins of the Green River, the Colorado River mainstem, and the White River. Intrabasin diversions are not an acquisition strategy, but are a method for relocating acquired water to oil shale plants. Except for selected tracts using ground water and for the few oil shale plants built very close to major tributaries, new intrabasin diversions will be needed.

Intrabasin diversions would not reduce the strain on the resources of the Colorado River system. They would simply redistribute water among individual subbasins. They could be used, for example, to augment the sparse natural flows of the White River with surplus surface water from the Colorado River mainstem. They could also be used to transport stored surplus water from Federal reservoirs in the Green River basin to developments along the White River or the Colorado River mainstem. Such diversions would be required regardless of whether the oil shale water supplies are obtained from new or from existing reservoirs,

costs

The costs of transporting water by an intrabasin diversion pipeline will depend on the fees charged by the supplying reservoir and the costs of building and operating the pipeline between the reservoir and the plantsite. Some USBR estimates of the unit costs of selected intrabasin diversion projects are summarized in table 84. Reservoir charges and operating costs for the pipeline are estimated, but not the costs of acquiring the water that is moved through the pipeline, Several types of supply systems and flow rates are shown, and both existing and new reservoirs are considered. The range of unit transportation costs is from $70 to $550/acre-ft. If the highest and lowest are excluded, the range is reduced to from $180 to $440/acre-ft.

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Table 84.–Summary of Cost Estimates for Intrabasin Diversions Within the Oil Shale Area

Data source	Type of reservoir	Destination	Flow volume, acre-ft/yr	Unit transportation cost, $/acre-ft
USBR[a]	New	Tract C-a	57,000	$240-390
USBR	New	Tract C-b	18,000	260-280
USBR	New	Tracts C-a and C-b	75,000	240-440
USBR	Existing	Tracts C-a and C-b	75,000	310-350
USBR	New	Tracts U-a and U-b	8,000	280-400
USBR	New	Tracts U-a and U-b	36,000	70-160
USBR	Existing	Tracts U-a and U-b	36,000	190-230
USBR	New	Tracts C-a, C-b, U-a, and U-b	111,000	180
DNR[b]	Existing	Green River basin	14,000	280
			30,000	260
DNR	New	Colorado River mainstem basin	29,000	550
			84,000	400
DNR	New	White River basin	141,000	380
			240,000	360

[a]U S Bureau of Reclamation *Alternative Water Sources for Prototype Oil Shale Development* Salt Lake City Utah September 1974
[b]Colorado Department of Natural Resources *Upper Colorado River Basin Section 13(a) Assessment A Report to the U S Water Resources Council (Draft)* August 1979

SOURCE Office of Technology Assessment

Summary of Supply Costs

Estimates of the costs of supplying industrial-quality water to oil shale sites by means of the several acquisition and transportation strategies discussed previously are summarized in table 85. The strategy costs include the costs of purchasing the water, of transporting it from the point of acquisition to the point of use, and of treating it for use in the facilities. The estimates are approximate. They were derived using the following assumptions:

- All surface water acquired in the oil shale region is transported over substantial distances through intrabasin pipelines.
- Water for interbasin diversions is purchased at a cost of $25/acre-ft.
- Surface water is of good quality and does not require substantial purification prior to use.
- Ground water quality is variable. Only brackish ground water must be treated prior to use.
- All ground water is developed in the immediate vicinity of the oil shale plants. Pipelines to points of use are of insignificant length.
- Surplus water from existing reservoirs costs $25/acre-ft. Water from new reservoirs costs $100/acre-ft.

The lowest cost strategy is the development of good quality ground water. Unit costs

Table 85.–Summary of Approximate Water Supply Costs for Several Acquisition Strategies

	Component cost, $/acre-ft			Strategy costs	
Strategy	Purchase	Transportation	Treatment	$/acre-ft	$/bbl of oil[a]
Perfection of conditional decrees	nil	$180-440	nil	$180-440	$0.09-0.23
Purchase from existing Federal reservoirs ...	$25	180-440	nil	205-465	0.11-0.24
Purchase from new Federal reservoirs, ., .,	100	180-440	nil	280-540	0.14-0,28
Purchase of senior Irrigation rights ., .,	100-250	180-440	nil	280-690	0.14-0,36
High-quahty ground water . .	20-60	nil	nil	20-60	nil-0.03
Brackish ground water	20-60	nil	$250-530	270-590	0.14-0.30
Interbasin diversions ., .,	25	750-1,500	nil	775-1,525	0.40-0,79

[a]Assumes that 8500 acre-ft/yr is consumed per 50,000-bbl/d Plant

SOURCE R F Probslem H Gold and R E Hicks, *Waler Requirements Po//u(lorr E/lecls, and Cos(s of Wafer .SWIp/y arrd Trealmerrf for fhe 0// S/ra/e induslry* report prepared for OTA by Water Purification Associates Oclober 1979 range from essentially zero to about $0.03/bbl of oil. The perfection of conditional water decrees is more costly, with unit costs ranging from $0.09 to $0.2/bbl of oil. It is comparable to purchasing surplus water from existing Federal reservoirs. Purchasing water from new Federal reservoirs is comparable in cost to developing brackish ground water—about $0.14 to $0.28/bbl of oil. Water obtained by purchasing senior irrigation rights costs a little more. Interbasin diversions are by far the most expensive, with unit costs from $0.40 to $0.79.The higher unit cost for interbasin diversions was calculated under the assumption that water would be transported for 800 miles from the Columbia River Basin.

Except for interbasin diversions, the costs of water supplies range from essentially zero to about $0.36/bbl of upgraded shale oil. Such water costs, which would have seemed unattractively high in the early 1970's when oil prices were about $3.00/bbl, are less consequential with current oil prices.

Legal and Institutional Considerations

The previous sections evaluated the physical and economic requirements of several water supply strategies. The feasibility of any of them also depends on a number of legal and institutional factors, some of which are examined below.

The Law of the River

As discussed previously, water development in the Upper Basin will be constrained by the following factors:

- The operating criteria for Federal reservoirs in the Upper Basin, which require a minimum discharge of 8.23 million acre-ft/yr from Lake Powell.
- The Upper Colorado River Basin Compact of 1948, which limits the percentage of total Upper Basin depletions that can be consumed by each State.

Different assumptions about virgin flow, regional growth rates, processing technologies, and plantsites can lead to widely different projections of the maximum size of the oil shale industry that could be supplied by surplus surface water in 2000. Assuming 13.8-million-acre-ft/yr virgin flow, medium growth rates, and an industry with an average water requirement of 8,500 acre-ft/yr per plant, the limit appears to be about 2 million bbl/d.

This estimate assumes that the States in the Upper Basin concur with the constraints identified above. This is a questionable assumption because several aspects of the law of the river are in direct conflict and not all have been accepted by the States, particularly in the Upper Basin. For example, the Colorado River Compact of 1922 assured delivery of 7.5 million acre-ft/yr to both the Upper and Lower Basins. This would be possible with virgin flows of at least 15 million acre-ft/yr; it would not be possible with the lower flows that have prevailed since 1930. The delivery obligation of the Mexican Water Treaty of 1944-45 is another source of conflict. The treaty has not been a constraint on the Upper Basin States because of their low water demands in the past. However, it could significantly affect future development programs. If the obligation were imposed on the Upper Basin under the percentage formula of the Upper Colorado River Compact of 1948, Colorado's share would be 388,000 acre-ft/yr, Utah's 173,000 acre-ft/yr, and Wyoming's 10 105,OOO acre-ft/yr. If the Upper Basin States were able to avoid the obligations through litigation, much higher levels of regional growth and energy development would be possible.

The States may choose to follow this path. For example, Colorado Governor Richard Lamm maintains that Colorado and the other Upper Basin States are not responsible for satisfying the Mexican treaty obligation.[39] The director of the Colorado Water Conservation Board describes the State's position as follows:[40]

> There has been a considerable amount of study, together with a considerable amount of speculation, concerning the amount of water which is still available to the State of Colorado under the terms of the Colorado River Compact and the Upper Colorado River Basin Compact. The problem with any study is that no one can actually define the precise amount of water to which Colorado is entitled under the terms of the compacts. In addition to existing uncertainties concerning the compacts, the Mexican Treaty of 1944 further complicates any water supply study. There are some basic disagreements among the various states of the Colorado River Basin as to the obligation of each State for the release of water to satisfy the Mexican Treaty. At some future time it appears likely that these differences will be taken to the United States Supreme Court for resolution.

Analysis of the legal position of the States in this controversial matter is beyond the scope of this assessment. It is possible, as the above citation implies, that resistance to supply obligations could be directed at the Mexican treaty itself. However, because the treaty is a national commitment, it is more likely that resistance will be manifested against the operating criteria for Federal reservoirs in the Upper Basin. These criteria have been implemented by DOI through requirements for minimum annual discharges from Lake Powell. The 8.23 -million-acre-f ft/yr discharge requirement incorporates both the Lower Basin allocation of 7.5 million acre-ft/yr and the Upper Basin's share of the Mexican obligation. The Upper Basin States do not agree with the operating criteria.[41 42]

The Doctrine of Prior Appropriation

As stated earlier, most of the water rights held by potential oil shale developers are either conditional decrees, which are large in quantity but junior in date of appropriation, or absolute irrigation rights, which are small but senior. Under the appropriation doctrine, only the irrigation rights would provide secure water supplies. They would be limited to about 10,000 to 20,000 acre-ft/yr. If the more junior decrees were perfected, they could be curtailed during dry periods to provide water to more senior users, with severe economic repercussions unless sufficient water storage had previously been constructed. Any new rights obtained through the prior appropriation system would be extremely junior and even more susceptible to curtailment. Any large-scale use of ground water for oil shale development would have to protect the water rights of senior surface water users.

Thus, the prior appropriation doctrine reduces the attractiveness of developing water supplies through perfection of existing or future conditional decrees. Given the constraints of the appropriation system, it appears that the most reliable strategies would be additional purchase of highly senior irrigation rights, purchase of surplus surface water from reservoirs, ground water development in selected areas, or interbasin diversions.

Federal Reserved Rights Doctrine

Under this doctrine, water has been set aside for use on Federal lands, but the amounts of water affected have not yet been quantified. An important aspect of the doctrine is that Federal rights, when perfected, will be senior to most others. Any more junior user will face curtailment in times of water shortage. The doctrine is an example of the constraints imposed by prior appropriation.

The doctrine would affect any acquisition strategy that relied on flows originating within the Upper Basin. The only strategies that would avoid the doctrine's constraints would be the development of nontributary ground water, interbasin transfers specifically for use in oil shale facilities, or the purchase of irrigation rights that are senior to the Federal rights. The latter would be difficult because many of the potential Federal rights date back to the late 19th century.

It is possible, although uncertain, that the Federal reserved rights could be used to assist oil shale development. Because the

Supreme Court has decided that the affected water may only be used to further the purposes for which a reservation was established, it appears that the only relevant rights would be those that might be claimed for the Naval Oil Shale Reserves in Colorado and Utah. These reserves were established in the 1920's and the rights, if they could be implemented, would be quite senior. However, the legal position of the rights in Colorado is complicated because the reserves do not border on the Colorado River and they contain little ground water. The Government has indicated that it intends to claim water for the Colorado reserves; the claim is in the early stages of litigation by the State,

Environmental Legislation

There are a number of environmental laws which do not directly restrict water use but which could affect the siting of facilities, the scale of operation, and particular water acquisition strategies, It is difficult to predict their effects on development of water resources in the oil shale region, but it is important to note their existence and to recognize that they could be of considerable consequence. Included are the following laws:

- The Fish and Wildlife Coordination Act. This Act required that all Federal agencies which direct, impound, or modify water bodies must consult with USFWS. Plans for water resource development are reviewed by the Service to assure that they include appropriate protective measures for fish and wildlife.
- The Endangered Species Act, Under this Act, Federal agencies are to conserve threatened or endangered species. In the Upper Basin there are species of endangered fish—the humpback chub and the Colorado River squawfish—which might influence the siting of reservoirs for energy development.
- The National Wild and Scenic Rivers Act. This Act is designed to preserve portions of selected streams in a natural state. The addition of any streams in the Upper Basin to this system might affect their future use for energy development,
- The Wilderness Act. This Act establishes a National Wilderness Preservation System composed of federally owned wilderness areas as designated by Congress. The Act also stipulates the conditions under which reservoirs and other facilities can be built within these areas. As a consequence of this Act, reservoirs and other water facilities needed for energy development might be restricted in certain areas.

These laws should not reduce the availability of water within the Green River hydrologic basin because there are presently no known endangered species or designated water areas within this basin. Furthermore, flows of the Green River will be insignificantly affected by the projected levels of shale oil production.

In contrast, environmental legislation could constrain oil shale development in the White River basin. High levels of shale oil production are projected for this basin, and the associated water requirements could significantly reduce river flows. Furthermore, the Colorado River squawfish, a federally designated rare and endangered species, is known to inhabit the lower portions of the White River. In addition, the Flat Tops Wilderness area, an existing Federal wilderness, includes portions of the headwaters of the north and south forks of the White River. Flat Tops could affect oil shale development in that reservoirs and other structures would not be permitted within the wilderness area, except under presidential approval.

Water availability within the basin of the Upper Colorado mainstem might be affected by the Endangered Species Act, the Wilderness Act, and the National Wild and Scenic Rivers Act. The Colorado River squawfish inhabits the Colorado River from the backwaters of Lake Powell upstream to the confluence of Plateau Creek. The humpback chub is found in the Colorado mainstem downstream from the Colorado/Utah State line.

This basin also contains three designated wilderness areas, and additional areas are being considered for inclusion in the wilderness system pursuant to the ongoing Roadless Area Review and Evaluation (RARE II) review. ' New reservoir storage would probably not be permitted in these areas. However, they are in high-elevation watersheds and thus would probably not contain potential sites for reservoirs. In addition, several rivers within this basin are being considered for wild and scenic designation.

Thus, these environmental laws might affect the siting of storage reservoirs and limit the amount of water that could be diverted from certain rivers. Water supply strategies that require extensive storage, such as the purchase of irrigation water, could be affected.

Instream Water Flow

Instream flow requirements are legally considered only in Colorado, where the State has retained the right to obtain water for preserving the natural environment to a reasonable degree. Instream rights are subject to the prior appropriation system, and have priority over consumptive rights only if they are more senior in time. The State recognized instream rights in 1973, and thus these rights are quite junior and should not impede the perfection of rights held by oil shale developers, some of which date back to 1949. However, if the oil shale industry were to file for additional surface rights they would be junior to the instream rights and would have a lower priority in times of water shortage. Other water acquisition strategies—such as the purchase of senior irrigation rights, transbasin diversions, and ground water development—would not be significantly affected. The purchase of surplus water from Federal reservoirs would be affected only if the perfection of instream rights reduced the amount of surplus water available for sale.

On the other hand, minimum flow bypasses around reservoirs and dams are required for aquatic life under the Clean Water Act. Depending on the interpretation given this Federal statute by the States, the total amount of surplus surface water could be decreased.

Finally, USFWS is engaged in a study to develop strategies for reserving flows to maintain fish and wildlife habitats. Although they are not yet part of the legal system, such strategies might ultimately reduce surface water availability for any type of growth in the oil shale region.

Interbasin Transfers

Several legal barriers constrain interbasin transfers of water to the oil shale region. The Yellowstone River Basin Compact of 1950 (65 Stat. 663) requires approval of Wyoming and Montana before transfers of Yellowstone water can occur. Moreover, the Colorado River Basin Project Act of 1968 (82 Stat. 885) specifically prohibits the Secretary of the Interior from undertaking feasibility studies of any plan to import water into the Colorado River Basin until 1978. This moratorium on water feasibility studies was extended under the Reclamation Safety of Dams Act (92 Stat. 2471) until November 1988. Thus, until this moratorium is removed no new imports can occur.

Salinity Standards

The States within the Colorado River system are committed to maintaining salinity at or below the average 1972 levels in the lower mainstem of the Colorado River. They have developed salinity criteria for three points in the Lower Basin—Hoover Dam, Parker Dam, and Imperial Dam. The criteria have been approved by EPA, but are tentative and subject to revision.

Salinity criteria could constrain oil shale development because such development has

*The Forest Service, in its RARE 11 program, is evaluating over 66 million acres of land to determine their suitability for designation as wilderness. During the period of initial evaluation and up to final disposition of the wilderness recommendation by Congress, these lands will be in some form of restrictive management.

been linked, through theoretical calculations, to salinity increases in the river system. Increases could occur through either of two mechanisms: salt loading (in which saline wastewaters are discharged from an oil shale plant) or concentration (in which waters of higher than average quality are removed from the Upper Basin tributaries for use in oil shale processing). Salinity increases from concentration are discussed in the next section of this chapter; those from salt loading are discussed in chapter 8.

It is possible that salinity criteria could affect oil shale operations if such operations acted to increase the salinity in the lower mainstem. If this were the case, acquisition strategies that increase the total depletions from the river system would be constrained. These would include the perfection of surface water rights and the purchase of stored surface water. Ground water development would be little affected, and interbasin diversions would not be constrained as long as the salinity of incoming water was lower than upstream surface flows within the basin. The transfer of senior irrigation rights would probably not be impeded because, as discussed in chapter 4, irrigation return flows are the chief man-related source of salinity in the Colorado River system. A reduction in these flows through diversion to oil shale processing should decrease the salinity of the lower mainstem.

In summary, the effects of emerging salinity standards cannot be predicted with any confidence. Certain water acquisition strategies would feel them more than others. They should not severely affect any strategy if water released from oil shale sites is treated to achieve the discharge standards promulgated under the Federal Water Pollution Control Act.

Critical Uncertainties

The previous analyses have calculated that an oil shale industry of up to 2 million bbl/d could be supported to the year 2000 by surplus water that is legally available to the oil shale States. This calculation is based on four key assumptions:

- The long-term average virgin flow is 13.8 million acre-f ft/yr—the running average between 1930 and 1974.
- The industry continues to use a mix of mining and processing technologies similar to that which would be used if presently active and proposed projects were completed.
- Water demand for conventional uses in the Upper Basin increases at a medium rate.
- The industry relies solely on surface water; ground water is not ‘developed.

Following is a discussion of how the industry's capacity might be affected if other assumptions were made in these areas. Consideration is also given to the problems of water availability beyond 2000.

Virgin Flow

As noted, the flows of the Colorado River vary widely. Estimates of future water availability have been based on the flows measured at Lee Ferry after 1930 because earlier estimates of virgin flow were less accurate. (Before 1922, flows were not measured at Lee Ferry; they were estimated from the measured flows of upstream tributaries.) However, it is not clear that the flows encountered in the past will continue into the future. The 13.8-million-acre-ft/yr average could sustain a large industry through 2000, but if the long-term average decreased by 3 percent, to 13.4 million acre-ft/yr, there would be no surplus surface water available then. Measurements of tree rings in the Colorado River Basin suggest that the long-term average flow may be closer to this level than to 13.8 million acre-ft/yr.[43] On the other hand, if the flows increased to 14.2 million acre-ft/yr, 3 percent above the 1930-74 average, there would be sufficient surplus water in 2000 for a 4-million-bbl/d industry. The average flow between 1906 and 1974 was 15.2 million acre-ft/yr. The average between 1922 (when flows were first measured at Lee Ferry) and 1974 was 14.2 million acre-ft/yr.

Technology Mix

The industry's actual average water requirement may be substantially higher or lower than the 8,500 acre-ft/yr per plant that would result if present trends continued. An industry based solely on directly heated AGR would consume only about 4,900 acre-ft/yr per plant. The amount of surplus surface water projected for 2000 would be sufficient for a 3.5-million-bbl/d industry if only this technology were employed. On the other hand, an industry of indirectly heated AGR facilities (at 12,300 acre-ft/yr per plant) could produce only 1.4 million bbl/d from the same surplus.

Conventional Depletions

Although the medium growth rate for conventional water uses is regarded by the States as most likely, it is possible that demands could increase at a much higher or lower rate. DNR analyzed the effects of low, medium, and high growth rates. Although the medium rate would allow an industry of up to 2 million bbl/d, a high rate would reduce the surplus surface water by 247,000 acre-ft/yr in 2000. Only a 550,00@ bbl/d industry could be accommodated. On the other hand, a low growth rate would increase the surplus by 326,000 acre-ft/yr and would allow an industry of up to 3.9 million bbl/d.

In any case, surplus water availability is much less assured after 2000. If the low growth rate prevails, demand will exceed supply by 2027, even without an oil shale industry. With a medium growth rate, the surplus will disappear by 2013. A high growth rate will consume the surplus by 2007, again without oil shale development. The implications of this potential problem for oil shale are controversial. On the one side it is argued that possible long-term water shortages should preclude the establishment of an industry. On the other side, it is maintained that a major industry could function for much of its economic lifetime without interfering with other users, and in any case would use relatively little water. (A l-million-bbl/d industry would accelerate the point of critical water shortage by about 3 years.)

Ground Water Development

If the presently active and proposed projects were completed, more than 40 percent of the shale oil production would come from ground water areas in the central and northern Piceance basin. If additional Federal leasing were pursued, a much higher percentage of the industry's facilities would be sited in this area. Ground water will have to be developed on these sites in order to allow mining or in situ retorting. The ground water extracted would have to be reinfected into the source aquifer, or treated for discharge to surface streams, or used in the facilities. If it were used as process water, the need for surface water would be substantially reduced. If 15 percent of the roughly 25 million acre-ft in the Piceance basin bedrock aquifers were used for oil shale, it could support a l-million-bbl/d industry for 20 years. However, this rate of consumption would exceed the recharge rate for the aquifers. Thus, the ground water levels would decrease and some of the surface streams that are supplied by ground water discharge would dry up. This would have relatively minor economic ramifications because the rate of ground water discharge is only about 20,000 acre-ft/yr. The environmental effects woulds be mixed, as discussed in the next section.

The Impacts of Using Water for Oil Shale Development

Introduction

The use of water by an oil shale industry will cause economic, social, and ecological changes in both the Upper and the Lower Basins of the Colorado River system. The effects of salinity increases are of special concern because salinity levels in the Colorado River have been identified as a matter of national concern.[44]his section discusses the salinity increases that are expected to result from use of surface water for oil shale development. The overall impacts of water diversion on the Upper and Lower Basins are then discussed. Because of time restrictions, OTA did not perform an independent analysis of these impacts, However, assessments have recently been completed by DNR, USBR, USGS, and USFWS. The following discussion is largely based on the results of these studies.

Impacts From the Construction and Operation of Water Supply Facilities

Construction of dams, wells, and diversion facilities would create jobs and increase disposable income. However, pressures on housing and on community facilities and services would result. Both the positive and the negative effects would diminish once construction was completed. Operation of the facilities would require fewer than 10 employees per plant, out of a total work force of approximately 1,500. Consequently, relatively few of the socioeconomic impacts that may accrue from creating an oil shale industry can be associated with the water supply systems.

New reservoirs will flood land that may presently be used for farming or grazing or that may have special scenic or ecological value. Homes, farms, businesses, roads, and utility lines would have to be relocated, and riparian and aquatic systems could be disturbed. These impacts should be minor compared to those of the mining and processing operations. Because the reservoirs will be relatively small, the overall impacts would be small compared to those that were associated with the construction of existing reservoirs. (The new reservoirs needed for a l-million-bbl/d industry would increase the total water storage in the Upper Basin by 0.6 percent.) These impacts will be site specific and have not yet been analyzed.

Impacts From Changes in Surface Flows

Extraction of surface water will decrease the instream flows of the Colorado River and its tributaries. These changes will have direct effects on water users and indirect effects on water quality and aquatic ecosystems. The direct effects are considered in this section; the indirect effects in the section that follows.

Decreased flows would reduce hydroelectric power production at specific CRSP reservoirs. According to the DNR assessment, revenue losses could reach $7 million per year in 2000 as a result of a 2.44-million-bbld/ industry. ’5 Flow reductions would also decrease deliveries to the Central Arizona project and force the agricultural industry in the Lower Basin to rely on more expensive ground water pumping. Net farm income would be reduced by about $2.3 million per year by 2000 as a result of a 2.44 million-bbl/d industry.[46]

According to USBR, environmental impacts in the Lower Basin depend more on reservoir operating criteria than they do on the quantity of water in a particular stream, and flow reductions in the Lower Basin would have significant effects only in that portion of the Colorado River between Glen Canyon Dam and Lake Mead.[47]

Reductions in instream flow will also affect recreational use of some stream reaches. Although most recreational activities, such as rafting, boating, and kayaking, would remain unchanged in 2000 even with high levels of oil shale development, negative impacts would occur in two river reaches. In the Colorado River between Rifle, Colo., and its confluence with the Gunnison River, rowing and rafting conditions would be degraded from the present fair condition to poor if a 2.44-million-bbl/d industry were established. Fishing conditions would be reduced from fair to poor with substantially lower levels of development. In the White River from Meeker, Colo., to Ouray, Utah, conditions for canoeing, kayaking, and fishing would be reduced from excellent to good. Adverse public reaction should be expected. Secondary impacts on tourism and recreational service suppliers may occur, although no detailed analysis of these impacts has been undertaken.

Impacts on Water Quality

Withdrawal of water of relatively high quality from upstream tributaries of the Colorado River system will increase salinity levels in the lower reaches of the Colorado River by making the water unavailable for dilution of more saline streams that enter the river below the withdrawal point. Some of the estimates that have been made of this salt concentration* effect are summarized in table 86.[48-54] Included for each source are estimates of salinity increases for the project or industry originally analyzed and estimates scaled to a common basis of a l-million-bbl/d industry. As shown, a l-million-bbl/d industry in the Upper Basin could increase salinity levels at Lower Basin measuring stations by 0.2 to 2.4 percent. The estimates incorporate widely differing assumptions regarding plantsiting, types of processing technologies, water requirements, and quality of water diverted. A very approximate average salinity increase for a l-million-bbl/d industry might be about 1 percent.

It should be noted that similar effects would be experienced if the same amount of water were used for other purposes. The University of Wisconsin study cited in table 86 estimated that diversion of 300,000 acre-ft/yr of upstream water to oil shale would increase salinity at Imperial Dam by about 20 mg/l. If the same quantity of water were used for irrigation, the salinity increase would be about 57 mg/1. Exportation of the water from the Upper Basin would increase salinity by about 24 mg/l.[55]

The economic losses, including damage to agricultural, municipal, and industrial users

*Increases in salt loading are discussed in ch. 8.

Table 86.–Projected Salinity Changes in the Lower Colorado River From Oil Shale Development

Source of estimate	Reference	Shale 011 capacity modeled, bbl/d	Measuring station	Present salinity, mg/l[a]	Salinity increase from 011 shale: For model Industry mg/l	For 1 million bbl/d: mg/l	For 1 million bbl/d: Percent
Colorado Department of Health	48	1,000,000[b]	Glen Canyon Dam	609	4	4	0.7
National Academy of Sciences	49	800,000	Hoover Dam	745	2	1,6	0 2
		1,600,000			4	2 5	0 3
Stanford Research Institute ., .,	50	250,000	Hoover Dam	745	1	4	0.7
Unversity of Wisconsin	51	1,000,000	Imperial Dam	850	20	20	2 4
Department of the Intenor	52	1,000,000	Hoover Dam	745	10-15	10-15	1 3-20
Bureau of Land Management	53	47,000	Hoover Dam	745	0 1	2 6	0.3
U S. Bureau of Reclamation	54	1,300,000	Imperial Dam	850	7	5	0 6
		2,440,000			15	6	0 7

[a]Data from reference 59
Calculated from estimates for Increases in the White River and the Colorado Mainstem

SOURCE Off ice of Technology Assessment

in the Lower Basin could reach $5.4 million per year in 2000 for a 2.44-million-bbl/d industry. This estimate is based on a salinity increase at Imperial Dam of 18.1 mg/l—l.8 percent of present salinity levels.'"

The full salinity impacts of water used in the Upper Basin are not felt until much later in the Lower Basin because of the dampening effects of Lake Powell and Lake Mead. For example, the Colorado River Basin Salinity Control Forum estimates that the full effects do not occur until after 17 years. The forecasts for 2000 therefore underestimate salinity effects on the Lower Basin, In addition, an assumption of the USBR analysis is that three authorized desalinization plants will be in operation by 2000, removing over 700,000 ton/yr of salt.

To a lesser extent other water quality parameters will be affected by the use of water for oil shale development. Sediment loading will increase in some reaches as the result in changes in land use associated with the dams, pipelines, and roads for the water supply facilities. Changes in river flow from reservoir operation could alter sediment transport and the biochemical oxygen demand in some reaches. These impacts have not yet been assessed in detail.

Impacts on River Ecology

Changes in instream flow can affect the aquatic ecosystem including the habitat of sport fish and rare and endangered species. Of special concern are the effects on rainbow trout, a major sport fish, and the Colorado River squawfish and humpback chub which are endangered species. Analyses of the impact of water use for oil shale on the rainbow trout, the squawfish, and numerous other fish species have been undertaken by USFWS and the U.S. Heritage and Conservation Service,[57] but the effects on the humpback chub have not been assessed due to lack of criteria in the USFWS study, These assessments do not include studies of the complete aquatic ecosystem and exclude impacts on the ecology of smaller streams at high elevation so no conclusions can be drawn on impacts on these streams at present.

Limited effects on fishery habitats were indicated for the Upper Basin as a whole, except for the White River. For rainbow trout in the Green River, the fry, juvenile, and adult stages would be little affected by a 2.44-million-bbl/d industry. Spawning conditions would remain poor. Adult Colorado River squawfish in the Yampa River would not be affected, but conditions for squawfish fry in the same stream would improve from their present poor level to fair. Conditions for adult squawfish in the White River would degrade from their present level of excellent to good.

Assessment of impacts on plants, invertebrates, and other components of the aquatic ecosystem have not been undertaken,

Transfer of Water From Irrigated Agriculture

Although it is not necessary to take water from irrigated agriculture to supply oil shale developments, such transfers are legally permitted. Because the economic value of an acre-foot of water to an oil shale developer is much greater than to irrigated agriculture, transfers of water rights could occur in some areas. These transfers would have social and economic ramifications, including a redistribution of income. Farm income would be reduced, but these reductions would be countered by a regional income gain because of increased employment in the oil shale industry,

According to DNR, the gain would be 10 to 100 times greater than the loss.[58] The number of farming families would also be reduced. Significantly larger impacts would be experienced, however, from factors not directly related to water use patterns, such as the competition for local labor and the purchase of agricultural lands for municipal expansion.

Irrigated agriculture diverts large quantities of surface water, but only a portion is actually consumed. The balance eventually returns to the water systems through agricultural return flows and/or percolation into ground water aquifers. Oil shale developers can only purchase rights to the consumptive portion of the diversion. Therefore, if irrigation rights were transferred to oil shale development, less water would be diverted from surface streams, and stream flows would increase. The effects of these increases were not modeled for DNR because of their small size and because a significant diversion of agricultural water to oil shale development is not anticipated in most areas. If significant effects occurred at all, they would most likely be in the White River Basin, where fish habitats and recreational opportunities would be improved as a consequence.

Ground Water Development

The impacts caused by well-drilling and maintenance would be similar to those for the construction of reservoir and pipeline facilities for surface water development—relatively small and of short duration. After the wells are drilled, only a few workers would be needed for maintenance. The number would be small in comparison with the estimated total work force of an operating oil shale plant. Unlike purchase of irrigation rights, ground water development should not have significant effects on the economic base of the oil shale region.

Stream flows would not be significantly reduced for the overall basin, although substan-

Photo credit OTA staff

Pumping water from the White River for agricultural purposes

tial reductions would occur in those areas in which ground water discharge supplies a major portion of surface flows, For example, some streams in the Piceance basin are fed by ground water discharge during most of the year. Aquifer drawdown as a result of ground water development would reduce flows in these streams, and in some cases would completely eliminate them except during the spring snowmelt. Fishery habitat in these streams would be severely affected.

According to DNR, the overall effects of ground water development on fish habitats and recreation would be much less than would be encountered with water acquisition strategies that relied solely on surface water diversions.[5’] However, heavy dependence on ground water could lead to using underground water resources faster than the rate of recharge and in some instances to mining geologically old water. The use of such water constitutes an irrevocable decision to exploit a nonrenewable resource, hence precluding its use for other purposes in the future.

Oil shale projects that use low-quality ground water may produce a net decrease in salinity in Colorado. For example, the Superior Oil project in Colorado’s Piceance basin will use water from the lower bedrock aquifer that has a salinity concentration of about 26,000 mg/l—about 30 times the salinity of the Colorado River at Imperial Dam. Withdrawal of this water would reduce the quantity of salts discharged into Piceance Creek by about 24,500 ton/yr. As a result, the salinity of Piceance Creek would decrease by about 1,040 mg/l. Salinity in the near reaches of the White River, into which Piceance Creek discharges, would be reduced by about 40 mg/l.[60] Salinity at Glen Canyon Dam would decrease by about 1.6 mg/1—about 0.3 percent of its present level.

Methods for Increasing Water Availability

Sufficient water should be physically available in the Upper Basin to support a large oil shale industry while simultaneously satisfying the needs of other users. However, water scarcity could constrain regional growth after 2000. Additional surface flows could be provided through conservation (i.e., more efficient use of water), interbasin diversions, and possibly by weather modification. Water use efficiency and weather modification are discussed below; interbasin diversions were discussed earlier.

More Efficient Use

By reducing demand, water conservation would increase net water availability. Opportunities exist in municipalities, in irrigated agriculture, and in industrial activities including oil shale development.

Municipal

Because municipalities in the oil shale region consume little water, conservation strategies would have to be focused on the larger cities in Colorado’s Front Range Urban Corridor that import water from the Upper Basin. For example, if Front Range cities lowered consumption by 20 percent, exports would be reduced by about 100,000 acre-ft/yr.[61] Demand could be reduced by methods such as restricted lawn watering or imposed peak-use surcharges, seasonal pricing differentials, and price incentives. Recycling systems could also be considered, but implementation could be hindered by high costs and their unfavorable image.

Irrigated Agriculture

Present irrigation methods are inexpensive to the farmer but relatively inefficient. Even small improvements could release large quantities of water for other purposes and decrease the quantity and perhaps salinity of agricultural return flows. Losses from canals could be reduced by adding impermeable linings or pipelines. Sprinkler systems or trickle irrigation would reduce evaporation from

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field soils. Losses to noncrop vegetation could be reduced by eliminating the vegetation. Crop evapotranspiration and loss of cropcaptured water could be reduced by substituting crops that need little or no irrigation water.

Few of these strategies could be introduced on a large scale, however, without substantial economic, social, and environmental penalties. Mechanical irrigation, for example, would be very expensive, as would fabricated pipelines. Vegetation removal could threaten the ecological balance along stream courses and manmade waterways. Dryland farming might not be technically or economically feasible. Furthermore, conservation could be risky because if a farmer did not use all of the water covered by his water rights, abandonment could be declared.[62]

Estimating possible reductions by conservation is technically straightforward. Estimating likely reductions is much more difficult because of the social and economic complications. DNR concluded that reductions would probably not exceed 120,000 acre-ft/yr even with vigorous programs.

Industrial

Oil shale plants will use water efficiently. This is a consequence more of the nature of the processing technologies and the desire to avoid having to treat excess process water to discharge standards than it is of an interest in water conservation. * However, different technologies consume different amounts of water for the same production rate and the overall requirements of the industry could be reduced by encouraging the use of processes with the lowest water requirements. It is unlikely that technologies would be chosen solely on this basis because water costs are a very small fraction of total processing costs.

*The U.S. Water Resources Council states that an AGR plant would consume about 89 percent less water than a steam- electric powerplant with the same net energy output, 25 to 87 percent less than a comparable coal gasification plant, and 40 to 90 percent less than a comparable coal liquefaction facility.’)’

Offsite powerplants to support municipal growth could adopt conservation methods without substantially increasing power costs. It has been estimated that water requirements for power generation in the oil shale States will increase by as much as 221,000 acre-ft/yr before 2000, If the new powerplants relied on a combination of wet and dry cooling, water consumption could be reduced by about 175,000 acre-ft/yr, sufficient water for production of 1 million bbl/d of shale oil.[65]

Weather Modification

Cloud seeding could be used to enhance precipitation and thereby increase surface water and ground water resources. The results of three major projects during the last two decades suggest that overall increases in snowfall could range from 5 to 20 percent. It appears that if snowfall were increased by 10 percent, runoff might increase by from 5 to 20 percent and might add up to 2.0 million acre-ft/yr to normal surface flows. Ground water aquifers would also be affected because they are recharged principally from snowpack. USGS has estimated that a 10-percent increase in snowfall in the Piceance basin would add over 10,000 acre-ft/yr of ground water that could be withdrawn without disrupting the aquifer equilibrium.[66]

Preliminary cost estimates range from $1 to $10/acre-ft of additional runoff, There would be additional costs for capturing and transporting the augmented flows, and storage facilities would still be needed, Any additional runoff would be subject to the prior appropriation system because the augmented flows would be indistinguishable from natural flows. Because of the problem of uncertain ownership, the delivered water cost might well exceed the costs of other supply methods.

The consequences of weather modification are not well understood, but a successful program could be expected to have widespread effects on the region's ecosystems. Species composition, vegetation growth rates, and wildlife habitats might be altered. Although there could be recreational benefits from increased snowfall and higher streamflows, agriculture and transportation could be hampered. Losses in precipitation to areas beyond the zone of augmented rainfall or snowfall could have severe ecological, agricultural, and economic impacts. There could be legal difficulties if cloud seeding were linked to drought in downwind areas.

Policy Options

The distribution of water from the Colorado River system is governed by a complex framework of interstate and interregional compacts, State and Federal laws, Supreme Court decisions, and international treaties. Policy decisions affecting the use of this water for oil shale development must take into account both the provisions of these documents and the need to protect the rights of competing water users. A number of policy options that would affect the availability of water for an oil shale industry in the Upper Colorado River Basin are examined below. Their implementation could involve actions by Congress, the administration, State governments, and the oil shale developers.

The Determination of Water Needs

In order to more accurately assess the total amount of surplus surface water that will be available for additional growth in the Upper Basin, the amount needed by all projected users must be determined. The uncertainty about the future availability of water supplies to the Upper Basin would be reduced if the necessary determinations were carried out by Congress, by Federal and State governments, and by private developers. Some possible options are:

The development of a water management system.—Preliminary water management studies have been conducted by the Bureau of Reclamation and by individual developers and other users. However, no systematic basin-wide evaluation of water management alternatives has compared water supply options with respect to their water and energy efficiency, their costs and benefits, and their environmental and social effects. Such an assessment—involving Federal, State, and local governments; regional energy developers; other users; and the general public—may be an appropriate prelude to actions to construct new water storage and diversion projects. It could be especially useful in evaluating and coordinating such controversial options as the importation of water. Funding could be provided by DOI, DOE, or other agencies. The study could be managed by the Bureau of Reclamation or by Colorado River Compact Commission.

The determination of the amount of water needed by the Federal Government.—This could be done for Federal lands for which water rights are set aside under the Federal reserved rights doctrine. One possible alternative for Congress is to provide legislation to facilitate this determination in coordination with one of the administration's task forces devoted to evaluating Indian and Federal reserved water rights.

It is anticipated that the largest Federal claims in the oil shale region will be for the Naval Oil Shale Reserves. The U.S. Navy has made a preliminary filing with the Colorado water court for 45,000 acre-ft/yr. In addition, small amounts of water may be needed for diversions, impoundments, wells, and stream flows. Although filings are being made under this doctrine, most indications are that the total amount of water that will be claimed by the Federal Government in the oil shale region will not be excessive. The exact quantities, however, have not been determined. Because the extent of future filings is unknown, reliable estimates of water availability for regional growth cannot be made. The uncertainty would be reduced if there were some indication in the near future of the amounts that will be claimed under this doctrine.

The determination of water needs by the Colorado State Government.—In Colorado, the requirements for instream flows are legally considered only where the State has retained the right to obtain water for preservation of the natural environment. Colorado recognized instream rights in 1973; thus, these rights are junior and should not impede the perfection of rights held by other users prior to this date. However, such rights could affect the amount of water available to users who file in the future for additional surface rights—any additional rights would have a lower priority in times of water shortage. The State is presently in the process of filing for rights for instream water needs. Completing this process would further clarify the total amount of water available for development in this region.

The determination of water needs by municipalities, private developers, and other water users.—Water rights in the oil shale States have been granted liberally. As a result, the quantities of water covered by conditional decrees far exceed the available resources of the river. At the same time, not all the conditional decrees have been perfected, and relatively little of the claimed water is actually being used. If it could be determined how much of the water allocated under the conditional decrees will actually be beneficially used in the near term (for municipal, agricultural, or industrial purposes), then the Upper Basin States would have a clearer indication of the actual amount of surplus water available.

Reservoir Siting and Direct-Flow Diversions

All water acquisition strategies that rely on the large-scale development of surface water resources within the oil shale area would necessitate the construction of new reservoirs and direct-flow diversions (e.g., pipelines). Such construction might be hampered, delayed, or even disallowed under provisions of the Endangered Species Act, the National Wild and Scenic Rivers Act, and the Wilderness Act. Potential problems could be reduced through several mechanisms.

Identification of endangered or threatened species.—The Endangered Species Act provides for the Federal identification of endangered and threatened species of fish, wildlife, and plants; prohibits private activity that imperils such species; and requires Federal agencies to avoid any activities that would jeopardize such species or result in the destruction of critical habitats. A number of studies are underway to identify endangered and threatened species in the Upper Basin. To date, two federally designated rare and endangered fish species have been found in the waters of the oil shale region. The Colorado River squawfish inhabits the lower portions of the White River and the Colorado River from the backwaters of Lake Powell upstream to the confluence of Plateau Creek. The humpback chub lives in the Colorado mainstem downstream from the Colorado/ Utah State line, Additional species requiring protection may be found in the future.

The Act may be interpreted as restricting activities that might adversely affect the critical habitats of such species, although none has been declared for the squawfish or the humpback chub. Knowing their approximate locations would be helpful because the timely siting of reservoirs and direct-flow diversions could be affected by agency interpretations involving instream flows. Should construction of these facilities begin before the critical areas were identified, there could be opposition to their completion, and water supplies from a particular reach of a river could be delayed or interrupted. If the locations of all designated critical habitats were identified by DOI and the required biological opinions obtained, the facilities could be sited to minimize interference and delay.

Designation of rivers to be set aside under the Wild and Scenic Rivers Act.—Any river area possessing one or more scenic, recreational, archeologic, or scientific values and in a free-flowing condition, or under restoration to such condition, may be considered for inclusion in the Wild and Scenic Rivers System. A number of rivers have already been designated under this legislation, and Congress is considering adding others. To date none in the oil shale region has been designated; however, several within the Colorado mainstem basin are being considered for wild and scenic designation. The amount of water that could be diverted from specific river reaches could be reduced if these rivers are set aside, thus an early designation of rivers eligible under this legislation would be of value in planning for future shale oil production. Given this information, direct-flow diversions could be sited downstream to those portions of rivers designated as wild and scenic rivers. This would avoid a direct conflict within a given river stretch but could add to the water supply cost.

Designation of wilderness areas.—The Wilderness Act created the National Wilderness Preservation System to provide “the benefits of an enduring resource of wilderness” for the whole Nation. In keeping with the purpose of preservation, the use of these areas is highly restricted. To date four areas in the White River basin and the Colorado mainstem basin have been designated under this legislation. Also, additional areas are being considered for inclusion in the system pursuant to the ongoing RARE II review. New reservoir storage would probably not be permitted in these areas, once designated. Since they are located at higher elevations in upper watersheds, they would probably not contain potential sites for reservoirs; however, additional wilderness areas at lower elevations could pose problems in siting storage facilities. A complete listing of wilderness areas that might be considered in the near uture would aid potential developers in locating their facilities in other areas.

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Financing and Building New Reservoirs

New reservoir and storage facilities would need to be constructed if a large shale industry were to be created. There area number of possible policy options for the financing and construction of such facilities.

Federal financing. —Congress could provide for the construction and funding of new Federal water projects through two mechanisms. First, Congress could appropriate funds for those Federal water projects that already have been authorized. Several projects have been evaluated by WPRS (formerly USBR), and their construction approved. Actual construction of these projects cannot begin until they are funded. However, not all of these projects have been evaluated for their suitability to supply water for oil shale development, and some project features may not be optimally located to serve oil shale projects.

A second option available to Congress is the passage of legislation that would specify the construction and funding of new, not previously authorized Federal water projects. However, unless language was included to expedite construction, these projects would require a long review process. They could, however, be designed and sited with their purposes as water sources for oil shale (as well as other possible uses) in mind. An example would be constructing irrigation reservoirs with additional capacity for oil shale requirements.

Under either option, DOI, through USBR, could operate these reservoirs in accordance with State water laws. Their costs could be recovered over the operating life of the facilities from revenues generated by selling water to oil shale developers and other users and in accordance with authorizing legislation.

State participation. —A State organization, such as the Colorado River Water Conservation District (CRWCD), could finance and construct new storage facilities. CRWCD holds large storage decrees in the basin of the Colorado River mainstem. The river district maintains that these decrees will likely be used as a source of supply for an oil shale industry. Several possibilities exist for the funding of reservoirs. One possible funding arrangement might be to sell water from existing State-administered reservoirs, such as Green Mountain and Reudi, to oil shale developers at very high cost (e.g., $250/acre-ft/yr). The short-term needs of many potential oil shale developers, depending on the siting of their facilities, could be met from such existing reservoirs. The profits from such sales could be used as leverage capital for marketing public revenue bonds. The capital generated from these bonds could then be used to finance the new reservoir facilities that would be needed by an oil shale industry in the longer term. A second funding scheme, which has been practiced by CRWCD in the past, is to sell options for water from proposed reservoirs to potential water users, thus raising the funds needed for the construction of the reservoirs.

Developer financing.—Reservoir and storage facilities could be financed and constructed by the oil shale industry itself.

Financing and Implementing More Efficient Practices and Water Augmentation

Surface flows in the Upper Basin could be increased if water conservation procedures were practiced by irrigated agriculture, municipalities, and industry. Weather modification is another possibility. Since carrying out these approaches could be quite costly for a particular developer or municipality, their chance of being implemented might improve if Federal and State governments were to supply some special funding or incentives. The following are some possible ways this could be done.

