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0208 Committee on Oil Shale, Coal, and Related Minerals

Colorado Legislative Council

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Report to the Governor and the
Colorado General Assembly:

COMMITTEE ON OIL SHALE, COAL, AND RELATED MINERALS

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COLORADO GENERAL ASSEMBLY

LEGISLATIVE COUNCIL

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To the Governor and Members of
the General Assembly:

Submitted herewith is the final report of the Committee on Oil Shale, Coal, and Related Minerals, a creature of the 1974 session of the Colorado General Assembly (H.J.R. 1008). The committee and staff toiled mightily throughout the summer and autumn to try and shed some light on the complexities of oil shale, coal, and certain other mineral developments. This report contains the findings and recommendations of the committee.

Very truly yours,

Michael L. Strang

Michael L. Strang
Chairman

MLS/mp

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COMMITTEE ON OIL SHALE, COAL,
AND RELATED MINERALS

Members of the Committee

Rep. Michael Strang, Chairman	Sen. Fay DeBerard, Vice-Chairman
Rep. Tilman Bishop	Sen. Les Fowler
Rep. Bob Kirscht	Sen. Dan Noble
Rep. Larry O'Brian	Sen. Maurice Parker
Rep. Morgan Smith	Sen. Albert Ruland

Staff

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Allan Green	Doug Brown
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COMMITTEE ON OIL SHALE, COAL, AND RELATED MINERALS

SUMMARY OF RECOMMENDATIONS

The Committee on Oil Shale, Coal, and Related Minerals was created by House Joint Resolution 1008 of the 1974 session of the Colorado General Assembly. This resolution directed the committee to study the following:

- Equitable methods of taxation, including the advisability of severance taxes;

- Socioeconomic consequences of extensive mineral development;

- Incentives for industry to develop innovative technology for extraction of minerals, such as <u>in situ</u> as opposed to open mining;

- The impact of oil shale development on water resources of the Colorado River Basin, and the feasibility of employing oil shale development methods which use the least practicable volume of water or employ the saline ground waters of the Piceance Basin;

- Utilization of the enormous reserves of sodium minerals, dawsonite, and nacholite which occur throughout the oil shale formations; and

- Analysis of long-range priorities to protect the citizens of Colorado from national exploitation of minerals on Colorado lands.

At its first meeting, the committee agreed that it would be necessary to limit the scope of its deliberations during the 1974 interim and thus confined itself to a study of oil shale, coal, and sodium minerals associated with oil shale deposits. Although all of the specific items charged to the committee for consideration were examined, primary emphasis was devoted to methods of taxation and socioeconomic consequences. With regard to innovative technology, water usage, and utilization of related mineral reserves, the committee examined the oil shale processes proposed by each company.

In order to compile the necessary background information, the committee toured each site that is presently proposed for a commercial oil shale facility and conducted public hearings in Grand Junction, Grand Valley, Rifle, Rangely, Craig, Hayden, Steamboat Springs, and Walden to learn from local officials and residents of their needs and concerns relative to impact from oil shale and coal development. The committee also visited a coal strip mine in Routt County to view reclamation efforts. In July, senior corporate representatives of principal oil shale concerns appeared before the committee in Grand Junction to detail their plans for development and explain their planning for community impact. In addition, representatives of major coal companies and public utilities testified before the committee.

The committee recommends four bills for consideration by the 1975 session of the General Assembly. Bill 1 would create the office of Energy Coordinator in the Governor's office. Bills 2, 3, and 4 are the result of the committee's review of proposals contained in the Tax Lead Time Study, a report commissioned by a subcommittee of the Governor's Oil Shale Advisory Committee. Bill 2 would separate the interest on investment from the principal of state revenues from oil shale leases, thereby relieving these monies from the federal restrictions. Bill 3 would provide enabling legislation for counties to enact a use tax and Bill 4 would expand the definition of "project" for industrial development revenue bonds.

In addition, the committee recommends three concepts for consideration by the General Assembly: (1) a severance tax on oil shale; (2) a revision of coal taxation statutes; and (3) a technical assistance program for planning for oil shale impact in region 11, to be funded by the state and federal governments and industry.

The committee concluded that changes in the federal Mineral Leasing Act of 1920 would be appropriate to assist the state in meeting impacts from oil shale development which may extend beyond schools and roads. Further, the committee urged the federal government to provide program funds to meet impacts created by federal actions. It is also recommended that the federal government guarantee local bonds and agree to a land exchange between the Superior Oil Company and the Bureau of Land Management.

In other actions, the committee recommended that an appendix be prepared to the report of the Governor's Oil Shale Coordinator to reflect recent changes in oil shale development plans and that the oil shale industry be encouraged to provide funds for facilities to impacted local governments.

Recognition of the needs for additional study was made by the committee in recommending that the Legislative Council's Committee on State and Local Finance examine increasing the limit on county general fund mill levies, changing the formula for state aid to the public schools, and revising property tax assessment dates. The committee also recommended that the General Assembly study the feasibility of granting counties the authority to levy general occupation taxes.

I. Recommendations of Bills

State Coordinator of Energy Problems -- Bill I

During the course of committee hearings and inquiries, it became apparent that the state has no single source of information concerning energy problems and potential development. It also observed that a lack of communication exists among various state agencies affected by energy development as well as between the state and impacted local governments.

The 1974 session of the General Assembly created the position of Coordinator of Oil Shale in the Governor's office in the Long Appropriations Bill (H.B. 1200). This position is limited to oil shale and will expire at the end of the current fiscal year.

The committee recommends that the position of coordinator of energy problems be established by statute in the office of the Governor. The coordinator would be charged with studying the problems of availability, allocation, distribution, and development of various forms of energy and coordinating state planning and programs relating to energy problems.

Use of Interest Monies from Federal Leasing Act Oil Shale Revenues -- Bill 2

Oil shale operations on federal lands under federal leases generate revenue to governments from bonus bids, rent payments, and royalties on production. The Federal Mineral Leasing Act of 1920 provides that 52.5 percent of these monies are to be credited to the federal reclamation fund and 37.5 percent of all monies received from bonuses, royalties, and rentals shall be paid to the state in which such lands are located. The remainder, along with revenues from naval reserves, are credited as miscellaneous receipts.

With regard to the use of this revenue by the state the act provides:

> ...said monies to be used by such State or subdivisions thereof for the construction and maintenance of public roads or for the support of public schools or other public educational

institutions, such as the legislature of the State may direct..." (30 USC 191).

Colorado law, as amended in 1974, provides that all of this revenue received from oil shale leases:

> ...shall be deposited by the state treasurer into a special fund for appropriation by the general assembly to state agencies, school districts, and political subdivisions of the state affected by the development and production of energy resources from oil shale lands, primarily for use by such entities in planning for and providing facilities and services necessitated by such development and productions, and secondarily for other state purposes. (H.B. 1046, 1974 session)

It is apparent that a change in federal law will be required to remove the federal restriction on the use of lease revenue for roads and schools only in order for the state fund to be used for other purposes as determined by the legislature. Senators Haskell and Dominick and Representative Johnson introduced bills in the 93rd Congress to remove this restriction on oil shale lease monies and allow its use by the state:

> ...and its subdivisions for planning, construction, and maintenance of public facilities, and provision of public services, as the legislature...may direct." (S. 3009, 93d Congress, 2d session)

This bill, and two subsequent amendments to other legislation, was adopted by the Senate. Neither the bill nor the riders were approved by the House prior to adjournment of the 93rd Congress. Although the subject will almost certainly be considered by the new Congress, at this time Colorado's oil shale monies remain subject to the federal restrictions.

The 1974 session of the General Assembly appropriated \$451,187 from the oil shale revenues in the Long Appropriations Bill (H.B. 1200) for: (1) a Governor's Oil Shale Coordinator; (2) school contingencies and mobile classrooms; and (3) planning for a wide variety of regional needs. During the course of the interim, the Attorney General opined that only those items relating to schools and roads and the planning therefor could be funded from the oil shale bonus monies.

The committee recommends that H.B. 1046 (1974) be amended to provide for the separation of monies earned on the investment from the principal of the state's share of the oil shale leasing funds. The committee concluded that the federal restriction does not apply to interest income and that the use of interest monies for purposes other than roads and schools would be consistent with existing federal law.

Testimony received by the committee from the Tax Lead Time Study projected that the following amounts of interest might be available from the investment of the state's share of oil shale bonus payments:

	1975	1976	1977
Deposit Date	9/1/74	9/1/75	9/1/76
Amount	$24,000,000	$24,000,000	$24,000,000
Balance in Fund	24,000,000	48,000,000	72,000,000
Est. Interest Rate	10%	10%	10%
Interest Earned	2,400,000	4,800,000	7,200,000
Date Available	9/1/75	9/1/76	9/1/77

The committee concluded that this amount of money, available for appropriation without federal restriction, would be a significant aid in appropriating funds to meet impacts in accordance with H.B. 1046. The committee also recognized that the interest earnings are overstated.

<u>County Use Tax Enabling Legislation</u> -- Bill 3

The committee received testimony from authors of the Governor's Tax Lead Time Study that:

> The use tax is usually viewed as complementary to the sales tax. It covers purchases of property outside the sales tax jurisdiction, but used within it. The tax serves as an essential enforcement tool for the sales tax, and also as a defense in support of local merchants. The two taxes are usually viewed as one tax and are customarily enacted together.

Colorado law presently authorizes cities, but not counties, to enact a use tax.

The study concluded that "a county use tax in the oil shale region would provide help to Rio Blanco and Garfield counties. Revenue generated from the construction of oil shale related industry...would be significant, and also of relatively short lead time when compared with property taxes." The committee recommends the Tax Lead Time Study Consideration

No. 8, that counties be given the power to enact use taxes. This recommendation, while proposed to aid counties affected by mineral development, would apply to all counties of the state.

Revision in the Definition of "Project" in County and Municipality Development Revenue Bond Act -- Bill 4

In explaining the rationale for expanding the definition of "project", the Tax Lead Time Study states as follows:

> The Colorado authority for industrial development bonds, the County and Municipality Development Revenue Bond Act (29-3-103, CRS 1973) takes a more narrow view than the federal Internal Revenue Code of 1954 of the types of projects which can be financed through the issuance of industry funded or guaranteed but governmentally issued, tax-exempt bonds. Many additional projects of a municipal nature are authorized by the Internal Revenue Code for tax-exempt status, but are not clearly authorized in Colorado. An expansion of the definition of "project" in the Colorado Act might provide an additional tool for financing in the oil shale region.
>
> Industrial development bonds are intended for use in those situations where an industry is contributing to a legitimate public purpose in the financing of its capital costs. Such public purpose might be achieved by a company locating in an area that needs the employment that is likely to be generated, or by a company expanding in its same location. However, an entirely different type of industrial development bond is possible. These are bonds that finance certain types of projects that are needed by an industry, but also are of a nature that a governmental entity or a community as a whole also benefit. Many different types of such projects have been authorized for tax-exempt status on the federal level by the Internal Revenue Code: housing, airports, mass transit, sewage and solid waste facilities, facilities for the local furnishing of electricity or gas, facilities for the furnishing of water, and also facilities needed for air or water pollution control (I.R.C. of 1954, Sec. 103 (c) (4)). The Colorado Act

clearly authorizes only pollution control facilities (29-3-103 (9)), although it is arguable that some sewage, water and solid waste disposal facilities are also authorized.

The committee recommends the Tax Lead Time Study Consideration No. 17. The definition of "project" for the purpose of industrial revenue development bonds would be expanded to include those items allowed at the federal level. The committee concluded that the issuance of such bonds for housing, however, should be limited to housing used as a sole place of residence and not for the construction of vacation homes or condominiums.

II. Recommendations of Concepts

In accordance with the study directive that the committee consider "equitable methods of taxation, including advisability of severance taxes" it is recommended that the General Assembly adopt a severance tax for oil shale. Although the committee examined legislation relating to the rate of such a tax, no specific rate nor method of allocation of revenues from the tax was determined. The committee concluded that such matters could be determined by the General Assembly through the process of considering the various severance tax proposals which will likely be introduced.

Coal Taxation

The committee recommends that the General Assembly adopt legislation clarifying the assessment and taxation of coal production. The committee discussed a proposal to bring coal assessment under the "producing mines" formula for ad valorem taxation and a tax on gross income from coal. It took no specific position on either approach, but concluded that any revision in the state's taxation of coal should take into account the "precarious financial condition" of small coal producers.

Technical Assistance Program

As conceived by its sponsors, the technical assistance program would provide funds for the employment of approximately 21 planners by local governments in Region 11 (Garfield, Mesa, Moffat, and Rio Blanco counties). As proposed, the program would be funded in equal shares by the federal government, the state government, and the oil shale industry. The planners would be under local control and would provide additional personnel to the governments of the region in planning for impacts from the development of oil shale. The committee recommends the concept of the Technical Assistance Program. The sponsor's statement of need and goals is appended to this report.

III. Recommendations for Federal Actions

Federal Mineral Leasing Act

The committee recommends that the federal Mineral Leasing Act of 1920 be amended to remove the roads and schools only restriction on the use of the state's share of lease revenues. Impacts will exist well beyond roads and schools and the state needs flexibility in the use of the funds in order to effectively meet problems. The committee concluded that the state's share of Mineral Leasing Act funds, currently 37.5 percent, should be reexamined and that perhaps a larger share should be returned to the state. In the absence of an upward revision, efforts should be made to ensure that the 52.5 percent of lease revenues that are credited to the federal reclamation fund be spent on reclamation projects located in Colorado and needed for energy development. The committee urges that the Governor, General Assembly, and Congressional delegation work toward this end.

Federal Impact Aid

The committee concluded that the federal government has a responsibility for providing aid programs to the state and local governments that are the situs of energy development impacts resulting from federal action. Regardless of whether such impacts result from direct federal actions, e.g., mineral leases, or indirect federal actions, e.g., a national energy policy calling for oil shale and coal development, the committee concluded that the benefits of such development extend beyond the boundaries of Colorado and that the federal government is obligated to finance programs to minimize local impact.

Federal Guarantees for Local Government Bonds

Consideration No. 21 of the Tax Lead Time Study commented on a federal guarantee for local government bonds, as follows:

It appears likely that the local governments in Colorado and elsewhere in the country faced with extreme growth pressure resulting from energy development will have to turn to bonding as the primary tool for raising sufficient capital to supply all of the governmental services needed by new residents. Bonds are capable of providing huge sums of capital in a relatively short period of time, they can be paid off over a period of many years by the eventual beneficiaries of the facilities built with the funds, and they possess generally favorable financing terms. On the other hand, problems do exist. Both the marketability of municipal bonds and also the interest rate reflect the risk of the investment. Often a particular small local government seeking a large bond issue will find it difficult to market its securities, and if marketable, may incur a very high interest rate. This problem is intensified in the case of local governments in the oil shale region. They have the added liability of seeking money to pay for growth that may never occur because of the failure of the oil shale industry to again find the mining of oil shale profitable. If another such "boom-bust" did occur after a local government issued bonds for the expected growth, a default on the issue would be a virtual certainty.

It appears patently unfair to ask a local government to assume such an enormous risk. If the nation needs oil shale energy, the entire nation should share in the risk inherent in its development. While such a risk might arguably be the responsibility of the oil shale industry as it is in a position to pass the risk on to its consumers nationwide, perhaps the federal government owes the greater duty to local governments in Colorado. The federal government is the largest holder of oil shale land, has launched both the oil shale leasing program and also the much publicized "Project Independence," and is in the unique position to affect the international economics of oil.

The committee concurred in this conclusion of the Tax Lead Time Study and concluded that the federal government has a responsibility in this area. The committee recommends that the Governor, General Assembly, and Congressional delegation work toward adoption of a federal program to guarantee local government bond issues to finance services and facilities needed for energy development.

Superior Oil Company Land Exchange

The committee recommends that the federal Bureau of Land Management proceed with the land exchange proposed by the Superior Oil Company on the White River. According to testimony presented to the committee by a spokesman for the company, the Superior process would meet several of the concerns expressed by the General Assembly in the study directive to the committee, including the use of saline ground water with resulting fresh water and recovery of associated minerals. The conclusion was that the Superior process should be encouraged for determination of commercial feasibility.

IV. Other Recommendations

Report of the Governor's Oil Shale Coordinator

The committee recommended that the report of the Governor's Oil Shale Coordinator on needs related to oil shale development, as required by H.B. 1200 (1974), be updated and an appendix prepared by March 1, 1975. The committee concluded that the data and assumptions of the original report were outdated as a result of Colony Development Operation's decision in October, 1974, not to initiate construction of a commercial oil shale complex in the spring of 1975. In addition, Union Oil indicated in correspondence with the committee a likely delay of one year in their oil shale plans.

The committee also expressed concern about the validity of the allocation of population impacts from potential oil shale development.

Industry Provision of Funds and Facilities for Oil Shale Impact

The Tax Lead Time Study, in consideration No. 22, observed that:

> Few persons question that industry should and will play some direct role in the provision of facilities for governmental-types of services necessitated by oil shale development. The ex-

tent of its role has not been defined. Several companies have made public comments of possible intentions. The most notable of these is Colony Development Operation which has proposed the development of a new town near Grand Valley to provide housing and governmental services and facilities for persons working at a potential neary-by oil shale operation. However, the extent of the Colony proposal has not been reflected by statements from other members of the industry.

The committee concurred in this premise of the study and concluded that the oil shale industry should be encouraged to finance or provide facilities for local governments impacted by the development of oil shale.

V. Topics Referred for Further Study

The committee recommends that the Legislative Council's Committee on State and Local Finance study some of the considerations contained in the Tax Lead Time Study. Specifically, the committee concluded that the following concepts have merit in aiding local governments meet energy development impacts. However, due to their state-wide implications, the committee decided that they should be examined by the committee that has historically dealt with these kinds of proposals.

No. 1 -- Increasing the maximum levy for county general fund purposes. These limits were set several years ago and may limit a county's options in preparing for rapid growth impacts or in instituting a county/municipality revenue sharing program which might be useful in funding oil shale impacts.

No. 2 -- Revision of the property tax assessment date. The addition of a mid-year assessment review to examine improvements made after January 1 might speed the receipt of property tax revenues from rapid development to local governments. Due to the many statutory dates involved, the committee recommends an analysis of the costs and benefits of such a change.

No. 13 -- Revision of School Finance Act to allow for enrollment increases during the budget year. Current state aid to school districts is based on fall enrollment prior to the start of the districts' calendar budget year. A provision for another count and a revision of state aid during the budget year would help districts which experience a large influx of students from oil shale development during the school year.

No. 14 -- Expansion of the state public school contingency funds. Current appropriation for these discretionary funds to the State Board of Education is $300,000 annually. This fund is potentially of great value in assisting school districts which experience a large impact from the development of oil shale, however, its present funding limits its ability to significantly help such districts.

It is also recommended that the General Assembly consider the feasibility of expanding Colorado law to give counties the authority to enact a general occupation tax. In Consideration No. 9, the authors of the Tax Lead Time Study observed that although Colorado municipalities have authority to enact a general occupation tax, counties do not. Employers are locating in areas that are and probably will remain unincorporated. The study concluded that:

> Authority to levy an occupation tax could in many counties add further fiscal flexibility and reduce dependence on the property tax for the generation of revenues. Such a revenue source would respond to growth while additionally taxing people who work but don't live in the county.

The committee concluded that this tax could potentially be of benefit to counties in meeting oil shale development because it responds rapidly to growth.

MINORITY REPORT

We, the undersigned, oppose the committee's recommendation of the concept of a severance tax for the following reasons:

First, a servance tax is a punitive one which discourages the production of minerals and hinders the attending economic development of the state. In particular, the imposition of a severance tax on an industry of doubtful economic potential, such as oil shale, may cause the indefinite delay in the development of that industry, thus running counter to the national energy goals and hindering the economic development of the northwest portion of the state.

Second, a severance tax is of no benefit to communities facing the problem of financing new or expanded facilities to meet impacts resulting from the development of mineral resources. A severance tax provides no lead-time monies.

Third, a severance tax does not encourage extraction methods which are the least harmful to the environment, nor does it encourage reclamation of the extracted lands. Instead, it simply penalizes a company for the production of a resource.

Fourth, a severance tax is a special tax applied to no other form of industry. Thus, the tax would single out the minerals industry for taxation beyond that applied to other corporations.

Fifth, the committee should have considered taxation alternatives to a severance tax. For example, an appropriate tax policy might be one which would encourage the industry to keep the mineral in Colorado for processing or refining and eventual use as a power source.

For these reasons, we urge the General Assembly to consider alternatives to the severance tax concept recommended by the committee.

Larry E. O'Brian
Representative Larry O'Brian

Fay DeBerard
Senator Fay DeBerard

MINORITY REPORT

We, the undersigned, submit the following minority report for two reasons. First, we believe the committee erred in failing either to adopt the bills described below or to give serious consideration to the concepts they represented. Second, while we believe the committee worked hard to gather facts and data concerning oil shale and coal development, we are disappointed at its unwillingness to tackle the complex but necessary policy decisions mandated by H.J.R. 1008. That unwillingness was most clearly demonstrated by the committee's summary rejection of these bills.

The Bills:

1. Bill I was the Strang proposal to place a tax on spent shale left outside a mine and to provide a tax credit for shale returned to the mine -- an important attempt to encourage the proper disposal of spent shale through tax incentives or disincentives. The bill provided for a one-half cent per ton tax for shale disposed of outside of the mine from which it came, and a one-half cent tax credit for each ton returned to the mine. Although the amount of the tax or tax credit needs further study, the concept was an important one and should have been adopted.

2. Bill E. This bill would have prevented any oil shale lease funds from being awarded to a school district with an ADAE of under 500 students. Its practical effect would have been to force some form of consolidation of the very small districts in the oil shale area. It was particularly aimed at the Grand Valley-Rifle problem. If shale is developed, the Grand Valley school district will reap the benefits, and the Rifle district will bear the impact. We think it is unrealistic for western slope communities to expect massive state assistance until they have first demonstrated a willingness to share both the benefits and the burdens of potential mineral development.

Because the purpose of the bill was principally to focus attention on this problem of the dislocation of the burdens and benefits of mineral development, we withdrew it and asked instead that the committee adopt language suggesting that the DeBeque, Rifle, and Grand Valley school districts reorganize or consolidate so that the burdens and the benefits would be more equally shared.

3. Bill H. (No. 5 in the Tax Lead Time Study) This bill would have repealed Senate Bill 47 of 1970 which changed the method of assessing oil shale lands. It is clear from

work done by staff that the effect of this bill was to cut in half the assessed value of the DeBeque and Grand Valley school districts. Those revenues could well have been used to meet potential impacts from development.

4. Bill J. (No. 6 in the Tax Lead Time Study) This bill would have made it clear that county assessors have the authority to assess leasehold interests on federal lands. It was based on a Michigan statute that has been upheld by the United States Supreme Court and appears to be consistent with several Colorado Supreme Court decisions cited in the Tax Lead Time Study.

We believe this bill could be a major source of the "front end" money need to provide governmental services. The county assessor in looking at tracts Ca and Cb, for example, would have the right to take into consideration the amounts bid for the leasehold interest in those tracts ($210.4 million for Ca and $117.8 million for Cb.) and could, we believe, justify the imposition of a substantial tax.

5. We withdrew the oil shale severance tax bill and the bill changing the methods of assessing and taxing coal and offered instead language indicating general support for a severance tax on oil shale and for a review of the assessment and taxation of coal. We appreciate the committee's support for that language but regret there wasn't more interest in working out the details and complexities of these tax issues. That was a specific study item in H.J.R. 1008.

<u>The Policy Decisions</u>:

The committee did work hard to get input from Western Slope communities and to gather technical data concerning not only oil shale but also coal and power development. We heard from many community people and local officials and particularly from representatives of major oil companies and other energy developers. (There was little attempt to involve environmental groups.) The result of this work will be a mass of data - data that may be valuable and important.

The problem, however, is that the committee never got from the data-gathering stage to the policy-making level. For example, the committee didn't make a study of "equitable methods of taxation, including advisability of severance taxes" it almost immediately rejected the one legislative attempt to develop "incentives for industry to develop innovative technology for extraction of minerals, such as <u>in situ</u> as opposed to open mining"; and it didn't conduct "analysis of long-range priorities to protect the citizens of Colorado from national exploitation of minerals on Colorado lands".

For these reasons, we, the undersigned, believe the committee did not fulfill the mandate of H.J.R. 1008.

Morgan Smith

Representative Morgan Smith

Bob Kirscht

Representative Bob Kirscht

BY

A BILL FOR AN ACT

CONCERNING ENERGY, AND CREATING THE OFFICE OF COORDINATOR OF ENERGY PROBLEMS IN THE OFFICE OF THE GOVERNOR, AND MAKING AN APPROPRIATION THEREFOR.

Bill Summary

(NOTE: This summary applies to this bill as introduced and does not necessarily reflect any amendments which may be subsequently adopted.)

Provides for a coordinator to study energy problems, coordinate state energy programs, and report to the governor, general assembly, and the public and makes an appropriation therefor.

Be it enacted by the General Assembly of the State of Colorado:

SECTION 1. Title 24, Colorado Revised Statutes 1973, as amended, is amended BY THE ADDITION OF A NEW ARTICLE to read:

ARTICLE 41.5

Coordinator of Energy Problems

24-41.5-101. Coordinator of energy problems. (1) There is hereby created within the office of the governor a coordinator of energy problems. The coordinator of energy problems shall be appointed by the governor as a member of the staff of the office of the governor. He may employ assistants and personnel as may be necessary.

(2) The coordinator of energy problems shall:

(a) Study the problems of availability, allocation, distribution, and development of the various forms of energy, including but not limited to oil and gas, oil shale, coal, uranium, solar, geothermal, various forms of gasification and liquefaction, and evaluate the impact on the environment of the various methods of extraction and refinement of energy resources;

(b) Act as the coordinator for the planning and execution of state programs which deal with the energy problems;

(c) Prepare and transmit to the governor and general assembly reports on existing programs and recommendations concerning changes in existing law and new measures to deal with energy problems;

(d) Prepare and transmit, in the form and manner prescribed by the controller pursuant to the provisions of section 24-30-208, an annual report accounting to the governor and the general assembly for the efficient discharge of all responsibilities assigned to the coordinator; and

(e) Inform the public of the results of all studies made and recommendations transmitted to the governor and the general assembly.

