ENVIRONMENTAL HAZARDS
OF SHALE OIL RECOVERY BY IN-SITU METHODS

Glen D. Weaver
Department of Geography
University of Wisconsin-Milwaukee

May 5, 1971

CONTENTS

Figures

Tables

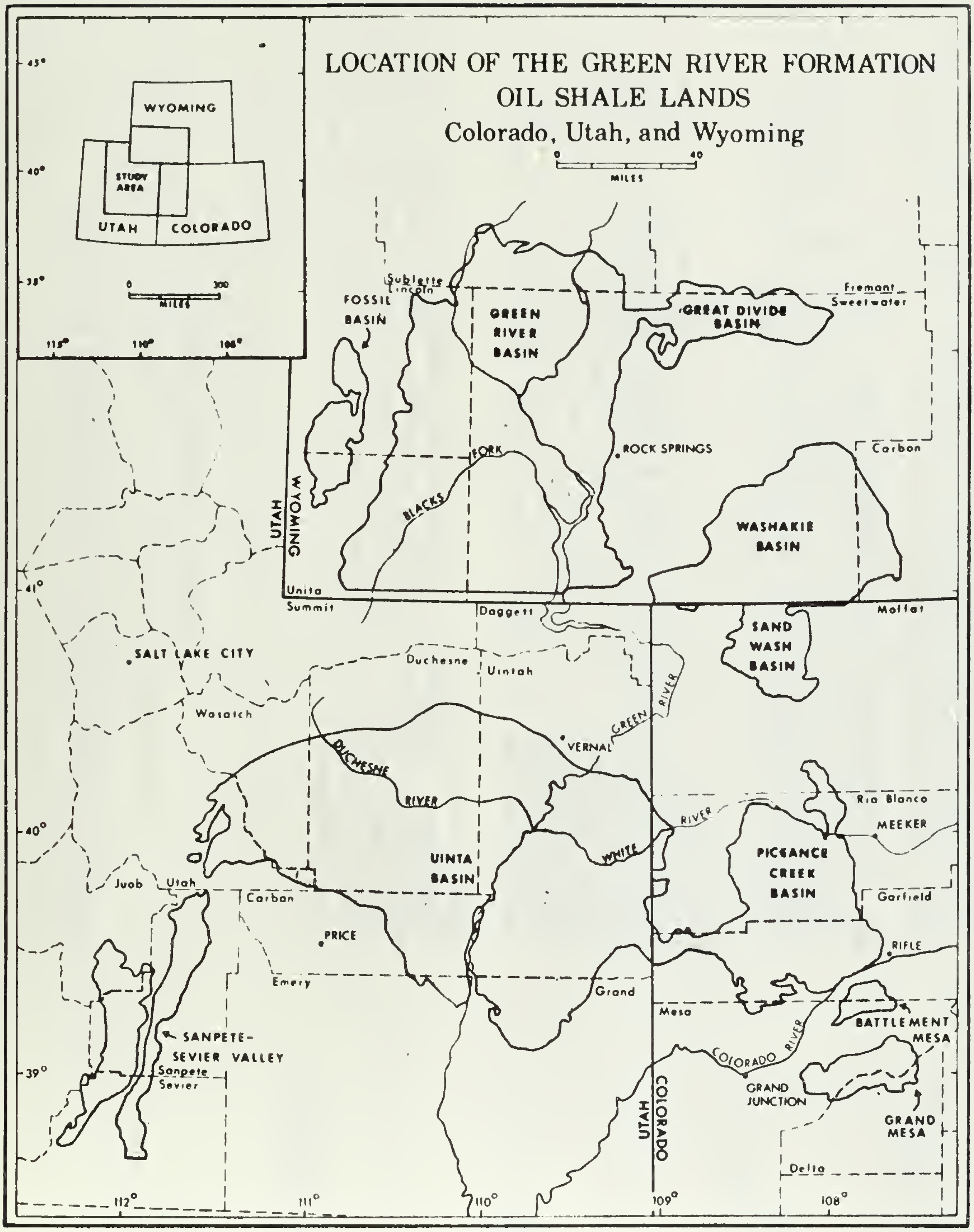
INTRODUCTION

Since 1955 the reserve to production ratio of domestic crude oil has fallen from 12 to 1 to 10 to 1. In six of the last ten years additions to proved reserves have failed to equal withdrawals, and in 1969 reserves declined by over a billion barrels.[1]

The resulting search for alternative petroleum supplies has once again focused attention on the Green River oil shales of Colorado, Utah, and Wyoming (Fig. 1). Although not currently utilized, the Green River shale deposits represent an extraordinarily large potential supply of synthetic liquid hydrocarbons.

Mineral evaluation studies on about one-half of the total oil-shale acreage reveal the in-place equivalent of some 1.7 trillion barrels of shale oil,[2] an amount which is nearly four times the proved crude oil reserves of the entire world, more than fifty times the proved petroleum reserves of the United States,[3] and almost the same as the estimated quantity of well oil originally contained under the entire United States land and continental shelf area.[4]

Other minerals of actual or potential economic interest contained in the Green River Formation (Table 1) include gilsonite, bituminous sandstones, well oil, natural gas, uranium, phosphate, and several sodium mineral varieties, notably trona, nahcolite, dawsonite, shortite, and halite. Although less ubiquitous than oil shale, the sodium mineral deposits are extraordinarily large and may locally exceed the value of the in-place shale oil (Fig. 2).



LOCATION OF THE GREEN RIVER FORMATION OIL SHALE LANDS
Colorado, Utah, and Wyoming

FIGURE 1

TABLE 1.--ECONOMIC MINERAL DEPOSITS OF THE GREEN RIVER FORMATION

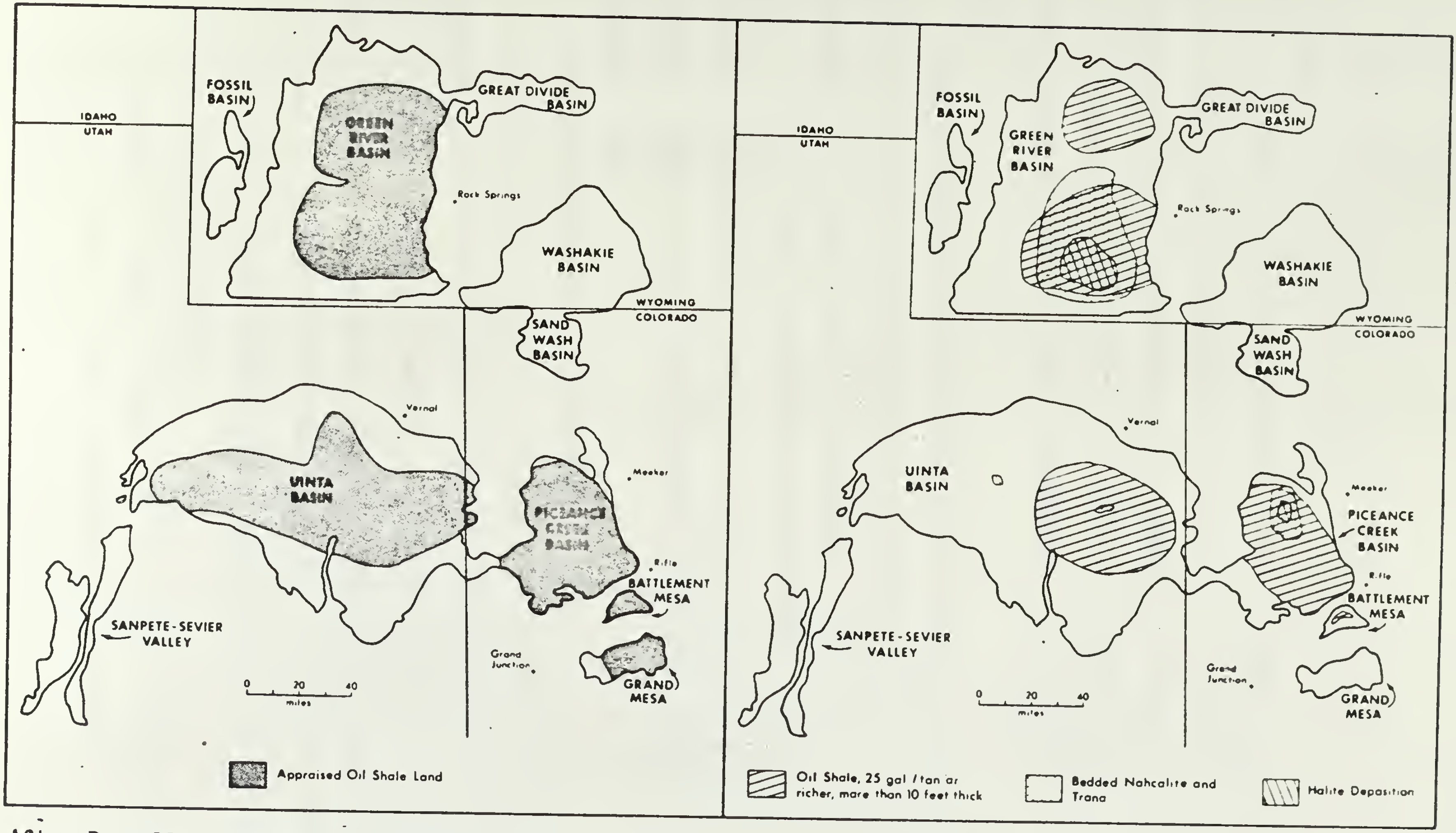
Mineral	Quantity and Areal Occurrence
Oil shale (kerogen-rich dolomitic marlstone	Underlies about 11 million acres (1.74 trillion bbl of shale-oil equivalents), distributed as follows: Colorado, 1.9 million acres (1.2 trillion bbl); Utah, 4.9 million acres (0.28 trillion bbl); Wyoming, 4.2 million acres (0.26 trillion bbl).[a] Deposits range in thickness from a few feet to 2,000 feet. Overburden thickness ranges from zero to 1,000+ feet. U.S. Dept. Interior (1968).
Trona (sodium sesquicarbonate)*	Interbedded with oil shales in the central and southern Green River Basin. Culbertson (1966, p. B-161): Estimated 67 billion tons contained in 24 beds, each 3 feet or more thick and extending over 100 to 1,000 square miles; additional 33.6 billion tons of intermixed trona and halite contained in 14 beds, each 3 feet or more thick and covering 10 to 410 square miles. Bradley and Eugster (1969, p. B20): Conservative estimate of 75.4 billion tons in 18 principal beds covering aggregate area of about 1,100 square miles.
Nahcolite (sodium bicarbonate)	Widespread in Colorado and Utah but rare in Wyoming. Disseminated in and interbedded with oil shales, and most abundant in the deep-basin saline facies. Preliminary estimate for 150,000-acre area in central Piceance Creek Basin shows 30 billion tons (=19 billion tons of soda ash). Hite and Dyni (1967); U.S. Dept. Interior (1968, p. 27).
Dawsonite (dihydroxy sodium aluminum carbonate)	Known only in Colorado's Piceance Creek Basin. Occurs as finely disseminated constituent of the Parachute Creek Member saline facies. Preliminary estimate of 27 billion tons (= 9.5 billion tons of alumina) in 150,000-acre area. Soda ash a likely coproduct. Hite and Dyni (1967); U.S. Dept. Interior (1968, p. 27)

TABLE 1.--(Continued)

Halite (sodium chloride)	Abundant in oil-shale saline facies in Piceance Creek and Green River basins, Hite and Dyni (1967, p. 27, fig. 1); Deardorff (1963).
Shortite (sodium calcium carbonate)	Abundant and ubiquitous in Utah and Wyoming but extremely rare if present in Colorado. Wyoming deposits dispersed through a thick vertical column of oil shale. Fahey (1962).
Gilsonite (solid asphaltic bitumen)*	Occurs in vertical vein deposits which cut across the Green River Formation and enclosing beds in the Uinta Basin. Original in-place reserves estimated at 45 million tons; probably one-tenth of this amount has been mined. Cashion (1964).
Bituminous sandstone	Occurs above, below, and within the Green River Formation in the Uinta Basin. Total oil content of 3.7 to 4.0 billion barrels. Cashion (1964); Utah Committee on Environmental Problems of Oil Shale (1971, p. 21-22).
Well oil and gas*	Occur in basal part of Green River Formation and in underlying sediments of the three-state area. Dunnell (1961, p. 673-675); Kornfeld (1970); U.S. Geol. Survey (1960, p. 23-25).
Uranium and phosphate	Syngenetic concentrations occur as thin persistent zones in Green River and Uinta basins. Uranium content seldom exceeds 0.1% and phosphate content 14%. Love (1964).

[a] Acreage figures include all oil-shale lands, appraised and unappraised. Shale-oil equivalents refer only to appraised deposits ⩾15 feet thick yielding 15-25 gal/ton, or deposits ⩾10 feet thick yielding >25 gal/ton.

*Mineral is being commercially exploited at present.



After Donnell, Cashion, and Culbertson (1967, fig. 1)

After Hite and Dyni (1967, fig. 1)

FIGURE 2. LOCATION OF SODIUM MINERAL DEPOSITS AND HIGH-GRADE OIL SHALES

Commercial development of the Green River oil shales poses a serious challenge to environmental conservation. Recovery by mining and surface retorting will produce tremendous volumes of solid wastes, most or all of which will have to be permanently stored on the surface. The magnitude of waste production can be exemplified by noting that a million-barrel per day industry will generate enough waste rock in one year to cover an area the size of Washington, D.C., to a depth of six feet.[5]

Both government and private industry are currently experimenting with an alternative technology which would permit in-situ underground retorting. The concept has been universally heralded as an environmental savior because it would eliminate the large-scale surface transformation inherent with conventional methods.[6] Whether in-situ processing will actually become an environmental messiah is the focal point of the study presented here.

Four main hypotheses are evaluated:

1) If perfected, in-situ processing would eliminate the land defacement, spent-shale disposal, and dust pollution problems inherent with mining and surface retorting. In exchange it poses the danger of land subsidence, and could significantly alter the hydrologic regime and water quality of both the oil-shale region and lower Colorado River basin. In other words, in-situ processing may prove to be an environmental monster rather than a savior.

2) Although certain oil-shale deposits may be amenable to in-situ retorting, the method will not have widespread applicability. Failure to utilize mining and surface retorting systems would therefore remove much of the oil-shale region from development.

3) Both government and private industry have conducted research on in-situ technology for over twelve years but have given minimal consideration to the environmental hazards of developing or using the technology. Both should therefore immediately justify the environmental safety of their ongoing R & D projects, or discontinue them in favor of a thorough technology assessment.

4) Unless there is a sudden breakthrough in underground technology, both in commercial application and environmental safety, shale-oil recovery in the near future can be accomplished only by mining and surface retorting. Current development proposals should therefore include specific strategies of regional land-use planning, spent-shale management, and mined-land reclamation.

Irrespective of the particular extractive techniques employed, commercial shale processing must be viewed in the following general terms:

The land area directly affected by oil-shale development could be extraordinarily large. In all, oil-shale deposits underlie approximately 17,000 square miles, or 11 million acres. Many of the deposits are too thin, too deeply buried, too low grade, or too something else to be of current or potential economic interest (Fig. 2). Still, the land area ultimately subject to direct exploitation could easily aggregate several thousand square miles.