Funding and implementing water use practices.—Techniques for more efficient water use in irrigation and farming were illustrated earlier. As noted, farmers would be taking risks by adopting water conservation strategies because capital recovery would be uncertain and they might lose water rights. At the sometime, improvements in irrigation and farming practices could substantially reduce the demands for water in the Upper Basin. A number of options are available that would encourage such improvements. Congress could provide financial incentives, through such mechanisms as tax advantages, to those farmers who used water more efficiently, Technical assistance teams specializing in conservation techniques could also be provided to cooperating farmers by the Federal and State governments. In addition, Congress could give direct financial assistance through grant programs, administered either by Federal or by State agencies.

Individual municipalities could institute voluntary education programs and regulatory strategies aimed at reducing overall water consumption. Regulatory programs could restrict the watering of lawns and promote the use of water-saving devices. Cities could establish peak-use surcharges, seasonal pricing differentials, and price incentives to reduce usage. Local municipalities could also adopt water conservation techniques for their wastewater treatment facilities.

Municipal conservation techniques, whether voluntary or mandatory, are costly. Financing is needed to pay for administrative personnel as well as to produce and distribute educational materials. While these programs would probably be administered at the local level, they could be financed at the Federal or State level by direct grants or cost-sharing programs. To help pay for carrying out costly conservation procedures in municipal wastewater treatment facilities, Congress could provide tax incentives for such expenditures.

Although oil shale facilities are expected to be efficient water users, a number of water-conserving techniques could be used to minimize overall consumption. For example, some development technologies require less water than others—directly heated AGR has the lowest requirement (4,900 acre-ft/yr for 50,000 bbl/d of shale oil), while indirectly heated AGR has the highest (about 12,300 acre-ft/yr for the same output). Total industry consumption could be reduced by encouraging the use of the lowest water-consuming process. One congressional option would be to provide financial incentives to those facilities that implemented this process. Another would be to provide tax advantages to any facility that introduced specific water-conserving techniques. Also, through Government contracts, Federal agencies could specifically fund R&D by developers to improve the efficient use of water.

Funding of weather modification programs.—A number of Federal agencies, including the Departments of Commerce and of the Interior, have sponsored programs relating to winter orographic weather modification, The Federal Government could continue to fund programs in the Upper Basin with the aim of eventually increasing overall regional surface flows. If programs are funded, they should include work to better understand the impacts of weather modification.

Weather modification programs, although costly, could be undertaken by a State organization, municipality, or private developer. However, the ownership of any additional surface runoff would be uncertain under the current water appropriation system, and legal complications could arise if cloud seeding were linked to drought in other areas. It is unlikely that a particular municipality or private developer would undertake such a program without some assurance that a portion of any additional runoff would be available for its own use.

Federal Sources of Water for Oil Shale Development

Congress, under its constitutional powers, could make water available for oil shale developments from Federal water projects, or potentially from the reserved right doctrine. If Congress decides that water from congressionally funded projects should be made available for oil shale development, then any legislation enacted should provide that the term "industrial use or purpose" includes the use of water for oil shale development. * Congress could also amend the authorizing legislation for those projects from which water for oil shale development might be sought to permit the use of their water for that purpose. In such a case, legislation may be required if the project authorization does not list among the contemplated purposes for its water "industrial purposes" or some other category that could encompass oil shale facilities. The objective of such legislation would be to overcome any administrative reluctance to permit the use of water for oil shale development under an authorization that did not specifically mention it.

The power of Congress over reserved waters is more limited than its power over waters in congressionally funded projects. The use of water under the reserved right doctrine must be "in furtherance of the purpose of the reservation. " For this reason, Federal water rights do not seem to be likely sources for oil shale development, except perhaps in the case of lands set aside for the Naval Oil Shale Reserves. This matter, however, is in the early stages of litigation. New reservations of land set aside for the purpose of making water available for oil shale development would not appear to be a feasible alternative, since Federal reserved water rights are subject to rights vested prior to the date of the reservation.

A final option available to Congress would be to deny Federal water for oil shale development, if it decides that such development should not be given a high priority.

The Allocation of Water Resources

If Congress were to pass legislation encouraging the development of an oil shale industry it might wish to address the issue of how the necessary water would be supplied and how oil shale legislation might affect water allocation.

Water in the oil shale region is presently distributed by a complex framework of interstate and interregional compacts, State and Federal laws, Supreme Court decisions, and international treaty and administrative decisions. Within Western States, water rights are apportioned by the States to competing users according to a doctrine of prior appropriation under which water rights are a form of property separate from the land.

If control over the water supply for oil shale is to be left to the States, then Congress should probably so specify in oil shale legislation to avoid any question of the preemption of State water laws. Legislation that would confirm preservation to the States of the same power over water for oil shale as they have over other water supplies should require the developer to comply with State procedures in securing a water supply and provide that the established State appropriation system has the same authority to grant, deny, or place conditions on water rights and permits as would prevail in the absence of the legislation.

If Congress were to attempt to remove the water supply for oil shale production from the control of the States, strong legal and political resistance would ensue. Such resistance could delay oil shale development.

*A Memorandum of Understanding exists between DOI and the State of Colorado with respect 10 the use of water from existing or authorized WPRS (formerly USBR) projects. The State desires that the water not be changed from agricultural, municipal, or light industry uses to energy production (including oil shale), that are inconsistent with State policies. Under this memorandum, the State will review any application to redistribute water from conventional uses to energy production. The memorandum could be superseded by congressional directives of overriding national importance.

Interbasin Diversions

Interbasin diversion is a technically feasible although costly* option for bringing additional water to the oil shale region. There are also serious political obstacles to this alternative. The Reclamation Safety of Dams Act of 1978, amending the Colorado River Basin Project Act, prohibits the Secretary of the Interior from studying the importation of water into the Colorado River Basin until 1988. If it were decided to pursue this option as a means of supplying water to an oil shale industry coming on line in 1990, this prohibition would have to be lifted.

Interbasin diversions could be used to relieve the water problems of the region in several ways. Water could be transferred directly to the area, either exclusively for oil shale development or for all users. Alternatively, the water needs of Colorado's eastern slope cities, presently being supplied in part from the Upper Colorado River Basin, could be met from other hydrologic basins. The water presently being exported from the Upper Basin then could be used for oil shale development. In a third application of interbasin transfers, all or a portion of the 750,000 acre-ft/yr presently being supplied to Mexico by the Upper Basin States under the Mexican Water Treaty of 1944-45 could be taken from another hydrological basin (perhaps the Mississippi basin). The water thus freed in the Upper Basin could be assigned in part to oil shale development (750,000 acre-ft/yr would be sufficient for a 3,000,000- to 7,500,000-bbl/d shale oil industry).

The transfer of water from another hydrologic basin could have detrimental impacts on that basin, and impact analysis should precede diversion.

*The cost of supplving water by interbasin transfers is estimated to be no more than 5 percent of the total cost of producing a barrel of shale oil.

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CHAPTER 10

Socioeconomic Aspects

Contents

List of Tables

List of Figures

CHAPTER 10
Socioeconomic Aspects

Introduction

An oil shale industry will bring new people into the oil shale region. As a result, the social fabric will be changed in ways both beneficial and detrimental, Growth problems arising from the simultaneous development of oil shale and other energy resources are likely to be more difficult to solve than those from shale development alone.

The 3,200-mi^2 area where near-term development will take place is rural and sparsely populated. The three counties in Colorado have only one community with over 5,000 residents. Even without expansion of the oil shale industry populations are projected to increase significantly. If a major oil shale industry is created within the next two decades there could be average growth rates of up to 40 percent per year in the early stages of development. Such a rapid population influx would have inevitable social and economic consequences. Among the benefits would be increased employment and expanded community services. Direct employment in the shale industry and the stimulation of support industries and services would increase wages. The larger tax base would permit the counties and municipalities to extend and upgrade their facilities and services. As long as the public and private sectors could keep pace with the growth, most residents probably would welcome it, Among the negative consequences could be a strain on public services and facilities, an increase in crime and other manifestations of social stress, certain private-sector dislocations such as business failures, and in the eyes of some, a deterioration in their quality of life. If these negative outcomes overwhelm the capacity to adjust, a boomtown situation would result, similar to what has happened in other western and plains communities during the rapid development of energy resources,

Time, money, and technical help are needed to ameliorate the detrimental aspects of sudden growth. Communities need time to catch up, particularly if extensive construction of private and public facilities—such as housing and water and sewer systems—is involved. Both Federal and State governments and oil shale developers are providing impact mitigation funds and technical support, To date in Colorado, upwards of $50 million of public and private funds have been invested in preparations for shale development growth. Programs to administer these resources have been successful, but they have yet to be tested under conditions of sustained rapid growth. Assuming that present plans can be realized in a timely fashion, a total of about 35,000 people could be accommodated in existing communities in the 1985-90 period. Any development that brought more than this number into the area would cause widespread problems unless the growth were carefully timed to the region's ability to accept the new migrants, or plans for additional new communities were quickly implemented.

The maximum growth rate that can be sustained by these communities before boomtown symptoms emerge, and the nature of the appropriate Federal role with regard to social and economic impacts are major issues. The Federal Government now is involved with impact identification, evaluation, and mitigation, but additional activities are controversial, Possible congressional policy options would be to continue present financial support to mitigation programs, to increase efforts to manage growth through regulation, and to expand Federal involvement in mitigation programs, including passage of new legislation directed to energy development in general or to oil shale impacts in particular.

The Setting

Historical Background

Oil shale country covers about 17,000 mi^2 in the tristate area of Colorado, Utah, and Wyoming. (See ch. 4 for a description of the geography of the region.) Archeological evidence reveals that people probably have lived there for at least 10,000 years.[1] The ancestors of today's Ute Indians arrived at an as yet undetermined time. The Utes were a nomadic people who lived in a few permanent settlements and had many scattered hunting camps. The earliest direct contact between these indigenous people and Europeans was most probably with Spanish explorers, and British and French fur trappers and traders. Trade between the Indians and the Europeans existed from the 1600's onward.

In the late 1700's and early 1800's, contact with Western explorers, traders, hunters, and trappers increased. In 1776, the Escalante-Dominguez expedition passed through the region in search of an overland route to California.[2] In 1868, John Wesley Powell led a party across Berthoud Pass, into Middle Park, and eventually to the White River valley. A small group wintered at a site near Meeker, Colo., which is now called Powell's Park.[3] The number of people entering the area rapidly increased during the mining boom of the mid-1800's. Settlement was made easier when transportation was improved. The Denver and Rio Grande Western Railroad obtained the route through the Colorado River valley to Salt Lake City. The Colorado Midland and the Denver and Salt Lake City railroads explored the White and Yampa River valleys as alternative routes, although neither was built,

The United States obtained title to the land as part of the Mexican Cession of 1848. From the time of the Cession until the 1880's the United States engaged in a number of treaty negotiations and councils with the Indians.[4] The treaties ceded the mineral lands to the United States and established reservations for the different bands of Utes. The final treaty was ratified by Congress in 1880. Under its terms, the White River Utes were given land in Utah in the southern part of the Uintah Indian Reservation to which they were removed in September of 1881. Congress declared the former Ute lands as public domain on June 28, 1882.

While the ownership questions were being debated, squatters appropriated some land illegally. In 1879, when miners founded Carbonate in the Flattops area north of Glenwood Springs, Colo., they displayed their awareness of this by naming their first building Fort Defiance. Coal camps were established west of Glenwood Springs along what came to be known as Coal Ridge Hogback. While silver and gold lured the miners, the rich grasslands attracted cattle and sheep raisers. Large beef herds roamed free; one in 1888 was numbered at 23,000.[5] The great runs lasted until the turn of the century, when they became uneconomic owing to severe winters combined with overgrazing.

Ranching, mining, and recreation became the economic cornerstones of the region. Although no great precious metal strikes were made, coal mining formed a stable industry for many decades. Coal was produced for the railroads and for the steel mills of Pueblo, Colo. (See ch. 4 for the history of oil shale and related mineral exploration.) Farms and ranches were established as homesteading flourished. Hay production in the valleys became profitable, especially with the advent of irrigation. The visits of Theodore Roosevelt to the Flattops area in the early 1900's, with their attendant publicity, gave impetus to tourism.[6] Communities grew, with Rifle, Meeker, and Rangely, Colo., as centers of trade. The town of Meeker was incorporated in 1885. A trading post was built at the location of Rangely in the early 1880's. Oil was discovered nearby in the early 1900's and production began in the early 1920's. Smaller communities sprang up along the valleys. West of Rifle, the town of De Beque was incorporated in 1890. Grand Valley, founded in

1882, soon became a farming center. To the east of Rifle, New Castle was the hub of the coal communities. Many of the residents today are descendants of the early settlers, Oil shale country, therefore, is an area with stable communities populated by many long-established families.

The Oil Shale Country Today

Agriculture, mining, and recreation have continued as the main economic activities.[2] Livestock grazing is the leading agricultural use, followed by dry land farming, and irrigated cropland production. Hay and winter wheat are major crops. The best irrigated land is in Mesa County, Colo., outside the immediate oil shale area, where orchards have long been established. Mineral resource production, mostly oil and gas, and recently coal, constitutes the major mining activity. Tourism, fishing, and hunting have long been the mainstays of the recreational sector, and with the expansion of winter sports areas in the mountains, year-round recreation has become important. In recent decades, trade, manufacturing, and construction industries have grown, along with public and private services. Economic indices, such as retail sales and per capita and family income, have reflected a steady economic growth.[3]

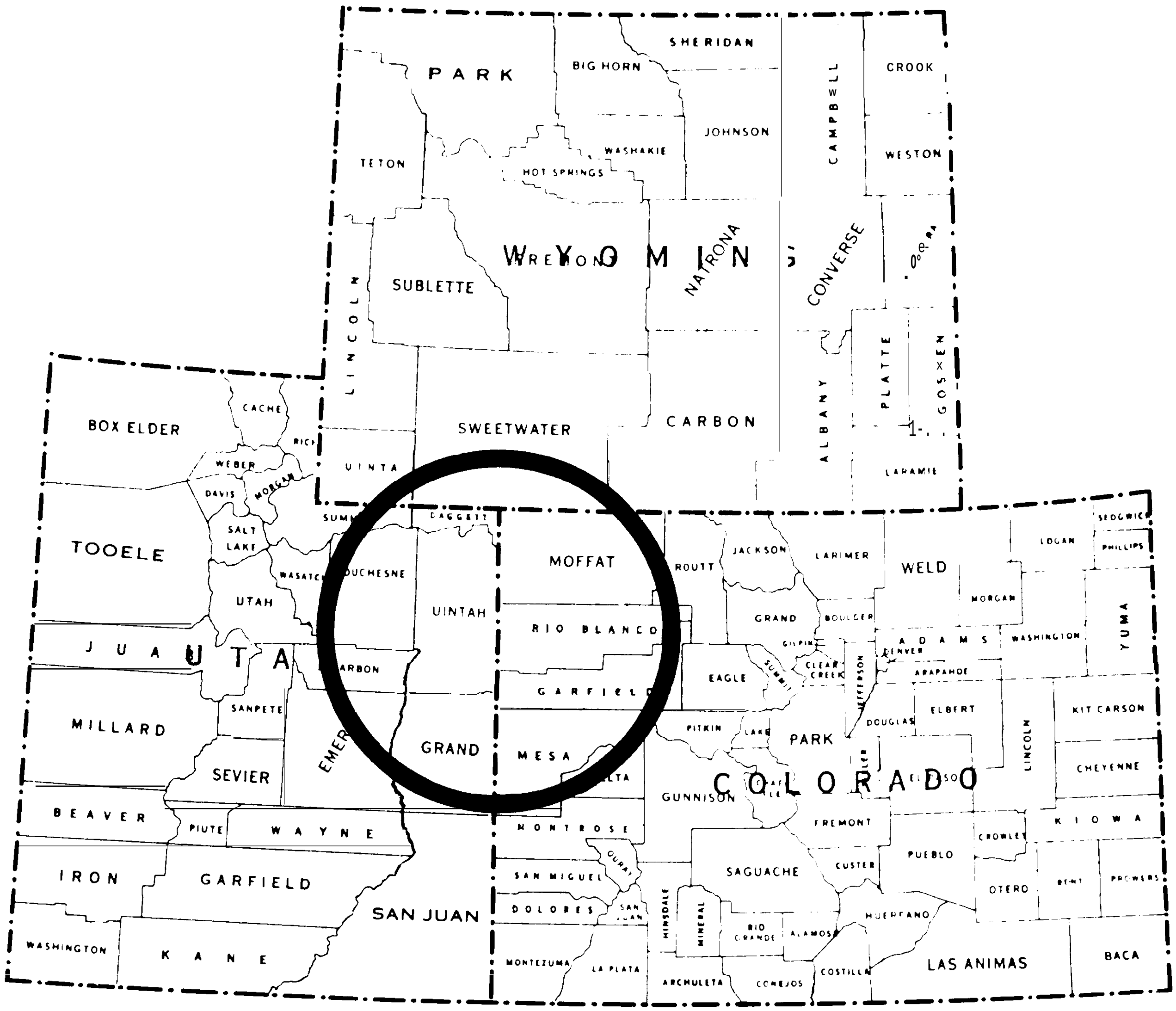
The oil shale region encompasses about eight counties. (See figure 69.) In Colorado, these are Rio Blanco, Garfield, and Mesa; some social and economic effects from expanded oil shale development may also be felt in Moffat County, north of the Piceance basin. The counties in Utah that will be affected are Uintah, Daggett, Grand, and Duchesne. The tricounty area of Colorado covers 9,563 mi^2, has a limited transportation system, and includes about a dozen communities that could be affected by oil shale industry expansion, (See figure 70.)

Stretching along the southern edge of oil shale territory, Mesa County is the transportation and service center for the western slope of Colorado. Grand Junction, the largest city of the region, is the site for the offices of several energy companies. Interstate 70 (segments of which are not yet completed) extends eastward up the valley of the Colorado River and westward into Utah; it is 260 highway miles to Denver and 285 to Salt Lake City. The only airport on the western slope able to accommodate commercial jets is in Grand Junction. The Denver and Rio Grande Western Railroad also has extensive facilities there.

Garfield County lies adjacent to Mesa County on the north. It encompasses the Roan Cliffs along the southern border of the Roan Plateau, and is the site of most of the private oil shale holdings. The Colorado River flows through the eastern part of the county, and transportation is readily available along this corridor. Glenwood Springs, the county seat, is located in the eastern portion. Rifle, Grand Valley, Silt, and New Castle are communities affected by the present modest scale of oil shale development. Rifle is the home of many oil shale workers from tracts C-a and C-b. A vanadium plant is located nearby, and coal development activities have recently increased along the valley. The Naval Oil Shale Reserve at Anvil Points lies between Rifle and Grand Valley. If present trends continue, the Rifle vicinity will experience the most growth.

Rio Blanco is the county most likely to experience the major effects of expanded oil shale development. Lying between Garfield and Moffat Counties, it is where the richest oil shale deposits in the United States are located. Most of these are on Federal lands in the Piceance basin. Rio Blanco is the least populated of the three, and has the most limited surface transportation. The White River flows along the northern part; the two major communities, Meeker (the county seat) and Rangely, lie within the river valley. Rangely is a center for oil and gas development activities. The primary north-south highway goes from Rifle through Meeker and Craig and then on to Wyoming. The main east-west road goes from Meeker to Rangely, before turning north to Dinosaur, where it passes into Utah. A State highway goes south from Rangely through Garfield County and eventually to

Figure 69.—Counties of the Oil Shale Region

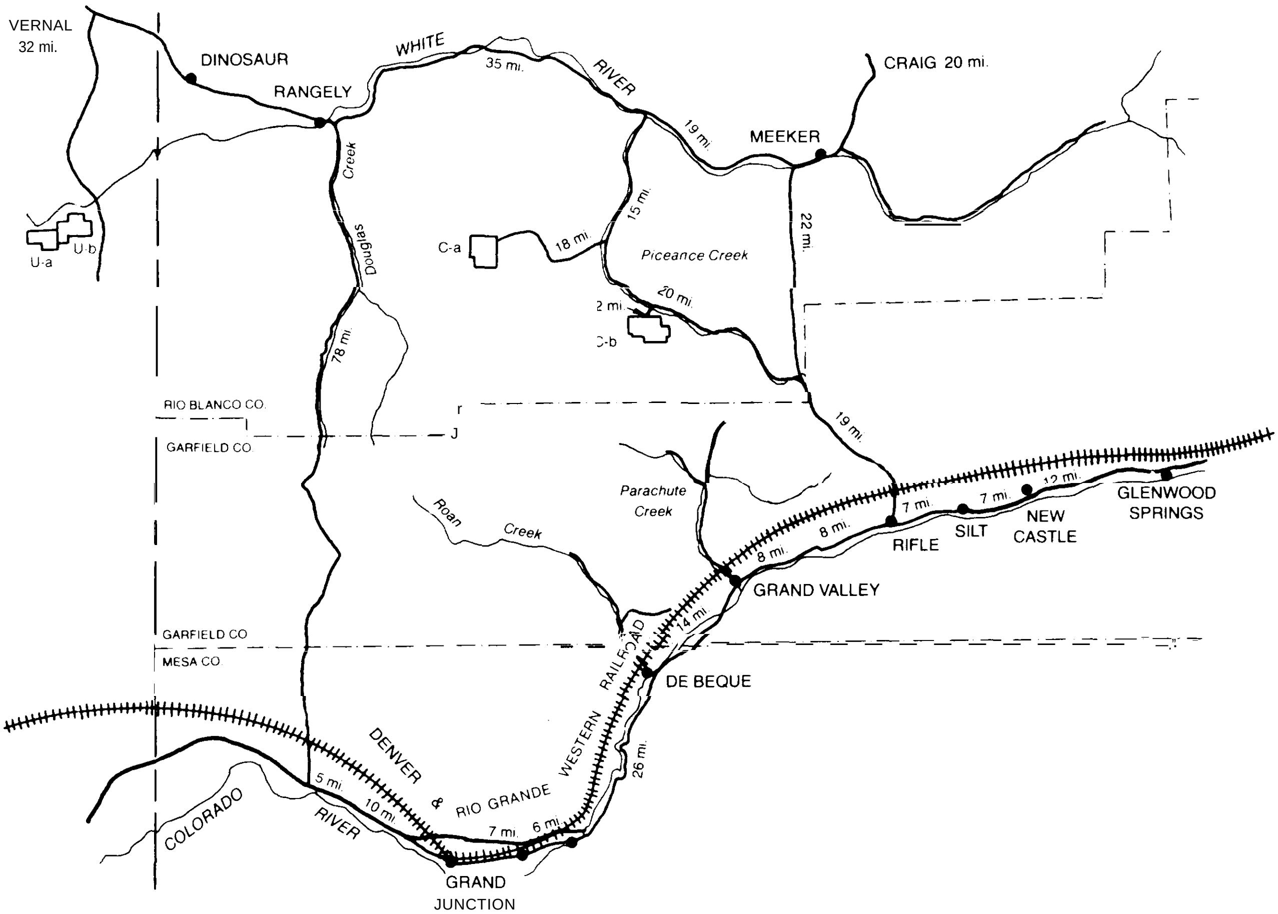


SOURCE *The National Atlas*, Department of the Interior

Grand Junction. A county road extends along the Piceance Creek valley and another goes eastward from Meeker up the White River valley to recreation areas. These are the only improved roads to serve the 3,263 mi^2 of Rio Blanco County.

Moffat County, which occupies the extreme northwest corner of Colorado, abuts on Wyoming to the north and Utah to the west. Its county seat, Craig, is in the east-central portion. The population of Moffat County has approximately doubled in the past decade with most of the growth centered in Craig. Coal development and the construction of a 760-MW coal-fired electric generation plant account for most of the expansion, which is expected to continue with a possible doubling in the size of the powerplant. Because Moffat County lies to the north of the principal oil shale areas, it will probably only experience indirect effects from shale development. The town of Dinosaur, however, which is located 18 miles northwest of Rangely in the extreme

Figure 70.—Communities in the Colorado Oil Shale Region



SOURCE Oil *Shale Tracf C-b Socio Ecomnic Ajssessment 76* VOI II

southwestern corner of the county, could be directly affected. It has already grown from oil and gas exploration, and oil shale activities in Utah as well as the Piceance basin could further accelerate its growth.

In sum, the oil shale region of Colorado, Utah, and Wyoming is a large area with a small population. Most of the residents are found in widely separated communities that are linked by a few highways. Before the recent increase in energy-related industrial activity, the main economic base was ranching and farming, supplemented by tourism, recreation, and mining. A large number of new residents have migrated to Moffat County, to the north of the oil shale region. The fastest growth from expansion of the shale industry will most likely take place in the least populated county, Rio Blanco, which contains the richest oil shale deposits. Garfield County is apt to experience major impacts from its growth.

Early Planning for Oil Shale Development

Concern about the social and economic effects on Colorado communities of large-scale oil shale development was expressed in the late 1960's.[9] As a result, planning activities began in the early 1970's. The environmental impact statement (EIS) filed in conjunction with the Prototype Leasing Program examined some social and economic elements.

However, its lack of detail prompted industry to take the initiative to undertake additional analysis. In 1972, an Oil Shale Regional Planning Commission was formed, which took an inventory of the area and of shale technologies. Contracts with consulting firms produced several planning documents. '" The responsibilities of the Commission were assumed later by the Colorado West Area Council of Governments (CWACOG). An awareness of the need to prepare for growth prompted these early planning efforts, but as work proceeded, an atmosphere of uncertainty arose. When the lessees requested suspensions, expansion of the oil shale industry became questionable in the minds of many who were charged with the responsibility of preparing for its consequences. "

Local programs to minimize possible adverse affects were begun after the leasing of tracts C-a and C-b. The C-a lessees, Rio Blanco Oil Shale Co. (Gulf Oil and the Standard Oil Co.—Indiana), prepared an impact analysis for their operation. '2 They hired a consultant, the Foundation for Urban and Neighborhood Development (FUND), to survey community attitudes toward energy development in Rangely, Meeker, and Rifle. The lessees also engaged a planning firm, the Gulf Oil Real Estate Development Co. (GOREDCO), that—with the participation and direction of the community—prepared a comprehensive development plan for Rangely. The master plan was completed in 1976 and subsequently adopted by the town, certified to the county, and incorporated in the county plan. Through FUND an attorney was engaged to update and codify Rangely's municipal ordinances. The lessees also contributed to the improvement of the county road leading to tract C-a, and paid for the design and preparation of cost estimates for a 22-mile extension from the tract more directly to Rangely.

In 1976, the lessees of the C-b tract (at that time consisting of Ashland, Atlantic Richfield, Shell, and Tosco) published a baseline description and an impact analysis study. '3 Like the tract C-a lessees, they hired a consulting firm, Quality Development Associates (QDA), to prepare socioeconomic monitoring reports and to work with local citizens on strategies for managing growth. The lessees were also members of a private development, the Colony project. Several socioeconomic reports were prepared as part of this joint effort,[14] and, under the direction of Atlantic Richfield, early plans were prepared for Battlement Mesa, a proposed new town to accommodate workers from the Colony project. '5

The tracts C-a and C-b lessees each contributed $40,000 to help establish the Rio Blanco County Planning Department. The money was used to prepare a comprehensive plan that was adopted and certified to the communities in the latter part of 1976. Both groups of lessees funded development of a growth-monitoring model by CWACOG, and the original tract C-b partners and one of the C-a partners participated in the preparation of a tax study. Planning was also underway in Utah between 1970 and 1975. For example, in 1975 a socioeconomic analysis was published by the White River Shale project that dealt with the effects of the proposed development of a 100,000-bbl/d industry in Utah. [16]

The value of the early studies varied because each had a different emphasis, coverage, and set of basic assumptions. Comparing the multipliers used to derive projected growth illustrates these differences. To obtain an estimate of new employment fostered by a project (local service employment), the expected work force for the project (basic employment) is multiplied by some factor (multiplier). Table 87 compares the multipli-

Table 87.–Comparison of Basic to Local Service Employment Mutipliers

Illustrative study[a]	Multipliers used: Construction phase	Multipliers used: Operating phase
1. Prototype EIS.	63	77
2. C-a (Rio Blanco) Social & Economic Statement .	5	5
3 C-b Soclo-Economic Assessment	5 to 1 0	1 5
4. Colony EIS. .,	.29	97
5. Uinta Basin Study	3 to 10	10 to 1.5

[a]See ref 1 7 for full title of the studies

SOURCE Of ftce of Technology Assessment

ers used in five of the early studies,[17] These vary so much that a single increment of employment can result in a twofold to threefold difference in the projected populations. (The five studies are compared in greater detail in tables 88 and 89.)

The differences occurred for several reasons. In the EISs, socioeconomic factors received little emphasis because at that time they were not considered—as is now the case—essential to environmental impact analysis. In general, the EISS assumed that existing

Table 88.–Baseline Data–Selected Social and Economic Studies (each dot indicates the inclusion in the study of this category of data)

Data categories[a]	Title of study[b]: Prototype EIS	C-a social and economic	C-b socioeconomic	Colony EIS	Uinta Basin
Existing economic/demographic data					
Population and employment					
County population	•	•	•	•	•
Number of households by county	•		•	•	•
Number of households by community			•		
Labor participation by county	•	•	•	•	•
Education					
Enrollment by county	•				
Enrollment by school district			•	•	
Enrollment by city		•			
Student/teacher ratio		•	•		•
Median school years attained	•	•		•	•
Dropout/turnover rates			•		
Employment by industry					
Total employed–sector by county	•	•	•		•
Total employed–sector by city					
Total employed–sector by region				•	•
Employment–other energy Industry					
Family/Indwldual Income Indicators					
Median family Income by county	•		•	•	•
Per capita Income by county		•			•
Unemployment rate by county	•	•	•		•
Poverty status by county			•	•	•
Rate of population growth					
By county and community		•	•	•	
Projected without 011 shale			•	•	•
Existing public services/facilities					
Education					
Age of school buildings by district			•		
Certified staff			•		
Excess pupil capacity			•		•
Public safety					
Fire/pollee protection by area			•		•
Manpower/number of vehicles			•		•
Water					
Estimated depletion (1970) by region .,	•				
Status of projects by State	•			•	
Source, storage capacity, number of taps per population served by community		•	•		
Status of water rights					•
Wastewater and solid waste disposal					
Treatment facilities by community type/population served/design capacity	•	•	•		•
Transportation					
Existing roads/airports by county	•			•	•
Status of current projects			•		
Average weekday traffic counts			•		
Health					
Facilities/manpower by county	•	•	•	•	•
Mental health facilties			•	•	
Recreation and land use					
Resource Inventory	•				

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Table 88.–Baseline Data–Selected Social and Economic Studies –continued

	Title of study[b]				
Data categories[a]	Prototype EIS	C-a social and economic	C-b socioeconomic	Colony EIS	Uinta Basin
Recreational facilities by type					•
Land by ownership by county	•				•
Agricultural land by county	•				•
Government structure/fiscal information					
County/municipal government finance					
Revenues and expenditures by county	•		•	•	•
Municipal revenues and expenditures			•	•	•
Property tax valuation, average mill levy, and total levy by county			•	•	•
Distribtion of levy revenues by county			•		
Sales tax Information .,			•		•
Retail trade information			•		•
School district finances					
Total expenditures by county.	•				
Total and per capita expenditures by districts					•
Comparison of per pupil expenditures and mill levies by districts .,					
Mill levy by fund. assessed value revenue by source, by district					
Bonding principal and remaining capacity					
Housing					
Inventory and costs					
Estimated housing by county		•		•	•
Status of available units by type		•		•	•
Value of owner-occupied units.				•	•
Value of other units					
Projected needs by tenure by county					
Characteristics by type by city					•
Public opinion					
Local opinion regarding					
Socioeconomic environment and quality of life .,			•	•	
Attitudes about changes In quality of life and society.		•	•	•	•
Attitudes about perceived advantages/disadvantages of 011 shale development		•	•	•	•

[a]Data categories are for illustration No attempt has been made to Include all of the information in these studies
[b]See ref! 7 for listing of full title

SOURCE Office of Technology Assessment

mechanisms could deal with most consequences of growth. When it became apparent they could not, subsequent studies went into greater detail about the effects of the expected growth and possible remedial actions. Not all of the studies, however, included the same types of information. For example, community facilities and local government data were not made a part of the C-a analyses because they were in the Rangely master plan. Little attention was paid in any of the studies to other resource development projects anticipated or underway in the region. As a result, all of them are deficient in analyzing the cumulative effects of industrial expansion.

Mechanisms to Manage Growth

Local Infrastructures

In Colorado, Garfield, Rio Blanco, and Mesa Counties all have planning councils, professional planning staffs, and approved countywide comprehensive plans. Meeker, Rangely, Rifle, and Grand Junction have full-time city managers, and Grand Junction and Rifle have city planners. Rio Blanco County has adopted an ordinance applying to land use that, in certain circumstances, requires filing an impact analysis statement specifying

Table 89.–impact Data–Selected Social and Economic Studies (each dot indicates the inclusion in the study of this category of data)

Impact categories[a]	Title of study[b]: Prototype EIS	C-a social and economic	C-b socioeconomic	Colony EIS	Uinta Basin
Population/employment projections					
Total basic population projections	•	•	•	•	•
Project-related employment projection[c] ,.	•	•	•	•	•
Estimated family size for construction and service populations	•	•	•	•	•
Timelag included for local service employment forecasts ....,.			•	•	•
Estimation of community choice for residence and allocation of population		•	•	•	•
Community facilities/services projections					
Education					
Site and plant costs, personnel needs, salary requirements				•	
Projected numbers of pupils and room requirements.			•		•
Projected increase in demand for teachers and classrooms					•
Public safety					
Fire and pollee needs and costs			•	•	
Cumlative impact on faci!ities and personnel					•
Water					
Expected needs by technology	•				
Needed Improvements and estimated costs–one municipal system			•		
Projected site, plant, personnel, and salary requirements				•	
Capacity and expansion by towns, depletion by sector by region					•
Solid waste disposal and wastewater			•	•	•
Transportation			•	•	
Health			•		•
Mental health			•		•
Recreation					
Land loss by State by technology	•				
Projected open space and recreational needs and costs			•		
New sites and facilities needed (project development area)					•
Local government fiscal need projections					
School district financing needs			•		
County and municipal government finances					
Estimated Federal, State and local revenues by tax source by State	•				
Projected total revenues and expenditures, by tax source/per capita			•		•
Facility and personnel costs, valuation and taxes levied				•	
Impact by development pattern or project phase			•		•
Housing					
Projected housing requirements					
Types needed by development phase			•	•	
Demand by community........			•		•
Land use requirements by units per acre, total units, and type				•	
Public construction expenditures and tax receipts by State	•				
Recent construction by communities			•		

[a] mPacl Cdlegorles are 'or ill usfra!lon only No attempt has been made 10 include all of the information available in these studies
[b] See ref 17 for a listing of full tit e
[c] See text for a discussion of the elf ferences in the projections as a function of the multipliers used in each study
[d] See text for an explanation of the lack of information for the C a social and economic study column

SOURCE Off Ice of Techno ogy Assessment

actions that will be taken to alleviate any adverse effects of changes in land use.[18]

In the early planning stages, special groups were created in Rio Blanco and Mesa Counties and the Rifle area. The most active, called the Impact Mitigation Task Force, is in Rio Blanco County. It was initiated following a series of informal meetings between industry representatives, their consultants, and county officials, and consists of about 30 members organized into a core group and two advisory panels. The core group, which meets monthly, is composed of the county commissioners; the city manager and mayor from the two municipalities, Rangely and Meeker; and representatives from industry, the Federal and State governments, and CWACOG. It has

Photo credit OTA staff

Monthly meeting of the Rio Blanco County Impact Mitigation Task Force

been officially designated to serve in an advisory capacity to the county commissioners. One advisory panel represents Meeker and the eastern part of the county, the other Rangely and the western portion. Many different interests are reflected, including agencies such as the sanitation district and the public schools, and less formally organized groups such as youth. The advisory panels, which also meet once a month, discuss different growth-related topics, and forward their concerns to the core group. They have prepared needs assessments on a variety of general subjects and have reviewed specific issues such as housing for teachers.

The Rifle area organization was formed in mid-1977 with a core group and series of working panels. When first established, it was called the Development Impact Committee, and consisted mainly of Rifle residents. A county commissioner from the area was a member but countywide communication was not extensive. Most of the development and planning management activities were carried out through the Rifle planning and administrator's offices. In the fall of 1979, the organization was enlarged to involve other communities along the Colorado River valley. The core group was broadened to include all of the county commissioners and representatives from each of six towns. To advise the core group, a West Garfield Impact Committee was created composed of 19 voting members chosen to represent a wide range of interests. The Impact Committee will undertake planning activities and recommend to the core group which projects they support for submission to the State for funding assistance. Prior to the establishment of this process, requests were made through the cities directly to the county commissioners.

In December 1977, Mesa County organized an Impact Assistance Team. Fifteen members, representing local, State, and industry interests, review funding requests made to the county commissioners. Applicants must provide information to the team justifying their requests. Responsibility for setting priorities rests with the commissioners.

The Functions of the Local Planning Processes

The work of the special groups has centered around three areas: physical planning and development, information generation and transfer, and screening and placing priorities on requests for funding. As an illustration of the first function, the Rio Blanco advisory and core groups, using population forecasts provided by CWACOG, have reviewed the ability of local public facilities, such as sewer and water systems, to handle larger loads, and have helped plan expansions where appropriate. Needs for housing, schools, recreational facilities, and downtown redevelopment have also been considered. Each planning group has struggled with the implications of comprehensive land planning for its region.

Because energy development often involves uncertainties about factors such as the timing of construction and the size of work forces, obtaining accurate information is important to officials and residents, The best estimates available are required and, in this regard, most groups receive frequent updates from industry representatives about the status of their projects. Sharing information also involves communication between local officials and citizens. The advisory groups provide a public forum for the presentation, analysis, and discussion of issues, which allows individuals to help determine future growth patterns. The core groups, especially when screening requests for impact mitigation funds, help establish a consensus among local interests on priorities and policies.

An important function of each group is recommending to their respective county commissioners which project applications should be forwarded to the Federal and State governments for consideration for funding. The Rio Blanco County structure is unique in this respect, The involvement of the task force core group and advisory panel members with local officials, industry representatives, consultants, CWACOG, State legislative and executive staff, and Federal agency personnel broadly allocates responsibility for decisions. Having the task force place priorities on applications for financial assistance validates the process and formalizes the responsibility.

This consideration of the functions of Colorado's local planning mechanisms illustrates several general questions related to socioeconomic effects. Among them are:

- Who identifies the consequences of growth?
- Who judges whether these are positive or negative?
- Who determines which ones require redress?

Local entities address all three questions in the model presently operating in Colorado. In some instances, these are established governmental units, such as planning offices; in others, unique panels with broad community representation. The latter arrangement has several advantages. It allows individuals close to the communities to judge the balance between positive and negative impacts, and provides an opportunity for citizens with different interests to propose solutions to local problems, Many share the responsibility of deciding which difficulties are severe enough to require assistance beyond that available from local resources. The assumption underlying the model is that those affected should have the prerogative of deciding what a negative impact is and how it might be ameliorated.

Private Sector Contributions

Throughout the West, energy development industries are contributing significantly to growth management.[19] As previously noted, several oil shale developers have voluntarily contributed to projects in communities affected by their activities. The Rio Blanco Oil Shale Co., for example, spent over $700,000 in direct grants and purchases of services to assist the Rangely area and over $135,OOO in support of Rio Blanco County. The Colony Development Operation invested about $3 million to acquire land and plan for the new town of Battlement Mesa. Industry has also adopted programs to deal with particular problems. To reduce traffic and contribute to highway safety, the tract C-b lessees operate buses for their workers from Rifle to the tract. They have also provided financial assistance to real estate developers for construction of apartment units in Rifle and Meeker, and for a mobile home park in Rifle.[20]

Photo credit OTA staff

Apartment units in Rifle, Colo., developed with industry assistance

State Programs

Colorado

Colorado's programs largely involve financial and technical assistance. Financial support is directed to municipal, county, and private agencies with money obtained from two main sources, lease revenues collected by the Federal Government and severance taxes collected by the State. Technical assistance is in the form of information gathering and dissemination, advisory services, program coordination, and similar support activities.

AGENCIES INVOLVED IN MITIGATION PROGRAMS

Two State governmental groups are involved in Colorado's programs for impact mitigation: the Division of Energy and Mineral Impact in the Department of Local Affairs (DLA) and the Joint Budget Committee (JBC) of the General Assembly.

JBC is a legislative committee composed of members from both houses of the Colorado General Assembly. It is responsible for drafting the State budget and forwarding it to the Assembly for final action. In 1974, the General Assembly created the State Oil Shale

Coordinator's Office,[21] which subsequently evolved into the Governor's Socio-Economic Impact Office (SEIO). SEIO, the lead agency for coordination within the State government, is now the Division of Energy and Mineral Impact in DLA. The Division reviews requests for Oil Shale Trust Fund assistance (described below), and recommends projects for funding to JBC. It is also responsible for contract negotiations and for administering appropriations. The Division also handles mitigation programs for communities experiencing boomtown impacts from other types of development. DLA coordinates State and local mechanisms in several ways:

- reliance on local and regional groups to take an advocacy role in presenting local needs to State agencies,
- review of requests by State-level agencies involved with or that might be affected by mitigation projects, and
- administration of appropriations and contracts through field representatives in concert with local officials and contractors.

Financial Assistance.–

Federal Revenues.—Under the provisions of the Mineral Leasing Act of 1920, as amended,[22] each State receives 50 percent of the proceeds from the sale or lease by the Federal Government of public lands within the State. Colorado has created two distinct funds to receive these revenues: one for those returned from oil shale lands and another for those returned from lands other than oil shale. The former is called the Oil Shale Trust Fund and the Oil Shale Interest Earned Fund; the latter is the Colorado Mineral Leasing Fund.

- Oil Shale Trust Fund and Interest Earned Fund. Colorado's Oil Shale Trust Fund[23] was created in 1974 to receive those revenues specifically coming from lease payments, royalties, and bonuses on the two Federal oil shale tracts in western Colorado. To date, the Oil Shale Trust Fund has received payments corresponding to the first three bonus payments paid to the Federal Government by the tract lessees. Under the bonus offset provision of the Prototype Leasing Program, expenditures for certain development work on the lease tracts can be credited against the final two payments. Since the lessees have proceeded with development, it is likely that 100 percent of the final two bonus payments will be offset, and that, therefore, neither the State nor the Federal Government will receive any additional lease payments in cash. (See table 90 for a summary of the Fund's revenues.)

The State statute creating the fund specifies that the income shall be disbursed as follows:

> . . . for appropriation by the General Assembly to state agencies, school districts, and political subdivisions of the state affected by the development and production of energy resources from oil shale lands primarily for use by such entities in planning for and providing facilities and services necessitated by such development and production and secondarily for other state purposes.[24]

The Oil Shale Trust Fund is not technically a trust since there is no statutory requirement that the principal be kept intact. However, JBC has maintained the principal at approximately $60 million,

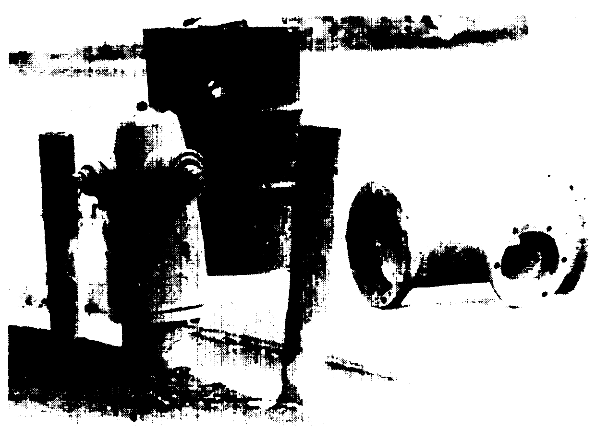

Photo credit: OTA staff

Upgrading of facilities in Rangely, Colo., utilizing Oil Shale Trust Fund monies

Table 90.–Revenues of the Colorado Oil Shale Trust Fund, Fiscal Years 1975-79

Year	Lease/bonus income[a]	Interest earned	Total annual income
FY1975[b]	$24,607,020	0	$24,607,020
FY1976[b]	24,607,020	$2,685,600	27,292,620
FY1977[b]	24,607,020	3,811,271	28,418,291
FY1978[b]	0	4,219,970	4,219,970
FY1979[c]	0	5,999,918	5,999,918

[a]See text for discussion of offsetting provisions applying to 197879
[b]*Summary and Status Report of the Mineral Lease and Severance Tax Fund,* Second Annual Report to the Colorado State Legislature Department of Local Affairs 1979
[c]State treasurer s office

SOURCE Office of Technology Assessment

and appropriations have been madeonly from interest earnings and from the principal in excess of $60 million. The interest earned by the State is set aside as the Oil Shale Interest Earned Fund, a special account established in 1975.[25] Loans as well as grants from the interest fund are permitted; the authorized purposes for appropriation of the interest earnings are identical to those of the principal fund. (See table 91 for a summary of expenditures.)

- Colorado Mineral Leasing Fund. Colorado's share of public land monies collected by the Federal Government for leasing of minerals other than oil shale is placed in the Colorado Mineral Leasing Fund.[26] The fund was created in 1977 to be used for planning, construction, and maintenance of public facilities, and the provision of public services. Priority is to be given to "those. .. political subdivisions socially or economically impacted

Table 91 .–Expenditures of the Colorado Oil Shale Trust Fund, Fiscal Years 1975-80

Year	Amount of appropriation	Amount expended	Outstanding commitments
FY 1975[a]	$ 451,187	$325,926[b]	0
FY 1976[a]	10,385,300	10,029,381	$ 2,000
FY 1977[a]	4,239,646	3,283,408	47,332
FY 1978[a]	6,464.793	4,702,737	993,510
FY 1979[a]	8,929,090	6,306,940	2,622,150
FY1980[c]	10,446,102	Not available	Not available

[a]*Summary and Status Report of the Mineral Lease and Severance Tax Fund* Second Annual Report to the Colorado State Legislature Department of Local Affairs 1979
[b]$125261 of the $451187 original appropriation was returned 10 the 011 Shale Trust Fund
[c]Department of Local Affairs Division of Energy and Mined Impact

SOURCE Offfice of Technology Assessment

by the development, processing, or energy conversion of minerals" that are leased from the Federal Government and/or that are subject to State severance taxation.[27] The State statute provides for an automatic distribution of the monies to the public schools, to the counties where the leased lands are located (except that no county can receive more than $200,000 in any calendar year), to the Colorado Water Conservation Board Construction Fund, and to the Local Government Mineral Impact Fund.