SECTION 2. Appropriation. In addition to any appropriation heretofore made for the current fiscal year, there is hereby appropriated out of any moneys in the state treasury not otherwise appropriated, to the office of the governor, the sum of _____ dollars ($_____), and for the fiscal year beginning July 1, 1975, the sum of _____ dollars ($_____), or so much thereof as may be necessary, for the administration and implementation of this act.

SECTION 3. Safety clause. The general assembly hereby finds, determines, and declares that this act is necessary for the immediate preservation of the public peace, health, and safety.

BY

A BILL FOR AN ACT

CONCERNING THE OIL SHALE SPECIAL FUND, AND PROVIDING FOR THE DISPOSITION OF INTEREST EARNED THEREON.

Bill Summary

(NOTE: This summary applies to this bill as introduced and does not necessarily reflect any amendments which may be subsequently adopted.)

Provides that interest earned by federal mineral leasing moneys from oil shale lands shall be expended for the same purposes as the original leasing moneys.

Be it enacted by the General Assembly of the State of Colorado:

SECTION 1. 34-63-104, Colorado Revised Statutes 1973 (numbered as 100-8-4, C.R.S. 1963), as enacted by section 1 of chapter 73, Session Laws of Colorado 1974, is amended to read:

34-63-104. Special fund relating to oil shale lands. (1) All moneys from sales, bonuses, royalties, leases, and rentals of oil shale lands received by the state pursuant to section 35 of the federal mineral lands leasing act of February 25, 1920, as amended, shall be deposited by the state treasurer into a special fund for appropriation by the general assembly to state agencies, school districts, and political subdivisions of the state affected by the development and production of energy resources from oil shale lands, primarily for use by such entities in planning for and providing facilities and services necessitated by such development and production, and secondarily for other state purposes.

(2) ALL MONEYS EARNED FROM THE INVESTMENT OF THE OIL SHALE SPECIAL FUND ESTABLISHED BY SUBSECTION (1) OF THIS SECTION SHALL BE ALLOCATED PRIMARILY TO STATE AGENCIES, SCHOOL DISTRICTS, AND POLITICAL SUBDIVISIONS OF THE STATE AFFECTED BY THE DEVELOPMENT AND PRODUCTION OF ENERGY RESOURCES FROM OIL SHALE LANDS FOR PLANNING AND, IN THE FORM OF GRANTS AND LOANS, FOR PROVIDING FACILITIES AND SERVICES NECESSITATED BY SUCH DEVELOPMENT AND PRODUCTION, AND SECONDARILY FOR OTHER STATE PURPOSES.

SECTION 2. Safety clause. The general assembly hereby finds, determines, and declares that this act is necessary for the immediate preservation of the public peace, health, and safety.

BY

A BILL FOR AN ACT

CONCERNING THE IMPOSITION OF USE TAXES BY COUNTIES.

Bill Summary

(NOTE: This summary applies to this bill as introduced and does not necessarily reflect any amendments which may be subsequently adopted.)

Authorizes counties to enact by resolution a use tax, either singly or in conjunction with a sales tax, subject to a vote of the qualified electors.

Be it enacted by the General Assembly of the State of Colorado:

SECTION 1. 29-2-101, Colorado Revised Statutes 1973, is amended to read:

29-2-101. Legislative declaration. The general assembly hereby declares that the imposition of sales or use taxes, or both, by COUNTIES, cities, and incorporated towns ~~or---the imposition--of--sales-taxes-by-counties~~ in this state affects the flow of commerce within this state and the welfare of the people of this state. The purpose of the general assembly in the enactment of this article is to provide a higher degree of uniformity in any sales taxes imposed by such entities.

SECTION 2. 29-2-102, Colorado Revised Statutes 1973, is amended to read:

29-2-102. <u>Municipal sales or use tax - referendum.</u> Any incorporated town or city in this state may adopt a municipal sales or use tax, or both such taxes, by ordinance in accordance with the provisions of this article, but only if such ordinance provides for the submission of any such tax proposal to an election by the qualified electors of such town or city for their approval or rejection, at a regular municipal election or at a special election called for the purpose if no such regular election will be held within ninety days after the adoption of such ordinance. Such election shall be conducted in the manner provided in the "Colorado Municipal Election Code of 1965". No such ordinance shall be proposed or adopted by any such town or city on or after the date of the adoption of a RESOLUTION FOR A countywide sales tax, ~~resolution~~ USE TAX, OR BOTH by the board of county commissioners of the county in which all or any portion of such town or city is located until after the date of the election on said county proposal. Nothing in this article shall preclude the initiation of such a proposal by the qualified electors of any such town or city, pursuant to section 1-40-116, C.R.S. 1973. Where a municipal sales tax has been approved by the qualified electors at an election held prior to July 1, 1973, the use tax provided for in section 29-2-109 may be levied by the governing body without an election.

SECTION 3. 29-2-103, Colorado Revised Statutes 1973, is amended to read:

29-2-103. <u>Countywide sales or use tax.</u> Each county in this state is authorized to levy a countywide sales tax, USE TAX, OR

BOTH in accordance with the provisions of this article. No PROPOSAL FOR A countywide sales tax, ~~proposal~~ USE TAX, OR BOTH, shall become effective until approved by a majority of the qualified electors of the county voting on such proposal. Such A PROPOSAL FOR A sales tax, ~~proposal~~ USE TAX, OR BOTH, upon approval by a majority of the qualified electors voting thereon, shall be effective throughout the incorporated and unincorporated portions of the county. WHERE A COUNTYWIDE SALES TAX HAS BEEN APPROVED BY THE QUALIFIED ELECTORS AT AN ELECTION HELD PRIOR TO JULY 1, 1975, THE USE TAX PROVIDED FOR IN SECTION 29-2-109 MAY BE LEVIED BY THE BOARD OF COUNTY COMMISSIONERS WITHOUT AN ELECTION.

SECTION 4. 29-2-104, Colorado Revised Statutes 1973, is amended to read:

29-2-104. Adoption procedures. (1) A PROPOSAL FOR A countywide sales tax, ~~proposal~~ USE TAX, OR BOTH shall be referred to the qualified electors of the county either by resolution of the board of county commissioners or by petition initiated and signed by five percent of the registered electors of the county.

(2) Such proposal shall contain a description of the ~~sales~~ tax in accordance with the provisions of this article and shall make provision for any distribution of revenue collections between the county and the incorporated cities and towns within the county. Such proposal shall also state the amount of ~~sales~~ tax to be imposed.

(3) A PROPOSAL FOR A countywide sales tax, ~~proposal~~ USE TAX, OR BOTH, by resolution of the board of county commissioners, shall be submitted at the next regular general election if there

is one within the next succeeding one hundred twenty days after the adoption of such resolution. If no general election is scheduled within such time, the board of county commissioners, in its resolution, shall submit the same to the qualified electors of the county at a special election called for the purpose, ~~and~~ to be held not less than thirty days nor more than ninety days after the adoption of such resolution.

(4) Upon being presented with a petition requesting a PROPOSAL FOR A countywide sales tax, ~~proposal~~ USE TAX, OR BOTH, signed by five percent of the registered electors of the county, the board of county commissioners shall, upon certification of the signatures on the petition, submit such proposal to the qualified electors of the county. The ~~sales-tax~~ proposal shall be submitted at the next general election if there is one within one hundred twenty days of the filing of the petition. If no general election is scheduled within one hundred twenty days following the date of filing of the petition, the board of county commissioners shall submit such ~~sales-tax~~ proposal at a special election called not less than thirty nor more than ninety days from the date of filing of the petition.

(5) Upon the adoption of a resolution by the board of county commissioners as provided in subsection (3) of this section or upon the filing of a proper petition as provided in subsection (4) of this section, the county clerk AND RECORDER shall publish the text of such PROPOSAL FOR A sales tax, ~~proposal~~ USE TAX, OR BOTH four separate times, a week apart, in the official newspaper of the county and each city and incorporated

town within the county. The cost of the election shall be paid from the general fund of the county. The conduct of the election shall conform, so far as practicable, to the general election laws of the state.

(6) If approved by a majority of the qualified electors voting thereon, the countywide sales tax, USE TAX, OR BOTH shall become effective as provided by section 29-2-106 (2).

(7) If a majority of the qualified electors voting thereon fail to approve the countywide sales tax, USE TAX, OR BOTH at any election, the question shall not be submitted again to the ~~county~~ QUALIFIED electors for a period of two years.

SECTION 5. 29-2-106 (3) (a), Colorado Revised Statutes 1973, is amended to read:

29-2-106. Collection, administration, enforcement. (3) (a) The executive director of the department of revenue shall, at no charge except as provided in paragraph (b) of this subsection (3), administer, collect, and distribute any sales tax imposed in conformity with this article. The executive director shall make monthly distributions of sales tax collections to the appropriate official in each county and in each incorporated city or town in the amount determined under the distribution formula established in accordance with this article. Except as provided in section 39-26-208, C.R.S. 1973, any use tax imposed pursuant to section 29-2-109 shall be collected, administered, and enforced by the city, ~~or~~ town, OR COUNTY as provided by ordinance OR RESOLUTION.

SECTION 6. 29-2-109 (1), Colorado Revised Statutes 1973, is REPEALED AND REENACTED, WITH AMENDMENTS, to read:

29-2-109. <u>Contents of use tax ordinances and proposals.</u> (1) The use tax ordinance, resolution, or proposal of any town, city, or county adopted pursuant to this article shall be imposed only for the privilege of storing, using, or consuming in the town, city, or county any construction and building materials, and motor and other vehicles on which registration is required, purchased at retail. The ordinance, resolution, or proposal shall recite that the use tax shall not apply:

(a) To the storage, use, or consumption of any tangible personal property the sale of which is subject to a retail sales tax imposed by the town, city, or county;

(b) To the storage, use, or consumption of any tangible personal property purchased for resale in the town, city, or county, either in its original form or as an ingredient of a manufactured or compounded product, in the regular course of a business;

(c) To the storage, use, or consumption of tangible personal property brought into the town, city, or county by a nonresident thereof for his own storage, use, or consumption while temporarily within the town, city, or county;

(d) To the storage, use, or consumption of tangible personal property by the United States government, or the state of Colorado, or its institutions, or its political subdivisions in their governmental capacities only or by religious or charitable corporations in the conduct of their regular religious or charitable functions;

(e) To the storage, use, or consumption of tangible personal property by a person engaged in the business of manufacturing or compounding for sale, profit, or use any article, substance, or commodity, which tangible personal property enters into the processing of or becomes an ingredient or component part of the product or service which is manufactured, compounded, or furnished and the container, label, or the furnished shipping case thereof;

(f) To the storage, use, or consumption of any article of tangible personal property the sale or use of which has already been subjected to a sales or use tax of another town, city, or county equal to or in excess of that imposed by this article. A credit shall be granted against the use tax imposed by this article with respect to a person's storage, use, or consumption in the town, city, or county of tangible personal property purchased by him elsewhere. The amount of the credit shall be equal to the tax paid by him by reason of the imposition of a sales or use tax of another town, city, or county on his purchase or use of the property. The amount of the credit shall not exceed the tax imposed by this article.

(g) To the storage, use, or consumption of tangible personal property and household effects acquired outside of the town, city, or county and brought into it by a nonresident acquiring residency;

(h) To the storage or use of a motor vehicle if the owner is or was, at the time of purchase, a nonresident of the town, city, or county and he purchased the vehicle outside of the town, city, or county for use outside the town, city, or county and actually so used it for a substantial and primary purpose for which it was acquired and he registered, titled, and licensed said motor vehicle outside of the town, city, or county;

(i) To the storage, use, or consumption of any construction and building materials and motor and other vehicles on which registration is required, if a written contract for the purchase thereof was entered into prior to the effective date of such use tax;

(j) To the storage, use, or consumption of any construction and building materials required or made necessary in the performance of any construction contract bid, let, or entered into at any time prior to the effective date of such use tax ordinance, resolution, or proposal.

SECTION 7. 39-26-208 (1), Colorado Revised Statutes 1973, is amended to read:

39-26-208. Collection of use tax - motor vehicles. (1) No registration shall be made of a motor or other vehicle for which registration is required, and no certificate of title shall be issued for such vehicle by the department of revenue or its authorized agent until any tax due upon the storage, use, or consumption thereof pursuant to section 39-26-202, or imposed by ordinance of any municipality OR RESOLUTION OF ANY COUNTY, has been paid.

SECTION 8. Safety clause. The general assembly hereby finds, determines, and declares that this act is necessary for the immediate preservation of the public peace, health, and safety.

LDO NO. 75 0399/1 BILL NO. 4

BY

A BILL FOR AN ACT

CONCERNING DEVELOPMENT REVENUE BONDS.

Bill Summary

(NOTE: This summary applies to this bill as introduced and does not necessarily reflect any amendments which may be subsequently adopted.)

Increases the types of facilities which may be financed through use of development revenue bonds.

Be it enacted by the General Assembly of the State of Colorado:

SECTION 1. 29-3-103 (10), Colorado Revised Statutes 1973 (numbered as 36-24-2 (8), C.R.S. 1963), and the amendment thereto enacted by section 1 of chapter 42, Session Laws of Colorado 1974, is REPEALED AND REENACTED, WITH AMENDMENTS, to read:

29-3-103. Definitions. (10) "Project" means any land, building, or other improvement and all real or personal properties, and any undivided or other interest in any of the foregoing, except inventories, raw materials, and other working capital, whether or not in existence, suitable or used for or in connection with:

(a) Manufacturing, industrial or commercial enterprises, or any utility plant. Research, product-testing, and administrative facilities for any such enterprise or utility may also be included.

(b) Hospital care or other services;

(c) Pollution control facilities;

(d) Residential real property if the selling price of family units does not exceed forty-five thousand dollars and such units are intended for use as the sole place of residence by the owners thereof;

(e) Sewage or solid waste disposal facilities;

(f) Facilities for the furnishing of water;

(g) Facilities for the furnishing of electric energy or gas;

(h) Sports facilities;

(i) Convention or trade show facilities;

(j) Airports, mass commuting facilities, parking facilities, or storage or training facilities directly related to any of the foregoing.

SECTION 2. Safety clause. The general assembly hereby finds, determines, and declares that this act is necessary for the immediate preservation of the public peace, health, and safety.

PREFACE

Among the goals of the Committee on Oil Shale, Coal, and Related Minerals was that of the assimilation of information concerning the impact of mineral resource development on Northwest Colorado and the dissemination of such information to the General Assembly. In order to gain the necessary data, the committee conducted nine public hearings in the area, received testimony from corporate executives of oil shale, coal, and public utility companies, and instructed the committee staff to interview various public officials in the oil shale region.

In addition to the committee's efforts, the 1974 session of the General Assembly appropriated $451,187 in the Long Appropriations Bill (H.B. 1200) for three programs. First, $87,187 was funded for a project director and staff in the Office of the Governor to coordinate all federal, state, and local planning with regard to oil shale development. Second, $204,000 was appropriated for mobile classrooms and for state financial support for additional students not counted under the School Finance Act for contingency, as determined by the Governor's project director. Third, $160,000 was provided for school planning, transportation planning, and "region, county, and town planning". The planning function was to include, "but not be limited to, an assessment of current conditions including various governmental services within the region, an analysis of oil shale impact on current conditions and existing services, a review of state and federal resources available, and recommendations outlining actions necessary to accommodate oil shale impact, including the level and methods of financing required".

Because it is the responsibility of the coordinator to compile information assessing the present capabilities of governmental entities and their needs related to oil shale development, these matters are the subject of only a cursory review in this report. Evaluation of the coordinator's inventory and review of his recommendations for actions can be undertaken by the 1975 session of the General Assembly or a future interim committee. The purpose of these materials is to provide background information to assist in the evaluation of the report of the Governor's coordinator, as well as other proposals which may be submitted to the General Assembly.

Overview

The development of a commercial oil shale industry has appeared to be imminent at various times in this century. At the time the interim committee was created by the General Assembly, development of the industry appeared likely for several reasons. First, the price of oil increased throughout the latter portion of 1973 and 1974, thus aiding the economics of an oil shale industry. Second, large bids were offered for two federal lease sites in Rio Blanco County, indicating that federal oil shale lands were more attractive to private investors than anticipated. Third, Colony Development Operation indicated that construction would commence in the spring of 1975 on a commercial operation on private lands in Garfield County.

These indicators of probable development continued throughout the summer as the committee toured the proposed sites, conducted public hearings in nearby communities, and received testimony from company officials. Throughout this time period there remained three factors which affected the prospects for major developments throughout the oil shale region: inflation, federal government policies or lack thereof, and actual construction of one facility which could provide better information concerning the economic viability of oil shale.

These factors remain and are perhaps more important than they appeared during the course of the committee's study. Inflation has not been halted and was cited as one reason for Colony's decision to delay a commercial operation indefinitely. A national energy policy has yet to be proposed by the President and actual construction of a commercial scale oil shale plant to demonstrate feasibility appears to be at least two years in the future.

The problems and prospects of the coal industry in Colorado are quite different than those relating to oil shale. First, the economic feasibility of coal is not subject to the same uncertainties as oil shale. There is no major processing or refining facility required for coal. Coal production is, of course, tied to economics, but the capital requirements are much less than for an oil shale plant. The coal industry in Colorado is by no means a new one and production is based on proven technology. Second, coal mines require far fewer employees than are necessary to construct and operate an oil shale retort operation, although power plants related to coal may substantially impact communities. Third, although there are some 8.8 million acres of federally owned coal in Colorado, as contrasted to 1.8 million acres of federal oil shale, the bids for coal lands have not produced revenues to state government comparable with the two oil shale leases of some 5,000 acres each.

Impact

Few would doubt that the development of a large oil shale industry would have a major impact on Northwest Colorado. The problem for policy makers becomes one of discerning when that impact might occur and determining the appropriate role for the federal, state, and local governments. Compounding the situation is the tax lead time problem, which could result if substantial numbers of people impact an area and require governmental services during construction of a facility whereas the ad valorem tax base of the local community would not be markedly increased until completion of the facility. The role of government in regulating the impact of development, through such devices as new communities, is at best limited.

The question of when major impact may occur is one of doubt. Recently, a spokesman for the lessees of federal tract Ca was quoted: "There's no way in the world we could have any impact" in Rio Blanco County before 1977. 1/ Some might contend that impact has already occurred as people have moved to the area in anticipation of the development of oil shale. Others could counter that any impact to this point has been minimal and well within the capabilities of local governments to provide services. Others yet would urge that, since no real impact has occurred, governments should not become engaged in the construction of costly facilities until more assurance of development is evidenced.

Coal, in contrast, is a rapidly developing industry. One of the most frequent frustrations expressed to the committee was that local governments have encountered difficulties in obtaining advance notice and information concerning new or expanded facilities in order to plan accordingly. At the least, communities with new or expanded facilities, such as power plants related to coal development, will experience substantial growth.

1/ Glenwood Post, December 3, 1974, p. 1.

I. LOCATION OF OIL SHALE DEPOSITS

What is Oil Shale?

The term "oil shale" is a misnomer. Oil shale is, in fact, neither oil nor shale, but a fine grained sedimentary rock (marlstone) containing organic matter derived chiefly from aquatic organisms, waxy spores, or pollen grains which is only slightly soluble in ordinary petroleum solvents. The organic matter, known as "kerogen", can be extracted from the shale in substantial amounts through destructive distillation to yield synthetic petroleum. In a sense, oil shale is a precursor of crude oil and would have become oil if subjected to higher pressures and temperatures.

Although oil shale is considered a relative new energy source, this can primarily be explained by the economics of the extractive process. Oil and gas can be removed by a relatively simple drilling process and have been available in generally abundant quantities throughout the world. Oil shale, on the other hand, must be subjected to a retorting process which has, for most areas of the world, constituted a prohibitively expensive source of energy.

It has been estimated that more than 400 million barrels of oil have been produced from oil shale throughout the world, principally in Scotland, the Soviet Union, and China. Other countries have mined the resource on a lesser scale. In the United States, experimentation with oil shale production has been conducted since 1850, but until the 1970's the cost of extraction was considered prohibitive. As the cost of oil has increased and environmental considerations decreased the use of coal, the attractiveness of oil shale as a supplementary or alternative source of energy has correspondingly proved enticing to industry, government, and the general public.

Oil shale reserves throughout the world are enormous, perhaps totaling 345.5 trillion barrels. Of this potential amount, more than 3 trillion barrels have been identified. The greatest amount of identified oil shale is contained in the United States, 418 billion barrels (61.7 percent of identified world supply) of 25 to 100 gallons per ton yield; 1,600 billion barrels (66.1 percent of identified world supply) of 10 to 25 gallons per ton yield, for a total of 2.02 trillion barrels.

Green River Formation

Of the identified U.S. supply, approximately 90 percent of the oil shale is located in the Green River Formation of Colorado, Utah, and Wyoming. Other deposits are located from Appalachia to California and Alaska, but are of a lower grade than those of the Green River Formation (see figures I and II on pages 41 and 42). About 1.8 trillion barrels are located in the Green River Formation, perhaps the largest oil deposit in the world. It is estimated that 80 billion barrels are recoverable from the formation under present technology.

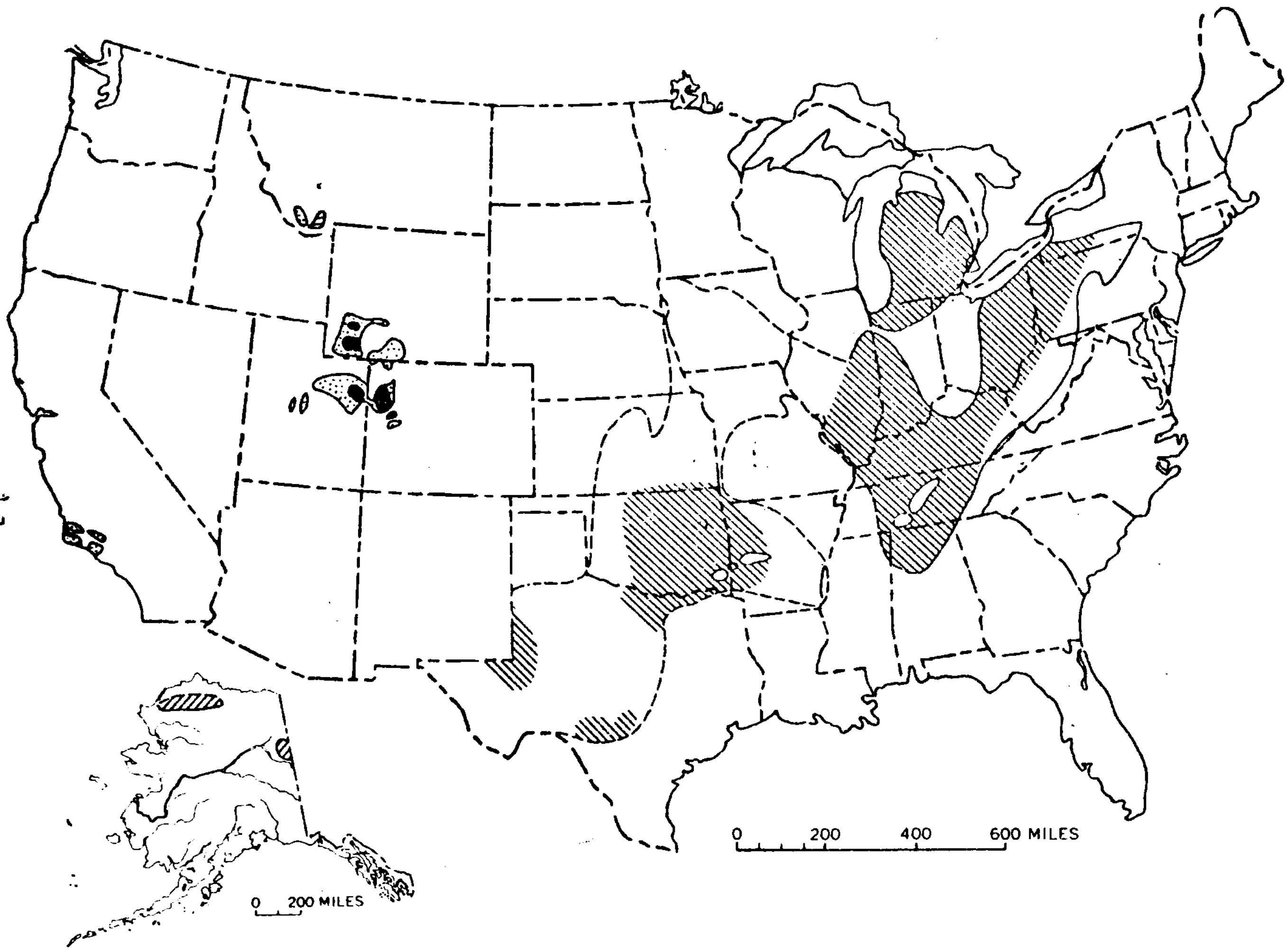
If 80 billion barrels were extracted at the rate of one million barrels per day, the extraction could occur for a period of 219 years. A one million barrels per day production figure (the Department of Interior's estimate for 1985) would represent, however, only four percent of total oil and gas needs in this country by that time.

The Green River Formation was created by sedimentary deposits about 50 million years ago from two large Eocene lakes, ultimately forming seven basins. The lakes were large and shallow, fostering development of surface algae which produced a clastic sediment. The lakes varied from fresh to briny water. As the basins slowly and irregularly sank, the sediment shifted and sank for millions of years while the transformation process to oil shale occurred. These deposits were subsequently uplifted some 8,000 feet about 10 million years ago and have been eroding since that time.

The oil shale deposits in the area are quite irregular, with the richest beds located in the Piceance Creek Basin of Colorado. Thinner and leaner deposits are contained in the Unita Basin of Utah with lesser reservoirs in the Sand Wash Basin of Colorado and the Green River, Great Divide, Washakie, and Fossil Basins of Wyoming. Within any basin, there is also a great variance in the quality and distribution of the shale deposits with depth.

