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IMPACTS OF SYNTHETIC LIQUID FUEL DEVELOPMENT-
Automotive Market
Volume II

Interagency
Energy-Environment
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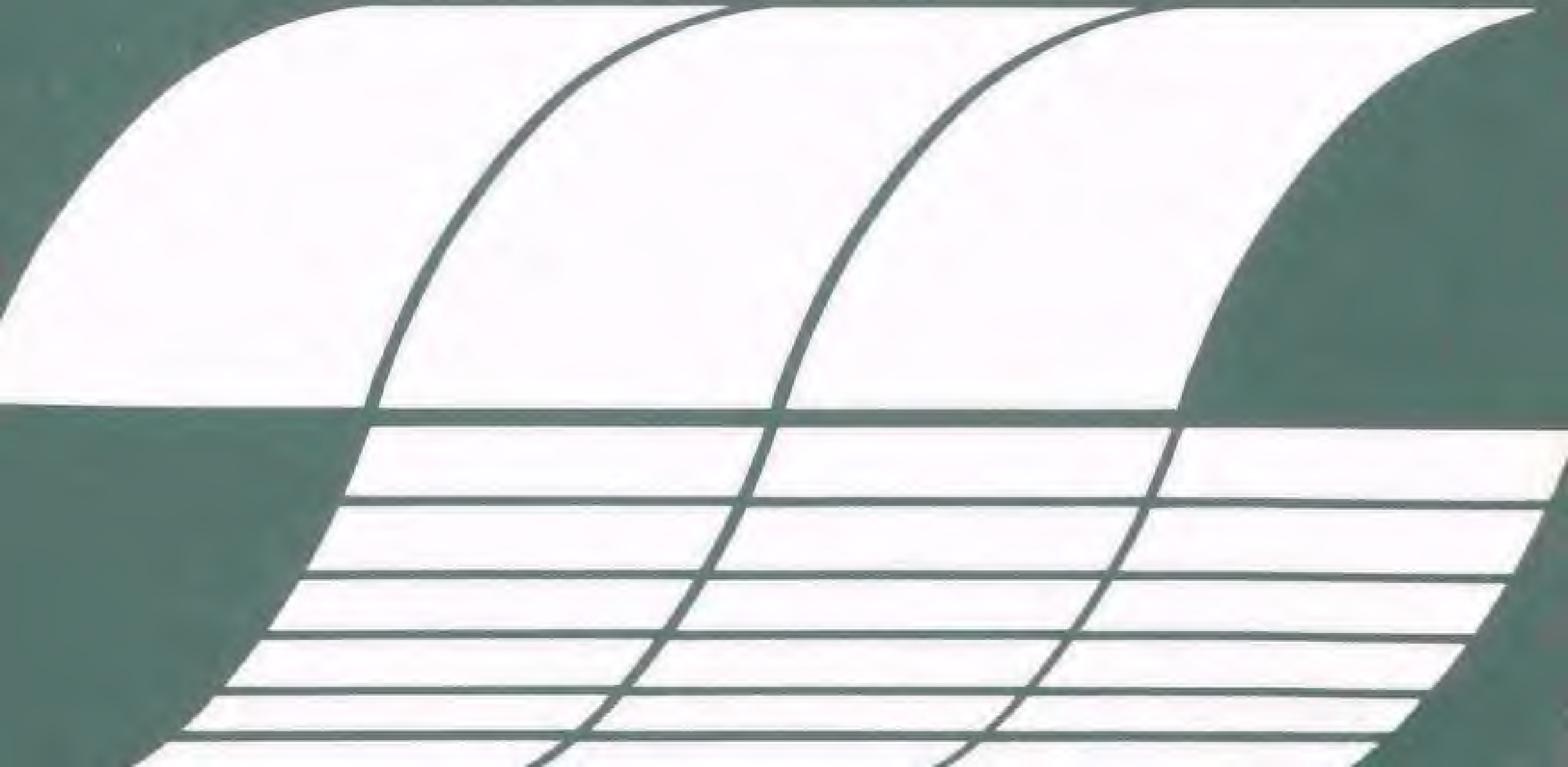
Program Report



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IMPACTS OF SYNTHETIC LIQUID FUEL DEVELOPMENT

Automotive Market

Volume II

by

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1--PROLOGUE TO VOLUME II

A. Introduction

This study has its roots in the realization that historical growth in automotive* fuel demand cannot be sustained, especially if the U.S. intends to become increasingly self-reliant in energy. Unless fundamental reduction occurs in the demand for available fuels, the United States will be unable to satisfy all of its requirements for petroleum products. Since automotive vehicles consume about 46 percent of all petroleum used in this country, the future vitality of the automotive sector is at stake.

There are several approaches to satisfying desires for energy in general and petroleum products in particular:

- Conserve.
- Step-up domestic oil (and gas) production by increasing activity in new areas.
- Import crude oil and refined products.
- Develop synthetic liquid fuels based on abundant domestic coal and oil shale resources.

The last option is the focus of this study.

Two previous studies,† commissioned by the Alternative Automotive Power Systems Division of the U.S. Environmental Protection Agency,

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*Cars, trucks, and buses.

†Kant, F., et al., "Feasibility Study of Alternative Fuels for Automotive Transportation," Environmental Protection Agency, Report EPA-460/3-74-009 (June 1974).

Pangborn, J., et al., "Feasibility Study of Alternative Fuels for Automotive Transportation," Environmental Protection Agency, Report EPA-460/3-74-012 (July 1974).

explored the economic and technical feasibility of a wide range of candidate synthetic automotive fuels ranging from hydrogen through methanol to gasoline. Various sources and production systems were considered. Both studies concluded that the leading candidates for automotive fuel for the future (1980 and beyond) were

- Coal-derived
  - Gasoline
  - Distillates
  - Methanol
- Oil shale-derived
  - Gasoline
  - Distillates.

B. Objectives

The basic objective of this study is to determine the feasibility of alternative automotive fuels production in a broader context--one that includes the environmental, societal, and institutional ramifications of synthetic fuels development. To provide a frame of reference in which to view these consequences, the environmental impacts of stepped-up domestic production and oil imports are also described. Both futures are based on the presumption that energy use growth rates are slackening as a result of increased conservation.

To achieve the basic objective, several general goals were set:

- Determine the impacts of a major deployment of synthetic liquid fuels technology
- Prepare a scenario of the maximum possible rate of deployment
- Identify the critical impacts that might decide the question of deployment, prove intolerable unless mitigated, or prove not to be amenable to mitigation

- Identify governmental policies that might lessen or avoid adverse impacts or enhance prospects for deployment of synthetic fuels capability
- Develop criteria on which to base comparison of alternative synthetic fuels options.

C. Study Approach

The study was organized as a technology impact assessment. The study core team consisted of a group of professionals with expertise in chemistry, physics, economics, sociology, and law. For supplemental expertise, the team drew on professionals in chemical engineering, meteorology, and biology. The team received inputs from experts at SRI, the staff of two coordinate contractors (Exxon Research and Engineering and The Institute of Gas Technology), industry, universities, and stakeholder groups. The EPA project officers maintained a close working liaison with the team and participated in a major observation trip in the field and many working sessions.

To facilitate the sharing of information within the team and review by outside parties, intermediate findings were put in the form of working papers. These working papers were revised to reflect subsequent findings, improvements in information, criticism from reviewers, and stakeholder inputs, and in their form revised the backbone chapters of Volume II.

