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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.

*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.

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 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.

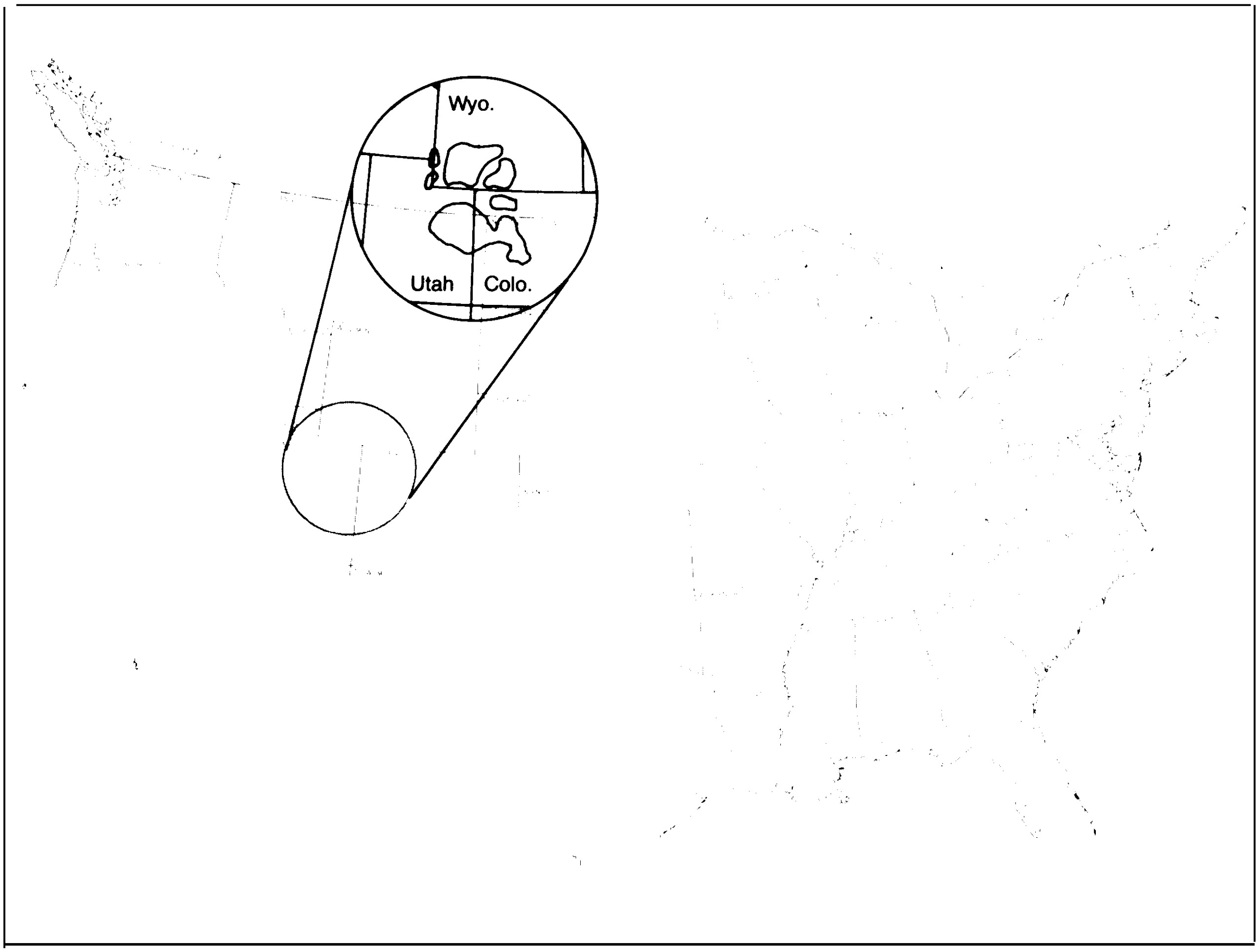
The formation has been divided into several distinct geological basins. (See figure 2.) The richest and most thoroughly explored deposits occur in Colorado's Piceance basin. The resources of Utah's Uinta basin are, in general, of somewhat poorer quality. The Wyoming deposits are relatively inferior and 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