Generally, oil shale occurs in zones below the surface of the earth, although in some areas erosion has exposed outcroppings of the shale in cliffs. In the case of the Piceance Creek Basin, the shale beds of major commercial value are located in the Parachute Creek Member with lower grade deposits in the other three areas of the basin. The Parachute Creek area contains three major zones. The upper zone varies in thickness from a few feet to more than 500 feet and contains the richest deposits. It is often referred to as the Mahogany Zone or Ledge. The lower zone ranges from a few feet in thickness near the edge of the basin to more than 1,000 feet near the center. Although the lower zone contains a low grade of

FIGURE I -- PRINCIPAL REPORTED OIL-SHALE DEPOSITS OF THE UNITED STATES



EXPLANATION

Tertiary deposits
Green River Formation in Colorado, Utah, and Wyoming; Monterey Formation, California; middle Tertiary deposits in Montana. Black areas are known high-grade deposits

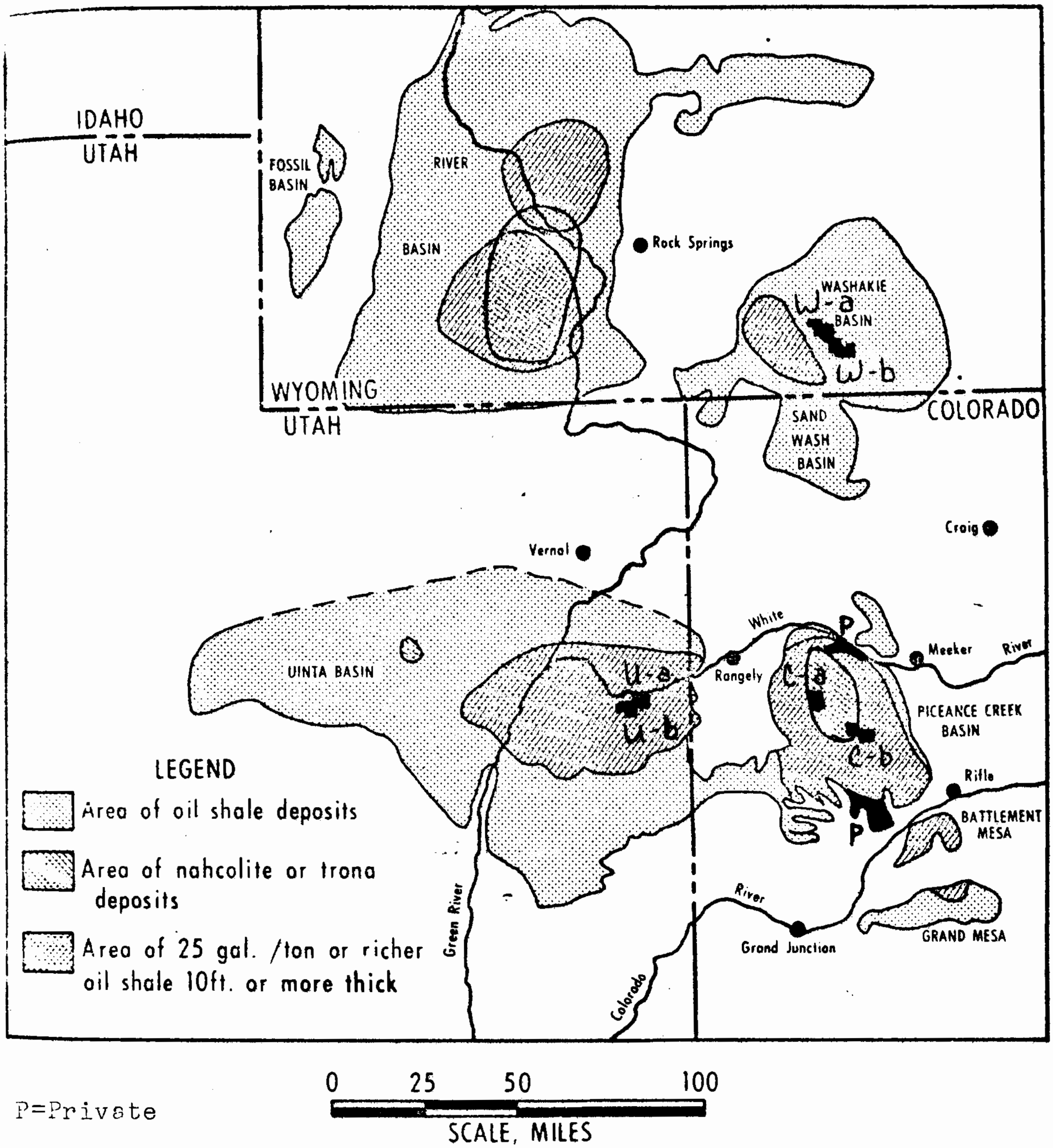
Mesozoic deposits
Marine shale in Alaska

Permian deposits
Phosphoria Formation, Montana

Devonian and Mississippian deposits (resource estimates included for hachured areas only in Geological Survey Circular 523). Boundary dashed where concealed or where location is uncertain.

SOURCE: Final Environmental Statement for the Prototype Oil Shale Leasing Program, Volume 1, U.S. Department of the Interior, page II-5.

FIGURE II -- OIL SHALE AREAS IN
COLORADO, UTAH, AND WYOMING



P=Private

SOURCE: Same as Figure 1, page II-3.

oil shale, the more important deposits of the sodium minerals nahcolite and dawsonite are located in it. A third zone, the leached, encompasses several hundred square miles of formerly saline mineral deposits which, in places, are hundreds of feet thick. The minerals in this zone have been dissolved by ground water, thus the term "leached".

The physiography of the Green River Formation is described in the environmental impact statement as follows:

> The oil shale areas of Colorado, Utah, and Wyoming are in sparsely settled, semiarid to arid country, at elevations of 5,000 to 10,000 feet above sea level. The region is part of the high Colorado Plateau Province of the Upper Colorado River Basin and the high plains of the Wyoming Basin. The terrain varies from dissected, wooded plateaus bounded by prominent oil shale cliffs, to sparsely vegetated plains with low escarpments, commonly exposing the ledge and cliff forming oil shale. The region is drained by the Upper Basin tributaries of the Colorado River. Geologic uplift, stream erosion, and the varying degrees of resistance of the rock layers control the land forms. 2/

Ownership of Oil Shale Deposits

Of the more than 11 million acres in the Green River Formation which are suitable for commercial oil shale production, about 72 percent of the lands are under administration of the U.S. Department of the Interior. The Interior lands are estimated to contain 80 percent of the high-grade oil shale. It should be noted that ownership of some lands is in doubt and that the State of Utah is involved in litigation with the intention of claiming substantial amounts of the Interior tracts in Utah. Several major oil companies own Colorado lands which have potentially commercial resources.

To encourage production of this resource, the Department of Interior began in January of 1974 to offer the lease of six prototype tracts of oil shale -- each approximately 5,120 acres

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2/ Final Environmental Statement for the Prototype Oil Shale Leasing Program: Volume I, Regional Impacts of Oil Shale Development. U.S. Department of the Interior, 1973, page II-4.

in size -- in Colorado, Utah, and Wyoming. The large size of early bids for these tracts led to concern over the impact of a large oil shale industry on the socio-economics and environment of sparsely populated regions. The $210.4 million bid for the first tract is only slightly lower than the December, 1973, record bid for an offshore oil and gas lease of $212 million.

Following is a table showing the bids received by the Department of Interior for the prototype oil shale leases and describing the resources of each lease. Industry sources explain the lack of bids on the Wyoming tracts as due to low resources and the absence of existing technology to process shale of that quality. A map which shows the location of the federal leases, and probable areas for private development is also included on page 42.

Tract	Lease Date	High Bid (Millions of Dollars)	Estimated Recoverable Resource (Millions of barrels)	Probable Extraction Method	Oil Saturation (per ton)
Colorado					
Ca	1-8-74	$210.4	4,070	Mining	30 gals.
Cb	2-12-74	117.8	723	Mining	30 gals.
Utah					
Ua	3-12-74	75.6	244	Mining	30 gals.
Ub	4-9-74	45.1	266	Mining	30 gals.
Wyoming					
Wa	5-13-74	None	16.8	In situ	20 gals.
Wb	6-11-74	None	17	In situ	20 gals.

(One barrel = 42 gallons)

The federal government has clear title to 290 billion barrels and clouded title to 1,090 billion barrels, while private concerns hold 360 billion barrels of in-place resources. Detailed information concerning ownership of oil shale deposits is included in the <u>Environmental Impact Statement</u>.

II. EXTRACTION AND PRODUCTION OF SHALE OIL

Mining

Because the kerogen ("oil") does not naturally flow out of oil shale, production of shale oil requires different technology than coventional oil and gas. In order to recover the shale oil from a formation, it is necessary to "process" the rock in a manner that will liberate the oil.

Two approaches are being considered for the production of shale oil: (1) mining of the rock followed by surface processing to extract the oil; and (2) *in situ* (in-place) processing to liberate the oil which would then be pumped to the surface. Of these two options, only the mining/surface processing method is generally believed to be technologically capable of commercial production in the 1970's. The rudiments of mining the basic raw material will be considered first, followed by a discussion of the extraction (retorting) of the shale oil from the rock and *in situ* recovery techniques.

Underground mining. The greatest amount of experience to date with oil shale has involved underground mining of the oil bearing formations. The most likely means of mining appears to be the "room and pillar" method which results in the largest amount of production in the shortest time. Essentially, this type of underground mining proceeds in the following sequence:

(1) Entry to the bed of oil shale to be mined is obtained by the construction of a vertical shaft down to the bed (or beds); 3/

(2) A tunnel is constructed more or less horizontally and parallel to the margins of the formation from the point of entry to the edge(s) of the area to be mined;

(3) Mining is begun at right angles to this tunnel in one direction towards the limit of the area to be mined, in the process creating large rooms where the shale is removed and leaving approximately 60 foot square pillars for support of the roof; pillars would be spaced about 60 feet apart and rooms would be about 60 feet high;

3/ In some instances, the mahogany zone outcrops on canyon walls and entry to the formation is directly available at this point.

(4) On the opposite side, the mining is carried out on the "retreat", i.e., by starting from a tunnel at the limit of the mine, then mining towards the original access shaft, proceeding until the entire area to be mined is completed.

In addition, several shafts must be constructed for communication with the surface to provide air and entry for men and materials. The entire mine, in a cut-away view, with the roof removed, would look much like a waffle.

This sort of mining is carried out with large conventional construction equipment such as front end loaders and dump trucks which transport the shale from the working faces of the mine, after loosening of the deposit by blasting, either directly out of the mine or to a conveyor system.

The necessity of leaving pillars to support the roof of the mine and prevent or minimize surface subsidence results in less than complete recovery of the in-place resource. Mine depth, rock strength, and formation fracturing all influence the size of the pillars that must be left and the amount of the shale that can be removed. The U.S. Bureau of Mines demonstration mine that was operated from 1944 to 1956 near Rifle, Colorado, achieved a 75 percent extraction ratio in a relatively shallow outcropping of the mahogany zone. Mining of the lower zone of oil shale on one of the lease sites is estimated by the Department of Interior to achieve only a 50 percent rate of extraction. However, for much of the Green River Formation, 60 to 70 percent recovery of the oil shale sequence mined is anticipated.

A drawback of the room and pillar method is the probable height limitation of 100 feet that could be mined due the rock characteristics concerning roof and pillar strength necessary to prevent collapse and subsidence. In formations with oil shale sequences over 100 feet thick, such a limitation would be wasteful in terms of maximum recovery and could result in total extraction below 50 percent if oil shale above or below the mine must be permanently left in place.

Surface mining. Due to the great depth of the lower oil shale formation and the generally limited quantity of resources in the shallower mahogany zone, it is thought that much, if not most, of the deposits are not amenable to surface mining. As the depth of the deposit increases, the amount of overburden that must be removed before the shale can be mined increases and the costs associated with its removal take a bigger share of the total investment. At some point, it is no longer economical to surface mine and underground mining would be preferable. Before the Arab oil embargo and associated price increases for oil, it was felt that the limit for economic surface mining would occur at a ratio of overburden to resource of somewhat below 2:1. It is not known what current thinking may be on the maximum at this time, even with a price stabilization in excess of twice that of the period when these estimates were made.

In surface mining shale, an open pit is excavated in a series of terraces to the bed of oil shale. The pit, which is generally an inverted cone in shape, is extended outwards and constantly enlarged to expose and mine the oil shale bed. Conventional construction equipment such as might be used in building a dam is employed on the benches of the pit to remove the overburden and shale once it is loosened by blasting. Working benches would be approximately 110 feet wide and 40 feet high.

In order to maintain slope stability as the pit is deepend and continually expanded, a slope of 1:1 (45 degrees) is necessary. This requirement, of course, results in a larger horizontal area of overburden (at the top of the pit) to be mined than that of the deposit (at the bottom of the cone). This limits the depth of deposit that could be economically mined at an average waste/resource ratio below 2:1. The Department of Interior (in 1973) anticipated that tract Ca with an average deposit depth of 450 feet could be economically feasible for this type of operation and the lessees are investigating this type of operation.

Under open pit mining, recovery of the resource bed would be 100 percent of the area of the bed mined and would only be limited by any perimeter restrictions on the mine opening which would cause the portion of the shale under the slope to be left in place. This could possibly be mined by room and pillar methods to increase recovery. A potential attraction of open pit mining is that it might make recovery and utilization of lower grade deposits of shale economical, in that such deposits would have to be removed in any case if they lie above the primary recovery zone.

Processing of Oil Shale to Remove the Oil

Crushing. In the mining of shale and surface processing to remove the resource, it is necessary to crush the ore to uniform size before processing. The crushing process, to reduce the size of the mined shale from massive blocks weighing several tons to at least ten inches (depending on the process), would probably be a three stage affair. Initial crushing could take place in the mine, in the case of an underground mine, or on the floor of an open pit mine, and the rock transported by conveyors to secondary and tertiary crushers near the processing plants. This arrangement would minimize the distance that large space wasting blocks would have to be transported. Fines, particles smaller than three inches, would have to be briquetted after crushing operations and before being fed to processing units except in the case of the TOSCO retort whose design is able to process these size particles.

<u>Surface processing</u>. Several surface processes have been investigated in field operations in the United States. All of these are retorting operations and the plants are referred to as "retorts". Retorting is the process of distilling or decomposing a substance by the application of heat. In the situation of an oil shale retort, the oil shale is heated to around 900° F. at which point the shale is decomposed, producing: (1) crude shale oil as a vapor; (2) by-product organic gas; and (3) processed (spent) shale.

Retorting of oil shale is the only known commercially practical method for the recovery of oil from shale deposits. Shale oil cannot be extracted using solvents. It is, at best, only slightly soluable in any known solvent. The demonstrated retorting processes are described below.

<u>Gas combustion retort</u>. Of numerous retorts studied by the U.S. Bureau of Mines, the gas combustion retort is the most promising. This retort is a vertical vessel lined with heat resistant ceramic material through which the crushed shale is drawn downward as a bed by gravity. The retort has four functional zones, although there is no precise demarcation between each zone.

The raw shale first moves downward through the product cooling zone where it is heated close to retorting temperature (900° F.) by hot rising gases from the retorting zone. It then flows down through the retorting and conbusion zones, being heated to temperatures of over 1200° F. The heat for the process is generated in the combustion zone by burning a portion of the recycled product gas and a portion of the carbon residue that is left on the retorted shale. The retorted shale moves down into the heat recovery zone where it is cooled by the transfer of heat to a rising stream of the recycle product gas. The cooled processed shale is discharged mechanically from the retort at a rate which controls the passage of the material through the vessel.

Cool product gas is recycled by injection at the bottom of the vessel and is heated as it rises through the retorted shale in the heat recovery zone. Air, mixed with product gas, is injected through a distribution system near the center of the retort and is heated quickly by contact with the processed shale. The oxygen in the mixture then burns the gas stream and residue on the processed shale to produce hot gasses that move upward through the vessel, contacting the raw shale with enough heat to effect retorting.

The organic vapors produced from the retorting mix with the rising hot flue gas and cool from contact with raw shale in the product cooling zone at the top of the retort vessel. This cooling causes the crude shale oil vapor to condense as a fine mist which flows out of the top of the retort and passes through separators which remove particulates and segregate the mist from the gas stream. The product gas is then either recycled into the retorting vessel or discharged as a by-product for storage.

To establish the scale of a typical operation, it has been projected that a plant producing 50,000 bbl/day of shale oil would consist of six retorts, each approximately 56 feet in diameter and with a working rock depth of 18 feet. The Paraho and Superior Oil Company retorts are very similar in operation to the gas combustion process.

<u>Union Oil Under Feed Retort</u>. The Union Oil retort works substantially the same as the gas combustion retort. The primary difference is that the oil shale is moved up through the retort (instead of down) by means of a unique "rock pump" at the bottom of the retort. This reversal necessitates that the combustion gases and product gases move down instead of up, which is accomplished through the use of blowers. The shale oil condenses on the raw shale at the bottom, rather than as the mist found in the gas combustion retort, and is separated from the shale and gases -- the gases being stored for recycle into the retort. In the Union SGR process, a second retort reprocesses the rock to remove virtually all (99%+) of the carbon in the shale and recover additional by-product gas.

Neither the gas combustion nor the Union Oil retorts require water to cool the processed shale. The by-product gas from both is a low Btu value fuel gas that is recycled for fuel to heat the shale in the retort.

<u>TOSCO II Retort</u>. The Oil Shale Corporation (TOSCO) originally developed this retorting process in the mid 1950's and it was extensively field tested by the Colony Development Operation from 1965 to 1972. The TOSCO retort utilizes a slowly rotating horizontal drum into which preheated crushed oil shale and hot ceramic balls are introduced. The rotating drum mixes the raw shale and hot balls which results in the rapid transfer of heat from the balls to the shale. The flow

rates of the shale and balls, and the temperature of the balls are adjusted to heat the oil shale to about 900° F., at which temperature the retorting reaction is rapid. The products are cool balls, shale oil vapor, and processed shale.

The cooled balls move from the retort to the ball heater to be reheated before reintroduction to the retorting drum. The ball heater consists of a moving ball bed through which the hot flue gas from burning fuel is circulated. After heating the balls, the flue gas is used to preheat the raw shale in a pipe that lifts the shale to the retort, at which point the gas is separated and does not enter the retorting chamber.

The product vapor from the retort contains hydrocarbon gases, vaporized shale oil, steam, hydrogen sulfide, and other components. The vapor flows to conventional refining facilities that separate the liquid shale oil into components of several different boiling ranges, impure water, and gas. Another aspect of the system would process the by-product gases to remove gasoline type components and convert the hydrogen sulfide to elemental sulfur leaving sulfur-free gas.

The TOSCO process produces a higher quality fuel gas than other retorts due to the absence of air in the retort which prevents the formation of inert components and is suitable for plant use or the production of hydrogen for shale oil upgrading.

In Situ. The alternative to mining oil shale and then extracting the oil in a surface retorting plant is to retort the oil shale in place, i.e., in naturally occuring formations. There has not been a commercially viable demonstration of the *in situ* method to date, although much research has been carried out by the U.S. Bureau of Mines and several private oil companies and is continuing. The *in situ* method, as surface processing, requires a large amount of heat and high temperatures to effect the retorting. Retorting efficiencies of up to 70 percent may be achieveable in the long run.

There are two keys to the process: (1) the establishment and control of the movement of sufficient heat in the shale to effect retorting; and (2) establishment of permeability in the formation to allow movement of the heat through the formation and movement of the retorted product to the withdrawal wells. Several methods of heating have been suggested and tried, all of which are either introduced or initiated, and controlled from, a series of wells drilled into the formation. Sources of heat proposed are: (1) underground combustion of the oil shale; (2) hot natural gas; (3) hot carbon dioxide; (4) superheated steam; (5) hot solvents; and (6) combinations of two or more of these.

Assuming for the moment that the formation is sufficiently porous to allow the movement of hot gases, the heat introduced from the wells would move through the formation, retorting and driving the shale oil ahead of it. Appropriately spaced wells in advance of the heat front would extract the retorted shale oil, probably as a fine mist. Although greatly simplified, this process is the essence of the <u>in situ</u> recovery process. The ability to remotely control the process from surface wells has been a major stumbling block in this development.

Several methods have been proposed to create permeability in a formation that is naturally non-porous to allow heat to move through the formation to retort the shale and the liberated shale oil to move to wells for extraction. Permeability can be induced by fracturing of the formation using high voltage electricity, hydraulic fracturing, or liquid explosives. It has also been suggested that nuclear fracturing could be used and a feasibility study on this was done, although it is not being actively considered at this time (Project Bronco). Several experiments have proved that facturing can be used to develop communication among wells, although fracturing sufficient to provide needed large heat exchange surfaces has been a problem.

There are several variations to the above general description of <u>in situ</u> processing. One alternative to fracturing of the rock is to introduce communication between wells by the construction of mine tunnels and shafts.

Another method being investigated by Garrett Research (Occidental Petroleum) is to mine the lower portion of the oil shale bed and collapse the formation into the cavity as a rubble heap which is quite permeable and amenable to heating the shale to retort temperatures. The retorting room in a commercial mine would be about 120 ft. x 120 ft. x 250 ft. and 30 ft. barriers are anticipated as needed between "rooms". The process has been tested on a pilot scale and a commercial scale test is under construction. The retorted oil would flow down through the pile into a sump and would then be pumped to the surface through wells.

<u>The product</u>. Generally, crude shale oil that is the product of surface retorts is classified as low-gravity, moderate-sulfur, high-nitrogen oil by conventional petroleum standards. Shale oils have a higher pour point (the temperature at which the oil will flow) and are more viscous (resistant to fluid movement) than many conventional crude oils. The products from the various surface retorting processes differ somewhat and the oil from <u>in situ</u> differs considerably, having lower pour points, viscosities, and nitrogen contents.

In addition to crude shale oil, the retorting produces by-product gases of varying qualities. Internal combustion surface retorts produce gases diluted with the products of combustion and inert components of the air introduced to support combustion. The gas from the indirectly heated TOSCO retort is composed only of the undiluted components of the oil shale itself whereas the gases from *in situ* retorting would vary depending upon the heating method used. A comparison follows:

TABLE 1 -- CHARACTERISTICS OF PRODUCT GASES

Component	Conventional Gas Moffat County, Colorado	Shale Oil: Surface Retort: Direct heat	Shale Oil: Surface Retort: TOSCO	Shale Oil: In situ Retort
Hydrocarbons (Volume Percent)	99.5	3-5	43	1.3
Gross Heating Value (Btu/scf) (scf = 1,000 cubic feet)	1008	80-100	775	30

Upgrading of Shale Oil

Due to the limited market for refined petroleum products in the immediate oil shale area, it is economically advantageous to transport crude oil rather than a multitude of finished products. Major refining centers are normally located in metropolitan areas to minimize the cost of distributing the products to market. For this reason, it is likely that the refining industry in the area will remain limited to that necessary to provide the region's needs and excess production will be transported to other areas for final refining.

Although shale oil is in most respects similar to conventional crude oil and can be refined by existing petroleum industry techniques to form a range of high quality petroleum products, including gasoline, jet and diesel fuels, and domestic and industrial heating oils, two characteristics will probably dictate that the shale oil be "upgraded" at the site before being transported to refining/marketing centers. These two properties are high pour points and high nitrogen contents. High pour points make pipeline transportation of the oil difficult or impossible because the oil will not flow freely at normal temperatures. High nitrogen contents decrease the versatility of the oil as a conventional refinery feedstock.

Upgrading of shale oil is, in essence, partial refining of the oil. The upgrading would be expected to utilize existing petroleum industry technology, particularly a process known as "hydrocracking". Quite simplified, hydrocracking involves breaking down heavy, long-chain hydrocarbon molecules into molecules that are shorter, lighter, and have lower boiling points. In addition, hydrocracking substitutes hydrogen atoms for the nitrogen and sulfur atoms on the hydrocarbon chain resulting in a product that is almost pure hydrocarbon, i.e., composed exclusively of the elements hydrogen and carbon. The process uses heat, catalysts, and pressure to achieve these results and utilizes water for process cooling. The upgraded crude oil product is substantially free of sulfur, has a reduced nitrogen level, and materially increased API gravity and flow characteristics compared to the shale oil as retorted. This material is considered to be a premium feedstock for refining into finished products.

Reduction of the nitrogen content of the shale oil is important because few existing refineries have the facilities to process large quantities of high nitrogen crude. A lower level nitrogen oil would be more flexible to market. However, at least one study suggests that refineries may wish to integrate the nitrogen removal into their processes in the long run when substantial amounts of shale oil are available as feedstock on a continuing basis. Upgrading might still be required to reduce the pour point and facilitate pipeline transportation of the crude shale oil. Occidental's _in situ_ shale oil apparently is a pipeline quality oil and will not require on-site upgrading.

Spent shale. The surface retorting of oil shale results in large quantities of processed, or spent shale in addition to the oil and gas products. This spent shale weighs 80 to 85 percent of the raw shale before retorting and even after maximum compaction, is at least 12 percent greater in volume than raw shale before mining. Obviously, this presents a disposal problem. It should be noted that _in situ_ retorting does not produce spent shale requiring disposal. Various alternative retorting plants and mining development plans produce different effective quantities of rock for disposal. For example, a surface mine would require disposal of the overburden in addition to spent shale.

A 50,000 barrel per day plant would process 26.9 to 29.9 million tons of raw oil shale per year, leaving at least 22.2 million cubic yards of residue for disposal (16.7 million cubic yards after compaction). The are two major options under consideration for the disposal of this shale: (1) surface disposal; and (2) a combination of surface disposal and backfiling of mining cavities. Due to the increased volume the amount of spent shale that could be returned to mined out areas would be around 60 percent. Additionally, several years of mining would be necessary before any spent shale could be backfilled in order to avoid interference between mining and disposal operations and the residue from this period would be subject to surface disposal. Spent shale would be transported to the disposal area either by conveyors and trucks or in a slurry, i.e., in combination with enough water to be able to be pumped through pipelines. The slurry system would be particularly amenable to disposal sites in the mine or a significant distance from the plant. Surface disposal would probably involve the filling of natural canyons either on or adjacent to the mine site and, in one case, on the opposite (west) side of the Cathederal Bluffs from the mining operation.. These gulches would be filled to a depth of several hundred feet and a face would be left in the canyon facing downstream at the completion of disposal operations. The slope would likely be less than 45°. Superior Oil Company claims that in its oil shale process which also recovers associated minerals, the spent shale has a small enough volume to be completely returned to the mined out area.