The chapters are the following:

2. Automotive Fuel Supply and Demand Forecasts
3. Reference Supply Case
4. Synthetic Liquid Fuels: The Technology, Resource Requirements, and Pollutant Emissions
5. Net Energy Analysis of Synthetic Liquid Fuels Production

6. Maximum Credible Implementation Scenario for Synthetic Liquid Fuels from Coal and Oil Shale

7. Legal Mechanisms for Access to Coal and Oil Shale

8. Financing the Synthetic Liquid Fuels Industry by the U.S. Capital Markets

9. Market Penetration of Synthetic Liquid Fuels--The Key Role of the Decision-Making Process Leading to Deployment

10. Government Policies to Encourage the Production of Synthetic Liquid Fuels

11. National Economic Impacts of the Synthetic Fuels Industry

12. Economic Impacts in Resource Development Regions

13. Comparative Environmental Inputs of Coal Strip Mining

14. Oil Shale Mining and Spent Shale Disposal

15. Region Specific Biological Inputs of Resource Development

16. Air Pollution Control for Synthetic Liquid Fuel Plants

17. Secondary Environmental Inputs from Urbanization

18. Health Issues in Synthetic Liquid Fuels Development

19. Water Availability in the Western United States

20. Water Availability in the Eastern United States

21. The Impact of Industrial Growth on Rural Society

22. Population Growth Constrained Synthetic Liquid Fuel Implementation Scenarios

23. Comparative Inputs of Controlled and Uncontrolled Urbanization

The following paragraphs describe the relationship of each chapter to the study as a whole.

D. Basic Information

The study required certain basic information as inputs to other analyses: (The relevant chapters are indicated by the number in parentheses.)

- Domestic automotive fuel demand and supply projections from 1975 to 2000 within a consistent total energy balance for the United States. (2)
- Projections of the (geographical) sources of future conventional domestic oil supplies to serve as the basis for the reference impact case. (3)
- Descriptions of synthetic fuels production processes, capital investments, labor forces, materials requirements, etc. (4)
- Information on the locations and amounts of coal resources. (5)
- Understanding of the institutional structure of the automotive fuels supply system. (9)

The study also required development of the following:

- Impacts description of the reference case for supplying conventional crude oil. (3)
- An implementation scenario for synthetic liquid fuels at the maximum rate of deployment that can be credibly imagined. (6)
- A description of how corporate stakeholders in the fuels industry perceive the prospective synthetic fuels industry would mesh with the existing system. (9)

E. Critical Factors

From the outset, information obtained from the literature and stakeholders made it clear that the following factors were critical and they were emphasized in the study:

- Availability of water for energy development--especially in the arid West. (19, 20)
- Strip mining practices and reclamation potential. (13, 14, 15)
- Mineral leasing procedures and constraints (since much of the relevant resource is owned by the federal government). (7)
- Control of air pollution from mines and conversion facilities. (16)
- Availability of capital for synthetic liquid fuels investments. (8)
- Transportation of coal between mines and liquefaction plants. (19)
- Corporate decisions about whether and when to deploy synthetic fuels. (9)
- The creation of boom towns in coal and oil shale regions--especially in sparsely populated regions of the West--and the effects of constraining growth. (21, 22, 23)
- Governmental incentives for synthetic liquid fuels production. (10)

F. Complementing Work

To provide a complete picture and to complement the analysis, it was necessary to prepare:

- Descriptions of the environmental impacts of urbanization specific to the most likely regions of expected synthetic fuels activity. (17)
- National and regional economic descriptions of synthetic fuels industry development. (11, 12)
- Impacts of deployment of synthetic fuels facilities at the maximum credible rate. (8, 11, 12, 18, 19, 23)

G. Applicability

Although this study is oriented toward fuels for the automotive sector, many of the analyses in the following chapters have more general applicability. The results of the analyses have equal relevance to understanding the consequences of strip mining for coal, of synthetic gas production, and of water intensive industrial development of the West.

2--AUTOMOTIVE FUEL SUPPLY AND DEMAND FORECASTS

By Edward M. Dickson

This study is concerned with the development of synthetic liquid fuels for the automotive market. Here the word automotive is taken to include cars, trucks, and buses. Together, these vehicles consume about 46 percent of all petroleum used in the United States.[1] Cars, of course, account for the majority of this use--some 70 percent. Figures 2-1 and 2-2 place automotive fuel use in perspective, both as a proportion of total energy use and as a proportion of total oil use.

There are many forecasts of future automotive fuel demand in the literature,[2-9] but few of them are based on anything more sophisticated than simple trend extrapolation.[*] Most, moreover, implicitly assume constant energy prices (in real terms). This assumption is understandable because, as shown in Table 2-1, between 1950 and 1973 the real price of motor fuels remained essentially constant with even a slight downward trend. Since the Arab oil embargo, however, it is no longer credible to assume either constant petroleum prices or availability of supplies to meet the desires[†] of motorists. Consequently, interest has begun to focus on synthetic liquid fuels.

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[*] One recent, more sophisticated projection[10] is described in the appendix.

[†] We use the word desires here rather than demand because, in the language of economics, supply must equal demand in an equilibrium economy, but desires may exceed supplies.