All of the major oil-shale lands are situated in the Upper Colorado River Basin. Effects on water yield or water quality would therefore be especially critical, not only locally, but also for downstream water-users in Nevada, Arizona, California, and Mexico. Serious legal questions would compound any physical or economic water problems created in the basin since the waters of the Colorado River are subject to both

interstate and international aspects.[7]

The oil-shale region itself represents one of the most arid and sparsely settled portions of the United States (Figs. 3-4). Because of its aridity the region is also one of the most ecologically fragile portions of the country. Careless exploitation would most certainly lead to widespread and possibly irreversible damage to watershed resources, wildlife, and other non-mineral values.

About 72 percent of the total oil-shale acreage lies in federal ownership.[8] As proprietor of a major share of the oil-shale resource pool, the Federal Government has the obligation to insure that activities on its lands represent a model of planned resource development. As sovereign promoter of the general welfare, the Federal Government should also question the basic wisdom of whether oil-shale exploitation would be in the best public interest relative to alternative energy sources and overall environmental goals.

For the past 18 months, the U.S. Department of the Interior has been formulating a test leasing program for the federal oil-shale lands.[9] Statements prepared under Section 102 of the National Environmental Policy Act (PL 91-190) were recently completed by the three states involved.[10] The federal statement should be forthcoming in a short time.

ACKNOWLEDGMENTS

Material presented in this study is based on extensive library research of published articles and reports; on interviews with government personnel, industry representatives, and other interested persons; and on letter communication with various knowledgable parties.

Visits were made to the major oil-shale areas during July and

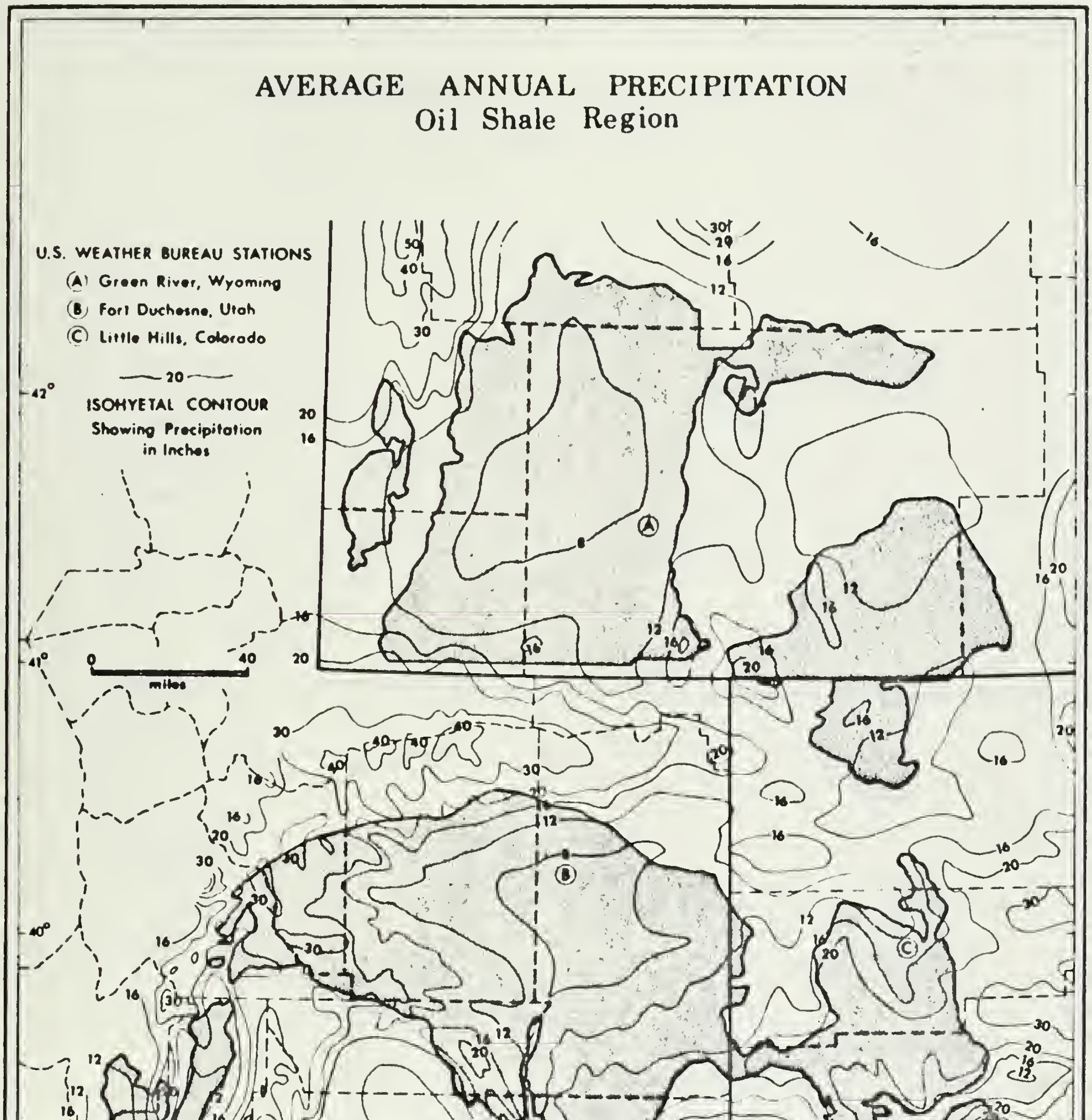

AVERAGE ANNUAL PRECIPITATION
Oil Shale Region
U.S. WEATHER BUREAU STATIONS
(A) Green River, Wyoming
(B) Fort Duchesne, Utah
(C) Little Hills, Colorado
—20—
ISOHYETAL CONTOUR
Showing Precipitation in Inches
0
40
miles
42°
41°
40°
39°
112°
111°
110°
109°
108°

FIGURE 3

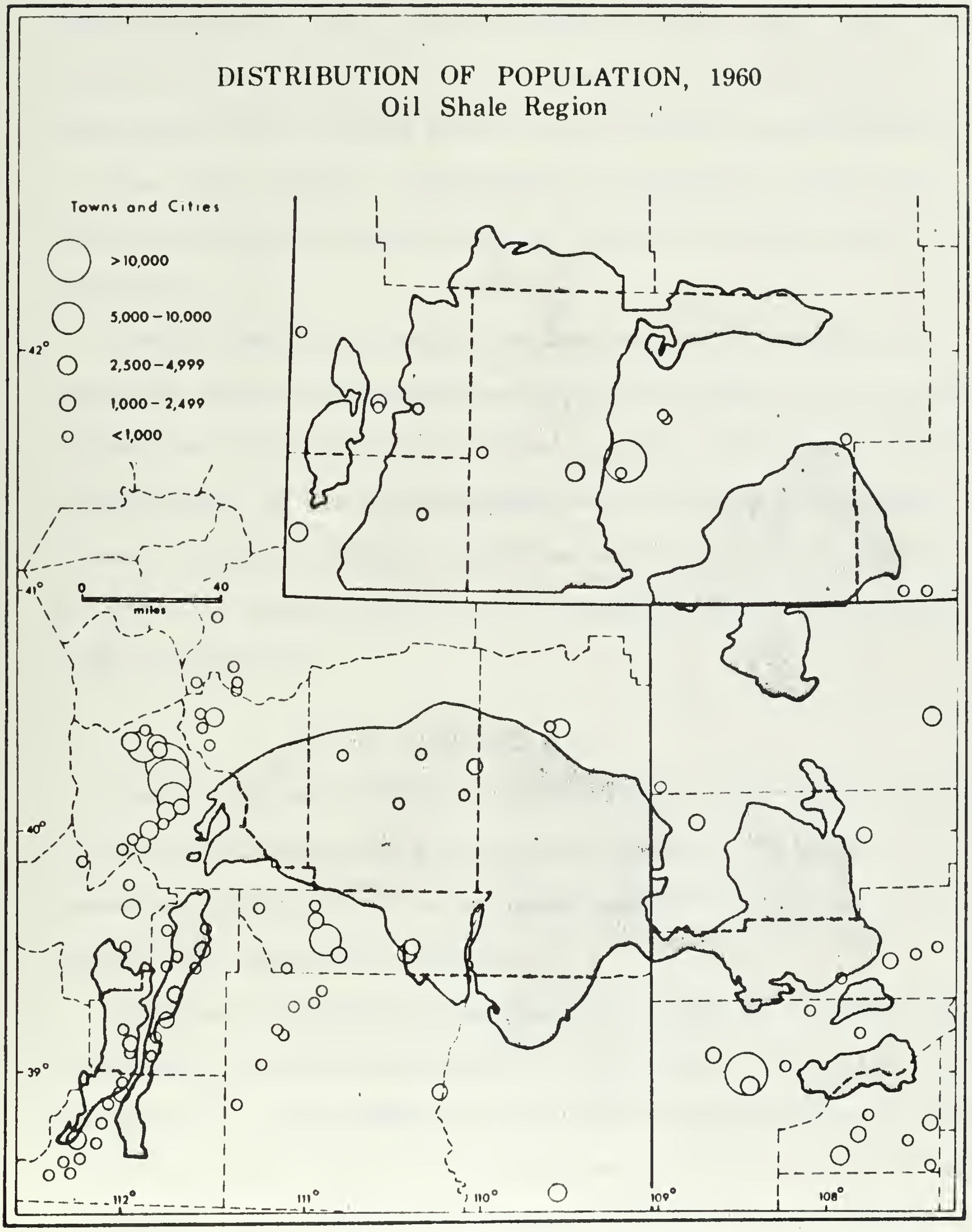

DISTRIBUTION OF POPULATION, 1960
Oil Shale Region
Towns and Cities
>10,000
5,000 – 10,000
2,500 – 4,999
1,000 – 2,499
<1,000
0
40
miles
42°
41°
40°
39°
112°
111°
110°
109°
108°

FIGURE 4

August, 1968, and again during the week of August 3-7, 1970. The latter visit was in accompanyment of a task force tour arranged by the U.S. Department of the Interior and comprised of federal, state, and private industry representatives.[11] The tour included an overflight of the three-state area and ground stops at ten potential development sites.

The author wishes to acknowledge the cooperative spirit of the many individuals and organizations who responded to requests for information.

Special thanks are given to Dr. Norman P. Lasca, Department of Geological Sciences, University of Wisconsin-Milwaukee, who critically reviewed the entire report; Dr. Walter A. Lyons, Department of Geography and the Center for Great Lake Studies, who reviewed the air quality section; Miss Marion Zirbel, who drafted most of the illustrations; and Mr. Donald G. Temple, University of Wisconsin-Milwaukee Cartographic Services Laboratory.

IN-SITU R & D

In-situ oil-shale processing involves three sequential operations: (1) creation of fractures in the oil-shale deposit; (2) ignition and combustion (retorting) of the fractured zone; and (3) aboveground recovery of the combustion products.

Creation of fractures in the oil-shale deposit is a first prerequisite since the matrix permeability of Green River oil shale is essentially zero.[12] Hence sufficient permeability must be induced by artificial means to allow the hot retorting gases and fluids to pass through the deposit. Both nuclear and conventional devices may be used to fracture the shale. Non-nuclear methods include hydraulic pressure,

electrolinking, chemical explosives, or some combination of these.

Once an adequate fracture system has been induced, it then remains to ignite the organic matter in the oil shale and drive a controlled combustion zone through the permeable reservoir toward the recovery wells, which carry the oil and gas to aboveground storage tanks or refinery plants (Fig. 5).

Perusal of the published literature dealing with in-situ concepts and experimental work yields little information on potential environmental hazards. The *Project Bronco* study by Lekas and others[13] does present some evaluation of hazards posed by using nuclear energy to fracture the oil-shale deposits. The Colorado, Utah, and Wyoming environmental impact statements, all prepared under Section 102 (2) (c) of the National Environmental Policy Act, give only brief mention to the problems of underground retorting.[14] All three studies evade substantive analyses by saying that proposed in-situ methods are too poorly known to permit definition of environmental aspects.

Actually, the U.S. Bureau of Mines has been investigating the feasibility of in-situ retorting for more than 12 years.[15] Its personnel have published numerous reports and articles on the Bureau's technological process achievements, but with exception of the Bureau's input to the *Bronco* study, none of these published materials gives data on environmental hazards other than to imply that in-situ methods would be less destructive of environmental values than mining and surface retorting.

Especially noteworthy is the Bureau's apparent failure to consider the environmental impact of its field tests near Rock Springs, Wyoming.[16] In August 1970, I visited the site along with members of the U.S.

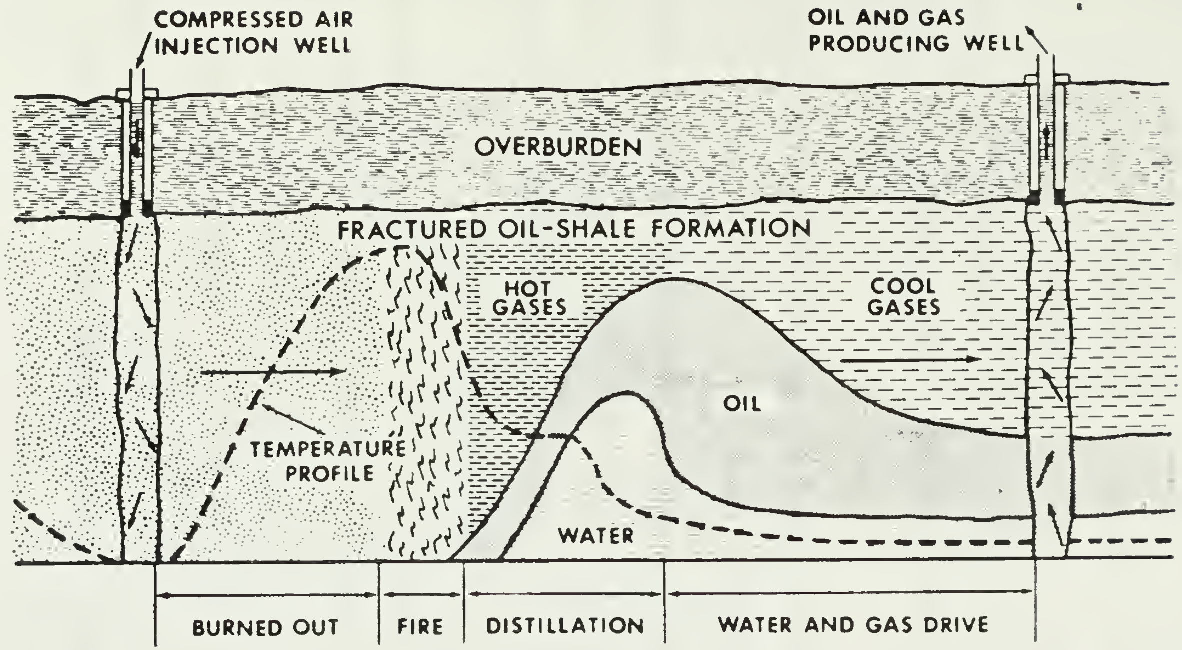


FIGURE 5. SCHEMA OF IN-SITU COMBUSTION PROCESS

Department of the Interior Oil Shale Task Force. The Bureau representative at the site responded positively to questions involving in-situ technology per se, but was unable to answer any inquiries relating to potential effects on groundwaters, surface waters, or other environmental issues. Later I wrote to the Director of the Bureau's Laramie Energy Research Center requesting data on groundwater surveys conducted at the site <u>before</u> and <u>after</u> the experiment, and was informed only that some of the holes drilled for the experiment encountered water; others were essentially dry."[17]

At least five private companies have conducted in-situ field tests in the Piceance Creek Basin of western Colorado. Sinclair Research conducted two separate projects, one near Debeque in 1953-54 and another northwest of the first site in 1964-66.[18] Equity Oil Company is currently operating an experiment which it began in 1964.[19] Mobil Oil, Humble Oil, and Shell Oil have carried out field work at various times within the past ten years, but have not published reports. Shell is currently undertaking an in-situ project in Rio Blanco County.