By-products and Associated Minerals

There are several potentially commercial products that are incident to the production of shale oil and others that may be economically produced in conjunction with the mining and surface processing of the kerogen.

Incidental products. As previously mentioned, a large amount of by-product gas is produced from the retorting of oil shale. This is probably the most significant by-product and would likely be of use in the immediate vicinity of the plant for process heat or steam production. Due to the low Btu yield of the gas, it is not believed that it would be economical to transport it any distance for marketing, with the possible exception of by-product gas from the TOSCO retort that might be used to supplement natural gas in the area.

Two other potential uses of TOSCO by-product gas are possible. The gas could be used in an electric power plant close to the site because certain boilers for this conversion of heat to electricity can run on low Btu fuels. Second, the gas may be utilized, after reforming, to provide hydrogen for the upgrading process.

Garrett says that the burning of their by-product gas will be used to generate electricity. The substantial surplus electricity will be sold in the area. Paraho has also indicated that their process is amenable to on-site electric production and would produce a surplus.

The upgrading of shale oil through removal of sulfur and nitrogen from the oil, provides two commercially valuable by-products. Hydrogen sulfide gas produced during hyrocracking can be converted to elemental sulfur (a solid) for sale. Amonia is the product that remains after nitrogen removal and once separated from other product gases can be liquified for storage and sale as fertilizer or as a raw material for fertilizer manufacture. Additionally, upgrading will produce coke as a primary product which is saleable as a fuel to the steel industry or as a fuel for specially constructed electric generating plants in the area.

Associated Minerals. Extensive deposits of sodium minerals, one containing aluminum, exist near the center portion of Colorado's Piceance Creek Basin. Approximately 27 billion tons of alumina in dawsonite beds and an additional 30 billion tons of nacholite are present in or associated with lower zone oil shale. Dawsonite deposits generally occur only in very small concentrations whereas in certain areas, nahcolite is present in massive beds, hundreds of feet thick.

A significant amount of research has been conducted regarding the extraction of these minerals from the shale and, although the processes are still in the experimental stage, recovery may be feasible. Superior Oil Company is contemplating a "three minerals" plant west of Meeker that would produce these minerals as co-products to shale oil. Recovery of these associated minerals would reduce the volume of spent shale enough to allow the return of all of it to the mine for disposal. A substantial amount of pure water could also be a by-product of Superior's process, if not recycled.

As envisioned, the process would start with retorted oil shale which would first be roasted to remove remaining organic matter. The nahcolite, now converted to soda ash, is recoverable by leaching. The dawsonite is converted to sodium aluminate and soda ash which can be recovered with dilute soda ash or other alkaline solutions and can be carbonated to yield a high grade alumina for the manufacture of aluminum metal. It is estimated that such extraction could supply 15 percent of the nation's need for soda ash in 1980, and 3 percent of the demand for aluminum. Probably no more than three 50,000 bbl/ day plants could produce these minerals unless additional markets develop. It is notable that the United States now imports the large majority of its alumina needs.

Alternative uses for the two minerals are in pollution control. Nahcolite can be used in a raw state for scrubbing flue gas to remove acid gases such as sulfur dioxide and nitrogen oxides. Successful development of this scrubbing technique would allow the use of large quantities of U. S. high sulfur coal, according to Superior Oil. Similarly, dawsonite may be processed to yield aluminum compounds useful for water treatment rather than metalurgical grade alumina. Realization could substantially change the demand for these associated minerals and the number of plants that could economically enter production.

III. INDUSTRY DEVELOPMENT

In July, 1974, companies with oil shale reserves of potentially commercial quantities in Colorado and the lessees of federal oil shale lands in Colorado and Utah were requested to detail their development plans to the committee. At that time, the committee received responses from nine oil shale projects which delineated development plans. Several other companies indicated that they had no detailed plans for their oil shale properties at this time.

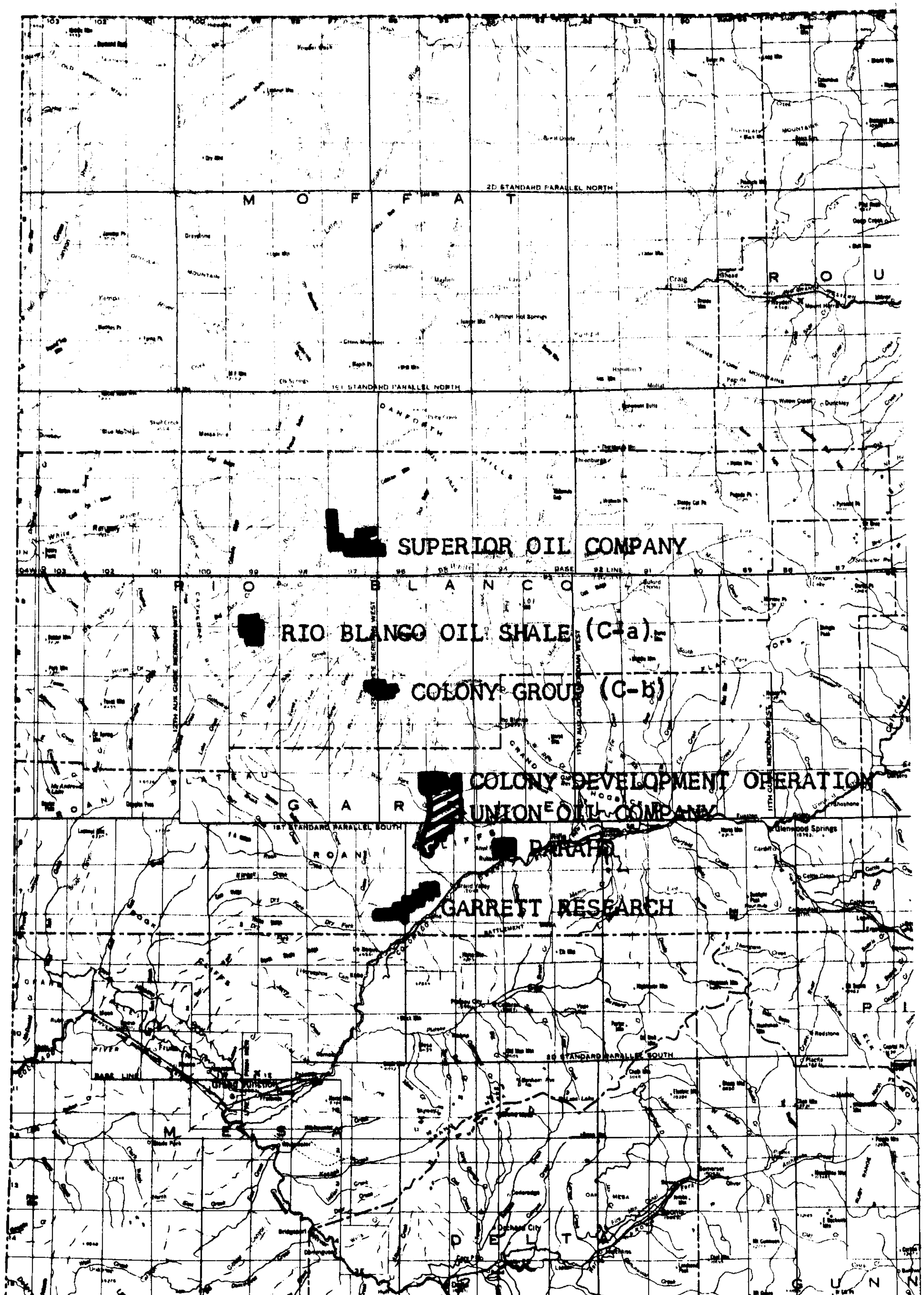
Subsequently, the committee continued communications with various companies in order to develop additional information. The companies' present development plans, as communicated to the committee, are summarized in outline form on the following pages.

The following companies indicated that they had no firm plans for the development of their private oil shale holdings in Colorado in July, 1974:

- Chevron Shale Oil Company (Standard Oil of California);
- Cities Service Oil Company;
- Continental Oil Company;
- Equity Oil Company;
- Getty Oil Company;
- Mobil Oil Corporation; and
- Texaco Inc.

The map on the following page shows the approximate location of planned oil shale projects in Colorado.

FIGURE III. LOCATION OF PROPOSED OIL SHALE OPERATIONS IN COLORADO



Private Lands -- Colorado

COMPANY: Colony Development Operation (ARCO, Ashland, Shell, and TOSCO)

LOCATION: 15 miles north of Grand Valley on Parachute Cr.

COMMERCIAL LEVEL PLANS:

Type of Mining: Underground -- room and pillar
Type of Retort: TOSCO II
Project Life: 20 years
Disposal: Surface

Products: Shale Oil -- 46,000 Bbl/day
Coke -- 740 tons/day
Sulfur -- 150 long tons/day
Ammonia -- 137 tons/day

TIME SCHEDULE 1/

Initial Construction: May 1975
Initial Production: October 1978
Complete Construction: September 1978
Full Production: October 1979

EMPLOYMENT

Construction: 2400 peak in 24th month of construction
Production: 1000

INDUCED POPULATION

Total:	construction - 6000	Production - 5000
Family size:	construction - 2	Production - 3
Induced Employment:		Production - 800

TRANSPORTATION

Road: Parachute Cr. county road to U.S. 6/24 (to be I 70)
Rail: Spur from D&RGWRR main line to staging area just north of Grand Valley
Pipeline: to 4-Corners pipeline
Utilities: Parachute Cr. corridor

WATER

Need: 8688 acre-feet/year
Source: Colorado River
Storage: No
Location: N.A.

ELECTRICITY

Source: Purchase (in Public Service Co. service area)
Need: 100 mega watts

1/ Initial timetable. Colony has since suspended its plans. A minimum one year delay is likely -- dates given only for purposes of showing length of various phases contemplated.

COMPANY: Union Oil Company

LOCATION: 9 miles North of Grand Valley on Parachute Cr.

COMMERCIAL LEVEL PLANS:

Type of Mining:	Underground -- room and pillar
Type of Retort:	Union Oil Underfeed -- SGR process
Project Life:	15 to 20 years
Disposal:	Surface
Products:	Shale oil -- 50,000 Bbl/day (possibly 100,000) Sulfur -- 33 long tons/day Ammonia -- 100 tons/day

TIME SCHEDULE

	Prototype	Commercial
Initial Construction:	late 1975	1978
Initial Production:	late 1977	1981
Complete Construction:	late 1975	1981
Full Production:	1977	Unknown

EMPLOYMENT

Construction:	200	900 average 2000 peak
Production:	100	850

INDUCED POPULATION

Total:	Unknown
Family size:	3.5 persons
Induced Employment:	Unknown

TRANSPORTATION

Road:	Parachute Cr. county road to U.S. 6/24 (to be I 70)
Rail:	Spur up Parachute Cr. to site from D&RGWRR line
Pipeline:	Under study: tie in to 4-Corners, Platte, or Arapahoe lines
Utilities:	Parachute Cr. from Colorado River

WATER

Need:	8,000 acre-feet per year
Source:	Colorado River, some purchased agricultural rights
Storage:	Yes; 33,000 acre-feet
Location:	"Union Meadows" on Parachute Cr.

ELECTRICITY

Source:	Purchase (in Public Service Company service area)
Need:	150 mega watts

COMPANY: Garrett Research 1/
(Occidental Petroleum)

LOCATION: North of Colorado River between Grand Valley and DeBeque

COMMERCIAL LEVEL PLANS:

Type of Mining:	Limited underground
Type of Retort:	Garrett *in situ*
Project Life:	15 years, possibly 30 years
Disposal Method:	Limited surface disposal of raw shale
Products:	Shale Oil -- 30,000 Bbl/day

TIME SCHEDULE

Initial Construction:	Commercial test underway
Initial Production:	1975
Complete Construction:	On-going
Full Production:	1978

EMPLOYMENT

Construction:	Presently about 150
Production:	At full scale -- 600

INDUCED POPULATION

Total:	1740
Family size:	2.9 persons
Induced Employment:	Unknown

TRANSPORTATION

Road:	Private road on BLM land to Roan Cr. county rd. to U.S. 6/24
Rail:	None
Pipeline:	Not planning initially
Utilities:	All on-site

WATER

Need:	Very little
Source:	On-site
Storage:	No
Location:	N.A.

ELECTRICITY

Source:	Produced on site as by-product
Need:	Unknown. but 100 mega watts surplus will be produced

1/ As of January 3, 1975, this operation was transferred to a new subsidiary of Occidental Petroleum -- Occidental Oil Shale, Inc.

COMPANY: Superior Oil Company — LOCATION: On White River, 20 miles west of Meeker

COMMERCIAL LEVEL PLANS:

Type of Mining:	Underground
Type of Retort:	Superior "three minerals" process
Project Life:	20 years
Disposal:	All returned to mine cavity
Products:	Shale Oil: 50,000 Bbl/day
	Nahcolite: 1 to 15 tons/day
	Soda Ash -- 2500 tons/day
	Alumina -- 2000 tons/day

TIME SCHEDULE 1/

	Prototype	Commercial
Initial Construction:	July 1975	1980
Initial Production:	1980	1980
Complete Construction:	December 1979	1982
Full Production:	1980	1983

EMPLOYMENT

Construction: July 75-Dec 76 -- 60; Jan 77-Aug 77 --150; Sept 77 - Dec 79 -- 250; 1980 - 1982 -- 600

Production: 1980 -- 250; 1983 -- 1100

INDUCED POPULATION

Total:	400 to 5500
Family size:	N.A.
Induced Employment:	N.A.

TRANSPORTATION

Road:	Via Colorado 64 and 13 to Craig or Rifle railheads
Rail:	Spur to Craig (D&RGWRR) or Wyoming (UPRR) lines
Pipelines:	To Rangely or new Utah Marathon Oil line
Utilities:	Have water and electricity access on site

WATER

Need: 33,873 acre-feet/year (may produce 30,647 acre-feet/yr surplus fresh water)

Source:	Underground on-site
Storage:	No
Location:	N.A.

ELECTRICITY

Source:	Purchase (White River REA service area)
Need:	80 mega watts

1/ Superior is held up by a land exchange with the BLM which might not be consumated until 1976 or 1977. The time schedules given here are for purposes of illustrating the length of various time periods only and assume that the land exchange occurred in mid 1974.

COMPANY: Development Engineering, Inc. -- Paraho (Contractor for 17 company consortioum)

LOCATION: Anvil Points (10 miles west of Rifle on Naval oil shale reserve number 3)

COMMERCIAL LEVEL PLANS:

Type of Mining:	Underground -- room and pillar
Type of Retort:	Paraho
Project Life:	Until early 1976 (research and development only) 1/ (p. 34)
Disposal:	Surface
Products:	Shale Oil -- Up to 8,000 Bbl/day

TIME SCHEDULE

	Prototype	Commercial Test
Initial Construction:	September 1973	1975
Initial Production:	May 1974	
Complete Construction:		
Full Production:		

EMPLOYMENT

Construction:	51	200
Production: N.A.		

INDUCED POPULATION

Total:	10 employees imported plus families (Fall, 1974)
Family size:	N.A.
Induced Employment:	N.A.

TRANSPORTATION

Road:	Private road to U.S. 6/24
Rail:	None
Pipeline:	None
Utilities:	Unknown

WATER

Need:	Minimal
Source:	Unknown
Storage:	No
Location:	N.A.

ELECTRICITY 2/

Source:	Public Service Company
Need:	Minimal

1/ Recent announcements note that the Paraho group has approached the Department of the Navy and the U. S. House Armed Services Committee concerning expansion of their lease terms to allow construction and operation of a commercially sized retort on the Anvil Points lease. Construction could begin in 1975 and the project life extended for three years.

2/ The PARAHO process in commercial application is anticipated to produce 300 megawatts for a 100,000 Bbl/day plant; 238 megawatts would be surplus.

COMPANY: Rio Blance Oil Shale (Gulf Oil and Standard Oil (Indiana))

LOCATION: Federal lease C-a in western Rio Blanco County

COMMERCIAL LEVEL PLANS:

Type of Mining:	Underground and/or open pit
Type of Retort:	TOSCO II under consideration
Project Life:	At least 20 years
Disposal:	Surface, possible back-fill to open pit
Projects:	Shale Oil -- 50,000 Bbl/day (possible expansion to 300,000)
	Coke -- 602 tons/day
	Sulfur -- 228 long tons/day
	Ammonia -- 168 tons/day

TIME SCHEDULE

Initial Construction:	February 1977
Initial Production:	1980
Complete Construction:	December 1981
Full Production:	1982 (possible expansion 1983-85)

EMPLOYMENT

Construction:	1977 -- 400: 1978 -- 2,000; 1979 -- 2,000
Production:	1,000

INDUCED POPULATION

Total:	Construction -- 8,600 production -- 6,200
Family size:	3.7 persons
Induced Employment:	Unknown

TRANSPORTATION

Road:	To be determined by BLM
Rail:	Not anticipated
Pipeline:	To be determined by BLM
Utilities:	To be determined by BLM

WATER

Need:	11,500 acre-feet/year
Source:	Undetermined; possibilities are Colorado or White Rivers or ground water
Storage:	Yes, up to 350,000 acre-feet
Location:	On Yellow Cr. South of White River

ELECTRICITY

Source:	Purchase (in Moon Valley REA service area)
Need:	95 mega watts

COMPANY: C-b Shale Oil Project (ARCO, Ashland, Shell, and TOSCO)

LOCATION: Federal lease C-b, 25 miles SW of Meeker

COMMERCIAL LEVEL PLANS:

Type of Mining:	Underground -- room and pillar
Type of Retort:	TOSCO II
Project Life:	At least 20 years
Disposal:	Surface
Products:	Shale Oil -- 46,000 Bbl/day Coke -- 740 tons/day Sulfur -- 150 long tons/day Ammonia -- 137 tons/day

TIME SCHEDULE

Initial Construction:	Mining -- 1975, Retort -- 1978
Initial Production:	1981
Complete Construction:	1981
Full Production:	1981

EMPLOYMENT

Construction:	2000 peak in middle of construction period
Production:	1000

INDUCED POPULATION

Total:	5000
Family size:	N.A.
Induced Employment:	N.A.

TRANSPORTATION

Road:	Probably private road to Piceance Cr.county road to Colo. 64 or 13
Rail:	Feasibility under study
Pipeline:	Connection to Platte (Wyoming) or 4-Corners pipelines
Utilities:	To be determined by BLM

WATER

Need	8688 acre-feet/year
Source:	Ground water and Colorado or White Rivers
Storage:	Yes, size unknown
Location:	On-site

ELECTRICITY

Source:	Purchase (in White River REA service area)
Need:	100 mega watts

COMPANY: Phillips Petroleum/
Sun Oil

LOCATION: Federal lease site
U-a southwest of Rangely
in Utah

COMMERCIAL LEVEL PLANS:

Type of Mining:	Underground
Type of Retort:	PARAHO
Project Life:	20 to 30 years if developed jointly with site U-b
Proposal:	Surface
Products:	Shale Oil -- 50,000 Bbl/day Coke -- 720 tons/day Sulfur -- 45 long tons/day Ammonia -- 100 tons/day

TIME SCHEDULE

Initial Construction:	Late 1976
Initial Production:	1978
Complete Construction:	Late 1980
Full Production:	Mid 1980

EMPLOYMENT

Construction:	1977 -- 425; 1978 -- 700; 1979 -- 900; 1980 -- 100
Production:	895

INDUCED POPULATION

Total:	8,400
Family size:	N.A.
Induced Employment:	N.A.

TRANSPORTATION

Road:	Utah state highways
Rail:	Not planned
Pipeline:	Yes, direction unknown
Utilities:	Unknown

WATER

Need:	8,250 acre-feet/year
Source:	White River
Storage:	Yes
Location:	Off-site in Colorado or Utah

ELECTRICITY

Source:	Purchase (in Moon Valley REA service area)
Need:	55 mega watts

COMPANY: White River Oil Shale (Sun, Phillips, and SOHIO)

LOCATION: Federal lease site U-b southwest of Rangely in Utah

COMMERCIAL LEVEL PLANS:

Type of Mining:	Underground
Type of Retort:	PARAHO
Project Life:	20-30 years if developed jointly with site U-a
Disposal:	Surface
Products:	Shale Oil -- 50,000 Bbl/day Coke -- 720 tons/day Sulfur -- 45 long tons/day Ammonia -- 100 tons/day

TIME SCHEDULE

Initial Construction:	Late 1976
Initial Production:	Early 1980
Complete Construction:	Late 1979
Full Production:	Mid 1980

EMPLOYMENT

Construction:	1977 -- 500; 1978 -- 1150; 1979 -- 1370
Production	895

INDUCED POPULATION

Total:	8,400
Family size:	N.A.
Induced Employment:	N.A.

TRANSPORTATION

Road:	Utah state highways
Rail:	Not planned
Pipeline:	Yes, direction unknown
Utilities:	Unknown

WATER

Need:	8250 acre-feet/year
Source:	White River
Storage:	Yes
Location:	Off-site in Colorado or Utah

ELECTRICITY

Source:	Purchase (in Moor Valley REA service area)
Need:	55 mega watts

IV. INDUSTRY SIZE PROJECTIONS

The rate at which the oil shale industry may develop will, of course, determine to a large extent its impact on the tri-county region. Small or slow development might be absorbed with little impact whereas rapid large-scale development could create significant growth problems for the region.

Initially, it should be noted that the construction of a surface processing plant would require three years before production of shale oil would begin. This time period would include design, engineering and construction, and the production and acquisition of plant and mine equipment. It is not unlikely that a concern would spend at least one or two years, prior to the decision to proceed with design, evaluating the resource, analyzing the economics of the operation, and lining up capital for the project.

The economics of the operation will undoubtedly affect the rate of build-up. Department of Interior projections were based on an assumed 1973 market value of $3.90 per barrel -- a figure about one-third the stabilized price of oil following the Arab oil embargo. The effect of inflation on the economics of the industry appears to be substantial - at least one project has been recently suspended primarily on these grounds. A significantly higher rise in the price of the product compared with the cost of production would, of course, favor more rapid development than projected whereas the reverse situation would have a delaying effect.

Another economic factor which could play a major role is the availability of capital. A tight money market and high interest rates could discourage rapid development of one aspect of industry such as oil shale. Funds for oil shale development will likely be in competition with other industry projects such as conventional drilling and production.

Many aspects of environmental considerations on public and private lands remain to be determined. Colony Development Operation has stated that 35 federal and state permits are required for development on the private lands. Delays pending determination of environmental impacts could be substantial.

The National Petroleum Council in July, 1972, projected that production on private lands would not exceed 100,000 barrels per day by 1985 in the absence of federal lands. The Department of Interior, for the purpose of projecting total industry size, assumes that the maximum rate of production that could be supported on private lands is 400,000 barrels per day in 1985. The four lease tracts are projected by Interior to support a total of 200,000 barrels per day for a cumulative total of 600,000 barrels per day in 1985. It is felt that additional public lands would be required to increase the production rate above this level. Such additional federal leases would not be available until preparation of an environmental impact statement (a two year undertaking) based on an evaluation of the prototype lease program. Based on these assumptions, Interior feels that the oil shale industry could not be larger than 1 million barrels per day in 1985.

The possible development schedule postulated by the Department of Interior is attached, with footnotes reflecting recent announcements by lease holders and others.

It is noteworthy that of the production projected by Interior to take place by 1982, 300,000 bbl/day of the 400,000 bbl/day total (75 percent) is attributed to Colorado. This is not unlikely, due to the concentration of commercial high-grade oil shale in the state and the higher quality private oil shale lands also located in Colorado.

Colony Development Operation estimates that they were a minimum of two years ahead of all other oil shale concerns. Colony's original timetable called for production to begin in 1978. However, in late 1974, they announced a suspension of their plans due to rising costs, uncertainty about the price of oil, and the lack of national energy policy defining the role of oil shale. Union Oil's original timetable called for production by 1979, which was later amended to 1980. Recent correspondence with the company indicates that they share many of Colony's concerns and that their current production may more realistically be for production in 1981. Occidental Petroleum, however, has continued to express confidence in their modified <u>in situ</u> process and if the commercial scale test is successful may make a decision late in 1975 to go to full scale commercial production. This might be expected to be reached in 1978 or 1979. It is notable that the Garrett <u>in situ</u> process is substantially less capital intensive than other more conventional processes. Superior Oil Company, which needs a land exchange with the BLM before they can commence pilot tests (which would precede commercial scale operations), may be two years away from a land exchange -- this would place their commercial production in 1983-1984.

On the basis of these announcements, it appears unlikely that any company besides Occidental will have a commercial scale oil shale operation in production by 1980. The Occidental project would produce an average 30,000 Bbl/ per day. The two federal leases in Colorado are planned to reach production between 1980 and 1985 at a projected rate of 100,000 Bbl/ day combined. It is Union's current expectation to be producing

50,000 Bbl/day prior to 1985. Both Colony and Superior may also reach production at 50,000 Bbl/day each by 1985, if conditions become favorable. Both Utah leases are projected by the lessees to reach a combined production level of 100,000 Bbl/day by 1985. This would indicate that the production level of the industry would be a maximum of 380,000 Bbl/day in 1985. It is perhaps not unrealistic to conclude that all of the projects now contemplated will not be carried out and that the industry's size will be somewhat less than 380,000 Bbl/day, possibly only 250,000 Bbl/day. Conversely, if the economy stabilizes and the federal government decides to either support shale oil production or participate in the investment, or both, the industry size could be more probably between 380,000 and 500,000 Bbl/day by 1985. To have such an effect, however, federal action would likely be required by 1977.

Industry sources and the Atomic Energy Commission concur in the belief that Interior's projection of 1,000,000 Bbl/day in 1985 is not feasible and that production of less than half that amount is more probable. The Federal Energy Administration in its Project Independence Report projects a production level of 250,000 Bbl/day by 1985, assuming "business as usual", and a world oil price of $7.00/Bbl. At an $11.00/Bbl price, the FEA projected a one million Bbl/day shale oil industry for 1985. It is noteworthy that FEA's projections were based on plant capital costs of only one-third of the latest estimates. A further note of interest is FEA's opinion that Colorado's air pollution standards on sulfur dioxide will limit production to 250,000 Bbl/day in the state.