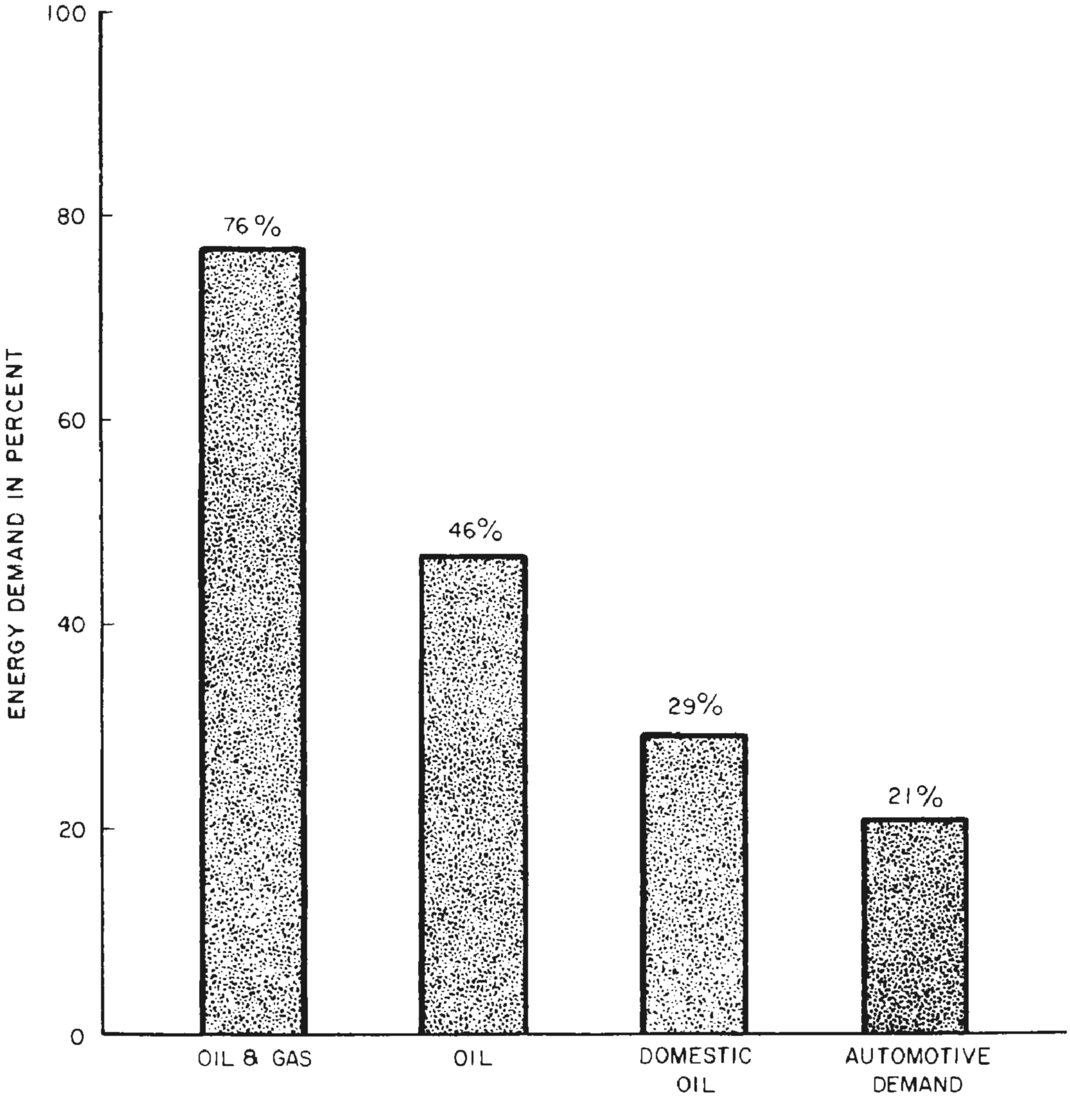

FIGURE 2-1. AUTOMOTIVE ENERGY DEMAND COMPARED TO 1974 PETROLEUM SUPPLY AND DEMAND

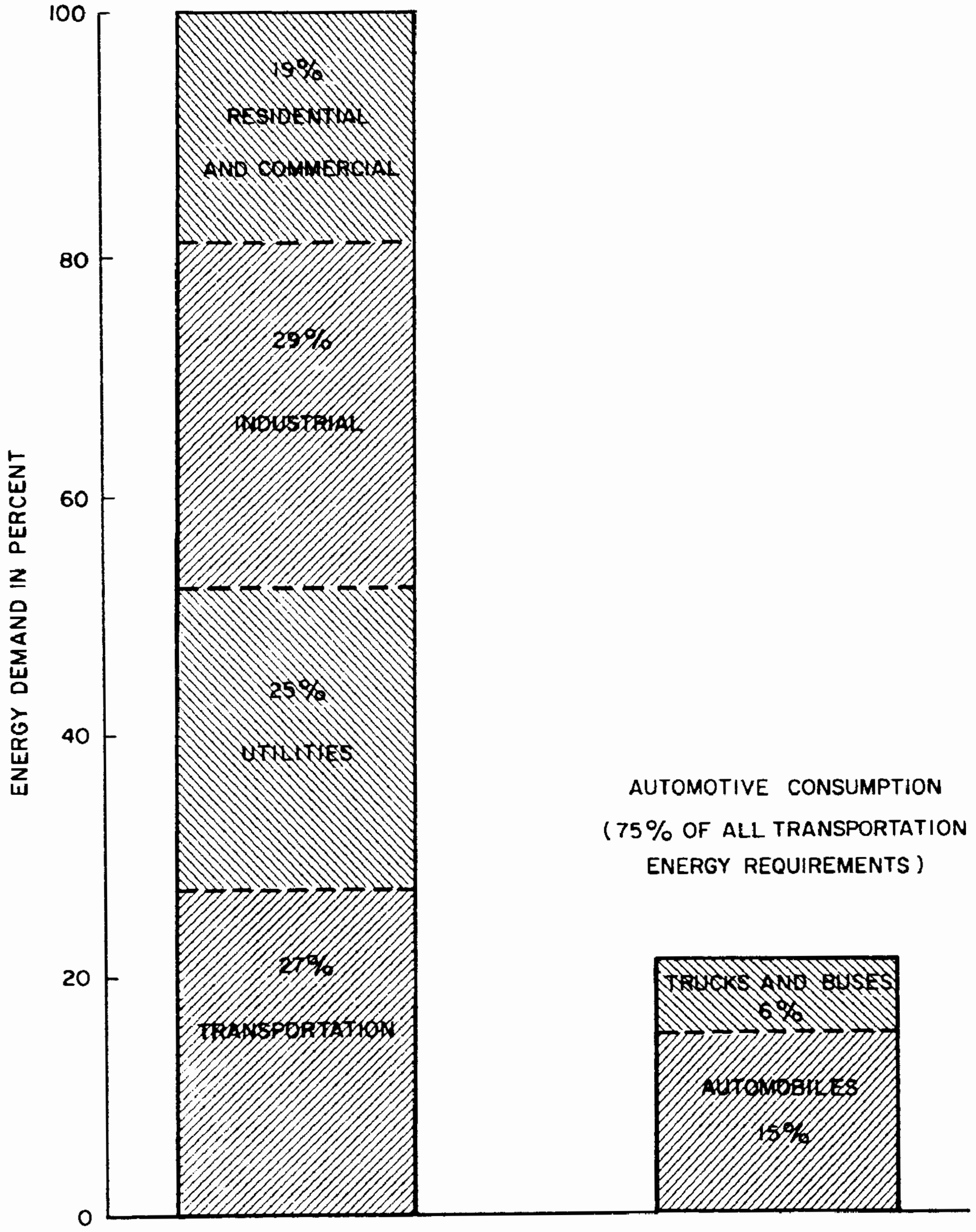

FIGURE 2-2. AUTOMOTIVE ENERGY DEMAND COMPARED TO TOTAL U.S. ENERGY DEMAND

Table 2-1

GASOLINE PRICES AND FUEL COST PER MILE
1950-74

Source: Reference 10

Year	Real Price (1967 dollars) ($/gal)	Real Fuel Cost ($/Mile)*
1950	0.37	0.0248
1955	0.36	0.0250
1960	0.35	0.0246
1965	0.33	0.0234
1970	0.31	0.0226
1973	0.29	0.0223
1974	0.35	0.0271 †

---

* Based on fuel economy of vehicles in operation.

† Assumed 1973 fuel economy.

To appreciate the quantity of synthetic liquid fuels that the U.S. might wish to produce in the years ahead, a forecast of both supply and demand is needed and these components must be coupled through a common and realistic assumption about fuel price. In addition, over a long period, such as 1980-2000, considerable interfuel competition could take place, which could result in substantial fuel switching. Thus, it is also necessary to use a forecast in which automotive use of petroleum (or equivalent) products is but a portion of a total energy economy balance.

Since construction of such a complete forecast was beyond the scope of this study, we have chosen to adapt for our use the three supply and demand scenarios of the Energy Policy Project of the Ford Foundation because they were the only such forecasts publicly available for the time frame 1980-2000.[11] Although they are flawed,* the Ford scenarios are sufficient to indicate the general magnitude of the future shortfall of domestically produced petroleum compared with the desired supplies. This shortfall is a measure of the amount of future petroleum imports that will be required, of synthetic fuel production needed, or a combination of these two alternatives.

The three Ford scenarios are entitled Historical Growth (HG), Technical Fix (TF), and Zero Energy Growth (ZEG).[11] Basically, the HG scenario assumes that consumers of fuels ignore the current high prices of fuels and return to historical high consumption rates with no government restrictions on consumption. Under the HG scenario, oil prices fall back to the

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*For example, the forecasts of aviation demand are generally agreed to be excessively high and the assumptions of fuel price are never made explicit Moreover, the Ford study makes the unrealistic assumption that synthetic fuels could be developed (without governmental subsidies) at a cost of $4-$6 per barrel.

$4 to $6 per barrel range, which is low enough to maintain demand at historical rates. The HG scenario assumes that fuels from nonconventional fossil sources (e.g., oil shale) would have to be developed because of the rapid growth of demand. However, one difficulty with the HG scenario is the doubtful assumption that synthetic fuels could be produced (without governmental subsidy) at a price range of $4 to $6 per barrel. Moreover, it is unlikely that these low prices could hold in the face of the projected continued rapid growth in demand.

The TF scenario assumes that fuel consumers will respond to the current high prices of energy and take steps to reduce fuel use over the 1975-2000 period and that the government will order mandatory conservation measures. With conservation measures in effect, the annual growth rate of total demand for energy is reduced from 3.4 percent under HG to 1.9 percent under TF. Primary factors in conserving energy are better insulation of buildings and better automotive fuel economy. For example, automobiles are assumed to achieve an improved fuel economy from the current 14 mpg to 20 mpg by 1985 and to 25 mpg by 2000. The study maintains that this could be achieved without giving up large automobiles and with existing technology.