None of the private companies have released data on the environmental hazards of their experiments. Letters were sent to the five companies in July 1969. The four who responded (Equity, Mobil, Humble, Shell) admitted doing little or no research on environmental aspects of shale-oil recovery.

EVALUATION OF IN-SITU PROCESSING

The most crucial issue here is whether in-situ recovery will be more beneficial to society than recovery by mining and surface retorting (Fig. 6).

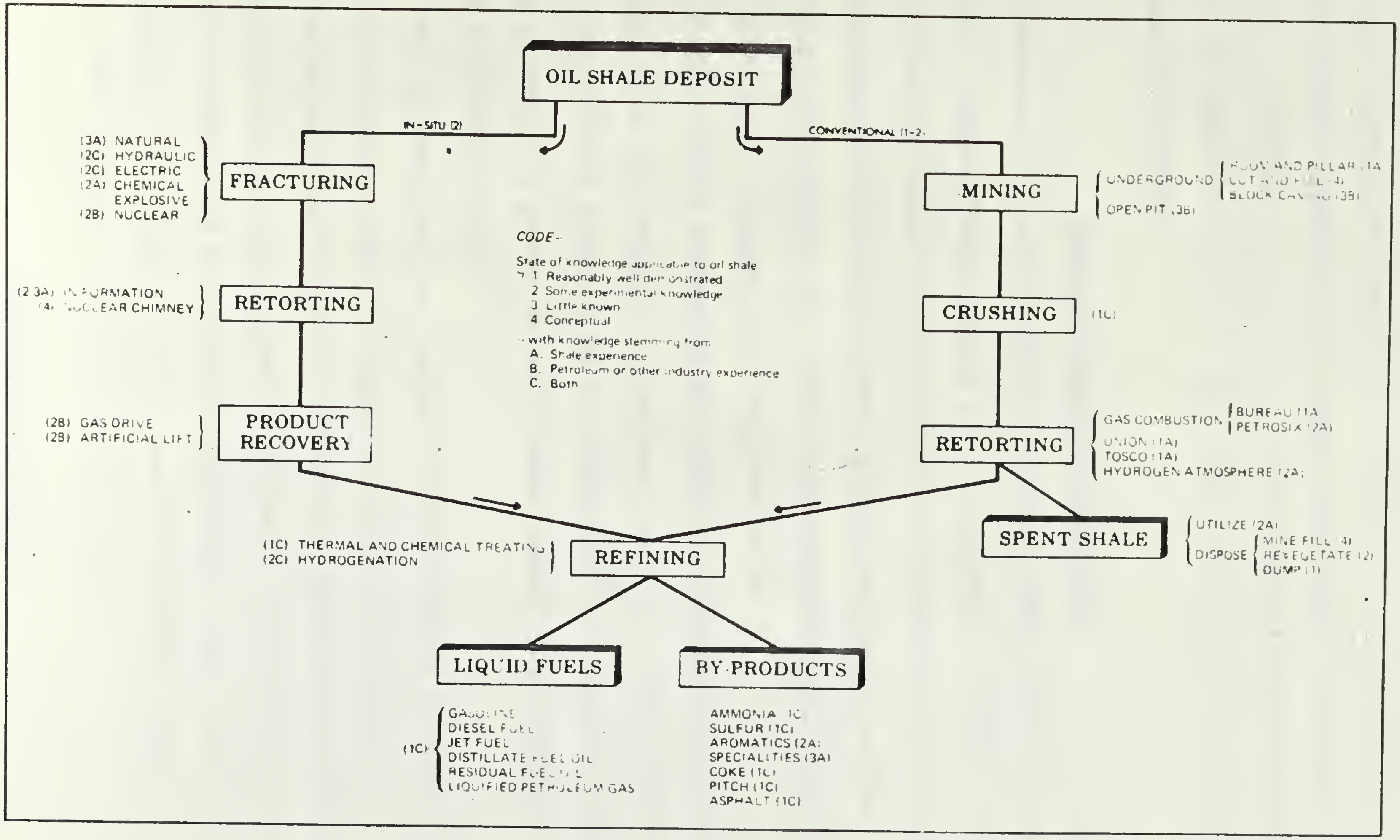


FIGURE 6. OIL SHALE AND SHALE OIL RECOVERY SYSTEMS
(Adapted from U.S. Dept. Interior, 1968, p. 47)

Three interrelated questions are involved: Will in-situ processing tend to maximize resource output from a given deposit? Can in-situ processing be used for most deposits or will the method be restricted to a limited range of conditions? Will in-situ processing tend to minimize environmental damage?

Shale-Oil Recovery Efficiency

Estimates of potential shale-oil recovery range from very pessimistic (1-10% of in-place Fischer assay) to very optimistic (50-70%). Seventy percent recovery would be about equal to the expected output from a plant using single-story underground room-and-pillar mining and surface retorting methods (Table 2). Fifty percent recovery would likely exceed that from a multiple-story underground mine.

Whether in-situ processing will actually achieve 50 to 70 percent recovery is an open question. Simulation tests in a surface batch retort have achieved yields of 28 to 81 percent.[20] The several field tests conducted by government and private industry have yielded very small quantities of oil.[21]

One may argue that the absolute recovery ratio is immaterial, as long as the process gives an acceptable investment return and is superior in opportunity costs to alternative oil-shale technologies. I accept this premise but hasten to add that a final decision should include consideration of interfuel competition. Others may flatly reject the premise on the basis that unforeseen technological advance will allow higher recovery in some future time period.

Geological Constraints

The extent to which in-situ methods may substitute for mining

TABLE 2.--RECOVERY EFFICIENCY OF VARIOUS EXTRACTIVE TECHNOLOGIES

Extractive Technology	Efficiency	Reference
MINING:		
Room-and-pillar, single story	75%	East and Gardner (1964)
Room-and-pillar, multiple stories	50% at best; possibly much less	U.S. Dept. Interior (1968, p. 49)
Cut-and-fill	90%	U.S. Dept. Interior (1968, p. 54)
Open pit or stripping	approx. 100%	
SURFACE RETORTING:		
BuMines gas-combustion process	max. of 95% of Fischer assay	U.S. Dept. Interior (1968, p. 48)
Union Oil Company process	75-85% of Fischer assay	Colorado Oil Shale Advisory Committee (1971, p. 83)
TOSCO II process	max. of 107% of Fischer assay	Lenhart (1969, p. 5)
IN-SITU RETORTING:		
Non-nuclear techniques	10% of in-place Fischer assay	Ertl (1967, p. 33)
	50-70%	U.S. Dept. Interior (1968, p. 70)
Nuclear techniques:		
Chimney	50-70%	U.S. Dept. Interior (1968, p. 68)
	70%	Lombard and Carpenter (1967, p. 733)
Fracture zone between chimneys	20-35%	U.S. Dept. Interior (1968, p. 68)
	50% within 5 ft of chimney edges	Lombard and Carpenter (1967, p. 734)
Total	1%	Ertl (1967, p. 33)

and surface retorting is clearly an important [illegible]. Should these methods be usable only under unique circumstances, then a major portion of the oil-shale region would automatically be precluded from development.

As discussed by Murphy and others,[22] the matrix permeability of Green River oil shale is essentially zero. Massive fracturing of the deposits to create fluid flow paths is therefore a necessary prerequisite to in situ retorting, except perhaps in cases where joints or solution cavities provide limited native permeability.[23]

Fracture permeability has been successfully initiated in shallow oil-shale beds (50-88 ft below ground level), although not necessarily in the manner required for control or maximization of subsequent combustion operations.[24]

Completely unresolved is the question of whether adequate permeability can be induced in the deep-basin deposits (several hundred to 1,000+ ft below ground surface), especially those with high organic content. Organic-rich shales are tough and resilient, and tend to resist fracturing by uniform flow.[25] Breakage in mine blasting and crushing operations tends to occur along preexisting laminations and often results in the production of large slabs.[26] These properties suggest that fracturing of organic-rich shales under high overburden pressure may require atomic energy to be successful. Smith and Trudell[27] propose that development possibilities may be enhanced if the deposit consists of alternating rich and lean beds, since the lean beds appear more amenable to fracture and could [illegible] heat transfer to the richer beds.

Developable underground sites must be capped by impervious rock to prevent the uncontrolled escape of combustion products and injection fluids (air, oil, gas). The sites must also be relatively free of groundwater and groundwater seepage, or else be amenable to dewatering and plugging.

Conservation of associated mineral deposits will impose constraints in many areas. Recovery of disseminated and interbedded minerals (Fig. 2; Table 1) could perhaps be achieved if an in-situ leaching technology were developed. Mine recovery might be possible before or after extraction of the shale oil, but only from those deposits in which the associated mineral has sufficient value to be mined for its sake alone. Even this would likely be impossible after retorting because of the weakened condition of the retorted shale body. Underground development near existing oil and gas wells would be automatically precluded.

Use of nuclear explosives to fracture the oil shale would amplify some of the problems discussed above and would introduce other constraints not mentioned.[28] This is particularly noteworthy since nuclear fracturing is generally regarded as the most economical and perhaps the only feasible means of in-situ recovery from the deep-basin deposits.

Environmental Constraints

Finally, there is the overriding question of whether in-situ processing will indeed minimize environmental damage. This is approached below under five general headings: land defacement, air quality, water yield, water quality, and support requirements.

Land Defacement

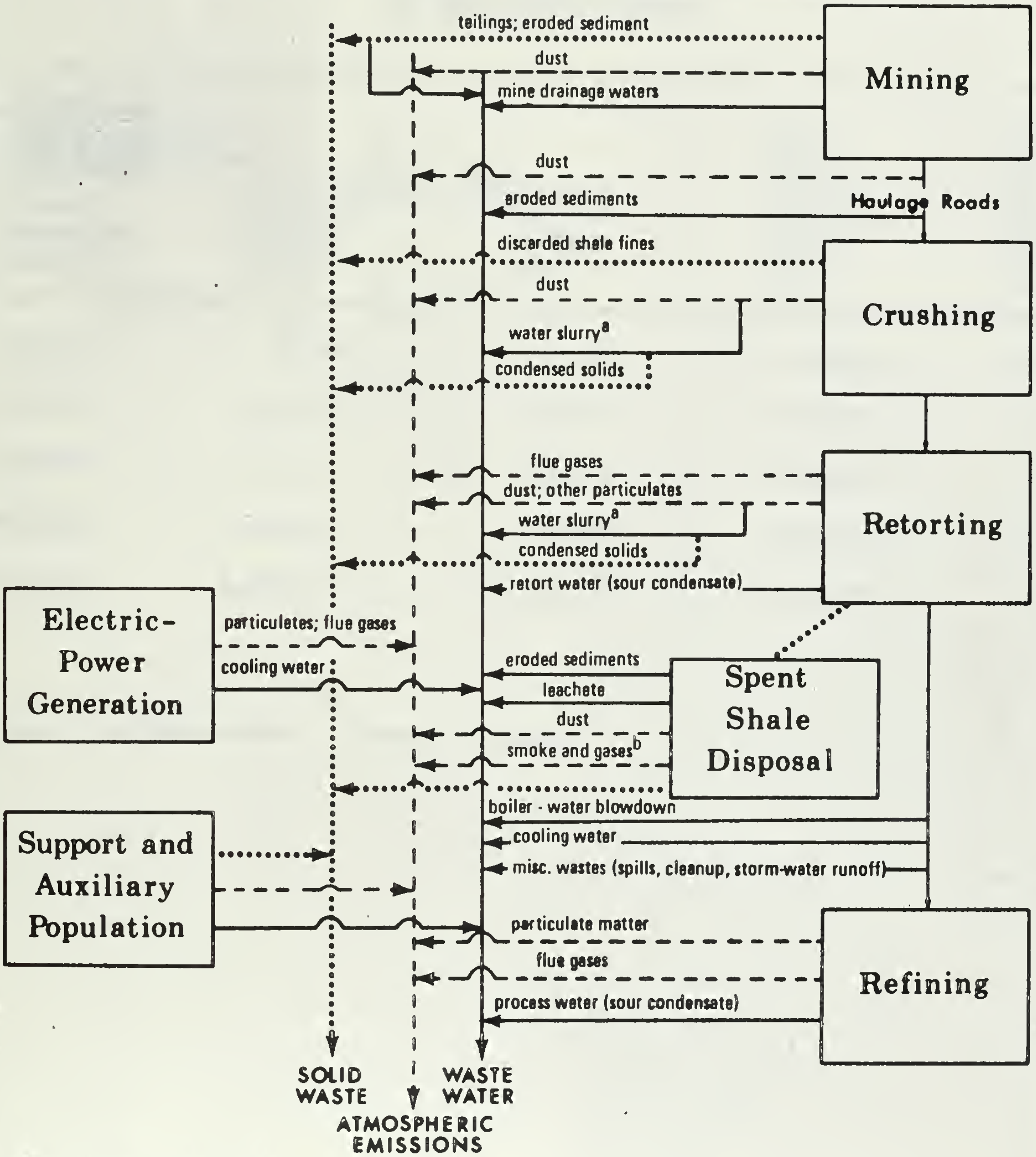
The environmental advantages and disadvantages of in-situ processing can be understood best by comparing them with the potential effects of mining and surface retorting.

As shown schematically in Figure 7, conventional recovery systems will generate various solid, liquid, and gaseous effluents. Although the amount and toxicity of waste streams will vary with the particular mix of extractive techniques employed, all systems will produce large quantities of spent shale and small to large amounts of mine tailings.

The volume of spent shale emplaced in the environment can be expressed by an equation of the form $O = f\ (G, M, E, P, R, C, B, D)$, where O is output of spent shale; G and M are grade and mineralogy of the raw shale feed; E is efficiency of shale-oil recovery from the mined rock; P is rate of shale-oil production; R is volume increase accompanying mining, crushing, and retorting; C and B are volume reductions from coproduct and byproduct recovery; and D is volume reduction from compaction at the disposal site.

Table 3 shows the output volume under differing rates of shale-oil production. Calculations are based on shale grade of 35 gallons per ton and recovery efficiency of 90 percent of in-place Fischer assay. Coproduct and byproduct recovery are assumed to be zero. In no case is byproduct recovery likely to be very significant.[29] Coproduct recovery will become important for shales mined from the saline-rich zones (Fig. 2), if and when the required technology becomes available.[30] Values of mineralogy, retorting, and compaction are assumed to be such that the final disposal volume will be 1.2 times that of the unmined shale. This is probably the maximum compaction value that can be expected.