Coal Conversion

Although coal conversion technology is at about the same stage of development as oil shale, it is in many respects similar and may be competing with oil shale for development capital. A 100,000 Bbl/day coal gasification or liquification plant would likely cost about as much as an oil shale plant of comparable size. In addition, its operating costs would likely be similar. The important note is that the federal government, through the Office of Coal Research, is financially supporting coal conversion effects. The lack of similar governmental interest in oil shale is noteworthy and may indicate that until there is a change in federal attitude, coal conversion will be tacitly encouraged and oil shale will remain in the shadows.

TABLE 2 -- PROJECTED POSSIBLE DEVELOPMENT PATTERN FOR OIL SHALE -- CUMULATIVE SHALE OIL PRODUCTION

(Thousands of Barrels Per Day)

Year	Colorado		Utah	Wyoming	Technology Assumed 1/	Total Oil (Cum.)
	Public Land	Private Land	Public Land	Public Land		
1973	--	--	--	--	--	--
1974	--	--	--	--	--	--
1975	--	--	--	--	--	--
1976	--	50 c/	--	--	1-U	50
1977	--	--	--	--	--	50
1978	50 a/	50 d/	--	--	2-U	150
1979	100 b/	--	--	--	1-S	250
1980	--	--	50	--	1-U	300
1981	--	50 f/	--	50 e/	1-U, 1-I	400
1982					2-U, 1-I	550
1983					3-U	700
1984					$1\text{-}S_1$	850
1985					1-U, 2-I	1,000

1/ Legend — 17 total Plants

- 1-U = one 50,000 bbl/day underground mine
- 1-S = one 100,000 bbl/day surface mine
- 1-I = one 50,000 bbl/day in situ mine
- $1\text{-}S_1$ = one 150,000 bbl/day surface mine
- 2-U = two 50,000 bbl/day underground mines
- 2-I = two 50,000 bbl/day in situ mines
- 3-U = three 50,000 bbl/day underground mines

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a/ Tract Cb - Announced by bidwinner to reach full production in 1982.

b/ Tract Ca - Announced by bidwinner to reach full production in 1982.

c/ Colony Development Operation stated, in late 1974, that plans for production have been suspended.

d/ Union Oil has indicated production to begin in 1981.

e/ Not leased.

f/ It is unlikely that Superior Oil will reach production before 1983 or later.

SOURCE: Final Environmental Statement..., page III-9.

V. PUBLIC V. PRIVATE DEVELOPMENT OF OIL SHALE RESOURCES

The impetus for interest in public or quasi-public oil shale development can be traced to the lack of private interest expressed toward prototype oil shale leases in 1968. At that time, for reasons including the price of crude oil and technological considerations, no serious bids were received. To foster development of the resource, Senator Henry Jackson introduced S. 2510 during the 1971 session of Congress. This bill would have established a government-industry corporation, jointly managed and funded, to select the two most feasible methods from a technical, economical, and environmental standpoint, for manufacturing synthetic petroleum from oil shale. The corporation would have been required to cease functioning in a development area as each new energy source was brought into commercial production.

Increased interest in oil shale was sparked by energy shortages of the early 1970's and became intense with major deficits experienced during 1973 along with increased prices for crude oil. Bids for the first Colorado prototype tract were far in excess of expectations and led to concern on the part of some members of Congress and others, that there was no method to determine a fair price for an oil shale lease. For this and other reasons noted in the arguments for public development of oil shale, Representative Patsy Mink and others introduced legislation in 1973 and 1974 (H.R. 12014 and H.R. 12170) providing for governmental operation similar to the Tennessee Valley Authority (TVA). No legislation of this type was adopted by the 93rd Congress.

"Oil Shale Mining and Energy Corporation" -- H.R. 12170

The stated purpose of this bill, proposed by Representative Mink, is to

> establish a public corporation to explore and develop all oil shale energy resources on Federal lands, to assure that the Nation's energy requirements are met without degradation to the environment, and to assume responsibility for ameliorating the adverse economic and social effects of oil shale development.

The bill would create an Oil Shale Mining and Energy Corporation with a board of three members appointed by the President. Among the powers of the corporation, would be the exploration and development of oil shale and other oil shale products, either alone or on a joint cooperative basis with any private or other public entity.

The corporation would render in lieu of taxation payments to state and local governments on the basis of a percentage of gross proceeds derived from oil shale and other products. The payments would range from nine percent of gross proceeds the first year to five percent after seven years. Allocations to state and local governments would be based on gross proceeds within each state and book value of property held by the corporation in each state.

The corporation would be authorized to issue up to $5 billion in bonds to assist in financing exploration and development. In addition, the corporation would be directed to sell oil shale products at prices which would produce gross revenues in excess of costs and to sell, on a priority basis, to firms which have no facilities for the primary production of oil and gas.

After payment of such items as operating expenses, in lieu of tax payments to state and local governments, and establishment of a continuing fund, corporate proceeds would be allocated to an American Indian fund, with monies distributed according to size of tribal membership.

Finally, the bill provides for an environmental advisory committee and environmental safeguards.

Public Ownership and Development of Oil Shale Lands -- Pro and Con

The following arguments for and against government-controlled development of oil shale resources represent general, popular points of view as reported by the media and expressed to the Subcommittee on Minerals, Materials, and Fuels, of the Committee on Interior and Insular Affairs, U.S. Senate, during hearings on the 1971 proposal of Senator Jackson (S. 2510). By no means are these arguments inclusive and they do not reflect technical objections to either government or private development.

Arguments For Public Development of Oil Shale

(1) Recent bids for prototype oil shale development indicate that private enterprise anticipates enormous financial gains from such projects. There is really no basis for determining the proper amounts to be bid for oil shale since

it is a new source of energy. Rather than provide for potentially excessive profits, government should develop the resource.

(2) The environmental impact of oil shale development is only speculative at this point, but could be of major consequences. A government operation would be more concerned with environmental matters since such operation would not be based on the profit motive.

(3) The public interest would be more fully protected with regard to considerations other than environmental (noted above). It is the responsibility of the federal government to develop resources on lands owned by the government in the best interest of the public.

(4) Because of the magnitude of oil shale projects, only the very largest of private concerns, or combinations of such concerns, will be financially capable of participation in development. This situation means that private development of oil shale will be counter-productive to a free, competitive market system and further disadvantage smaller, independent operations which have historically fostered resource exploration and development.

Arguments Against Public Development of Oil Shale

(1) Government operation would not be consistent with the principle of relying on the force of competition and the profit motive to foster and encourage private enterprise to develop ways and means of providing fuel supplies.

(2) Government operation would be counter to the Federal Mineral Lands Leasing Act of 1920 which provides for private development of minerals contained in federal lands.

(3) The private sector is spending and has spent many millions of dollars for research and development of oil shale lands. Government intervention at this point would, in effect, penalize the private initiative.

(4) Private enterprise has demonstrated the ability to form a consortium of companies to develop oil shale lands, thus countering the argument that such projects are too large for any one company.

(5) Mineral development, unlike space exploration and atomic development, is of a commercial nature, dependent primarily upon economics rather than technology. Because of the commerical feasibility of such a project, it should be subject to the competitive forces of private enterprise.

Development of Oil Shale on Private Lands

Although only 28 percent of oil shale reserves are under private ownership, there are some 238,780 acres of such lands held by the major oil companies, 90 percent of which are in Colorado. According to the environmental statement, some three to five of the privately-held tracts contain enough oil shale to support commercial operation. It may be questioned, therefore, why the private lands have not been developed. There appear to be several reasons.

First, because of the major financial commitment (estimated to be at least $800 million for 50,000 barrels per day production), private firms have not found the return on investment sufficient to commence development.

Second, the technical expertise required to develop a new resource such as oil shale is only in the process of refinement. Because of the extensive financial commitment (noted above) and the required technology, private corporations have waited for others to take the lead.

Third, the environmental impact in general has caused corporations to hesitate with regard to oil shale exploration. Generally, the impact on private lands has not been assayed to the extent of the public lands. It is known, however, that certain topographical features, such as high canyon walls, would pose difficulties including area for waste disposal and possibilities of revegetation.

Fourth, oil companies have been very reluctant to commit themselves to production of shale oil due to its requirement of techniques so dissimilar to others of the industry.

The case of Colony Development Operation appeared to be a major exception with regard to private development. Beginning in 1964, a consortium of companies commenced technical and environmental exploration of the feasibility of oil shale development. During this time, more than 100 studies ranging from wildlife impact to pipeline location have been prepared by the group. With the higher price of crude oil, the development of testing of technology, and extensive study of environmental impact, Colony announced plans to commence construction on private lands, but postponed those plans due to economic conditions. Colony was also the successful bidder for tract Cb on federal lands.

One of the reasons cited by Colony for delaying developmental plans was the lack of a national energy policy. Such a national policy might include a federal guarantee of the price of oil from shale, a guarantee of the purchase of such oil, land exchanges or special use permits, and relaxation of environmental standards. It appears that a federal price policy could be a requirement for the development of a commercial oil shale industry in Colorado.

VI. REVENUES FROM THE INDUSTRY

Lease Revenues. In addition to revenues from taxation that will accrue regardless of the location of an oil shale operation, those operations on federal lands under federal leases will generate revenue to governments from bonus bids, rent payments, and royalties on production. The Federal Mineral Leasing Act of 1920 provides that 52.5 percent of these monies are to be credited to the federal reclamation fund and 37.5 percent of all monies received from bonuses, royalties, and rentals shall be paid to the state in which such lands are located. The remainder, along with revenues from naval reserves, are credited as miscellaneous receipts.

With regard to the use of this revenue by the state, the statute provides:

> ...said monies to be used by such State or subdivisions thereof for the construction and maintenance of public roads or for the support of public schools or other public educational institutions, such as the legislature of the State may direct..." (30 USC 191).

The following discussion of state and local revenue is directed exclusively to Colorado. Colorado law, as amended in 1974, provides that all of this revenue received from oil shale leases:

> ...shall be deposited by the state treasurer into a special fund for appropriation by the general assembly to state agencies, school districts, and political subdivisions of the state affected by the development and production of energy resources from oil shale lands, primarily for use by such entities in planning for and providing facilities and services necessitated by such development and productions, and secondarily for other state purposes. (H.B. 1046, 1974 session).

It is apparent that a change in federal law will be required to remove the federal restriction on the use of lease revenue for roads and schools only in order for the state fund to be used for other purposes as determined by the legislature. On February 18, 1974, Colorado Senators Haskell and Dominick introduced a bill in Congress to remove this restriction on oil shale lease monies and allow its use by the state:

...and its subdivisions for planning, construction, and maintenance of public facilities, and provision of public services, as the legislature...may direct." (S 3009, 93d Congress, 2d session).

This amendment passed the Senate several times in 1974, but it did not reach the floor of the House. It is clear that local governments will receive only that money that the legislature is inclined to so appropriate.

Bonus bids. Under the provisions of the federal oil shale leases, development costs may be credited against the fourth and fifth installments of bonus bids. For this reason, only the state's 37.5 percent share of the first three installments is considered to be money that can be anticipated by the state at this time, although it presently appears unlikely that development will occur at a pace which will provide significant offsets against the last two installments. The amount the state will receive in each of the first three years, and possibly five, is $24,607,020. The federal government will retain $41,011,700 each year. It should also be mentioned that the lessees may forfeit the lease during the first three years and in so doing not be liable for the fourth and fifth bonus bid installments.

Royalties. The federal oil shale leases provide for a minimum royalty rate to be paid beginning in the sixth year of the lease and continuing throughout the lease term regardless of whether production is realized or not. The basic royalty rate is 12¢ per ton of shale yielding 30 gallons of shale oil and is adjusted up or down depending upon actual assayed yield of the shale. Development costs not credited against bonus bid payments, but occuring in the first decade of the lease, are deductible from the royalty or minimum royalty, as the case may be. If there is actual production, the minimum amount that is due is $10,000 per lease and this amount may not be offset by development credits. If there are no offsetting development costs, the state's share of the minimum royalty in 1979 would be $78,570 per year and would increase by $78,570 each year until the fifteenth year of the lease when the state's share would be $785,700 for that year and each succeeding year. The federal share of this royalty would be $130,950 for 1979 and increase by that amount each year until 1988 when it would be $1,309,500 for that and each subsequent year. It should be reiterated that this assumes no offsetting development costs. In the event that there are deductible development costs, which is likely if the lessees do develop the land as planned, the royalty might be zero until production occurs and then the minimum $10,000 per lease per year through 1984 of which the state would receive $3,750 and the federal government \$6,250. Probably the actual royalties received will fall somewhere in between these two extremes until the year ten when development costs cease to be credits. Assuming both tracts reach full production by or in 1984, the royalties would be \$7,283,909 and the state's share \$2,731,466 per year with the federal government retaining the rest.

Rent. Rental payments are set statutorily at 50¢ per acre per year and serve as a credit against any royalty payments due. Rent on the Colorado tracts will total \$5,092 per year and the state will get \$1,909 of this amount.

The following table summarizes anticipated state receipts under the lease terms of tracts Ca and Cb in Colorado. It should be emphasized that any revenues beyond those projected for 1976 are far from certain because the leesee's may forfeit their leases at that time and avoid further liabilities.

TABLE 3 -- STATE REVENUES FROM OIL SHALE BONUS BIDS,
RENT, AND ROYALTIES -- TRACTS Ca AND Cb

	BONUS BIDS			ROYALTIES			TOTAL STATE REVENUE	
Year	Bonus Bid Payments	Possible Bonus Bid Payments 1/	RENT*	Minimum 2/	Possible Payments 3/	Production Payments 4/	Minimum	Maximum
1974	$24,607,020		$1,909				$24,608,929	$24,608,929
1975	24,607,020		1,909				24,608,929	24,608,929
1976	24,607,020		1,909				24,608,929	24,608,929
1977		$24,607,020	1,909				1,909	24,608,929
1978		24,607,020	1,909				1,909	24,608,929
1979			1,909	$ 78,570			1,909	78,570
1980			1,909	157,140			1,909	157,140
1981			1,909	235,710			1,909	235,710
1982			1,909	314,280		$ 7,500	1,909	314,280
1983			1,909	392,850		7,500	1,909	392,850
1984			1,909	471,420	$471,420	2,731,466	471,420	2,731,466
1985			1,909	549,990	549,990	2,731,466	549,990	2,731,466
1986			1,909	628,560	628,560	2,731,466	628,560	2,731,466
1987			1,909	707,130	707,130	2,731,466	707,130	2,731,466
1988 et seq.			1,909	785,700	785,700	2,731,466	785,700	2,731,466

1/ Assumes no deductable development costs for first four years of lease.
2/ Assumes neither lease reaches production.
3/ Assumes neither lease reaches production, but that sufficient development costs are incurred by lessees to offset minimum royalties. Allowed only for ten years.
4/ Assumes both tracts reach full production by 1984, are operating in 1982, but have developmental costs that are deducted over the allowed ten year period.

* Rent is an allowed credit against any royalties due.

Federal taxes. Corporations conducting oil shale production on federal or private lands will be subject to the federal income tax. Federal tax law currently provides a depletion allowance for oil shale of 15 percent of the lessee's share of the gross production calculated at the value of the oil after retorting but before upgrading.

State taxes. The Colorado corporate income tax currently has a rate of five percent. Colorado's taxable income allows a depletion allowance which is computed in the same manner as the federal allowance but has an effective rate of 27.5 percent.

Local taxes. Under Colorado law, local subdivisions levy property taxes on the assessed value of all property as determined by county assessors. For most property, the assessed value is equal to 30 percent of the actual value of the property and improvements. Special assessment methods exist, however, for oil and gas production and mining productions. Oil shale production utilizing mining and surface retorting currently would be assessed under the statute governing the assessment of metallic minerals. This section provides that such assessment shall be "...at an amount equal to twenty-five percent of the gross proceeds but if net proceeds shall exceed twenty-five percent of the gross proceeds, then such mine shall be valued for assessment at the amount of such net proceeds.". Retort plants, pipelines, and shale mines would be valued as other improvements, i.e., at 30 percent of actual value. It is likely that the majority of the assessed values from oil shale mines will come from the capital investments for retorts and upgrading facilities rather than mine production. No analysis has been made at this time to determine possible local revenues from the oil shale industry.

The taxation of oil shale production probably would not yield the amount that might be anticipated due to the provision that the assessment be based on minerals as removed from the ground and before any processing. In the case of oil shale, this will mean that the assessed value will be the raw shale before retorting -- a substance that may have a very low value compared with shale oil. A possible solution might be to adopt a similar tact to that of the federal government with regard to depletion allowances, i.e., set the value for taxation at the product value after retorting but before upgrading. This tact, however, would be inconsistent with the valuation of metal ores such as molybdenum. Any shale oil either held in Colorado for sale or shipped out of state for sale would be assessed under Colorado's inventory or freeport law at a rate of five percent of value.

A large portion of oil shale lands are owned by the federal government and, as such, are non-taxable. Much of this federal land, however, has been or will be leased to private concerns and in this instance is taxable under the possessory rights of the lease. This is based on a 1960 Colorado Supreme Court case but statutory clarification of the assessment of oil shale leaseholds may be necessary in order for county assessors to assess these lands.

With regard to non-producing oil shale deposits, Colorado law provides that such lands shall be assessed on the basis of their surface use plus any additional value attributable to the presence of undeveloped oil shale deposits. The value of the oil shale may not exceed the per acre value for the surface use of the tract of land. Due to the poor grazing land overlying oil shale in Colorado, the undeveloped oil shale lands are being assessed at approximately $2 to $3 per acre.

Confusion exists over the assessment of _in situ_ production. _In situ_ is not really a mining operation and is more similar to conventional oil and gas production. If _in situ_ production were to be taxed as conventional oil and gas in Colorado, it would be assessed at 87.5 percent of production -- the highest rate of any ad valorem assessment in the state. In addition, this could decrease state income tax revenues as local taxes are deductible items. It is probable that this situation will require clarification either by the legislature or the courts.

VII. SELECTED IMPACTS OF OIL SHALE DEVELOPMENT

Water

The major water supplies of the tri-state oil shale region are from the Green, White, Yampa, and Colorado Rivers which comprise the Upper Colorado River Basin. This river system receives most of its water from the higher elevations of the Rocky Mountains which are adjacent to and upstream of the oil shale area. The relatively lower elevations of the oil shale area receive from 7 to 24 inches per year of precipitation and most streams are intermittent. Local areas of ground water exist and the wells in these areas generally yield low to moderate quantities of varying quality.

Surface water. The Colorado River Compact of 1922 and the Mexican Water Treaty of 1944 limit the amount of water that can be used consumptively in the tri-state oil shale region from the Colorado River Basin. The Upper Basin States (Colorado, New Mexico, Utah, and Wyoming) have been estimated by the Bureau of Reclamation to have up to 5.8 million acre-feet available for consumption. This estimate for the Upper Basin States represents the calculated total remaining after deducting the Upper Basin's one-half share of the 1.5 million acre feet allocated to Mexico.

The computation is further based on the assumption that approximately 26 million acre-feet of active storage in the upper basin will be available to carry over water from wet years to meet commitments in years of drought. There may not be sufficient water in drought years to meet all requirements and some water shortages may occur.

The Upper Colorado River Basin Compact of 1948 gave Arizona the right to the first 50,000 acre feet per year. Estimates have been made of 1970 water depletion and resources committed for future use. The following table gives a summary of water resources, uses, and the amount that is potentially available for oil shale development in the tri-state region.

There are competing uses for this water, however, including domestic, agricultural, recreation, power generation and other industrial uses. Several factors will affect the final determination of the amount of water available for oil shale development, such as: (1) priority of water right; (2) the amount of water available in tributaries within transportation range of the oil shale region; (3) the nature of decreed water rights; (4) the extent of domestic and agricul-

TABLE 4 -- PRESENT AND FUTURE WATER USE
IN THE UPPER COLORADO RIVER BASIN
(Thousand acre-feet per year)

Use	Colorado	Utah	Wyoming	Total
Allocated share of 5,750,000 acre-feet 1/	2,976	1,322	805	5,103
1970 use.....................	-1,788	- 684	-304	-2,776
Committed future use..........	- 955	- 397	-392	-1,744
Evaporation from storage units	- 342	- 152	- 92	- 586
Credit for water salvage......	+ 121	+ 18	+ 31	+ 170
Not identified as to use......	12	107	48	167
Committed future use that could be made available for oil shale......................	155 2/	---	19 3/	174
Total potential water that could be made available for depletion for oil shale development 4/........	167	107	67	341

1/ Arizona received the right to the consumptive use of the first 50,000 acre-feet per year.

2/ From the existing Green Mountain and Ruedi Reservoirs and the authorized West Divide Project.

3/ From the existing Fontenelle Reservoir - Seeskadee Project.

4/ This includes water not presently identified for a particular use, plus water from authorized projects committed to oil shale development and water from existing reservoirs not presently committed to a particularly use. Additional water can be made available if the States permit the industry to purchase some of the water rights from those presently using water and if the use category is changed from some of the future commitments.

SOURCE: Final Environmental Statement, page II-29.

tural water demands; (5) the relative timing of oil shale development related to other demands; and (6) the availability of water storage to correlate water demands with supply.

Uncommitted water in the upper basin has been overappropriated by conditional decrees, applications, permits, and claims by the federal government. Many of these water rights may never be perfected or proven due to the lack of available water and abandonment of developments for which they were filed.

Several private companies interested in oil shale development have acquired water rights over the years. In Colorado, conditional decrees for 829,000 acre-feet per year were awarded by Colorado District Courts from 1949 to 1968 and filings had been made totaling 274,319 additional acre-feet per year over this same period. In Utah, applications totaling 72,380 acre-feet per year were pending in 1973. If all of these rights are perfected, a total of 1,175,728 acre-feet per year of water would be available for oil shale development in Colorado and Utah, assuming all other rights prior to these can be fulfilled.

Additional water rights have been obtained by private companies through the purchase of oil shale lands and water rights held by the owners of those lands. Although most of this land is being leased back to the ranchers from which it was purchased, and the water is being used for agricultural purposes, a change of use can be obtained to municipal or industrial. Although changes in use or point of diversion must be approved by the district courts, the quantities of water involved in these transactions is thought to be small. Only Union Oil has indicated, at this time, intention to use agricultural rights for their oil shale plant. They state that in their view, oil shale will be the priority use and therefore, during periods of low water supply, some agricultural lands may experience temporary shortages.

<u>Salinity problems</u>. Salinity, the concentration of dissolved solids in the water reported in milligrams per liter (mg/l), is increasing in the Colorado River. The salinity of the water, of course, affects the uses to which the water is amenable and has far reaching economic implications. The average salinity of the Colorado River increases from less than 50 mg/l at the headwaters to 850 mg/l at Imperial Dam, near the United States/Mexico Border. Projections of salinity, if uncontrolled, indicate that the level may reach 1,200 mg/l at Imperial Dam by the year 2000.

For comparative purposes, water with a salinity no more than 500 mg/l is considered acceptable drinking water by the U.S. Public Health Service. Agricultural uses are increasingly affected as levels rise from 500 mg/l to 700 mg/l, primarily by the types of crops that can be grown and reductions in yield. At levels above 1000 mg/l, types of irrigated crops are more limited and above 2000 mg/l only certain crops can be produced using special costly techniques. Other uses are, of course, also affected by increases in salinity with differing impacts at different levels of salinity.

Initial studies indicate that salinity increases will have only small effects in the upper basin, but existing salinity in the lower basin is already significant and could become an even greater problem. Studies of the economic disbenefit have been conducted by the U.S. Environmental Protection Agency using 1960 as the base year. These economic costs were not computed to reflect total costs but rather the incremental costs of rising salinity levels. Adjusted to 1970 dollars, it was estimated that the economic impact of salinity was $9.5 million in 1960 and $15.5 million in 1973. If development of water resources continues as proposed and no salinity controls are imposed, it is estimated that the economic detriments would be: $27.7 million in 1980; and $50.5 million in 2010. If development is limited to projects under construction in 1973, the impact would be $21 million in 1980 and $29 million in 2010.1/

Much research is under way concerning the control and understanding of salinity. A comprehensive ten year water quality improvement program is also under investigation to help control salinity increases in the lower basin. Projected reductions for this program show that the salinity level can be held at 850 mg/l at Imperial Dam using source control, vegetative management, desalting, weather modification and other practices.

In early 1972, the seven basin states agreed in principle to the adoption of qualitative standards to hold the salinity of the Colorado River to the level of April, 1972. Subsequent to this meeting, EPA endorsed the objective. Under the requirements of the Federal Water Pollution Control Act Amendments of 1972, EPA has encouraged the realization of this policy as a water quality control tool and, in November of 1973, wrote a discussion draft of regulations to that end. Under the 1972 Amendments and the regulations, basin states would be required to adopt appropriate mechanisms to enforce the policy or supervisory power would rest with the EPA. Much controversy exists concerning the effect of this policy on water use, some holding that it may preclude any further develop-

1/ Final Environmental Statement, pages II-35-47.

ment of the river's water. The Colorado Water Conservation Board has stated that no further development of the river will be possible without federal aid to reduce existing salinity under the proposed standards.

Ground water. Ground water resources in the oil shale region are not as well known as surface supplies. It is believed that the only significant quantities of ground water occur in the Piceance Creek Basin of Colorado.

The Green River Formation is considered to be the best potential source of ground water in the Piceance Basin in two principal aquifers, one about 200 feet deep and the other no more than 500 feet deep. The lower aquifer may contain as much as 25 million acre-feet in 630 square miles underlying Piceance and Yellow Creeks. The Colorado Water Conservation Board has stated that this estimate is "many times too high" if it was meant to indicate water available for use.

Wells in the Evacuation Creek Member (Colorado) are expected to yield from 484 to 3,226 acre-feet per year. The Green River Formation in Utah may yield 355 acre-feet per year from a well. Wells in the Wyoming oil shale area would probably not produce more than 645 acre-feet per year and more likely would be in the range of 323 acre-feet per year. With the exception of Colorado, these ground water supplies are not expected to play a significant role in the demand of the oil shale industry.

The salinity of the Green River Formation ranges from 250 to 63,000 mg/l, with water in the peripheral half of the basin averaging below 2,000 mg/l and that in the center averaging 25,000 mg/l. Generally, the upper-zone water is of superior quality to the leached zone water, the two being separated by the relatively impermeable mahogany zone of shale.