The ZEG scenario is similar to the TF but with more stringent governmental controls. For example, the efficiency of automobiles increases from its current 14 mpg to 33 mpg by 2000.

The Ford Foundation Energy Policy Project gives a complete energy balance for the U.S. economy in all three scenarios. Table 2-2 shows the annual fuel demand by the entire transportation sector and the annual fuel demand by autos, trucks, and buses in the three Ford scenarios HG, TF, and ZEG.

On the supply side, the Ford study not only presents different assumed domestic petroleum supplies under the three main scenarios, but

Table 2-2

PROJECTED ANNUAL FUEL CONSUMPTION BY SECTOR
Quadrillion Btu per year (million B/D product equivalent)[*]

Source: Reference 11 (Tables 1, 5, 16, and A-8)

		1970	1975	1985	2000
	Total all sectors	66.0	78.0		
	Transportation	15.7	19.1		
	Autos, trucks, and buses	11.9 (6.2)	14.4 (7.5)		
	Percentage of transportation	76%	75%		
HG	Total all sectors			116.1	186.7
	Transportation			26.0	38.4
	Autos, trucks, and buses			18.0(9.3)	21.9(11.4)
	Percentage of transportation			69%	57%
TF	Total all sectors			91.3	124.0
	Transportation			19.6	24.7
	Autos, trucks, and buses			12.7(6.6)	11.4(5.9)
	Percentage of transportation			65%	46%
ZEG	Total all sectors			88.1	100.0
	Transportation			18.4	17.2
	Autos, trucks, and buses			12.5(6.5)	8.5(4.4)
	Percentage of transportation			68%	49%

---

[*] We use 1 bbl oil product (typically gasoline) = 5.25 x 10^6 Btu, so that 1 quad (10^{15}Btu) per year equals about 0.5 million B/D; 1 quad is also approximately equal to 10^9 GJ.

subscenarios are also given. Under HG, three subscenarios are presented --normal development (HG1), accelerated nuvlear development (HG2), and high imports (HG3); these subscenarios are shown in Figure 2-3.* In HG2, accelerated nuclear development substitutes for domestic oil in power generation; in HG3, imported oil substitutes for the development of domestic oil. The greatest assumed development of domestic oil occurs under scenario HG1. Under TF, two subscenarios are presented--TF1 and TF2. Under TF1, the United States moves toward self-sufficiency by reducing imports by almost one-half.† Under TF2, dependency on imports is not reduced but some environmental restrictions are included. The TF scenario is shown in Figure 2-4. The ZEG scenario, shown in Figure 2-5, includes stringent environmental controls, which then restrict the development of offshore and outer continental shelf areas. The various supply scenarios are summarized in Table 2-3. As discussed extensively in Chapter 3, of the three assumed supply cases of HG, only the HG3 domestic supply scenario has reasonable likelihood of being realized in light of the most recent U.S. Geological Survey estimates of the total recoverable U.S. reserves of petroleum.

Figures 2-3 to 2-5 indicate that an automotive fuel shortfall of about 6 million B/D (HG1 demand minus HG3 supply) to 2 million B/D (TF demand minus TF2 supply) might occur in the year 2000. Table 2-3 shows that the total (for all sectors) liquid fuel shortfall (listed as imports) might be in the range of 4 to 18 million B/D. This leaves a considerable

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*Figures 2-3 to 2-5 assume that domestic crude production has been distributed among all use sectors in proportion to the demand of that sector compared to total petroleum demand. This proportion varies with time.

†The original projections in the Ford Foundation study assume that imports are cut exactly in half from the levels given in the HG case. In this table, all production of synthetic fuels shown in the Ford study has been added to imports of crude oil.