State revenues.—In 1977 Colorado levied a severance tax on the production and export of metallic minerals, molybdenum ore, oil and gas, coal, and shale oil.[28] Proceeds are allocated to different accounts according to the mineral being taxed. To date, most of the income has been derived from oil and gas, molybdenum, and coal. Two new funds were established at the time of passage of the severance tax: a State Severance Tax Trust Fund and a Local Government Severance Tax Fund. When shale oil revenues are realized, they will be distributed as follows:

- **40** percent to the State General Fund,
- 40 percent to the State Severance Tax Trust Fund, and
- 20 percent to the Local Government Severance Tax Fund.

Although separate legislation created the Local Government Mineral Impact Fund and the Local Government Severance Tax Fund, for practical purposes they have been combined into an Energy Impact Assistance Fund that is administered by the Division of Mineral and Energy Impact.

Mechanisms for Disbursement.–

The Colorado General Assembly makes appropriations from the oil shale principal and interest funds based on the recommendations of JBC. Requests for financial assistance from the oil shale funds are initiated at the local level. Priorities for needs are assigned at the local level and forwarded to JBC. In addition, the requests are reviewed by the Division of Mineral and Energy Impact. JBC receives the requests in public hearings and subsequently corresponds with local officials if clarification is needed. After analyzing the requests, JBC incorporates, as a series of line items in the appropriations bill, the sums recommended for expenditure from the oil shale funds. (See tables 92 and 93 for a listing of the general categories under which these monies have been expended and the projects that have been funded.)

In contrast to the legislative process controlling the oil shale monies, disbursements from the Energy Impact Assistance portion of the Mineral Leasing Fund are at the discretion of the executive director of DLA. Obligations are made by contracts negotiated and administered by field representatives from the Department. DLA uses the same local and regional review process followed in the oil shale appropriations procedure for the identification of needs and the ranking of funding requests. It is assisted by a statewide energy impact assistance advisory committee that makes recommendations to the executive director of DLA.

Technical Assistance.–

Information gathering and dissemination, program coordination, regional planning, and advisory services are the main types of technical assistance provided to local planners. For the oil shale region, this assistance comes from CWACOG and DLA.

Table 92.–Appropriations From the Oil Shale Funds by Object, Fiscal Years 1975-80

Purpose	Amount appropriated FY 1975-80[ab]	Percent of total appropriation
Road, bridge, and drainage	$14.298736	35.1
Schools	9,262,714	22.7
Water	9,402,403	230
Sewer	2,802,058	6 9
Health and mental health	440,668	11
Municipal facilities	3,013500	7 4
Recreation	370,000	0.9
Coordination and planning	1,190,788	2 9
Total	$40,780.867	1000

[a]*Summary* **and** *Status Report of* **the** *Mineral Lease and* **Severance** *Tax* **Fund** Second Annual Report to the Colorado Stale Legislature Department of Local Affairs 1979
[b]State Appropriation Act for FY 197980 IS B 5251

SOURCE Office of Technology Assessment

Colorado West Area Council of Governments.—CWACOG is a clearinghouse for the municipalities and counties of northwestern Colorado. With respect to energy development, it provides communities with information about industry plans and government assistance programs, and makes local groups aware of the responses of neighboring jurisdictions to impact problems. It also assists the mitigation task forces in preparing their needs assessments and in assigning priorities to the final requests submitted to the State; and it is the central agency through which grant applications to both State and Federal agencies must pass.

CWACOG uses a growth-monitoring system to project future employment and total population figures. Industry work force information and economic and demographic multipliers are combined for these forecasts. The computer model can accommodate updated information, and can supply outputs such as projections based on alternative assumptions and growth scenarios. The system provides a single source of data for government and industry officials.

Field Representatives for DLA.—Field personnel are located in several areas of Colorado that are experiencing energy-related growth. They help organize community mitigation teams and coordinate local, county, and regional requests for funding assistance. They also negotiate and administer contracts involving the expenditure of impact funds. They serve a valuable function by expediting State funding, advising local officials about current assistance programs, and monitoring the progress of authorized work.

Utah

Between 1970 and 1977, the population of Utah increased by 20 percent. Unlike other Western States, however, most of this growth was from a high birth rate, with immigration accounting for only 4 percent of the increase. Although there has not been a large migration to the State as a whole, energy development

Table 93.–Projects Funded by the Colorado Oil Shale Trust Fund, 1975-80

FY 1975		FY 1976		FY 1977	
Recipient	Amount	Recipient	Amount	Recipient	Amount
Mesa County schools (Re-51)	$42,575	Water Construction fund	$2700,000	Piceance Creek Road	$2,135,000
Moffat County schools (Re-1)		(Colorado Water Board)		Roan Creek Road	665,858
Garfield County schools (Re-2)	12,389	Piceance Creek Road	1,873,091	Rangely sewer	460,000
RIO Blanco County planning	10,000	RIO Blanco County schools (Re-1)	1,189,000	Craig Hospital	230,000
Garfield County planning	10,000	Garfield County schools (Re-2)	1,000,000	Craig water tank	215,000
Mesa County planning	10,000	Moffat County schools (Re-1)	670,000	Mesa County schools (Re-49)	147,000
Garfield County schools (Re-1)	8,000	Bonanza Road	497,909	011 Shale Coordinator's Off Ice	106,000
Mesa County schools (Re-49JT)	7,260	Rulison Bridge	471,000	Garfield County planning	100,000
Meeker schools	4,000	Roan Creek Road	467,595	Moffat school leases	51,456
Colorado West Area Council of Gov'ts	781	Mesa County schools (Re-51)	400,000	Mental health services	34,000
Office of the Governor		De Beque Bridge	299,658	Hayden school site	25,000
Administration	87,187	Garfield County schools (Re-1)	200.000	Colorado West Area Council of Gov'ts	25,000
State Impact Report	92,734	Colorado West Area Council of Gov'ts.	200,000	Delta County	17,000
		(technical assistance)		De Beque sewer	15,000
		Garfield County schools (Re-16)	121.057	New Castle sewer planning	6,666
		Routt County Road	100,000	Silt sewer planning	6,666
		Oil Shale Coordinator's Off Ice	100,000		
		Town of Hayden, streets	50,000		
		Mesa County schools (Re-49)	36,000		
		Rio Blanco County schools (Re-4)	10,000		

FY 1978		FY 1979		FY 1980	
Recipient	Amount	Recipient	Amount	Recipient	Amount
De Beque water	$608,000	Rifle water	2,056,000	Rifle school construction	$2,750,220
Grand Valley Bridge	532,125	County Road 24	1,000,000	Rifle bypass	2,000,000
Rangely streets	500,000	Rangely streets	900,000	Meeker sewage treatment expansion	1,440,000
Carbondale sewer	479.000	Craig High School	750,000	Silt water Improvements	1,400,000
Moffat County–Sunset School	450,000	Colorado Water Conservation Board	600,000	Meeker streets and drainage	800,000
Hayden Elementary School	450,000	Rifle bypass	500,000	Mesa County sewer system	
Rifle sewer	438,750	Meeker sanitation	368,000	Improvements	796,787
Meeker streets	435,400	Meeker pool	350,000	C-a to Rangely Road engineering	300,000
Mesa County schools (Re-51)	350,000	Meeker streets	320,000	De Beque water system	300,000
Hayden water	280,000	Mesa County airport water	293,250	Rifle senior center	172,500
Craig City Hall	275,000	Garfield County airport	260,000	Grand Valley sewage treatment plant	141,206
Garfield County schools (Re-2)	273,757	Grand Valley water	250,000	Dinosaur water system	66,153
Moffat County bypass	250,000	Fruita sewer	200,000		
Roan Creek Road	135.000	Transportation planning, CWACOG	198,000		
Craig water	125,000	New Castle water	196,000		
Oak Creek water	122,000	Silt water	151,000		
Oil Shale Coordinator's Office	114,079	Impact Coordinator's Office	114,079		
Rangely sewer	100.000	Colorado Northwest Community			
Mental health center	95,857	College	110000		
Carbondale Municipal Building	75,000	Mesa County sewer	104,450		
Moffat–modular rooms	74,000	Regional School Fund	100,000		
Rifle lift station	66,825	Rangely Hospital	50,811		
Colorado West Area Council of Gov'ts		Mesa County transportation	25,000		
(Planning)	62,500	RIO Blanco County Impact Coordinator	17,500		
Hayden drainage	41,000	Silt planning	15.000		
Meeker Hospital	30,000				
Craig drainage	25.000				
Delta County water	25,000				
Hayden recreation	20,000				
Walden water	15,000				
Rifle planning	10,000				
Silt planning	6,500				

SOURCE Summary and Status *of the* Mineral ***Lease and Severance Tax Fund*** Second Annual Report 10 the Colorado State Legislature. Colorado Department of Local Affairs 1979 activities have been responsible for rapid population increases in certain rural counties and communities. Until the recent boom, the population in most of these areas had decreased over several decades, As a consequence, the communities have been ill-prepared to respond effectively to current changes.

The oilfields of eastern Utah attracted people to Duchesne and Uintah Counties, although oil drilling there has peaked and the growth is now waning, Area residents hope that the present emphasis on synthetic fuels will lead to a boom from oil shale and tar sands development.[29] Increased coal mining has caused growth in Carbon, Sevier, and Emery Counties. In 1960, the population of communities in these counties was under 1,000; several even declined during the 1960's. Because there are no larger towns in the area that can provide housing and other services, they have been forced to absorb all the migration. A resurgence of uranium mining along with oil exploration has stimulated growth in San Juan, Grand, and Garfield Counties. The towns of Blanding, Moab, and Monticello, which have all gained new residents, are expected to continue growing.

Utah created a Community Impact Account in 1977 to assist areas affected by energy development.[30] It is a "revolving account for loans and grants to state agencies, political subdivisions of the state, and special service districts which are or may be socially or economically impacted by mineral resource development . . ."[31] Revenues come from a portion of the State's share of Federal mineral lease payments, Projects are chosen by a board comprised of chairpersons of several State boards, councils, committees, and departments. The board establishes the criteria for awarding grants and loans, determines the order in which projects will be funded, and serves as the sponsoring agency. The chief criterion for determining which projects to support is urgency of need. To date, almost all support has been for water and sewer projects. Only those communities already impacted have received assistance even though the legislation creating the account specified that those expecting large population increases are eligible for help. The Uinta basin, where the oil shale deposits are located, has not received any funds from the account even though it is undergoing oil and gas exploration and development. Because the Community Impact Account is the only funding source in the State designed to respond to problems associated with energy development, requests for help have far surpassed the available monies. In mid-l979, with only $4 million available for distribution, a total of $11 million had been requested.

Adequate water supplies are one of the paramount needs in the energy-impacted areas of Utah. Several towns have had to place moratoriums on additional building because water systems cannot service increased demands, and during summer months many communities are forced to ration the available water. To help solve these problems, the City Water Loan Fund[32] was created by the State legislature in 1975. It provides interest-free loans to cities for the construction of water supply and water treatment facilities. The fund provides up to 80 percent of the amount needed with the only qualification that the community be incorporated. Originally the revenue came from taxes on the sale of alcoholic beverages, but recently the funding source was changed to State mineral lease royalties; the amount varies from around $2 million to $2.5 million annually. Surprisingly, the fund has pretty well been able to keep up with the demand for loans. Every application has received a loan offer, even though not always the amount requested, A problem that might arise in the long term could be that a loan taken out during a time of boom would have to be paid by the remaining, smaller population during a subsequent time of bust. Also, since the loans are just for water-related projects, help is limited to only this one problem area.

Wyoming

Some of the largest growth in the Western States has been in Wyoming. Between 1970 and 1978, the population in all but one of Wyoming's 23 counties increased. In contrast, in 15 of the 23 it declined in the decade between 1960 and 1970. Much of the recent growth has been related to energy development, although some reflects the trend of settling in rural areas for simpler living patterns or for retirement. From 1970 to 1978, population expanded 30 percent or more in eight counties. These are distributed in three distinct geographical areas. Lincoln, Uintah, Carbon, Sweetwater, and Teton Counties lie in the west and southwest where there are coal, uranium, and oil deposits and the only large oil shale deposits in the State. Most of the growth in Campbell and Converse Counties, in the Powder River basin in central Wyoming, has been from the opening of coal and uranium strip mines. Platte County, in southeastern Wyoming, is the site of a 1,500-MW coal-fired plant.

Wyoming has several programs for managing growth. The major tool, designed for large development activities, is the Wyoming Industrial Development Information and Siting Act.[33] This Act, passed in 1975, requires that any project with construction costs in excess of $63,588,000 obtain a siting and construction permit from the Industrial Siting Council, a board appointed by the Governor. Before a permit is granted, the developer must submit a plan for the alleviation of social, economic, and environmental impacts, and can be required by the council to undertake their mitigation. For example, applicants can be asked to provide direct loans and grants to a political subdivision. Another management device, created by the Joint Powers Act,[34] allows two or more agencies, such as cities, counties, and school districts, to form a Joint Powers Board that can create, expand, finance, or operate facilities. This not only makes possible combined financing by the participating political entities but also makes them eligible for Joint Powers Loans. There is no ceiling on a loan, and the terms must be no longer than 40 years at an interest rate of not less than 5 nor more than 10 percent.

Wyoming also has an array of mitigation programs. (See table 94.) They are funded by Federal mineral lease revenues and State severance and excise taxes. Most are administered by the Farm Loan Board, composed of the Governor, secretary of state, auditor, treasurer, and state superintendent of public instruction. Allocation of funds is specified in most cases by the taxing legislation, and there are few discretionary programs. One alternative available to local communities to generate discretionary revenue is an optional l-cent sales tax.[35] It has been used successfully in several communities although approval by the local voters must be sought every 2 years. Case studies of boomtowns in Wyoming indicate that there are major differences in the effects of rapid growth, and to accommodate these differences, flexible policies are needed. This is especially true for providing such human services as day care centers, youth assistance and senior citizen programs, and alcohol counseling. Too few funds are available to alleviate the social impacts accompanying rapid growth.[36]

Evaluation of State and Local Mechanisms

State policies regarding social and economic effects vary. In Colorado, local initiative is central in the mitigation process. The State and its oil shale counties and municipalities have been preparing for increased shale development for nearly 10 years. However, in the past, this development has been interrupted or delayed by market changes, regulatory modifications, and technological complications, which has made planning difficult. In addition, oil and gas, coal, electric generation, and uranium industries are all expanding at the same time as oil shale. This complicates the identification of impacts specifically attributable to shale development and adds to the potential for disruption.

An elaborate planning infrastructure is in place in the Colorado counties and municipalities. Over $40 million has been appropriated for oil shale impact mitigation, with

Table 94.–Wyoming Programs to Mitigate Social and Economic Impacts

Name of mitigation program	Objectives	Funding	Implementing agencies	Comments
Wyoming Industrial Development Information and Siting Act (1975)	Provide information about new Industrial facilities costing over $63,588,000 Siting and construction permits required before building starts	Not applicable	Wyoming Siting council	Council can require applicants to take actions to mitigate adverse socioeconomic Impacts
Joint Powers Act (1975)	Allows different political entitles to join together to finance and operate public facilities through a Joint Powers Board	Joint Powers Loans from FLB. [a]FLB is restricted to $60 million in outstanding loans	Farm Loan Board (FLB)[a]	Some towns and counties have difficulty cooperating Smaller towns lack manpower to prepare detailed applications.
Wyoming Government Royalty Impact Assistance Account (1976)	Grant program for communities in areas of mineral development	Mineral Leasing Act of 1920, as amended [b]	FLB	Grant funds extremely limited. competition keen
Wyoming Water Development Program (1975)	Encourage optimal development of human, Industrial, mineral, agricultural, water, and recreational resources through projects and facilities for water storage, distribution, and use	1 1/2-percent excise tax on coal Revolving loan account, up to $100 million can be outstanding	Water Development Commission, Dept of Economic Planning and Development, FLB, local agencies	Requires feasibility study. authorizing legislation, and vote to approve any public debt (such as bonds) before construction can begin.
Coal Tax Revenue Account (1975)	Grants to political subdivsions in areas Impacted by coal development for Public facilities. 50 percent must go for streets and highways	2-percent severance tax on coal Maximum cumulative tax revenues limited to $160 million	FLB	$160 million will probably be expended before synthetic fuel development occurs
Capital Facilities Revenue Account (1977)	Permanent capital facilities by legislative appropriation, 30 percent for school district capital construction entitlements, formula allocation to community colleges, remainder for highways	1 1/2-percent excise tax on coal, trona, and uranium Maximum tax revenues limited to $250 million	Capital Facilities Commission	Used mostly for major State facilities (university, prison), approval of bonds needed for school construction
Wyoming Community Development Authority (1975)	To provide funds for private mortgages at low interest through mortgage lending institutions	Mortgage monies generated through issuance of bonds Authority granted for up to $250 million in bonds c	Wyoming Community Development Authority	Program delayed by litigation. only recently implemented

[a]The Farm Loan Board consists of [he Governor secretary of state auditor treasurer and slate superintendent of public instruction
[b]See text for a discussion of Federal financial assistance programs
'The 1980 Wyoming legislature has under consideration raising this amount 10$750 million
SOURCE Office of Technology Assessment

over **90** percent allocated to the four counties of Mesa, Garfield, Rio Blanco, and Moffat. (See table 95.) Most of the remainder has gone for the State's support services. As a result, the region is prepared for reasonable growth and is awaiting expanded oil shale development. However, the ability of existing strategies to deal with a large or sudden population influx, such as might occur with a rapid expansion of the industry, is as yet untested. Although the State has ambitious programs, the General Assembly has adopted a cautious approach to the expenditure of the Oil Shale Trust Fund monies. While not required to do so, JBC has elected to retain a principal of **$60** million in the trust fund. This has caused some discontent in the oil shale region where expenditure of the full amount would accelerate preparations for growth. Because the trust fund is disbursed by legislative appropriation, intrastate political differences also come into play. The General Assembly has greater representation from the eastern, more densely populated, urban parts of the State; thus western slope Senators and Representatives can be outvoted. Impact mitigation, in this case, is subject to the political compromises of the Colorado appropriation process.

Utah and Wyoming have not been preparing extensively for oil shale development im-

Table 95.–Allocation of Oil Shale Trust Funds, Fiscal Years 1975-80

County or agency	Percentage of total appropriation FY 1975-79	FY 1980
Garfield County	285	619
Mesa County	130	124
Moffat County	11 2	0 6
RIO Blanco County	400	243
Subtotal–oil shale region	927	992
Delta County	01	0ª
Jackson County	005	0
Routt County	37	0
Subtotal–all counties......	966	992
Division of Energy and Mineral Impact	21	0.6
CWACOG	12	01
Total	100	100

[a] The 1979 General Assembly adopted the policy 10 allocate trust funds only to the counties in the Immediate 011 shale vicinity

SOURCE OTA based on data for FY 197579 from *Summary and Status Report of the Mineral Lease and Severance Tax Fund* Second Annual Report to the Colorado Stale Legislature, Department of Local Affairs 1979 and FY 1980 from State Appropriation Act for FY 19791980 (S B 525)

pacts. Both States, however, have had to come to grips with other energy industry expansion, and presumably could use programs similar to the ones now established for coal and uranium mitigation to adjust to oil shale growth. They emphasize a more centralized process with State government playing a larger part in the determination of needs and the allocation of assistance. Utah may be limited by a lack of funding, although the bonus payments from the U-a and U-b lease sales—now being held in escrow pending the outcome of the ownership question—should be available in the future. The State may experience difficulty from a lack of adequate local infrastructures capable of handling rapid growth. Evaluation is complicated for Utah as it is for Colorado by similar uncertainties about the future timing, pace, and size of the industry. Wyoming has many programs that could be adapted for oil shale impact mitigation. At present, its funding levels appear to be adequate.

No State facing social and economic problems from energy development is able to anticipate which communities will be able to adjust to growth and which may be disrupted. Whether towns will suffer from rapid growth or take it in stride depends on a unique set of complicated factors within each community. For example, Douglas and Wheatland in Wyoming have experienced few of the negative effects identified in the literature as boomtown impacts. Rock Springs and Gillette, on the other hand, appear to be at the opposite end of the spectrum, with the former being the classical example of a town disrupted by energy development. Yet these four communities are undergoing the same types of industrial growth (primarily coal, oil, and gas prospecting and production) and have the same kinds of impact assistance available to them.[17] A conclusion from these cases is that the capability of adapting to rapid growth appears to be highly site specific.

Federal Programs

Only a few of the over 1,000 existing Federal programs are designed to deal with socioeconomic impacts. A 1978 Report to the President[38] lists 160 that were judged "potentially applicable to energy impact issues. " They are administered by 20 departments or other Federal agencies. About two dozen programs that are of importance to the Western States have been identified by Murdock and Leistriz.[39] (See table 96.) Only those that contribute to the alleviation of negative impacts from oil shale development are examined in detail here, Federal programs can be placed in two broad categories: financial and technical assistance.

Financial Assistance

Section 35 of the Mineral Leasing Act of 1920[40] is a major source of Federal financial assistance. This legislation originally provided for the Federal Government to return 37 1/2 percent of the revenues it receives from mineral leases on public lands to the States in which those lands are located; these monies were to be used by the legislatures of the States for support of public schools and roads. In 1976, this section was amended by the passage of the Federal Coal Leasing Amendments Act[41] and the Federal Land Policy and Management Act[42] (also known as the Bureau of Land Management Organic Act or

Table 96.–Selected Federal Programs Used by Western States for Assistance With Social and Economic Effects of Energy Development'

Name of program	Implementing agency	Objectives	Comments
Assistance in planning and growth management			
Comprehensive planning assistance HUD 701 program National Housing Act of 1954, as amended (40 U S C 461)	Community Planning and Development, HUD	Strengthen planning and declslon-making capabilities of States, local governments, and areawide planning organizations	Urban orientation overall, smaller cities and counties receive funding through States Funds allocated on basis of past population which is a disadvantage to rapidly growing communities Some State and local concern over recent decline in funding levels
Community development block grants–small cities Housing and Community Development Act of 1974 Title I (42 U S C 5301-531 7)	Community Planning and Development, HUD	Assist communities in providing decent housing and a suitable living environment, expand economic opportunities	Primarily for urban areas, most funds allocated by formula Some discretionary funds for special-purpose grants to small communities Provides 100-percent funding that can be used as local matching contribution for other programs Can also be used for facility construction as well as for planning
Economic development–planning and technical assistance Public Works and Economic Development Act of 1965, as amended (42 U S C 3151, 31 52) Title III	Economic Development Administration (EDA), Commerce	Foster multicounty planning and Implementation capability, solve problems of economic growth through project grants, feasibility and other studies, and management and operational assistance	Criteria for project selection makes it difficult for energy-impacted communities to obtain funding Competition for funds is keen.
Technical assistance–personnel sharing Intergovernmental Personnet Act of 1970 (5 U S C 3371-3376)	Off Ice of Personnel Management	Aid in problem-solving and delivering Improved services by sharing professional administrative, and technical expertise.	Few communities appear to have taken advantage of program. Time involved in Iocating and negotiating for an individual may be a constraint for small counties and communities
Water quality planning sec 208 grants Clean Water Act, as amended (33 U S C 1251 et seq.)	Office of Water and Waste Management, Environmental Protection Agency (EPA)	Develop water quality management plans	Funds limited to planning only
Assistance in expanding public facilities and services[c]			
Water and waste disposal systerns for rural communities Consolidated Farm and Rural Development Act, sec 306 (7 U S C 1926)	Farmers Home Administration (FMHA), Agriculture	Provide amen! ties, alleviate health hazards promote orderly growth of rural areas by providing new and Improved water waste disposal facilities	Sewer and water systems cannot serve areas with a population in excess of 10,000 population, priority is given to communities of less than 5,500 inhabitants
Community facilities loans Consolidated Farm and Rural Development Act, sec 306 (7 U S C 1926)	FmHA Agriculture	Construct, enlarge, or Improve community facilities	Targeted for areas with Iow-income rural residents Priority to projects enhancing public safety (fire, pollee, rescue services), health care facilities needed to meet life/safety codes, public buildings and courthouses, recreation facilities, new hospitals
Construct Ion grants for wastewater treatment works Clean Water Act as amended (33 U S C 1251 et seq)	Office of Water and-Waste Management, EPA	Assist in construction of municipal sewage treatment works	Funds allocated to States on a population-based formula No funding of collector systems in "communities not in existence" in October 1972 Some difficulty allocating funds on a timely basis
Economic development and adjustment assistance Title IX– EDA Public Works and Economic Development Act of 1965, as amended (42 U S C 3121 et seq)	EDA, Commerce	Assist State and local governments to arrest and reverse long-term economic deterioration, address dislocations from Federal actions, from compliance with environmental requirements, and from severe changes in economic conditions	Targeted to communities experiencing economic decline but funds are available to energy-impacted areas Flexibility an advantage

Table 96.–Selected Federal Programs Used by Western States for Assistance With Social and Economic Effects of Energy Development[a]—continued

Name of program	Implementing agency	Objectives	Comments
Outdoor recreation " BOR program' Land and Water Conservation Fund Act of 1965, et al. (16 U .S. C. 1-4 et seq.)	Heritage Conservation and Recreation Service, Interior	Financial assistance for planning, acquisition, and development of outdoor recreation areas and facilities	Limited funding restricts the number of projects that can be supported A popular program
Planning and site acquisition Sec. 601 program Power Plant and Industrial Fuel Use Act of 1978 (Public Law 95-620)	FmHA, Agriculture	Assist in developing plans for growth management and housing and in acquiring sites for housing and public facilities	Newly Implemented, Currently limited to coal and uranium Impacts,
Assistance for housing			
Rural housing loans Housing Act of 1949, as amended. Title V, sec. 502 (42 U.S. C. 1471 et seq., 42 U.S. C. 1480; *42* U.S.C. 1472)	FmHA, Agriculture	To assist rural families through guaranteed/insured home loans	Loans are regarded as a ' 'source of last resort to be used only if commercial lending Institutions cannot finance housing.
Rural housing site loans Housing Act of 1949, as amended. Sees. 523 and 524. (42 U.S. C. 1490c and 1490d)	FmHA, Agriculture	Assist public or private nonprofit organizations to acquire and develop land to be subdivided on a nonprofit basis for homes.	Priority given to housing for low- and moderate-income families
Rural rental housing loans Housing Act of 1949, as amended. Sees. 515 and 521. (42 U.S.C. 1485, 1490a)	FmHA, Agriculture	Provide economically designed and constructed rental and cooperative rental housing for rural residents,	

[a]The programs listed are illustrative of the types of aid available in Western States no attempt has been made to Include all possible Federal programs used by impacted communities
[b]General categories are based on the format used by Murdock & Leistritz *Energy Development in the Western United States—Impact on Rural Areas* (N y Praeger Publishers 1979)
[c]Revenue sharing acts such as the Local Government Funds Act (Public Law 94-565) are not included see text for a discussion of the Mineral Leasing Act Of 1920 aS amended

SOURCE Office of Technology Assessment

FLPMA). The Federal Coal Leasing Amendments Act increased the States' share of royalty and lease proceeds to 50 percent, and specifically directs the legislatures, when distributing these proceeds, to give priority to those subdivisions of the State where leasing occurs under the Act. At the same time, the purposes for which the funds could be used were broadened to include "planning, . . . construction and maintenance of public facilities, and . . . provision of public services."[43] FLPMA further amends the 1920 Act to authorize the Secretary of the Interior to make loans to States and their political subdivisions. The amounts of the loans are not to exceed the revenues anticipated by the States or their jurisdictions for any prospective 10-year period. Loans are to be repaid, at 3-percent interest, from these proceeds. The language of the Coal Leasing Amendments Act that allows broader use of the funds and specifies their application to affected areas is also extended to the loans.[44]

Section 601 of the Power Plant and Industrial Fuel Use Act of 1978[45] established the Energy Impacted Area Development Assistance Program (popularly, the sec. 601 program). Its objective is to "help areas impacted by coal or uranium development activities by providing assistance for the development of growth management and housing plans and in developing and acquiring sites for housing and public facilities and services.[46] The lead agency designated to administer the section is the Farmers Home Administration (FmHA). The Governor of a State wishing to participate must designate energy-impacted areas and prepare a State investment strategy for allocating the funds. Grant applications for impact aid must be consistent with the State investment plan. Local governments, councils of local governments, and State agencies are among the eligible applicants. Grant funds will pay 100 percent of the costs of developing plans for managing growth and/or plans for new housing, and up to 75 percent of the cost of acquiring or developing sites for housing, public facilities, or services.

Three criteria are specified for designation as an impacted area. First, employment in coal or uranium development activities must have increased, or be expected to increase over 3 years, by 8 percent or more from the preceding year. Second, the increased employment must result in a housing shortage or inadequate public facilities and services. Third, the available State and local financial resources must be inadequate to meet the current needs or those projected for the following 3 years. Within the oil shale region, the purchase of land by the city of Meeker for the construction of low- and moderate-income housing was included as a priority project in the 1979 Colorado investment strategy.

Technical Assistance

THE FEDERAL REGIONAL COUNCIL

The Energy Impact Office of the Federal Regional Council (FRC), Region VIII, oversees Federal technical assistance programs. The Office was created early in 1978 to coordinate the response of Federal agencies to local needs. In addition to the development of an improved system of service delivery, the FRC efforts are designed to evaluate Federal legislation for impact assistance and to collect impact data and related information. The agencies comprising the Federal Regional Council are the Departments of Agriculture; Commerce; Energy (DOE); Health, Education, and Welfare; Housing and Urban Development (HUD); the Interior; Labor; Transportation; the Community Services Administration, and the Environmental Protection Agency (EPA). Senior staff members of these agencies make up an Intergovernmental Committee that assists the Energy Impact Office.

Dissemination of information and interagency coordination are the main functions of the Federal programs. Several examples can be cited. FRC has a representative in the Oil Shale Environmental Advisory Panel (OSEAP) who serves as contact with this group. The Federal Assistance Program Retrieval System (FAPRS) is a computerized information bank, keyed to programs described in the Catalog of Federal Domestic Assistance. The Energy Impact Office uses it to help communities identify various Federal assistance programs and determine their eligibility for aid. DOE's Office of the Regional Representative, Region VIII, in cooperation with FRC, publishes an annual Regional Profile—Energy Impacted Communities[47] that collates data on the energy impacted areas.

OFFICE OF THE AREA OIL SHALE SUPERVISOR

The Office of the Area Oil Shale Supervisor of the U.S. Geological Survey (USGS) also provides technical assistance to communities by serving as a clearinghouse for information about social and economic impacts and programs for their alleviation.

Summary of Federal Support Initiatives

At the present time, there is no single Federal policy with respect to the social and economic effects of energy development. At the regional level, the Federal point of view is best expressed in the Region VIII DOE Regional Profile. The edition of March 1979 reiterates a position taken in earlier volumes:

> The Region VIII office maintains the position that local communities and counties must take the initiative to become involved in assessing, planning for, and mitigating adverse energy related impacts. To effect a team effort involving industry, Federal, State, and local government, the initiative and follow-up must first be taken by local leadership,”

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Several programs are operating that address limited aspects of socioeconomic effects but, at present, none directly addresses the impacts that may come with synthetic fuel development or the specific consequences of accelerated shale oil production. A wide variety of assistance is available through avenues not specifically designed to deal with energy development impacts. These various Federal programs have different emphases and modes of providing help, and impacted communities must compete with everyone else for the limited funds available.

These regular Federal programs usually require elaborate proposal development but small towns with limited manpower often do not have the expertise to prepare grant applications. Furthermore, many programs have lengthy review processes before decisions are made, which can be a disadvantage for boomtowns. For example, EPA grants for sewer facility upgrading take about 3 years from the time of application to the time of decision; if a community does not get a grant, this time is lost entirely and the town can only fall further behind in its effort to keep up with its growth. In addition, although the specific programs may be adequately meeting the needs for which they were designed, their limited nature means that the cumulative impacts of all types of industrial development are not being addressed.

At present, the major role of the Federal Government is providing revenues for mitigation; these monies come primarily from the Mineral Leasing Act of 1920, as amended. A somewhat expanded Federal impact mitigation role is found in section 601 of the Powerplant and Industrial Fuel Use Act of 1978. The extent and nature of any additional Federal involvement in impact mitigation are controversial. On the one side, it can be argued that social and economic impacts are State and local problems. They should be viewed as the inevitable consequences of industrial development, and the Federal Government need not be involved with their amelioration. This viewpoint, opposing Federal involvement, also contends that specific Federal mitigation programs would increase bureaucracy, and cites the public's growing displeasure with the perceived intervention of Federal agencies in the daily life of the citizenry as a reason for not expanding Federal activities. On the other side is the position that national requirements are the root causes of the local impacts, therefore an expanded Federal role is appropriate. Several Western States contend that because expanded domestic energy production is a national goal, for reasons of equity the Federal Government should assume a more direct role in the alleviation of negative impacts from this development.

Assuming additional Federal involvement is desired, how can the Government most appropriately assist impacted communities? One position is that providing financial assistance is sufficient programmatically and only the amounts need to be increased; new programs and regulations are not desirable. Another position is that Federal regulation could be used to mitigate impacts by, for example, pacing industry's growth rate through leasing policies. A third position is that the Government should be substantially involved in mitigation programs that use Federal funds. Part of this issue includes the question of when and where the Federal Government might to be involved. The provisions of the Powerplant and Industrial Fuel Use Act suggest that it should step in only when State and local governments cannot handle impact problems. A similar position is that Federal participation should be confined to areas requiring long-term commitments, such as housing, sewer, and water systems. Another possible Federal approach could be to help specific groups (such as retired persons on fixed incomes or young adults seeking to enter the job market) who may be particularly hard hit in boomtowns.[49]

Possible Consequences of Oil Shale Development

General Effects of Rapid Population Growth

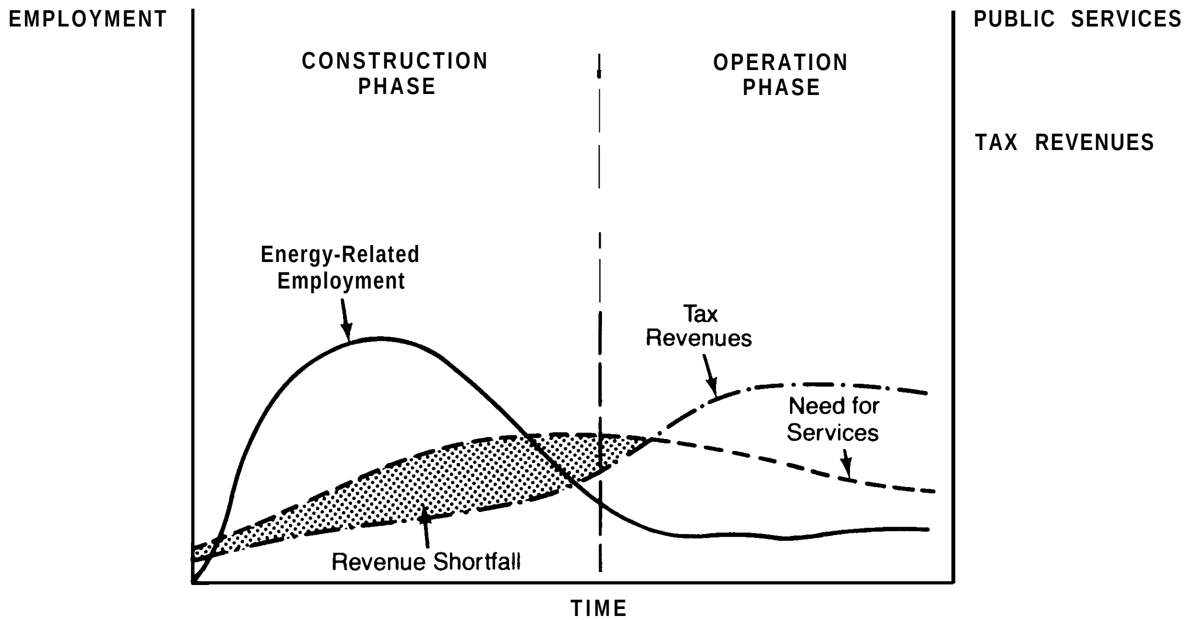
The recent development of energy resources has caused large numbers of people to move into established rural communities within short periods of time. All parts of a community are affected by this kind of growth. Local government agencies are pressed to provide additional services. A major difficulty is that the expanded facilities and services are needed before new tax revenues can be realized. A 3- to 5-year lag appears to be the average between the time the increased services and facilities are required and the time additional revenues can be generated. (See figure 71.) In the long run, however, local governments should benefit from the increased tax base resulting from energy development.

Local governments need help in the early stages of rapid growth. One traditional means of raising the needed funds is by issuing bonds. While this remains important, experience indicates that it is far from adequate. First of all, State law usually places limits on the amounts of indebtedness that counties and communities can incur through bond issues. Second, the assessed valuation upon which bonding limits are based increases over the life of a project but funds are needed during the early stages when the population is growing rapidly. Third, local

Photo credit: OTA staff

Municipal facilities will need to be upgraded to handle the population growth

Figure 71 .—Energy-Related Employment, Tax Revenues, and Need for Public Services in an Area Affected by a Large-Scale Energy Development

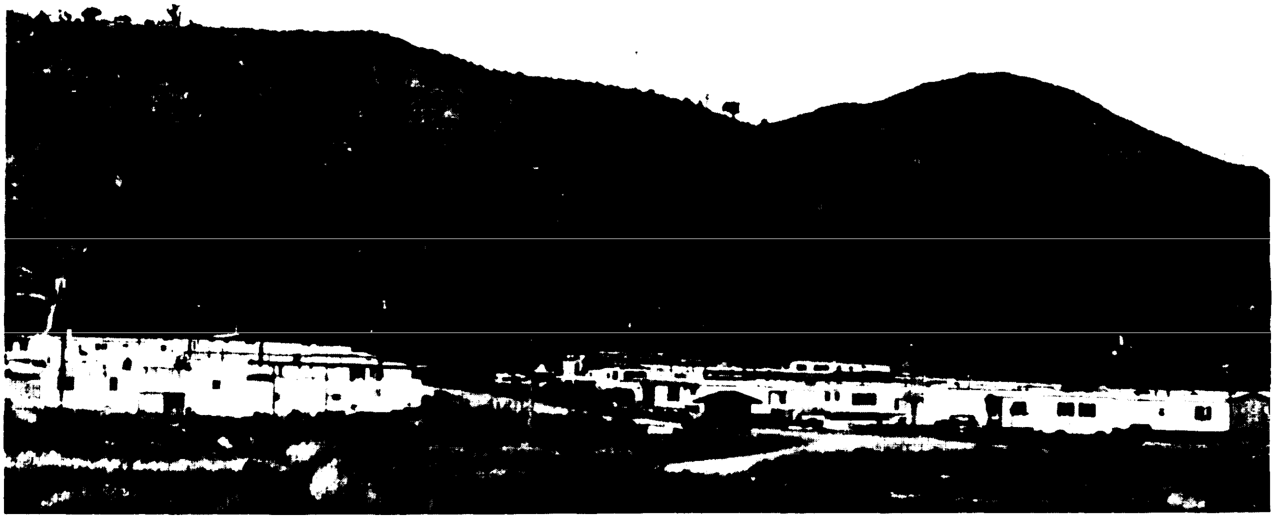


SOURCE S H Murdock and F L Leistritz. Energy Development in the *Western United* States, 1979, Praeger Publishers

residents are often afraid to approve bond issues because of the instability of the boom cycle. People who have moved in during construction, and who are among those needing new services and infrastructure, usually leave at the end of the construction period. Longtime residents are fearful that they will be left to discharge debts incurred during this period. Consequently, voters in many of the most severely impacted communities have rejected bond issues. Similar difficulties are found with loan and loan-guarantee programs. In this instance, the statutory or constitutional limits on the debt that rural communities can incur is an obstacle to the use of the loans to meet front-end funding needs.

Yet another statutory limitation can be a ceiling on the expansion of local government budgets. For example, in Colorado most small towns are prohibited from "the levying of a greater amount of revenue than was levied in the previous year plus seven percent . . ."[50] The practical effect of this restriction on mill levy increases is to limit municipal and county budgets to a 7-percent-per-annum growth. Finally, the ability of local governments to respond may be complicated because the development and the population growth may be in different places. When the project is in one taxing jurisdiction and the community in a different one, there is a jurisdictional mismatch. In this case, the town that must provide increased facilities and services cannot look forward to larger revenues from taxes on the new industry.

In the private sector, housing can be a major problem. It usually is in short supply; its prices are often greatly inflated; and land may not be available for new construction because of terrain, price, or public ownership. Shortages of construction financing and mortgage money are common and, in some cases, new employees may not qualify for mortgages. The need for temporary housing for construction workers can exacerbate these problems. Mobile homes often fill this need but their siting and providing services to the sites add to the difficulties faced by local government. Industry has, in several instances, sought to assist by supplying capital



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for housing construction. Because public housing is statutorily limited to low- and moderate-income groups, Federal Government agencies cannot provide much help.

Other affected parts of the private sector are the local retail trade and service industries. These businesses often anticipate increased income from energy development. What may not be expected are increases in labor costs, taxes, and competition. In some cases, this sector has not been able to meet the new demands; business failures have been the most extreme consequences. More common have been difficulties in getting and keeping help, providing the goods that customers want, and expanding stores and shops to keep up with the increased business. Like local governments, retail businesses should profit in the long run from energy development; their dislocations occur during the early periods of rapid growth when services cannot keep up with the new demands.

Those parts of the community that provide services to the residents also are affected. In many areas, this support sector is inadequate prior to any sudden growth. For example, doctors and dentists are not readily available in many rural regions. School systems, while established, cannot offer broad curricula, and may have difficulty attracting and keeping personnel. The number of public safety professionals often is limited. Sheriff's offices and town police departments seldom have large forces; fire protection is usually provided by volunteer departments. Recreation facilities may be lacking. Social welfare services may depend on itinerant professionals, such as a public health nurse or social worker who visits the communities periodically.

The functions of a community's social infrastructure often are carried out through informal social networks. In rapid growth situations, these networks can break down simply because of the increased number of newcomers. If there are no established formal structures, then the services cannot be provided. For example, in many rural communities the school is the center of recreational activities, and there are few structured programs. Increased demands to use the school gym cannot be met because there aren't enough hours in the day or enough basketball courts to accommodate the large number of new players, Established informal recreation patterns can thus be disrupted and nothing takes their place until a formal community program can be set up. The effects of rapid population growth on the various aspects of

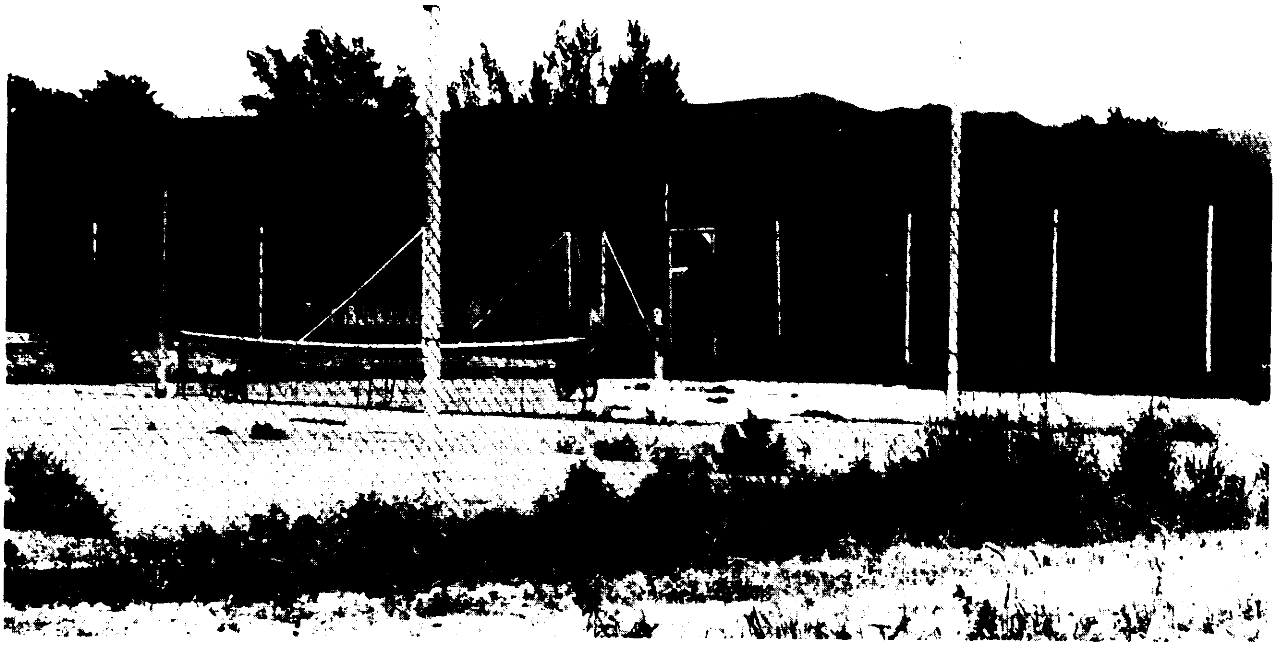


Photo credit OTA staff

Adequate recreational areas are often lacking in boomtowns

the existing community support systems are among the more ubiquitous social impacts of energy development activities.

Rapid growth inevitably causes social changes; those communities experiencing excessive strains on their social structure from sudden growth have been called modern boomtowns.[51] A well-documented example is the Rock Springs—Green River (Sweetwater County) area of Wyoming.[52] Here the population grew from 18,391 in 1970 to 36,860 in 1974. Among the consequences were:

- Housing availability fell far short of demand. In 1974, between 4,500 and 5,000 families were living in mobile homes, many on scattered, isolated tracts in unincorporated parts of the county.
- These housing areas often lacked adequate water, sewer, and other facilities.
- Health care became a major problem. An estimated 40 percent of the residents had to seek medical care outside the county; the mental health clinic caseload expanded ninefold as alcoholism, suicide attempts, and divorce rates soared.
- Local government was overwhelmed with difficulties. Costs for capital construction of public facilities, such as water and sewer treatment plants, were greater than the communities' borrowing capacity, and demands for public services, such as fire and police protection, were beyond the available resources.
- Schools could not keep up with the pupil increases. The school districts were already bonded up to the legal limit and were not able to provide the needed additional services.
- As a result of the boomtown conditions, industry was unable to recruit and retain employees. Employee turnover in 1973 ranged from 35 to 100 percent, and productivity declined. Cost overruns resulted from construction delays.[53]

It is difficult to determine whether a community will be able to respond adequately to the pressures of growth; however, some generalizations have been drawn from case studies of towns like Rock Springs and Green River. Boomtowns have been described as having the following characteristics:[54]

- a small population base, usually under 10,000 residents;
- geographic isolation from urban areas;
- rapid population growth;
- a shift in economic activities away from agriculture, trade, and services to constructing and operating energy-related industries;
- demand for temporary and permanent housing that exceeds supply, with accompanying price escalation;
- increased symptoms of social stress such as crime, truancy, child abuse, alcoholism, and suicide;
- inability of the public sector to provide, in a timely fashion, services and facilities such as streets, water, and sewers;
- dislocations in the private sector such as business failure, labor shortages, and cost increases;
- strain on health services from increased need for access to professionals and facilities;
- high employee turnover with accompanying decline in productivity; and
- in the early stages, a lack of community concern for planning and growth management.