It is believed that the development of oil shale in Colorado would require dewatering to keep mines dry. The best estimate for water from this source appears to be 22,000 to 29,000 acre feet per year potentially available for use by the plant. However, rates and quality will be high initially, when needed least, and decrease over time as the water table is drawn down in the vicinity of the mine. Such a dewatering operation would actually produce more water than is needed by the plant and the excess would have to be disposed of in some manner. Initially, the high quality water could be discharged to local streams and could dilute the concentration of dissolved solids thereby improving salinity. Over time, as the quality deteriorates, it would be necessary to either desalt the water before discharge or reinject it, the latter option having the disadvantage of raising the level of high salinity waters in the aquifer and possibly increasing the saline discharge where the aquifer meets the surface.

Demand. The water required for the development and processing of oil shale and for associated urban populations has been estimated several times. These early estimates of water consumed by a 1 million barrel per day industry ranged from 61,000 to 145,000 acre feet per year and are set out in more detail below:

Source	Demand, acre-feet per year Adjusted for 1-million-barrel-per-day oil shale industry.
Prien	227,500 diverted, 145,000 consumed
Cameron and Jones	200,000 diverted, 130,000 consumed
Department of the Interior	145,000 diverted, 61,000 to 96,000 consumed

An expanded and more detailed study was done by the Department of the Interior in the preparation of the Environmental Impact statement for the prototype leasing program. This study indicates that between 121,000 and 189,000 acre feet per year would be consumed by a one million barrel per day oil shale industry and associated urban population. The larger estimate is attributed to added water demands for spent shale disposal, revegetation and power. The table which follows delineates expected water requirements for three different mine situations, and for total production of 400,000 and 1 million barrels per day based on the development schedule on page 38.

Shale oil upgrading, processed shale disposal and revegetation, and power plant cooling account for the majority of the water estimated to be required for the industry. A change in the technology of any of these operations would have a significant impact on the water consumption estimates. For example:

Upgrading. If as recently suggested, upgrading proves to be unnecessary in order to obtain adequate flow characteristics for shale oil through pipelines, water consumption would be reduced.

Disposal. The use of a slurry disposal system would increase water requirements for disposal of spent shale, but possibly, would reduce revegetation water needs.

Cooling. Various alternative methods of cooling water used in the production of power for the industry could increase or decrease the estimates accordingly.

TABLE 5

WATER CONSUMED FOR VARIOUS RATES OF SHALE OIL PRODUCTION

	Shale Oil Production (Barrels per day)				
	50,000 Underground	100,000 Surface Mine	50,000 In Situ	400,000 Technology Mix 2/	1,000,000 Technology Mix 2/
PROCESS REQUIREMENTS					
Mining and Crushing	370- 510	730-1,020	---	2,600- 3,600	6,000- 8,000
Retorting	580- 730	1,170-1,460	---	4,100- 5,100	9,000-13,000
Shale Oil Upgrading	1,460-2,190	2,920-4,380	1,460-2,220	11,700-17,500	29,000-44,000
Processed Shale Disposal	2,900-4,400	5,840-8,750	---	20,400,30,900	47,000-70,000
Power Requirements	730-1,020	1,460-2,040	730-1,820	5,800- 9,200	15,000-23,000
Revegetation	0- 700	0- 700	0- 700	0- 4,900	0-12,000
Sanitary Use	20- 50	30- 70	20- 40	200- 300	1,000- 1,000
Subtotal	6,060-9,600	12,150-18,420	2,210-4,780	44,800-71,500	107,000-170,000
ASSOCIATED URBAN					
Domestic Use	670- 910	1,140-1,530	720-840	5,400-6,900	13,000-17,000
Domestic Power	70- 90	110- 150	70- 80	500- 600	1,000- 2,000
Subtotal	740-1,000	1,250-1,680	790-920	5,900-7,500	14,000-19,000
GRAND TOTAL	6,800-10,600	13,400-20,100	3,000-5,700	50,700-79,000	121,000-189,000
AVERAGE VALUE	8,700	16,800	4,400	65,000	155,000

SOURCE: *Final Environmental Statement*, page III-34.

In addition, the development of an ancillary industry to process and recover the associated minerals nahcolite and dawsonite by two plants could increase total water consumption by the industry by one-third. Based on what the Department of Interior calls "contingencies" which were outlined above, high and low estimates of total consumption have been made. The lower range is considered to be in the area of 76,000 to 82,000 acre-feet/year, the most probable range (initially discussed) is from 121,000 to 189,000 acre-feet/year and the upper range is 255,000 to 295,000 acre-feet/year.

The committee received testimony from various groups on the amount of water that they anticipate will be necessary for their operations. Exploration, construction, and production startups will also require substantial amounts of water. The projections, however, should be the maximum need of each oil shale project and include water for dust control, spent shale compaction, and revegetation. Each of the operations is planned for 50,000 Bbl/day shale oil production and their water needs are as follows:

Company	Site	Water Need at Full Production
Colorado		
Colony	Private	8,688 acre-feet/year
Union	Private	8,000
Occidental	Private	Minimal (on-site supply)
Superior	Private	33,873
Rio Blanco Oil Shale	C-a	11,500
Colony	C-b	10,000
Utah		
Phillips/Sun	U-a	8,250
White River Oil Shale	U-b	8,250
Total		88,561 @ 380,000 Bbl shale oil/day

The average water use for a 50,000 Bbl/day plant would be 9,115 acre-feet/year, not including Superior Oil and Occidental because of the special nature of their projects. Occidental's *in situ* process uses essentially no water whereas Superior's three minerals process requires substantially more water than other processes but which can use recycled water to a great extent. A one million barrel per day industry might be projected to require 182,300 acre-feet/year. This is favorably comparable with Interior's upper "most probable" projection.

Rolly Fischer, Secretary-Engineer of the Colorado Water Conservation District, testified that they estimate that a 50,000 Bbl/day plant producing upgraded shale oil will consume 8,000 acre-feet/year of water. He further estimated that a 500,000 Bbl/day industry would therefore require 80,000 acre-feet annually. In addition, an industry of such size was estimated to require 1,000 mega watts of electricty (2 kilowatts/Bbl) -- this would require 27,000 acre-feet of water annually assuming the use of wet stack scrubbers for pollution control. Also, the district estimated that an industry of that size would have an associated population of 40,000 people and that their water requirements would be 10,000 acre-feet each year (1 acre-foot/year for 4 persons). Thus, the total of the district's estimate for a 500,000 Bbl/day oil shale industry would be 117,000 acre-feet/year. A one million Bbl/day industry could be expected to use twice as much, or 234,000 acre-feet/year. This latter estimate is approximately 25 percent greater than Interior's "most probable" estimate but still within their upper range estimate.

The district made a further estimate of the amount of water required for power plants planned or under construction which came to 50,000 acre-feet/year. If it is assumed that the power requirements of the oil shale industry will be in addition to presently planned power facilities, as testimony by Colorado-Ute Electric Association indicated to the committee, this 50,000 acre-feet/year should be added to the oil shale water needs to give a total of the amount of water needed for energy development in the foreseeable future. Therefore, a 500,000 Bbl/day shale oil industry and power plants would use 167,000 acre-feet/year.

The Colorado Water Conservation Board estimated in the spring of 1974 that a one million Bbl/day shale oil industry would consumptively use 200,000 to 250,000 acre-feet/ year. This estimate is comparable to that of the Colorado River Water Conservation District but higher than what might be expected from industry testimony to the committee. It is also higher than the Department of Interior's estimate of most probable use but it is below or within the maximum range of water consumption estimated by Interior.

The U.S. Bureau of Reclamation in September of 1974 estimated that the four federal leases would require 111,000 acre-feet/year at full production (full production would be 500,000 Bbl/day combined). This estimate was a revision of a July estimate by an additional 32,000 acre-feet/year. At one million barrels per day, this estimate would indicate an anticipated consumption of 222,000 acre-feet/year.

Probably the only conclusion that can be drawn from these various estimates is that no one really knows how much water the oil shale industry will require. However, it should be noted that the figures do not drastically contradict one another and some difference may be accountable by different assumptions that were used in the estimates. It would seem that a figure of around 200,000 acre-feet/year for a one million Bbl/day oil shale industry might not be an unreasonable minimum to use at this time. Presumably, as the industry develops, water requirements will be more defined and better estimates will be able to be prepared and carry a greater assurance of reliability.

Demand v. supply. From the Department of Interior's estimate of the maximum probable water needs of the 1 million Bbl/day industry of 189,000 acre-feet per year can be subtracted 10,000 to 40,000 acre-feet per year that are produced by oil shale retorting and upgrading, leaving a maximum probable need of 179,000 acre-feet per year. In addition, ground water that would be obtained in the process of mine dewatering in Colorado would supply 22,000 to 29,000 acre-feet per year for each mine, further reducing demand for surface water supplies. For the purposes of this discussion, it is assumed that 10,000 acre-feet per year savings will be realized from the use of water produced in the process but that water from mine dewatering cannot be credited until more is known about development and location of the industry in Colorado.

The Department of Interior's adjusted estimate that the probable maximum surface water consumption for a 1 million Bbl/day oil shale industry and related urban populations would be 179,000 acre-feet per year compares favorably with the Bureau of Reccamation's estimate of 341,000 acre-feet per year of surface water from the Upper Colorado River Basin potentially available for the industry. The total water potentially available in each state for oil shale development is:

Colorado	167,000 acre-feet per year.
Utah	107,000
Wyoming	67,000

Obviously, if the entire 1 million Bbl/day industry were to locate in Colorado, the maximum estimated demand (179,000 acre-feet/year) would exceed the supply (167,000 acre-feet/year) unless water surplus to compact requirements from other states could be utilized. The distribution of available water may, therefore, have an effect on the areas of oil shale that are developed, or, possibly, the rate of development in any single state.

The Colorado Water Conservation Board has stated that Interior's estimate of uncommitted water available for use in the state is too low. The board has indicated that there is at least 800,000 acre-feet of water available in Colorado annually that is not being used. They note, however, that all of this water is covered by conditional decrees. According to the board, 50,000 acre-feet/year is available from the Colorado-Big Thompson project and 70,000 acre-feet from Ruedi Reservoir at the present time. In addition, the potential West Divide project would provide another 80,000 acre-feet annually. However, the potential Basalt project would utilize about 40,000 acre-feet from the Ruedi surplus. All of this water from storage projects would be in the main stem of the Colorado River, close to private oil shale projects near Grand Valley but not easily utilized by any of the federal leases.

The Water Conservation Board has further stated that the White River produces about 610,000 acre-feet whereas only 50,000 acre-feet are being used annually. It points out, however, that both Utah and the federal government claim substantial portions of the river's water. Also, much of the river's water has been appropriated in other parts of the Colorado River system. The board concluded that little if any uncommitted water is available from the White River. It should be noted that the Yellow Jacket project proposed for the river would provide 71,000 acre-feet/year based on a 1972 feasibility report, however, the board doubts that other Colorado River Basin states would readily assent to construction of the project.

The water board has also stated that of the 800,000 acre-feet currently not being utilized, conditional decrees for seven authorized but not constructed reclamation projects total 450,000 acre-feet. A re-examination of priorities by the state could reallocate portions of these conditional decrees for use by the oil shale industry if so desired.

Another proposal that would increase supplies of water for the oil shale industry would be cloud seeding operations in the Colorado mountains. One estimate indicates that such activity could increase the flow of the Colorado River by 1.3 million acre-feet/year. A problem, however, is the question of who would own that water -- the state, the federal government as operator of the project, or all states in the Colorado River Basin.

Probably the most obvious conclusion that can be drawn from these conflicting estimates of how much water is actually available for energy development in western Colorado is that no one really knows at this point. There are many different views about how much water is in the Colorado River systems, how much of it belongs to the state, and how much of this is still available for use. It would appear that a thorough inventory of the resources of the system is needed in the near future in order for energy development planning to be conducted on a rational basis.

Effect on salinity. Assuming all water for the industry comes from surface sources, the consumptive effect of 189,000 acre-feet/year on the Colorado River system by the development of a one million barrels per day oil shale industry and related urban population is projected by Interior to increase salinity 10 to 15 mg/l at Hoover Dam. Use of the EPA's economic disbenefit computations shows such an increase would have an economic cost of $670,000 to $1 million per year, an increase of 4 to 6 percent over 1970 detriments. If the oil shale industry consumed the entire 341,000 acre-feet per year of available water, salinity increases would be about 27 mg/l at Hoover Dam and the economic penalty about $1.8 million, about a 10 percent increase over 1970 levels.

Committee findings. During the course of its investigations, the committee repeatedly heard from western slope residents that water is a very important and limiting factor in the development of that portion of the state. The committee noted that irrigated "bottom lands" which are used for winter forage production in the area are the limiting factor affecting the use of summer range on the mesas. It was mentioned that the removal of one acre of hay production could eliminate as much as 20 acres of summer pasture from use due to the reduction in winter feed for livestock production. The committee was concerned about this and whether the development of oil shale would take any water from existing agricultural use, thereby, further resulting in changes in the character and economy of the region.

Electric Power Generation for the Oil Shale Industry

Testimony before the committee indicated that power requirements of the oil shale industry may be quite large. The production of shale oil could require as much as three kilowatts (kw) per barrel. Consequently, a 50,000 barrel per day shale oil plant could require 150,000 kw of electricity, or 150 mega watts (mw). A 100,000 barrel per day industry in

Colorado could require new electric generating capacity of 300 mw. For comparison, the Craig, Yampa Project (which is not planned to supply power for oil shale) will have a capacity of 760 mw.

There are several different oil shale processes under development and some of these would produce surplus electric power from by-product low-btu gas through the use of gas turbines. The table below summarizes the information that the committee has received from the industry regarding electric power sources for the various processes:

Process	Source of Power	Power Needs	Users	Surplus
TOSCO	Purchase	2 kw/Bbl	Colony Ca	No
SGR	Purchase	3 kw/Bbl	Union	No
Oxcy *in situ*	On-site Generation	?	Oxcy	100+ mw @ 30,000 Bbl/Day
Paraho	Potential On-site Generation	0.62 Kw/Bbl	Ua Ub Ca	238 mw @ 100,000 Bbl/Day
Superior	Purchase	0.8 kw/Bbl	Superior	No

If the industry develops with this technology mix, there would be five 50,000 Bbl/day plants purchasing power of up to 525 mw. In addition, Occidental would be producing 30,000 Bbl/day and supplying 100+ mw of surplus power that could be used by other concerns in the areas. Three plants might be operating at 50,000 Bbl/day (including two in Utah) using a process amenable to on-site generated power with 357 mw of surplus power that could be utilized by others in the industry. In such a situation, the deficit that would need to be purchased by the oil shale companies from utilities serving the area would be somewhat less than 100 mw. However, if the Occidental commercial test is not successful, the result would be another 100 mw of demand. If the Paraho process is likewise not proven but development of the three lease tracts proceeds utilizing other processes, or without self contained electricity generation, these operations would become power users rather than suppliers, resulting in a demand of 645 mw total, 525 mw for Colorado operations.

Colorado-Ute stated to the committee in August that this amount of power could not be supplied by the utilities to the industry without at least a six-year lead time and firm requirement estimates would be needed. However, the probability that the industry will develop at a rate that would outstrip the provision of power appears in doubt to many observers and the actual power requirements may therefore be significantly below the above figures, low enough that they could be supplied by the utilities with existing and planned capacity, therefore, leaving time for the utilities to undertake additional expansion to meet the needs of the industry as various plants are realized.

The question was raised as to whether or not other oil shale processes could produce their own electric power needs either from retort products or by-products. Industry sources would likely agree that they could produce their own electricity on-site if they wanted to or had to, however, there are several reasons why the industry feels such a course of action would be undesirable.

- Capital costs for a power plant for a 50,000 Bbl/day oil shale complex could be, in 1973 dollars, an additional $30 million. As an example, this would represent over a five percent increase in the capital costs of Colony's Parachute Creek plant (early 1974 figures).

- On-site generation would not be as reliable as purchasing power from a utility with multiple sources of supply.

- The oil industry has little expertise in generating electricity and would prefer to leave it up to the utilities who are experts and, they feel, could produce the power more efficiently.

- At least one oil shale company feels that their product (they have no surplus by-product gas) is too valuable for power generation. For example, at current price levels ($11/Bbl for oil and $35/ton for coal), upgraded shale oil would cost $1.90 per million btu's whereas coal would cost $1.35 per million btu's to generate approximately the same quantity of electricity.

Surface Disturbance of Land

Oil shale development will require land for core drilling, mine development, overburden disposal for a surface mine, storage of low-grade oil shale, surface facilities and plants, and offsite lands for such needs as access roads, waterlines, gas and oil pipelines, power plants, and urban development.

The final decisions that determine which processing options are used by the industry will, of course, effect the total land use. In order of increasing land requirements the three major options would rank as follows: (1) in situ; (2) underground mining; and (3) surface mining with surface disposal and surface processing.

Assuming a development schedule and technology mix reaching one million barrels per day of production by 1985 (page 74), the surface land requirement of the industry would approach 80,000 acres at the end of 30 years. Of this total, approximately 50,000 acres would be required for production, however, the amount of surface area affected at any one time (assuming successful reclamation) would be only about 20,000 acres. After one million barrels of production is reached, a total of 1,200 acres annually is required to maintain this rate. No more than 10,000 acres are projected to be necessary for utility corridors and urban expansion is estimated at 15,000 to 20,000 acres total.

Transportation

The Colorado oil shale area is roughly bounded by state highway 64 to the north, state highway 139, to the west, state highway 13 to the east, and interstate highway 70 to the south (see map on page 104). Several county roads are also located within this area.

State Highways. The "1973 State Highway Sufficiency Rating and Needs Study", prepared by the State Department of Highways in cooperation with the U.S. Department of Transportaion, has evaluated state highway needs through 1993. In that report it is determined that every highway in the state will need resurfacing and many will need widening at an estimated cost of $4,245,190,000. The cost projection for Highway 13, from Rifle to Meeker, is $2,371,000 of which almost half would be for resurfacing. State Highway 64 from the western state border to Meeker is estimated to need $5,100,000 in improvements by 1993. About one-third of that cost is for resurfacing. State Highway 139 runs from I-70 north to Rangely. From the southern border of Rio Blanco County to Rangely it has recently come under state jurisdiction. The cost projection for this highway is $1,114,000, of which almost 80 percent is for resurfacing. The total cost for the three state roads would be $8,585,000 or 0.2 percent of total state needs. Over the projected 20 year period, the annual cost would be $429,250.

Federal Highways. Interstate 70 is the primary east-west route through Colorado and serves as an important link between Denver and points west. Major portions of this highway are not completed, including a controversial route east of Glenwood Springs. The state estimates that I-70 from Silt (seven miles east of Rifle) west to Plateau Creek (approximately 49 miles) will be completed by 1979. With construction of that section, the interstate will be completed from Glenwood Springs to the Utah border.

County roads. Two county roads are of major importance to an oil shale industry in Northwestern Colorado. In Garfield County, the Parachute Creek road runs from Grand Valley north to the Union and Colony sites. In Rio Blanco County the Piceance Creek road runs northwest from Rio Blanco and connects with state highway 64 some 20 miles west of Meeker. This road will serve federal lease site Cb, Superior, and possibly federal lease site Ca. Both county roads will likely need upgrading to service a commercial scale oil shale industry. In addition, some county bridges are presently in need of major repair. In Grand Valley, the bridge over the Colorado River is of doubtful quality for present uses. A similar status relates to a bridge at Rulison, near Rifle. The 1974 road and bridge fund levies for the three counties are: Garfield, 4.00; Mesa, 2.00; and Rio Blanco, 4.00.

Distance to the sites. The table on page 105 indicates the road mileage from existing communities to the proposed oil shale sites. The map on page 106 indicates the location of the Colorado communities.

Figure IV. Location of Federal, State, and County Roads in Colorado Oil Shale Region

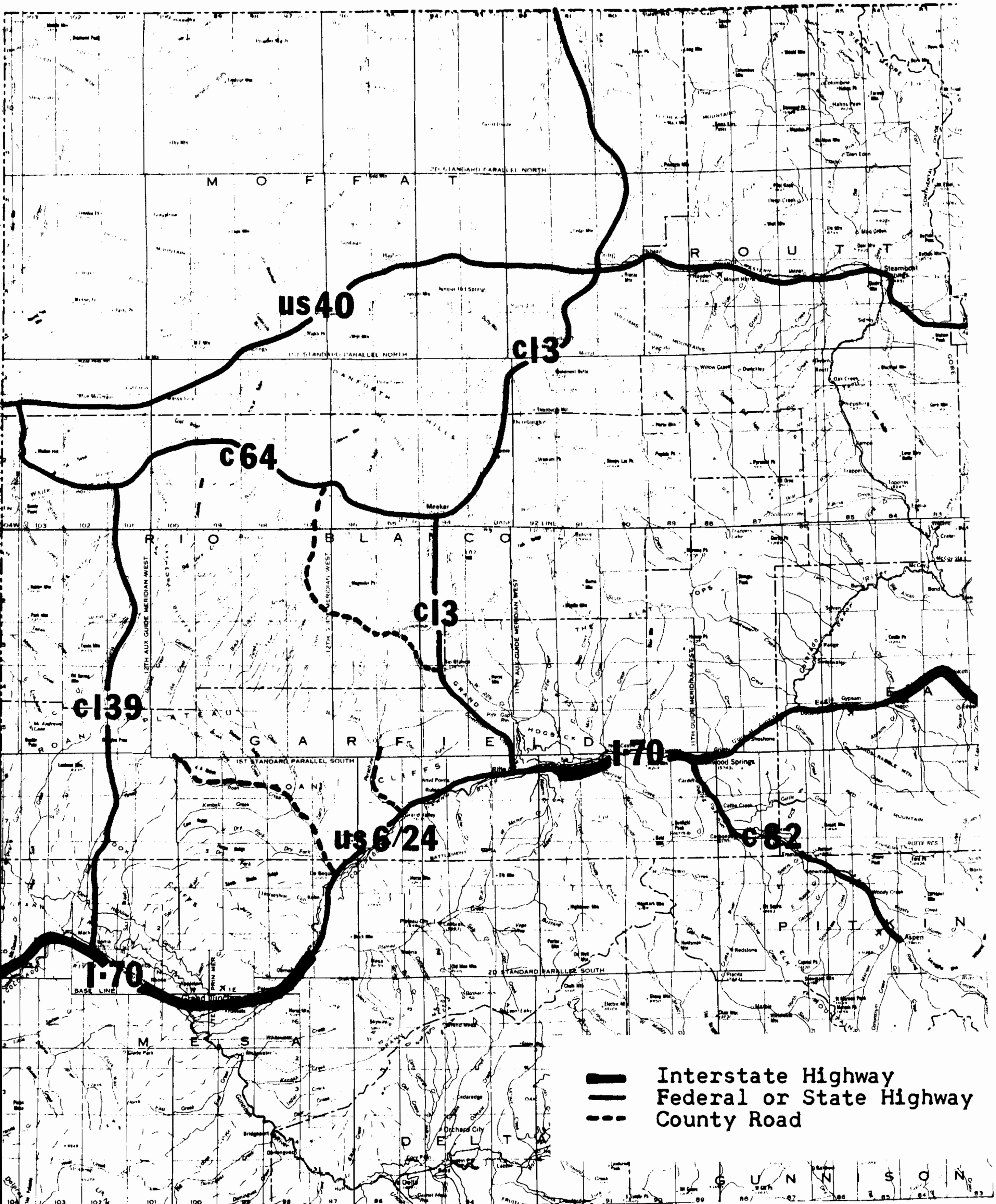


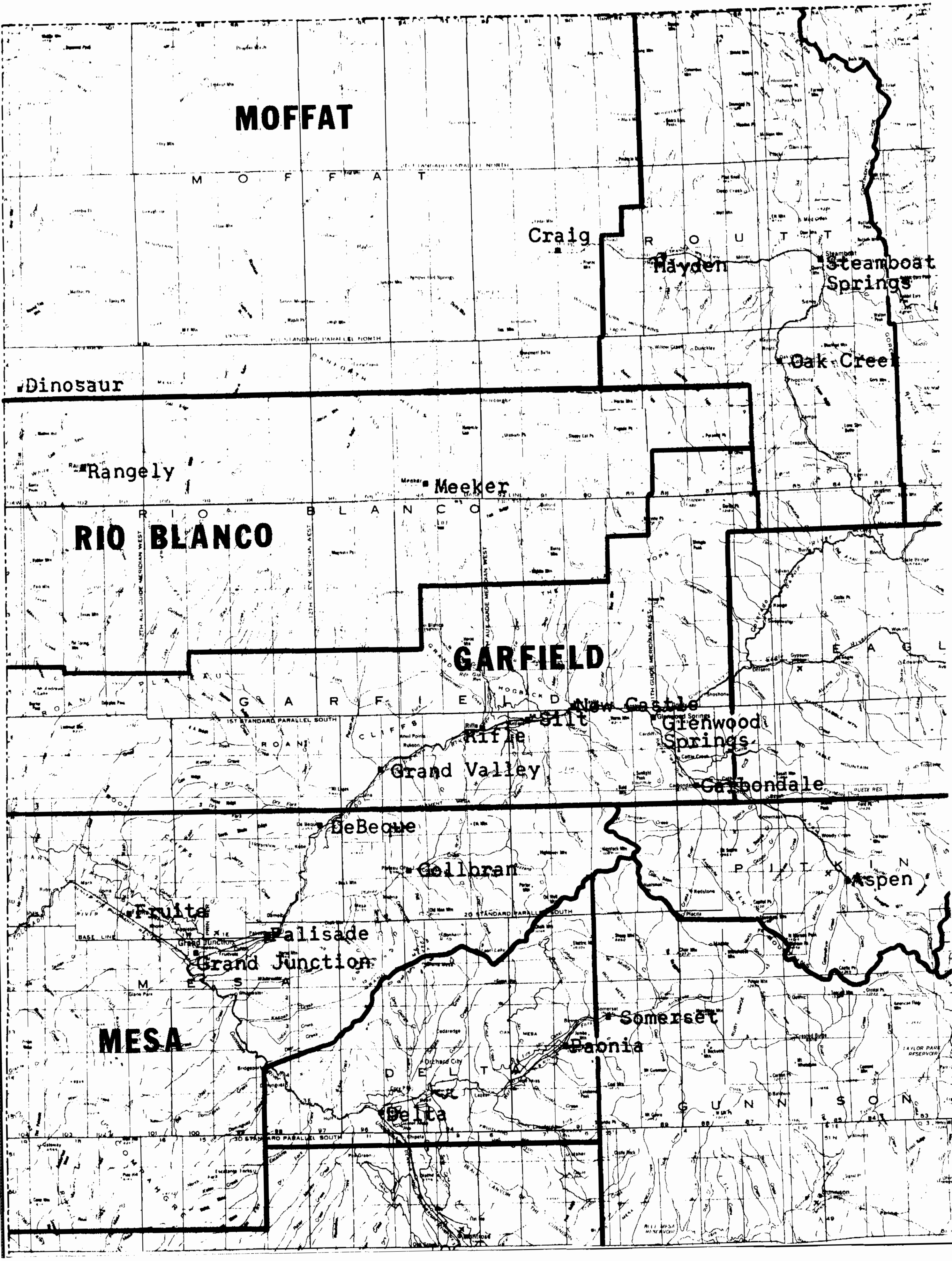
Table 6

DISTANCE TO OIL SHALE SITES FROM EXISTING COMMUNITIES OVER EXISTING ROADS (MILES) 1/

Community	Colony	Union	Garrett	Superior	C-a	C-b	U-a	U-b
Grand Junction	65	57	47	126	126	106	90	90
DeBeque	29	21	11	90	90	70	126	126
Grand Valley	17	9	23	78	78	58	138	138
Rifle	34	26	40	61	61	41	155	155
Silt	41	33	47	68	68	48	162	162
New Castle	48	40	54	75	75	55	169	169
Glenwood Springs	56	48	62	83	83	73	177	177
Carbondale	69	61	75	96	96	76	190	190
Meeker	75	67	81	21	51	44	114	114
Craig	122	114	128	68	98	91	128	128
Rangely	132	124	135	38	42	58	57	57
Bonanza, Ut.	181	173	184	87	91	107	8	8
Vernal, Ut.	183	175	186	89	93	109	46	46

1/ Some access roads are unimproved and, at this time, accessable only on a seasonal basis.