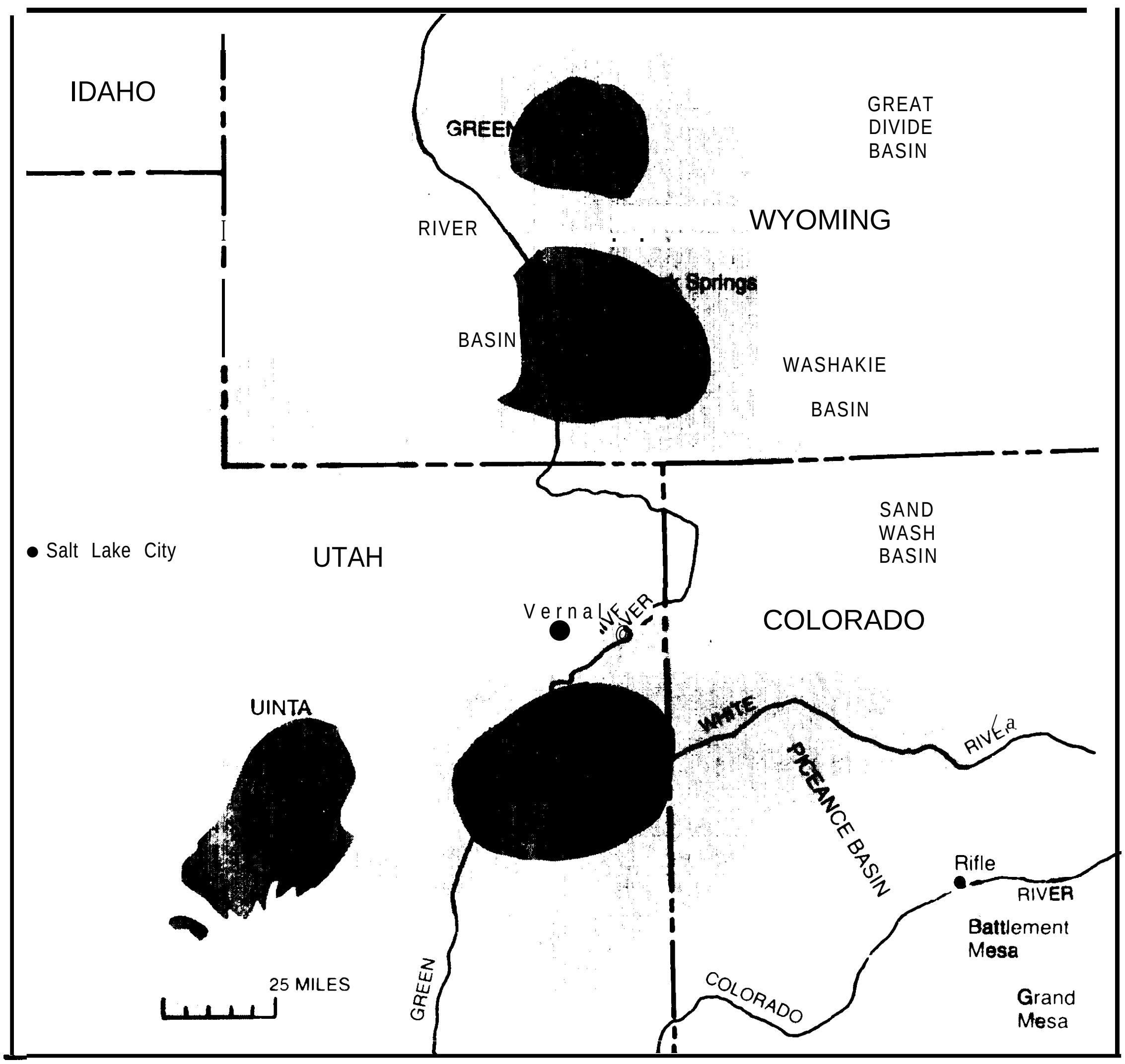
ƆURCE *The National Atlas*, Department of the Interior

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 Formation in which the 011 shale is 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