Alterations in human relationships underlie the changes accompanying rapid growth.[55] Some social and behavioral scientists contend that these are among the most pervasive and significant consequences of growth and are the basic causes of boomtown symptoms.[56] Among the alterations that have been identified in the social roles individuals must fill are increased anonymity, impersonalization, and specialization. At the institutional level, greater bureaucratization, centralization, and orientation of community units toward systems outside the local social structure have been found.[57] Among the psychological factors identified in boomtowns are value conflicts between established residents and in-migrants, and shifts in personal interaction patterns such as the deterioration of longtime friendship patterns, At the social institution level, dramatic realinements of political party membership, and an atmosphere of uncertainty about the future that undermines established systems of social control have been documented.[58] On the other hand, a comparison of the experiences of four Colorado boomtowns found a picture of resilience and adaptability suggesting the "hope that people can adjust to changes instead of being overwhelmed by them . . . ."[59]

Anticipated Growth in the Colorado Oil Shale Region

As a sparsely populated, rural region, western Colorado is vulnerable to boomtown conditions. The three oil shale counties had a population of 90,748 at the time of a special census in 1977. Growth between 1970 and 1977 ranged from 5 percent for Rio Blanco County to 27 percent for Garfield County; the largest growth (58 percent) was in Moffat County, to the north of the oil shale region. (See table 97.) None of the communities in the immediate area had a population over 3,000, (See table 98.) There are 2 to 19 persons per square mile and a high proportion of older residents. (See table 99.) Sixteen percent of the residents of the oil shale communities in Rio Blanco and Garfield Counties are over 65 years old, which is over sixty percent higher than the national average.[60]

The first step in attempting to forecast whether there might be disruption is to gauge the magnitude of possible migration to the area. As indicated earlier in the chapter,

Table 97.–Population Growth of Colorado Oil Shale Counties 1970-77

County	Population 1970	Population 1977	Percent change
Rio Blanco	4,842	5,100	5.3
Garfield	14,821	18,800	26.8
Mesa	54,374	66,848	22.9
Moffat	6,525	10,303	579

SOURCE U S Bureau of Census data

Table 98,–Population of Colorado Communities Apt To Be Affected by Oil Shale Development, 1977

Location	Population
Rio Blanco County	
Meeker	1,848
Rangely	1,871
Garfield County	
Glenwood Springs	4,051
Grand Valley	377
New Castle	543
Rifle	2,244
slit	859
Mesa County	
De Beque	264
Grand Junction	25,398
Moffat County	
Craig	6,677
Dinosaur	347

SOURCE 1977 special census

Table 99.–Selected Demographic Indices of Oil Shale Counties of Colorado, July 1975

County	Number of people per square mile	Percent aged 65 and over
Rio Blanco	2	8.3
Garfield	6	105
Mesa	19	119
Moffat	2	8 3

SOURCE Bureau of the Census City *and County Data Book* 1977

CWACOG has a growth-monitoring system that provides projections of future growth. Because this organization serves the day-to-day needs of the individual counties and communities, the projections are frequently modified in an attempt to reflect the current situation. To an outsider, there appear to be several sets of data none of which coincide since it is possible for a town to be using one set of projections to plan for additional housing, another to determine water and sewage treatment requirements, and a third to estimate the costs of providing public services. Although this arrangement creates some confusion as to which projections are the most accurate, it is important to modify projections when the assumptions change. As an illustration, Rangely's projections have been overestimated in the past because they have assumed a new road would be built from the town to tract C-a. Since the road was not being constructed when the most recent housing projections were made, the CWACOG housing data took this into account and Rangely's figures were adjusted downward; but because these revisions are not reflected in all of the projections, discrepancies can be found between different sets of data.

Each year, CWACOG prepares for the region an official set of projections to the year 2000, based on the following information:

- baseline population data from the 1970 regular and a 1977 special U.S. census;
- energy company employment projections with a family multiplier (2.0);
- support industry worker multipliers with accompanying family multipliers (2.5);
- base worker distributions assigned by county and community; and
- cohort survival factors.

Three population projection scenarios are derived using these factors:

Scenario I— Natural population growth without energy development;

Scenario II— Growth with energy industry development, as presently planned;

Scenario III— Growth with energy development including shale oil 'production of 500,000 bbl/d in 1990 and 750,000 bbl/d in 1995and 2000.

The first scenario is a conservative estimate of growth with a population induced from non-energy-related employment figures. Its major benefit is to provide a lower limit against which to compare the growth scenarios. The second scenario, growth with energy development, contains base worker projections from 18 companies including 6 that expect to proceed with oil shale development. These are the developers of tracts C-a and C-b, Superior, Union Oil, Paraho, and Colony (Atlantic Richfield and Tosco).[61] This scenario has been selected by the CWACOG Board as the officially endorsed set of projections because it reflects the stated plans of companies active in the region. The third scenario illustrates an upper limit generated by assumptions for a rapidly deployed oil shale industry.

The latest official CWACOG projections for the oil shale counties, published in November 1979, show that Rio Blanco and Garfield Counties are expected to have sharp population increases under the energy development scenario. (See table 100 and figure 72.) The number of people in Rio Blanco County is forecast to be, by 1985, four times the 1977 special census count, while the number in Garfield County is seen as nearly tripling. Moffat County is projected to have a large increase in the early 1980's but this growth is attributed to coal and electric generation development, not to oil shale, Mesa County is expected to grow without extreme fluctuations, but the number of people is projected to nearly double by 1990 over the 1977 figure.

CWACOG prepares projections for individual communities as well as for the counties. (See figure 73.) For the energy development conditions (Scenario II), these figures reveal:

- Rifle's population is projected to grow by 1985 to over six times the 1977 count.
- Meeker's population is projected to grow by 1985 to over seven times the 1977 count.
- Rangely's population is projected to grow by 1985 to over three times the 1977 count.

The projections for Scenario III, assuming an industry producing 500,000 bbl/d of shale oil by 1990 and 750,000 bbl/d by 2000, disclose exceptionally high growth for the region. By 1985, Rio Blanco County is projected to have almost 8 times the number of people counted in 1977; Garfield is forecast to have $3^1/_2$ times its 1977 count. Mesa and Moffat Counties are not forecast to have such spectacular growth, although Mesa County's population is seen as growing to almost 3 times the 1977 figure by 2000.

The populations of Rifle, Meeker, and Rangely are projected to increase from around 2,000 to over 22,000 by 1985, with a net increase of approximately 18,860 residents for Rifle. Like the counties, the biggest increments for the towns occur in the early years, between 1980 and 1985. Under Scenario HI, the projected growth for these three communities exceeds 500 percent in the period between 1980 and 1985. (See table 101.)

Needs Arising From Anticipated Growth

The projections are used by the counties and communities to prepare plans for their

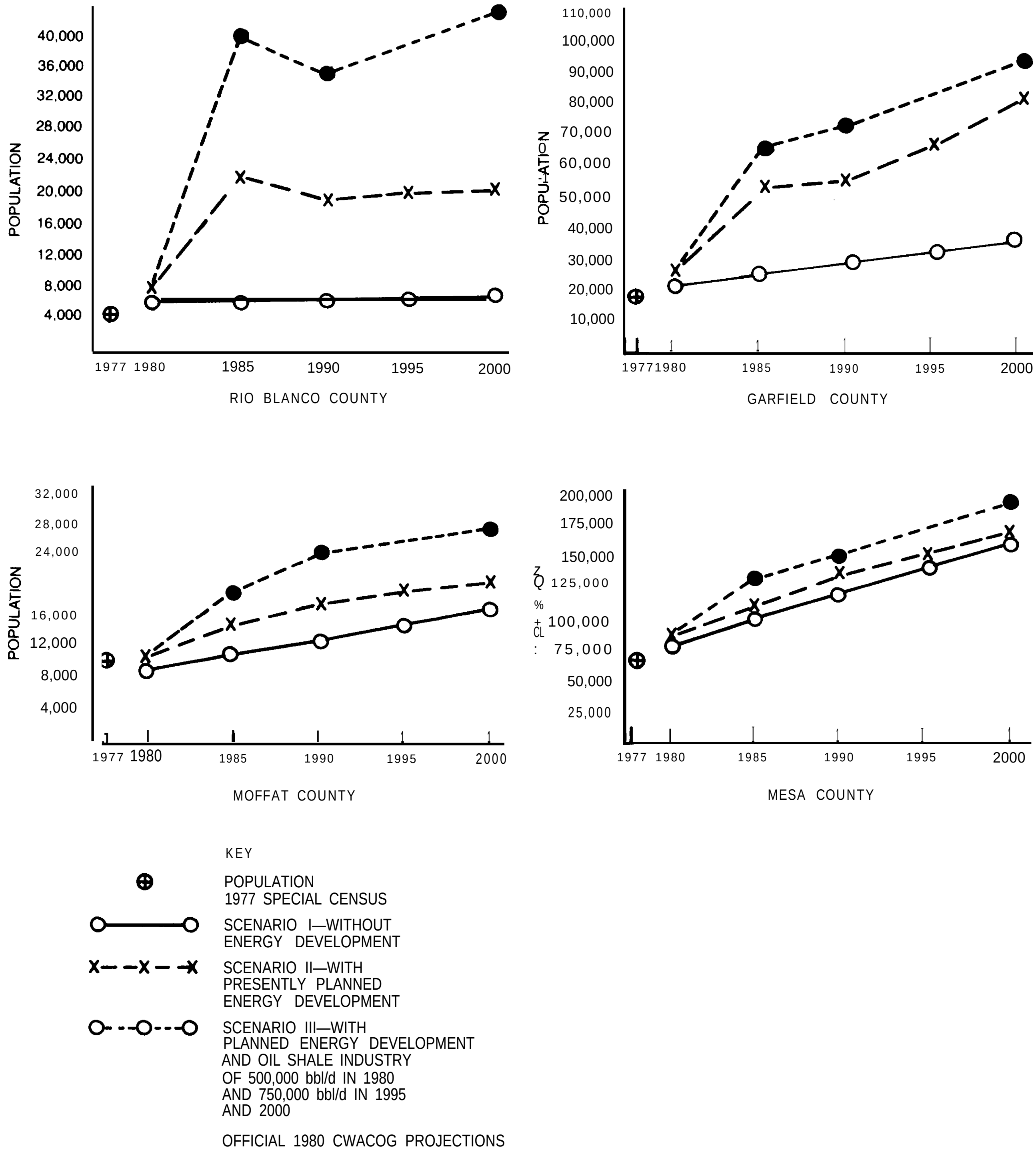
Table 100.– Population Projections by Development Scenario for the Oil Shale Counties of Colorado

	Rio Blanco	Garfield	Mesa	Moffat
1977				
Actuals[a]	5,100	18,800	66,848	10,303
1979				
Estimated[b]	5,580	22.000	75,000	10,925
1985				
Scenario I[c]	5,779	28,181	101.005	11,509
Scenario II	22,809	50.559	107,855	15,306
Scenario III	40,501	66,820	128.460	18,892
1990				
Scenario I	6,177	32,080	121,091	13,311
Scenario II	19,522	56,909	128,308	17.090
Scenario III	35,881	71,621	147,583	24,302
2000				
Scenario I	6,973	45,344	161,266	16,914
Scenario II	20,318	83,012	169,882	20,693
Scenario III	44,303	95,365	190,484	27,905

[a]From a 1977 special U S census
[b]End of the year estimate prepared in July 1979 by the Colorado West Area Council of Governments
[c]Based on the following
Scenario I – Natural population growth without energy development
Scenario II - Growth with energy development according to employment forecasts from 18 industries active in the region (official 1980 CWACOG projections)
Scenario III –Energy development including shale 011 production of 500000 bbl/d in 1990 and 750000 bbl/d in 1995 and 2000

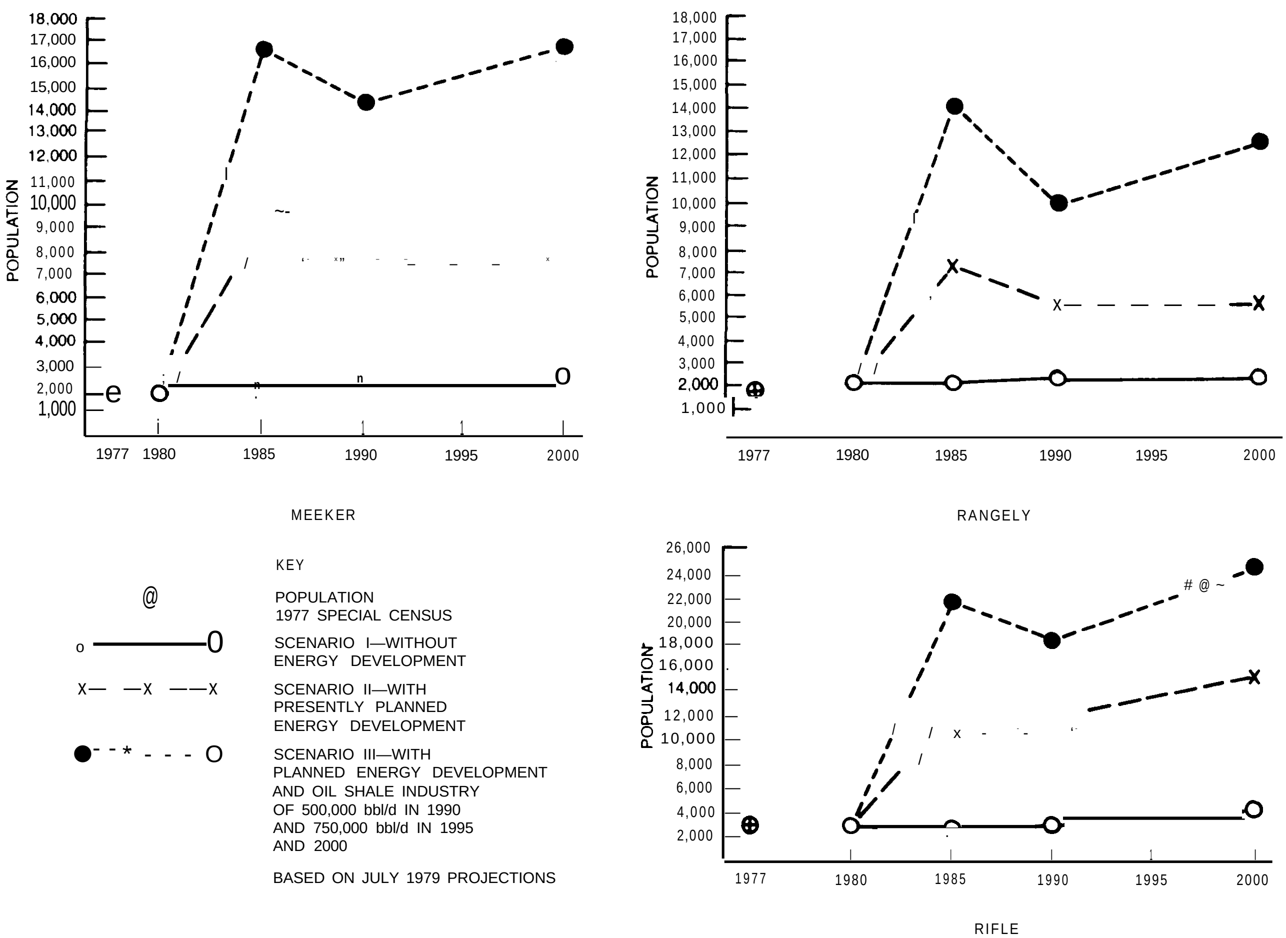
SOURCE Colorado West Area Council of Governments

Figure 72.—Population Projections for Colorado Oil Shale Counties by Development Scenario, 1980-2000



SOURCE Colorado West Area Council of Governments

Figure 73.—Population Projections for Selected Oil Shale Communities in Colorado by Development Scenario, 1980-2000



SOURCE Colorado West Area Council of Governments

growth. There are over 20 documents that identify specific needs expected to arise in the period between 1980 and 1985. * Examples in the following discussion have been taken from these various planning documents.[62]

Needs for the entire region are mainly in the areas of health and education; over 90 percent of them are for improving schools and upgrading hospital facilities. Technical assistance for CWACOG is also included.

*Because the needs appear in plans prepared by different groups at different times, a variety of CWACOG projections have been employed (see discussion at the beginning of the preceding section). For this reason, it is difficult to link specific requirements directly to the CWACOG population scenarios.

Table 101.–Projected Population Growth of Selected Oil Shale Communities, 1979-85

Community	Projected population 1979[a]	Projected population 1985[b]	Percent Increase
Rifle	3,200	22,060	589
Meeker	2,250	16,745	644
Rangely	1,900	14,088	641

[a]Estimate at end of year
[b]CWACOG Scenario III (does not include fringe areas around each town)

SOURCE OTA based on projections from the Colorado West Area Council of Governments

Compilation of regional requirements is complicated by overlapping or differing jurisdictions for a number of services. For example, the Valley View Hospital, located in Glenwood Springs, in a recent needs assessment included as a service area the central part of Garfield County. This portion of the county encompasses Rifle, site of the Clagett Memorial Hospital, and overlaps the Grand River Hospital District in which the Rifle hospital is placed. School districts, although not overlapping, encompass a number of different communities, which makes it difficult to separate their requirements from those of the municipalities. Sanitation and recreation districts with differing boundaries add to the complications.

For Garfield County, planning documents contain over two dozen projects needed between 1979 and 1984: 41 percent of them are in the area of education; 19 percent in the health and medical services; 15 percent in public services, especially water supply projects; 11 percent each in mental health and public facilities, the latter primarily roads; and 3 percent for welfare services.

Rio Blanco County and its communities, Meeker and Rangely, expect large growth from expanded shale development. For the period from 1980 to 1985, planning groups have identified five categories of needs for the county. About half are for public facilities and services: roads, highways, and bridges; airport improvements; trash compactors; a public safety building; and similar projects. Educational necessities, hospital improvements, recreational projects, and support for the planning infrastructure make up the remainder.

Needs From Oil Shale Development

Several different kinds of energy industry activities are taking place in the region. Unless it is rapid, the expansion of the oil shale industry, in and of itself, may not disrupt the communities of western Colorado; combined with accelerated coal development, oil and gas exploration and production, the installation of electric generation plants, and the possibility of other synthetic fuel activities, the effects could be devastating. Separating the potential consequences of shale development from the combined effects is difficult, and local planners do not try to do so. The following discussion emphasizes oil shale development while recognizing that it will occur in the larger context.

Mesa County

The effects on Mesa County depend on the location of development. At present, between 30 and 40 percent of the employees at Logan Wash facilities operated by Occidental Oil Shale, Inc., live in the Grand Junction area, and further development along the southern rim of the Piceance Basin would add to these direct effects in the county. Otherwise, they are likely to be indirect, taking the form of demands on the transportation and service sectors, both public and private, and on support industries. Benefits, such as increased revenues and cash flow, will occur when shale workers go to Grand Junction to purchase goods and services.

De Beque is the Mesa County community now experiencing direct effects of oil shale development activities. It is the nearest community to Logan Wash and exemplifies several of the problems associated with boomtown growth. It is located in Mesa County, while Logan Wash is in Garfield County; thus tax revenues from the energy development accrue to a jurisdiction different from the one receiving the impacts. De Beque has had difficulty preparing for increased growth, particularly in dealing with the effects of inflation. A 1976 study detailed the improvements needed by the water supply system. It estimated the costs at $608,000; when bids were opened in 1978, they came to $787,000; but only $500,000 was available. The city was unable to assume any additional debt and had to turn to the State for help. When completed, the facilities will be adequate for the present population but would have to be expanded if a large number of new residents were to be accommodated.

Garfield County

In 1975, the Colony Development Operation proposed that a new residential community, to be called Battlement Mesa, be constructed south of the Colorado River near Grand Valley. The Garfield County commissioners granted zoning approval for the development of 7,000 housing units for up to 21,000 residents, to be constructed over a 10- to 15-year period. Colony invested a little over $3 million in land acquisition and related activities for Battlement Mesa. The new town was designed to serve the Colony shale activities on Parachute Creek; actual development of the site was suspended when the company chose not to move ahead with its plant. It is probable the new town will be constructed in the 1980's.

RIFLE

Rifle is the community displaying the most visible effects of shale development activities. It is estimated to have grown by about 1,000 residents from the 1977 census figure of 2,244. Using the increase in the value of building permits as an indicator, it has grown about 45 percent in the past 2 years, A population of 10,000 has been used as the target for planning purposes, and city officials feel this number could be accommodated within the next 3 to 5 years. Over 40 projects have been identified as needed between 1979 and 1984 to ease the effects of this expected growth. About half of these are for public facilities, mostly water supply projects and public buildings. About 10 percent are for roads, and another 10 percent for public services, such as a new fire-rescue vehicle. Educational expansion, including programs and buildings, account for another 10 percent, with housing, health, and recreation projects representing the remainder.

Rifle is beginning to display some symptoms of boomtown stress. The incidence of reported spouse and child abuse is increasing. Statistics maintained by the police department show a rise both in the number of juvenile crimes and in cases of substance abuse; alcohol abuse is the biggest problem. Mental health personnel note an increase in the number of individuals having problems in their relations with other people. Consistent data col-

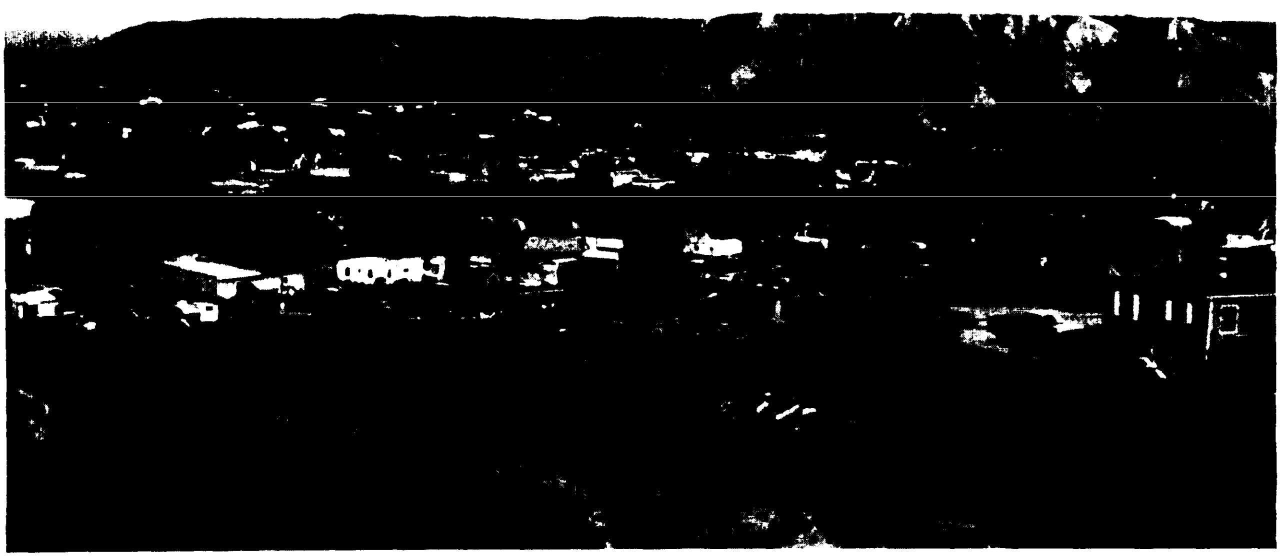


Photo credit OTA staff

View of Rifle, Colo.

lected over several years are not available in these categories, but what has been obtained points to the emergence of increasing social and psychological stress.[64]

A large number of retired persons live in the area, and more than 20 percent of the population is estimated to be over 60 years old. A number of programs have existed for several years for these residents, and they themselves are active advocates for their interests. Should the current rate of inflation be compounded by increased costs from rapid growth those who live on fixed incomes would suffer even more than they are now.

For some time, Rifle has had severe traffic congestion. The main highway to the north goes through the middle of town, passing the elementary and high schools. Dust and exhaust fumes, particularly from trucks, have polluted the downtown area. It has taken a long time to correct the problem because of the necessity to coordinate plans with the State highway department. City services have been hampered by a lack of adequate office space. Rifle is in the first stage of a planned three-stage water expansion project. The entire project will accommodate 10,000 residents, in increments of 3,000 to 3,500 per stage. The sewer system is also currently being upgraded.

Sufficient land is available for about 1,700 new housing units; construction has been underway in recent years. The junior high school building is being expanded and, on completion of the addition, will become a combined junior-senior high school, A new elementary school is needed and the city has applied to the State for assistance in its construction. The hospital needs to expand its outpatient facilities. The nursing home is operating almost to capacity, and will soon require repairs and renovation.

OTHER GARFIELD COUNTY COMMUNITIES

Grand Valley reflects the types of difficulties faced by communities living with the uncertainties of energy development. Several years ago, in anticipation of growth from increased oil shale development, the school was expanded. Because the expected growth did not come to pass, the school is presently operating below capacity; and the citizens, while desiring it, view current promises of development with some skepticism.[65] Like Silt and New Castle, Grand Valley has had to place a moratorium on new building because the water and sewer systems are operating at, or beyond, capacity. The town applied for an EPA construction grant for a new sewage treatment facility in 1976 but did not know if it would receive the funds until 1979. In the interim, it tried to obtain money from the Colorado Department of Health, but was unsuccessful. Although the EPA grant, plus assistance from the Oil Shale Trust Fund, has now been received, the site had not been approved in mid-l979.

Silt is one of the fastest growing communities in the valley. The population doubled between 1970 and 1977—from 434 to 859—and the town planner believes it was close to 1,000 at the end of 1979.[66] The CWACOG projections estimate 1,211 by the end of 1980 under energy development conditions (Scenario II). Current plans call for public facilities to accommodate 2,800 residents by the mid-1980's. These facilities include an improved water supply and an expanded sewer system. The sewer system improvements are currently in the design phase and the water system is already being upgraded. Like many small communities, the town lacks sufficient skilled manpower. There is only one police officer and no budget for additional personnel. Only two people are in the public works department, and they cannot keep up with the increased workload.

In New Castle, ultimate growth probably will be limited by the availability of land, since the town is located in a fairly narrow part of the Colorado River valley. The official CWACOG energy development projections estimate a population of 1,055 in 1985 and 1,608 by 2000. The city is now improving its water supply and distribution system to permit additional growth; a moratorium on new water taps was necessary after a new elementary-junior high school facility was opened. A revitalization of coal mining in the area could combine with oil shale development to add to growth pressures in the town.

Because Glenwood Springs, the county seat, is located in the eastern part of Garfield County, the community will experience more secondary than direct effects. The city has been growing mainly from recreational development in the Aspen and Vail areas. If the communities down the Colorado River valley are unable to cope with rapid growth, the consequences will extend to the Glenwood Springs area.

In sum, Garfield County has received most of the growth so far from oil shale development. This growth has been combined with the expansion of other industries and, as a result, the county has been pressed to meet the needs of the new populace. All the communities in the area have increased population, and three have had to place moratoriums on new construction because of inadequate water and sewer systems. Rifle should be able to accommodate a population of 10,000 if current plans can be completed, but is already beginning to experience some of the symptoms of boomtown conditions. If accelerated growth occurs, Rifle will need additional funds in order to make public facilities and services available to the new residents, and will have to increase its efforts to prevent social and individual stress.

Rio Blanco County

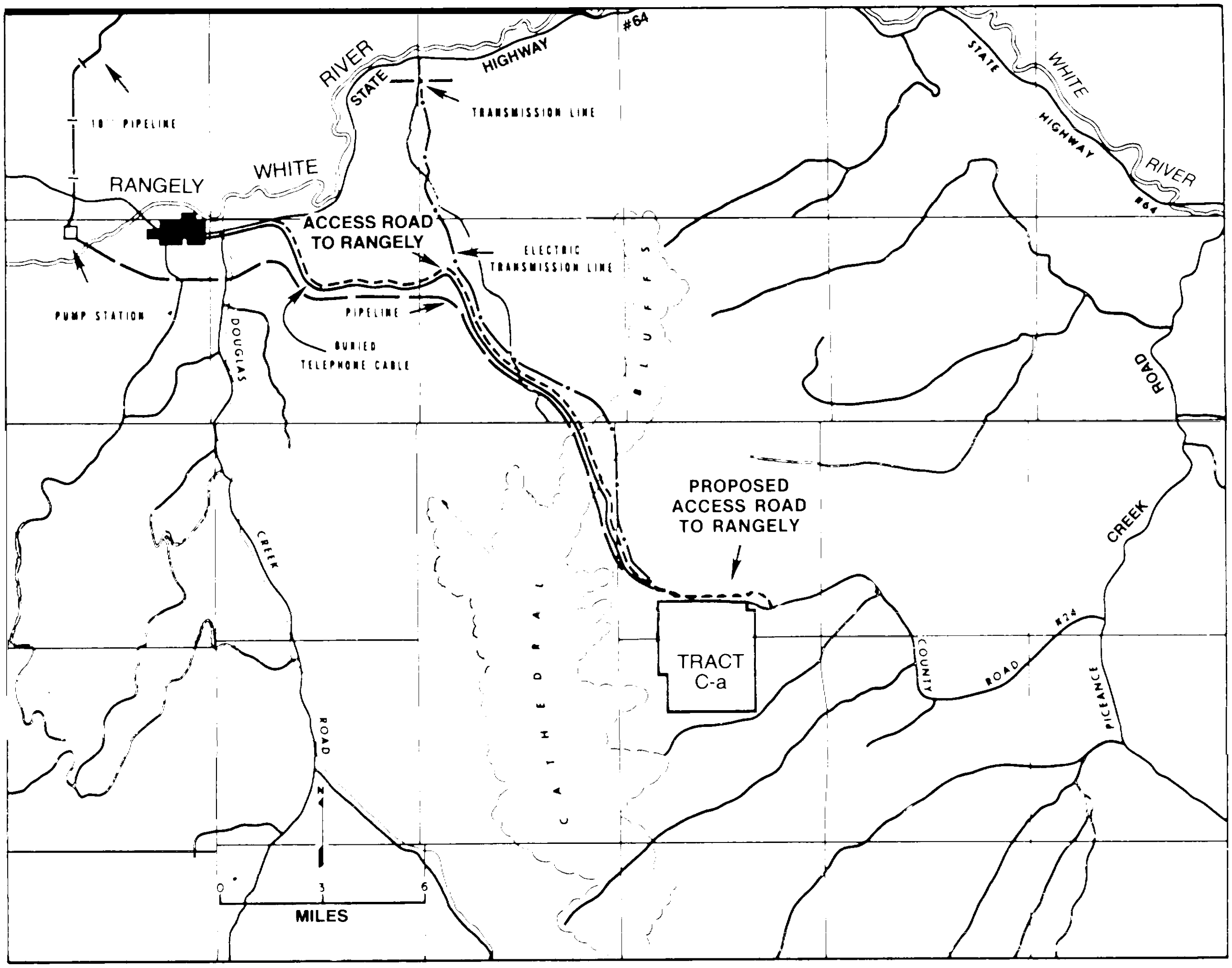
In anticipation of future growth, a significant planning effort has been underway for a half-dozen years, zoning and other growth-control laws have been enacted, and support for these measures appears widespread. Roads have been a longstanding need but their cost has proven a barrier to construction. Extension of County Road 24 from the C-a tract site to Rangely was proposed by the developers in their early plans (see figure 74); however, the State legislature has been reluctant to appropriate funds for construction, A feasibility study of 10 alternatives was made and 1 was recommended to the State: planning for it is now underway, Timing is critical; if the C-a tract begins production and the road is not available, permanent employees will choose to live in Meeker or Rifle, both of which are now closer. Without this access, the opportunity to allocate some of the county's growth to the Rangely area will be forfeited.

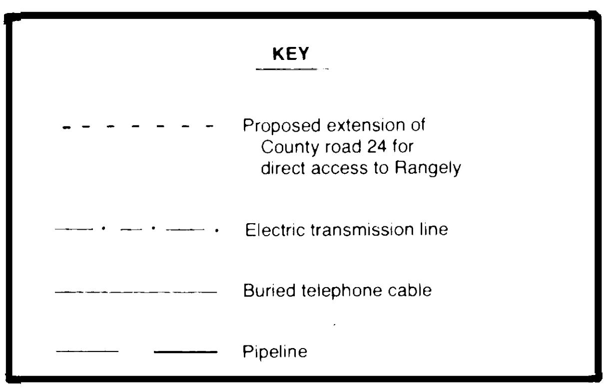
MEEKER

Meeker grew about 15 percent between 1970 and 1977; its estimated population in 1979 was 2,250 to 2,300.[67] The community's physical infrastructure (e.g., water, sewer, streets), when current improvements are completed, could support between 4,000 and 5,000 residents; this figure may be reached in 1982 or 1983. However, the growth rate could accelerate. For instance, the draft EIS for the proposed Superior development, in projecting cumulative growth for its own and seven other energy projects,[68] places Meeker's population at 5,077 in the first year of operation, a doubling of the present estimated population in one calendar year. Even this projection could be low, since there are more than this number of possible projects under consideration by different industries for the area.

Of the needs identified by local officials, 55 percent are for public facilities and services, 15 percent for the schools, 19 percent for recreational projects, 9 percent for day care and senior citizens' support, and 2 percent are for hospital projects, Housing so far has kept up with demand. In the immediate area, four subdivisions are under construction, and a mobile home park has been approved. Under review, but not yet approved (in late 1979), were another mobile home park and a number of smaller subdivisions, none of which is presently within the Meeker water service area. Furthermore, the town is presently committed to the subdivisions now being built for 100 percent of its available water taps. Although the streets within the large subdivisions will be built by the developer, the town must provide the main arteries to those areas. The wastewater treatment plant is committed almost to capacity, and planning has started for its expansion.

Figure 74.— Area of Proposed Road From Rangely to Oil Shale Tract C-a





SOURCE 1977 Ad Addendum to the Rio Blanco Oil Shale Project Social and Econmic Impact Statement.

The construction of water and sewer facilities is an example of the kinds of projects requiring adequate leadtime. If Meeker fails to begin preparing to expand its water supply and sewage treatment capacity now, it will not be able to absorb increased growth in 3 to 5 years. These kinds of improvements also serve as examples of the financing difficulties faced by rural towns. In constructing its present water system Meeker created a $2.4 million debt that requires an annual debt service equivalent to 20 mills of the property tax levy.

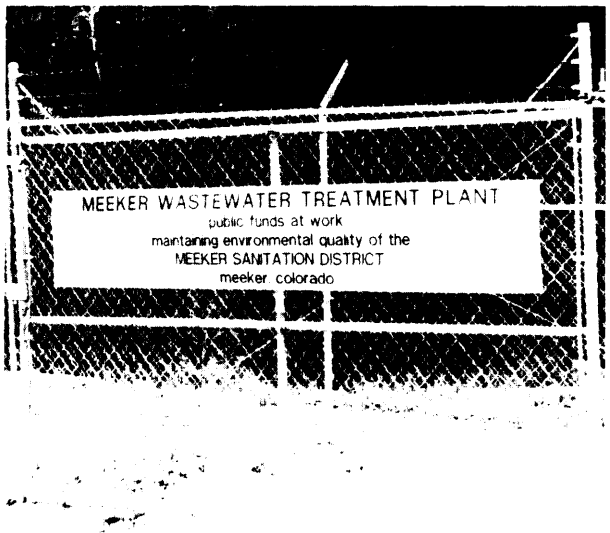


Photo credit: OTA staff

Approximately $760,000 will be required to expand the storage capacity of the water system and $2.5 million to upgrade the wastewater treatment plant. Thus, the city is facing a potential additional debt of over $3 million in the next 3 to 5 years.

Meeker also reflects some of the administrative difficulties faced by growing towns. Colorado's statute, which restricts spending by municipalities (except home-rule cities) to a 7-percent increase over the annual property tax revenues,[69] means for Meeker that the maximum the town can increase its spending is about $3,000 per year. Recently, the annual inflation rate has approached 16 percent, which makes such a small increase essentially nil in real revenues. The statute does provide for some administrative relief with the approval of the State DLA but an application for an exemption filed by the city in 1976 was turned down. A manpower shortage plagues the city government. During the summer, when demands for labor are highest, the town has used inmates from the jail for assistance. According to the town manager, all of the municipal government staff but two are paid salaries lower than the HUD poverty guidelines for rural Colorado.[70]

Overall the incidence of symptoms of social stress has not been increasing at the rate seen in other towns. A shift in the types of crimes committed has been noted, with increases in thefts, bad checks, and drug-related incidents; and a rise in the number of runaways has occurred in recent years. The number of cases reported by the police has increased at a faster rate than the population growth. ” The hospital outpatient services are operating at capacity; an additional emergency room and laboratory are pressing needs. The school district is operating below its total capacity but some of the individual schools are full. A new elementary school will be needed between 1981 and 1982.

Attitudes about growth have been divided. In a survey conducted in 1974, 35 percent of the respondents agreed and 53 percent disagreed with a statement that the majority of growth from resource development should occur in Meeker. The town manager said in 1979[72] that he felt the community wishes enough growth to pay the indebtedness incurred by construction of public facilities and to provide new amenities such as a larger supermarket and expanded recreation facilities.

RANGELY

Rangely finds itself in the paradoxical position of desiring additional growth but foiled in its efforts to obtain it. The biggest difficulty has been gaining improved access to oil shale activities. The proposed road to tract C-a was discussed above. Rangely's earlier experiences with oil and gas booms have made the town receptive to energy development and the residents feel that growth from an ex-

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panded oil shale industry would be beneficial.

In addition to the access road, a dozen projects are judged to be needed by 1985. Half of these are for public facilities, such as a water supply pipeline to areas of new home construction. With improvements, the water system could serve a population of about 11,000 and the sewer treatment facilities are adequate to serve 10,000 people if the sewer mains can be upgraded. Because of the need for these improvements, however, the capacity of the town between 1985 and 1990 is estimated at only 6,000 residents.[73] Like most rural health care facilities, the Rangely Hospital has had to defer some maintenance and equipment needs in order to meet operating expenses but will have to take care of them before services can be provided for a larger clientele.

Recent school construction has provided sufficient capacity to absorb more pupils, but this again reflects Rangely's paradox. If the town is unable to attract more families, the expansion of the schools will leave the buildings half-full and the remaining residents burdened with the debt of the expansion. The optimism of the citizens is reflected in their willingness to approve construction of a new indoor recreation facility that opened in the late spring of 1979.

The Rangely area has a strong feeling of identification with eastern Utah. The town is located about 15 miles east of the border. It is a little over 45 miles to Vernal, Utah, less than the distance to Meeker (57 miles) and to Grand Junction (85 miles). The road to Grand Junction goes over Douglas Pass (8,628 ft), making the route less appealing than the flatter highway to Utah. For these reasons, it is easier for Rangely residents to travel to Vernal. Colorado officials have sometimes acted in a way that the residents view as reinforcing their links with Utah; it took about 40 years to get the State to build the road over Douglas Pass. If the region experiences rapid

Photo credit *OTA staff*

Recreational facility in Rangely, Colo.

growth from oil shale development, the feelings of being ignored could add to other negative impacts. Moreover, if the oil shale activities are in Utah but the workers live in Colorado, a prime example of the problems of jurisdictional mismatch will occur.

In sum, Rio Blanco is the least populated county with the most limited highway system. Planning is well advanced with provision for extensive community participation. Some urgent needs, such as improved access to the Federal oil shale tracts, have not been met with as rapid a response as the local citizens might have wished; the State legislature has been reluctant to appropriate the large sums necessary for these projects. Rangely desires growth but will not receive much if a road to tract C-a is not constructed; Meeker is less inclined to have more growth than it has already gotten from coal development, yet may have to absorb new population from oil shale activities.

Summary

The socioeconomic consequences of oil shale development depend, among other things, on the location of the activities. Increased development of the private lands along the southern rim of the Piceance basin will lead to growth in Garfield and Mesa Counties and the communities of the Colorado River valley. Additional activity on the Federal lands in Rio Blanco County will mostly affect Meeker and Rangely, although Rifle could grow as well from this expansion. In Moffat County, Craig could be influenced by activities in the northern section and, if development occurs in Utah, Dinosaur and Rangely would be directly affected. Growth will tend to concentrate in established communities where services are already available. The limited surface transportation system will also foster concentration. In Rio Blanco County it is encouraged by a zoning policy that is intended to direct growth to Meeker and Rangely.

The needs by county and community between 1980 and 1985 are summarized in table 102. The table shows clearly where the local leaders see the greatest constraints on growth: water supply systems for the municipalities, schools, and medical and health services and facilities. Several towns indicate a need for more personnel. Rifle and Meeker are the communities with the largest number of priorities. Assuming that the projects now underway are completed, Rifle should be able to absorb, between 1985 and 1990, up to 10,000 people, The other Garfield County communities in the oil shale vicinity could accommodate about 7,000 and the rural areas between 1,500 and 2,000 persons. If construction were started immediately, the new town of Battlement Mesa might house 2,500 people by 1985. In Mesa County, De Beque might be able to accommodate a total of 700 to 1,000 but most workers from the southwestern part of the Piceance basin will probably reside in the Grand Junction area. In Rio Blanco County, both Meeker and Rangely are judged to be capable of providing for 6,000 persons apiece, " A total of 2,000 people might live in the rural areas. Altogether, by 1985 Garfield County could accommodate about 21,000 and Rio Blanco about 14,000, for a total of 35,000 residents. (See table 103,)

Other than the planning efforts of CWACOG, no systematic evaluation of the full range of consequences for the entire region is being undertaken. For example, the draft EIS for the proposed Superior Oil Co. project [75] discusses, in the section on cumulative impacts, seven other activities that might interact with the Superior development. However, a total of 30 energy-related projects are identified by CWACOG and impact studies as possibly affecting the region. Similarly, planning documents give attention to individual counties or communities but do not address areawide problems in detail. For instance, the relationships and responsibilities of local, State, and Federal government agencies are critical for communities facing boomtown conditions, but they are not dealt with in any of the plans. Jurisdictional mismatches also are seldom addressed. Development on pri-

Table 102.–Priority Needs Identified by Oil Shale Counties and Communities, 1980-85[a]

Source of request	Municipal facilities	Public buildings	Water	Sewer	Public facilities	Flood control	Roads and streets	Housing	Schools and education	Public safety	Medical and health	Community services	Parks and recreation	Miscellaneous[b]
Regional									•		•			•
Mesa County	•	•	•	•	•				•					
De Beque			•											
Garfield County		•	•		•		•		•		•	•		
Grand Valley			•	•					•				•	•
New Castle			•											
Rifle	•	•	•	•	•	•	•	•	•	•	•	•	•	
Silt	•	•	•					•					•	•
Rio Blanco County					•		•		•	•	•		•	•
Meeker	•	•	•	•		•	•		•	•	•	•	•	•
Rangely	•	•	•		•	•	•		•		•	•		
Moffat County	•	•	•	•	•		•		•	•	•	•		
Dinosaur			•										•	

[a]See ref 62 for listing of sources of needs
[b]Includes support for planning infrastructure and personnel needs of local agencies

SOURCE Office of Technology Assessment

Table 103.–Actual and Projected Population and Estimated Capacity of Oil Shale Communities in Colorado

	Population		
Location[a]	1977 census[b]	1980 projected	1985-90 capacity[d]
Garfield County			
Rifle	2,244	4,362	10,000
Silt	859	1,211	2,800
New Castle	543	831	1,000
Grand Valley	377	589	3,000
Battlement Mesa[e]	—	198	2,500
Other[f]	–	–	1,700
Subtotal	4,023	7,191	21,000
Rio Blanco County			
Meeker	1,848	2,779	6,000
Rangely	1,871	2,223	6,000
Other	1,381	1,542	2,000
Subtotal	5,100	6,544	14,000
Total	9,123	13.735	35,000

[a]Does not include Mesa or Moffat Counties both of which are more distant from the area of development
[b]Actuals from a special U S census
[c]End of the year projections by the Colorado West Area Council of Governments
[d]Estimated by OTA from various planning and needs assessments documents assumes completion of currently planned projects (e g housing water and sewer system expansions street and road improvements etc)
[e]A new town construction anticipated to begin in the early 1980s
[f]Includes only the immediate oil shale vicinity

SOURCE Office of Technology Assessment

vate oil shale holdings in Garfield County could cause rapid growth in Mesa County, and workers in Utah could reside in Colorado; neither problem has been systematically analyzed.

Potential Effects of Accelerated Development

The response of a given community to growth depends on a number of elements. Among these are:

- the absolute numbers and abruptness of the population influx;
- the attitudes of both long-term residents and newcomers;
- past experiences with boom and bust cycles;
- the ability of local political structures to prepare for population growth; and
- the availability of assistance—financial and other—for mitigation of impacts.

Whether the consequences of growth are favorable or unfavorable depends on whether the people can adapt to the stresses accompanying change. This ability is unique to each community and must be viewed as part of a dynamic set of complex events. Conclusions about the possible effects of future oil shale development must recognize the complex and changing nature of the different communities and of the events impinging on them.

Industrial expansion in western Colorado will have positive as well as negative consequences, In the economic sphere, a primary benefit will be increased economic activity. The direct effects of increased employment, higher wages, and stimulation of support industries and services would be felt throughout the region. Both the public and private sectors would benefit from industrial and services expansion. Towns and counties should enjoy a broader tax base. A sense of identity and pride, combined with an anticipation of the advantages of growth, have already been manifested. Planning activities, such as the preparation of the master plan for Rangely, have contributed to the public's expectations for the future. The successful operation of the task forces that propose solutions for growth problems is tangible evidence of increased sociological and psychological cohesion. The confidence that many local officials express in their community's ability to deal with growth is also an indication that, to date, the social consequences of oil shale development have been positive. The involvement of the oil shale developers in growth management efforts shows industry's responsiveness to the social effects of its expansion.