V. Location of Communities in Region 11



Railroads. Northwest Colorado is served by the Denver and Rio Grande Western Railroad with a main line from Denver along the Colorado River. In addition, a spur extends from the main line to Craig. Several oil shale companies have plans or interests for additional or expanded rail service in the area. The plans are as follows:

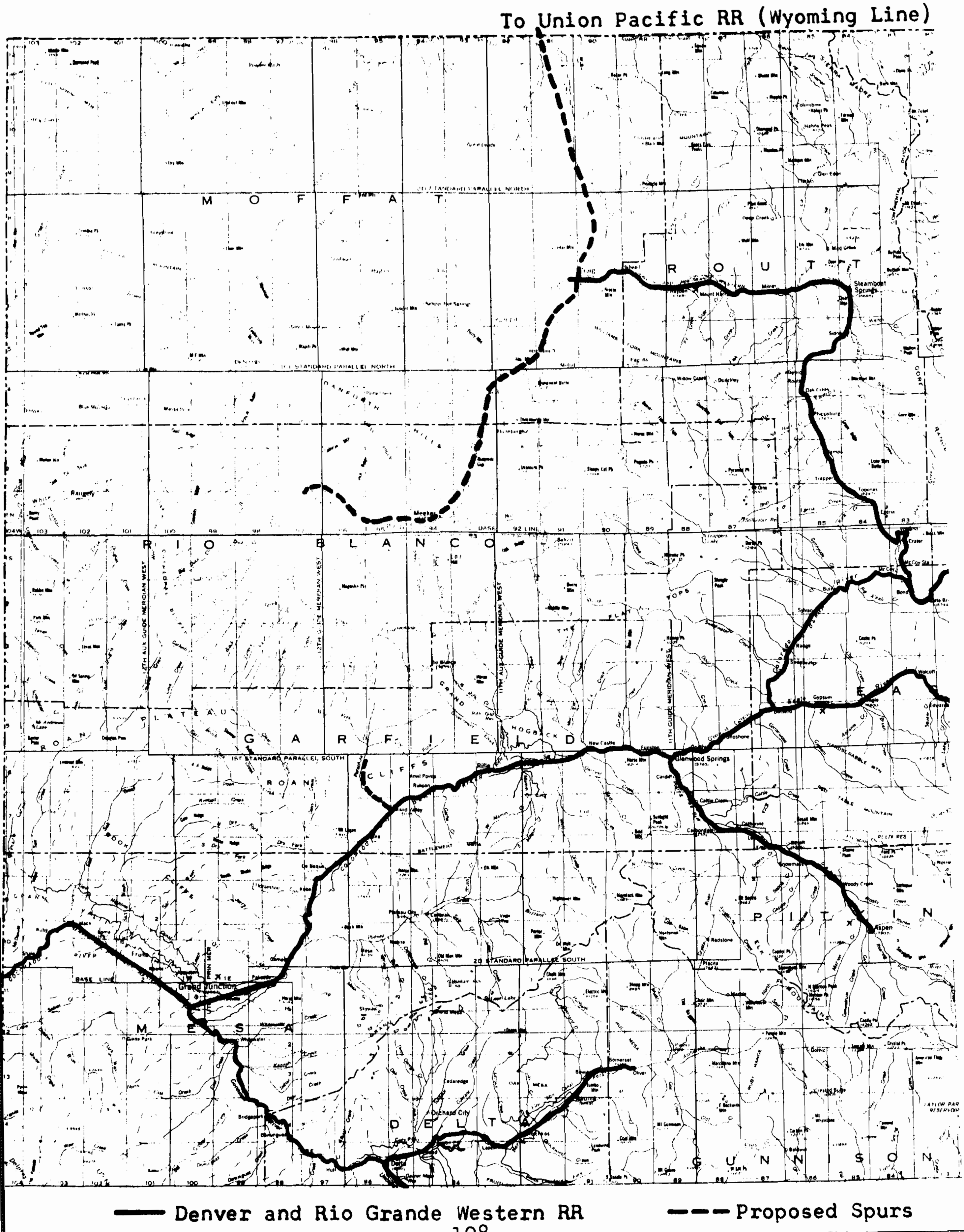
- Union Oil plans a spur from the main line about 7 miles up Parachute Creek to their plant site;

- Colony Development Operation plans a two mile spur from the main line to a staging area just north of Grand Valley on Parachute Creek;

- Superior Oil has stated that they would need a spur to their site from Craig at full production in order to handle nahcolite, alumina, and soda ash; they also mentioned the desirability of a line from Craig north to the high-speed Union Pacific Railroad main line in southern Wyoming.

Also of note, are the plans by Colorado-Ute Electric Association for a spur from Craig about nine miles south to the Yampa Power Plant and Colowyo Coal Company's plan for a spur south to their mine near Axial (W. R. Grace). Another possibility has been advanced by Kemmerer Coal Company for a spur from their proposed strip mine just south of the Wyoming border to the UPRR. Page 108 contains a map showing the location of existing area rail lines and approximate location of proposed spurs.

Figure VI. Location of Existing Rail Lines and Proposed Extensions in Colorado Oil Shale Area



VIII. COAL DEVELOPMENT IN COLORADO

The committee instructed the staff to compile information which would give the committee some indication of the amount of increased coal production that Colorado may experience in the forseeable future. A table is attached which was prepared primarily by the Colorado Geological Survey giving pertinent information on plans for expanded coal activities. In 1973, a total of 6.2 million tons of coal was produced in state from 25 underground and 8 strip mines.

Increased coal production in the state is very speculative -- probably no one knows how much expanded coal production will occur, the only agreement seems to be that it will.

Colorado ranks fourth in bituminous coal reserves, most of it low sulfur and much of it coking quality coal for the steel industry. There are 250-300 billion tons of coal in the state mineable by underground methods and 25-40 billion tons strip mineable. Colorado has more high quality bituminous coal mineable by underground means than Wyoming, Utah, New Mexico, and Montana combined.

About 60 billion tons are under federal ownership with about 6.4 million tons mineable by strip methods. There are currently 113 federal coal leases in the state involving 122,155 acres. Seventeen leases were producing in fiscal 1974 at a rate of 2.5 million tons per year or about 40 percent of the state's production. Applications for 65 more leases are pending which would cover 156,188 acres -- more than all existing leases combined. There are a total of 8.8 million acres of federally owned coal in Colorado.

The State of Colorado owns an unknown but substantial amount of coal, perhaps 50 billion tons or more. Approximately 223,944 acres of state school lands have been leased through fiscal 1974. The production level of state coal lands is approximately 43,112 tons annually, representing less than one percent of total state coal production. It may be of interest that a recent state offer of 20,000 acres resulted in bids for less than half the land and all but 708.9 acres for the minimum price.

The amount of coal in the state under private ownership is not known but could be in the neighborhood of 150-200 billion tons. The huge majority of this is mineable by underground rather than surface methods. Privately owned coal accounts for approximately 60 percent of the state's annual production at this time.

Most of the information available about plans for expanding coal production is sketchy and almost invariably incomplete in some respects. Many operations are merely rumored at this point. Of the 25 potential major coal developments in the state about which something is known, probably less than half can be projected to occur with any degree of certainty. However, if all came to fruition, additional state production of over 25 million tons per year could be projected for the next decade -- approximately five times the level of production in 1973. It is also possible that coal's reemergence as a comparatively cheap energy source and the perfection of gasification and liquification processes could accelerate this projection. Conversely, a price drop in the world oil market and emission problems could dampen the expansion.

Certainly the amount of resource available for development (private or already leased) will not be a constraint on development. Regulating factors for coal development might more likely be manpower availability, equipment availability, and transportation requirements.

Although Colorado is a net coal importer at present, this situation will likely reverse in the future due to the availability of coking quality coal, the limited size of Colorado's steel industry, and the demands of eastern markets for low sulfur coal to meet emission standards. The railroad industry may be likely projected as increasing along with coal production. Another possibility could be the proposed slurry to Texas which could export 9,000,000 tons per year.

Approximately 1,500 miners produced Colorado's 6.2 million tons of coal in 1973. If this ratio were to hold, 30 million annual tons of production in a decade or so would directly employ some 7,250 miners. Using a rough multiplier of 4, this could mean a population of over 29,000 persons. A shift to a greater percentage of underground coal would bring this number up significantly, as might liquification or gasification efforts.

The map on page 111 shows the approximate location of the proposed coal mine openings or expansions in Northwest Colorado. Letter designations on the map correspond to companies listed in Table 7.

Figure VII. Approximate Location of Proposed Coal Mine Openings or Expansion

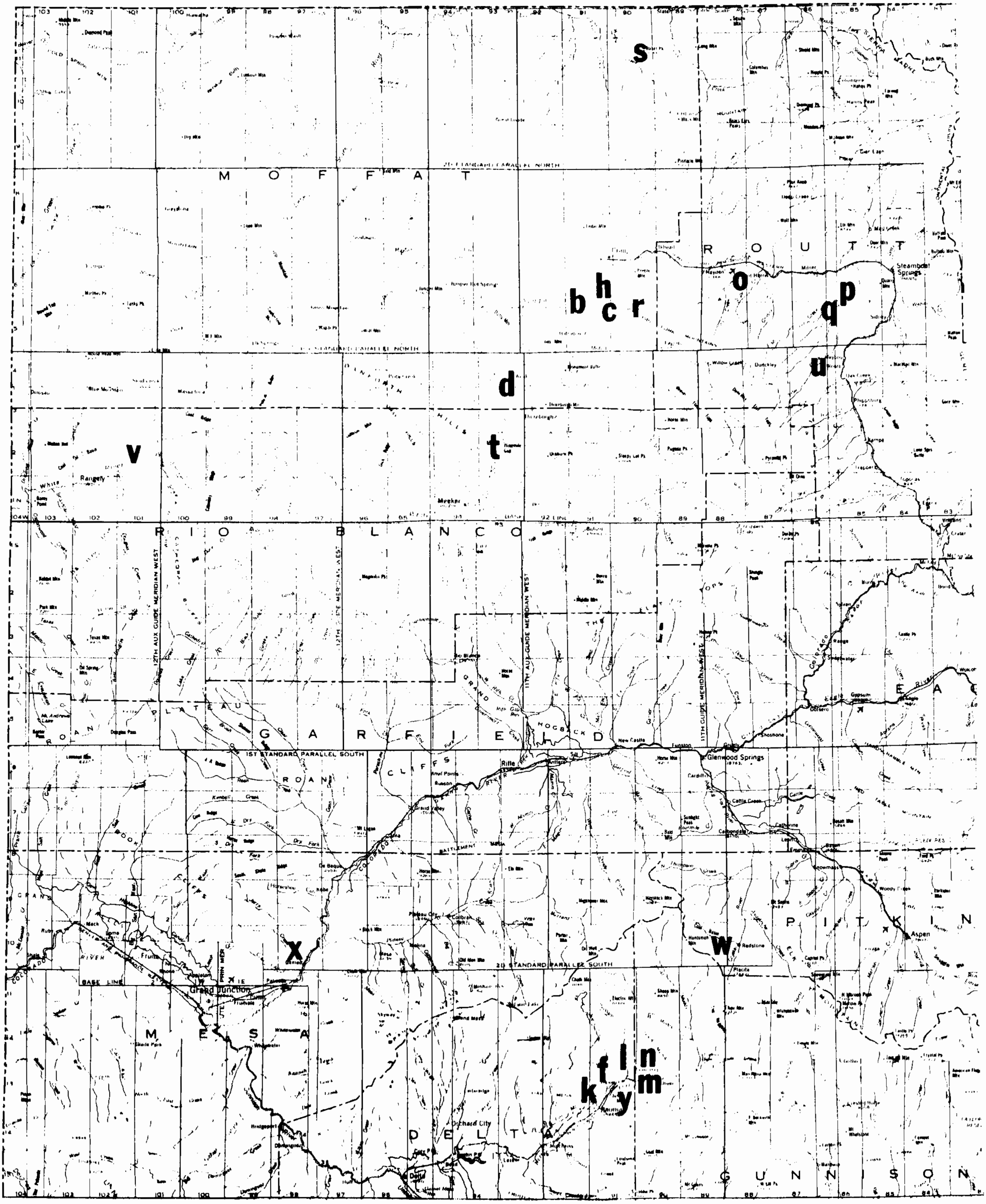


Table 7

PLANNED NEW COAL OPERATIONS OR MAJOR EXPANSIONS OF EXISTING OPERATIONS IN COLORADO
(Over 250,000 tons per year, or ±700 tons per day)

Prepared for Legislative Committee on Oil Shale, Coal, and Related Minerals
Representative Mike Strang, Chairman

Company Name Location of Operation (County, Area, Tp. & Rge.)	Stage of Planning/ Start-up Dates	Size of Operation (Tons/Yr.)	Type of Operation (Strip, etc.)	Disposition/ Use of Coal	Est. No. of Employees	Mined Land Reclamation Permit App'n Received?	Size of Leasehold Area	Miscellaneous Comments
a Kerr & Flesch Jackson Co., North Park (2 mines) T.8N, R.78W.	now beginning to remove over burden. May begin to mine in 1975	est. 548,000 to 1,095,000 ?	strip	ship by UPRR no. into Wyoming	42	Yes	13 ac.	Ralph Flesch & Sons, Inc., Walden, Colo. Open Mining permit waiting receipt of bond; reclamation plan appvd. by Board
b Empire Energy Corp. Moffat Co., Axial Basin Williams Fork area T.5 & 6 N., R.91W.	now in planning stage	~1 million (~2 million by 1978?)	strip & underground	ship by new D&RGRR to Craig	160	Yes	9,000 ac. total for co.	Possible slurry pipeline. Permit not issued.
c Utah International, Inc. Moffat Co., S.W. Craig (Yampa Project of Colo-Ute Electric Assoc'n.) T.5 & 6N., R.90 & 91W.	pre-production activities in 1975; mining in 1977	~2.82 million	strip	Colo.-Ute Craig power plant ("Mine-mouth" use)	~160	No	~6,000 ac.	
d W.R. Grace Co. (Colowyo Coal Co.) Moffat Co., Axial Basin	planning	3 million	strip	ship by new D&RGRR to Craig	159	No	?	
e Adolph Coors Co. Boulder-Weld field	planning		underground	Coors, Golden	?	No	?	No info. released.
f Adolph Coors Co. Bowie mine North Fork area, Grand Mesa	planning		underground (& strip ?)	Coors, Golden	?	No	1,600 ac.	No info. released.
g Canon Coal Fremont Co. Corley S & A	planning expansion	~1 million ?	strip	Drake Power Plant	?	No	?	
h Houston Natural Gas	start-up 1978-80		--					Poss. $300 million slurry pipeline, Craig to Houston 9 million TPY coal, 4,700 ac-ft wtr (saline ?) per yr. (water req. 240 gal/ton of coal) Has option to buy 80% of Empire Energy Corp. holdings in Craig area

	Company Name Location of Operation (County, Area, Tp. & Rge.)	Stage of Planning/ Start-up Dates	Size of Operation (Tons/Yr.)	Type of Operation (Strip, etc.)	Disposition/ Use of Coal	Est. No. of Employees	Mined Land Reclamation Permit App'n Received?	Size of Leasehold Area	Miscellaneous Comments
i	Mintech Corp. Adams Co. Watkins Lignite Project (Cameron Eng., Marathon Oil- poss. UPRR & Amoco, also)	start-up 1980	~8 million	strip	Gasification (mine-mouth)	?	No	25,314 ac. leases requested	Coal gasification, 250 MMCF
j	Kerr-McGee & Arco Watkins area	start-up 1980	?	strip	Gasification ?	?	No	11,823 ac.	
k	Columbine Glass Co. (of Wheat Ridge, Colo.) Paonia, Delta Co. North Fork area	Dec. '74 ?	~2 million	underground	D&RGRR	?	No (?)	?	Proposed to sell Northern Indiana Public Service Co. 2 million TPY
l	U.S. Steel Corp. Gunnison Co. Somerset area (No. Fork)	In operation Poss. Exp.		underground	by rail to Geneva Steel Mill, Provo, Utah				
m	Atlantic Richfield (Arco) Gunnison Co. Somerset area	start-up ~1980 (?); poss. start const. by '78	up to ~2 million	underground	by rail to ?	poss. 600 eventually (400 by 1980)		~11,000 ac. total	Per Fred Scheerer, Arco, 11/13/74
n	Western Slope Carbon Gunnison Co. Hawksnest Mine #3 North Fork area	"near future"	double to 600,000	underground	by rail to CF&I, Pueblo	double to 140		?	
o	Peabody Coal Co. Routt Co. Seneca Mine (second mine)	Oct. '75 (expansion)	850,000	strip	Hayden #2 power plant (Colo-Ute)			4,942 ac.	
p	Morgan Coal Co. Routt Co. (?) S.W. of Steamboat Springs	?	?	strip (?)	?	?			
q	Energy Fuels Corp. Routt Co. Energy #3 Mine T.5N, R.86W. (Secs. 1 & 2)	mining underway	1 mm T/P/Y total Oper.	strip	by D&RG to Denver	?	Yes	± 200 ac. (~129 ac. to be affected)	Open Mining Permit #24 issued 8/28/74

Source of Information: Colorado Division of Mines, U.S. Bureau of Mines, U.S. Bureau of Land Management, local newspaper articles/ compiled by Keith Murray, Colorad Geological Survey, 11/13/74

Company Name Location of Operation (County, Area, Tp. & Rge.)	Stage of Planning/ Start-up Dates	Size of Operation (Tons/Yr.)	Type of Operation (Strip, etc.)	Disposition/ Use of Coal	Est. No. of Employees	Mined Land Reclamation Permit App'n Received?	Size of Leasehold Area	Miscellaneous Comments
r Dravo Corp. Moffat Co.	?	1 million	strip ?	?	115	No	?	
s Kemmerer Coal Moffat Co., Wyo. Border	in process - filing of application for fed. lease	?	?	?	?	?	?	
t Consolidated Coal Moffat Co., Nine Mile	Exploration early 1975							
u Pittsburg-Midway Coal Routt Co., Oak Cr.	Planning expansion		strip					
v Moon Lake REA Rio Blanco Co., Rangely	planning		underground	REA power plant ("mine mouth" use)			?	
w Mid Continent Coal & Coke Pitken Co, Carbondale	Expansion 1975	.6 million	underground (Longwall)	out state Coke Prod.	70	No	?	Would be first use of "longwall" mining method in U.S.
x Public Service Co. Mesa Co., Cameo	new mine being developed	.75 million	underground	Power Plant ("mine mouth" use)				
y Pittsburg-Midway Coal Gunnison, North Fork	exploration							

APPENDIX A

Taxation of Mineral Resources In Colorado

The purpose of this appendix is to explain the existing Colorado state tax structure for mineral resources. It is divided into two parts, the first dealing exclusively with ad valorem taxation, and the second dealing with other state taxes that are particularly relevant to the industry, i.e., taxes that have provisions that in some way specifically and exclusively affect mineral resources production. Each section is introduced by a summary report on provisions of the relevant taxes as they apply generally to all subject taxpayers, including mineral resource concerns, followed by the specifics for various minerals.

Two tables are attached which summarize the information in the memorandum and give information on production values.

Ad Valorem Taxation

Generally

All tangible real property is subject to assessment and property taxation unless specifically exempted by law or the constitution. Most taxable property is assessed at 30 percent of actual value based upon the assessors' determination of actual value through the use of six statutory criteria (six factors):

- Location and desirability;
- Functional use;
- Current replacement cost, new, less depreciation;
- Comparison with other properties of known or recognized value;
- Market value in the ordinary course of trade; and
- Earning or productive capacity.

It should be noted that these six factors are set by law but because the Property Tax Administrator does not have enforcement or supervisory powers the factors are not necessarily used by the assessors. It might also be observed that in the case of mineral resource lands, these factors may have little relation to the actual value of a piece of property (with the exception of "earning or productive capacity" on producing properties).

Reports. The production of mineral resources is required by law or regulation to be reported to the county assessors along with other pertinent information.

Surface rights. Surface rights are assessed separately and are in addition to any assessment for minerals when used for another purpose besides mining.

Leaseholds. Possessory interests are assessable under *Rummel v. Musgrave* (142 Colo. 249).

Severed interests. Severed mineral interests are required by law to be assessed at a minimum of $1 per acre if no market activity exists to aid in the determination of actual value.

Undeveloped minerals. Undeveloped mineral resources are assessed on the same basis as other real property, through the application of the six factors listed above.

Improvements. Surface improvements on mineral bearing lands are assessed separately and are in addition to any assessment for mineral values present or produced.

Equipment. Equipment is assessed separately and in addition to any assessments for mineral resources.

Oil and Gas

Oil and gas leaseholds and lands are valued for assessment at "...an amount equal to eighty-seven and one-half percent of the gross value or selling price of the oil and gas produced, saved, or sold..." from the lease or land during the preceeding calendar year.

"Gross value or selling price" applies at the wellhead. "Produced, saved, or sold" includes any oil and gas pumped back into the ground.

Reports. Reports are required by law to contain production and gross value or selling price information.

Leaseholds. Leaseholds are required by law to be assessed in the same manner as fee interests.

Severed interests. In 1973, the average assessed value of severed oil and gas mineral interests was $1.50 per acre.

Nonproducing. Oil and gas lands which are not producing are assessed at 30 percent using the six factors for other real property to determine actual value.

Coal

Assessment. Coal mines are assessed at 30 percent using the six factors to arrive at actual value.

Reports. Reports describing the amount and value of reserves, stockpiles, and prior year production are required by regulation.

Leaseholds are not specifically required by law to be assessed, but such a policy is recommended by the Property Tax Administrator.

Severed interests. The 1973 average assessment was $1.08 per acre of coal.

Undeveloped. Coal lands which did not produce coal during the previous year are assessed at 30 percent of value on the basis of the six factors previously listed.

Metals (Producing Mines)

Assessment. This class of property includes all mines whose gross proceeds exceeded $5,000 in the preceding year from production of molybdenum, vanadium, uranium, zinc, cadmium, tin, pyrite, beryllium, or other minerals not specifically excluded. 1/ These lands are assessed at 25 percent of gross proceeds or 100 percent of net proceeds for the previous year, whichever is larger.

1/ The distinction between producing and non-producing mines is not precisely the metaliferous v. non-metaliferous quality of the product. Rather, the difference is between those minerals which may be used in substantially the raw conditions as opposed to those which must undergo some sort of processing, e.g. milling, before being in ultimate condition for use. Examples of each would be coal, non-producing, which may be burned in its raw state for fuel, and molybdenum which must be concentrated from the raw ore into a nearly pure product before its use elsewhere in the economy.

"Gross proceeds" is equal to the gross value of the ore immediately after extraction and which may be determined by using the "gross value" less treatment, transportation, and sales costs. "Gross value" is the amount the ore or its products were or could have been sold for. "Net proceeds" equals gross proceeds less all extractive costs.

Reports. Reports required by law must include production, gross values, and costs for the mine for the previous year.

Leaseholds are specifically required by law to be assessed.

Severed mineral interests were assessed at an average of $1.18 per acre in 1973.

Undeveloped. Lands which produce less than $5,000 worth of ore the preceeding year (or none at all) are assessed at 30 percent of actual value as determined through the use of the six factors.

Non-metals (Non-producing Mines)

Assessment. Non-metals include asphaltum, rock, limestone, dolomite, other stone products, sand, gravel, clay, and earths and are assessed at 30 percent of actual value as determined by use of the six factors.

Reports. Production reports are required by regulation to include prior year production, gross sales, costs, and net income, and the amount and value of any reserves.

Leaseholds are not required to be assessed by law but are recommended for assessment by the Property Tax Administrator.

Severed interests in these minerals were assessed at $0.99 per acre average in 1973.

Undeveloped non-metallic mineral resources without production are assessed at 30 percent of actual value, actual value being determined through application of the six factors as for other real property.

Oil Shale

Assessment. Production of shale oil from oil shale is not precisely placed under any statutory assessment method.

Mining retorting operations for the recovery of oil shale are most closely akin to metaliferrous mining from a technical point of view, i.e., the need for processing of the raw ore to get a saleable product. If taxed in this manner as a producing mine, oil shale would be assessed at 25 percent of gross proceeds or 100 percent of net proceeds, whichever would be greater. Gross proceeds would generally correspond to the value of the oil shale as removed from the ground but before crushing, retorting, or upgrading. Because oil shale is not specifically excluded from the producing mines assessment procedure, it can be convincingly argued that it would come under this formula with little opportunity for challenge.