Waste Effluents Generated by Conventional Oil-Shale Processing



[a] water slurry from wet scrubber

[b] smoke and gases from sponteneous or accidental combustion of spent shale rich in organic carbon.

FIGURE 7

TABLE 3.—EFFECT OF RATE OF SHALE-OIL PRODUCTION ON SPENT SHALE OUTPUT

	Raw Shale Input			
Shale-oil Production (bbl/day)	In-place Weight (tons)	In-place Volume (yd^3)	Spent shale output compacted volume (yd^3)	Days required to fill box canyon 1 mi. x 1000 ft x 300 ft
50,000	66,700	38,300	46,000	638
250,000	333,500	191,600	230,000	128
500,000	666,900	383,300	460,000	64
1,000,000	1,333,900	766,600	919,900	32
2,000,000	2,667,700	1,533,200	1,839,800	16

See text for assumptions. Numbers rounded.

The right-hand column of Table 3 emphasizes the tremendous storage space required for even a minimum sized plant using high-grade shale. Surface loading with spent shale could be alleviated by returning 50 to 80 percent of the material to underground openings (assuming the shale was extracted by underground mining). Conversely, the quantity of spent shale output would be vastly increased if lower grade shales were used. Surface mining would produce additional solid wastes in the form of mine tailings. For deep-basin deposits this could easily exceed 1 cubic yard of overburden per barrel of shale oil produced.

In-situ recovery would obviously eliminate the large-scale surface transformation inherent with mining and aboveground retorting, and it is this advantage which prompts ready acceptance of the concept.

Presumably, underground development sites would have a visual impress similar to conventional oil and gas fields. Injection wells, recovery wells, bulk storage facilities, and other structures would give testimony to the ongoing industrial activities. Initial disturbance of the soil and vegetation cover would probably be extensive because of the close spacing of wells. (E.g., the ongoing Bureau of Mines experiment near Rock Springs, Wyoming, involves 54 wells spaced in 1.3 acres.) However, plugging of the wells and revegetation of the land surface should leave the abandoned site in good condition.

The time required for retorting would be relatively short, perhaps on the order of 4.5 years for a 1-square-mile area or 36 years for a 5,120-acre lease.[31]

These favorable conditions must be balanced against the possibility of seismic damage during or after in-situ processing.

Massive fracturing of the in-place oil shale creates a volume expansion which must inevitably lift the overburden rock and land surface. The overburden rock will absorb the lift by uniform flow, faulting, or both.[32] Deformation by uniform flow may produce no significant effects at the land surface. Faulting (breakage) may occur entirely at depth or it may be transmitted to the surface.

Without data on rock temperature, confining pressure, pore pressure, anisotropy, etc., the potential for surface faulting cannot be determined. It is nonetheless evident that massive fracturing cannot be done in willy-nilly fashion.

Retorting of the fractured shale will alter the structural properties of the rock, again posing the hazard of surface faulting and land subsidence. Oil shales retorted in a stress-free environment lose cohesion and compressive strength.[33] Structural breakdown by fracturing and swelling becomes extensive as the grade of shale increases. The retorted underground shale body may be relatively weak or strong, depending on the interrelated variables of initial mineralogy and grade, induced fracture pattern, retorting temperature, burn time, partial pressure of reactants, and volume loss. Any groundwater solution after retorting would be important also.

The danger of surface subsidence applies also to recovery by underground mining. Perhaps the major difference is that collapse of mine sites would be localized occurrences; whereas in-situ processing may induce collapse over broad areas.

<u>Air Quality</u>

The major air quality effect of conventional processing (Fig. 7) will likely be dust pollution from mine blasting, truck loading and

haulage, shale crushing and retorting, and spent shale disposal and storage. Uncontrolled dust losses from crushing and retorting will be on the order of 1.5 to 2.0 percent of the raw shale input, or about 990 to 1,320 tons per stream day from a minimum sized plant using high-grade shale.[34] Blowing dust from spent shale dumps will pose a serious problem unless the pile surface is stabilized.

In-situ processing will eliminate most dust problems but will still generate the same kinds of gaseous effluents as conventional methods. Site selection must be preceded by careful geophysical surveys to insure that retort combustion gases will not reach the surface via natural fracture pathways. Extensive joint systems characterize both the Piceance Creek and Uinta basins.[35] Intersection of surface joints with the underlying retorting zone would allow free passage of gases to the atmosphere,

Noncondensable gases collected by recovery wells should consist mainly of nitrogen and carbon dioxide, and smaller amounts of carbon monoxide, oxygen, hydrocarbons, methane, and hydrogen sulfide.[36] Quantity and heating value of the gases produced are unknowns at this time. Unless recycled or recovered for commercial use, the gases will have to be vented or flared.

Air pollution problems associated with upgrading of the raw shale oil should be identical regardless of the retorting method used.[37]

The Colorado, Utah, and Wyoming studies foresee no significant air quality problems with either conventional or in-situ processing systems. This optimistic outlook reflects a preoccupation with source emission values and a corresponding failure to consider meteorological factors which determine accumulation or dispersion of pollutants.

Atmospheric dispersion is basically a function of wind speed and mixing depth.[38] Mixing depth, or the air-layer thickness characterized by neutral stability or instability, varies directly with the vertical temperature profile. It reaches a maximum when temperature decreases rapidly with height and is zero under inversion conditions, or when temperature increases with height.

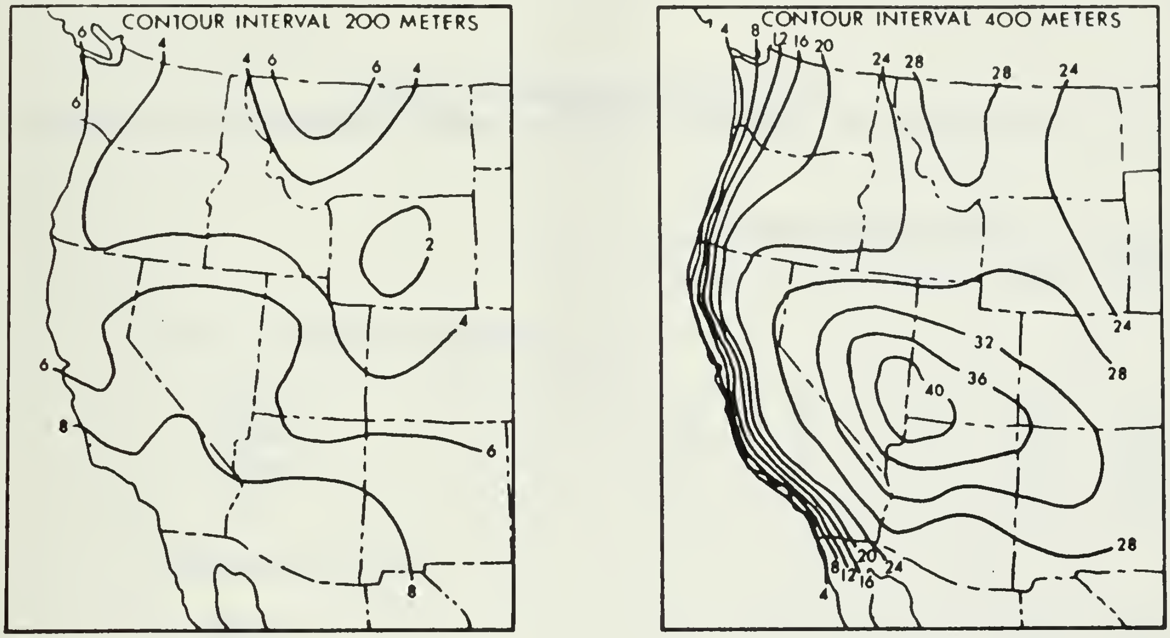
Figure 8 illustrates the high air pollution potential common to most areas in the western United States. Maps A and B show mean morning mixing depth for January (winter) and July (summer). Winter depths are seen to be especially shallow, being only 200 to 400 meters (656 to 1,312 feet) within the oil-shale region. Mixing depth increases to more favorable levels during summer and spring but decreases again in the fall.

Maps C and D show the frequency of low-level temperature inversions (surface to 500 feet). As noted earlier, the mixing depth becomes zero under inversion conditions.

Although temperature inversions occur over both flat-lying and dissected terrain, they are most frequent and intensely developed in arid or semiarid valleys.[39] Table 4 contrasts the percent frequency of inversions at Grand Junction, Colorado, and Washington, D.C. Grand Junction lies in a broad valley southwest of the Piceance Creek Basin (Fig. 1), at about 4,600-feet elevation, and is bordered on the north and south by bluffs which rise above 6,700 feet elevation. Annual rainfall averages slightly over 8 inches.

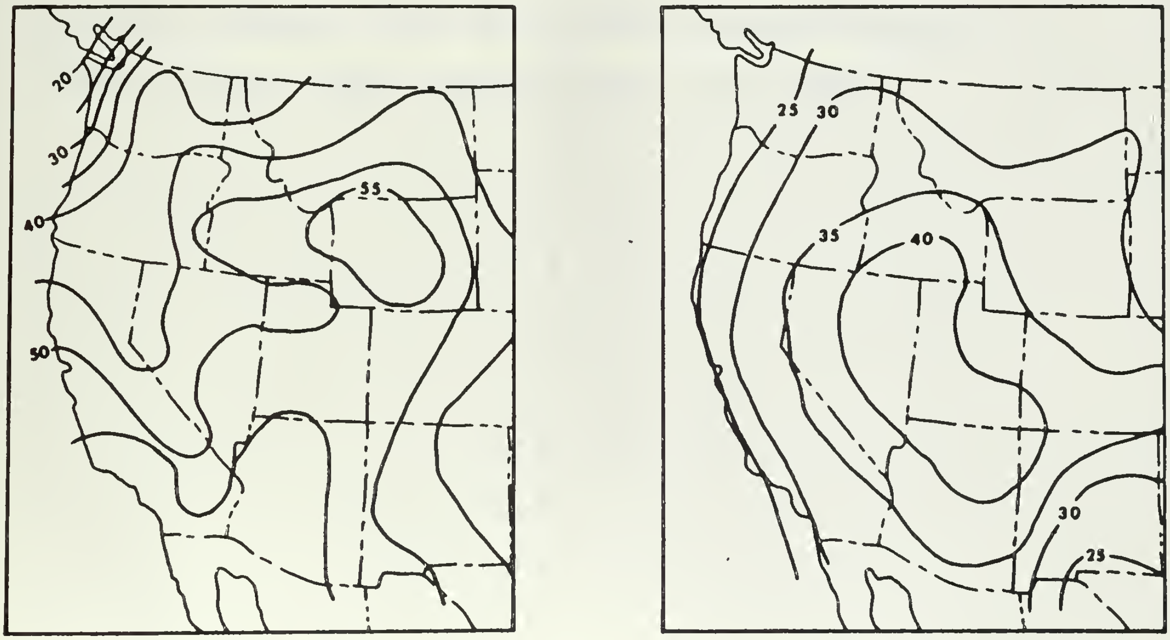
The inversion data for Grand Junction may be taken as representative of larger valley locations throughout the oil-shale region. If anything, the narrow valleys experience an even higher incidence of

AIR POLLUTION POTENTIAL FOR THE WESTERN UNITED STATES



A. January **B. July**

MEAN MAXIMUM MIXING DEPTH
(AFTER HOLZWORTH, 1962)



C. Winter **D. Summer**

INVERSION FREQUENCY (PERCENT OF TOTAL HOURS)
(AFTER HOSLER 1962)

FIGURE 8

TABLE 4.—PERCENT FREQUENCY OF TEMPERATURE INVERSIONS, GRAND JUNCTION, COLORADO, AND WASHINGTON, D.C.[a]

	Greenwich Mean Time				Total Time
	0300	1500	0000	1200	
Grand Junction, Colorado:					
winter	81	86	8	91	53
spring	60	32	0	67	31
summer	67	17	4	90	38
fall	90	75	6	84	49
Washington, D.C.:					
winter	44	22	30	48	28
spring	42	5	12	51	23
summer	47	2	5	57	24
fall	56	8	34	59	32

[a] Inversion frequency below 500 feet above station elevation.

Source: Hosler (1961, Appendix table, p. 335, 339)

inversions.

Corollary to the temperature inversion is a diurnal reversal of local winds, downslope or downvalley at night and upslope or upvalley during the day. This mesoscale circulation, called a mountain-valley breeze, is analogous in many ways to the land and lake breeze effect which is known to reinforce atmospheric pollution loadings along the shores of Lake Michigan.[40]

The essence of the above discussion is clear: source emission values must be substantially below state air quality emission standards; otherwise pollutants will accumulate under inversion conditions and reach dangerous levels. Refinery plants, aboveground crushers and retorts, spent shale dumps, and electric-power generating facilities should all be located on uplands rather than in valleys. Unfortunately the reverse situation is likely to prevail.

Water Yield

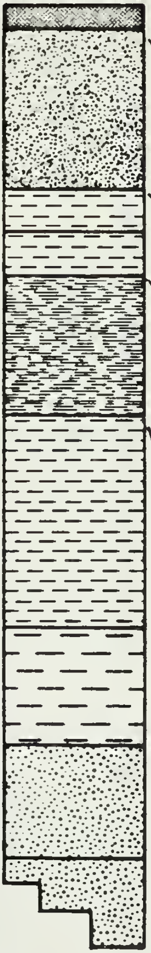
The Colorado environmental impact statement mentions that "creation of fractures (in the oil-shale formation) can change existing hydrology, thus introducing new unknowns."[41] This brief comment represents nearly the sum total of published information on the potential effects of in-situ processing on water yield.

A logical starting place for further investigation is to examine the existing hydrologic regime.

Figure 9 summarizes the oil-shale and water-bearing characteristics of rock formations in the Piceance Creek Basin. The light-shaded units are relatively impermeable. The dark-shaded units have greater porosity and permeability, and are capable of transmitting significant quantities of groundwater. Particular attention is directed to the valley

OIL-SHALE AND WATER-BEARING CHARACTERISTICS OF THE GREEN RIVER FORMATION AND VALLEY ALLUVIUM, PICEANCE CREEK BASIN, COLORADO

VALLEY ALLUVIUM 0'-140'	Sand, gravel, clay
EVACUATION CREEK MEMBER 0'-1,250'	Mainly sandstone & siltstone with minor amounts of low-grade oil shale & barren marlstone
PARACHUTE CREEK MEMBER 500'-1,800'	Moderate to high-grade oil shale Mahogany Zone Richest oil-shale interval Leached Zone Saline minerals & moderate to high-grade oil shale. Main saline deposits in lower half. High resistivity zone Low- to high-grade oil shale
GARDEN GULCH MEMBER 0'-900'	Mainly clay shale & low- to moderate-grade oil shale
DOUGLAS CREEK MEMBER 0'-800'	Mainly sandstone with minor amounts of algal & oolitic limestone
ANVIL POINTS MEMBER 0'-1,870'	Shale, sandstone, marlstone; grades into other members



Best aquifer per unit volume but limited in areal & vertical extent; well yields up to 1,500 gpm

Water moves primarily through fractures. Mostly drained above stream level but saturated below. Well yields ≥ 100 gpm. Dissolved solids range from 250 to 1,800 mg/l.

Low porosity & permeability. Limited percolation through vertical joints is important in regional flow of groundwater.