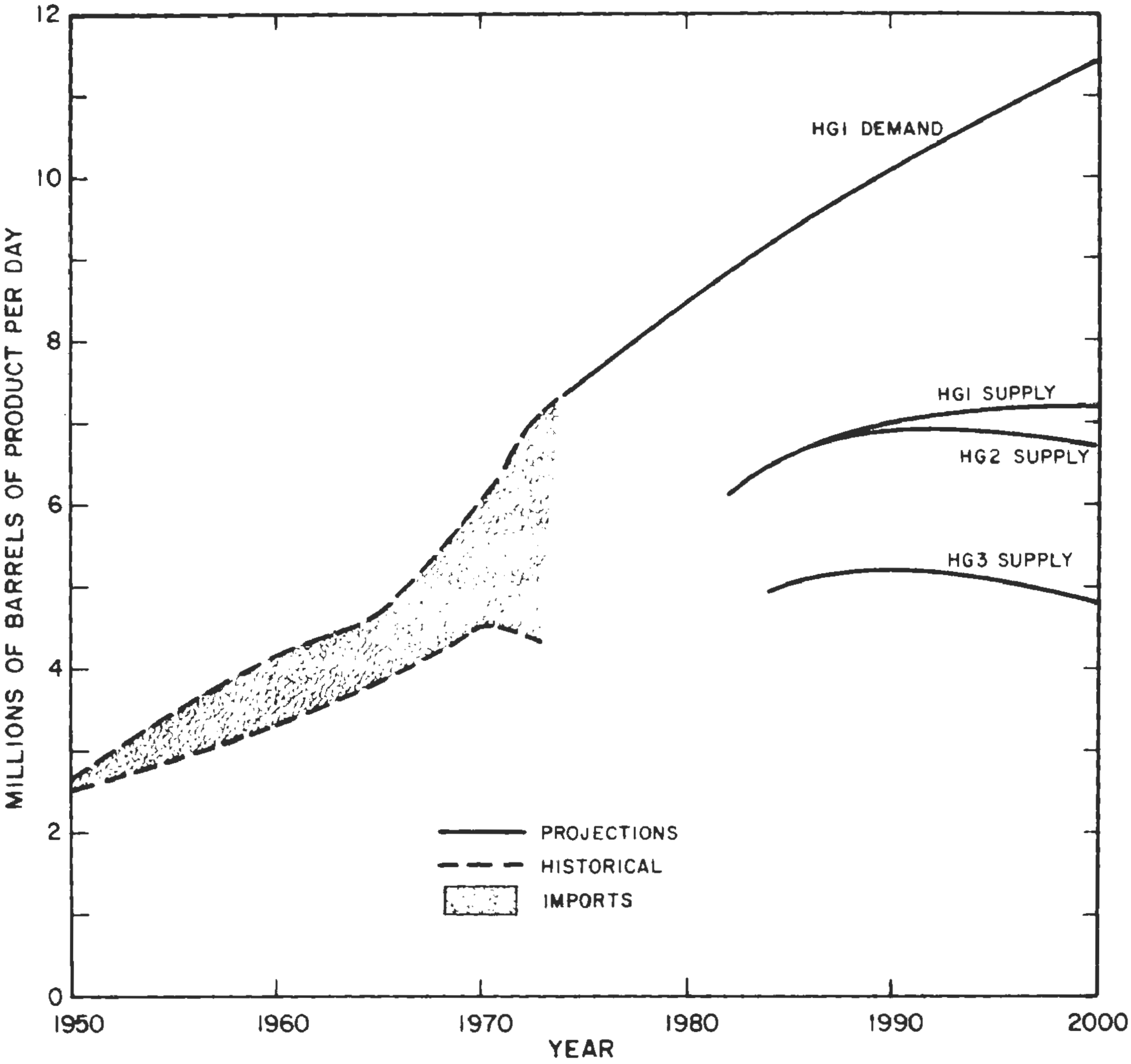

FIGURE 2-3. HISTORICAL GROWTH SCENARIO – AUTOMOTIVE FUEL DEMAND AND DOMESTIC SUPPLY PROJECTIONS

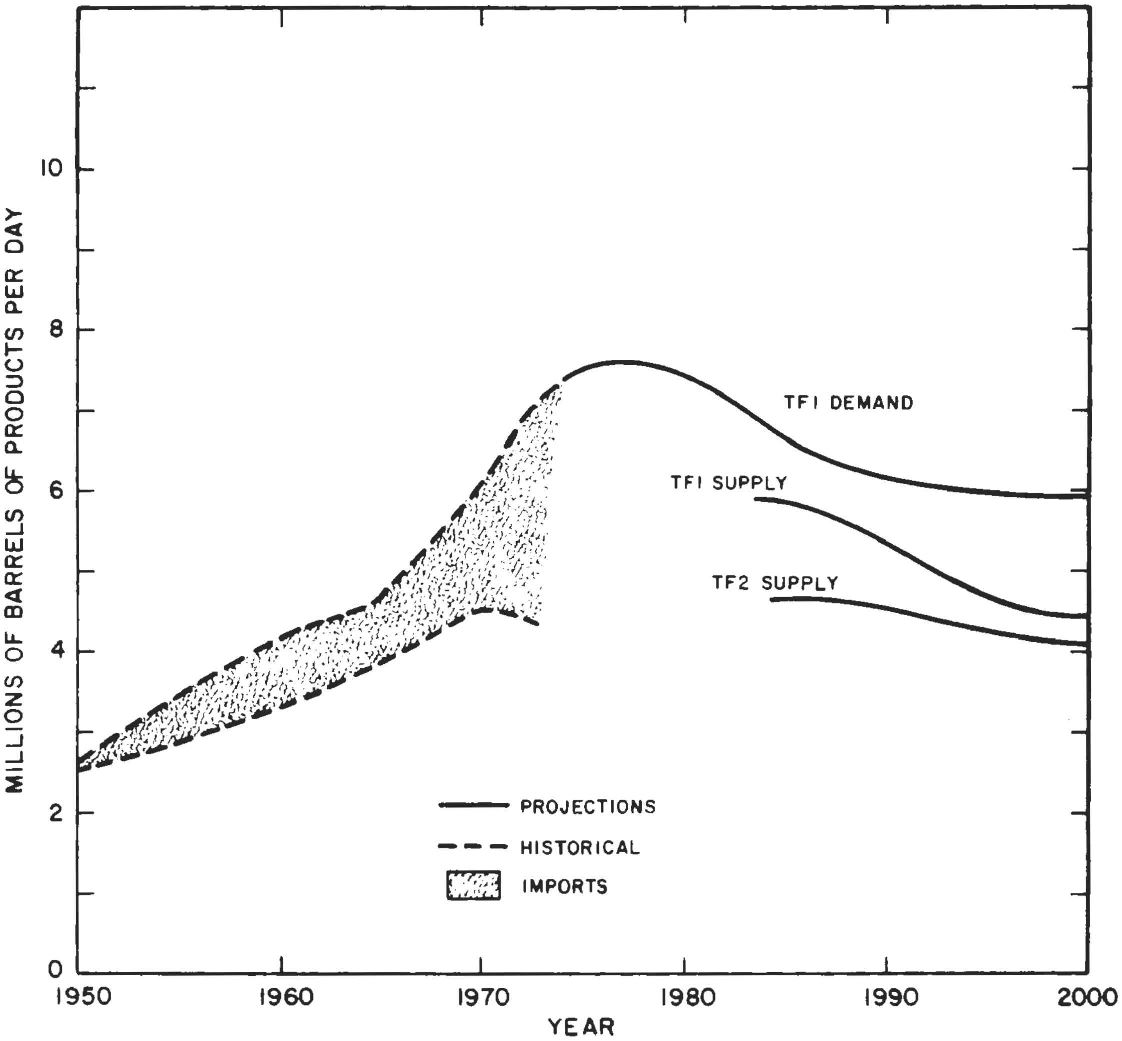

FIGURE 2-4. TECHNICAL FIX SCENARIO – AUTOMOTIVE FUEL DEMAND AND DOMESTIC SUPPLY PROJECTIONS

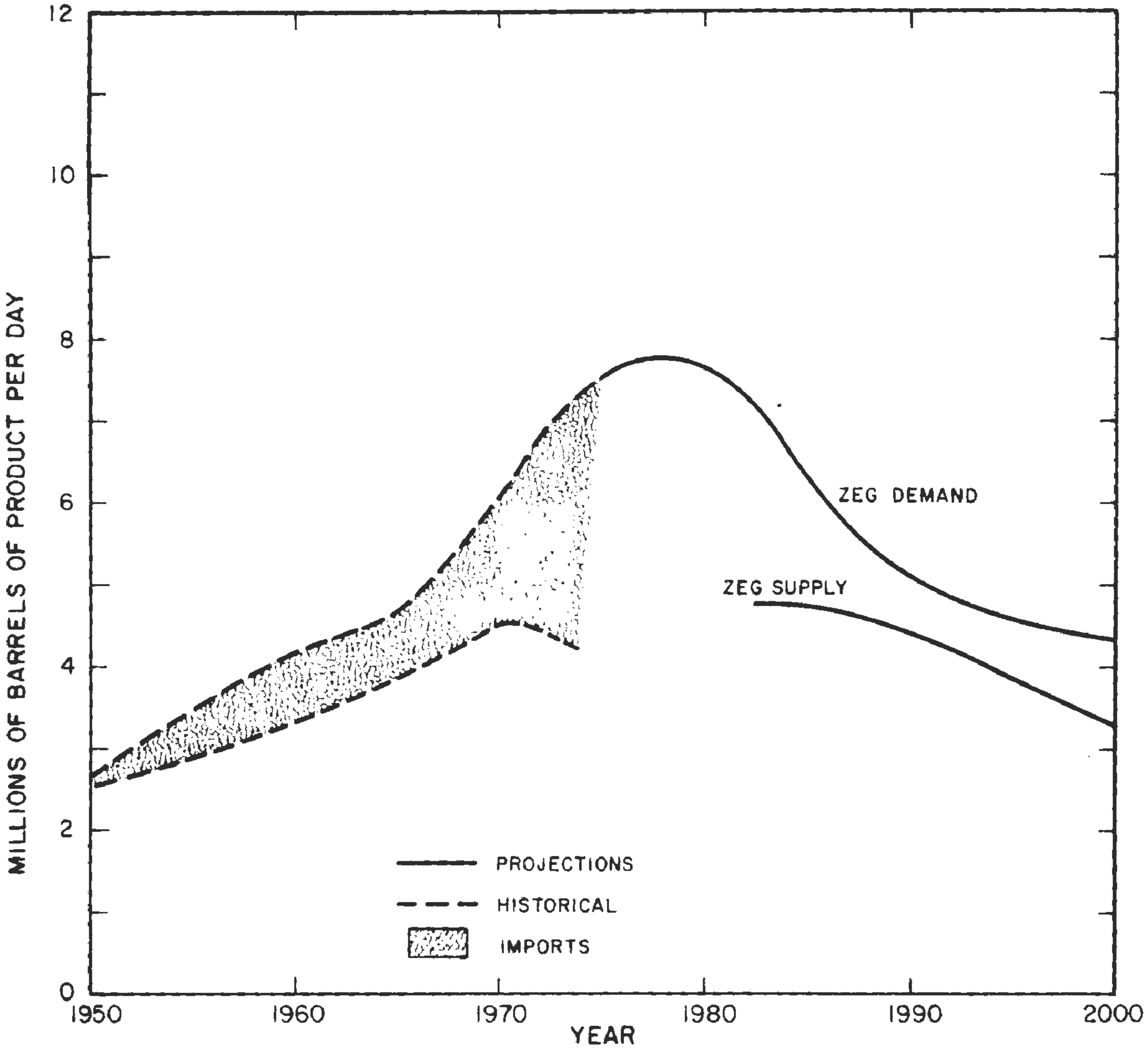

FIGURE 2-5. ZERO ENERGY GROWTH SCENARIO–AUTOMOTIVE FUEL DEMAND AND DOMESTIC SUPPLY PROJECTIONS

Table 2-3

OIL SUPPLY PROJECTIONS
Million B/D (Quadrillion Btu)