A purely _in situ_ shale oil operation is more similar to conventional oil and gas recovery than other types of operations. If assessed under this formula, the shale oil would be assessed at 87.5 percent of the value of the shale oil as removed from the ground (before upgrading). Occidental's _in situ_ operation is substantially a mining/processing arrangement and would likely be consistent with assessment as a producing mine.

Reports. Regardless of which procedure were used, a report would be required either by law or regulation.

Leaseholds. Under either situation for shale oil assessment leaseholds would be required by law to be assessed. (Note: The federal Oil Shale Lease, Section 20, specifically requires the lessee to pay property taxes lawfully assessed.)

Severed interests. In 1973, no severed mineral interests containing oil shale were reported by assessors.

Undeveloped. Under state law, non-producing oil shale lands and mines are assessed at an amount not greater than the assessment of the land's surface use, an average of $1.83 per acre in 1973.

Other Taxes

Generally

Income. Any individual or corporation engaged in mineral extraction in the state would be liable for Colorado income taxes. This tax is based on the federal income tax with some adjustments to federal adjusted gross income. The rate of the corporate tax is five percent, the individual tax rates graduate from two and one-half to eight percent.

Depletion allowance. Because of the state's reliance on the federal definition of adjusted gross income as the basis for computing the state income tax, depletion allowances granted by the federal government for depleteable natural resources and allowed as deductions in the computation of federal adjusted gross income are also effectively allowed at the state level. There are two methods of computing a depletion allowance and, by federal law, the taxpayer must use the one which results in the largest deduction. The two are:

- Cost depletion, computed as follows:

    1. Total mineral reserves of the property are estimated.

    2. Cost of the property allocable to the resources is computed.

    3. This cost is divided by the total reserves to give cost depletion per unit of reserve (e.g., ton or Bbl).

    4. Cost per unit is multiplied times the total reserves extracted during the tax year which gives the cost depletion deduction.

- Percentage depletion, computed as follows:

    1. Gross income from the property is computed for the year (excluding rents and royalties).

    2. Gross income is multiplied times a statutorily set percent which results in the percentage depletion deduction.

       Note: Percentage depletion deductions cannot exceed 50 percent of the net taxable income as computed without application of the deduction. Percentage depletion deductions are generally larger than cost depletion deductions.

Local property taxes. Under federal law, and hence, state law, payments by the taxpayer for local property taxes are deductible in the computation of adjusted gross income.

Inspection fees. All mining activities and some construction activities are liable for a state inspection fee for safety inspections performed by the Division of Mines. Rates are graduated downward from $15 per employee as the size of the work force increases.

Oil and Gas

Income. Oil and gas production subject to Colorado's income tax would be computed on the basis of a 22 percent depletion allowance deduction.

Production. Oil and gas produced in Colorado is subject to a production tax imposed on income from the production at rates from two to five percent, as follows:

Gross Income	Rate
Under $25,000	2%
$25,000 - $100,000	3%
$100,000 - $300,000	4%
$300,000 and over	5%

Local property taxes paid during the year on oil and gas lands, leaseholds, and royalties (but not improvements) are deductible from production tax liability. The production tax resulted in $693,777 revenue to the state in FY 1973. (It should be remembered that oil and gas is assessed at 87.5 percent of wellhead value or price and that property tax deductions are often larger than the production tax liability, therefore, the low yield.)

Drilling permits. A permit to drill an oil or gas well costs $75. Total revenues for FY 1974 to the state were $82,875.

Conservation tax. Oil and gas production is subject to a conservation tax of one mill per dollar market value at the wellhead. FY 1974 revenues from this source were $217,331.72.

Inspection fees. Drill rig operators are assessed $75 per rig annually to cover safety inspection costs by the Division of Mines.

Coal

Income. Production of coal in this state subject to income taxation would be entitled to a deduction based on a ten percent rate for percentage depletion.

Tonnage tax. Coal produced in Colorado is subject to a tonnage tax of 7/10 of 1¢ per ton for deposit to the Coal Mine Inspection Fund. FY 1974 revenue from this source was $49,563.

License fees. Coal mines must pay a license fee annually depending on production, as follows:

Annual Production	Fee
Less than 500 tons	$10
500-1000 tons	25
over 1000 tons	50

FY 1974 revenues from these fees were $5,630.88.

Reclamation permit fees. Surface mining operations are subject to annual permit fees of $50 plus $15 per acre. Total FY 1974 revenue was $37,140 from these fees. (This total includes revenues not only from coal but also from limestone and sand and gravel quaries. Coal would likely represent around one-half of the total.)

Inspection fees. Coal mine operators are assessed inspection fees on the basis of the full-time employees during the previous year's operations. Total collections from this source were $60,040 in FY 1974. (Note: This sum includes fees from all inspected activities. Since coal mines account for 14.8 percent of the mining industry's employees, it can be projected that their share of revenue would be somewhat less than $9,000.)

Metals

Income. Income taxes on these minerals would be computed on the basis of federal adjusted gross income which would allow deductions based on the following percentage depletion allowances:

Mineral	Percentage Depletion Rate
Uranium	22 percent
Beryllium	"
Cadmium	"
Lead	"
Molybdenum	"
Tin	"
Vanadium	"
Zinc	"

Mineral	Percentage Depletion Rate
Gold	15 percent
Silver	"
Copper	"

Inspection fees. Operators of metal mines would also be subject to inspection fees based on the number of full-time employees. The maximum rate would be $15 per employee.

Non-metals

Income. Non-metallic mineral production in the state subject to income taxation would benefit from depletion allowances at the following rates:

Mineral	Percentage Depletion Rate
Clay	22 percent
Fluorspar	"
Asphalt	14 percent*
Dolomite	"
Feldspar	"
Limestone	"
Rare Earths	"
Perlite	10 percent
Sand	5 percent
Gravel	"
Scoria	"
Some stone	"

Reclamation permits. Reclamation permits at $50 plus $15 per acre annually are required from surface mines producing construction limestone, sand, gravel, and quarry aggregate.

Inspection fees. Annual inspection fees are required of

*If used for rip rap, ballast, roads, rubble, or concrete aggregate, the rate is reduced to five percent.

mine operators. The maximum rate is $15 per employee and graduated downward as work force size increases.

Oil Shale

Income. Oil shale production subject to income taxation would be allowed a depletion deduction. Colorado law sets the rate for percentage depletion at 27.5 percent (federal law is 15 percent).

Inspection fees. Inspection fees for safety inspections by the state Division of Mines would be assessed at a maximum rate of $15 per employee. For a 1,000 worker plant, approximately the size work force contemplated for a 50,000 Bbl/day plant, the fees would come to $5,975.

Table 8

AD VALOREM TAXATION OF MINERAL RESOURCES

Mineral	1972 Production Value	Producing Lands: How Assessed	Producing Lands: 1973 Ave. AV/Acre	Producing Lands: Total AV 1973	Producing Lands: % AV of Production	Non-producing Lands: 1973 Ave. AV/Acre	Non-producing Lands: Total AV 1973
Oil and Gas	$135,064,711	87.5% Well-head Value	N.A.	$ 99,699,175	73.82%	N.A.	$ 1,524,940
Coal	33,734,093	30% Actual Value as Other Real Property	$43.76	406,430	1.20	$42.37	1,021,150
Metals	168,926,296	25% Gross or 100% Net, Whichever is Larger	N.A.	29,140,170	17.25	20.55	9,643,000
Non-Metals	67,827,415	30% Actual Value as Other Real Property	N.A.	1,144,370	1.69	N.A.	70,970
Oil Shale	745,333	?	None	None	None	1.83	654,920
Total	$406,297,848			$130,390,145			$12,914,980

SOURCES: "Summary of Mineral Industry Activities in Colorado" 1973, Division of Mines; "THIRD ANNUAL REPORT" 1973, Division of Property Taxation

Compiled by: Legislative Council staff
November, 1974

N.A. - Not available.

Table 9

OTHER TAXES ON MINERAL RESOURCES

Mineral	1973 Production Value	Income Tax: % Depletion Allowance	Production Taxes: Type	Production Taxes: Rate	Production Taxes: FY 1974 Yield	License, Permit, and Other Fees: Type	License, Permit, and Other Fees: FY 1974 Yield
Oil and Gas	$335,536,225	22%	Production	2-5% well-head value	$693,777	Drilling	$82,875.00
			Conservation	1/10% well-head value	217,332	Safety Inspection ($75 rig)	N.A.
Coal	50,731,909	10%	Tonnage	0.7¢/ton	49,563	License	7,152.00
						Reclamation Permit	N.A.
						Inspection	9,000.00
Metals	159,655,563	Gold, Silver, Copper - 15% Other - 22%	None			Inspection	N.A.
Non-Metals	80,814,689	Clay, Fluorspar -- 22% Asphalt, Dolomite, Feldspar, Limestone - 14% Perlite - 10% Sand, Gravel, Scoria - 5%	None			Sand, Gravel, Limestone: Reclamation	N.A.
						All: Inspection	N.A.
Oil Shale	8,750	27.5%	None			Inspection	N.A.
Total	$626,747,136				$960,672	Drilling Permits	$82,875.00
						Inspection Fees	60,040.00
						License Fees	5,630.88
						Reclamation Permits	37,140.00

APPENDIX B

DRAFT STATEMENT OF NEED, GOAL,
AND OBJECTIVES

TECHNICAL ASSISTANCE PROGRAM

PROPOSAL

Prepared By

Colorado West Area

Council of Governments

August 30, 1974

STATEMENT OF NEED

National interest in the development of natural energy resources in Northwest Colorado, Utah and Wyoming have presented public officials and residents of the region with unprecedented challenges and opportunities as efforts to extract these resources progress. In both public testimony and informal discussion local officials have emphasized the pressing need for additional technical and administrative staff at the county, municipal and regional levels in all areas of planning and growth management. The Colorado West Area Council of Governments is moving to meet this need. However, due to the magnitude of the problem, outside assistance will initially be required. Although the state, the federal government and the industry will all be involved in the planning process, the local governments must have the resources to enable them to take the lead in planning for the future of the region. During these critical early years of energy resource development, it is extremely important that local governments have the technical information and expertise available to them which is necessary to make rational management decisions and to plan for development in a most orderly fashion. Every advantage must be taken of what little lead time does exist. As actual development activity increases, the local tax base will increase and with it the capacity of local governing bodies to meet their own need for technical expertise should occur.

A report entitled Impact Analysis and Development Pattern Related to An Oil Shale Industry prepared by THK Associates, Incorporated in February, 1974 for the Colorado West Area Council of Governments and the Oil Shale Regional Planning Commission recommends an agenda for planning and decision making for the region.

The recommended agenda for year one is as follows:

1. Organize for planning at all levels of government by accomplishing recommended staffing of regional and local planning agencies. Collectively decide how the various levels of planning (regional, county, city) are to relate to each other and the division of responsibility. Establish interregional and state to region relationships. Set priorities to be addressed.

2. Adopt regional goals and regional growth policy as the basis for decisions on development at all levels of government. Interpret for general public consumption and dissemminate widely. The handling of the initial influx of people will probably set future settlement and commuting patterns. The policy should address land use decisions such as dispersed versus concentrated housing, location of settlements and sebsequent commuting patterns, ease or difficulty of providing services, and acquisition of land for open space and other public uses. It may also include pricing policies for public services and utilities and a water policy for allocation to maintain existing environmental amenities, agriculture and tourism as a part of diversification efforts.

3. Stimulate the review by area governments of the adequacy of their land use regulations and public services. Offer assistance in the drafting approaches from community to community. Specifically provide for mobile homes.

4. Solidify information needs for decision making and begin to develop information systems. Adopt a policy that information gathered should lead to better decisions rather than being gathered for its own sake. Make decisions on scale and types of base maps. Investigate availability of aerial photos for region and its communities. Begin the development of a land use classification and mapping

system which shows both urban and rural land uses in some detail. Develop procedures for gathering and quantifying land use.

5. Begin definitive soils mapping and complete as soon as possible. Identify prime agricultural lands and hazard areas. Using this and tentative conclusions from any studies of air pollution potential, determine suitable locations for new growth. Use this as basic information with which to begin the preparation of a regional development, land use, transportation and environmental quality plan based on the adopted regional goals and growth policies.

6. Make preliminary investigation of probable air pollution basins whose location might affect future developmental decisions. Develop an air quality data base to provide information needed later for decisions on plant building permits and subdivision zoning under the complex sources regulation. In year ten with an oil shale population of 78,975, plants and settlements may be dangerous complex sources unless non-polluting transportation is available by then. This suggests beginning to develop data on non-polluting transportation alternatives.

7. Discuss the adequacy of information on domestic water supplies. There has been considerable discussion of water for oil shale development, little on whether the communities of Western Colorado have sufficient domestic water to accommodate projected populations. Determine extent of USGS coverage of this subject in their hydrological study of the Piceance Basin and decide if further investigation is needed. If this merits a special study it ought to be done quickly since water availability may determine future settlement patterns.

8. In view of probable development patterns, initiate regional transportation study

in conjunction with Colorado Division of Highways. If first plants are announced in Parachute Creek area, initiate immediate study into commuting alternatives between Grand Valley and Parachute Creek to assure compliance with state air quality standards and be compatible with a future transportation system.

9. Given the prospective competion for different uses of this land, planning should begin for the Rifle airport development: capacity, landing fees to cover operating costs, and compatibility with surrounding residential and commercial development. Coordinate with State Airport Study.

10. Make decision on the first oil shale plant building permit under the complex sources regulation (in conjunction with the Colorado Air Pollution Control Commission).

11. Determine institutional means of financing housing in addition to the conventional sources, e.g., a housing authority with revenue sharing or other public funds, oil companies supplying front end money for construction, or a non-profit housing corporation with varied industrial and public support, etc.

12. Determine location and zone for 2,000 units of housing (both mobile home and permanent) which will be required by year three. Communities or areas affected will depend on plant locations.

13. Begin trunk utility construction to planned housing areas.

The Technical Assistance Program will address itself to many of the agenda items, specifically all or portions of Items 1, 2, 3, 4, 7, 8, 11 and 12.

GOAL OF THE PROGRAM

The goal of the program is to establish the capacity of local governments in an area of energy-related resources development to effectively plan and implement municipal expansion required for resource development and to facilitate a rational regional approach to the management of the short and long range impacts of this development.

OBJECTIVES OF THE PROGRAM

The objectives of the program are as follows:

A. Provision of expertise in the form of additional manpower at the local and regional levels of government to insure a professional level of in-house staff assistance for locally elected officials in the decision-making processes in their efforts to effectively plan and manage the socio-economic impacts of energy development.

B. Development of a regional growth management information system to provide objective data for rational planning and management decision making to locally elected officials.

C. Development of special specific technical studies to provide necessary technical guidance to local units of government in their efforts to make logical, sound short and long range development decisions.

APPENDIX C

TAX LEAD TIME STUDY
FOR
THE OIL SHALE REGION

Conclusions and Recommendations

The time for local governments in the oil shale region to prepare specific inventories, budget analysis, policies and strategies for their implementation is now. Once the individual governments have established their policies and goals, they should compare them with those of other governments in the region and resolve any conflicts. Strength in dealing with the lead time problem, whether with industry or state and federal governments, lies in the region acting as a unit.

INTRODUCTION

In compiling the potential fiscal problems and the alternatives available to local governments to deal with them, we have reached a number of conclusions for financial strategies and actions. Since solutions to the tax lead time problem will greatly influence the achievement of community and regional goals for many years to come, strategies need to be localized to meet the specific needs of each city, county, and school district in the oil shale region. It is not within the scope of this study to accumulate and analyze this type of data, but it is essential that those steps be taken on the local level and that in-depth discussions be held with local leaders to set needs, actions, and priorities for the communities involved. Lacking this detailed data, the recommendations of this report reflect general needs and opportunities in the region which will bear on all governmental units.

As stressed throughout this report, the major revenue concerns of local government are having sufficient funds available in the early stages of new development with equitable distribution of those funds to areas impacted most heavily by that development. Fiscal policy and management decisions should seek responsive, efficient actions related to revenue flow. The degree of success in interrelating fiscal policy with land use development policy and operational management decisions will determine overall costs and operational efficiency. The success of fiscal strategies in achieving short- and long-range goals will be greatly affected by the degree of participation by citizens, industry, and governmental agencies in the decision-making process. This participation should be actively sought.

In developing fiscal policy for local government, officials should weigh their decisions against the information contained in this report, bearing in mind that this study, by necessity, utilizes a number of assumptions which may not hold true over an extended period of time since the near term projections of oil shale industry development may not be realized and technology, economics, environmental constraints, national policy, and world politics weigh heavily on this as yet commercially unproven industry. The duration of the industry, once developed, is another question that must be considered. Development delay will not affect the scope of the task of local governments; it will simply give them more time to prepare a course of action.

GOALS AND OBJECTIVES

As a result of this study, we, as consultants, feel that the following goals and objectives should be accorded highest priority in developing fiscal action programs in the oil shale region:

1. Communities should predetermine the manner in which they wish to develop, giving appropriate weight to quality, location, and phasing of development as well as efficiency in providing public services.
2. Adequate public facilities and services must be provided when and where needed at minimal cost.
3. Cost of providing public facilities and services should be equitably shared among present residents, new residents, industry, energy consumers, and state and federal governments with each community determining its own concept of equity in this regard.
4. A diversified tax base should be established or preserved in order to avoid long-term dependence upon a single industry for revenues in the region.
5. Local control of government and public decision-making on local issues should be maintained, especially with regard to revenue and expenditure decisions.

PRIORITIES OF ACTION

The following actions are recommended for local governments and school districts in the region:

1. The highest continuing priority for action is the strengthening of collective efforts of all governmental entities in the region acting as a single unit when dealing with industry and state and federal governments.
2. Each local government and school district should inventory its facilities according to the following: size, specifications, quality, and expansion requirements. A detailed base information system collected and kept current in a uniform manner is not only essential to good planning practices, but will minimize delays when it comes time for action.
3. Each local government should develop community goals and policies with regard to desired development patterns, then review them on a regional basis with other local governments to avoid conflicts and alleviate concerns.

4. The local government should then develop generalized plans indicating where such development should occur, then measure the plans against the ability to provide public services to these areas and the regional affect such development might have. These plans would then be submitted for review by all concerned governments in the region.

5. As a representative of all of its members, the Colorado West Area Council of Governments should develop a monitoring system which would systematically record the type, location, and extent of all new development and redevelopment in the region. These figures would provide a base for checking the projections and signalling points in time when public actions will become necessary to keep pace with growth.

6. The Colorado West Area Council of Governments should develop seminars with its members to discuss various social, physical, economic, environmental, and governmental issues facing the region, thereby increasing awareness of the decisions which will have to be faced by administrators and legislative bodies.

7. Each local government should establish fiscal management strategies and measure them against their effect on the region as a whole. Each local government should decided if a pay-as-you-go philosophy is to be used or phased into and take the necessary steps to implement such a philosophy.

8. Each local government should analyze its budget and make five-year revenue/expenditure projections to know precisely what the trends are and what the sensitivity of each item is to growth impact.

9. As a result of the above procedures, each local government should use its accumulated data base, its goals and objectives, and its comprehensive plan to develop a five-year capital improvements program.

10. Through the Colorado West Area Council of Governments, local governments should act in concert to analyze and prepare ideas for desired state legislation, discuss them with area legislators, and present them to the Strang and Dittemore legislative committees prior to January 1, 1975.

SPECIFIC RECOMMENDATIONS

School Districts

Because of the special revenue sources and laws pertaining to school districts, they are treated here as an independent funding problem. The following recommendations should aid school districts in meeting the lead time requirements and in achieving the recommended goals and objectives.[1]

1. Temporary facilities, leased or purchased, should be used to meet immediate classroom needs. This would permit a quick response with minimum investment in the location of greatest demand. It would also allow for a permanent settlement pattern to develop before capital funds are committed to new permanent facilities.

2. Local land use regulations should require that new developments dedicate land or pay fees in lieu thereof for public facilities, including schools. School districts should encourage city and county governments to make such amendments to their regulations.

3. Where permanent housing is proposed, including new towns, school sites should be designated and dedicated before plan approval is given by the local government. Such a requirement should be based on land area and location determinations by the school district. Districts should maintain continuous input with city and county planning efforts and not wait until plans are formulated.

4. Joint taxing districts or a consolidated school district for limited purposes should be considered. Individual school districts would retain responsibility for curriculum, personnel, textbooks, innovations, and administration; but purchasing, taxing, and specialized personnel would be shared by contract under the Intergovernmental Relations Act.

5. Amendment of the 1973 School Finance Act should be sought immediately to allow some form of periodic rather than annual reporting of enrollment. This would make state funds more readily available for rapid growth areas. School boards should work with their state representatives in seeking this amendment.

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[1] These suggestions were identified for the Bureau of Educational Field Services of the University of Colorado as they developed their <u>Oil Shale Impact Study</u> for the Colorado Department of Education.

6. Federal impact funds under Public Law 81-814 and 81-815 should be sought as soon as impact begins.

7. A State Building Authority similar to California or New York authorities should be considered as a mechanism to lower bond interest rates over those available to local districts. (The Colorado Housing Finance Authority has set a precedent in this area.) Local requests to the state legislature for such considerations will be necessary. Support from other agencies such as the Municipal League and County Commissioners Association should be sought.

8. School bond guarantees under the School Bond Guarantee Loan Program (H.B. 1035, 1974) should be used by the school districts whenever bonds are used.

9. School districts should seek legislative authority to lease equipment for more than one year.

Cities and Counties

Revenue Sources

Our review of revenue sources indicates that, with the exception of federal and state funds in the form of grants or loans, there are no sources immediately available in sufficient magnitude to meet rapid growth needs. Such intergovernmental funds are being sought now and this effort should continue. The problem for local governments, if additional funds prove necessary, is how to safely borrow from anticipated revenues or build facilities with minimal local government financing. The following recommendations, either singly or in combination, may assist local governments in meeting the needs of the oil shale region:

1. Bonding (Borrowing):

   a. Commitments to long-term debt should be made only after careful consideration of alternative financing methods and only after the issuing city, county, or district is satisfied that the risks involved are appropriate in light of its ability to repay the debt; its right to bear the obligation to underwrite the risks; its ability to finance the continuing operation of the facility or service financed; and the impact on other government finances as a result of the project.

b. Local governments should work together on a regional basis to obtain industrial or federal or state guarantee of debt payment to assure an equitable distribution of the risks involved in financing based on repayment from oil shale associated development and, in particular, to assure against bankruptcy if the anticipated tax revenue is not realized. Without such guarantees, local government should wait for the growth to occur before borrowing--if at all possible.

c. Local governments should consult a fiscal advisor immediately upon consideration of debt financing to assure that all alternatives are considered and the one selected is the one that best serves local needs.

d. Early bond issues should be structured to allow early refunding.

e. Bonding should not be undertaken until a capital improvements program has been established with total costs, both operating and capital, and revenue producing potential of all projects identified.

f. General obligation bonds should be avoided when revenue producing projects are being considered.

g. Industrial revenue bonds and non-profit corporation financing should be considered as debt financing methods to reduce the risk to local governments.

h. Bond insurance should be considered a necessity for any issue backed solely by local government.

2. Cities and counties should consider lease or use installment purchase of facilities to avoid capital expenditures when such an approach is consistent with fiscal policy.

3. Cities and counties should assure that they are charged rates that reflect tax exempt borrowing for construction of capital facilities that they will lease from private companies.

4. Non-profit corporations, special districts, as well as industry, may provide some necessary facilities and services. However, creation of numerous quasi-governmental units should be avoided. "Self-destruct" clauses

requiring quasi-governmental units to phase into general purpose government should be mandatory for all new units seeking approval from the county commissioners.

Distribution

Geographic imbalance of anticipated tax revenues and population impact is clearly a problem for the oil shale region. Two of the following recommendations have been authorized by state legislation; the other two would probably require enabling legislation. We recommend that the local government in the region develop a system for county collected-city shared property taxes before it becomes necessary for the state to step in and collect taxes for local redistribution.

1. A regional service authority (RSA) may be the most comprehensive answer to the regional problems arising from oil shale development. Schools are not addressed in the RSA approach, but legislation could change the existing enabling legislation to include them. Local governments should consider, collectively, the appropriatness and desirability of suggesting an RSA to the local electorate.

2. Intergovernmental agreements are used in the area at present. A single taxing district could be established on a regional basis with funds redistributed to participating governments. The enabling legislation for such contracts provides that participation is voluntary which may cause some problems on a regional basis. To be most effective, such an agreement should be multi-county, encompassing all governmental entities.

3. A third voluntary alternative would be that the counties would levy property taxes as usual, but the revenues would be returned to all local governments and school districts in proportion to population impact, not just assessed valuation.

4. A regional revenue distribution method similar to that used in the Minneapolis-St. Paul region would require enabling legislation, but would make property tax sharing mandatory among all levels of local government based on statutory criteria related to population impact and need.

5. If local efforts to achieve equitable distribution fail, the state should

consider collecting property taxes from the region and redistributing them to local governments of the region based on population impact and need.

Management

1. Management techniques for capital improvement programming should be established quickly to meet the anticipated impact of oil shale development.

2. Management decisions should be based on a comprehensive fiscal policy related to achievement of community goals.

3. Management decisions should be directed toward making facilities and services financially self-perpetuating.

4. The real cost of expanding public systems should be determined and assessed to each new user consistent with community goals.

5. Management decisions should relate to maintaining and expanding the existing economic base and avoiding dependence upon one industry.

SUMMARY RECOMMENDATIONS

Local efforts to prepare for the expected impact of oil shale development have been started and should be continued. The wisest investment for the area, even if oil shale development does not materialize, is to use currently available planning monies for inventorying public facilities, reviewing budgets, analyzing management decisions, and developing comprehensive plans. Energy development is far broader than just oil shale and this region is one of the prime storehouses of the nation's energy resources. Therefore, this effort will benefit the region regardless of when, why, or how growth occurs.

It is essential that the citizens of the area be kept informed and involved in governmental planning activities. When time for action comes, there will be informed discussion without the loss of time involved in educating the electorate. Also, the multiplicity of private and public interests must be dealt with and should be kept involved throughout the planning and implementation processes. These special interest groups are not going to change.