Artesian aquifer; more porous & permeable because of fractures & solution voids. At least 2.5 million acre-feet of water in storage. Well yields may equal 1,000 gpm. Fresh to moderately saline (≲ 2,000 mg/l) near basin margin; saline to briny (25,000 mg/l average) near center.

Relatively impermeable & probably little fractured.

Relatively impermeable. Not known to yield water to wells.

Relatively impermeable. Maximum well yields unknown but probably < 50 gpm. Dissolved solids range from 3,000 to 12,000 mg/l.

Poorly permeable. Known well yields < 10 gpm. Springs yielding < 100 gpm issue from fractures.

Source: Oil-shale data after Donnell (1961) and others; water data after Coffin, Welder, Glanzman, and Dutton (1968); Coffin, Welder, and Glanzman (1969).

FIGURE 9

alluvium, to the saturated zone of the Evacuation Creek Member, and to the 3 divisions of the Parachute Creek Member: the oil-rich beds of the Mahogany Zone aquitard, the artesian leached zone, and the relatively impermeable high resistivity zone.

Figure 10 shows the relationship of these hydrologic units in terms of regional groundwater flow patterns in the northern half of the basin. The arrows, indicating direction of water movement, show that recharge on the basin margins flows downward through the Evacuation Creek Member or Mahogany Zone aquitard, laterally toward the center and northern edge of the basin, and upward from the Evacuation Creek Member and leached zone. Discharge occurs primarily via Piceance Creek (shown in diagram), with smaller amounts being discharged to Yellow Creek, White River, and springs or flowing wells.

Figures 9 and 10 are based partly on preliminary investigations and are therefore subject to later revision or refinement. Assuming the data to be substantially correct, however, the following hypotheses become evident:

1) Massive fracturing across the Evacuation Creek-Mahogany zone interface, if accomplished near the basin margin, would drain waters from the saturated unit of the Evacuation Creek Member.

2) Fracturing across the oil-rich Mahogany beds near the basin center would facilitate upward movement of artesian water from the leached zone.

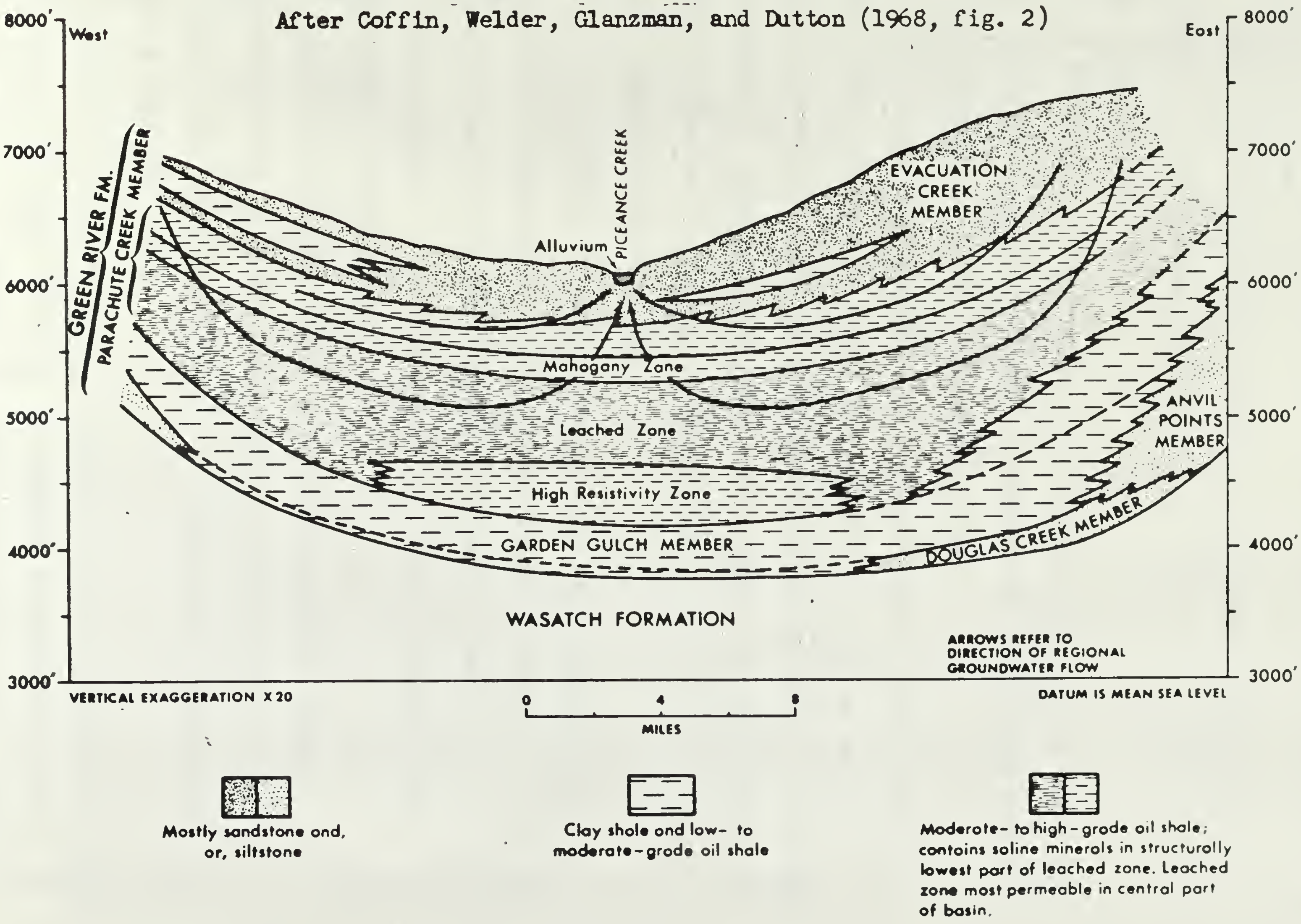
3) In-situ development of the leached zone might require dewatering prior to retorting. Pumping large quantities of water would lower the artesian pressure.

4) Fracturing and retorting in the leached zone would increase

FIGURE 10

DIAGRAMMETRIC SECTION ACROSS THE PICEANCE CREEK BASIN SHOWING OIL-SHALE STRATIGRAPHY AND DIRECTION OF GROUNDWATER FLOW

After Coffin, Welder, Glanzman, and Dutton (1968, fig. 2)



the formation's porosity and permeability, with attendant effects on artesian pressure.

5) Fracturing across the interface of the leached zone-high resistivity zone would enlarge the artesian aquifer, thus producing a drop in pressure.

6) Fracturing, retorting, or dewatering of shale formations would alter existing hydraulic gradients, thus producing long-range changes in the direction and rate of groundwater flow.

7) The underground spent shale dump created by retorting will be highly soluble and may be highly decrepitated. Dissolved salts and suspended particles picked up by groundwaters moving through the burned out dump may be deposited elsewhere, thus reducing the permeability of existing groundwater flow paths. This plugging effect could produce serious long-range consequences.

Any one of the above actions could alter the existing points and rates of water discharge. The net effect might be positive or negative. Adverse effects would include drying up of wells, desiccation of wildlife watering holes, and reduction of base flow in Piceance Creek, Yellow Creek, and White River.

Failure to consider effects on water yield can be traced to the common belief that in-situ processing of oil shale will be analogous to thermal recovery of petroleum.[42] The comparison breaks down in two important respects.

First, petroleum reservoirs initially contain a multitude of interconnected pores through which oil and combustion gases can flow to producing wells. In contrast the matrix permeability of oil shale is essentially zero because the rock pores are filled with solid organic

matter. Hence thermal recovery requires only the application of heat to reduce the oil's viscosity and make it more mobile. Shale-oil recovery necessitates fracturing the rock or otherwise increasing its bulk permeability before heat can be applied.

Second, petroleum reservoirs are hydrologically isolated by impervious formations, or else the petroleum would never have accumulated in the first place. Oil shales may or may not be hydrologically isolated from the rest of the environment. In the Piceance Creek Basin (Fig. 10) only those in the high resistivity zone appear to be isolated from regional groundwater and surface water systems, and this may be true only in a relative sense. More favorable conditions may exist in the Uinta and Green River basins. It can be noted, however, that the Uinta Basin is dominated by major jointing and fracture patterns which are remarkable for their lateral and vertical persistence. Gilsonite veins which fill many of the larger joints are known to extend downward for 1,500 feet or more.[43]

Mining and surface retorting will also affect water yields. Drainage from surface mines intersecting the Evacuation Creek Member saturated zone could result in lowered water tables. Mines or wells tapping the leached zone would probably produce several thousand acre feet of water per year for many years, with an accompanying drop in water levels[44] and alteration of existing hydraulic gradients. Diversion works and retention ponds constructed in spent-shale disposal areas will alter both the quantity and timing of surface runoff waters.

Water Quality

The major waste-water streams from conventional oil-shale processing

(Fig. 7) will include mine drainage, retort water, cooling water, refinery effluent, and storm-water runoff.

Quantity of mine drainage waters will vary with the rate of groundwater seepage from enclosing formations and, for surface openings, with the amount of precipitation falling on the mine site.

Mine openings in the Piceance Creek Basin, particularly those in the central portions, may be subject to high rates of groundwater inflow (Figs. 9-10). Test wells in the leached zone of the Parachute Creek Member indicate potential yields of as much as 1,000 gpm. Yields from the Evacuation Creek Member are reported as high as 100 gpm.

The quality of mine drainage may be fresh or extraordinarily saline (Fig. 9). Groundwaters near the edges of the Piceance Creek Basin contain less than 2,000 mg/l dissolved solids, but waters near the basin center average 25,000 and range upward to 63,000 mg/l.[45]

Groundwater potentials in the Uinta and Green River basins are poorly known. Available data indicate generally low yields of fresh to briny water.[46]

Waste streams from retorting and refining operations may be classed as oily or non-oily. This distinction is purely relative, as the sources of oily waste are so general that the so-called non-oily streams are usually contaminated with variable amounts of oily substances.

Non-oily sources contribute the largest volume of waste water. By far the larger portion comes from cooling water which may be used on a once-through or recirculating basis.

Once-through cooling water carries waste heat and is therefore a potential source of thermal pollution. Otherwise the water is subject to contamination only by occasional process leaks.

Recirculating cooling water, on the other hand, is a significant source of contamination.[47] The more times cooling water is recirculated, the more polluted it becomes, either from process leaks (bearings, exchangers, etc.) or from the addition of water treatment chemicals (corrosion inhibitors, stabilizers and dispersants, and microbiocides). The need for minimizing water withdrawals in the oil-shale region means that cooling water is likely to be concentrated as far as possible, or that other waste streams will be used as cooling tower makeup. Either practice would increase the pollution loading of the final blowdown.

The oily waste stream differs from non-oily water in that the volume is generally lower, and the quantity of noxious and toxic substances is much higher.

The oily stream from retorting operations is that produced by thermal treatment of the oil-shale rock. Water contained in the raw shale feed, in the form of rainwater or snow, interstitial groundwater, and water of hydration, volatilizes during heating and pyrolysis of the shale and mixes with the oil mist and combustion gases. Some of the vaporized water is vented along with other flue gases. The remainder is condensed along with the shale oil, from which it must then be separated.

The quantity of retort water produced could be substantial. Union Oil Company reports that its retorting system "does not use any process water and does not produce any water."[48] However, the TOSCO retort produces about 3 gallons of water per ton of shale processed,[49] and the Bureau of Mines retort may produce as much as 10 gallons per ton.[50] A minimum size plant (66,000 tons/day) might therefore produce 198,000 to 660,000 gallons of retort water per day.

The retort water is highly contaminated with suspended solids,

dissolved inorganic salts and toxic metals, and dissolved and emulsified organic compounds.[51] Table 5 presents analytical data for the waste stream produced during operation of the modified Bureau of Mines gas-combustion retort. The degree to which the data are representative of gas-combustion retorting, not to mention other systems, is unknown.

Considerably more information is needed before the pollution hazard of retort water can be specified in detail. From Table 5, it is apparent that there will be a mix of dissolved inorganic salts, some of which will be present in very high concentrations. Such toxic metals as cyanide, arsenic, boron, and selenium may also be present (see Table 6). An old Bureau of Mines publication mentions the detection of up to 10 ppm arsenic in retort waters at the Anvil Points plant.[52] Other likely contaminants include organic acids, ammonium and other nitrogen-bearing compounds, sulfates, sulfides, phenolic materials, and free and dissolved oil.

Oily waste streams from refinery operations will include those associated with shale-oil storage and handling, visbreaking, delayed coking, and hydrogenation. Other waste streams will be produced if additional refinery processes are conducted on site.

Storage and handling afford opportunity for seemingly inevitable tank and pipeline leakages. Periodic cleaning of storage tanks contributes oil and a bottom sludge of oily solids.

Visbreaking, delayed coking, and hydrogenation can be expected to produce sour condensates containing sulfides, ammonia, phenolic materials, and perhaps cyanides. Strength and quantity of the waste streams will depend on the particular subprocesses used.[53]

TABLE 5.—CHEMICAL ANALYSIS OF WASTE WATER PRODUCED BY U.S. BUREAU OF MINES NUMBER 3 GAS-COMBUSTION RETORT

	Sample[a]		
	GC6710465WP	GC6710405WP	GC6710485WP
pH	8.6	8.8	9.0
Sodium	41	7	0
Calcium	50	35	49
Magnesium	0	0	0
Chloride	3,196	2,978	7,938
Sulfate	2,362	2,707	ND
Bicarbonate	12,187	10,992	14,884
Carbonate	2,100	2,148	5,730
Calcium carbonate	211	87	125
Potassium	11	3	0
Ammonium	9,694	6,990	16,908
Organic acids as acetic acid	33,017	30,615	10,205

[a] All values in mg/l, except pH. Color of waters and organic complexes materially interferred with determinations of iron, calcium, and magnesium. Although present, it was not possible to get accurate values. High carbonate value due to reaction with organic acids.

Source: U.S. Bureau of Mines, Bartlesville Petroleum Research Center.

TABLE 6.--COMPOSITION OF GREEN RIVER OIL SHALE

Major Constituents (weight-percent)[a]

Mineral Matter:	(86.2)	Organic Matter:	(13.8)
Dolomite and calcite	48	Carbon	80.5
Feldspars	21	Hydrogen	10.3
Quartz	13	Nitrogen	2.4
Clays, mainly illite	13	Sulfur	1.0
Analcite and others	4	Oxygen	5.8
Pyrite	1	Total	100.0
Total	100.0		

Minor Constituents (maximum percent)[b]

Arsenic	0.005	Molybdenum	0.001
Barium	.03	Phosphorus	.4
Boron	.003	Selenium	.001
Chromium	.007	Silver	.001
Copper	.008	Strontium	.08
Gold	.001	Tellurium	.7
Lead	.09	Titanium	.6
Lithium	.05	Vanadium	.06
Manganese	.08	Zinc	.1

[a] Mahogany Zone oil shale averaging about 25 gal/ton (Thorne, Stanfield, Dinneen, and Murphy, 1964, table 3, p. 7).

[b] Mahogany Zone oil shale (Stanfield, Frost, McAuley, and Smith, 1951, p. 12).