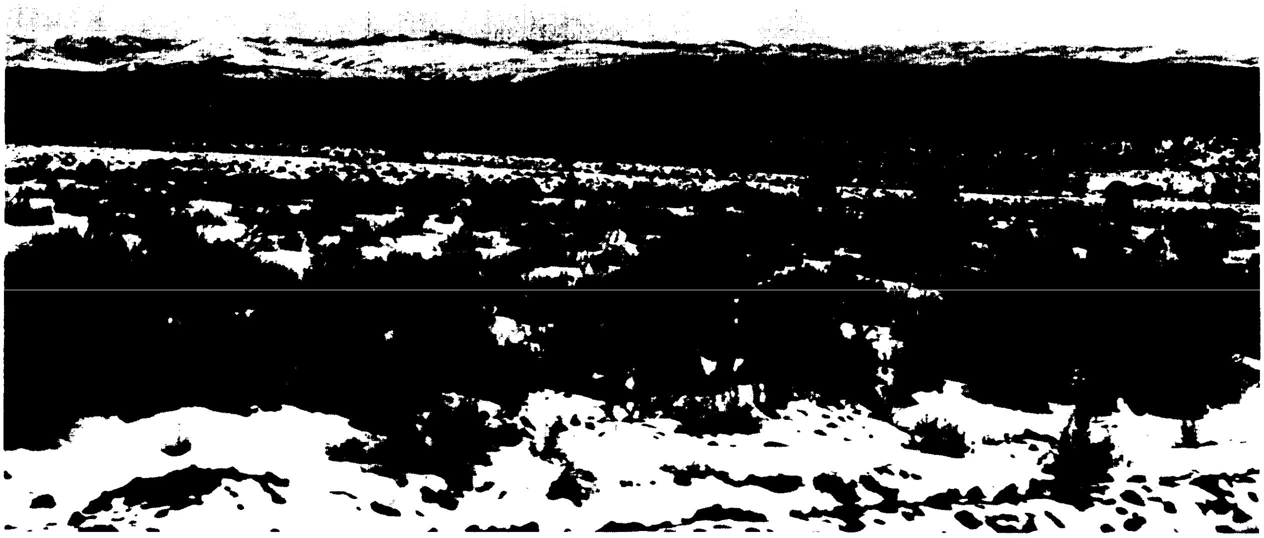


Photo credit George Wallerstein

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

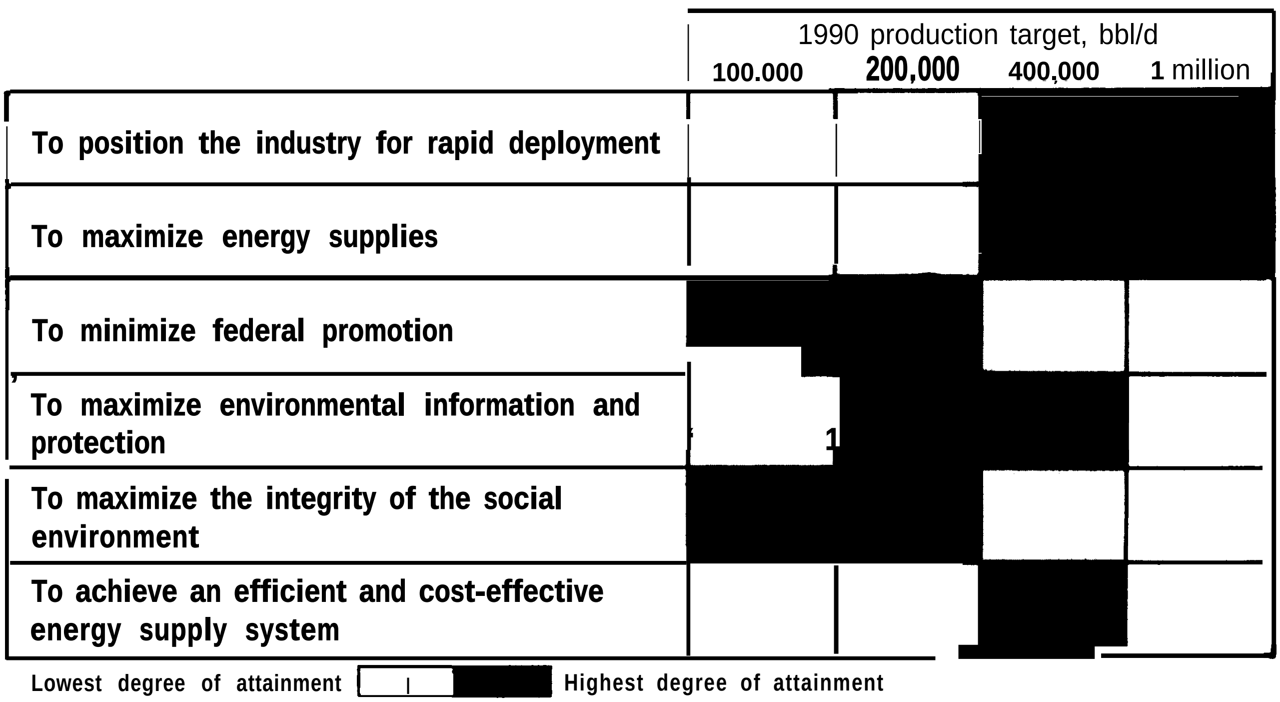
OTA analyzed four production targets for 1990: 100,000 bbl/d, 200,000 bbl/d, 400,000 bbl/d, and 1 million bbl/d. Strategies to reach the targets would entail substantially different requirements, consequences, and policy responses. Regardless of the strategy, tradeoffs among objectives are inevitable. 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 Off Ice 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.