	1973	1985	2000
Domestic oil			
HG1	11.0 (22)	15.9 (32)	20.9 (40)
HG2		15.9 (32)	17.7 (34)
HG3		13.4 (27)	13.4 (27)
TF1		14.9 (30)	17.9 (36)
TF2		14.4 (29)	17.4 (35)
ZEG		13.9 (28)	14.9 (30)
Oil imports*			
HG1	6.0 (12)	6.5 (13)	12.0 (24)
HG2		6.5 (13)	12.0 (24)
HG3		11.5 (23)	18.4 (37)
TF1		3.2 (7)	6.0 (12)
TF2		6.0 (12)	8.0 (16)
ZEG		4.5 (9)	4.5 (9)

HG1: Historical growth
HG2: High nuclear
HG3: High imports
TF1: Self-sufficiency (rapid coal development; cut imports in half)
TF2: Environmental controls (no synthetic fuels)

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*The synthetic liquid fuels in the Ford scenarios have been shifted to this category.

amount of uncertainty in the projected shortfall, an uncertainty matched in global geopolitics and U.S. energy policy, which will largely determine both the U.S. supply and demand for fuels.

In Chapter 6, we advance a Maximum Credible Implementation (MCI) scenario for synthetic liquid fuels derived from coal and oil shale that yields 10 million B/D.* Thus, the MCI would be capable of filling a substantial part of the total anticipated shortfall for liquid fuels.

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*of oil equivalent energy.

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APPENDIX

Reference 10 presents a sophisticated econometric model that projects future automotive fuel demand taking into account the following variables:

- Automobile ownership
  - -The real price of automobiles by class
  - -The fuel efficiency of automobiles by class
  - -The real price of gasoline
  - -Total real disposable income
  - -Total number of households in each income group
  - -The unemployment rate.
- Travel demand
  - -household income
  - -trip purpose by income class
  - -cost factors.

The model relates five basic submodels:

- An estimator for market shares of new car sales (sales-weighted fuel economy of new cars).
- An estimator for new car sales.
- An estimator for scrappage (fleet size, fleet fuel economy).
- An estimator for miles traveled.
- A fleet model to calculate fuel consumption.

The fuel demand projections are made with three assumed fuel price schedules: constant fuel prices, rising fuel prices, and falling fuel prices. Table A-1 summarizes the fuel price assumptions.

Table A-1

FUEL PRICE ASSUMPTIONS
(per gallon)

Source: Reference 10

Year	Constant	Rising
1976	$0.61	$0.61
1980	0.61	0.72
1985	0.61	0.87
1990	0.61	0.88
1995	0.61	0.90
2000	0.61	0.90

The model projects only car fuel demand, but this can be corrected to total automotive fuel demand by assuming that cars use 70 percent of all automotive fuel in all years. This conversion, shown in Table A-2, allows easy comparison with the projections shown in Figures 2-3 to 2-5 in the text.

Table A-2

PROJECTED AUTOMOTIVE FUEL DEMAND FOR CONSTANT AND RISING PRICES
(million B/D)

Source: Reference 10

Year	For Constant Price	For Rising Price
1976	7.4	7.4
1980	7.6	7.5
1985	8.3	7.8
1990	9.2	8.5
1995	10.3	9.4
2000	11.4	10.3

3--REFERENCE SUPPLY CASE

By Barry L. Walton

A. Introduction

Meeting the anticipated fuel demands for autos, trucks, and buses will require the development of oil resources in new areas together with vigorous activity to enhance oil recovery from known fields. With continuing high prices for imports (about $11 per barrel of crude in 1974 dollars) and governmental price regulation of a kind to encourage new production, stepped up attempts to develop domestic oil resources are likely. However, even with increased production, domestic supplies of oil will not meet demands for the entire period between now and the year 2000, and, in the absence of synthetic fuels, imports will be necessary to supply the difference between domestic oil supplies and domestic oil demands.

1. Content of the Reference Case

As a measure against which to set the topics treated in this technology assessment, we have developed a reference case in which the expected shortfall in U. S. automotive fuels is met by increased production within the existing petroleum industry, without the use of synthetic fuels. Specifically, the demand is met by

- Onshore production--lower 48 states onshore and near-shore production from state leases.
- Offshore production--outer continental shelf (OCS) production from federal leases off the coasts of the lower 48 states.
- Alaskan production--onshore and offshore production.
- Imports--both crude oil and refined products.

Figure 3-1 shows the boundaries of the reference case considered in this chapter. Under the assumption of these sources of oil for the United States to the year 2000, the reference case contains a projection of (1) domestic oil supply by region and the requirements for imported oil, (2) the resources required to increase domestic oil production without recourse to synthetic fuels development, and (3) the environmental impacts that could result from this production and importation. Environmental impacts are given in terms of quantified indicators derived from scaling factors applied to the projections of oil supply and demand and the resource requirements for an intensive U.S. oil recovery program.

2. Scenarios: Bases for Projections of Supply and Demand

In selecting a domestic fuel supply scenario for the reference case to correspond to the EPP demand forecasts described in Chapter 2, we faced considerable difficulty. Although six possible supply projections are described by the EPP[1], only HG3 retains some credibility in the light of recent projections by the U.S. Geological Survey (USGS) of domestic oil resources[2] (Appendix A discusses these and other projections). Table 3-1 shows the six EPP scenarios and displays approximate cumulative production between 1973 and 2000 for these scenarios. For this baseline analysis the synthetic fuels originally postulated by the EPP have been shifted to the category of imports. The estimates of possible domestic oil production shown in the table were made prior to the recent USGS projections. Even the comprehensive Federal Energy Administration, Project Independence Blueprint[3] was based upon the out of date USGS resource estimates shown in Appendix A, Table A-2. As discussed in Appendix A, it is now necessary to abandon estimates of future crude oil production which show impossibly large cumulative production estimates. Among the scenarios of the EPP, HG3 projects the lowest cumulative production rates into the next century.