Uncontrolled runoff from snowmelt or summer thunderstorms may erode sediments from haulage roads and solid-waste dumps, leach inorganic salts from spent shale dumps, and break through waste-water retention ponds and lagoons (Fig. 7).

For example, on July 29-30, 1968, heavy rains generated a flash-flood which broke through a small earthen-dam retention pond at the Colony Development prototype site, washing approximately 2,000 gallons of bottom oil and an undetermined amount of spent shale tailings into the Middle Fork of Parachute Creek.[54]

The potential for such catastrophic runoff events exists throughout the oil-shale region[55] and should therefore be recognized as a major potential source of pollution.

The pollution threat of storm waters is especially great in view of the plans to emplace large volumes of spent shale in the surface environment. One plan developed by the Colorado Oil Shale Advisory Committee envisions filling 7 dry canyons with about 5.9 billion cubic yards of spent shale residue.[56] The affected area would total about 12,500 acres.

Implementation of any such disposal scheme must include engineering safeguards to prevent erosion or leaching of the spent shale. Tests of shale samples retorted under various conditions show that high concentrations of soluble salts will be removed from shale dumps if they are leached by percolating groundwaters or surface runoff. Nevens, Culbertson, and Hollingshead[57] report maximum concentrations of 1340, 990, and 310 ppm for calcium, sodium, and potassium respectively. Table 7 presents additional data on leaching potential.

Backfilling underground mines with spent shale will also produce serious pollution if the site is located in an area of active groundwater

TABLE 7.—WATER SOLUBLE IONS IN THE SATURATION EXTRACTS OF
DERIVED FROM OIL SPENT SHALE SAMPLES

	Spent shale designation[a]					
	A	B	C	D	E	F
Ion	Equivalents per million					
Ca^{++}	25.4	21.2	10.9	31.5	20.0	[illegible]
Mg^{++}	1.6	18.4	78.5	12.0	24.5	[illegible]
Na^{+}	124.0	113.1	195.8	57.0	[illegible]	[illegible]
K^{+}	1.4	0.7	2.6	7.0	16.6	[illegible]
$CO_3^{=}$	5.9	0.2	1.2	0.0	0.8	[illegible]
HCO_3^{-}	1.9	3.0	1.6	0.6	[illegible]	[illegible]
Cl^{-}	3.0	1.0	4.5	0.8	[illegible]	[illegible]
$SO_4^{=}$	137.5	139.3	266.3	99.3	[illegible]	[illegible]
pH (1:5)	9.9	9.4	9.3	9.2	9.0	

[a] Samples A-C taken from the TOSCO II retort; samples D-F from the Bureau of Mines gas-combustion retort. Sample F was taken from a dump that was exposed to atmospheric weathering for about 10 years. All other samples were taken soon after the pilot run.

Source: Schmehl and McCaslin (1969, p. 17-18, tables 1-2).

movement. Hydraulic emplacement of the spent shale will also produce a contaminated slurry which could dewater and mix with potable ground-waters.

Nearly all of the water quality problems enumerated above for conventional recovery systems could be duplicated in one form or another by in-situ processing (Table 8).

Analogous to mine drainage would be the necessity of dewatering certain underground sites prior to retorting. Any developments in the Piceance Creek Basin leached zone (Figs. 9-10) will almost certainly encounter large volumes of water. Much or all of the water will likely be highly mineralized and therefore unsuitable for most purposes, including release to streams in the area.

Substantial quantities of water will likely be produced along with the shale oil. (E.g., the Bureau of Mines field experiment near Rock Springs, Wyoming, produced approximately equivalent volumes of shale oil and water.[58]) This waste stream will carry the same organic-inorganic contaminants as water produced by aboveground retorts.

Treatment of the waste streams produced before or during retorting would be clearly prohibitive if large volumes of water are involved. Costs of desalting along would range between $0.25 and $3.00 per 1,000 gallons, depending on the process used and removal efficiency required.[59]

Disposal by deep-well injection, as suggested by the Colorado Oil Shale Advisory Committee,[60] is an attractive but not necessarily practical alternative. The petroleum industry has long disposed of its excess oil-field brine by injecting it into underground aquifers containing non-potable water. Various other liquid wastes are now handled in the same manner.[61] Unfortunately deep-well injection is no more than short

TABLE 8.—TYPES AND POTENTIAL SOURCES OF WATER QUALITY CHANGES EFFECTED BY COMMERCIAL OIL-SHALE AND SHALE-OIL PROCESSING

Source of Pollution	Type of Pollution
Conventional Processing:	
Erosion of mine tailings and spent shale dumps	S, M, C
Leaching of spent shale dumps (surface or underground)	S, M, C
Dewatering of mine sites	M
Disposal of retort waste waters	M, C, T, N
Water slurry from wet scrubbers on crushers and retorts	M
In-Situ Processing:	
Dewatering of shale formations prior to retorting	M
Leaching of retorted in-situ shale body	M, C, N
Nuclear fracturing of oil-shale deposit	R, C
Conventional and In-Situ Processing:	
Erosion of access roads and other disturbed sites	S, M
Disposal of refinery waste waters (including water separated from raw shale oil)	M, C, T, N
Cooling water and boiler-water blowdown	M, C, T
Accidental oil spills	C
Consumptive use of process water	S, M
Consumptive use and effluent releases associated with support population and auxiliary industries	S, M, C, T, N

Pollution S = sediment (suspended solids); M = mineral (dissolved inorganic solids); C = chemical (oils, phenols, toxic metals, etc.); N = nutrient (nitrogen and phosphorus); T = thermal (waste heat); R = radionuclide

and in some cases the "stored" wastes have contaminated fresh-water supplies.[62]

Although in-situ processing eliminates the spent shale disposal inherent with surface retorting, it does not eliminate the spent shale. Instead, the spent shale dump is simply located underground rather than aboveground. Unless the site is hydrologically isolated, circulating groundwaters will move through the fractured, highly porous and permeable dump, leaching soluble salts and any oily residues not recovered by wells or consumed by passage of the combustion zone.

Support Requirements

Table 9 compares the support requirements of conventional and in-situ processing systems. Values cited are for a 50,000-barrel per day operation, which is probably the minimum sized plant that can operate efficiently using mining and surface retorting methods.

Electric-power generating facilities can be expected to produce waste heat and air pollutants (Fig. 7).[63] Most of the waste heat from power plants is carried by cooling water which may be recirculated or used once-through. Once-through use contributes to thermal pollution of the receiving stream. Recirculating cooling systems must be routinely drained off. The "blow-down" is high in minerals and chemicals and must be treated or diluted before being released or recycled. Air pollutants from fossil-fuel plants include sulfur oxides, nitrogen oxides, hydrocarbons, and particulates. The quantities emitted may vary widely, depending on the choice of fuel and control techniques.

The population associated with oil-shale development will produce various solid, liquid, and gaseous effluents. For example, urban dwellers in the United States generate an average of 130 gallons of

TABLE 9.—SUPPORT REQUIREMENTS
FOR A 50,000-BARREL PER DAY SHALE-OIL INDUSTRY

Industry Type	Direct Employment (number)[a]	Service Employment (number)[b]	Total Population (number)[c]	Consumptive use of water (acre-feet/year)[d]	Electric Power (MM Kwh/yr)[d]
Mining and surface retorting	900	720	5,994	4,700	140
In-situ processing	500	400	3,330	4,700	50

[a] Employment in mining, crushing, retorting, spent-shale disposal, shale-oil upgrading, and auxiliary equipment (or injection and recovery wells).

[b] Assumed basic-service ratio of 1:0.8.

[c] Direct employment + service employment + assumed average family size of 3.7.

[d] Water and power requirements for oil-shale processing only.

Source: Cameron Engineers (1969); Ryan and Welles (1966).

municipal sewage and 5.72 pounds of collected solid wastes per capita per day.[64] Multiplying these figures by the population data shown in column 3 of Table 9, the daily values become 432,900 to 779,220 gallons and 19,048 to 34,274 pounds, respectively, depending on whether the oil-shale industry uses conventional or in-situ recovery methods. Some of the population effects will come from persons already residing in the oil-shale region. However, much of the labor and service employment will represent new growth in the area,[65] which means additional pollution loading of the environment.

The environmental effects of water use may be resolved into depletion, loading, and concentrating effects.

Depletion is synonymous with consumptive use, whereby water withdrawn from surface or groundwater supplies is discharged to the atmosphere by evaporation or is incorporated in industrial products. Consumptive use automatically reduces the total quantity of water available. Although an in-situ industry will require less water for urban purposes than a conventional one, the amount of water consumed directly will either be about equal (Table 9) or substantially higher. Higher consumptive use would prevail if the industry utilized hydraulic fracture methods or steam injection for retorting and heat recovery. Should either industry draw upon local groundwater supplies, care must be taken to prevent overpumping. For example, large-scale pumping in the Piceance Creek Basin would drop the water table several hundred feet in a short time.[66]

Loading and concentrating effects refer to the degradation of water quality caused by addition of pollutants or abstraction of water. The two processes may operate separately or concurrently; both increase

the concentration level of pollutants in the water. Possible sources of industrial pollution loading have been described elsewhere in this report (see Fig. 7 and section entitled Water Quality). Concentrating effects occur automatically whenever part of the water is consumptively used and part is released as return flow. The full impact of loading and concentrating effects cannot be ascertained without data on the specific categories of water withdrawals, consumptive use, and return flows.

CONCLUSIONS AND RECOMMENDATIONS

Table 10 summarizes the potential advantages and disadvantages of in-situ processing. The high potential for adverse effects must be recognized and dealt with:

1) Shale-oil recovery from a given deposit is expected to equal no more than 50 to 70 percent of the in-place Fischer assay and could be substantially lower. Maximum recovery would equal or exceed the efficiency of underground room-and-pillar mining but would be appreciably lower than that of underground cut-and-fill or surface mining.

2) Development should not be allowed in the oil-shale saline facies unless methods are available for prior, concurrent, or subsequent recovery of the valuable sodium minerals. Limitations on recovery of other economic mineral deposits must also be considered.

3) Massive fracturing and underground retorting could induce land subsidence, particularly if the development site is located in high-grade shales. Subsidence would not only deface the land surface but could also rupture subsurface hydrologic barriers, thereby altering groundwater flow patterns and leading to contamination of aquifers and

TABLE 10.—POTENTIAL ADVANTAGES AND DISADVANTAGES OF IN-SITU PROCESSING

Advantages:

a) Lower private costs of production

b) Foreclosure of land defacement by mine scars, mine tailings, and spent shale dumps

c) Foreclosure of dust pollution from mining, crushing, surface retorting, and spent shale disposal

d) Oil recovery from shale deposits not readily amenable to conventional processing

e) Shorter period of industrial use

f) Smaller support population required

Disadvantages:

a) Generally lower oil recovery ratio

b) Not applicable to wide range of field conditions

c) Non-recovery of economic minerals disseminated in or interbedded with oil shale (?)

d) Land defacement from grading of well sites, etc.

e) Land defacement from subsidence

f) Alteration of groundwater flow patterns, surface water yields, well yields, and discharge from springs

g) Pollution of groundwaters and surface waters

h) Air pollution by retort gases or gases escaping to surface via natural or induced fractures

i) Air pollution by dust from graded well sites and access roads

j) Higher consumptive use of process water (?)

k) Air and water pollution from on-site refining of shale oil

streams. Surface drainage patterns could also be seriously disrupted.

4) Extensive joint systems in the Piceance Creek and Uinta basins afford ample opportunity for the uncontrolled escape of combustion products. Development of these sites could produce serious air and water pollution.

5) Development sites must be hydrologically isolated. In no case should development proceed within the groundwater recharge or discharge areas.

6) Development should not be permitted in aquitards which separate more permeable formations. In the Piceance Creek Basin, for example, no developments should be allowed in the Mahogany Zone and related beds (Figs. 9-10).

7) Development sites must be relatively free of potable groundwater. Our energy needs are not so great as to justify destruction of freshwater aquifers.

8) Development should not be allowed in mineralized aquifers known or thought to connect with surface-water or potable groundwater systems (e.g., the Piceance Creek Basin leached zone).

9) Development sites containing large quantities of mineralized groundwaters would have to be dewatered prior to retorting. Treatment of the waste stream would be uneconomic under present-day conditions. Disposal of the untreated waste by deep-well injection could contaminate potable groundwaters and related surface waters.

10) Water produced along with the shale oil will carry the same organic-inorganic contaminants as that produced in aboveground retorts. Under no circumstances should this waste stream be injected underground or otherwise disposed of without first receiving at least biological

treatment.

11) In-situ retorting yields a highly permeable spent shale dump rich in soluble inorganic salts. Groundwaters and surface waters could therefore become contaminated after the site is abandoned.

12) Extensive grouting of natural fractures and groundwater flowpaths would be economically if not technologically infeasible. Hence, proposals to seal off underground sites must be critically examined.

13) The best development opportunities appear to be in deep-basin deposits which contain small amounts of immobile groundwaters. Whether massive fracturing of these deposits can be accomplished with non-nuclear techniques is questionable. Use of nuclear energy poses serious environmental hazards.

14) Extensive fracturing and retorting of the deep-basin deposits could elicit seismic adjustments affecting groundwater flow patterns in both overlying and underlying formations.

15) Grading of the closely spaced well sites, access roads, etc., will remove the soil and vegetation cover from extensive areas. Measures must be taken to prevent wind and water erosion during the lifetime of the plant. Revegetation of the site must be consistent with wildlife and domestic livestock needs.

16) Well casings must be designed to prevent pollution by contaminated water or oil during normal operations. Wells must also be carefully plugged when the site is abandoned. The long-range stability of plugged wells must be seriously questioned.

17) The method may produce an excess of retort waste gases. Disposal of the gases must be consistent with air quality standards.

18) Oil storage, upgrading, and waste-water retention facilities afford the same air and water pollution potential as those employed in mining and surface retorting systems. Appropriate safeguards must be instituted.

19) Federal leasing should exclude in-situ experimentation until the method is appraised and proven to be environmentally sound.

The obvious conclusion here is that underground retorting will not constitute an environmental panacea. Indeed, there is ample reason to demand that both government and private industry publicly justify the environmental safety of their ongoing R & D projects, or else discontinue them in favor of a thorough technology assessment.

Three field experiments are now in progress: one by the U.S. Bureau of Mines near Rock Springs, Wyoming, and one each by Equity Oil Company and Shell Oil Company.

The Bureau has never published a report on environmental constraints of in-situ processing. My own contact with the Bureau leads me to believe that its past and current projects have involved little environmental thinking.

The Equity site is located along Black Sulphur Creek in the Piceance Creek Basin of Colorado, and has been operative since 1964. In response to a letter dated July 1969, Equity replied that "we have not, in the past nor are we now doing, any specific research into potential effects of our in-situ process on the environment."[67] Personal interview with an Equity representative in August 1970 produced the same comment.

The field test by Shell Oil Company is located along Piceance Creek, and is an extension of previous work conducted by Shell in the basin. In a letter dated August 18, 1969, Shell claimed not to have

carried out or supported "any research in the environmental conservation aspects of oil shale recovery."[68] Shell's comments on in-situ processing were as follows: "In situ shale recovery poses fewer problems since the spent shale disposal is eliminated....*It is possible, however, that in situ recovery will cause mild surface subsidence. We do not anticipate this subsidence will affect surface vegetation significantly and, so long as there are no extensive structures in the area, we do not anticipate that it would create a problem*" (underlining added).