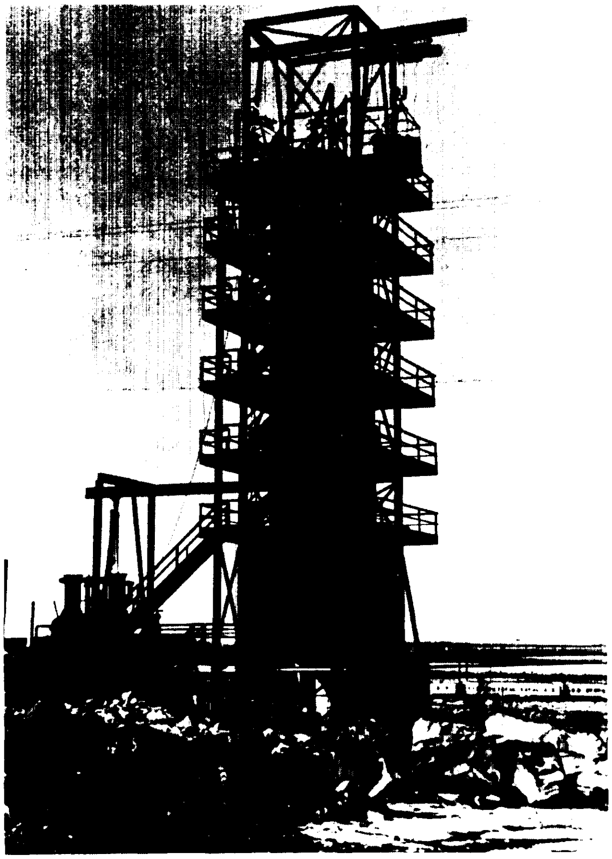


Photo credit *Departmenf of Energy*

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,

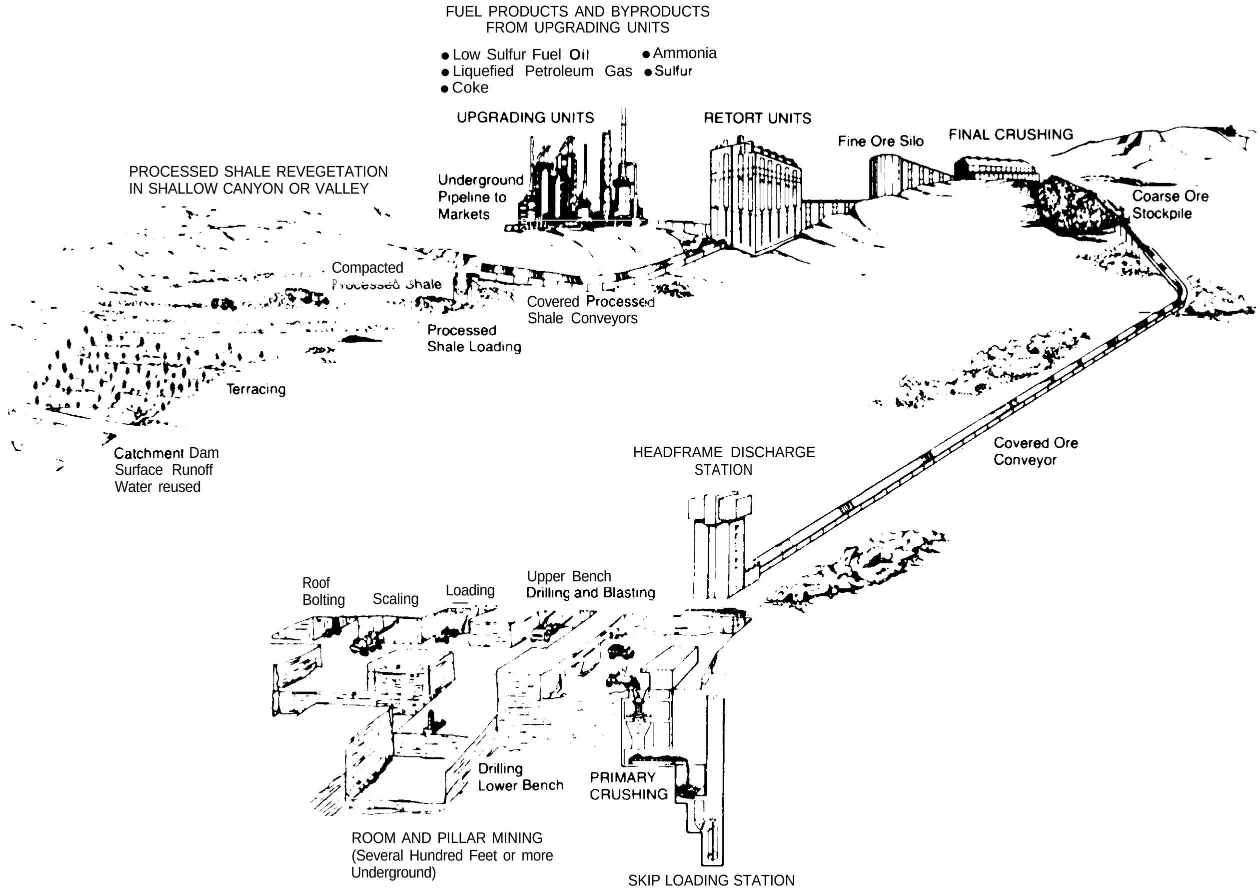
The MIS process requires mining 20 to 40 percent of the deposit to be retorted, and involves more facilities and waste disposal on the surface. More oil is recovered per ton of rock processed than with TIS, but less than with aboveground processing. Oil recovery per acre is probably higher with MIS than 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	1990 production target, bbl/d: 100,000	200,000	400,000	1 million
	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

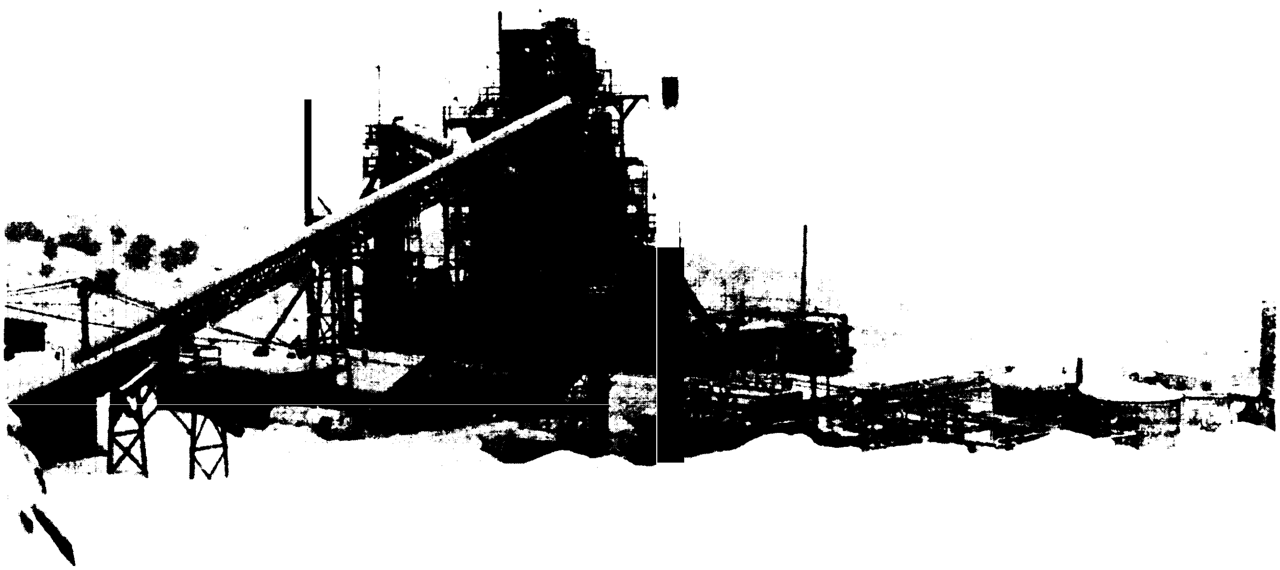


Photo credit OTA staff

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

Incentive	Effect of incentive on program objectives: Subsidy effect	Risk-sharing effect	Financing effect	Extent to which incentive meets policy guidelines: Promotion of economic efficiency	Minimization of administrative burden	Promotion of competition: 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-Intenswe 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-Intenswe 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.

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

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 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.