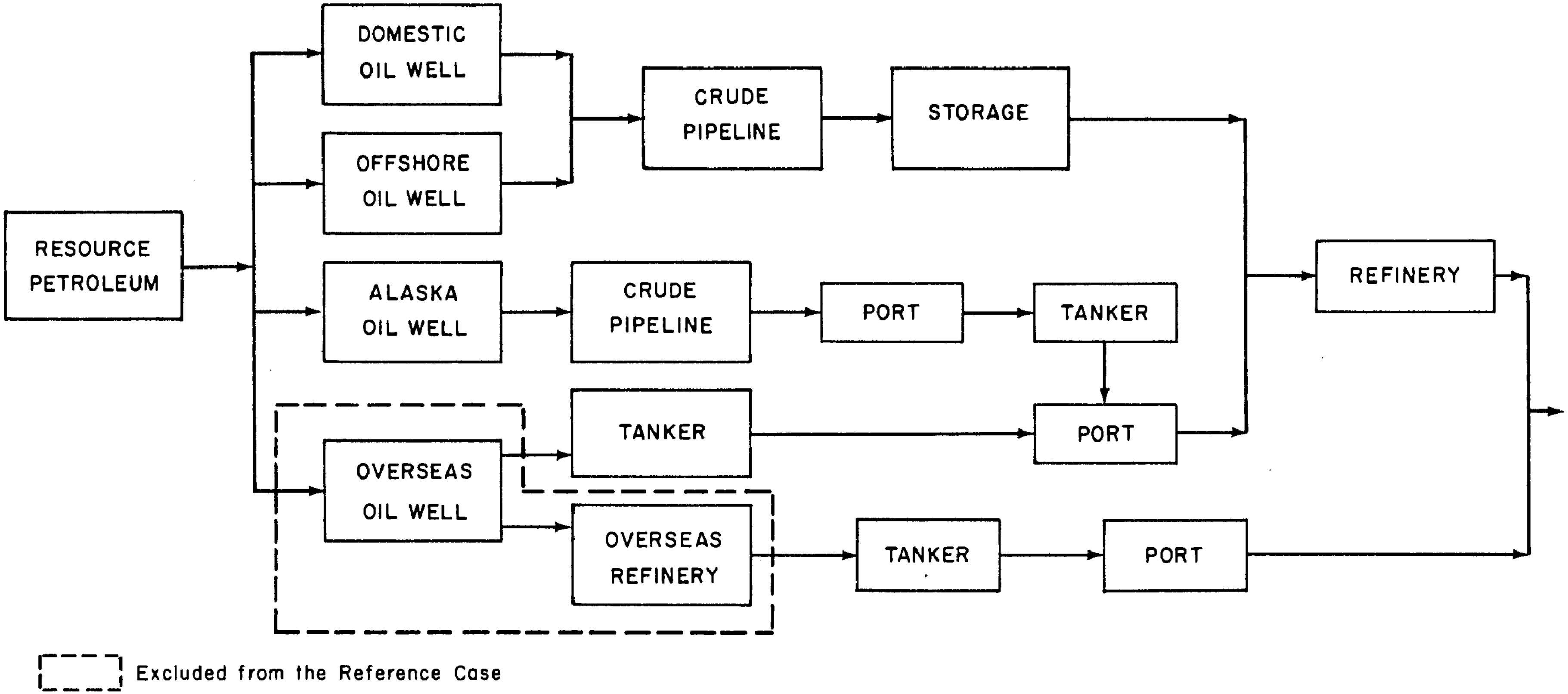

FIGURE 3-1. REFERENCE CASE PETROLEUM FUEL SYSTEM

Table 3-1

CONVENTIONAL DOMESTIC OIL SUPPLY PROJECTIONS

Supply Source	Annual Projections in Millions of Barrels per day (Quadrillion Btu per Year)				Cummulative Projections in Billions of Barrels
	1973	1974	1985	2000	1973-2000
Domestic Oil					
HG1[*]	11.0 (22)	10.5 (21)	15.9 (32)	20.9 (40)	160
HG2			15.9 (32)	17.7 (34)	150
HG3			13.4 (27)	13.4 (27)	127
TF1			14.9 (30)	17.9 (36)	150
TF2			14.4 (29)	17.4 (35)	140
ZEG			13.9 (28)	14.9 (30)	130
Oil Imports[†]					
HG1	6.0 (12)	6.0 (12)	6.5 (13)	12.0 (24)	
HG2			6.5 (13)	12.0 (24)	
HG3			11.5 (23)	18.5 (37)	
TF1			3.5 (7)	6.0 (12)	
TF2			6.0 (12)	8.0 (16)	
ZEG			4.5 (9)	4.5 (9)	

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[*] HG1: Historical growth
HG2: High nuclear
HG3: High imports
TF1: Self-sufficiency (rapid coal development; cut imports in half)
TF2: Environmental controls (no synthetic fuels; offshore production forbidden in new areas until after 1985)
ZEG: Zero energy growth

[†] 5.5 x 10^6 Btu/barrel

Source: Reference 1, Tables 3, 13, 24.

A problem with HG3 that had to be overcome for the reference case is that it contains no corresponding regional supply projections which are necessary for impact analysis. Accordingly, the relative regional oil supplies from Project Independence Oil Task Force Report[4] were applied to the aggregated domestic supply projection under HG3 to give regional supplies for our impact analysis requirements. Unfortunately, no regional supply projections to the year 2000 using the most recent USGS resource estimates have been made public, and the Project Independence projections were based on discredited resource estimates and were not extended past 1988. We have, however, assumed that the relative distribution among future producing regions given in Project Independence remain valid.

3. Summary of Conclusions

The major conclusions drawn from the reference case are the following:

- Under all of the EPP scenarios the demand for liquid fuels exceeds the HG3 domestic supply of conventional crude oil.
- Even with much higher crude oil prices, domestic petroleum supplies are extremely unlikely to meet domestic demand, even a demand as low as in ZEG.
- In the absence of synthetic crude oil, continued imports will be necessary unless demand for crude oil is reduced below the production level of HG3.
- Producing oil at the HG3 subscenario rate requires considerable increase in oil production from offshore and Alaska, and a massive tertiary recovery program onshore. Tertiary recovery offshore and in Alaska would also be needed. Yet domestic oil production from conventional sources will begin a long term decline before 2000.
- Capital investment in domestic crude oil exploration and production must increase to over $12 billion (1973 constant

dollars) annually by 2000 if production is to approximate that projected under HG3.

- Labor requirements for drilling will more than double between 1977 and 2000.
- Steel requirements for crude oil production will increase to over 3.5 million tons (3.2 billion kg) annually in 2000.
- The coastlines will be a major focus for the environmental impacts from offshore resource development and from oil import activity.
- Alaska will be a second major focus for the environmental impacts from developing oil resources in offshore areas and along the North Slope. A second TAPS is necessary for transporting North Slope oil under HG3.
- The potential for large scale environmental disaster resulting from a large oil spill along the coastal regions is significant. Based on an extrapolation of past spill statistics, perhaps 13 spills of over 100,000 barrels can be expected.

The significant implications of these conclusions are the following:

- Without synthetic fuels from coal and oil shale, imports of petroleum will grow to over 18 million barrels per day under demand levels of Historical Growth, and will grow to over 10 million barrels per day under Technical Fix, since these demand levels cannot be met by the HG3 supply.
- Supplying domestic oil at the HG3 rates will require considerable capital investment. Recent investment and supply projections made by Texaco and published in the Oil and Gas Journal[5] show 1990 crude oil production at about 13 million barrels per day with annual investment in crude oil and natural gas production at over $30 billion (1975 $). This production and investment projection supports our conclusion that the $12 billion required annually under HG3 is a lower limit to the investment necessary to bring about oil production at the HG3 levels.

- Because the better economic prospects for oil production will be exhausted by the year 2000, investment costs for new oil reserves will go to between $1.80 and $3.20 (1973 $). These costs are comparable to or greater than investments for syncrude.
- The price of crude oil in constant dollars will increase under almost any realistic scenario, particularly if national independence from foreign crude oil supplies is sought.
- Oil production from offshore and Alaskan oil resources will continue to be the center of environmental controversy. Indeed, the major impacts of future oil production result from producing resources from these areas.

B. Projected Domestic Oil Supply and Imported Oil Requirements

To project detailed domestic oil supplies for HG3, the Project Independence Oil Task Force supply projections[4] are used to define the relative percentages of oil supplied from each National Petroleum Council (NPC) region.[*] Figure 3-2 defines regional boundaries used in this chapter. Table 3-2 shows HG3 supplies aggregated into onshore production, offshore production, and Alaska production.[†] The apparent heavy reliance on oil supplies from Alaska, offshore, and tertiary recovery for future production reflects general expectations of future production.[6]