Unless there is a sudden breakthrough in underground technology, both in commercial application and environmental safety, shale-oil recovery in the near future can be accomplished only by mining and surface retorting.

It therefore seems prudent to recommend that government and private industry join together in land-use planning, spent-shale management, and mined-land reclamation studies. Need for this research would not be diminished by withholding of federal leasing. Approximately 28 percent of the total oil-shale acreage already lies in private, state, and Indian ownership. The resource potential of private lands is sufficient to support one or more commercial scale operations.[69]

The environmental impact of conventional processing will be determined largely by operational goals and size of the industry. Three operational goals may be identified with respect to non-mineral values: (1) selective preservation, (2) planned enhancement, and (3) minimum depletion.

Review of the Colorado, Utah, and Wyoming environmental statements reveals few proposals for selective preservation or planned enhancement of the non-mineral environment.

In its 57-page report, the Wyoming Committee[70] makes only the following brief proposal: "Possibilities of enhancing the habitat and recreational values of the area, such as water development, should be investigated to offset any loss of habitat."

The Utah Committee is similarly reluctant to recommend specific preservation or enhancement opportunities. In its 54-page report, the Committee[71] comments only that "sound reclamation and restoration of the land may afford a unique opportunity to reshape the land and alter existing drainage so that erosion can be checked and runoff retarded" (underlining added).

An appendix to the 204-page Colorado report apparently offers suggestions on restoring, or compensating for loss of, wildlife habitat. Since the report appendices were sent only to people on the official distribution list, I have not been able to review the appendix in question.

Overall, the three state reports are strongly biased in favor of mineral development. Conflicts between mineral recovery and other environmental values will apparently be decided in favor of mineral exploitation. The conclusion section of the Colorado report has this to say:[72]

> "The carrying capacity of winter deer habitant adversely affected by industrial activity should be restored, as far as possible, by prompt revegetation and stimulation of remaining browse or provision for substitute browse areas. Environmental standards for off-site facilities such as water and oil pipelines, electric transmission lines, and roads should be formulated to minimize the impact on wildlife and to protect other environmental values of the region" (underlining added).

Minimizing environmental damage is little more than a polite synonym for degrading environmental resources. Although an acceptable

operational goal in particular cases, the idea of minimizing adverse effects must not be so prevalent as to limit full consideration of the alternative goals of selective preservation and planned enhancement.

In the case of the Piceance Creek Basin deer habitat, for example, the Colorado Committee failed to mention that meadow counts over the period 1947-68 show a pronounced downward trend in the number of deer wintering in the basin. Deer numbers declined by 64 percent from 1947-51 to 1964-68 and 39 percent from 1957-63 to 1964-68.[73] Increases in the deer kill limit account in part for the decline, but this action was taken because of deteriorating winter browse conditions.

Regional masterplans must accordingly be formulated in advance of any commercial oil-shale startup. The plans should represent joint efforts of the Bureau of Land Management, appropriate divisions of the Environmental Protection Agency, state governments, local governments, and interested private firms. The masterplans should designate areas suitable for mineral development and should likewise exclude those areas which are more valuable for recreational use, wildlife habitat, watershed protection, or other non-mineral purposes.

Development planning must also take explicit account of opportunities for enhancing the oil-shale environment as mineral exploitation proceeds. For years the Bureau of Land Management and private landowners have attempted to improve the natural quality of Western rangelands by instituting vegetation and water management programs.[74] Reclamation of mine and waste-disposal sites could be blended with this type of land improvement activity. For example, shale disposal should be integrated into watershed programs similar to those now operated by the Soil Conservation Service in various parts of the United States.[75]

Opportunities for systematic development planning are especially great, in part because most of the land is federally owned and in part because state and private holdings frequently occur as small parcels intermixed with federal land. As a condition to blocking-up uneconomic units by exchange or leasing of federal property, the federal government can impel the owners to work within an overall masterplan.

Given an appropriate mix of engineering controls <u>and</u> administrative planning, a commercial oil-shale industry could undoubtedly generate net benefits to the developers, to the local areas and states involved, and to the nation as a whole, <u>providing</u> the size of the industry is small or novel methods of land reclamation are developed and fully utilized.

The land area required to support an industry of a given size will depend on the recovery methods used, the grade and stratigraphy of the oil-shale deposit, and the character of the terrain relative to solid waste disposal. A minimum sized industry (50,000 bbl/day) will likely require several thousand acres even under the most favorable conditions. Table 11 shows the minimum acreage requirement of underground room-and-pillar mining under varying rates of production and shale grade, assuming recovery from an oil-shale section measuring 100-feet thick. The land requirement for mineral recovery alone is seen to vary from about 0.5 to 20 acres per stream day.

Current proposals for the handling of spent shale may be adequate for a very small industry but are clearly unsuitable for a moderate or large sized operation. As now envisioned, the spent residue will be emplaced in dry stream canyons or partly returned to the mine site.[76] Both methods involve storing large quantities of material which is high in

TABLE 11.--MINIMUM LAND REQUIREMENTS FOR A HYPOTHETICAL OIL-SHALE INDUSTRY USING UNDERGROUND ROOM-AND-PILLAR MINING[a]

In-place Oil Content		Recoverable Shale Oil (bbl/acre ft)	Acres Mined Per Stream Day at		
gal/ton	bbl/acre ft		50,000 bbl/day	250,000 bbl/day	1,000,000 bbl/day
15	738	498	1.00	5.02	20.07
25	1,140	769	0.65	3.25	13.00
30	1,330	898	0.56	2.78	11.14
35	1,500	1,012	0.49	2.47	9.88

[a] Assumptions: 90 percent retorting efficiency and 75 percent mine recovery from an oil-shale section measuring 100-feet thick.

soluble inorganic salts. The material will also be contaminated with various organic substances if retort or refinery waste waters are used for dust control and compaction at the disposal site.

Aboveground or belowground, the spent shale must be permanently shielded from percolating groundwaters or surface runoff. Engineering safeguards may be effective during the lifetime of the oil-shale plant, but who is to maintain the protection works after the site is abandoned? Will diversion structures and retention dams in canyon sites be built to withstand the 10-year, 100-year, or 1,000-year flood?

"Management" rather than "disposal" thus becomes a key word. Ideally, the spent shale should be rendered non-toxic before being emplaced in the environment. The scientific and economic challenge of developing suitable techniques is no more formidable than the challenges already overcome in perfecting the raw shale process technology. Materials might be added to the spent shale which would reduce its solubility, permeability, and erodibility. Current practices affect these properties only insofar as the shale residue is amenable to compaction.

Studies by Union Oil Company[77] and Colony Development Operation[78] indicate that spent shale from the Union and TOSCO retorts can be successfully vegetated. However, an independent investigation by Schmehl and McCaslin reached these conclusions with respect to shales from the TOSCO and Bureau of Mines gas-combustion retorts:[79]

1) Soil reclamation will be required to reduce the toxic effects of salinity and alkalinity.

2) Fertilization with nitrogen and phosphorus will be essential to establish and maintain growth.

3) Irrigation water will be required for reclamation of soils and germination of plant seeds.

4) Supplemental water may be required continuously in some areas to maintain sufficient growth to control wind and water erosion.

5) Tile drains or other mechanisms may have to be installed to remove saline drainage from the root zone.

6) The dark color of unburned shales may cause lethal temperatures for germinating seeds.

7) The pH of shale ash (spent shale burned at high temperatures in an oxygen atmosphere) is two to three units higher than that for spent shale. Little, if any, plant growth can be expected without treatment to reduce alkalinity. (Note: The spent shale will be burned if dawsonite is recovered as a coproduct.)

Current plans for the restoration of mine sites are completely conventional. Such thinking is totally unacceptable if development is to proceed on a large scale, particularly if surface mining is to occur over extensive areas. While surface mine openings can be functional scenic attractions, e.g., the Bingham Canyon copper pit near Salt Lake City or the Hull-Rust iron pit near Hibbing, Minnesota, they can also be ugly disfunctional entities. One need only visit the uranium open pit abandoned near Maybell, Colorado, for a classic example of the latter. Even more important is the potential impact of surface and underground mines on local and regional hydrologic relationships.

Economical methods of mine backfilling must be developed. Except in those cases where large quantities of sodium minerals are recovered from the shale deposits, there will be more than enough shale residue and mine overburden for complete filling of surface openings. The potential certainly exists for leaving open pit sites in a condition equal to or superior to the original land surface. Restoration of underground sites must be sufficient to prevent groundwater pollution and collapse of the surface cover.

Irrespective of the amount of land subject to disturbance at any one moment, it is clear that large-scale development over many years would have a cumulative effect on hundreds to thousands of square miles. Developers must therefore adopt a systems approach which recognizes the continuity of exploitation over time, and which recognizes that both mining and spent shale disposal will unavoidably alter the existing hydrologic regime of the larger area in which development occurs. The net effect on water balance could be positive, at least in terms of water quality, or it could be irreversibly negative.

In brief, commercial oil-shale development must not be allowed to proceed until the environmental integrity of the oil-shale region and downstream areas can be assured. The task will unquestionably require move novel thinking than is embodied in the Colorado, Utah, and Wyoming planning studies.

According to one observer,[80] "it would be hard for man to match the destruction nature has already wrought" in the oil-shale region.

Let us not try!

REFERENCES CITED IN TEXT

1 Laird, W. M., 1970, Remarks before the Annual Meeting of the Rocky Mountain Oil and Gas Association, Denver, Colorado, October 2[illegible]: Washington, D.C., U.S. Dept. Interior, Office of Oil and Gas, mimeo, p. 5.

2 U.S. Department of the Interior, 1968, Prospects for oil shale development: Colorado, Utah, and Wyoming: Washington, D.C., U.S. Dept. Interior, p. A1-A2.

3 World Oil Staff, 1969, World crude oil reserves increase 4.1%, natural gas rises 6.7%: World Oil, v. 169, no. 3, p. 63.

4 U.S. Department of the Interior, 1968, United States petroleum through 1980: Washington, D.C., U.S. Dept. Interior, Office of Oil and Gas, p. 11.

5 U.S. Dept. Interior, op. cit., note 4, p. 75.

6 E.g., Campbell, G. G., Scott, W. G., and Miller, J. S., 1970, Evaluation of oil-shale fracturing tests near Rock Springs, Wyo.: U.S. Bur. Mines Rept. Inv. 7397, p. 1; Hickel, W., Secretary, U.S. Department of the Interior, quoted in *The Denver Post*, Aug. 6, 1970, p. 19; Northern Environmental Council, 1971, Oil shale policy in the public interest: Duluth, Minn., Northern Environmental Council Policy Research Paper No. 6, 7 p

7 Ely, N., 1967, The oil shale industry's water problems: Colorado School Mines Quart., v. 62, no. 3, p. 9-17.

8 U.S. Dept. Interior, op. cit., note 2.

9 U.S. Department of the Interior, 1970, Environmental findings of Oil Shale Survey Team now under intensive review, Secretary Hickel says: Washington, D.C., U.S. Dept. Interior News Release, Aug. 23, 1 p.; U.S. Senate, Committee on Interior and Insular Affairs, 1970, Oil shale development, hearings before Subcommittee on Minerals, Materials, and Fuels: U.S. 91st Cong., 1st sess., Comm. Print, 97 p.

10 Colorado Oil Shale Advisory Committee, 1971, Report on economics of environmental protection for a federal oil shale leasing program: Denver, Colorado Dept. Natural Resources, 204 p. + appendices; Utah Committee on Environmental Problems of Oil Shale 1971, Environmental problems of oil shale: Salt Lake City, Utah Dept. Natural Resources, 54 p.; Wyoming Oil Shale Environmental Planning Committee, 1971, Environmental and economic report on Wyoming oil shale: Cheyenne, Wyoming Dept. Economic Planning & Development, 97 p.

11 U.S. Dept. Interior, op. cit., note 9.

12 Campbell, G. G., Scott, W. G., and Miller, J. S., 1970, Evaluation of oil-shale fracturing tests near Rock Springs, Wyo.: U.S. Bur. Mines Rept. Inv. 7397, 21 p.; Murphy, W. I. R., 1959, In situ shale oil production problems: Proc. Second Plowshare Symp., Univ. Calif. Lawrence Radiation Lab, UCRL-5678, p. 80-101; Sohns, H. W., and Carpenter, H. C., 1966, In situ oil shale retorting: Chem. Eng. Progr., v. 62, no. 8, p. 75-78.

13 Lekas, M. A., and others, 1967, Project Bronco; a joint study of nuclear fracturing & in-situ retorting of oil shale: Springfield, Va., Federal Clearinghouse, PNE-1400, 64 p.

14 See note 10.

15 Watkins, J. W., and Sohns, H. W., 1968, In situ retorting of oil shale: Paper presented at United Nations Symp. on Development and Utilization of Oil Shale Resources, Tallinn, U.S.S.R., mimeo, p. 5.

16 Burwell, E. L., Carpenter, H. C., and Sohns, H. W., 1969, Experimental in-situ retorting of oil shale at Rock Springs, Wyoming: U.S. Bur. Mines Tech. Prog. Rept. 16.

17 Dinneen, G. U., Director, Laramie Energy Research Center, Letter dated Sept. 16, 1970.

18 Grant, B. F., 1964, Retorting oil shale underground--problems and possibilities: Colorado School Mines Quart., v. 59, no. 3, p. 39-46.

19 Dougan, P. M., Reynolds, F. S., and Root, P. J., 1970, The potential for in situ retorting of oil shale in the Piceance Creek Basin of northwestern Colorado: Colorado School Mines Quart., v. 65, no. 4; Hill, G. R., and Dougan, P., 1967, The characteristics of a low temperature in situ shale oil: Colorado School Mines Quart., v. 62, no. 3, p. 75-90.

20 Carpenter, H. C., Tihen, S. S., and Sohns, H. W., 1968, Retorting ungraded oil shale as related to in-situ processing: Am. Chem. Soc.—Div. Petrol. Chem., v. 13, no. 2, Preprints for March 31-April 15, p. F50-F57; Harak, A. E., Dockter, L., and Carpentor, H. C., 1971, Some results from the operation of a 150-ton oil shale retort: U.S. Bur. Mines Tech. Progr. Rept. 30, 14 p.

21 Burwell, Carpenter, and Sohns, op. cit., note 16; Grant, op. cit., note 18; Dougan, Reynolds, and Root, op. cit., note 19.

22 See note 12.

23 Dougan, Reynolds, and Root, op. cit., note 19.

24 Burwell, Carpenter, and Sohns, op. cit., note 16; Campbell, Scott, and Miller, op. cit., note 12.

25 Budd, C. H., McLamore, R. T., and Gray, K. E., 1967, Microscopic examination of mechanically deformed oil shale: Soc. Petrol. Engineers Ann. Fall Mtg., Houston, Paper SPE-1826.

26 East, J. H., Jr., and Gardner, E. D., 1964, Oil-shale mining, Rifle, Colorado, 1944-56: U.S. Bur. Mines Bull. 611, 163 p.; Matzick, A., Dannenberg, R. O., and Guthrie, B., 1960, Experiments in crushing Green River oil shale: U.S. Bur. Mines Rept. Inv. 5563, 64 p.