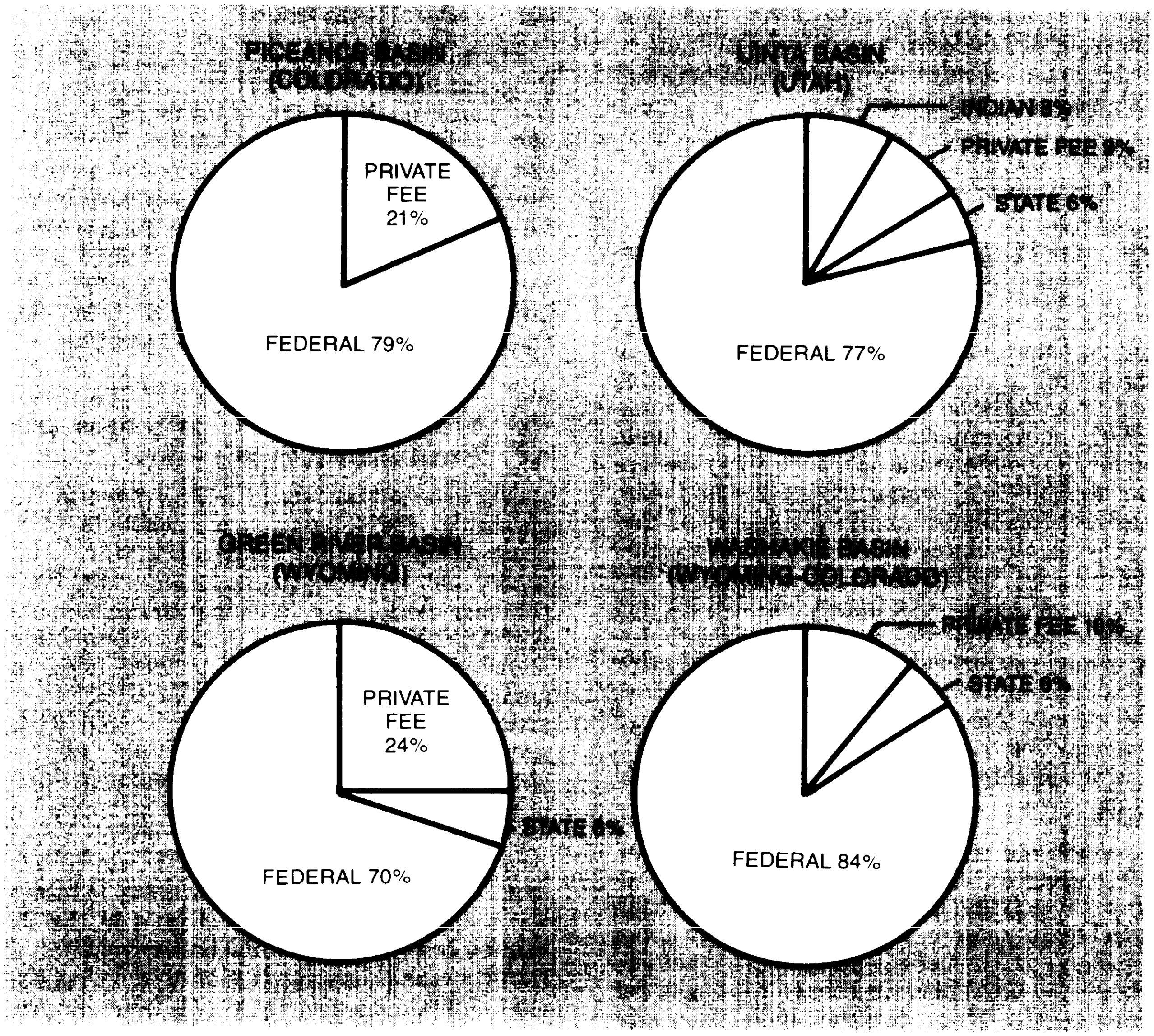
3 What other projects have been proposed or are presently active?

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.

*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



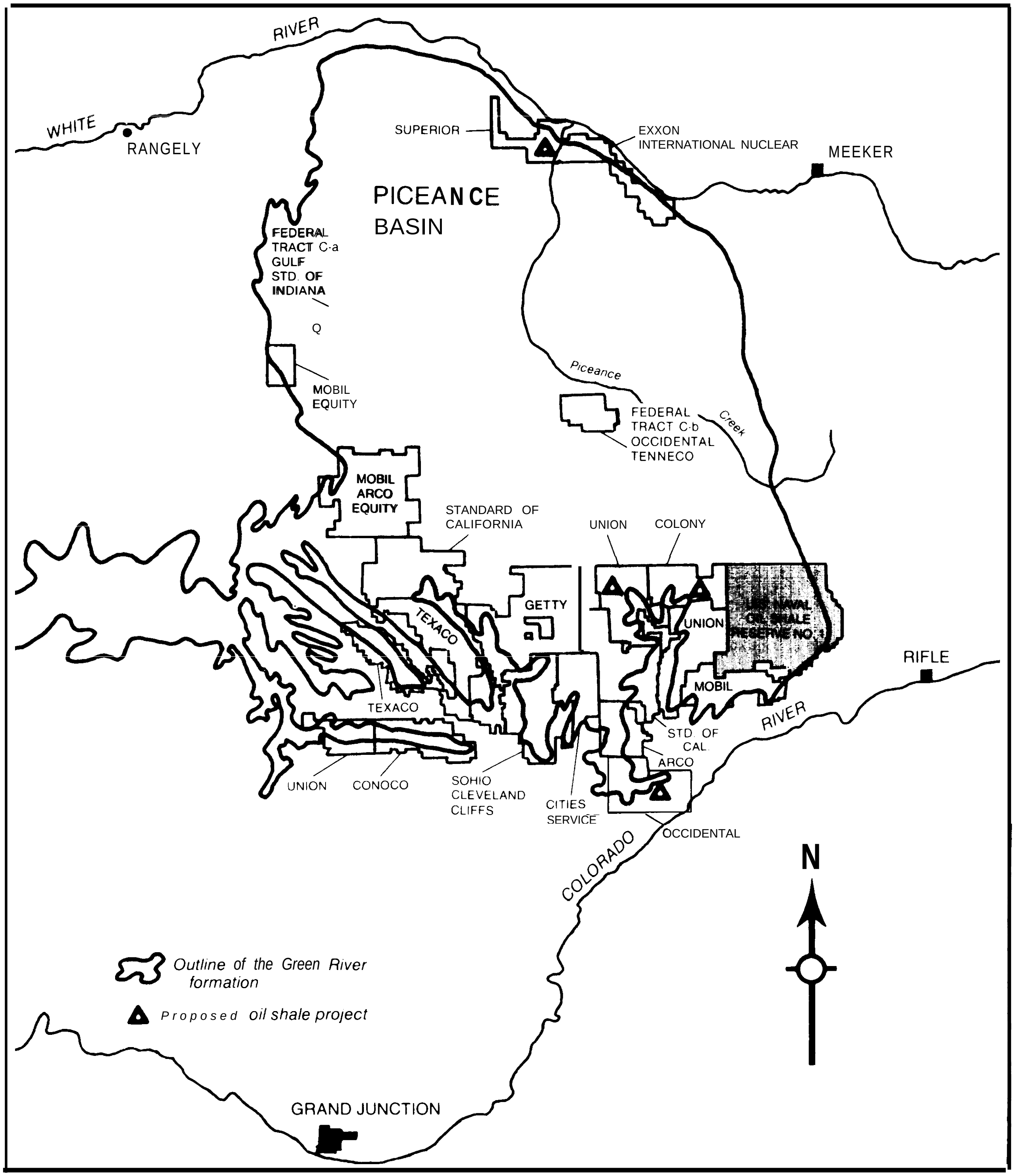
SOURCE *Map of the Major Oil Shale Ho/dregs—Colorado, Wyoming, Utah,* Denver, Colo Cameron Engineers, Inc , January 1978