Oil shale development has been and will continue to take place concurrently with other activities, especially energy-related ones, such as coal, uranium, oil, and gas production. Dealing with the cumulative effects of all the growth may prove difficult. In addition, the nature of new oil shale ventures is unclear, Factors of particular importance for social and economic adjustment will be the:

- number—how many new oil shale developments occur;
- size—how large the facilities will be;
- location—where shale mining and processing activities take place;
- timing—when each is built and how this relates to other development;
- rapidity—how quickly any new ventures are built; and
- type—the nature of the technology and ancillary processes chosen.

The position of the State regarding both oil shale development and social and economic impact mitigation is also not certain. Until more is known about these factors, the exact nature of the population in-migration that will accompany new development cannot be adequately projected, nor can the full dimensions of the consequences, both positive and negative, be forecast. So long as oil shale development continues according to the plans already laid, the people of oil shale country should be able to adjust to the resulting growth. Only if expansion occurs suddenly or to a greater degree than now planned will boomtown consequences occur. (See ch. 3 for a further discussion.)

Issues and Policy Approaches

Summary of Issues

Identifying and Evaluating Social and Economic Impacts

In the usual course of economic development, Government assistance in coping with the consequences of growth is not a prime concern. One question underlying energy development is the distinction between effects that can be handled by local communities—that is, those that can be considered a normal concomitant of development; and those that are problems because they cannot be readily solved by local resources—boomtown effects. An example of criteria used to make this distinction is found in section 601 of the Powerplant and Industrial Fuel Use Act of 1978. These include increased employment of 8 percent or more per year in coal or uranium activities, a resulting or projected housing shortage, and inadequate State and local financial resources to meet needs over a 3-year period.

Thus far, Federal agencies have assisted in the identification of boomtown conditions mainly through data-gathering and information-sharing activities. With respect to evaluation, the position is that "local communities and counties must take the initiative to become involved in assessing, planning for, and mitigating socioeconomic impacts . . . ."[76]

The process of evaluating impacts involves their classification as either positive or negative. This requires making value judgments about what is good or bad for particular individuals, communities, regions, and the Nation. Often there are conflicts—what is seen as good for the Nation may entail difficulties for individuals or disruptions of communities. Additionally, what is judged as a positive impact for one group may appear as a negative one for a different group.

The process is further complicated because the basis for distinguishing positive from negative impacts is seldom clearly delineated, and the assumptions underlying the definitions of the two classes are rarely spelled out. As an illustration, concepts such as the "degradation of the quality of life" are used; and a variety of indices, like an increase in the number of visits to a mental health clinic, are cited to support the finding of "degradation." Yet there is hardly ever verification of the causal chain presumably linking rapid population influx to the indices and thence to perceived changes in the quality of life.

Finally, several of the most important boomtown consequences are hard to measure (for example, the ability of newcomers to adjust to an established community); and the changes in the social structure may not be manifested immediately. A question that has not received great attention is whether the long-term basic changes are more important than the immediate ones occurring at the onset of a boom.

The debates about oil shale development include conflicts involving these kinds of value judgments. On the one hand is the need for synthetic fuel production; on the other are the boomtown consequences for communities. Who participates in the definition of positive and negative impacts and in the resolution of the value conflicts that emerge is an important issue. At present, in Colorado, local groups play a large part in this evaluation. They identify the impacts they believe will affect their communities, decide which ones are severe enough to require corrective action, and participate in the decisions to allocate resources for mitigation. Federal programs designed to assist communities must recognize what has been done to date and face the issue of the allocation of responsibility for these decisions.

Determining a Maximum Growth Rate

How rapidly can the communities expand? How much growth can be accommodated before a community breaks down? The social and economic impacts of oil shale development will depend on the total number of newcomers, the rapidity with which they come into the area, the size of the industry's expansion, its location within the oil shale region, and the ability of the communities to prepare. The maximum amount of growth the different areas can accommodate without incurring boomtown consequences is a critical question.

Attempts to determine a maximum rate have discovered that generalizations are difficult to derive and that the capability to adjust to rapid growth turns out to be highly site specific. Whether communities will suffer from rapid growth or take it in stride depends on a unique set of factors within each individual community, for example, the threshold when negative impacts outweigh positive ones. Since the positive and negative impacts may vary from one town to the next, establishing this threshold is highly dependent on local conditions. In the past decade, identifying and measuring the social changes that accompany rural energy development have received increasing attention. The results have been an expansion of the factual base describing these changes, and a more systematic framework for seeking to explain them. To date, however, there are neither sufficient facts nor theories to understand fully why one town becomes vulnerable to boomtown impacts but a similar one does not.

No systematic study of the factors determining a maximum growth rate is being carried out for the oil shale communities. The groups presently involved in growth management and planning would benefit from a determination of thresholds of growth for their individual communities and policy makers could use this information when considering the rate of future development. The population of the Colorado oil shale region was about 10,000 in 1977 and is projected to be about 14,000 by the end of 1980. OTA estimates that the communities could accommodate up to 35,000 total residents during the period from 1985 to 1990. This assumes that construction of the new town of Battlement Mesa in Garfield County is started in the near future and that the existing communities can continue to improve their physical facilities and services. Boomtown symptoms could emerge at any time, however, if individual and social stress prevented adjustment to the growth.

The Mitigation of Impacts

Solving the problems of rapid growth involves local, regional, State, and Federal agencies. Questions about the role of the Federal Government fall into two categories:

- the extent to which the Federal Government should be involved, and
- the form the involvement might take.

The first category raises the fundamental question of whether the Federal Government should be involved at all. The extent and nature of Federal involvement in impact mitigation are controversial. On the one hand it is argued that social and economic impacts are State and local problems which should be viewed as the inevitable consequences of industrial development. On the other hand is the position that national requirements are the root causes of the local impacts, therefore an expanded Federal role is appropriate. Several Western States have taken the stance that expanded domestic energy production is a national goal and thus, for reasons of equity, the Federal Government should assume a more direct role in the alleviation of negative impacts from this development.

The second category deals with the nature of Federal involvement. One position states that present programs are sufficient but that the amount of money they provide needs to be increased. Another is that Federal regulation could be used to mitigate impacts by, for example, pacing industry's growth rate through leasing policies. A third position is that the Government should be directly involved in mitigation programs that use Federal funds.

The question of the effectiveness of mitigation programs arises as well. Some observers contend that the success of oil shale mitigation processes to date is proof of their effectiveness. Others maintain that the processes have never been adequately tested because rapid, large-scale development has not yet occurred, and that existing programs could break down under such circumstances. Most questions about the effectiveness of the processes relate to intrastate issues. For example, it can be questioned whether the legislative approach to disbursement of the Oil Shale Trust Fund deals adequately with the desires of the oil shale counties. The Federal Government could respond to such questions by, for example, providing funds directly to the communities. The desirability of such an action is a topic of current debate, however.

Increased Federal assistance probably will be required if the region experiences sustained rapid growth. This could come about from accelerated oil shale development, but is more likely to be the consequence of combined growth from several industries. Aside from the planning efforts of CWACOG, which are limited to northwestern Colorado, no systematic evaluation of the full range of effects from an increase in all types of industrial growth on the entire region is being undertaken. Thus, it is difficult to determine which types of Federal assistance might be the most productive.

Policy Approaches

Confronting the social and economic effects of an expanding domestic energy industry involves policies for all parts of the Nation. Concern for the consequences of oil shale development, however, for the time being centers only on northwestern Colorado, east-central Utah, and southwestern Wyoming. In addition, although the impacts themselves are basically similar regardless of the geographic region, the responses of particular communities can differ significantly depending on the State and location involved. Flexible policies are best, given this situation. The following discussion is concerned with policies that bear most directly on the effects of a larger oil shale industry.

Background

The initial action responsible for consideration, in public policy decisions, of the socioeconomic effects of Federal projects was the National Environmental Policy Act of 1969 (NEPA).[77] It requires Federal agencies to consider environmental factors in decisions involving "major Federal actions significantly affecting the quality of the human environment."[78] The broad wording of the Act has led to a considerable amount of litigation. In these court cases,[79] NEPA has been interpreted as granting authority for the imposition of conditions to mitigate adverse social as well as environmental impacts. As a result of the litigation, and subsequent regulations issued under NEPA, socioeconomic considerations have of late received greater emphasis in the preparation of EISs.

The Coastal Zone Management Act Amendments of 1976[80] set up a program of assistance for communities experiencing impacts from Outer Continental Shelf (OCS) energy development. Loans, loan guarantees, and grants are available to States and communities where an energy facility planning process has been established under the Coastal Zone Management Act of 1972[81] (CZMA). Site plans must include the identification and mitigation of anticipated adverse impacts from OCS-related development. The program is tied closely to land use planning mechanisms that State and local governments are required to develop if they participate in the coastal zone management program. The impact assistance portion depends upon the initiative of the States in meeting the CZMA requirements; Federal involvement is therefore indirect, in the sense that the policy makes Federal funding contingent upon the establishment of State and local land use planning processes.

In March 1978, DOE published for the Energy Impact Assistance Steering Group a Report to the President—Energy Impact Assistance.[82] The Steering Group, composed of representatives from Federal, State, local, and

Indian Tribal governments, was established following a meeting of several Governors with the president in mid-1977. At that time the Governors expressed concern for potential adverse results from the 1977 National Energy Plan. Four policy options were presented representing "different points along a continuum ranging from minimal new efforts to undertaking major program reform and investment of substantial new Federal funds,] (See table 104.)

In an effort to pull together the various Federal programs that can assist communities, the Region VIII FRC has created an Energy Impact Office. Its establishment was a direct response to recommendations of the National Governors Conference and of the General Accounting Office (GAO) .8' A GAO report, published in 1977, concluded that at that time the need for additional Federal assistance to impacted communities had not been demonstrated, Among its conclusions, the report stated:

> Rocky Mountain State and local governments should be primarily responsible for providing facilities and services prior to or concurrent with population increases , . .
>
> It is not industry's responsibility to provide the facilities and services needed because of energy resource development. But industry does have a strong and continuing responsibility to communicate its plans to State and local governments, as soon as possible, and to establish and maintain a continuing liaison with these governments,
>
> The Federal Government should continue to provide some assistance ., . (but) the need for additional Federal assistance at this time has not been demonstrated.
>
> GAO believes there should be some assurances that impacted communities will receive funds available to mitigate the socioeconomic impacts of energy resource development.[85]

A theme running through each of these Federal policy documents is that the Federal role regarding the social and economic effects of energy development should be primarily indirect assistance. Examples are providing funds to the States and improving the delivery of existing Federal programs (e.g., the establishment of a "one-stop shopping center" where local officials can go to determine whether their towns are eligible for the many Federal programs already available).

A recent departure from this theme is found in the Energy Impacted Area Development Assistance Program that was enacted in the Powerplant and Industrial Fuel Use Act of 1978 (sec. 601).[86] This program, administered by FmHA, is designed "to help areas impacted by coal or uranium development activities by providing assistance for the development of growth management and housing plans and in developing and acquiring sites for housing and public facilities and services. " The probability of greater Federal involvement in the direct amelioration of impacts is reflected in the amendments to the Powerplant and Industrial Fuel Use Act considered during the fall of 1979. A review of the problems, legislative issues, and proposals being considered by the 96th Congress is available in a Congressional Research Service (CRS) study titled Energy Impact Assistance: A Background Report prepared for the Senate Committee on Energy and Natural Resources.[87]

In general, the Western States have adopted policies that supplement and fill gaps in Federal programs. Colorado provides funds, from Federal revenues and a State severence tax, and technical assistance to counties and towns with growth problems. The State's position is that local initiative must be central in the mitigation process. As a result, sentiments are strong among leaders in Colorado's oil shale communities that local government should play a significant part in the control and management of growth.[88] For a number of years, because of the delays in oil shale development, these leaders were skeptical about its eventual occurrence; now they are fearful that a national crash program might ignore the plans that they have so carefully laid and cause a population surge that the communities could not absorb. Utah has

Table 104.–Selected Policy Options, 1978 Report to the President

Need areas	Option A Expansion of industry role and modification/reprioritization of existing programs	Option B Enhancement of State, local, and Tribal capabilities through new initiatives and programs	Option C Modification and expansion of existing programs to assure greater Federal share of long-term costs	Option O New Federal grant program to pay long-term costs
Information	implementation or national energy information systems by DOE with State/local/Tribal access to certain NEIS data Encourage States to require in-m-industry release of employment, population, and siting data for proposed projects as precondition for receipt of certain State/local permits (water, construction, etc)	Opation A, plus nave appropriate Federal agencies give prior notification to State/localities, and Tribes of BLM, OCS leasing plans, decisions and other data related to industry projects proposed to Federal agencies, improve conformance with NEPA and A-95 review processes	Option B, plus establishment by DOE of a new information system to gather and disseminate impact assistance related data from energy developers ($1 5 million).	Option C
Participation in decision making	Continued ad hoc efforts by State/ local governments and Tribes to impact Federal decision processes on energy resource development and project siting.	Issue Presidential Executive order requiring Federal agencies to provide for State/local/Tribal involvement m all energy development decisions affecting their jurisdictions, and to provide for consideration of the findings of the impact assessment teams prior to final decisions.	Option B, plus establishment of due process mechanism to review appeals of Governors/Tribal officials.	Option C
Planning and management	Conduct joint Federal/State/local/Tribal impact assessments Provide Federal technical assistance and information to commu - mties which are now, or expected to experience energy development Increase funding under selected existing planning program by $20 million and target to energy impact areas	Option A, except Incorporate new planning monies into proposed comprehensive State energy planning and management bill, and specifically target new funds to support State/local/Tribal participation on assessment teams and ongoing impact-related capabilities. A set-aside of funds for Tribes would be provided. Also, bonus funds for States with energy facility - siting mechanisms.	Option B, plus require all Federal energy decisions to be compatible with approved State impact mitigation strategies	Option B • Establish Federal/State assessment teams as specified. • Federal assistance to State to develop facility - siting mechanisms and to provide intial and second-round planning grants ($1 5 million). • Federal compatibility requirement
Coordination of assistance programs	Expand the role of the Federal Regional Councils in coordinating and packaging assistance funds to energy-impacted areas, make greater use of joint funding authority.	Option A, plus designate DOE as lead agency to oversee and support coordination of programs at the regional level through an interagency board	Option B, plus issue Execu- We order mandating appropriate Federal agencies to support FRC efforts and to give priority consideration to funding requests channeled through this mechanism	The Federal agency designated as the lead assessment agency would be responsible for coordinating all relevant Federal programs,
Financing	Modify requirements of selected existing programs to provide for eligibility and priority for funds to impact areas (within existing statutory limits) Increase funding of selected programs by $30 million to offset reduction in funds for other pri - ority needs (e g , urban poverty) Give priority to States, etc , securing industry cost-sharing Possible amendment to Federal tax code to encourage prepayment of taxes by Industry	Establish Federal loan and loan-guarantee programs in EDA with forgiveness provisions and competitive interest rates to be used by States, communities, and Indian Tribes ($75 million) Fund sec. 306 of the proposed Coal Conversion Act ($60 million) Give priority to States, etc , with energy facility-siting mechanisms	Option B, plus increase EDA funds by additional $50 million and authorize grants as well as loan/guarantees. ($125 million plus$60 million for 306). Priority to States, etc , with Increased commitment of State/local/Tribal revenues and facility siting procedures. Suboption Consolidate Coastal Energy Impact Program and sec. 306 program into EDA to create single, flexible program to relet Infrastructure needs m all States	Establish a new program to provide grants to the States for. –State revolving funds ($200 million) –Highways construction and railroad grade separations. –Mismatches ($10 million) (Interstate and State/Tribal) –Loan guarantees ($15 million). Fund housing support in sec. 306 but expand and augment to cover energy facility construction and 011 shale development ($60 million).
Annual authorization	$50 million	$160 million	$212 million	$300 million

SOURCE Department of Energy DOE /IR-0009, UC 13.

been faced with rapid growth from coal and uranium development, and has not planned extensively for oil shale activities. The State created a Community Impact Account in 1977 to provide loans and grants to areas impacted by mineral resource development. Because it is the only funding source in the State designed to respond to problems associated with energy development, requests for help have far outstripped the available monies. Wyoming does not anticipate consequences from shale development in the near future, The State has an array of mitigation programs dealing with other energy industry impacts that could be adapted to growth problems from accelerated oil shale activities.

Evaluation of Existing Policies

The diverse nature of present policies, Federal and State, makes their overall evaluation difficult. State policies vary: Colorado places emphasis on local initiative and advocacy, whereas Utah and Wyoming emphasize more centralized State determination of needs and allocation of funds. At the present time, there is no single Federal policy with respect to the social and economic effects of energy production. Some programs are operating that address certain aspects of these effects but, at present, none speaks directly to the general impacts that may come with synthetic fuel development nor to the specific effects of accelerated shale oil production. A limited amount of assistance is available through avenues not specifically designed to deal with energy development impacts, but these Federal programs each have different emphases and modes of providing help. While they may be adequately fulfilling their policy mandates, the specific nature of the mandates means that the entire range of problems is not being addressed. Additionally, even though steps have been taken to consolidate the fragmented nature of Federal programs, effective implementation of a more uniform set of practices has yet to reach the oil shale communities.

An increasing recognition of the problems caused by national energy decisions has led to several reviews of existing policies and to suggestions of ways to achieve a more unified policy. Congress has had before it proposals for a comprehensive inland energy impact assistance program, but to date none has been enacted. Up to the present, return to the States of portions of the lease, rental, and bonus payments for development on Federal lands has been the major Federal contribution to mitigation efforts.

Colorado has an ambitious set of policies and programs to assist with impact mitigation. Overall, these efforts have been successful in helping the oil shale counties and municipalities to get ready for shale development. The ability of existing policies to deal with a large or sudden population influx, such as might occur with the rapid expansion of the oil shale industry, is as yet untested. The uncertainties about the specific growth of the industry make it difficult to evaluate whether any policies—Federal or State—will be adequate to deal with the effects of rapid expansion of the industry.

Approaches to Impact Mitigation

There are three approaches available to Congress when considering the social and economic effects of oil shale development. The impacts can be viewed:

- as part of the consequences of all kinds of energy development;
- as an aspect of specific energy initiatives; or
- as the result only of shale development.

From the perspective of the first approach, oil shale impacts would be included along with the problems accompanying all domestic energy efforts. As noted above, Congress has recently considered bills providing comprehensive assistance for these problems, and programs for oil shale could be in such legislation. The second approach would place shale impacts along with those from other major national efforts. Proposed amendments to the Powerplant and Industrial Fuel Use Act of 1978 are illustrative. These amendments are directed to the adverse effects of major energy developments, which could include oil shale. They authorize grants, loans, loan guarantees, and payments of interest on loans, and propose an expediting process for present Federal programs as well as an inter-agency council to coordinate Federal assistance. The third approach sees the effects as the result of oil shale development alone. In this case, specific language dealing with socioeconomic impacts could be included in bills providing for the development of oil shale resources.

Regardless of the approach adopted for oil shale, there are three options that Congress can consider to address social and economic impacts.

CONTINUATION OF PRESENT PROGRAMS

Under this option, Federal assistance would continue to emphasize revenue sharing and technical assistance. Funding through existing channels, such as the Mineral Leasing Act, as amended, would be the major mechanism. Certain other existing Federal programs, not now designed to deal specifically with socioeconomic impact mitigation, could be redirected. For instance, EPA water and sewer grants could be accelerated, with additional appropriations made available and limited to impacted communities. Restrictions on existing programs could be modified. An example is Federal housing programs, now restricted to projects for low- and moderate-income families, that could be provided to rural communities undergoing rapid growth regardless of local income levels.

The advantages of this option are that it would require only minor adjustments to existing laws. Mechanisms for delivery are already in place. Flexibility would be maintained since the focus would be on already established programs designed to meet a variety of needs. The disadvantages include the possibility that the amount of aid might not be adequate to meet the demands of severely impacted communities. In this case, appropriations would have to be increased for some programs now being held at particular funding levels. The fragmentation of programs, now viewed by some States and localities as a barrier to efficient delivery of Federal aid, probably would not be reduced.

INCREASED FEDERAL INVOLVEMENT IN GROWTH MANAGEMENT

This option would emphasize regulation. Present Federal revenue sharing would continue. Several possibilities exist for increased growth management participation. consideration of social and economic effects on adjacent communities could be made a part of executive agency criteria when selecting Federal lands for energy mineral leasing. In this case, given natural resource deposits of approximately equal value, leases would be made available only in areas where the socioeconomic impacts could be minimized. Also, the number and timing of leases could be adjusted to take into account the ability of nearby communities to absorb growth. Finally, the lease provisions could include mandatory participation of lessees in mitigation efforts.

Greater involvement of Federal agencies in monitoring socioeconomic impacts and in providing assistance to mitigation efforts is another alternative. For example, the regulatory activities of the Area Oil Shale Supervisor's Office could be expanded to include monitoring social and economic indices in off-tract communities. Attention could be given to difficulties not now being systematically faced, such as interstate jurisdictional problems between Utah and Colorado. The Region VIII Energy Impact Office could have a field representative permanently stationed in oil shale country to provide the services of FRC locally. This representative could provide technical assistance to area planners and could address problems they are too busy to consider now, such as anticipating the post-boom period. Increased technical assistance could also address the problems of defining and identifying boomtown conditions. A determination of the maximum growth communities could sustain without experiencing severe disruption would be valuable for policymakers at all levels.

Identifying and evaluating social and economic impacts, determining a maximum growth rate for specific sites, and coordinating Federal programs are needed in all parts of the country experiencing energy-related growth, Thus, actions to deal with these problems would be of nationwide value, For this reason, R&D could be undertaken by any of several agencies on a national basis, and would not necessarily have to be limited to the oil shale region.

Among the advantages of this option is that it would supplement existing mitigation programs already established by local and regional entities. It would provide a link between Federal decisionmaking bodies and State and local agencies responsible for growth management. Access to Federal programs would be enhanced. Among the disadvantages are the increased bureaucracy needed to implement the option, and the possibility that local individuals would perceive the Federal efforts as increased infringement on their lives. Energy development companies would most likely object to additional lease restrictions and to required participation in mitigation programs. Executive agencies might find implementation burdensome.

EXPANSION OF FEDERAL PROGRAMS FOR IMPACT MITIGATION

Under this option, programs already enacted would be expanded or new ones adopted. The Powerplant and Industrial Fuel Use Act of 1978, section 601 program, is the obvious candidate for extension. Under this Act,[89] Federal assistance was provided for areas experiencing rapid growth from coal or uranium production. The assistance is aimed at improved planning for growth management, and for land acquisition for housing and public facilities development. Expansion of the program would include areas affected by growth from industries other than coal and uranium producers, and could encompass a wider range of problems than growth management planning and land acquisition. A bill to expand the section 601 programs is currently under consideration. *

The advantages of this option are that it expands an already existing program. The mechanisms for implementation are in place and have already been operating under the present law, Disadvantages include the need for increased appropriations to fund the various elements of the program and expansion of the Federal bureaucracy to carry out the Act's provisions. Some flexibility may be lost as uniform standards are applied to all States wishing to participate in the expanded program.

*S. 1699.

Chapter 10 References

[1]For a discussion of current controversies about the early inhabitation of the North American continent, see Graham Chedd, "On the Trail of the First Americans, " Science 80, vol. 1, No. 3, March/April 1980, pp. 44-51. For general information, see Handbook of North American Indians (Washington, D. C.: The Smithsonian Institution, 1979).

[2]Angelico Chavez (tr.), Ted J. Warner (cd.), The Dominguez-Escalante Journal: Their Expedition Through Colorado, Utah, Arizona and New Mexico in **1776** (Provo, Utah: Brigham Young University Press, 1976).

This was Powell's second expedition to the Rockies. It followed a trail pioneered by Berthoud in 1861; Jim Bridger served as guide. Powell's wife accompanied the group and was the only woman to spend the winter. Powell made a trip in November, which he nearly didn't complete, to get supplies at Green River City, Wyo, Powell's Park, a few miles west of Meeker, Colo., was the site of the "Meeker Massacre" in 1879, Here, a group of Ute Indians shot and killed Nathan Meeker and several other workers at the Indian Agency. See Robert Emmitt, The Last War Trail: The Utes and the Settlement of Colorado (Norman, Okla.: Univ. of Oklahoma Press, 1954) and Marshall Sprague, Massacre: The Tragedy at White River (Boston, Mass.: Little, Brown & Co., **1957).**

[4]The Ute Indians signed four treaties with the United States: in 1840, 1863, 1868, and 1880, See Gerald T. Hart, Leroy R. Hafen, Anne M. Smith, and the Indian Claims Commission, Ute Indians II (New York, N. Y.: Garland Publishing, Inc., 1974) and George E. Fay, Land Cessions in Utah and Colorado by the Ute Indians, **1861-1899** (Greeley, Colo.: Univ. of Northern Colorado, Museum of Anthropology, Misc. Series No. 13, **1970). See also** Emmitt, Supra No. **3.**

[5]Range wars erupted in the latter part of the 19th and early decades of the 20th centuries when sheep and cattle raisers fought over the use of the rangelands. See James H. Baker and LeRoy R. Ha fen (eds.), History of Colorado (Denver, Colo.: Linderman Press, **1927).**

[6]In **1901,** Roosevelt spent 5 weeks hunting mountain lion near Meeker; the party killed 14, of which the largest weighed over 220 lb and was over 8 ft long. In 1905, he returned for a bear hunt in the area south of New Castle.

[7]Bureau of the Census, County and City Data Book, 1977 (Washington, D, C.: Government Printing Office, **1978). See** also Colorado Department of Agriculture, Agricultural Land Conversion in Colorado (Denver, Colo.: Resource Analysis Section, **1979).**

'Bureau of the Census, Congressional District Data Book, 93d Cong. (Washington, D. C.: Government Printing Office, **1973).**

'’Frank G. Cooley, "The Growing Awareness of Oil Shale's Impact on Communities in Western Colorado, " Rocky Mountain Association of Geologists—1974 Guidebook to the Energy Resources of the Piceance Creek Basin, Colorado, 171-3.

'['Altogether, more than 20 studies were published between **1970** and 1977 dealing with one or another aspects of oil shale development. See, e.g., Oil Shale Regional Planning Commission and the Colorado West Area Council of Governments, Profile of Development of an Oil Shale Industry in Colorado (Rifle, Colo.: CWACOG, 1973), and Colorado West Area Council of Governments, Oil Shale and the Future of a Region: A Summary Report (Rifle, Colo.: CWACOG, 1974).

[11]Alys Novak, "Oil Shale—1976/1977, " Shale Country, vol. 2, No. 12, December 1976, pp. 2-6.

[12]Rio Blanco Oil Shale Project, Social and Economic Impact Statement—Tract C-a (Gulf Oil Corp. - Standard Oil Co. (Indiana), March **1976);** an Addendum was published in May 1977.

'[1]C-b Oil Shale Project, Oil Shale Tract C-b Socio-Economic Assessment, **2** vols. (Ashland Oil, Inc. - Shell Oil Co,: March 1976).

[14]Colony Development Operation, An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado (Denver, Colo.: 1974).

[15]Jonijane Paxton, "Whither Now, Battlement Mesa?" Shale Country, vol. **2, No. 6,** June **1976, p.15,**

[16]Western Environmental Associates, Inc., Baseline Description of Socio-Economic Conditions in the Uinta Basin and Socio-Economic Impact Study of Oil Shale Development in the Uinta Basin (Denver, Colo.: White River Oil Shale Corp., 1975).

[17]The five studies are:

a. Department of the Interior, Final Environmental Statement for the Prototype Oil Shale Leasing Program, 6 vols. (Washington, D. C.: Government Printing Office, 1973),
b. Rio Blanco Oil Shale Project, Social and Economic Impact Statement—Tract C-a (Gulf Oil Corp. - Standard Oil Co. (Indiana), March 1976), including 1977 Addendum,

c. C-b Oil Shale Project, Oil Shale Tract C-b Socio-Economic Assessment, 2 vols. (Ashland Oil, Inc. - Shell Oil Co., March 1976).
d. Department of the Interior, Final Environmental Impact Statement: Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, 2 vols, (Washington, D. C.: Government Printing Office, 1975).
e. Western Environmental Associates, Inc., Baseline Description of Socio-Economic Conditions in the Uinta Basin and Socio-Economic Impact Study of Oil Shale Development in the Uinta Basin (Denver, Colo.: White River Oil Shale Corp., 1975).

[18]Rio Blanco County Ordinances, sec. 1003; 1974.

[19]See Steve H. Murdock and F. Harry Leistritz, Energy Development in the Western United States—Impact on Rural Areas (New York, N. Y.: Praeger Publishers, 1979).

[20]It is difficult to place a dollar value on the contributions of industry, In Wyoming, the Missouri Basin Power Cooperative (a consortium of REA electric cooperatives) estimates that it spent $21 million in mitigation efforts in conjunction with the construction of the 1,500-MW Laramie River Station in Platte County. This included in-kind services; direct grants and revenue guarantees to towns, counties, and agencies; bond guarantees; and similar assistance. The cooperative believes it saved approximately $50 million in costs by reducing employee turnover and by allowing the plant to be constructed on schedule. Furthermore, they anticipate recovering all but about $3 million of the $21 million outlay as the bonds are paid and other revenues become available. Eventually the amount spent for mitigation probably will fall between one-half and 1 percent of the total cost of the plant. (Personal communication from Dr. James Thompson to OTA, Nov. 5, 1979.)

[21]Co1. Gen'1 Ass'y, H.B. 1200 (1974, 2d sess.).

[22]41 Stat. 437 (1920), as amended and supplemented, 30 U. S. C., sec. 181 et seq. (1976),

[23]C.R.S. 1973,34-63-104.

[24]C.R.S. 1973, 34-63-104 (l).

[25]C.R.S. 1973.34-63-104 (2).

[26]C.R.S. 1973, 34-63-101 and 102, as amended.

[27]C.R.S. 1973, 34-63-102 and 39-29-110.

[28]C.R.S. 1973, 39-29-101 through 114 (Supp. 1977).

[29]Personal communication, Stan L. Albrecht to OTA, Oct. 16, 1979.

[30]U.C.A. 1953, 63-51-1 through 4.

[31]U.C.A. 1953, 53-7-1 and 2; 65-1-64 and 65; and 65-1-115.

[32]U.C.A. 1953, 73-10-8 and 73-10-23.

[33]W.S. 35-12-101 through 121,

[34]W.S. 9-1-129 through 136.

[35]W.S. 39-6-412.

[36]Personal communication, Dr. James Thompson to OTA, Oct. 16, 1979. An example of an imaginative program is the Wyoming Human Services Project (WHSP). The WHSP program trained human service personnel at the University of Wyoming campus and then placed the students in Wyoming boomtowns for field experience. After completing the program, many students found jobs in the communities and stayed to continue their service. See Judith A, Davenport and Joseph Davenport, III, Boom Towns and Human Services (Laramie, Wyo.: Univ. of Wyoming, 1979).

[37]Personal communication, Dr. James Thompson to OTA, Oct. 16, 1979. See also Stan L. Albrecht, "Socio-Cultural Factors, " in Mohan K. Wali (cd.), Mining Ecology.

"Department of Energy, Report to the President—Energy Impact Assistance (Washington, D. C.: DOE/IR-0009, UC-13; March 1978).

[39]Supra No. 19. Under Public Law 95-238, DOE has awarded grants to Colorado and Utah for socioeconomic planning. Also, grants have been given to Rio Blanco and Garfield Counties and the the Northern Ute Indian Tribe.

[40]Supra No, 22.

[41]90 Stat. 1083 (1976), amending 30 U.S.C. sec. 201 et seq. (1976).

[42]90 Stat. 2743, (1976), 43 U.S.C. § 1701-1782 (1976).

[43]Supra No. 41.

[44]For a number of reasons, the loan program authorized by FLPMA has yet to be implemented.

[45]92 Stat. 3323 (1978).

[46]Ibid.

'department of Energy, Regional Profile—Energy Impacted Communities—Region VIII (Denver, Colo.: TIC-1OOO1, UC-13; 1979).

[48]Federal Energy Administration, A Report—Regional Profile—Energy Impacted Communities (Denver, Colo.: Region VIII Socioeconomic Program Data Collection Office, July 1977) pp. 5-6.

[49]For a complete discussion of alternatives, see Economic Impact of the Oil Shale Industry in Western Colorado, hearing before the Subcommittee on Public Lands of the Committee on Interior and Insular Affairs, U.S. Senate, 93d Cong., 2d sess., Jan. 19, 1974; Inland Energy Development Impact Assistance Act of 1977 (S. 1493), hearings

before the Subcommittee on Regional and Community Development of the Committee on Environment and Public Works, U.S. Senate, 95th Cong., 1st sess., August 1977 (ser, No. 95-H28); and Energy Impact Assistance Act of 1978 (S. 1493), hearing before the Subcommittee on Energy, Nuclear Proliferation, and Federal Services of the Committee on Governmental Affairs, U.S. Senate, 95th Cong., 2d sess., Aug. 18, 1978.

[50]C.R.S. 1973, 29-1-301 and 302.

[51]For an introduction to the boomtown literature, see Charles F. and Jane Archer Cortese, "The Social Effects of Energy Boomtowns in the West: A Partially Annotated Bibliography, " Council of Planning Librarians Exchange Bibliography No. 1557 (Monticello, Ill.) June 1978; and P. B. Allison, "A Bibliography of Bibliographies Connecting Energy and the Social Sciences, " Social Science Energy Review, vol. 1, No. 2 (New Haven, Corm.: Yale University Institution for Social and Policy Studies), spring 1978,61-70.

[52]John S. Gilmore and Mary K. Duff, Boom Town Growth Management: A Case Study of Rock Springs—Green River, Wyoming (Boulder, Colo.: Westview Press, 1975).

[53]Ibid., passim.

[54]Adapted from Ross M. Bolt, Dan Luna, and Lynda A. Watkins, "Boom Town Financing Study, " in Financial Impacts of Energy Development in Colorado—Analysis and Recommendations (Denver, Colo.: DLA, 1977), pp. 11-12.

[55]Study of these changes necessitates the combination of theory and data from several disciplines: sociology, psychology, anthropology, economics, and political science. Such a combination is difficult to accomplish given the differences between the disciplines. In addition, applied science of this kind is often viewed with a measure of disdain by some professionals within each field.

'0'' The Social Impacts of Energy Development in the West: A Symposium, " The Social Science Journal, vol. 16, No. 2, April 1979.

"Charles F. Cortese and Bernie Jones, "The Sociological Analysis of Boom Towns, " Western Sociological Review, vol. 8, No. 1, 1977, pp. 76-90.

[58]Ronald L. Little, "Some Social Consequences of Boom Towns, " North Dakota Law Review, vol. 53, No, 3, 1977, pp. 401-425.

[59]William R. Freudenburg, People in the Impact Zone: The Human and Social Consequences of Energy Boomtown Growth in Four Western Colorado Communities (unpubl. doctoral dissertation, Yale Univ., **1979).**

[60]CWACOG, Oil Shale Trust Fund Request (Rifle, Colo.: Nov. 1978), p. 6.

'0]The complete list of developments includes:

C-a Rio Blanco Oil Shale project (Gulf and Standard)

C-b Cathedral Bluffs Shale Oil Co. (Occidental and Tenneco)

Paraho (oil shale)

Snowmass/Anschutz (coal)

Mid-Continent Garfield I/Mid-Cont. Mesa II (coal)

Superior (oil shale and minerals)

Colowyo (coal)

Utah International (coal)

Colorado Ute (powerplant)

Empire (coal)

Moon Lake (coal)

GEX CMC (coal)

Sheridan (coal)

Energy fuels (coal)

Union Oil (oil shale)

Storm King (coal)

Colony/Atlantic Richfield and Tosco (oil shale)

Northern Minerals (coal)

[62]The complete list of documents consulted includes:

1980 Oil Shale Trust Fund Request

1979 Oil Shale Trust Fund Request

Housing Plan for Meeker, Colorado, **1979**

Northwest Supplemental Report—A Supplement to the Northwest Colorado Coal Regional Environmental Statement, Colorado

Development Guide for Meeker, Colorado—A Working Draft

Development Guide for Rifle, Colorado—A Working Draft

CWACOG New Housing Unit Needs, 1979

Rifle Needs Assessment

Meeker Five Year Capital Improvements Needs

Grand Valley School District No. 16—Estimated Needs 1980-1985

Meeker School District RE-1 Projected Needs

Meeker Regional Library Projected Needs

Pioneer Hospital, Rio Blanco County, Projected Needs

Five Year Capital Improvements Projection—Rio Blanco Criminal Justice

Rangely District Hospital Projected Needs

Colorado Northwestern Community College Long Range Plan

Grand River Hospital District

Rifle—Water Facility Needs (1980 - 1984)

Garfield County School District (Projected Needs)

Silt Projected Needs

Roaring Fork School District RE-1—Five Year Needs Assessment/Capital Improvements Plan

Valley View Hospital Needs Assessment

[63]Personal communication, Dan Deppe (city manager) to Dr. Donald Scrimgeour and Miss Ellen Hutt, July 1979.

[64]Donald P. Scrimgeour and Marilyn Cross, Development Patterns and Social Impacts: A Focus on the Oil Shale Region (Denver, Colo,: Quality Development Associates, July 1979).

[65]Discussion with Mr. Floyd McDaniel, Chairman, Planning Commission, Grand Valley, August 1979.

[66]Personal communication, Peter Kernkamp (town planner) to Dr. Donald Scrimgeour and Miss Ellen Hutt, July 1979.

[67]Personal communication, Bob Young (town manager) to Dr. Donald Scrimgeour and Miss Ellen Hutt, July 1979.

[68]Department of the Interior, Draft Environmental Statement: Proposed Superior Oil Company Land Exchange and Oil Shale Resource Development (Denver, Colo.: BLM, August 1979) pp. 77-90.

[69]Supra No. 50.

[70]Supra No. 67.

[71]Supra No. 64.

[72]Supra No. 67.

[73]Personal communication, Mr. William Brennan to OTA, January 1980.

[74]Ibid,

[75]Supra No. 68.

[76]Supra Nos. 47 and 48.

[77]83 Stat. 852 (1970), as amended by 89 Stat. 424 (1975), 42 U.S.C. 4321-4347.

[78]Ibid.

[79]See, for example, Calvert Cliffs Coordinating Committee, Inc. v. U.S. Atomic Energy Commission, 449 F.2d 1109 (D.C. Cir. 1971), cert. denied, 404 U.S. 942.

[80]90 Stat. 1013 (1976), 16 U.S.C. 1451-1464.

[81]86 Stat. 1280 (1972), 16 U.S.C. 1451-1464.

[82]Supra No. 38.

[83]Ibid., pp. 59-81.

[84]Rocky Mountain Energy Resource Development: Status, Potential, and Socioeconomic Issues (Washington, D, C.: GAO, July 1977), EMD-77-23.

[85]Ibid., pp. 5-7.

[86]Supra No. 45.

[87]Energy Impact Assistance: A Background Report, printed at the request of the Committee on Energy and Natural Resources, U.S. Senate, 96th Cong., 1st sess., October 1979 (publ. No. 96-34) (committee print).

[88]For a spirited elucidation of this position, see Raymond L. Gold, "On Local Control of Western Energy Development, " The Social Science Journal, vol. 16, No. 2, April 1979, pp. 121-127.

[89]Supra No. 45.

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Appendixes

Description and Evaluation of the Simulation Model

To evaluate quantitatively the alternative incentives, a computerized model was used, developed by Tyner and Kalter[1] that captures the probabilistic attributes of the oil shale development process through Monte Carlo simulation techniques. The core of the model is a discounted cash flow algorithm computing the after tax profit.

In computing aftertax profit, the model uses a conventional discounted cash flow algorithm in which the net cash flow for each year (i. e., revenues less costs and taxes) is discounted to the beginning of the project. These discounted cash flows are then summed to arrive at the aftertax net profit.

With the model, the user can input probability distributions of prices and costs instead of single value estimates. The model then constructs a probability distribution for aftertax profits using the Monte Carlo method. With this method, the model makes repeated runs in which profit is calculated. In each run the model randomly selects values from the input distributions. The resulting profit calculations are then cumulated into probability y distributions characterized by an expected value and standard deviation, The expected value gives the average profit for all the Monte Carlo runs and the standard deviation provides a measure of dispersion or variation about this average value. The model also totals the number of Monte Carlo runs that results in positive profits and plots a histogram of the frequency distribution of the profit outcomes, From this output the user can compute the probability that a loss will be incurred.

Although the model was designed to test the effects of alternative mineral leasing systems on profits and Government revenues, it incorporates several financial incentives, including construction grants, price supports, purchase agreements, investment tax credits, depletion allowances, and variable depreciation schedules. Indeed, its authors used an earlier version to evaluate the effects of some of these incentives on the profitability and risk of oil shale development. ’

However, because the model was not designed specifically to test incentives, it has several limitations. First, it does not provide for inflation indexing of the floor price under a price support program. Thus, if the user inputs nominal (i.e., gross of inflation) values into the model, the real (i.e., net of inflation) floor price will decline over time. Alternatively, the user can input all real values (as OTA did) which implicitly indexes the floor price. However, this solution causes some distortion in the tax calculations. With inflation, income increases in nominal value, but the amount of depreciation deducted for tax purposes remains constant. Thus, in real terms, the value of depreciation decreases with inflation. However, since the model does not account for this real decrease when the user inputs all real values, the model underestimates the amount of tax payments. This distortion was not considered serious, given the short depreciation period and the higher fraction of depreciation claimed in early periods.

Second, the model has a limited capability with respect to purchase agreements. To model a purchase agreement for the entire production, the user can input the purchase price in place of the market price for oil. However, the model cannot directly handle purchase agreements for only a portion of the output in a given year. To evaluate a partial purchase agreement, the user must perform offline calculations to obtain an average of the market and purchase agreement prices, weighted by the proportion of output sold for each price, A similar calculation must then be performed for the standard deviation of the price distribution.

Third, the model has no capability to simulate the effects of production tax credits. It does allow for a price subsidy, but this subsidy is not a tax credit. Unlike a tax credit, the subsidy increases taxable income and hence income tax payments. Because of this limitation, the model was not used to perform the necessary calculations for the $3/bbl tax credit. To estimate the increase in expected profit, the per barrel tax credit was multiplied by each year’s production. The total annual credits were than discounted to the present and summed. The same procedure was used to calculate the expected cost to the Government, except that the Government discount rate was used in the calculation. To evaluate the effect on risk, it was assumed that the standard deviation would not change as a result of the tax credit. This assumption follows because the tax credit does not alter costs or prices; these alterations determine the standard deviation. Because the standard deviation is the same for the tax credit as it is with no incentive, it was possible to transform the histogram computed for the no-incentive case into

a histogram for the production tax credit case. With this new histogram an estimate could be made of the percentage of cases falling below the zero profit level. Finally, the breakeven price was calculated by subtracting the production tax credit from the breakeven price with no incentive.

Fourth, the model is not able to simulate the effect of low-interest loans. Although the user could adjust the discount rate downward to account for the low-interest loan, this method has several limitations because it fails to account for all the terms of the loan. In particular, this method is not sensitive to the time when the loan is received and the time when it must be repaid. Moreover, the approach is based on very restrictive and unrealistic assumptions about the structure of debt financing for the project.[3]

Accordingly, the model was not used to perform the calculations for the low-interest loan. The steps for the low-interest loan computations are referenced in table A-1, The actual cash flows (both loan payments and repayments) to the firm were set up based on the Government's lending rate and the structure of the loan. These cash flows were then discounted using the borrowing rate for the firm on the open market (assumed to be 3-percentage points higher than the Government lending rate), A similar calculation was performed to estimate the expected cost to the Government. As with the production tax credit, it was assumed that the standard deviation of the distribution of profits would not change, since the loan does not alter any of the costs or prices in the model. With the estimated mean for the profit distribution and the standard deviation, the histogram of profit distribution from the no-incentive run was subsequently used to estimate the probability of a loss. The price increment was then computed, which, when multiplied by the production for each year, yielded a discounted value equal to the estimated increase in expected profits. The price increment was then subtracted from the breakeven price with no incentive to yield the breakeven price under the low-interest loan program.

Finally, the model does not directly calculate the net cost to the Government. However, if the Government and the firm use the same discount rate, the cost to the Government exactly equals the gain in expected profit to the firm calculated by the model. This is so because, except for small tax payments to State governments, all the monetary exchanges occur between the Federal Government and the firm. If the discount rates are the same, the present value of the exchanges to both entities is the same, Therefore, since a lo-percent Government discount rate has been assumed, the net cost to the Government of each incentive is equal to the net gain in profitability to the firm calculated at a lo-percent discount rate. The only exception occurs with the Government loan. Because it has been assumed that the real interest rate on debt financing for firms is less than 10 percent, the present value to the firm of the low-interest loan is less than its cost to the Government.

Table A-1 .–Calculating Change in Expected Profit and Cost to the Government for a Low-Interest Loan

Assumptions
- The average total construction cost is $1.7 billion
- 70 percent of one-fifth of the total construction cost, $238 million, is loaned at the end of each of the 5 years of construction
- Interest is calculated on the principal from the moment the first loan is made
- The loan principal plus interest is amortized over 20 years
- The interest rate is 3 percent in real terms
- The firm market borrowing rate is 6 percent in real terms
- The Government's discount rate is 10 percent in real terms

Calculations

Step		Result ($ million)
1.	Calculate annual loan amounts (1 ,700x .7x 2), .,	238/yr
2	Calculate the future value in year 5 of five payments of $238.00 (3-percent Interest) . .	1,264
3.	Calculate the annual principal and Interest payment to the Government (years 6-25) based on the future value in step 2 (3-percent Interest)	85/yr
4.	Calculate the present value to the firm year 5 of the payment from step 3 (6-percent Interest)	974
5.	Calculate the present value to the firm in year O of the value from step 4 (6-percent Interest),	726
6.	Calculate the present value to the firm in year O of the annual loan amount from step 1 (6-percent Interest).	1,003
7.	Calculate the *change in profit* for the firm (1 ,003-726)	277
8.	Calculate the present value to the Government in year 5 of the payment from step 3 (l O-percent interest) .,	723
9.	Calculate the present value to the Government in year O of the value from step 8 (l O-percent Interest)	448
10,	Calculate the present value to the Government in" year O of the annual loan amounts from step 1 (10-percent interest)	401
11.	Calculate the *net cost the Government (901-448)*	453

SOURCE :Office of Technology Assessment

Appendix A References

[1]Wallace E. Tyner and Robert J. Kalter, "A Simulation Model for Resource Policy Evaluation, " Cornell Agricultural *Economic* Stuff Paper, September 1977.