27 Smith, J. W., and Trudell, L. G., 1968, Wyoming Corehole No. 1—A potential site for production of shale oil in place: Colorado School Mines Quart., v. 63, no. 4, p. 62-68.

28 Lekas and others, op. cit., note 13; Lombard, D. B., Bray, B. G., and Sohns, H. W., 1970, Technical considerations for Plowshare applications to oil shale: Proc. Symp. on Engineering with Nuclear Explosives, Las Vegas, Nev., CONF-700101, v. 2, p. 1343-1363.

29 Culbertson, W. J., Jr., Nevens, T. D., and Hollingshead, R. D., 1970, Disposal of oil shale ash: Colorado School Mines Quart., v. 65, no. 4, p. 89-132; Nevens, T. D., Culbertson, W. J., Jr., and Hollingshead, R., 1970, Disposal and uses of oil shale ash: Denver, Colo., Denver Research Institute, Final Rept., U.S. Bur. Mines Project No. SWD-8, p. 4.

30 Nielsen, I., 1969, The amazing Piceance mineral suite—and its industrial potential for energy-oil-metals-chemicals: Eng. & Mining Jour., v. 170, no. 1, p. 57-60.

31 Wyoming Oil Shale Environmental Planning Committee, op. cit., note 10, p. 38.

32 Badgley, P. C., 1965, Structural and tectonic principles: New York, Harper & Row, p. 4-49.

33 See references cited in note 29, and Dinneen, G. U., Smith, J. W., Tisot, P. R., and Robinson, W. E., 1968, Constitution of Green River oil shale: Paper presented at United Nations Symp. on Development and Utilization of Oil Shale Resources, Tallinn, U.S.S.R., mimeo. p. 4-5.

34 Whitcombe, J. A., Vice President, The Oil Shale Corporation, letter dated June 3, 1970.

35 Utah Committee on Environmental Problems of Oil Shale, op. cit., note 10, p. 24-25; Welder, F. A., 1970, Map showing jointing patterns inferred from aerial photographs: U.S. Geol. Survey, unpublished.

36 Burwell, Carpenter, and Sohns, op. cit., note 16, p. 4-5; Harak, Dockter, and Carpenter, op. cit., note 20, table 1, p. 9-10.

37 Elkin, H. F., 1968, Petroleum refinery emissions, *in* Stern, A. C. (ed.), Air pollution, Vol. III, Sources of air pollution and their control: New York, Academic Press, p. 97-121.

38 Holzworth, G. C., 1962, A study of air pollution potential for the western United States: Jour. Applied Meteorology, v. 1, p. 366-382; Holzworth, 1967, Mixing depths, wind speeds, and air pollution potential for selected locations in the United States: Jour. Applied Meteorology, v. 6, p. 1039-1044.

39 Scorer, R., 1968, Air pollution: New York, Pergamon Press, 151 p.

40 Lyons, W. A., 1970, Mesoscale transport of pollutants in the Chicago area as affected by land and lake breezes: Second Internat. Clean Air Cong., Internat. Union of Air Pollution Prevention Assoc., Washington, D.C., Paper ME-3A.

41 Colorado Oil Shale Advisory Committee, op. cit., note 10, p. 157.

42. Colorado Oil Shale Advisory Committee, op. cit., note 10, p. 152-153; Utah Committee on Environmental Problems of Oil Shale, op. cit., note 10, p. 34; Wyoming Oil Shale Environmental Planning Committee, op. cit., note 10, p. 35.

43 Utah Committee on Environmental Problems of Oil Shale, op. cit., note 10, p. 24.

44 Colorado Oil Shale Advisory Committee, op. cit., note 10, p. 37, 39.

45 Coffin, D. L., Welder, F. A., and Glanzman, R. K., 1969, Geohydrology of the Piceance Creek structural basin between the White and Colorado rivers, northwestern Colorado: U.S. Geol. Survey Open-File Rept., p. 25.

46. Feltis, R. D., 1968, Preliminary assessment of ground water in the Green River Formation, Uinta Basin, Utah, *in* Geological Survey Research 1968: U.S. Geol. Survey Prof. Paper 600-B, p. B200-B204; Welder, F. A., 1968, Ground-water reconnaissance of the Green River Basin, southwestern Wyoming: U.S. Geol. Survey Hydrol. Inv. Atlas HA-290; Wyoming Water Planning Program, 1970, Water and related land resources of the Green River Basin, Wyoming: Cheyenne, State Engineers Office, Wyoming Water Planning Program Rept. No. 3, table II-2.

47 Freedman, A. J., Miller, R. M., and Robertson, R. S., 1967, The chemistry of refinery and petrochemical waste water: Washington, D.C., Nat. Petrol. Refiners Assoc., p. 4.

48 Carver, H. E., Project Manager, Oil Shale Department, Minerals Exploration Company, Letter dated May 14, 1970.

49 Whitcombe, op. cit., note 34.

50 U.S. Department of Interior, op. cit., note 2, p. 99.

51 U.S. Bureau of Mines, 1950, Oil from oil shale; annual report of the Secretary of the Interior on synthetic liquid fuels, 1949, part II: U.S. Bur. Mines Rept. Inv. 4652, p. 23; Bureau of Mines, 1951, Oil from oil shale; annual report of the Secretary of the Interior on synthetic liquid fuels, 1950, part II: U.S. Bur. Mines Rept. Inv. 4771, p. 86.

52 U.S. Bur. Mines, 1951, op. cit., note 51.

53 Beychok, M. R., 1967, Aqueous wastes from petroleum and petrochemical plants: New York, John Wiley & Sons, 370 p.; Federal Water Pollution Control Administration, 1967, The cost of clean water, volume III, industrial waste profile No. 5, petroleum refining: Washington, D.C. Federal Water Pollution Control Adm. Pub. I.W.P. 5.; Freedman, Miller, and Robertson, op. cit., note 47, 25 p.

54 Rogers, G. E., Northwest Regional Manager, Colorado Division of Game, Fish and Parks, Letter dated April 28, 1970.

55 Gifford, R. O., Ashcroft, G. L., and Magnuson, M. D., 1967, Probability of selected precipitation amounts in the western region of the United States: Reno, Univ. Nevada Agr. Expt. Sta. Pub. T-8.

56 Colorado Oil Shale Advisory Committee, op. cit., note 10, p. 134-149.

57 Nevens, Culbertson, and Hollingshead, op. cit., note 29, p. 58-62.

58 Dinneen, op. cit., note 17.

59 Eliassen, R., and Tchobanoglous, G., 1968, Advanced treatment processes: Chem. Eng., Oct. 14, table II, p. 97.

60 Colorado Oil Shale Advisory Committee, op. cit., note 10, p. 155.

61 Piper, A. M., 1969, Disposal of liquid wastes by injection underground--neither myth nor millennium: U.S. Geol. Survey Circ. 631, 15 p.; Talbot, J. S., 1968, Deep wells: Chem. Eng., Oct. 15, p. 108-111.

62 Evans, D. M., 1968, Industrial disposal wells--solution or more pollution?: Paper presented at 134th Mtg. of Am. Assoc. Adv. Sci., Dallas, Texas.

63 Legislative Reference Service, Environmental Policy Division, Library of Congress, 1970, The economy, energy, and the environment: U.S. 91st Cong., 2d sess., Joint Economic Committee Print, p. 92-114.

64 Black, R. J., and others, 1968, The national solid wastes survey; an interim report: Washington, D.C., U.S. Public Health Service, table 2, p. 13.

65 Ryan, J. J., and Welles, J. G., 1968, Regional economic impact of a United States oil shale industry: Denver, Denver Research Inst. Public Policy Studies of a U.S. Oil Shale Industry No. 1.

66 Coffin, Welder, and Glanzman, op. cit., note 45, p. 21.

67 Dougan, P., Secretary, Equity Oil Company, Letter dated July 15, 1969.

68 Breckenfeld, R. R., Manager, Unconventional Raw Materials, Shell Development Company, Letter dated August 18, 1969.

69 Steele, H., 1968, Current prospects for entry into oil shale production: Natural Resources Jour., v. 8, p. 652-687.

70 Wyoming Oil Shale Environmental Planning Committee, op. cit., note 10, p. 54.

71 Utah Committee on Environmental Problems of Oil Shale, op. cit., note 10, p. 50.

72 Colorado Oil Shale Advisory Committee, op. cit., note 10, p. 27.

73 McKean, W. T., Director, Little Hills Experiment Station, Colorado Division of Game, Fish and Parks, personal interview, Aug. 1, 1969.

74 Love, R. M., 1970, The rangelands of the western U.S.: Scientific American, v. 222, no. 2, p. 88-94.

75 Sharp, A. L., Gibbs, A. E., and Owen, W. J., 1966, Development of a procedure for estimating the effects of land and watershed treatment on streamflow: U.S. Dept. Agr. Tech. Bull. 1352, 57 p.

76 Colorado Oil Shale Advisory Committee, op. cit., note 10.

77 Carver, op. cit., note 48; Colorado Oil Shale Advisory Committee, op. cit., note 10, p. 97-98.

78 Colony Development Operation, 1970, Colony Development Operation Oil shale facilities, Parachute Creek, Colorado, progress report on environmental studies, 1965-1970: Colony Development Operation, 16 p.; Colorado Oil Shale Advisory Committee, op. cit., note 10, p. 112-115; The Oil Shale Corporation, 1970, Annual report 1969: New York, The Oil Shale Corp., p. 7; Whitcombe, op. cit., note 34.

79 Schmehl, W. R., and McCaslin, B. D., 1969, Some properties of spent oil-shale significant to plant growth: Internat. Symp. on Ecology and Revegetation of Drastically Disturbed Areas, Pennsylvania State Univ., 24 p.

80 Hand, J. W., 1967, Letter to the editor: Science, v. 157, p. 755.

REFERENCES CITED IN FIGURES AND TABLES

Bradley, W. H., and Eugster, H. P., 1969, Geochemistry and paleolimnology of the trona deposits and associated authigenic minerals of the Green River Formation of Wyoming: U.S. Geol. Survey Prof. Paper 496-B, 71 p.

Cameron Engineers, 1969, Review and forecast, Wyoming mineral industries: Denver, Cameron Engineers, Rept. prepared for State of Wyoming.

Cashion, 1964, Other bituminous substances, in Mineral and water resources of Utah: U.S. 88th Cong., 2d sess., Senate Interior and Insular Affairs Committee Print, p. 65-70.

Coffin , D. L., Welder, F. A., Glanzman, R. K., and Dutton, X. W., 1968, Geohydrologic data from the Piceance Creek Basin between the White and Colorado rivers, northwestern Colorado: Colorado Water Conserv. Board, Colorado Ground Water Circ. No. 12, 38 p.

Coffin, D. L., Welder, F. A., and Glanzman, R. K., 1969, Geohydrology of the Piceance Creek structural basin between the White and Colorado rivers, northwestern Colorado: U.S. Geol. Survey Open-File Rept., 97 p.

Colorado Oil Shale Advisory Committee, 1971, Report on economics of environmental protection for a federal oil shale leasing program: Denver, Colorado Dept. Natural Resources, 204 p. +appendices.

Culbertson, W. C., 1966, Trona in the Wilkens Peak Member of the Green River Formation, in Contributions to Geological Research: U.S. Geol. Survey Prof. Paper 550-B, p. 159-164.

Deardorff, D. L., 1963, Eocene salt in the Green River Basin, Wyoming, in Symposium on salt: Northern Ohio Geol. Soc., p. 176-195.

Donnell, J. R., 1961, Tertiary geology and oil-shale resources of the Piceance Creek Basin between the Colorado and White rivers, northwestern Colorado: U.S. Geol. Survey Bull. 1082-L, p. 835-891.

Donnell, J. R., Culbertson, W. C., and Cashion, W. B., 1967, Oil shale in the Green River Formation: Seventh World Petrol. Cong. Proc., p. 699-702.

East, J. H., Jr., and Gardner, E. D., 1964, Oil-shale mining, Rifle, Colorado, 1944-56: U.S. Bur. Mines Bull. 611, 163 p.

Ertl, T., 1967, Exploitation of Colorado's oil shale: Western Oil Reporter, v. 24, no. 7, p. 32-33.

Fahey, J. J., 1962, Saline minerals of the Green River Formation: U.S. Geol. Survey Prof. Paper 405, 50 p.

Hite, R. J., and Dyni, J. R., 1967, Potential resources of dawsonite and nahcolite in the Piceance Creek Basin, northwest Colorado: Colorado School Mines Quart., v. 62, no. 3, p. 25-38.

Form 1279
(June 198

BORROWER'S CARD

TN 859 .U5 W4 1971 c.2
Weaver, Glen D., 1931-
Environmental hazards of
shale oil recovery by in

DATE LOANED	BORROWER	OFFICE	DATE RETURNE

USDI – BLM

(Continued on reverse)

Holzworth, G. C., 1962, A study of air pollution potential for the western United States: Jour. Applied Meteor., v. 1, p. 366-382.

Hosler, C. R., 1961, Low-level inversion frequency in the contiguous United States: Monthly Weather Review, v. 89, p. 319-339.

Kornfeld, J. A., 1970, Uinta Basin oil discoveries increase Utah drilling: World Oil, v. 171, no. 5, p. 113, 115, 117-118, 120.

Lenhart, A. F., 1969, The TOSCO process; economic sensitivity to the variables of production: Am. Petrol. Inst. Div. Refining, 34th Midyear Mtg., Chicago, Preprint No. 52-69.

Lombard, D. B., and Carpenter, H. C., 1967, Recovering oil by retorting a nuclear chimney in oil shale: Jour. Petrol. Tech., v. 19, no. 6, p. 727-734.

Love, D., 1964, Uraniferous phosphatic lake beds of Eocene age in intermontane basins of Wyoming and Utah: U.S. Geol. Survey Prof. Paper 474-E, 66 p.

Ryan, J. J., and Wollen, J. G., 1966, Regional economic impact of a United States oil shale industry: Denver, Denver Research Inst. Public Policy Studies of a U.S. Oil Shale Industry No. 1.

Schmehl, W. R., and McCaslin, B. D., 1969, Some properties of spent shale significant to plant growth: Internat. Symp. on Ecology and Revegetation of Drastically Disturbed Areas, Pennsylvania State Univ., 24 p.

Stanfield, K. E., Frost, I. C., McAuley, W. S., and Smith, H. N., 1951, Properties of Colorado oil shale: U.S. Bur. Mines Rept. Inv. 4825, 27 p.

Thorne, H. M., Stanfield, K. E., Dinneen, G. U., and Murphy, W. I. R., 1964, Oil-shale technology: A review: U.S. Bur. Mines Info. Circ. 8216, 24 p.

U.S. Department of the Interior, 1968, Prospects for oil shale development, Colorado, Utah, and Wyoming: Washington, D.C., U.S. Dept. Interior, 134 p. + appendices.

U.S. Geological Survey, 1960, Mineral fuels, in Mineral and water resources of Wyoming: U.S. 86th Cong., 2d sess., Senate Doc. 76, p. 23-26.

Utah Committee on Environmental Problems of Oil Shale, 1971, Environmental problems of oil shale: Salt Lake City, Utah Dept. Natural Resources, 54 p.