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

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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	60,000-185,000[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 Oil land exchange and a leasing of Anvil Points by Paraho Development A 30 000-bbl/d production increment from 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

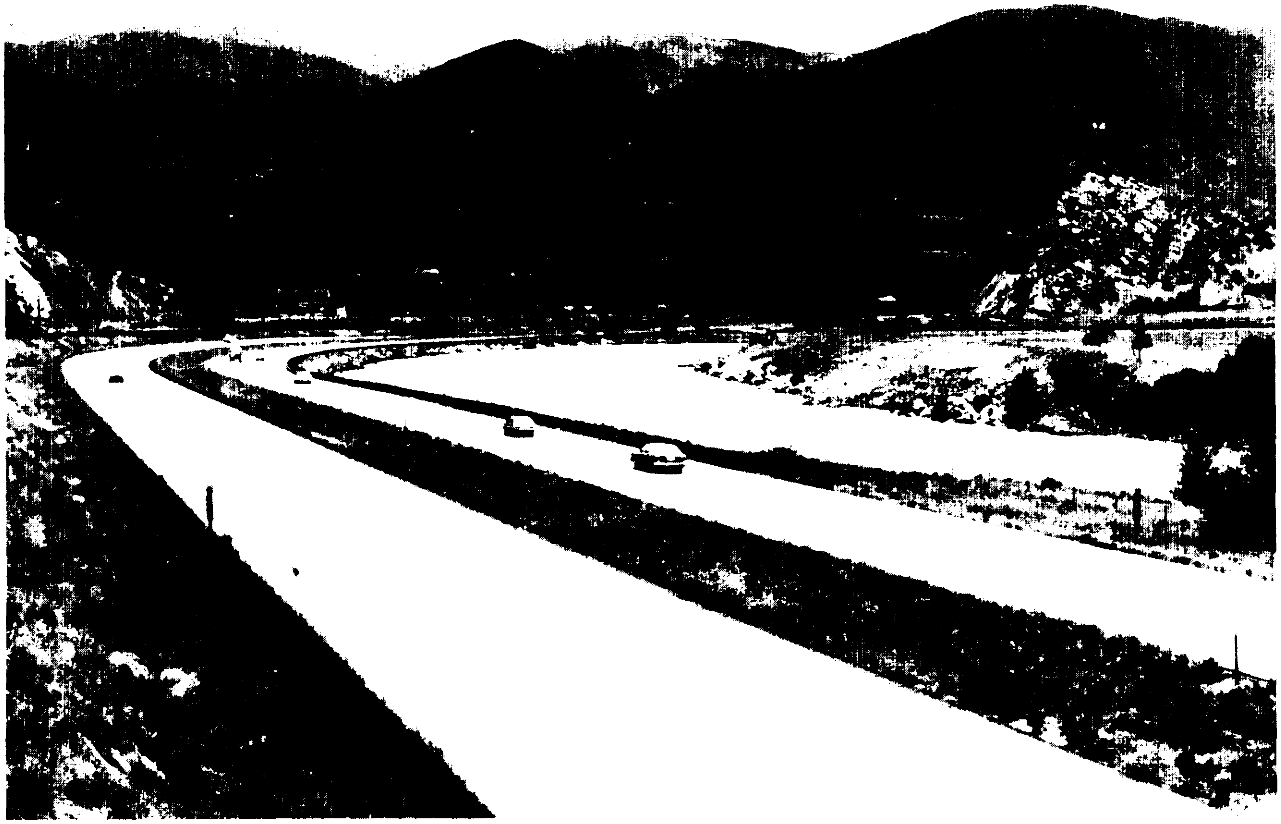
1 How will oil shale development affect the environment?