[2]Wallace E. Tyner and Robert J. Kalter, An Analysis of Federal Leasing Policy for Oil Shale Lands, prepared for the Office of Energy R&D Policy, National Science Foundation, April 1975.

[3]tewart C. Meyers, "Interactions of Corporate Financing and Investment Decisions—Implications for Capital Budgeting, " in Modern Developments in Financial Management, Hinsdale, Ill.: Dryden Press, 1976.

APPENDIX B

Assumptions and Data for Computer Analyses

Most of the assumptions used in the computer simulation analyses are embodied in the input data displayed in table B-1. All cost and price data in the exhibit are in constant 1979 dollars.

Table B-1 .–Data Used for Quantitative Analysis[a]

Data item	Value used	Explanation
costs		
Capital cost distribution		
Maximum capital cost,	$2.0 billion	The capital cost data apply to all the capital equipment needed to mine and retort shale and hydrotreat the raw shale oil product, the costs do not Include land acquisition or interest charges, Data were based on recent industry cost estimates,
Most probable capital cost:	$1.7 billion	
Minimum capital cost	$1.4 billion	
Operating and maintenance (O&M) cost distribution.		
Maximum O&M cost.	$17/bbl	Operating costs include hydrotreating costs. Data were based on recent industry cost estimates
Most probable O&M cost :	$12/bbl	
Minimum O&M cost	$ 9/bbl	
Operating cost Increase	4 percent/year	Operating costs were assumed to increase 4 percent per year in real terms (i e., net of inflation) to account for probable Increases in labor costs due to expansion of shale Industries in sparsely populated areas Assumption was based on expectations expressed to OTA by industry sources
Construction period	6 years	A 6-year construction period (i. e , a l-year delay between the fourth and fifth years) decreased expected profits by $117 million for the no-incentive, 12-percent discount rate case.
Fraction of costs occurring each year during construction		
Year 1 .,	10	
Year 2	25	
Year 3 ., : : : : :	30	
Year 4 .,	25	
Year 5	00	
Year 6 .,	10	
Prices		
Initial oil price (1979) ., .,	$35/bbl	Based on the price of imported oil, which at the time of the analysis ranged from $33 to $37/bbl.
Mean annual 011 price increase	3 percent	The assumed 3-percent real increase in oil prices accounts for increasing scarcity as cheap domestic supplies are exhausted, and is midway in the range (2-4 percent) used by DOE planners
Standard deviation of annual oil price change distribution	3 percent	Based on historical trends from the American Petroleum Institute, Basic Petroleum *Data Book,* 1976.
Taxes and transfers		
Federal corporate tax, .,	46 percent	Current Federal corporate income tax rate,
State corporate tax	3 percent	Colorado corporate income tax rate.
State severance tax .,	4 percent	Colorado severance tax on 011 shale reserves,
Investment tax credit,	10 percent	Investment tax credit of 10 percent applies to all investments, an existing additional 10-percent credit for energy-related Investments was ignored because it is to expire in 1982,
Depletion allowance	15 percent	Depletion allowance computed on 011 shale revenues and deducted from taxable income.
Royalty .,	1 percent	Current royalty is 12.5 cents per ton of mined shale; this is equivalent to a royalty on 011 revenues of less than 1 percent.
Depreciation lifetime	12 years	Based on discussions with industry sources.
Annual rent .,	$2,600	Based on a 50-cent-per-acre rent on Federal shale leases of 5,200 acres,
Depreciation method	Sum-of -years digits with switch-over to straight line	Provides the most rapid tax writeoff,
Production		
Maximum output of facility .,	50,000 bbl/d	Size of typical commercial facility,
Production lifetime ., ., .,	22 years	Based on production lifetime of 20 to 30 years in industry cost estimates.
Annual output		
Year 1	15,000 bbl/d	2-year buildup accounts for probable startup difficulties.
Year 2 ..., :	35,000 bbl/d	
Years 3 to 22, ., ., .,	50,000 bbl/d	

[a]All monetary values in constant 1979 dollars

SOURCE :Office of Technology Assessment

APPENDIX C

Oil Shale Water Pollutants

Introduction

The types and amounts of water contaminants that are likely to be produced by major kinds of oil shale facilities are discussed here,

Water Pollutants Produced by Major Oil Shale Processes

Types and Origins of Pollutants

The following summarizes the major sources of each class of waterborne contaminants found in oil shale facilities.

- **Suspended solids** will occur primarily in water from the dust-control systems used in shale mining and crushing operations. Mine drainage water will also contain suspended solids, as will a retort condensate stream that picks up fine shale particles as it trickles down through the broken shale. In aboveground retorts, some fine shale may be entrained in the retort gas and captured in the gas condensate, but levels should be low, thus should not be a problem to treat, Cooling water will pick up dust from the atmosphere, particularly if the cooling tower is near a shale crushing or disposal site. Precipitated salts and biological matter may also be present in the cooling tower blowdown.
- **Oil and grease** will be present in the retort condensate water that is removed from the in situ retort together with the product oil. Some oil remains in the water after product recovery and must be removed prior to further treatment. Part of the oil forms an emulsion in the water and its removal may be difficult. [1] Volatile hydrocarbons leave with the retort offgas and condense in the gas condensate water. Tests indicate that the oil in the gas condensate occurs in well-defined droplets that can be separated without difficulty.[2] Oils in the coker and hydrotreater condensates are expected to be similar to those in the gas condensate.
- **Dissolved gases** include all of the NH_3 and some of the CO_2 and H_2S formed in the retorting process. These gases dissolve in the retort and gas condensates. Any NH_3 and H_2S that are formed during upgrading will appear in the hydrotreater condensates.
- **Dissolved inorganic** will be found in mine drainage water and retort condensates because these streams leach sodium, potassium, sulfate, bicarbonate, chloride, calcium, and magnesium ions from the shale that they contact. [3] In addition, some inorganic volatilize and may be captured from the gas phase in the retort, Of the heavy metals present in raw oil shale, cadmium and mercury (probably as their respective sulfides) are expected to be present in the gas condensate in low concentrations.' An analysis of TOSCO II gas condensate water showed the presence of cyanide, sodium, calcium, magnesium, silica, and iron ions, with only trace amounts of some of the heavy metal elements.[5]
- **Dissolved organics** arise largely from the organic compounds in the raw oil shale, which may be altered during pyrolysis and end up in the retort, gas, or hydrotreater condensates. The types of organics in each condensate will probably depend on the volatility and volubility of the organics and the temperature at which the wastewater is condensed. No data are available on this subject but it is known that a wide range of compounds, particularly carboxylic acids and neutral compounds, can be expected.[6] Many of the individual compounds should be biodegradable, but studies have shown that less than 50 percent of the organic matter can be removed by conventional biological oxidation. This poor performance is attributed to the effect of toxic compounds on waste-treatment bacteria. Both inorganic and organic toxic substances may be responsible. The specific types of toxic pollutants will differ with the retorting process and with raw shale composition. [789]
- **Trace elements and metals** are not expected to occur in large concentrations in the major waste streams except those streams dis-

cussed under dissolved inorganics.[10 11] Chromium was used for corrosion control in older cooling-water systems but other agents are now available and should be used to avoid the problem of chromium contamination of blowdown streams. If trace element and metal removal is required, chemical treatment, specific ion exchange, and membrane processes are available.

- **Trace organics** are toxic or hazardous organic compounds present in low concentrations. They may occur in the retort and gas condensate streams and in the wastewater stream from the upgrading section. These constituents can generally be removed together with other dissolved organics by ultrafiltration with carbon adsorption for final cleaning ("polishing").
- **Toxics,** including carcinogens, mutagens, priority pollutants, and other hazardous-substances, have been reported for various types of oil shale processing wastes. Any toxic substances present in the wastewater streams will be removed along with the trace organics or inorganic substances. It is not expected that thermal oxidation, which is often employed to destroy hazardous organic compounds, will be required for the wastewater streams, although it may be considered for concentrates or sludges. However, the presence of toxic substances may interfere with biological oxidation processes used for bulk organic removal. If this is a problem, the substances could be removed in any of several conventional pretreatment steps.
- **Sanitary wastes** in "domestic" and service waste streams can be kept separate and treated in commercially available package biological treatment units.

The Amounts of Pollutants Produced

Table C-1 indicates the principal contaminated process streams and their flow rates for four commercial-scale [50,000 bbl/d)* oil shale facilities. These facilities correspond to the plants for which water requirements are estimated in chapter 9. The "aboveground direct" plant uses directly heated aboveground retorts like the Paraho direct or gas combustion. The "aboveground indirect" uses indirectly heated retorts like TOSCO II. It is similar to the design proposed by Colony Development. The "MIS" plant uses Occidental's MIS process. It is similar to the design proposed by Occidental and Tenneco for tract C-b. The "MIS/aboveground" plant combines Occidental's MIS process-with Lurgi-Ruhrgas indirectly heated aboveground retorts. It is similar to Rio Blanco's design for tract C-a.

The flow rate estimates were derived from tables 71, 74, and 75. (See ch. 9.) Estimates have been added for the internally recycled gas washing and hydrotreater wash streams that were not considered in chapter 9. (The water availability

*Barrels per stream day.

Table C-1 .–Flow Rates of Contaminated Streams in Oil Shale Facilities Producing 50,000 bbl/d of Shale Oil Syncrude (acre-ft/yr)

	Aboveground direct	Aboveground redirect	MIS	MIS/aboveground
Cooling tower blowdown	1,550-1,820	1,320-2,070	1,040-1,280	910-1,130
Boiler blowdown ...	325	370-405	370	350
Boiler feedwater treatment wastes	165	190-210	185	180
Gas washing condensate .,	1,070-1,190	(a)	3,320-3,640	2,270-2,500
Gas condensate (net). .	490-540	730-800	2,160-2,370	1,480-1,630
Retort condensate, ...	(a)	(a)	1,240-1,370	850-940
Coker condensate. .,	60	60	60	60
Hydrotreater wash condensate	875	875	875	875
Net hydrotreater condensate			40	40
Excess mine drainage	(a)	(a)	0-10,000	0-10,000

[a]Neglected for processes designs or sites considered

SOURCE R F Probstein H Gold and R E Hicks, *Water Requirements Pollution Effects and Costs of Water Supply arrd Treatment for the Oil Shale Industry*, prepared for OTA by Water Purification Associates October 1979 analysis presented there deals only with streams that cross the project boundaries.) These additional streams are of significance for water quality analysis because they contain all of the NH_3, most of the CO_2, and some of the H_2S that is removed from gas streams in the plants. Flow rate ranges are shown in some cases to account for the expected variations in shale grades and plant designs, as discussed in chapter 9. The following points should be noted with respect to the flow rate estimates.

- Cooling tower blowdown varies substantially among the plants, largely because of different modes of power generation.
- Boiler blowdowns are fairly uniform because it is assumed that boilers will generate steam for use in the upgrading units, which are identical for all four plants.
- For the same reason, all four plants have the same flow rates for coker condensate, hydrotreater wash condensate, and net hydrotreater condensate.
- Excess mine drainage is indicated for the MIS and MIS/aboveground plants because it was assumed that they would be located in the ground water areas of the Piceance basin. The other two plants were assumed to be located in drier areas (e.g., in the Uinta basin or along the edge of the Piceance basin),
- No retort condensate is shown for the AGR plants because it was assumed that condensation in the retort would be avoided by adjusting the operating temperature. A large value is shown for the MIS retort condensate because of unavoidable condensation in the lower portions of the MIS retorts. The value for MIS/aboveground is a weighted average of Lurgi-Ruhrgas (no condensate) and MIS (large quantities of condensate).
- Large values are also shown for gas condensate and gas washing condensate in all systems except the aboveground indirect. In the aboveground direct and the two MIS operations, large quantities of moist retort gas must be treated, resulting in large volumes of condensate. Much of the moisture is a combustion product. In contrast, the above--ground indirect has no combustion within the retort and produces less gas that must be cooled and cleaned.

In table C-2, estimates are presented of the concentrations of contaminants in the condensate streams. It is important to note that extensive data on contaminant concentrations are not available for the process condensate streams and that published measurements show considerable variation. Only the estimate for the aboveground indirect gas condensate is based on extensive field measurements.[13] The other values are consistent with material balance calculations and information from the literature but they are at best approximate. Moreover, only concentrations of major contaminants are shown. Trace contaminants, including most toxic elements, are not indicated because information on their occurrence is even more limited, Although toxic elements are not ex-

Table C-2.–Contaminant Concentrations in Oil Shale Process Condensate Streams (mg/1)[a]

Contaminant	Gas condensate			Retort condensate	Hydrotreater condensate
	Aboveground direct	Aboveground redirect	MIS or MIS/aboveground	MIS or MIS/aboveground	All plants
NH_3	17,990C	5,150	21,330[c]	720	41,000[c]
H_2S	206[c]	810	118[c]	—	18,000[c]
CO_2[b]	32,400[c]	6,150	41,800[c]	9,940	None
Calcium :	Low[d]	6	Low	20	Low
Magnesium.	Low	2	Low	17	Low
Potassium	Low	0 4	Low	100	Low
Sodium	Low	5	Low	3,600	Low
Chloride	Low	5	Low	280	Low
Fluoride	Low	0.3	Low	39	Low
Boron,	Low	Low	Low	25	Low
Sulfate	Low	Low	Low	1,200	Low
Organic carbon	—	6,100	—	—	—
BOD[e] .,	10,000	10,000	2,200	2,220	10,000

[a]Trace elements and organics for which data are unavailable are not shown
[b]Bicarbonate and carbonate concentrations reported as CO_2 equivalent
[c]In internal acid wash before gas separation and wash recycle
[d]Based on available dala or estimates
[e]Biochemical oxygen demand estimated al one half of the theoretical oxygen demand

SOURCE R F Probstein H Gold and R E Hicks *Wafer Requirements, Pollution Effects and Costs of Water Supply and Treatment for the Oil Shale Industry* prepared for OTA by Waler Purification Associates October 1979 pected to be present to any significant extent in the gas condensates, some could be present in the MIS retort condensate. ”

The hydrotreater condensate concentrations were developed for Colony's upgrading unit, but they should be typical of values for any facility (MIS or aboveground) that processes Green River shale oil. A retort condensate is shown only for the MIS and MIS/aboveground facilities, for reasons mentioned previously. Significant differences are indicated for the three gas condensate streams with respect to NH_3, H_2S, and CO_2 concentrations. The aboveground indirect stream is much lower in CO_2 and NH_3 because of the lack of combustion (which produces soluble CO_2 and NO_x gases) in the retort. H_2S concentration is higher in the aboveground indirect stream because there is little oxygen available in the retort to oxidize the H_2S to SO_2 A lack of data prevents evaluation of process-related effects on concentrations of other contaminants.

In table C-3, the likely rates of pollutant production are shown for the gas condensate streams.

Table C-3.–Production Rates for Principal Pollutants in Gas Condensate Streams (ton/d)[a]

	Type of facility			
Contaminant	Aboveground direct	Aboveground Indirect	MIS	MIS/ aboveground
NH_3	75.6	147	276	189
H_2S[b]	0.87	2.3	15	1.1
CO_2	136	17,5	541	371
BOD[c]	19.2	28.5	185	127

[a]Tons per stream day for production of 50000 bbl/d shale oil syncrude
[b]Additional sulfur is recovered directly from the retort gas
[c]Biochemical oxygen demand

SOURCE R F Probstein 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 Waler Purification Associates October 1979

The values shown were obtained by multiplying the flow rates in table C-1 by the pollutant concentrations in table C-Z. Only a single value is shown for each contaminant in table C-3 and in the other pollutant production-rate tables that follow. The rates shown were calculated for average stream flows wherever a range is shown in table C-1. This approximation is justified because the uncertainty in pollutant concentrations is larger than the relatively narrow range shown for the flow rates. These uncertainties result from a paucity of published data, and also because large differences can occur in some plants with different feed waters and process designs.

Table C-4 indicates the pollutant production rates for the retort condensate streams produced

Table C-4.–Production Rates for Principal Pollutants From MIS Retort Condensates (ton/d)[a]

	Type of facility	
Contaminant	MIS	MIS/aboveground
NH_3	349	2.40
H_2S	—	—
CO_2	48,2	33.1
Calcium	0.10	0.07
Magnesium	008	0.06
Potassium	0.49	0.33
Sodium	17.5	12.0
Chloride	1,36	0.93
Fluoride	0.19	013
Boron	0.12	0.08
Sulfate	5,82	3.99
Biochemical oxygen demand	10.07	7.32

[a]Tons per stream day for production of 50000 bbl/d shale oil syncrude

SOURCE R F Probstein 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

in MIS retorting. It is assumed that retort condensates are produced only with MIS processing. These condensates leach inorganic salts from shale in the retort, as indicated by the contaminant production rates shown.

Table C-5 shows the production rates for the principal contaminants in the process waste waters generated in the upgrading portion of the Colony design. This is the only plant for which an upgrading section has been described in the literature. Since shale oils produced by different retorts are not markedly different in their nitrogen and sulfur contents, it is reasonable to apply the pollutant production estimates for the TOSCO H upgrading section to all of the facilities considered.

In table C-6, the pollutant production rates for all of the process condensate streams are combined. It can be seen that the biochemical oxygen demand (BOD) does not have a wide range between facilities. This is in large measure a result

Table C-5.–Production Rates for Principal Pollutants in Upgrading Condensates (ton/d)[a]

	Waste stream	
Contaminant	Hydrotreater condensate	Coker condensate
NH_3	133	1.15
H_2S[b]	58.6	0,18
CO_2	0	1.37
Biochemical oxygen demand	1.49	2.23

[a]Tons per stream day for production of 50,000 bbl/d shale oil syncrude Based on a TOSCO II process design Similar values anticipated for the other process models
[b]Additional sulfur is recovered directly from the retort gas

SOURCE R F Probstein, 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

Table C-6. –Sum of the Production Rates for Principal Pollutants in Retorting and Upgrading Condensates (ton/d)[a]

	Type of facility			
Contaminant	Above-ground direct	Aboveground indirect	MIS	MIS/ aboveground
NH_3	210	149	414	326
H_2S[b]	597	611	603	599
CO_2[c]	137	189	591	405
BOD[d]	229	322	329	237

[a]Tons per stream day for production of 50 000 bbl/d shale oil syncrude
[b]Additional sulfur is recovered directly from the retort gas
[c]This does not represent total CO_2 production CO_2 is also generated in combustion and lost up flue gas stacks as in TOSCO II indirect process and in steam and power production
[d]Biochemical oxygen demand

SOURCE R F Probstein 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

of the BOD concentrations assumed. The H_2S production, which represents about a third of the total sulfur recovered in the plant, varies little among the different facilities. This is reasonable, since the amount of sulfur removed per unit of shale oil produced should be similar for the different processes. However, this H_2S includes only that amount that dissolves in the condensate streams; it does not include the gas that goes directly to the sulfur recovery units.

The most striking estimate in table C-6 is the extremely high CO_2 production rate for the MIS facility. The rate for the aboveground indirect facility is lowest because decomposition of carbonate minerals to CO_2 is much less at the lower retorting temperatures (about 900° F or 500° C) than in the higher temperature (about 1,500° F or 800° C) MIS or aboveground direct processes. The rate is highest for MIS because the shale remains at high temperatures for a long time, thus allowing nearly complete decomposition of the carbonates. The combined MIS and AGR facility shows a correspondingly lower value—a weighted average of MIS and Lurgi-Ruhrgas rates. It should be emphasized that CO_2 is also produced by combustion in the indirect AGR plant, which does not show up in the condensate streams because it is lost directly up flue gas stacks, However, even if this gas were included, the ratio of CO_2 produced in MIS or aboveground direct to that in indirectly heated retorting would still be large.

Differences in NH_3 production rates also result from combustion in MIS and directly heated aboveground retorts. The aboveground indirect process produces the least NH_3 because it is essentially one of pyrolysis in which the nitrogen is mostly obtained from the organic matter in the shale. In fact, almost all of the NH_3 that will be produced in the indirectly heated AGR will be manufactured in the upgrading section when nitrogen is removed from the crude shale oil by hydrotreating. Differences in BOD yields are not statistically significant, given the lack of precision in the data base.

In order to calculate pollutant concentrations in cooling tower blowdown and waste streams from boiler feedwater treatment, it is necessary to know the raw water composition to the plant. Table C-7 shows the raw water compositions assumed for this assessment. The surface water quality is that of the Colorado River near Cameo, Colo., and the mine drainage water is a composite of the expected quality of water to be drawn from the bedrock aquifers of the Piceance Basin. [15]* The raw water compositions are only approximate.

Table C-8 presents the estimated composition of the cooling tower blowdown of four facilities

*The bedrock aquifer system, and other water resources in the oil shale region, are described in ch. 9.

Table C-7.–Composite Water Quality Data for Colorado River Water and Mine Drainage Water in the Piceance Basin (mg/l)

	Source of process water	
Contaminant	Surface water	Mine drainage water
NH_3	—	1.2
Bicarbonate	168	750
Boron	—	3
Calcium	72	50
Carbonate	—	50
Chloride	205	20
Fluoride	—	15
Magnesium	19	60
Phenol	—	25×10^{-3}
Silica	7	15
Sodium	153	300
Sulfate	158	350
Total dissolved solids	734	1,350

SOURCE R F Probstein 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

Table C-8.–Estimated Concentrations of Principal Contaminants in Cooling Tower Blowdown (mg/l)

	Type of facility	
Contaminant	AGR with surface water supply	MIS retorting with mine drainage water supply
Calcium,	215	200
Chloride	615	80
Fluoride	—	60
Magnesium	60	240
Sodium	460	1,200
Sulfate	840	1,400

SOURCE R F Probstein, 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 Wafer Purification Associates October 1979 considered, based on an average of three cycles of concentration for AGR (surface water supply) and four cycles of concentration for MIS retorting (mine drainage water supply). The relatively low numbers assumed for concentration cycles are based on the assumption that all of the blowdown water is needed for solid waste disposal. Under this assumption there is no advantage to the more costly procedure of using a larger number of cycles.

Table C-9 gives the estimated composition of the waste streams from treating the raw supply water by ion exchange to obtain a high-quality water for boiler feed. The estimates assume the removal of all the calcium, magnesium, and sulfate ions from the supply water. Most of the other ions will also be removed but only the principal ones are shown for the waste streams. The waste volume is about 7.5 percent of the water treated. This corresponds to a fairly efficient ion exchange treatment system. Boiler blowdown waste composition is not shown because the quality of this water is usually equivalent to that of the raw water entering the plant. It can therefore be mixed with the raw water and used as a makeup source.

Table C-9.–Estimated Concentrations of the Principal Contaminants in an Ion Exchange Regenerant Waste Stream From Boiler Feedwater Treatment[a] (mg/l)

Contaminant	Type of facility: AGR with surface water supply	MIS retorting with mine drainage water supply
Calcium	950	660
Chloride	2,400	790
Magnesium	250	4,600
Sodium	990	2,200
Sulfate	2,080	3,460

[a]Volume of regenerant wastewater assumed to be approximately 75 percent of the volume of treated water

SOURCE R F Probstein 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

Table C-10 gives the estimated pollutant production rates in the cooling tower blowdown and boiler waste treatment streams based on the compositions of tables C-8 and C-9. Also shown are the total production rates from these two sources; the streams would usually be combined in the plant and used for solid waste disposal. There is not a great deal of difference in the total quantities of pollutants produced by the facilities considered,

In table C-1 it was assumed that oil shale mines in ground water areas might result in production of from O to 10,000 acre-ft/yr of excess mine drainage water for a 50,000-bbl/d in situ facility. At this time, it is not known whether the water will be treated for discharge to surface streams,

Table C-10.–Production Rates for Principal Pollutants in Cooling Tower Blowdown and Boiler Treatment Wastes (ton/d)

Contaminant	Aboveground direct	Aboveground indirect	MIS	MIS/aboveground
	Cooling tower blowdown			
Calcium	1 35	1,36	0.86	076
Chloride	385	3.88	035	0.30
Fluoride	—	—	0.26	023
Magnesium	038	0.38	1.04	0,91
Sodium	2.88	290	5.18	4,55
Sulfate	5.26	529	604	5.31
	Boiler treatment wastes			
Calcium	0,58	0.71	0.45	0.44
Chloride	1,47	1 79	0.54	0,53
Magnesium	015	0.19	3.16	3.08
Sodium	061	0.74	1,51	1.47
Sulfate	1 28	1.55	2.38	2,32
	Total			
Calcium	193	2.06	1.32	1.20
Chloride	533	5,66	089	083
Fluoride	—	—	0.26	0.23
Magnesium	0,53	056	4.20	3.99
Sodium	349	3.64	6.69	6.02
Sulfate	654	6.84	8.42	7,63
Total	17.82	1876	21.78	19,90

SOURCE R F Probstein 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 or reinfected into the aquifer from which it was drawn. The question has economic as well as environmental implications. If it is to be discharged, then it must be treated, and wastewater streams will be produced that will require management and disposal. The level of treatment is not known at present. In DRI's analysis of the costs of environmental protection, "less strict" and "more strict" pollutant discharge criteria were assumed.'" In table C-1 I their estimates are given for the total quantities of pollutants produced by treatment for surface discharge of 10,000 acre-ft/yr of excess mine drainage water of the quality shown in table C-7 for the less strict and more strict regulations. These quantities could be appropriately scaled down or up for different rates of drainage-water production. The effect of the different standards on the total quantity of pollutants produced is not large. However, the costs of achieving the "more strict" criteria would be much higher.

Table C-1 1.–Rates of Pollutant Production From Treatment of 10,000 acre-ft/yr of Excess Mine Drainage Water for Surface Discharge

	Regulatory scenario			
	"Less strict"		"More strict"	
Contaminant	% Removal	Ton/d	% Removal	Ton/d
NH_3	85	004	91 7	004
Bicarbonate	77	21 47	943	2630
Boron	70	008	982	011
Calcium	99	184	999	1 86
Carbonate	90	1 67	958	1 78
Chloride	94	070	996	074
Fluoride	90	050	99.0	055
Magnesium	99	221	999	223
Silcia	83	046	967	054
Sodium	94	10.49	997	11 12
Sulfate	97	1262	999	1300
Total		5208		5827

SOURCE Adapted from T D Nevens et al (DRI Wafer Purification Associates and Stone and Webster Engineering) *Predicted Costs of Environmental Controls for a Commercial Oil Shale Industry Volume I An Engineering Analysis* Department of Energy July 1979

Appendix C References

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[10]E. F. Bates and T. L. Thoem (editors), *Pollution* **Control** Guidance *for Oil Shale* Development, Revised Draft Report, Environmental Protection Agency, Cincinnati, Ohio, July 1979.

[11]Supra No. 4,

[12]Supra No. 5.

[13]Ibid.

[14]Supra No. 4.

"Denver Research Institute, **Predicted Costs** *of* Environmental Controls *for* A *Oil Shale* Industry; *Volume I*— An Engineering Analysis, prepared for the Department of Energy under contract No, IZP-78-S-O2-51O7, July 1979.

[16]Ibid.

APPENDIX D

Technologies for Managing Point Sources of Wastewater

Introduction

This appendix describes the wastewater streams that will be produced in oil shale facilities, including leachates from solid waste disposal. The physical, chemical, and biological treatment devices and systems are then described, Finally, developer plans are reviewed to show how water supply, wastewater treatment units and systems, and methods of disposition might be combined into comprehensive water management schemes for commercial-scale oil shale facilities.

Oil Shale Waste Streams That Will Require Treatment

The major point source streams that will require treatment are:

- excess mine drainage water—principally for plants near the center of the Piceance basin;
- retort condensates—especially and perhaps exclusively for in situ operations;
- gas condensates—for all systems;
- coker and hydrotreater condensates from all plants that have onsite upgrading or refining operations; and
- streams from service operations—including boiler feedwater treatment wastes and cooling tower blowdown.

The other streams are either relatively small or relatively clean and consequently require little treatment. They include boiler blowdown, rain and service water runoff, and sanitary wastes. Sanitary wastes will certainly need treatment, but they should be similar to typical domestic wastes and can easily be handled in commercially available biological u-nits.

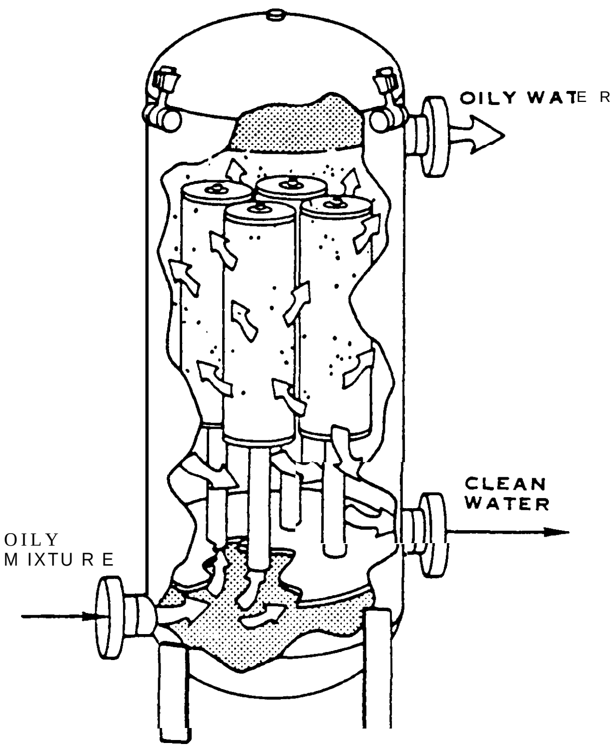
Leachate from spent or raw shale piles on the surface is not considered as a separate stream requiring treatment during the operating life of the plant. With proper compaction and irrigation, water will be either retained in the pile or lost by evaporation. There should therefore be little accumulation of leachates. [1] There will be storm and snowmelt runoff, but this will be in limited quantities and will have a low salt content.[2] The small quantity of water that may percolate through the pile after intentional leaching can be expected to be low in both organic and inorganic substances,] This water can be used for dust control in raw shale crushing operations and will thus find its way back to the retort, Leachate from spent in situ retorts poses a potential problem of unknown magnitude, Design concepts for its control are discussed in chapter 8.

Individual Methods for Point Source Wastewater Treatment

Physical Methods

- **Gravity separators** are used to treat nearly all oily wastewaters. They are especially common in refineries and chemical plants. The simplest are impingement-type devices such as API separators, corrugated plate interceptor separators and parallel plate interceptor separators. These devices are very inexpensive and reliable but they can be used only for first-stage oil removal. Additional treatment is usually needed before the wastewater can be sent to sensitive treatment systems like biological oxidizers.
- **Coalescing cartridge separators** (figure D-1) are more effective devices that can reduce oil concentrations to as low as 1 mg/l. In this type of separator, oily wastewater is pumped through a coarse filter medium within the cartridges, causing oil droplets and some mechanically emulsified oil to coagulate into large globules which float to the top of the separator

Figure D-1 .—Cartridge-Type Coalescing Oil-Water Separator

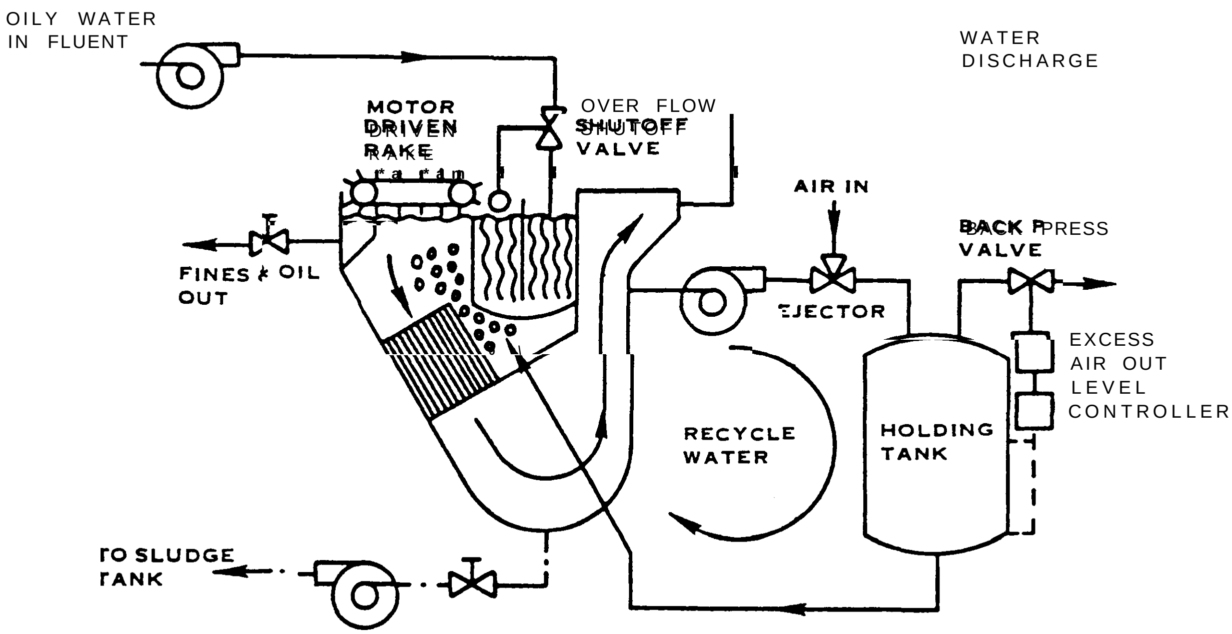


SOURCE. *Assessment of Oil Shale Retort Wastewater Treatment and Control Technology,* Hamilton Standard **Division of United Technologies, July 1978, p 5-3.**

and are removed. These devices have high removal efficiencies but tend to clog if the water contains suspended particles. They can also be fouled by growth of micro-organisms on the filter medium.

- **Air flotation** is even more effective but is relatively complex. One device—the dissolved air flotation cell—is shown in figure D-2. In this separator, air is injected into the oily wastewater as fine bubbles, The oil droplets adhere to the air bubbles and rise to the surface as a froth, which is skimmed off by a motor-driven rake, Some small suspended particulate contaminants can also be removed in the froth and others will settle to the bottom of the cell and can be removed as a sludge. Coagulant can also be added to aid removal efficiency. If lime is added, for example, it will precipitate some heavy metals and certain anions such as carbonates.
- **Clarification** [also called coagulation/sedimentation or precipitation/sedimentation) may be used to settle out oil, to remove suspended solids, or to precipitate toxic metals, carbonate, and other anions. A slant-tube clarifier is shown in figure D-3. Accumulation of oil droplets and particulate on the tubes greatly enhances separation of the materials compared with the performance of simpler gravity devices, Chemicals can also be added in an up-

Figure D-2.— Dissolved Air Flotation



SOURCE: *Assessment of Oil Shale Retort Waste water Treatment and Control Technology,* **Hamilton Standard Division of United Technologies, July 1978, p. 5-3.**

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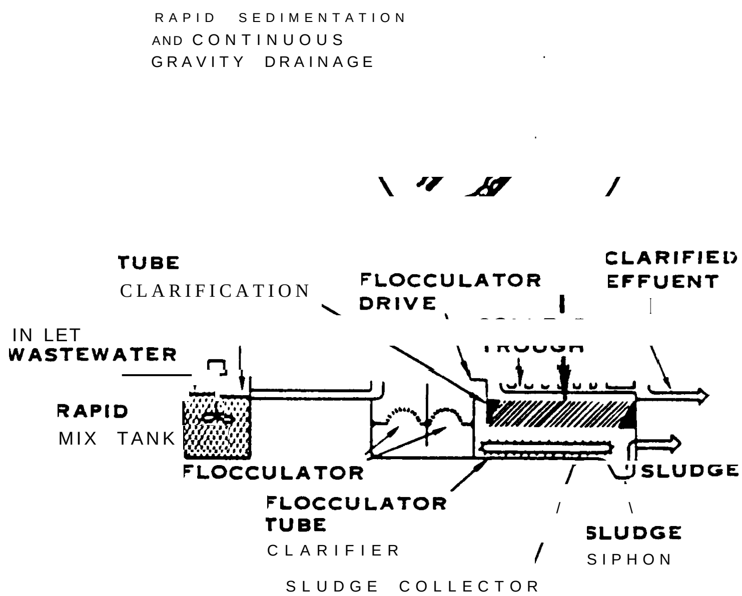
Figure D-3.—Clarification and Precipitation



SOURCE: *Assessment of* Oil *Shale Retort Wastewater Treatment and Control Technology,* Hamilton Standard Division of United Technologies, July 1978, p. 5-3

stream mixing tank to aid precipitation (such as sodium hydroxide) or coagulation (such as alum or a polyelectrolyte).

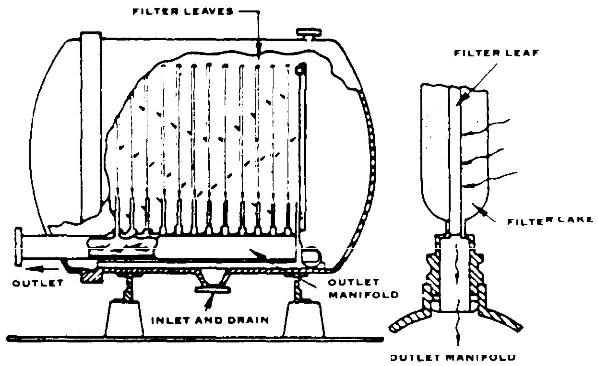
- **Filters** can be used to remove particles and in some cases oil. Some of the more common filtering devices are shown in figure D-4. Pressure filters are generally automatic devices in which the contaminated water is sucked inwards through a series of leaves on which a filter cake forms. The filter may be used to remove particles from dilute wastewaters as the first stage in a treatment system, or it can be used to dewater the sludge products from other separators. The filter cake is generally very low in moisture, which eases disposal problems.

  Vacuum filtration can also be used to remove suspended particles from wastewater but is more suitable for dewatering concentrated streams and sludges. Two vacuum devices are shown in figure D-4, In the rotary vacuum filter, a rotating drum dips into a trough filled with wastewater, and suction is applied to the inside of the drum. Water is drawn through the perforated surface of the drum and solids are deposited on the outside as a filter cake. As the drum rotates, the dewatered sludge is scraped off and falls into a receiving trough. **A** filter press is functionally similar except that the wastewater is sucked or pumped through a series of plate-and-frame assemblies. The dewatered sludge is periodically removed from the filter medium by mechanical cleaning. Ultrafiltration, in which the wastewater is forced through a membrane, is often used for separation of oil and water. It is generally limited to separation of chemically stabilized emulsions and is not suitable for mechanical emulsions.

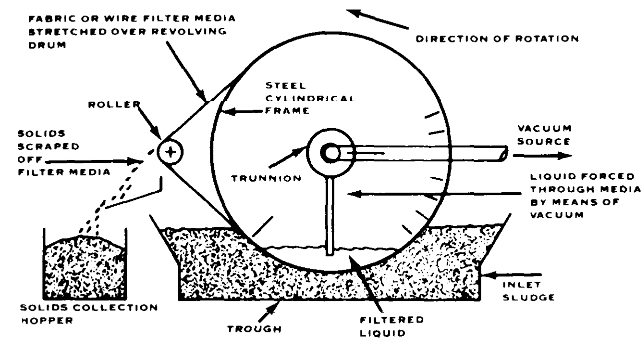
  In multimedia filters, granular materials such as sand forma filtering bed through which the wastewater is pumped. The water passes through a series of layers with granules of increasingly fine size, The collected solids are subsequently removed by backflushing with clean water. This filter produces a sludge, rather than a dry cake, which requires additional dewatering before disposal. The multimedia filter is generally more economical than pressure filters for high flow rates and dilute slurries.

- **Stripping** with steam (figure D-5) or with air or flue gases is used to remove NH_3 and sulfide gases from wastewater. The operation is carried out in a packed column or a plate column, and two-stage processing is sometimes employed to provide independent recovery of NH_3 and sulfuric acid, If the stripper is part of a treatment system that includes biological treatment, some NH_3 is usually left in the stripper product to act as a nutrient for the micro-organisms.

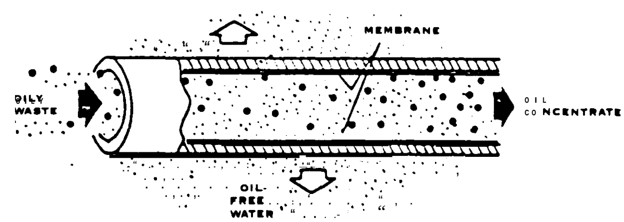
Figure D-4.— Filters for Wastewater Treatment



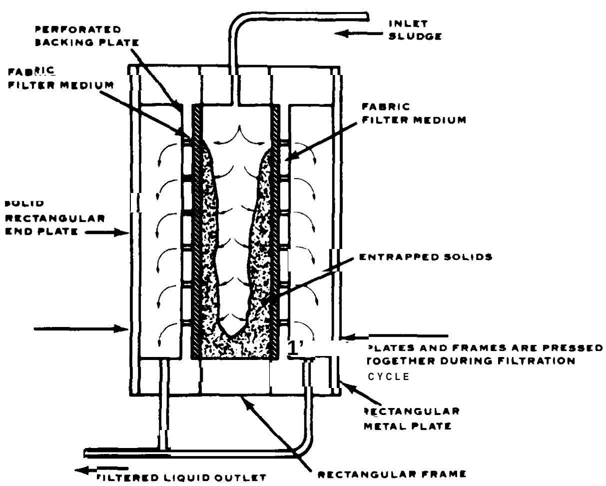
A. Pressure filter



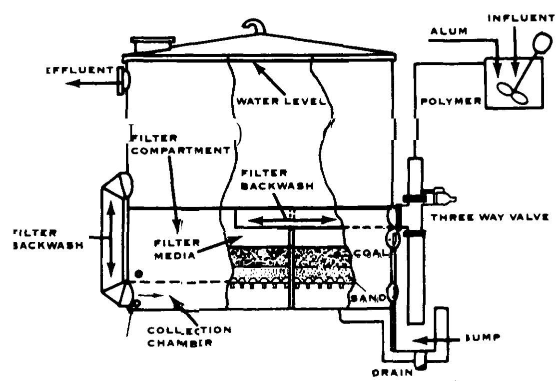
B. Rotary vacuum filter



C. Ultrafiltration



D. Filter press

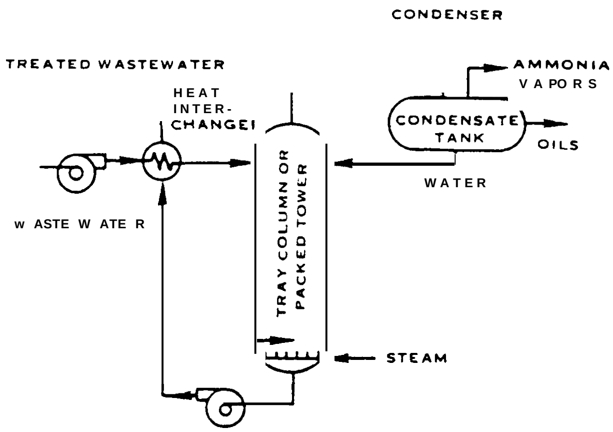


E. Multimedia filtration

SOURCE: *Assessment of Oil Shale Retort Wastewater Treatment and Control Technology,* **Hamilton Standard Division of United Technologies, July 1978, pp 5-4, 5-6,** 5-11, and 5-12

- **Adsorption** is used to remove dissolved metals, organic compounds, and many toxic substances. Adsorption with regenerated carbon slurries and with resin particles is shown in figure D-6. Other systems use activated carbon particles that are contained in a fixed bed, either without regeneration or with regeneration within the column. In all cases, the separation involves physical adsorption of the contaminants on the surfaces of the particulate medium.
- **Distillation** (figure D-7) is a simple process in which wastewater is purified by boiling. The products are a very clean steam, which can be condensed with cooling water or in air-cooled condensers, and a highly contaminated concentrate. Very pure water can be obtained, but the process has large energy requirements. Cooling water is also needed in most applications.
- **Reverse osmosis** can also recover very pure water from concentrated salt solutions. Some dissolved organic materials can also be re-

Figure D-5.—Steam Stripping



SOURCE: *Assessment of Oil Shale Retort Wastewater Treatment and Control Technology,* **Hamilton Standard Division of United Technologies, July 1978, p, 5-4**

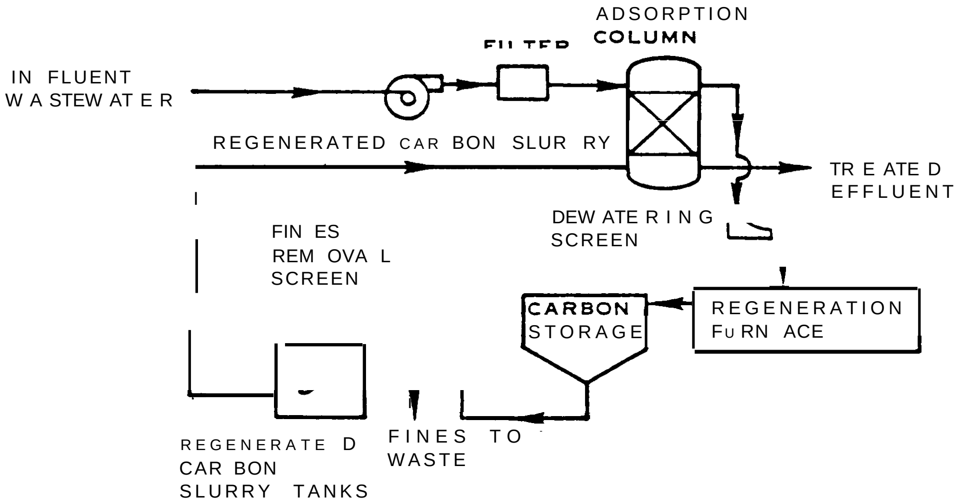
moved. **A** typical reverse osmosis system is shown in figure D-8. Each element in the separation system contains a membrane that separates the clean product (permeate) from the concentrated waste or residual. The membrane is pressurized on one side, which forces the pure water through the membrane and leaves the salt and organic contaminants on the other side. The process is very effective, but problems arise if the wastewater stream contains very fine suspended solids (colloids) that can clog the membranes and reduce their performance.