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 non-point 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;

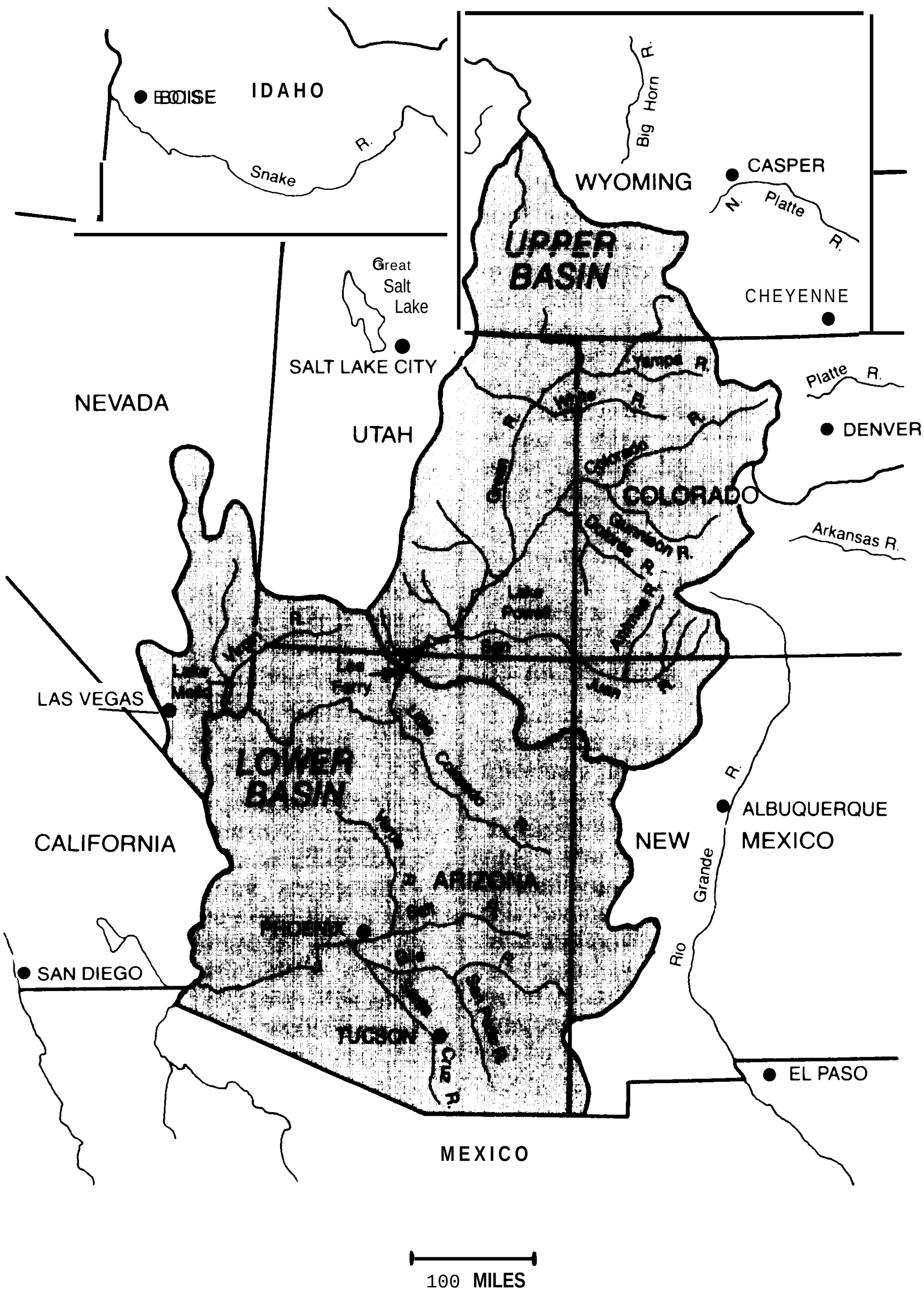
  and
- demand for other uses increases no faster than the States” high growth rate projections;

  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 longstanding 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 complehon 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

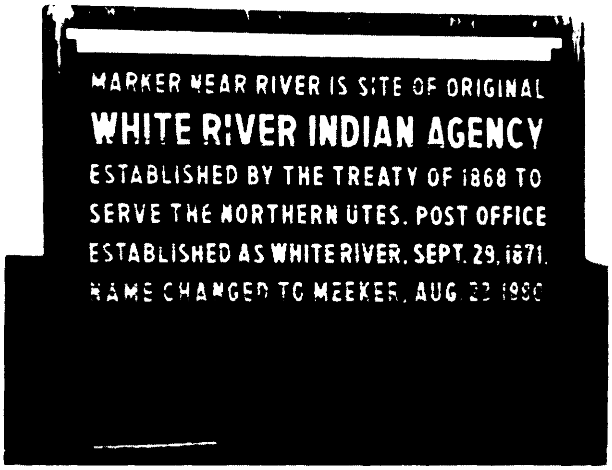


Photo credit OTA staff

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?

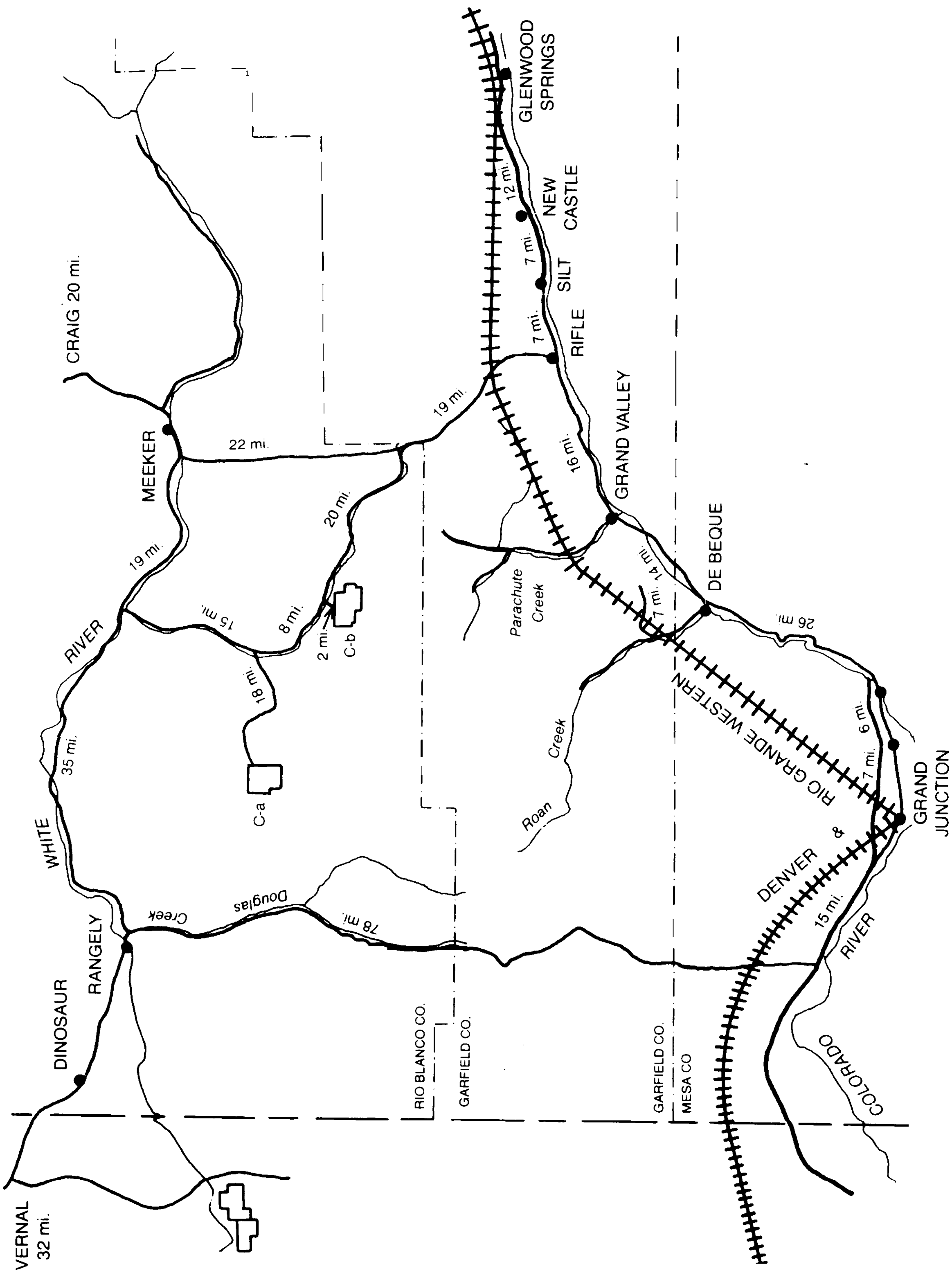
Not enough is known about the causes of boomtowns to be able to predict the exact threshold beyond which oil shale development would lead to serious impacts. However, establishing a l-million-bbl/d industry by 1990 would exceed the capacity of all of the communities, and stressful living conditions would 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

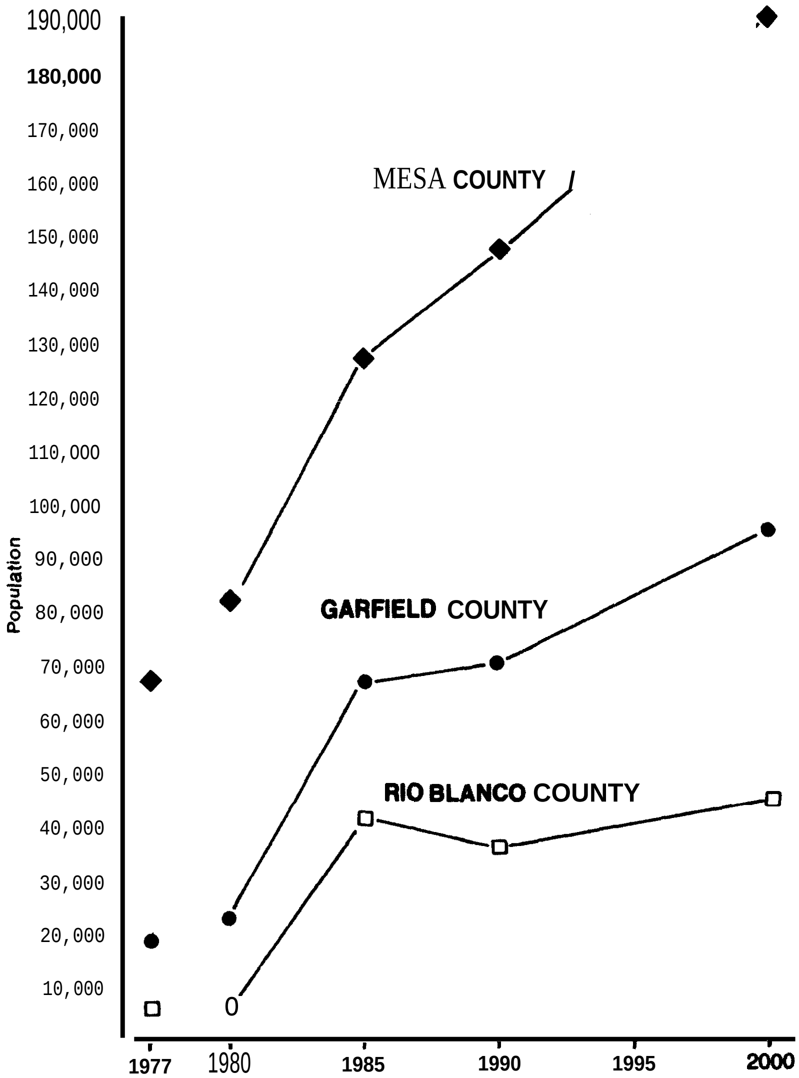
*Planning for oil shale impacts in Utah has not been as extensive as in Colorado for a number of reasons. Most important is that mitigation funds from a major source (the State's share of bonus and lease payments under the Mineral Leasing Act) have been held in escrow pending settlement of the ownership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