- **Electrodialysis** cells consist of an anode and a cathode separated by two membranes—one near the cathode through which cations (positively charged ions) can pass and one near the anode that is permeable to anions (negatively charged ions). A system consisting of several such cells is shown in figure D-9. The wastewater is pumped between the membranes. Upon application of an electric current, the anions migrate through one membrane towards the anode and the cations migrate through the other to the cathode. The concentration of ionic species in the central chamber is thereby reduced. The concentrated streams beyond the membranes are the waste products. Electrodialysis is very effective in removing dissolved salts but it is very expensive because each system must be specifically designed and manufactured for the particular application.
- **Thickeners** (figure D-1 O) are used between a sludge-generating step (such as clarification) and a sludge-dewatering step (such as vacuum filtration). These concentrate the sludge through gentle agitation and thereby reduce the amount of water that must be removed in subsequent processes.
- **Evaporation** (figure D-1 1) is a final step for concentrating solid residues. It is generally accomplished in evaporation basins, which are simply lined ponds into which the sludge is pumped and allowed to stand while the moisture evaporates, or in sludge drying beds, which contain a layer of coarse sand over a layer of fine sand over clay or perforated plastic drainage tiles. Both systems require large areas of land compared to other more compact devices such as vacuum filtration but they are inexpensive and require little maintenance. Sludge drying beds are faster but more expensive. Both systems require mechanical removal of the dried sludge, usually with a backhoe or front-loader.

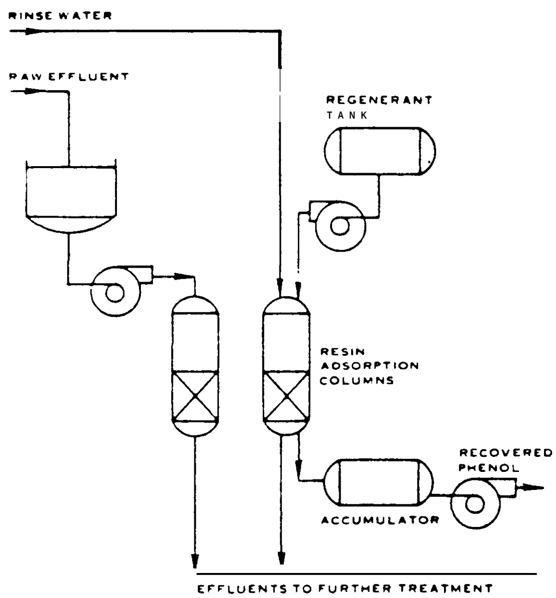
Chemical Methods

- **Ion exchange** is a process in which ions held by electrostatic charges on the surface of resins are exchanged for ions with similar charges in the wastewater. An example is a home water softening system in which sodium ions (from rock salt) are exchanged for calcium ions in the water supply, thereby reducing the hardness of the water. The process is classified as adsorption because the ion exchange occurs on the surface of the resin particles and the ions to be removed must undergo a change of phase: from the liquid phase of the wastewater to the solid phase of the resin. By this technique, harmful ions in the wastewater can be exchanged for the harmless ions of the resin. Ion exchange can be used only for removing ions (such as those from dissolved salts) from solution; it cannot be used for non-ionic contaminants such as organic compounds and suspended solids. A regenerating ion exchange system is shown in figure D-12. Such a system is suitable for recovery of valuable ions from dilute streams. It has a limited capacity, thus would not be useful for first- or second-stage salt removal but would more likely be reserved for "polishing" a treated effluent from another treatment technology.
- **Wet air oxidation was** developed for destruction of organic contaminants. In this process (see figure D-13), wastewater is exposed to air under elevated temperature and pressure, thus causing organic compounds to oxidize com-

Figure D-6.—Adsorption Systems for Wastewater Treatment



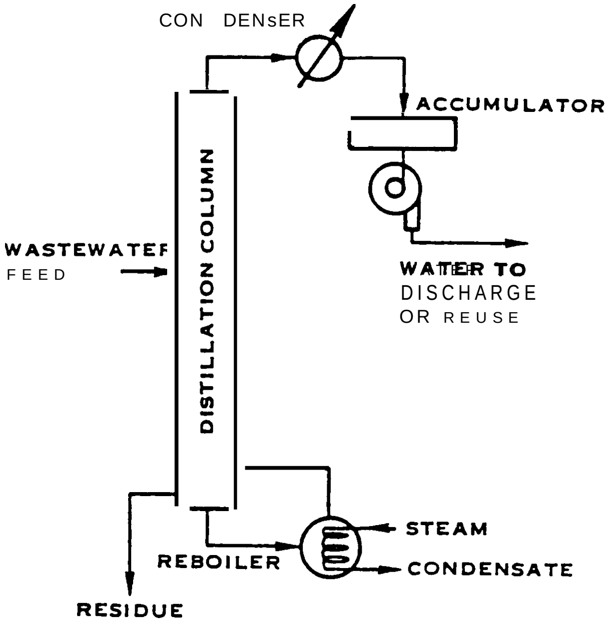
A. Carbon adsorption with external regeneration



B. A two-tank adsorption system

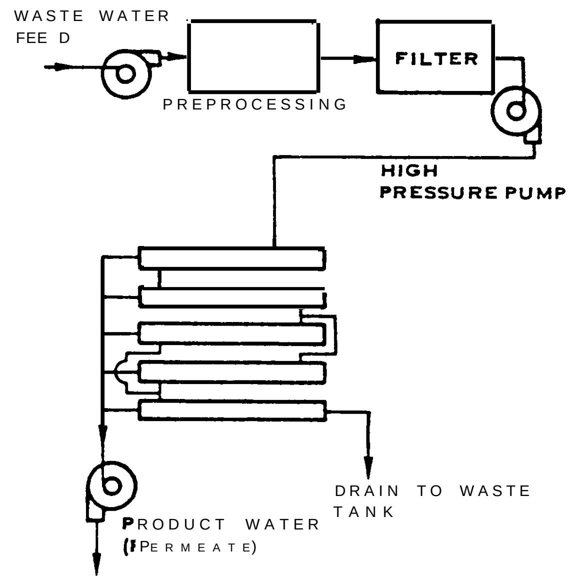
SOURCE: *Assessment of Oil Shale Retort Wastewater Treatment and Control Technology,* **Hamilton Standard Division of United Technologies, July 1978, pp. 5-4 and 5-6**

Figure D.7.– Distillation



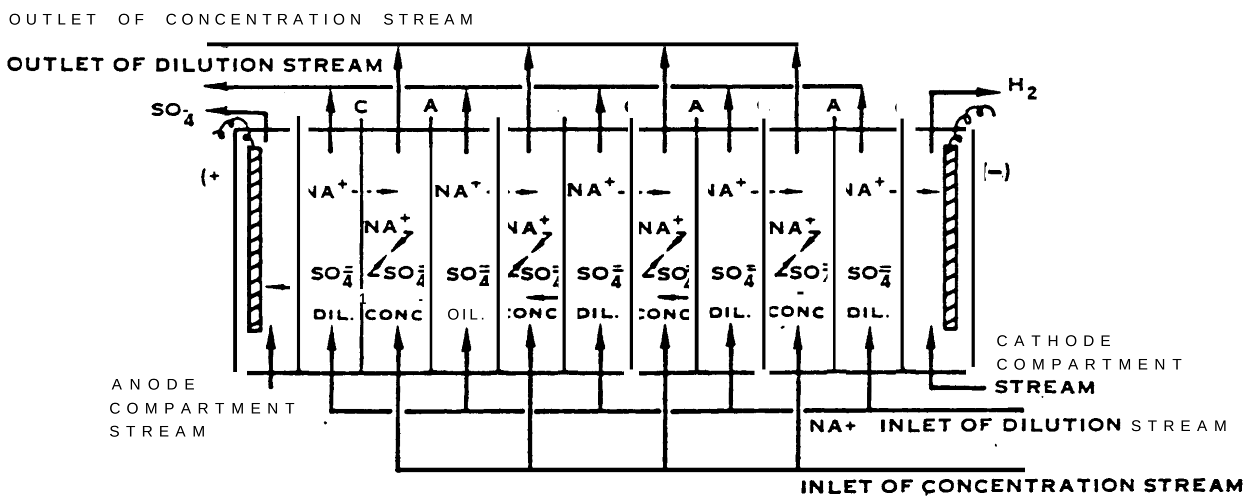
SOURCE: *Assessment of Oil Shale Retort Wastewater Treatment and Control Technology,* **Hamilton Standard Division of United Technologies, July 1978, p. 5-7**

Figure D-8.–Reverse Osmosis



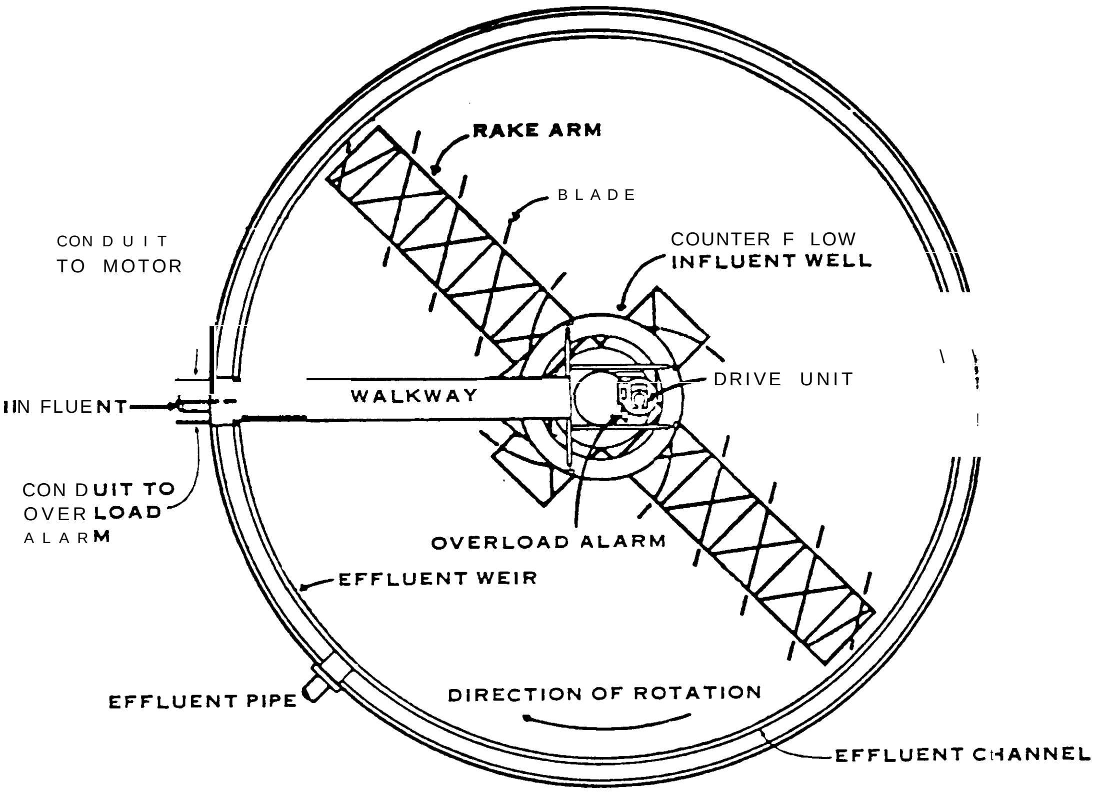
SOURCE: *Assessment of* **Oil** *Shale Retort Wastewater Treatment and Control Technology,* **Hamilton Standard Division of United Technologies, July 1978, p 5-7.**

Figure D-9.—Electrodialysis

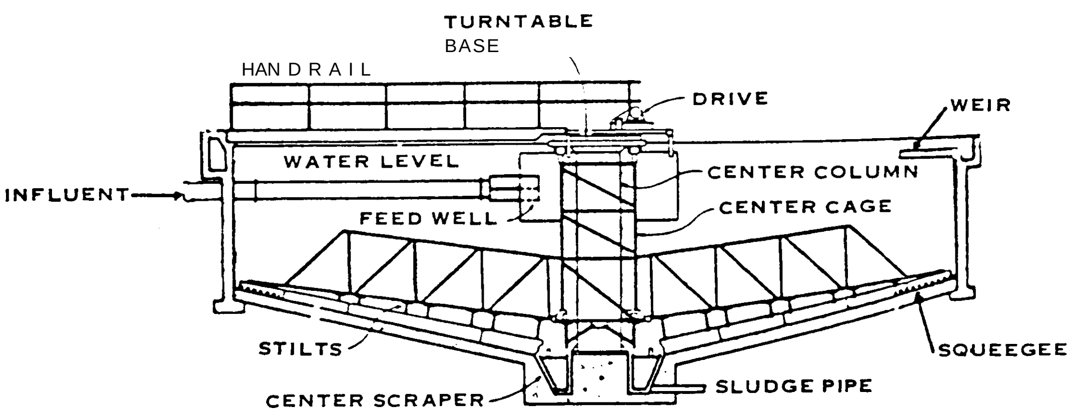


SOURCE: *Assessment of Oil Shale Retort Wastewater Treatment and Control Technology,* **Hamilton Standard Division of United Technologies, July 1978, p. 5-7.**

Figure D10.-Mechanical Sludge Thickening

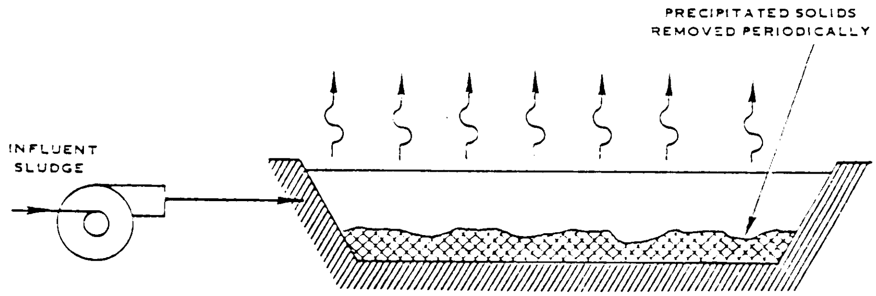


PLAN

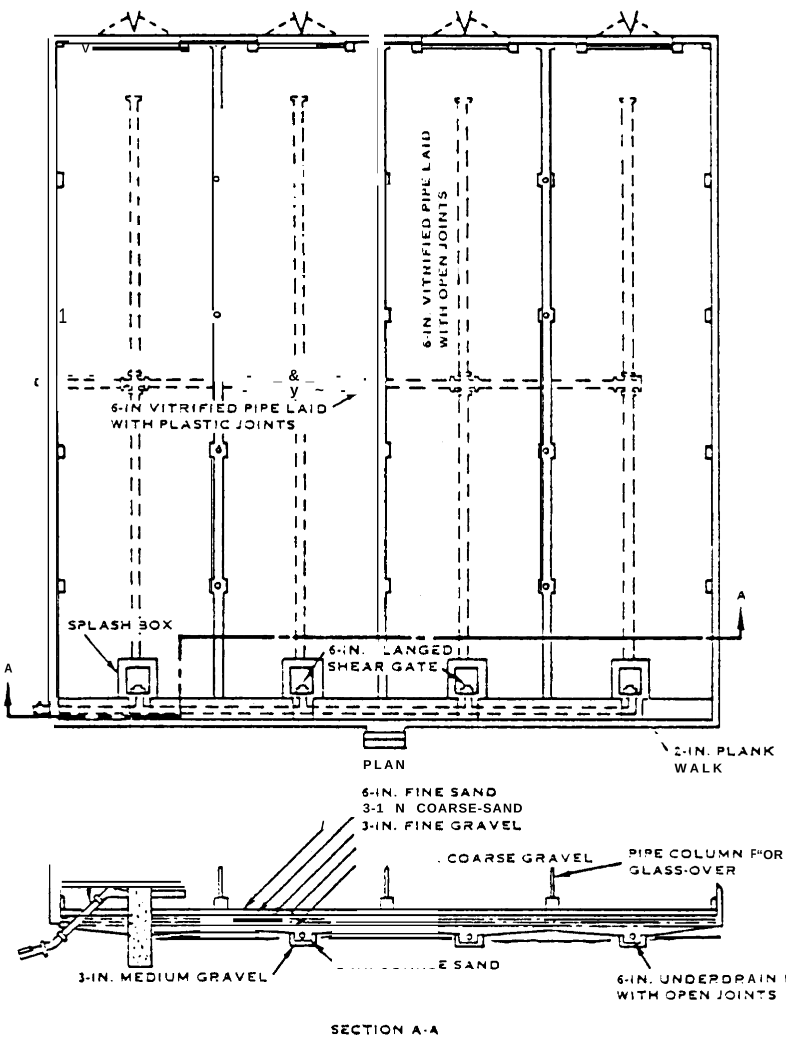


SOURCE: Assessment of Oil Shale Retort Waste Water Treatment anrd Control Technology, Hamilton Standard Division of United Technologies, July 1978, p. 5-9

Figure D-11 .—Evaporation Systems for Sludge Drying



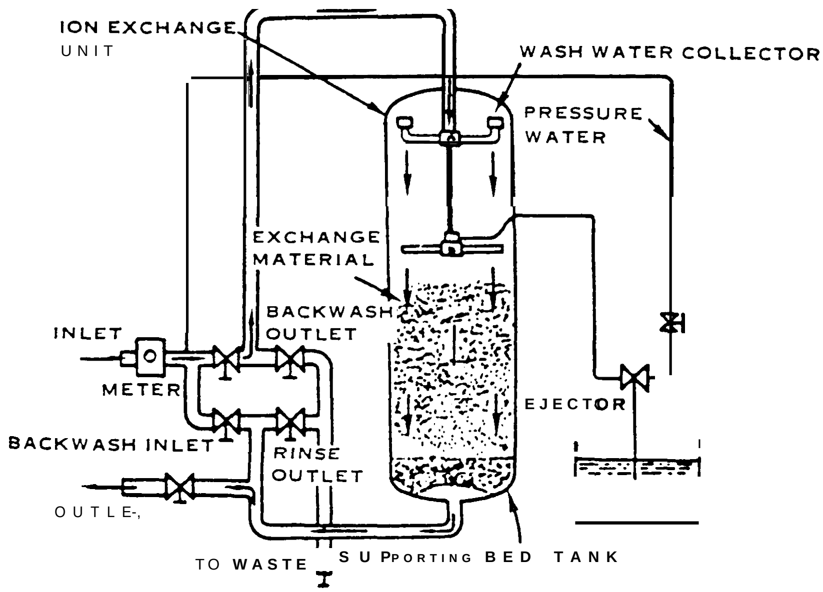
A. Evaporation pond



B. Sludge drying bed

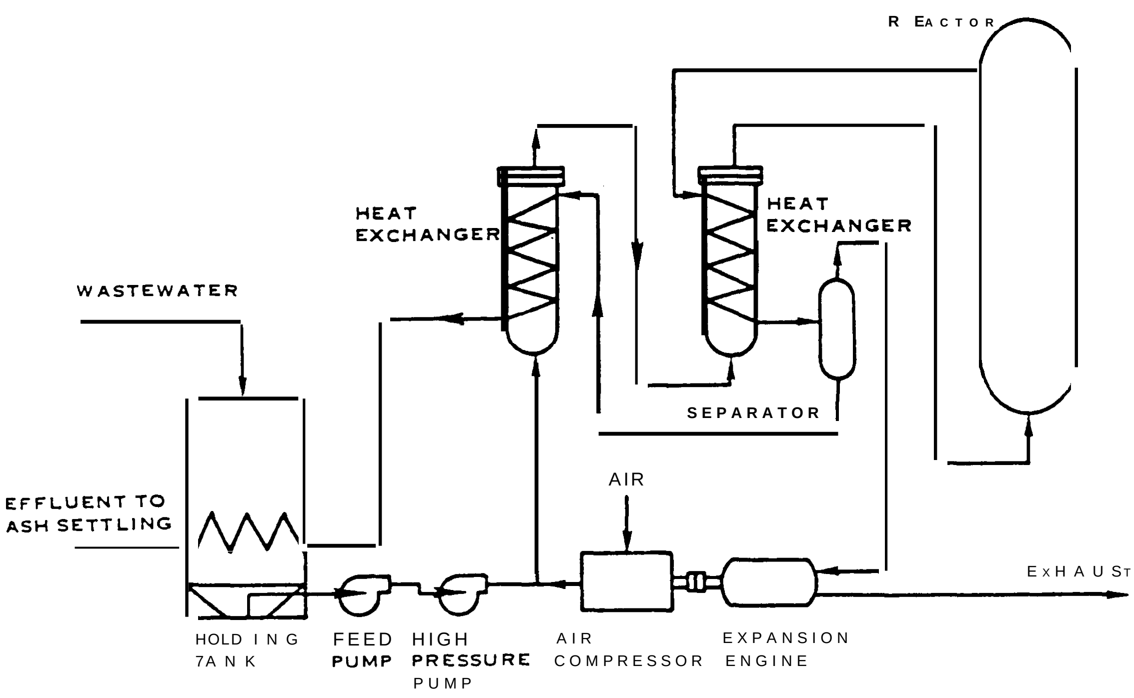
SOURCE: *Assessment of Oil Shale Retort Wastewater Treatment and Control Technology*, Hamilton Standard Division of United Technologies, July 1978, pp. 5-10 and 4-11.

Figure D-12.—A Regenerable Ion Exchange System



SOURCE *Assessment of 011 Shale Retort Wastewater Treatment and Control Technology,* Hamilton Standard Divlsion of United Technologies. July 1978, p 5-14

Figure D-1 3.— Wet Air Oxidation



SOURCE. *Assessment of 0il Shale Retort Wastewater Treatment and Control Technology,* **Hamilton Standard Division of United Technologies, July 1978, p 5-14**

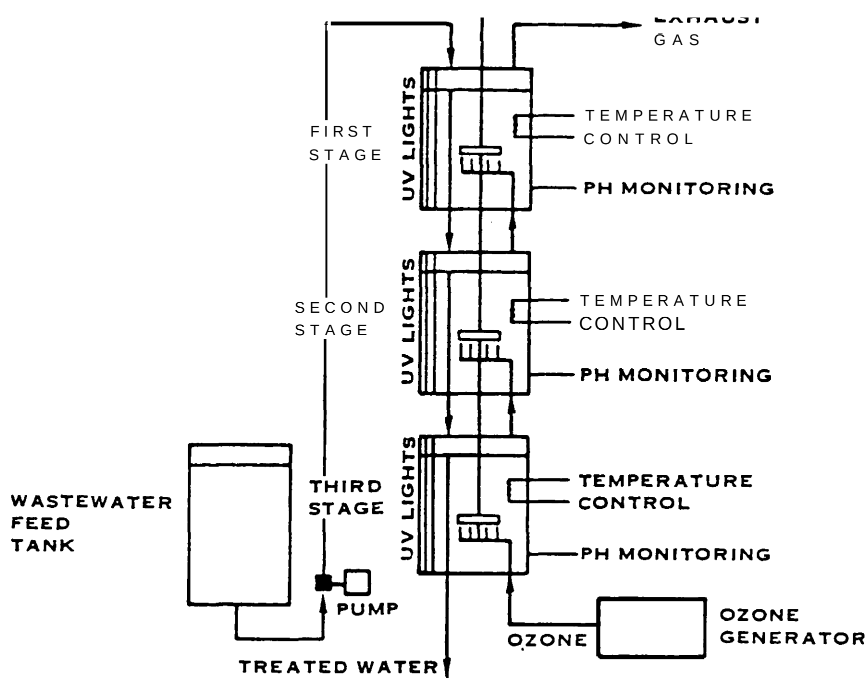
pletely or at least decomposing them into forms that are more easily treated. In particular, the process can be used to increase the biodegradable properties of compounds that are normally refractory (resistant) to biological oxidation. The method is very effective but is costly because the highly corrosive environment within the equipment requires expensive materials and construction methods.

- **Photolytic oxidation** processes (figure D-14) use light to oxidize organic contaminants. They can be used in conjunction with chemical oxidizers. One technique that works well in many industrial situations is the combination of ultraviolet light and ozone gas. The process has the disadvantage of requiring relatively long residence times.
- **Electrolytic oxidation** is similar to electrodialysis except that it can be used to oxidize or reduce dissolved contaminants to their gaseous forms. **A** typical system is shown in figure D-15. The method is costly to operate, and is generally reserved for removing very valuable or very hazardous substances, It has been used with industrial wastewaters to remove, for example, chromic acid and cyanide. In oil shale plants, it could be employed for removing hazardous organics.
- **Chemical oxidation** relies on contacting wastewater with oxidizing chemicals. **As** mentioned previously, chemical oxidation can be combined with other oxidizing systems. The example of ozone combined with ultraviolet light was mentioned above. The chemical combination of ozone and hydrogen peroxide has been found to work well with refinery wastes, which are similar to the expected wastes from oil shale processing. Potassium permanganate has been tested with oil shale streams.

Biological Methods

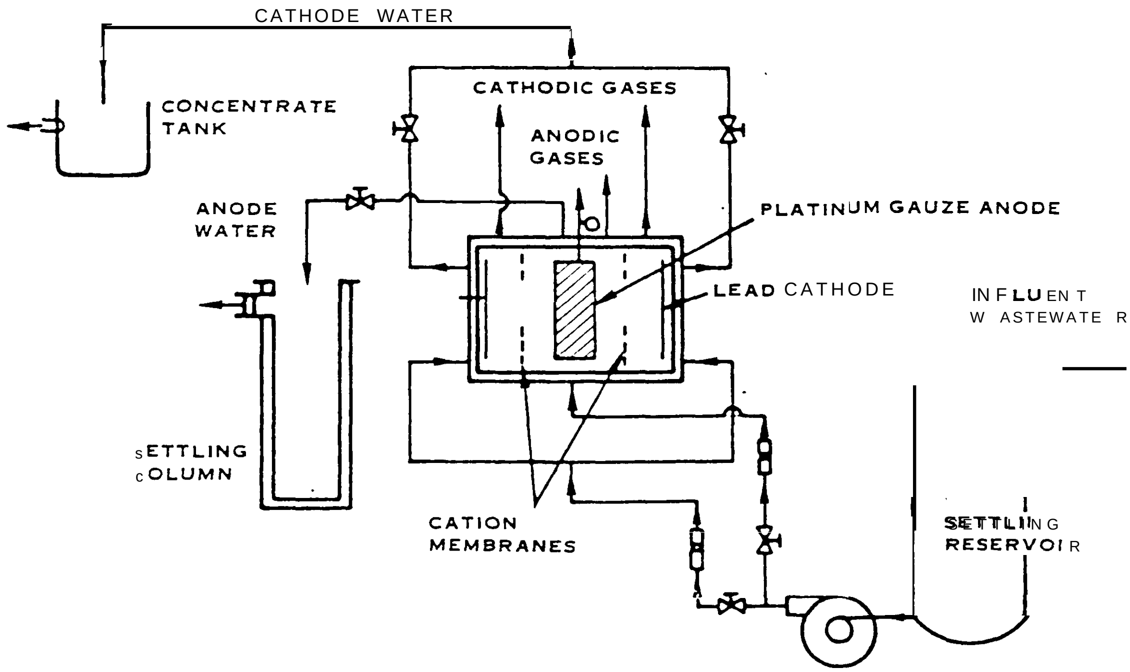
- **Anaerobic and aerobic digestion.-The principal** anaerobic system is the anaerobic digester, which is a closed, heated vessel in which the microbial population is maintained under an atmosphere of its own waste gases. Such systems have a long history of application in treatment of municipal wastes. **A** typical digester is

Figure D-14.— Photolytic Oxidation



SOURCE: *Assessment of Oil Shale Retort Wastewater Treatment and Control Technology*, Hamilton Standard Division of United Technologies, July 1978, p. 5-15.

Figure D-15.—Electrolytic Oxidation

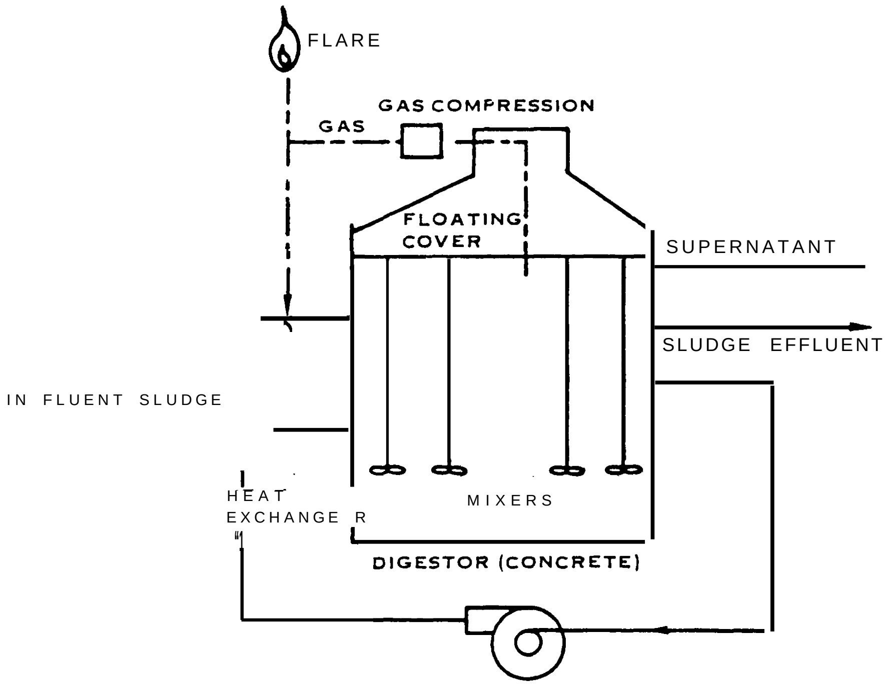


SOURCE *Assessment of* **Oil** *Shale Retort Wastewater Treatment and Control Technology,* **Hamilton Standard Division of United Technologies.** July 1978, p 5-15

shown in figure D-16. The illustration shows a flare stack for disposal of the digester gas. It is also possible **to use** the gas for many industrial purposes. In municipal systems, the gas is used as fuel for the compressors that maintain the atmosphere within the unit. Some of the common aerobic biological systems, in which digestion takes place in an oxygen-rich atmosphere, are described below,

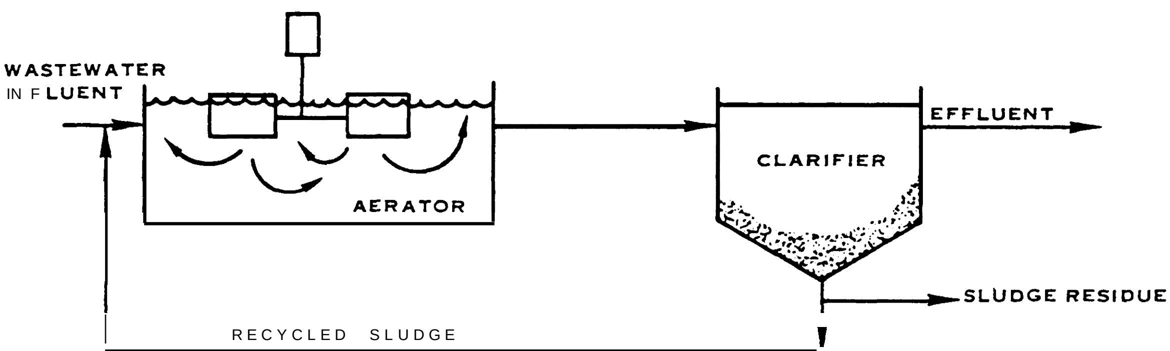
1. Activated sludge processes treat waste streams that contain 1 percent or less of suspended solids. In this process, flocculated biological growths are continuously circulated in contact with organic wastewater in the presence of oxygen. Organic compounds that can be decomposed include polysaccharides, proteins, fats, alcohols, aldehydes, fatty acids, alkanes, alkenes, cycloalkanes, and aromatics. The process is widely used for industrial wastes and is even more common in municipal treatment plants, It is relatively inexpensive to fabricate and operate, and is usually cost effective for a variety of organic contaminants. Its major disadvantages are complex control procedures and high maintenance and power requirements. A typical activated sludge system is shown in figure D-1 7,
2. Trickling filters are also commonly used for municipal wastewater treatment. One system is shown in figure D-18. In this process, the microbial population lives on the fixed elements of the filtering medium, and the wastewater trickles past them. Stones were a common medium in the past; plastic is more common today. Extra nutrients are often added to the entering waste stream to accelerate the biodegradation process. The process requires relatively little land area and can achieve high throughputs with the proper adjustments of acidity, nutrients, and trace chemicals. It does not work well if the waste is chemically unstable or if it contains suspended solids.
3, Aerated lagoons are similar to activated sludge processes except that the micro-organisms are not circulated. The lagoons are essentially stabilization ponds that are equipped with mechanical agitators and aerators to provide the microbial population with uniform conditions and with the oxygen that they need to grow. About **60 to 90** per-

Figure D-16.—An Anaerobic Digestor



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

Figure D-1 7.—The Activated Sludge Process

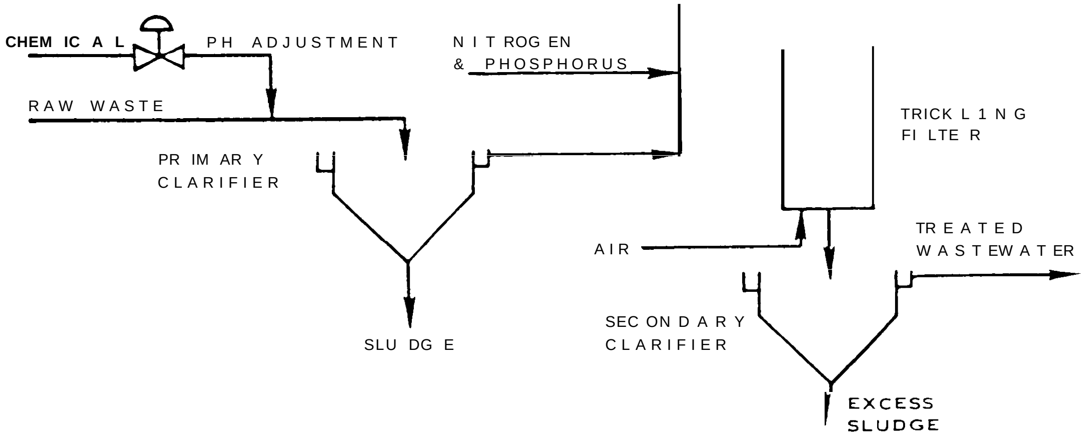


SOURCE: *Assessment of Oil Shale Retort Wastewater Treatment and Control Technology,* Hamilton Standard Division of United Technologies, July 1978, p. 5-17

cent of organic matter can be removed by this process. A typical arrangement is shown in figure D-19.

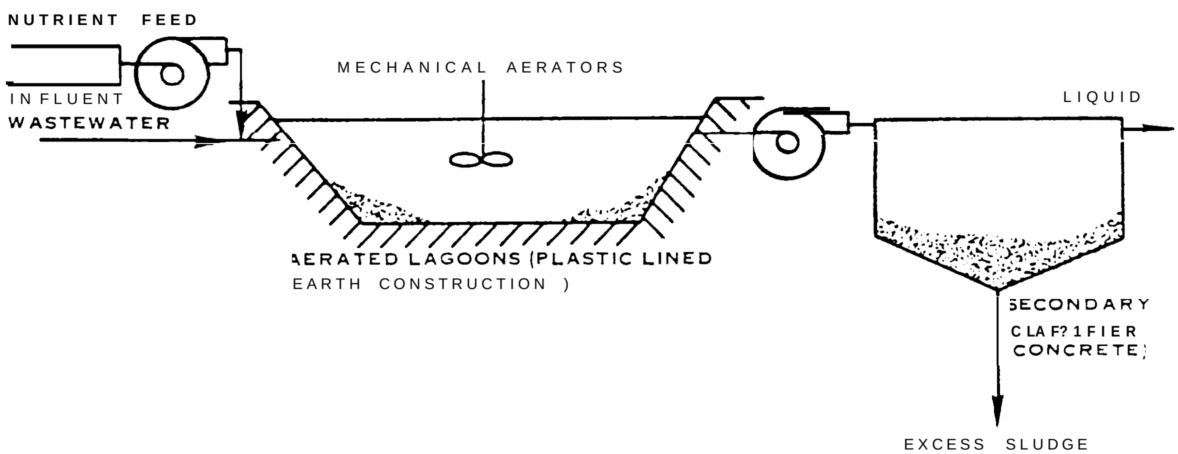
4. *Rotating biological contactors (RBCs)* are a combination of activated sludge and trickling filter processes. One system is shown in figure D-20. The micro-organisms are attached to a large number of disks that are rotated through a pool of the wastewater. Thus, a thin film of wastewater is simultaneously exposed to the microbial colony and to the air. Biodegradation occurs very rapidly. A unique advantage of RBCs is that different strains of micro-organisms can be established on each of the disks, One strain could be established on an upstream disk to remove the organic compounds that might be harmful to another strain on a downstream disk. This could not be done in other biological systems in which all micro-organisms are exposed to essentially the same environment.

Figure D-18.—Trickling. Filter Waste Treatment



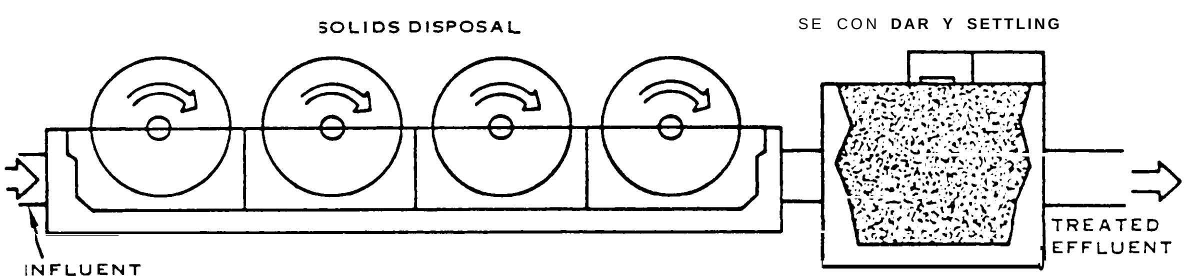
SOURCE *Assessment of Oil Shale Retort Waste water Treatment and Contro/ Technology,* Hamilton Standard Division of United Technologies, July 1978 p 5-17

Figure D-19.—Aerated-Lagoon Waste Treatment



SOURCE *Assessment of Oil Shale Retort Wastewater Treatment and Control Technology.* Hamilton Standard Division of United Technologies, July 1978 p 5-17

Figure D-20.— Rotating Biological Contractor



SOURCE *Assessment of* Oil Shale Retort *Wastewater Treatment and Control Technology,* Hamilton Standard Division of United Technologies. July 1978, p 518

Status of Point Source Water Pollution Control Methods

The removal efficiencies, reliabilities, adaptabilities, and cost features of some point source control technologies are summarized in table D-1.

Removal Efficiency

All of the systems could perform adequately for first-stage oil and grease removal, and meeting discharge standards should be possible if a biological oxidation unit is used for final cleaning. If not, single-stage cleaning in a coalescing filter would be sufficient. For dissolved gases, any of the stripping techniques should be adequate alone, and a biological oxidation unit could be used for final removal of any residual NH_3. For removal of organic compounds, carbon adsorption would be suitable if used in conjunction with pretreatment and post-treatment systems. Photolytic methods should also work, but they are not well demonstrated. Any filtration method would reduce suspended solids to acceptable levels. For dissolved inorganic, clarification would generally have low removal efficiency but could be suitable for removing metals. Distillation would be very effective for salt removal. Ion exchange or reverse osmosis would also work well, but their limited capacities might restrict their use to final removal of low-level contaminants. For sludges, sludge drying beds and evaporation basins would be very effective in the semiarid oil shale region. The alternate processes would be much less effective.

Table D-1 .–Relative Ranking 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		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

BOD = biological oxygen demand COD = chemical oxygen demand

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

Reliability

For oil and grease removal, the coalescing filter has the only potentially severe reliability problem because it tends to clog. For dissolved gases, all of the stripping techniques should be sufficiently reliable, Biological oxidation is considered less reliable because of the need for carefully controlled inlet conditions. For organics removal, chemical oxidation should be the most reliable; the biological systems (activated sludge, trickling filters, rotating contractors, and anaerobic digestion) should also be satisfactory. All systems for removal of suspended solids should be highly reliable, For dissolved solids, clarification and ion exchange are highly reliable. Distillation is downgraded because of its potential for corrosion; reverse osmosis because of potential fouling problems; and electrodialysis because it has a relatively short history of successful applications. For handling sludge, thickening, anaerobic digestion, and all of the filtration techniques should be highly reliable,

Adaptability

Few treatment techniques have been extensively tested with oil shale waste streams, and most will be adapted directly from other industries. Physical and chemical conditions in which a device will be expected to operate may differ significantly from those for which it was originally developed and in which it is normally operated. For example, **a** method suitable for petroleum refineries may not work well in the oil shale industry where it will be exposed to shale fines, organometallic complexes, or other contaminants peculiar to oil shale wastewaters. Although a system cannot be fully evaluated until it has been tested under commercial operating conditions, indications of the expected performance can be obtained by examining how easily the technique has been adapted to other new industries significantly different from the one for which it was developed.

As shown in table D-1, all of the systems for oil and grease removal are highly adaptable. For dissolved gases, air stripping and steam stripping are highly adaptable; flue gas stripping is downgraded because suitable gases may not be available. Biological systems are downgraded because they may have problems with the high NH_3 concentrations in some oil shale wastewaters. They could probably be used only with some pretreatment system. For dissolved organics, the oxidation systems and carbon adsorption are very adaptable, the biological systems less so because of potentially toxic substances and because they are sensitive to inlet conditions. All methods for removing suspended solids are highly adaptable. However, problems may be encountered with the removal of dissolved solids because of possible interference from high salt loadings or membrane clogging. The only significant problem with distillation is its need for cooling water, which may not be readily available at oil shale sites. For sludge handling, thickeners and filters are highly adaptable. Sludge drying beds and evaporation ponds should have no technical adaptability problems, but they are downgraded because evaporation would mean a loss of the contained moisture, which could be recovered with filtration systems. Aerobic digestion is downgraded because some of the components of oil shale sludges may resist biological degradation.

cost

Costs in table D-1 are based on experience with similar systems in other industries. As indicated, systems with moderate capital and operating costs are available for all of the major contaminants, and many of the lower cost options also have reasonable removal efficiencies, reliability, and adaptability. The only potentially serious problem is in removal of dissolved solids, where the medium-cost systems (reverse osmosis and clarification) have questionable removal efficiencies.

Integrated Wastewater Treatment Systems

Generally, no one device is able to remove all the contaminants from a process stream, Furthermore, certain process streams may be combined before treatment or at different stages of treatment to take advantage of scale economies.

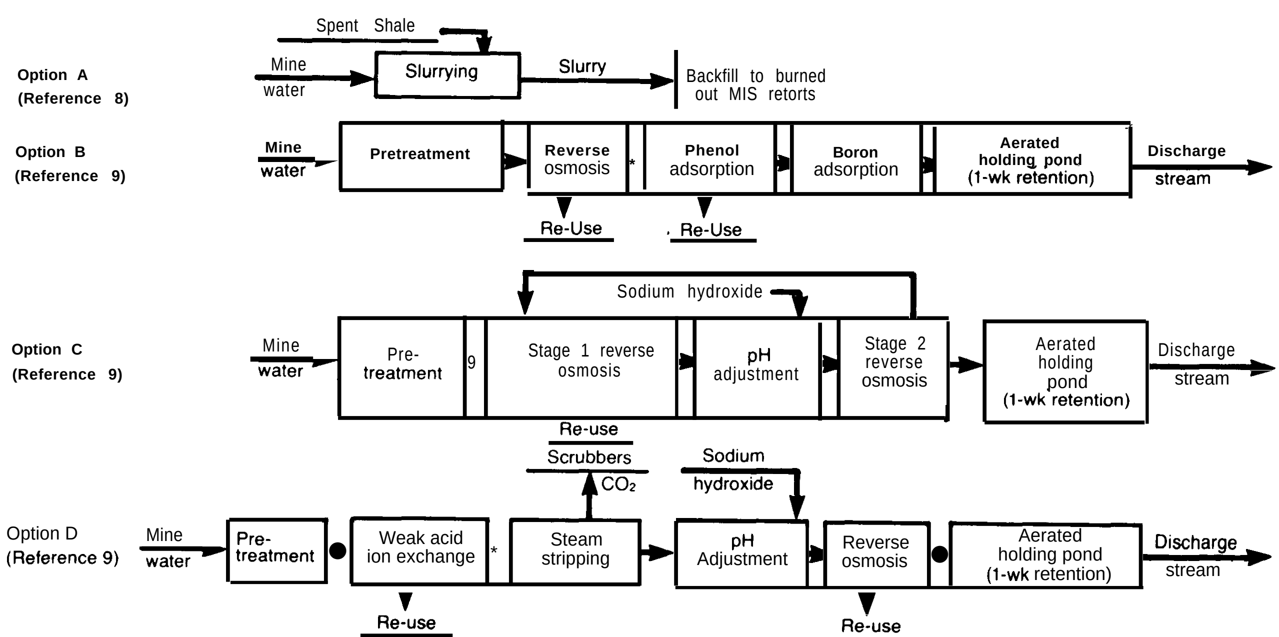
Treatment systems that have been proposed for oil shale wastewater streams are shown in figure D-21 for mine drainage water, figure D-22 for gas condensate, and figure D-23 for retort condensate. These systems and their component units are discussed below.

Excess Mine Drainage Water

This water can be used without treatment as a slurry medium for backfilling burnt out in situ retorts,' but sufficient ground water may not be available over the lifetime of the plant for this control option. Additional water might have to be imported from other sites. Another disposal option is reinfection, but for this purpose the water should be free of suspended solids and contain no constituents that would react adversely with the water in the receiving strata.[5 6 7] While mine drainage water could easily be treated to meet these requirements, reinfection is a costly disposal option, because deep wells would be required to avoid contamination of aquifers that discharge to the surface, and an extensive piping network would be needed. It has been suggested that the reinfection option be used only for very objectionable and relatively untreatable wastes and that underground disposal of the relatively clean mine drainage water would be wasteful in a region where water is scarce.[17 18]

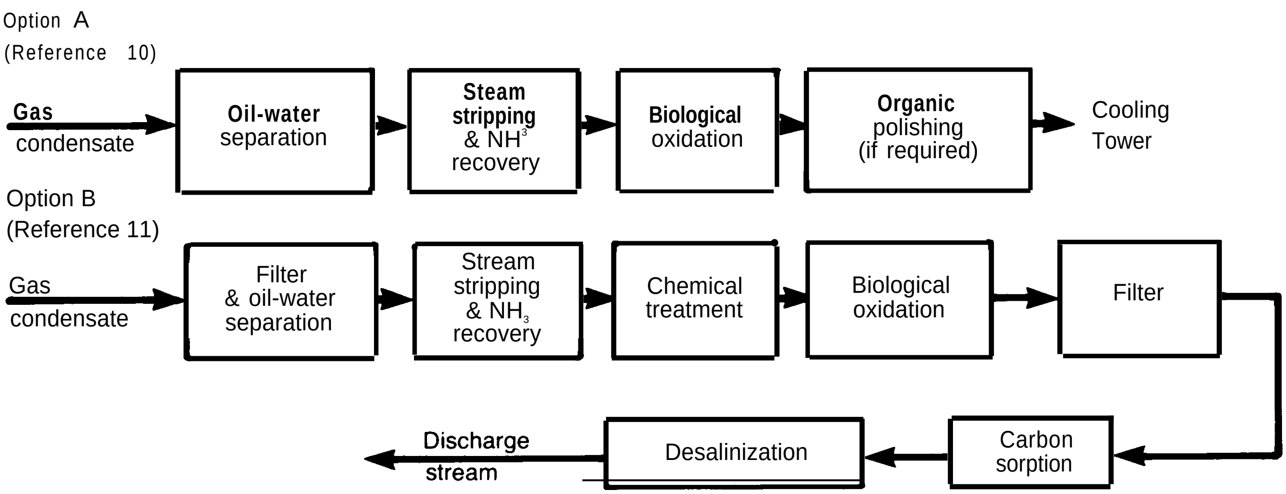
For the option of discharge to a river, dissolved solids would have to be reduced to less than 500 mg/l, which can easily be achieved by a membrane process such as reverse osmosis, as shown in figure D-21. Treatment is not expected to be difficult, but conclusive test data are not yet available.[19] Discharge permits will probably also specify a phenol concentration of no more than 0.001 mg/1 and a boron concentration of less than 0.75 mg/1. Specific ion absorbents are available for these substances and can be used, as suggested in option A of figure D-21. Alternatively, a second-stage reverse osmosis step may prove more economical, as suggested in option C of figure D-21. A single-stage, high-pH reverse osmosis step may also prove adequate, particularly if some of the

Figure D-21 .—Possible Treatment Options for Excess Mine Drainage



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

Figure D-22.— Possible Treatment Options for Gas Condensates



SOURCE R F Probstetn H Gold and R E Hicks, *Wafer RequirementsReaufrernenfs, PollutionEffectsandCostsof Wafer SupplyandTreatmentfortheOil Shale Industry,* prepared for OTA by Water Purification Associates, October '1979

dissolved salts are first removed by chemical pretreatment in a weak acid ion exchange degasifier as shown in option D of figure D-21,

An aerated holding pond would be used in any of the options to dissipate any NH_3 and phenol that are not removed in the treatment units. The pond would also serve as an equalization basin for blending in waters that can bypass the treatment train. The size of the bypass stream will vary with the quality of the drainage water, the effectiveness of the aeration pond, and the criteria of the discharge permit.

Gas Condensate

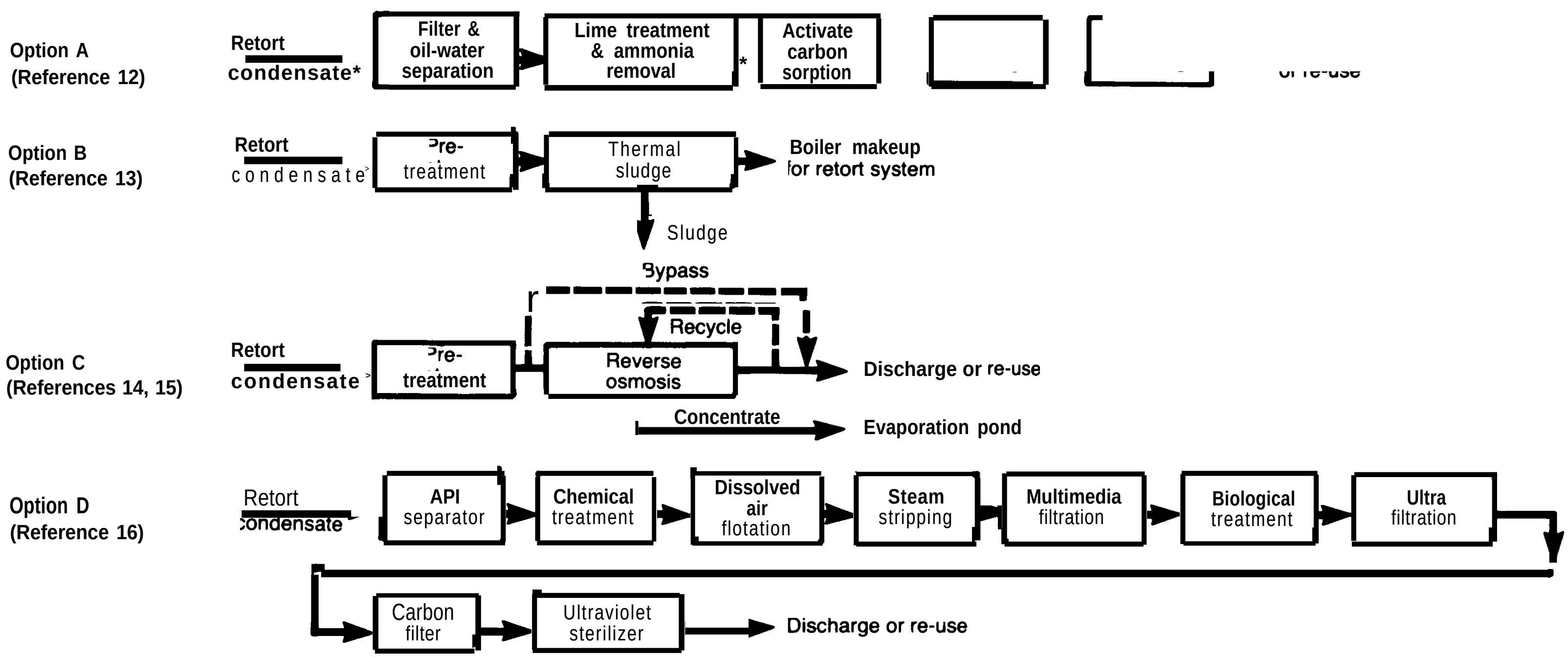
This stream requires treatment for removal of dissolved gases and organics. Dissolved NH_3 will largely be combined with CO_2 in the form of ammonium bicarbonate. Both gases can easily be removed by steam stripping. Stripping has been tested in the laboratory with both a synthetic ammonium bicarbonate solution and an actual gas condensate.[20 21] It was found that the small amount of oil present in the condensate was rapidly removed in the stripping operation, but even if an oil-water separator is required before the stripper (as suggested in figure D-22) separation difficulties due to emulsification are not expected.

Organic control by biological oxidation has not yet been demonstrated on an actual gas condensate stream, The organic mix is different from that of retort condensates and may prove to be more or less amenable to biodegradation. Other processes such as resin adsorption, carbon adsorption, and wet air oxidation are available for organics control and may prove adequate in combination. Preliminary laboratory investigations on retort condensates suggest that no single process (except possibly wet air oxidation) will be capable of controlling all the organics present.

The use of a cooling tower as part of the treatment systems (as shown in option A of figure D-22) would have two advantages. First, experience with similar wastewaters has shown that some degradation of organics occurs in a properly operated cooling tower circuit.[22] Second, the volume of blowdown water leaving the cooling tower is one-half to one-tenth that of the makeup water, depending on the number of concentration cycles used. Final organic polishing, if necessary, can therefore be done on a smaller, more concentrated stream. Because the wastewater stream will previously have been subjected to high-temperature steam stripping, air pollution by volatilization of organics in the cooling tower is not expected to be a problem. This assumes that any organics created in the biological oxidation step will be either nonvolatile or nontoxic.

Although salts are not a major contaminant in the gas condensate stream, desalination by reverse osmosis could be used to remove inorganic and organics. In option B of figure D-22, a desalination step is included to provide a very clean discharge stream. An effluent stream could also be

Figure D-23.—Possible Treatment Options for Retort Condensates



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

taken from any intermediate stage of the treatment system to provide water for various reuse options.

Retort Condensate

The retort condensate stream presents the most formidable treatment challenge. As discussed in chapter 8, this stream is created when water and oil vapors condense within in situ retorts, and some aboveground retorts if they are operated at a low top temperature. The condensate will be contaminated with oil, dissolved gases, inorganic salts, and organic substances, all of which will have to be removed.

In the conventional treatment scheme of option A in figure D-23, oil and suspended solids are first separated from the water. Oil-water separation by API units may not be adequate because of emulsions, and some emulsion-breaking technique will probably be required. The techniques that would be appropriate for oil shale wastewaters have not yet been determined.

The addition of lime will facilitate NH_3 removal and will also remove calcium, magnesium, and carbonate ions. NH_3 is easily removed by steam stripping, but unlike the gas condensate, the retort condensate contains strong acid anions that will "fix" the NH_3 as ammonium ions, which cannot be directly stripped. Lime addition will elevate the pH and convert ammonium to NH_3.[23] The pH elevation is also needed to prevent scaling and fouling of the steam stripping column by carbonate precipitates.

Removal of organic substances from retort condensates has not been adequately demonstrated. Activated carbon adsorption (option A in figure D-23) would remove only about half of the organics and would be expensive, given the high organic concentrations found in retort condensates.[24 25] Biological treatment (option D) has been suggested for control of organics, but complete removal by biological processing may not be achievable. The two major problems with biological treatment are the presence of resistant (biorefractory) and toxic materials. It is expected that as much as half of the organic matter in retort water will be biorefractory and that adequate removal may not be possible even with novel process modifications such as the addition of powdered activated carbon to the biological unit. Laboratory tests have shown that the addition of powdered activated carbon to the aeration basin in an air-activated sludge biological system improves organics removal by only about 10 percent, indicating that much of the biorefractory organic matter is not adsorbed on carbon. Polymeric resins have been shown to facilitate removal of organics from retort condensates,[26] but it **is not** known whether the ones removed are those that are resistant to biological and activated carbon treatment.

The inhibition of biological action by toxic substances is also expected to be a problem, The toxics may be either organic or inorganic, and can be expected to be different in the condensates from different retorts. Their characteristics and concentrations may even change with time if retorting conditions are not constant—a normal situation in MIS processes. Even with all of its potential disadvantages, biological oxidation could prove more economical and more effective than other processes (such as wet air oxidation) when combined with appropriate pretreatment and polishing steps.

Wet air oxidation removes a much wider variety of organics but it is also more expensive. In this process, organic material in water is oxidized by air at about 500° F (260° C). The water is pressurized to prevent boiling. The reaction takes about 30 minutes and a pressure vessel is required that is large enough to contain the water for this length of time. The cost of wet oxidation is not strongly dependent on the concentration of the waste, and unlike biological treatment it can be cost effective for very concentrated wastes. Wet air oxidation also has several technical advantages, Because it relies on chemical oxidation, the organic material that is to be destroyed does not have to be biodegradable. In fact, biorefractory materials are often converted to biodegradable substances, and a biological process could be effectively used as a polishing step. No data have been published on the performance of a wet air oxidation process with oil shale retort condensates, but an investigation has been initiated.[27]

Reverse osmosis membranes (option C in figure D-23) are also available for organics control,[28] but recent tests have shown that considerable pretreatment will be required to provide a feed that will not plug or foul the membranes, [29] In fact, a pretreatment system similar to the treatment train of option A in figure D-23 may be required for very dirty condensates. If this is done, then it is not clear that a final reverse osmosis step will be required to provide an effluent suitable for some of the low-quality reuse options. Nevertheless, reverse osmosis is of interest because it also provides a means for control for some of the inorganic contaminants for which lime softening is not adequate. Ion exchange demineralization after organics removal is an alternative to reverse osmosis, but its costs escalate rapidly with increasing salt concentrations in the feed.

It is apparent that even if the retort condensate is to be treated to only the low-quality levels required by some re-use options, an elaborate treatment system similar to that shown as option D in figure D-23 will be required. Even here additional treatment steps may be required. API separators may not be adequate, and an ultrafiltration step upstream of the steam stripper may be needed to remove emulsified oil and large organic molecules. As discussed above, biological oxidation and carbon adsorption will not adequately control the remaining organics, and resin adsorption or wet air oxidation steps may be required. An additional processing step to remove inorganic may also be required for some re-use options.

In view of the difficulty in treating the retort condensate (option B in figure D-23) in which the treated water is used to raise steam for retorting is the most attractive. Volatilized organics will be incinerated in the retort, and other substances can be removed in a concentrated sludge for disposition at a hazardous-waste disposal site. A stripping pretreatment step may be needed to avoid accumulating NH_3 and CO_2 in the thermal sludge device. No information has been published on the feasibility of a thermal-sludge steam raising process fed with retort condensates. Scaling and fouling may be problems unless appropriate pretreatment steps are used.

Other Wastewater Streams

The two other major streams are the coker and hydrotreater condensates from the shale oil upgrading section. Compositions of these streams are not known, but they should be somewhat similar to the gas condensate. The exception is the concentration of dissolved gas because, in the absence of CO_2, the NH_3 will probably react with H_2S to form ammonium hydrogen sulfide. Different steam stripping conditions will be required in that more stages or more steam will be needed to remove H_2S. Modifications should not be extreme because, unlike in the retort condensate, there should be no NH_3-fixing inorganic anions present. The treatment systems can be expected to be similar to any of the options shown in figure D-22.

Blowdown streams, regenerant streams, concentrates, and sludge products from water treatment processes must also be handled. If a thermal sludge process is included in any water treatment train, it could be used to reduce the reverse osmosis concentrates and ion exchange regenerant streams to a disposable sludge. If not, vapor compression evaporators may be used. These have been successfully demonstrated on a commercial-scale at, for example, electric power generating stations. Because cooling towers will probably be operated with few cycles of concentration, blowdown streams should not have high salt concentrations, and should be suitable for dust control and shale disposal operations.

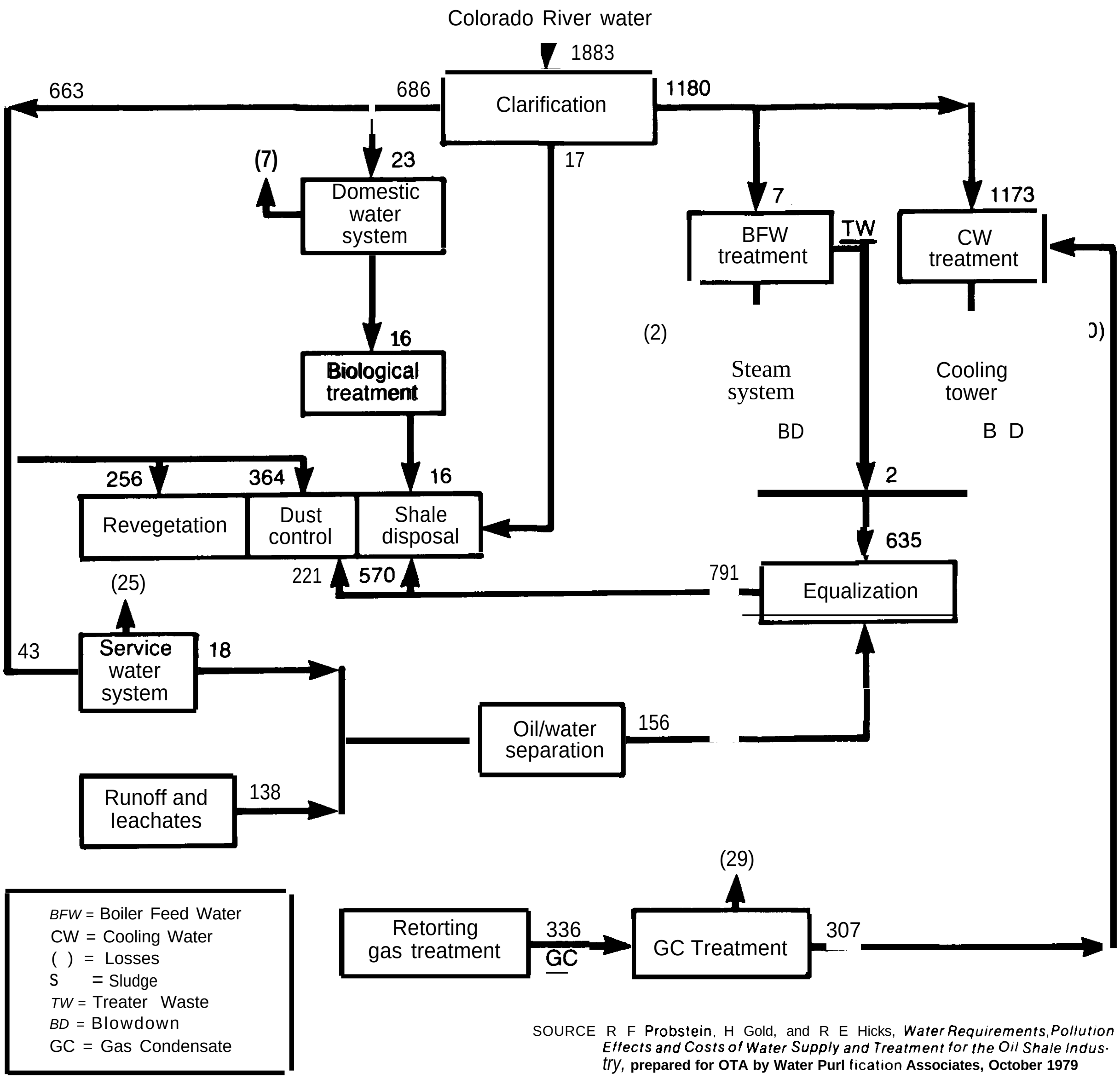
Water Management Plans for Oil Shale Facilities

Complete water management plans must consider supply, treatment, waste recovery and removal, and ultimate disposition. Figures D-24 through D-26 are flow sheets that show how water would be used, treated, and disposed of in three typical oil shale facilities. The flows into, within, and out of the plants are indicated in gallons per minute.

Figure D-24 is a water management plan for an aboveground direct facility that uses Paraho retorts. The major sources of water are the Colorado River, contaminated runoff from the facility site and its associated disposal area, and gas condensates from the retorting section. No upgrading facilities are included, so there are no upgrading condensates. The total water inflow is 2,357 gal/rein, of which about 40 percent is lost to the atmosphere through evaporation within the facility. The rest is eventually used for dust control and in the solid waste disposal area for spent shale moistening, compaction, and revegetation. The principal components of this water are treated river water, sanitary wastes, blowdowns, runoff, service water, and condensates.

Figure **1)-25** is a plan for an aboveground indirect plant that uses TOSCO II retorts. Because the retorts are indirectly heated, and because upgrading facilities are included, water requirements are substantially higher than for the Paraho plant. The total inflow is 7,386 gal/rein from the Colorado River, from surface runoff, and from gas condensates and upgrading condensates.

Figure D-24.— Major Streams in a 50-000-bbl/d Aboveground Direct (Paraho) Oil Shale Plant (gal/rein)



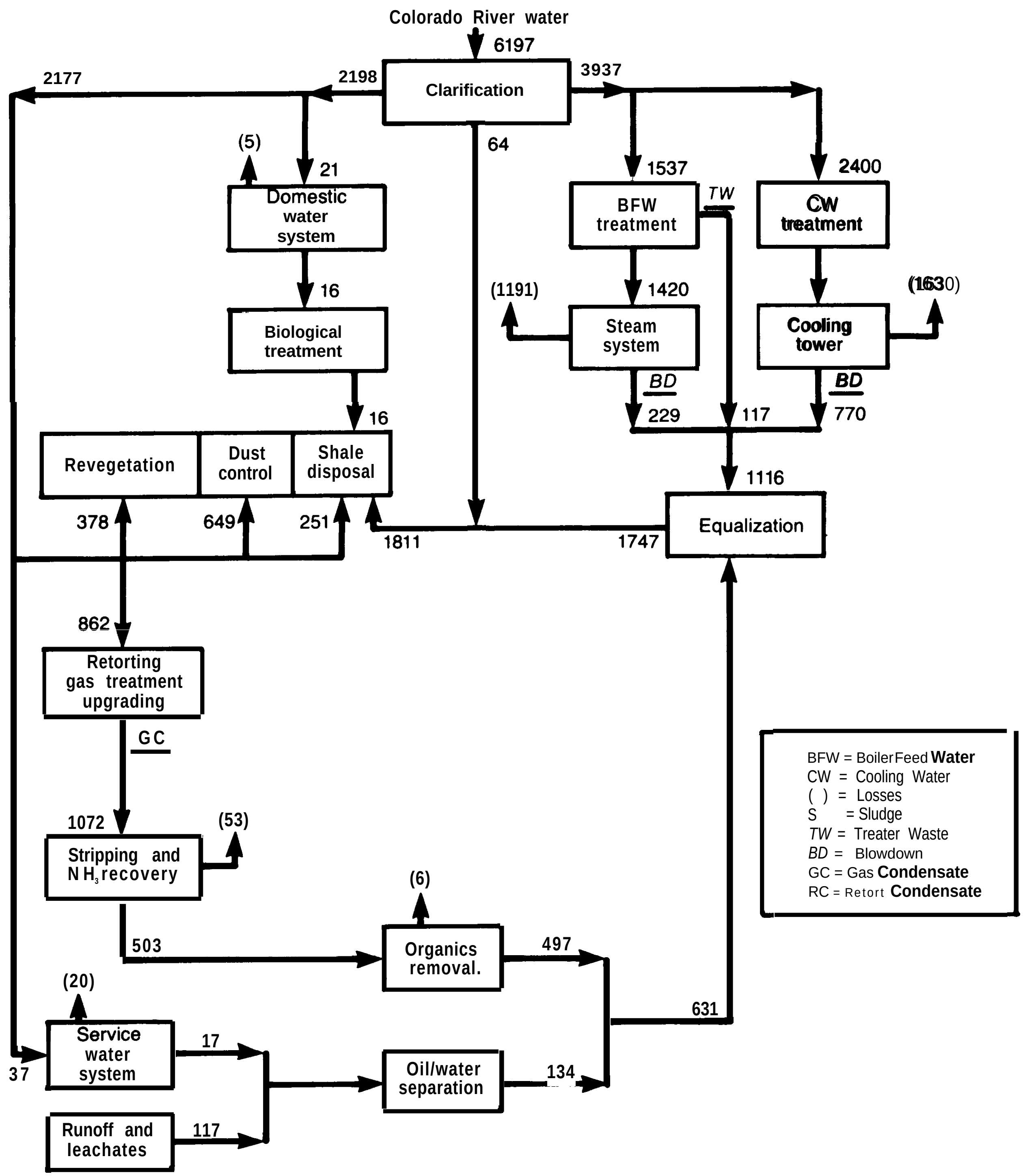
SOURCE R F Probstein, H Gold, and R E Hicks, *Water Requirements, Pollution Effects and Costs of Water Supply and Treatment for the Oil Shale Industry*, prepared for OTA by Water Purl fication Associates, October 1979

About 40 percent of the water is lost through evaporation. The rest is eventually used for dust control, or finds its way to the spent shale pile.

Figure D-26 is a plan for an MIS facility that is located in a ground water area, Excess mine drainage water is produced, and over 70 percent of it is reinfected. The rest is used in the plant, together with retort condensates, gas condensates, and surface runoff, The plant uses a thermal sludge system to process the retort condensate and to generate steam for injection into the in situ retorts. The system produces no liquid effluent. The total net inflow is about 5,059 gal/rein, of which 34 percent is lost through evaporation and 34 percent is converted to steam for the retorts. The rest is used to control dust and for disposal of the mined raw shale.

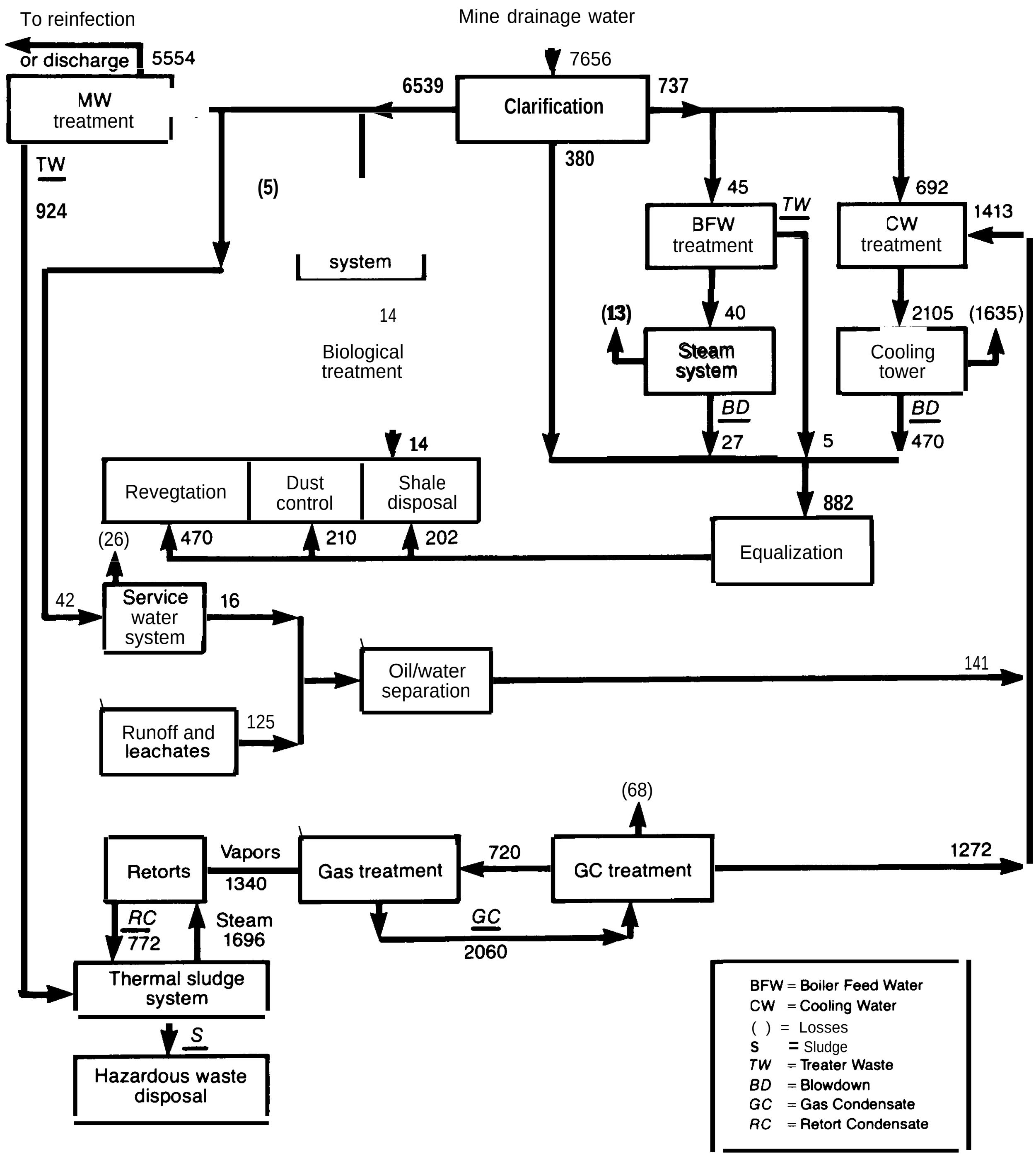
In summary, the aboveground direct plant will dispose of about 604 gal/min of treated wastewater and treated condensates in the spent shale disposal pile. An additional 22 I gal/rein of treated wastewater will be used for dust control. The

Figure D-25.—Major Streams in a 50,000-bbl/d Aboveground Indirect (TOSCO II) Oil Shale Plant (gal/rein)



SOURCE: R. F. Probstein, 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.

Figure D-26.— Major Streams in a 50,000-bbl/d MIS Oil Shale Plant (gal/rein)



SOURCE: R.F. Probstein, 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 aboveground indirect plant will add about 1,827 gal/rein of treated wastewater and concentrates to the disposal pile. The MIS plant will use about 686 gal/rein of treated wastewater for raw shale disposal and 210 gal/rein for dust control An additional 5,554 gal/rein of treated mine drainage water will be reinfected into the source aquifer. Thus, the methods for wastewater management and disposal are recycling after treatment, followed by disposal through evaporation, in dust control, and in solid waste disposal areas. Excess treated mine drainage water will be reinfected.

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[29]Supra No. 19.

APPENDIX E

Acronyms, Abbreviations, and Glossary

Acronyms and Abbreviations

acre-ft	—acre-feet
acre-ft/yr	—acre-feet per year
AGR	—aboveground retorting
API	—American Petroleum Institute
AQCR	—Air Quality Control Regions
ARCO	—Atlantic Richfield Co,
BACT	—best available control technology
BaP	—benzo(a)pyrene
BAT	—best available technology
bbl	—barrel(s)
bbl/d	—barrels per day
BLM	—Bureau of Land Management, Department of the Interior
BOD	—biochemical oxygen demand
BPT	—best practicable control technology currently available
Btu	—British thermal unit
cm	—centimeter
cm/h	—centimeters per hour
CO	—carbon monoxide
CO_2	—carbon dioxide
COS	—carbonyl sulfide
CRS	—Congressional Research Service
CRSP	—Colorado River Storage Project Act of 1956
CRSS	—Colorado River System Simulation Model
CS_2	—carbon disulfide
CWACOG	—Colorado West Area Council of Governments
CZMA	—Coastal Zone Management Act
DDP	—detailed development plan
DEI	—Development Engineering, Inc.
DLA	—Department of Local Affairs (Colorado)
DNR	—Department of Natural Resources (Colorado)
DOD	—Department of Defense
DOE	—Department of Energy
DOI	—Department of the Interior
DRI	—Denver Research Institute
EIS	—environmental impact statement
EPA	—Environmental Protection Agency
ERDA	—Energy Research and Development Administration
FAPRS	—Federal Assistance Program Retrieval Systems
FLPMA	—Federal Land Policy and Management Act of 1976
FmHA	—Farmers Home Administration
FMSHA	—Federal Mine Safety and Health Amendments of 1977
FRC	—Federal Regional Council
ft	—feet
ft^2	—square feet
ft^3	—cubic feet
FUND	—Foundation for Urban and Neighborhood Development
FWPCA	—Federal Water Pollution Control Act of 1972
gal	—gallon
gal/rein	—gallons per minute
gal/ton	—gallons per ton
GOREDCO	—Gulf Oil Real Estate Development COO
HC	—hydrocarbons
HEW	—Department of Health, Education, and Welfare
H_2S	—hydrogen sulfide
IFS	—Institute Francais du Petrol
JBC	—Joint Budget Committee of the General Assembly (Colorado)
mg/l	—milligrams per liter
mg/m^3	—micrograms per cubic meter
mi^2	—square miles
MIS	—modified in situ
mm	—millimeters
mmho/cm	—milliohms per centimeter (conductivity)
MSHA	—Mine Safety and Health Administration
MW	—megawatt
µg	—microgram
µg/m^3	—micrograms per cubic meter
NAAQS	—National Ambient Air Quality Standards
NAS	—National Academy of Sciences
NEPA	—National Environmental Policy Act of 1969
NH_3	—ammonia
NIOSH	—National Institute for Occupational Safety and Health
NO_x	—nitrogen oxides
NOSR	—Naval Oil Shale Reserve

NPC —National Petroleum Council
NPDES —National Pollutant Discharge Elimination System
NSPS —New Source Performance Standards
NTU —Nevada, Texas, and Utah
O_3 —ozone
OCS —Outer Continental Shelf
OMB —Office of Management and Budget
OSEAP —Oil Shale Environmental Advisory Panel
OSHA —Occupational Safety and Health Administration
Oxy —Occidental Petroleum
PADD 2 —The Petroleum Administration for Defense District 2
PAHs —polycyclic aromatic hydrocarbons
Pb —lead
p/m —parts per million
POM —polycyclic organic matter
PSD —prevention of significant deterioration
QDA —Quality Development Associates
Quad —1 quadrillion = 10^{15} Btu
RARE II —Roadless Area Review and Evaluation (Forest Service)
RCRA —Resource Conservation and Recovery Act of 1970
R&D —research and development
RISE —rubble in situ extraction
scf —standard cubic foot
SCOT —Shell Claus Offgas Treating process
SEIO —Governor's Socio-Economic Impact Office (Colorado)
SIP —State implementation plan
SMCRA —Surface Mining Control and Reclamation Act of 1977
SMR —standardized mortality ratio
SO_2 —sulfur dioxide
SOHIO —Standard Oil Co. of Ohio
SRI —Stanford Research Institute
TDS —total dissolved solids
TIS —true in situ
ton/d —tons per day
Tosco —The Oil Shale Corp.
TSCA —Toxic Substances Control Act of 1976
UBCOG —Uintah Basin Council of Governments
USBM —U.S. Bureau of Mines
USBR —U.S. Bureau of Reclamation
USFWS —U.S. Fish and Wildlife Service
USGS —U.S. Geological Survey
USPHS —U.S. Public Health Service
WPA —Water Purification Associates
WPRS —Water and Power Resources Service

Glossary

Adit: A nearly horizontal opening to a mine.

Aquifer: An underground formation containing water.

Aromatic hydrocarbon: A compound of carbon and hydrogen characterized by a ring of six carbon atoms, e.g., benzene.

Best available control technology (BACT): The most advanced control technology that can be used for new sources of pollution. Required for nonattainment regions (where air pollution presents a danger to the public health) by the Clean Air Act as amended in 1977.

Biochemical oxygen demand: A chemical measure of the power of an effluent to deoxygenate water.

Bitumen: The smaller (about 10 percent) soluble, organic component of oil shale.

Breakeven price: The constant price at which shale oil syncrude would just earn its minimum rate of return.

Calcite: The mineral calcium carbonate, found in nature in the form of limestone, marble, or chalk.

Catalytic cracking: A process of breaking down petroleum hydrocarbons by heating them in the presence of a catalyst. The products are hydrocarbons of lower molecular weight, having lower boiling points, e.g., gasoline.

Coking: One of the processes used to upgrade shale oil and improve its transportation properties. The oil is thermally decomposed at high temperatures (900° to 980° F or 480° to 525° C) forming coke as a solid product.

Criteria pollutants: Under the Clean Air Act, the reduction and prevention of air pollution is regulated by measuring five criteria pollutants: particulate, sulfur oxides, carbon monoxide, nitrogen dioxide, and photochemical oxidants. National Ambient Air Quality Standards were developed for six pollutants associated with the

criteria pollutants. Sulfur oxides are measured by sulfur dioxide and photochemical oxidants are measured by ozone and hydrocarbons,

Crude short: The condition when a company has limited or inadequate access to crude petroleum.

Dawsonite: The mineral, dihydroxy sodium aluminum carbonate. It is a potential source of alumina, which can be converted to aluminum.

Deposit: A natural accumulation, e.g., of coal, iron ore, or oil shale.

Deposit dewatering: The removal of ground water from an oil shale deposit.

Distillates: The liquid products condensed from vapor during distillation (as of petroleum),

Light distillates contain the lowest boiling constituents of the petroleum, from which gasoline is produced.

Middle distillates contain higher concentrations of the high boiling constituents, from which diesel and jet fuels are produced.

Heavy distillates contain higher concentrations of the high boiling constituents, from which lubricating and residual oils are produced.

Distillation: A separation process in which a substance is vaporized, and the vapor collected after condensation as a liquid.

Diversion: A channel constructed to divert water from one source or body of water to another.

Interbasis diversion-Moving water from one major hydrologic basin to another.

Intrabasin diversion—The redistribution of water within a major hydrologic basin.

Dolomite rock: Similar to limestone but composed mainly of the mineral, calcium magnesium carbonate (Ca Mg $(CO_3)_2$).

Electrostatic precipitator: A device that uses an induced electrical charge to recover fine particles from a flowing gas stream.

Environmental impact statement (EIS): The National Policy Act of 1969 requires that an environmental impact statement be prepared for "major Federal actions significantly affecting the quality of the human environment."

Fischer assay: Small samples of crushed oil shale are heated to 932° F (500° C) under carefully controlled conditions. The oil yield by this method is the standard measure of oil shale quality.

Fracturing: Breaking up a deposit by means of chemical explosives, electricity, or injecting high-pressure air and water to increase its permeability to fluid flow.

Fugitive dust: Particulate matter discharged to the atmosphere in an unconfined flow stream.

Gas oil: A liquid petroleum distillate with a viscosity and boiling range between kerosene and lubricating oil (450° to 500° F or 230° to 260° C).

Ground water aquifer: Water contained underground in the interstices of soil and rock, obtainable through wells or springs.

Halite: The natural mineral form of sodium chloride (NaCl).

High-Btu gas: Gas with a high heating value, e.g., pure butane has a heating value of 3,200 Btu/ft^3.

Hydrocarbons: Organic compounds containing only carbon and hydrogen.

Hydrocracking: The breaking apart of relatively heavy petroleum hydrocarbons into smaller, lighter molecules by means of heat in the presence of hydrogen and using special catalysts.

Hydrologic basin: The entire area of land drained by a river and its tributaries.

Hydrotreating: The hydrogenation of crude shale oil to convert it to -synthetic crude oil (syncrude).

Kerogen: The organic oil-yielding material present in oil shales. It is not a definite compound but a complex mixture varying from one shale to another, and is only slightly soluble in ordinary organic solvents,

Low-Btu gas: Gas with a relatively low heating value (about 100 Btu/ft^3), e.g., producer gas,

Locatable minerals: Minerals on public land that can be transferred to private ownership by the process of staking claims and filing for patents.

Marlstone: A hardened mixture of dolomite and calcium carbonate.

Middle distillate cracking and reforming: Breaking down and converting straight chain petroleum hydrocarbons into cyclic and aromatic hydrocarbons, by means of heat, pressure, and catalysts (usually in the presence of hydrogen). Used to produce fuels with high octane rating from lower grade products.

Mining:

Block caving—Sections of the area being mined are undercut and then allowed to cave in, thus crushing the material being mined.

Continuous—A machine cuts and loads ore from a mine face in a continuous operation, without the use of drills and explosives.

Long-wall—The ore seam is removed in one operation along a working face that maybe several hundred yards long. The mine roof collapses as the working face advances through the ore body. The technique is commonly used for coal mining, especially in Great Britain.

Open pit—The overburden is drilled and blasted loose over a large area and removed to expose the oil shale beds. These are then drilled and blasted.

Room-and-pillar-Some shale is removed to form large rooms, and some is left in place, as pillars, to support the mine roof.

Solution—The injection of fluids into the formation to dissolve soluble salts from among the oil shale layers, thereby creating a honeycomb pattern of voids.

Strip—The overburden and deposit are removed with a dragline—a massive type of scraper shovel.

Subsidence—The mine roof is allowed to collapse into the working area after the ore is removed.

Mining bench: A shelf or ledge made in a mine tunnel or working when an upper section is cut back.

Modular retort: The smallest unit that would be used in commercial practice. Its capacity varies with the developer.

Molecular weights: The relative mass of a molecule as compared with that of an atom of hydrogen. It is calculated by adding up the weights of the molecule's constituent atoms.

Mucking: Removal material broken up in the mining process.

Nahcolite: A mineral chemically identical to commercial baking soda (sodium bicarbonate).

New Source **Performance Standards (NSPS):** The Clean Air Act requires that the Environmental Protection Agency set standards of performance for major new potential sources of pollution, and that such facilities use the most advanced technology available for pollution control.

Nonattainment area: The air in the region does not satisfy the National Ambient Air Quality Standards as established under the requirements of the Clean Air Act.

Nondegradation area: The air in the region is cleaner than that required by the National Ambient Air Quality Standards.

Nonmethane hydrocarbons: All the organic compounds of carbon and hydrogen that are not straight chain, saturated (no more hydrogen can be added) molecules in which the carbon atoms are joined to each other by single bonds.

Nonpoint source: A site from which there is uncollected runoff, e.g., a mining operation, construction site, or agricultural area.

Olefin hydrocarbons: Unsaturated (lower ratio of hydrogen to carbon) compounds of carbon and hydrogen having at least one double bond.

Onstream factor: The fraction of the time that a plant could be expected to operate at design capacity.

Organic compounds: The compounds of carbon. These fall roughly into two classes: compounds containing only carbon and hydrogen (hydrocarbons), and compounds in which one or more hydrogen atoms have been replaced by other elements or groups of elements (heteroatomic compounds).

Overburden: The material overlying a deposit that must be removed before surface mining.

Paraffin hydrocarbons: Saturated compounds of carbon and hydrogen having only single bonds.

Particulate: Minute separate airborne particles, one of the criteria pollutants under the Clean Air Act,

Perfection of water right decree: Meeting all the requirements under applicable law to establish legal rights to the water—implies not only ownership but also actual use.

pH: A means of expressing the acidity or alkalinity of a solution. At normal temperatures, pure water has a pH of about 7 (neutral); the pH of a strong acid is about 1 and that of a strong base about 14.

Photochemical reactions: Chemical reactions induced in the atmosphere by ultraviolet radiation from the Sun.

Phreatophyte: A deep-rooted plant that obtains water from the water table or the layer of soil just above it.

Placer deposit: A deposit of alluvial material found along and in riverbanks, streambanks, and in beach sands.

Polycyclic organic compounds: A compound whose molecular structure contains two or more rings (usually fused) that are mostly constructed of carbon atoms (e.g., anthracene).

Pour point: The lowest temperature at which a liquid will flow.

Prevention of significant deterioration (PSD): A statutory program of the Clean Air Act aimed at preserving the existing high air quality in those areas having the cleanest air (nondegradation regions).

Pyrolysis: The breaking down of complex materials into simpler units by means of heat.

Radionuclide: A radioactive atom.

RARE II: The Roadless Area Review and Evaluation process being undertaken by the Forest Service for all potential wilderness areas in the national forest system.

Refluxing: Distillation in which the liquid is condensed with the rising vapor in a fractionating column.

Reserve: A resource that can be extracted from the deposit and processed to yield products that can be marketed at a profit.

Resource: A naturally occurring substance with properties that can be put to use.

Retort: The vessel or container in which the oil shale is pyrolyzed to recover the shale oil.

Retort plant:

Commercial scale—A commercial-size oil shale facility would use several modular retorts in parallel to obtain the desired production rate,

Pilot-plant scale—About one-hundredth of the capacity of a commercial scale module.

Pioneer commercial scale—Would contain several commercial-size modules.

Semiworks scale—About one-tenth of the capacity of commercial-size.

Retorting: The raw oil shale is heated to pyrolysis temperatures (about 1,000° F (540° C)) to obtain crude shale oil.

Above-ground (AGR)—In this process, the retorting vessels are essentially large, steel cylindrical or cone-shaped containers lined with refractory brick. The retorting systems, which differ widely with respect to technical and operating characteristics, fall into four classes based on the mode of transferring heat through the oil shale: 1) by conduction through the retort wall, 2) by flowing gases generated from the carbonaceous material and hot gases created in the retort, 3) by gases heated outside the retort, and 4) by mixing hot solid particles with the oil shale.

Modified in situ (MIS)—In this process, a portion of the shale deposit is mined out, and the rest is fractured with explosives or by other means to create a highly permeable zone through which hot fluids can be circulated.

True in situ (TIS)—In this process, the shale is left underground and is heated by injecting hot fluids.

Rubbling: Shattering by explosives of a portion of an oil shale deposit so that it can be retorted underground. A modified in situ process.

Sedimentary rocks: These are derived from the disintegration and weathering of older rocks, and deposited in layers by water, wind, or ice (e.g., sandstone, limestone, shale.)

Shale oil syncrude: A synthetic crude oil produced by adding hydrogen to crude shale oil, comparable with the best grades of conventional crude.

Spent shale: The retorted residual material after the oil and gas products are removed. Its properties vary with the type of retorting procedure used; indirectly heated retorts product a carbonaceous spent shale, while directly heated retorts produce a material essentially stripped of carbon.

Spot market price: The nonposted price for a barrel of oil,

Syncrude: Synthetic crude oil, produced from any source other than conventional petroleum.

Trona: A hydrated mixture of sodium carbonate and sodium bicarbonate. It is a **source of soda ash for glass production.**

Upgrading: The treatment of crude shale oil to improve it to a transportable refinery feedstock, e.g., hydrotreating.

Virgin flow: The flow of a river that would occur in the absence of human-related activities. In this assessment most of the analysis of water availability refers to the average flow between 1930-74, because of its common use in other water resources analyses.

Viscosity: A measure of a liquid's resistance to flow.

Water rights:

Absolute—The right created when a holder of a conditional right perfects that right by actually diverting the water and applying it to a beneficial use.

Conditional—The right obtained by filing for a conditional decree from the State water courts, and then proceeding diligently towards the actual use of the water,

Diversion—Permits the diversion of water from a stream followed by its immediate application.

Junior—The prior appropriation doctrine for water rights is based on the principle "first-in-time, first-in-right. " In times of shortages, rights that are junior in terms of the initiation date are curtailed to assure water supplies to users with more senior rights.

Senior—The more senior (older) the water right, the higher its priority for the use of limited resources.

Storage—Permits the impoundment of water for later application.

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ERRATA - AN ASSESSMENT OF OIL SHALE TECHNOLOGIES

1. The shading on Figure 2, page 7 is incorrect: SEE INSTEAD FIGURE 13, PAGE 90.

2. Issue **4, p. 32:** The total estimated cost of pollution control should be **2.4 to 6.0** cents/gal.

3. Figure 51, p. 187: The minimum and maximum increases from environmental costs should fall lower on the graph (about 2 x 1971 estimate).

4. Page 60, Table 8, Site 11/line 11, under status should read: Initial environmental, health and safety tests underway.

5. Page **136, first** column, lines **6 and 7,** should read: Multi Mineral has begun use of an 8-ft-diameter shaft. . . .