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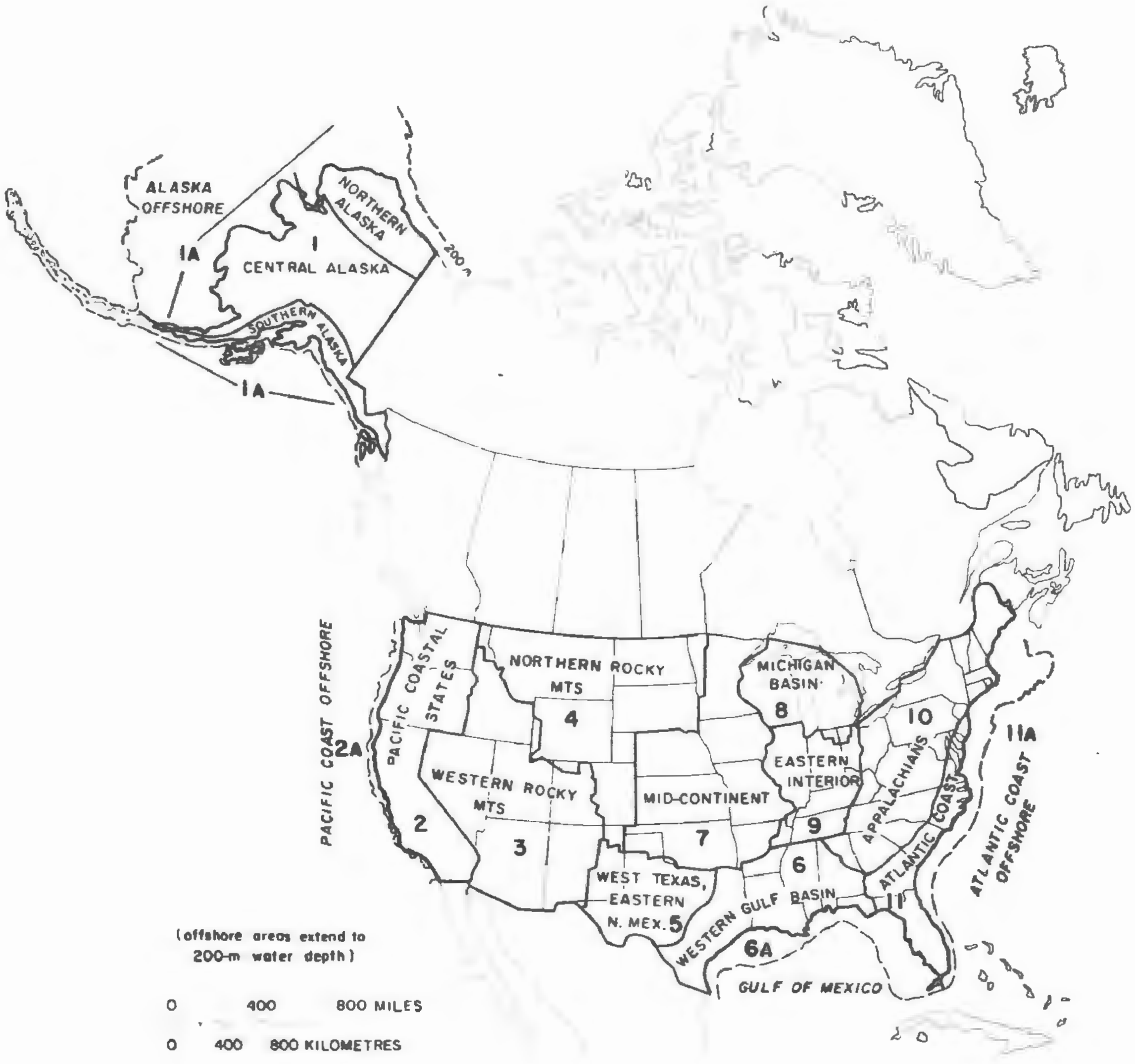
[*] The NPC regions (modified from the usual National Petroleum Council regions) as defined by the Oil Task Force.[4]

[†] Aggregated from Table B-1 of Appendix B.



Source: U.S. Geological Survey, Circular 725

FIGURE 3-2. INDEX MAP OF NORTH AMERICA SHOWING THE BOUNDARIES OF THE 15 OIL PRODUCTION REGIONS, ONSHORE AND OFFSHORE

Table 3-2

DOMESTIC OIL SUPPLY, IMPORTS, AND TOTAL DEMAND UNDER HG3

10^6 Barrels per day (% of Domestic Supply)

SUPPLY/DEMAND	YEAR			CUMULATIVE 1974-2000 (10^9 Barrels)	
	1974	1985	2000	Total	From Advanced Recovery
Domestic Supply					
Onshore Lower 48 states	8.9 (85)	6.8 (52)	5.0 (38)	63	34
Offshore Lower 48 states	1.4 (13)	3.0 (21)	4.0 (30)	28	15
Alaska Onshore and offshore	0.2 (2)	3.6 (27)	4.4 (32)	30	16
Total	10.5	13.4	13.4	121	
Imports	6.0	11.5	18.4		
Total U. S. demand	16.5	24.9	31.8		

Source: Appendix B, Table B-1.

Table 3-3 shows the onshore production for HG3 by NPC region. Table 3-4 shows the offshore production for HG3 by offshore NPC region, including production from military oil reserves in the Pacific and Gulf of Mexico offshore areas. Table 3-5 shows the Alaska production for HG3 by onshore and offshore areas.

Cumulative production under HG3 between 1973 and 2000 is approximately 130 x 10^9 barrels of oil--about 25 percent greater than the cumulative total U.S. production up to 1973. Cumulative tertiary recovery under HG3 is assumed to be about 70 billion barrels, an assumption that reflects the availability of oil through primary recovery given the 1975 USGS resource estimates.[2]

We assume that cumulative recovery between 1973 and 2000 from each region by tertiary methods is proportional to total cumulative recovery by tertiary methods divided by total cumulative recovery over the same period.

Table 3-3

ONSHORE OIL PRODUCTION FROM THE LOWER 48 STATES UNDER HG3

(10^6 Barrels per day)

Region or Source*	1974	1985	2000
Pacific Coast NPC Region 2	0.792	0.59	0.38
Naval Petroleum Reserve No. 1	0	0	0.08
Western Rocky Mountains NPC Region 3	0.215	0.16	0.12
Eastern Rocky Mountains NPC Region 4	0.614	0.34	0.23
West Texas/Eastern New Mexico NPC Region 5	2.553	1.6	1.1
Western Gulf Basin NPC Region 6	3.526	3.2	2.4
Mid-Continent NPC Region 7	0.994	0.68	0.56
Northeast NPC Regions 8, 9, 10	0.213	0.28	0.19
Atlantic Coast NPC Region 11	0.007	0	0.01
Total†	8.914	6.8	5.0

---

* See Figure 3-2 for geographical locations.

† Items may not sum to totals due to rounding.

Table 3-4

OFFSHORE OIL PRODUCTION FROM THE LOWER 48 STATES UNDER HG3

(10^6 Barrels per day)

Region or Source*	1974	1985	2000
Offshore military reservations	0	0	0.16
Atlantic offshore NPC Region 11A	0	0.04	0.60
Gulf of Mexico NPC Region 6A	1.311	2.3	2.0
Pacific offshore NPC Region 2A	0.058	0.6	1.2
Total†	1.369	3.0	4.0

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* See Figure 3-2 for geographical locations.

† Items may not sum to totals due to rounding.

Source: Tables B-1, Appendix B

Table 3-5

ONSHORE AND OFFSHORE OIL PRODUCTION FROM ALASKA UNDER HG3

(10^6 Barrels per day)

Region or Source[*]	1974	1985	2000
Prudhoe Bay	0	1.8	1.2
North Slope Other than Prudhoe Bay	0	1.3	0.68
Naval Petroleum Reserve No. 4	0	0	1.6
Gulf of Alaska and other offshore areas NPC Region 1	0.201	0.54	0.96
Total[†]	0.201	3.6	4.4

---

[*] See Figure 3-2 for geographical locations.
[†] Items may not sum to totals due to rounding.

Source: Table B-1, Appendix B

The economic incentives provided by high prices for imported crude oil and refined products will tend to increase the supply from the three domestic sectors--onshore (lower 48 states), offshore (Atlantic, Pacific, Gulf of Mexico areas), and Alaska (onshore and offshore). Of course, the distribution of the supply available from each of the sectors cannot be forecast to the year 2000 with precision.

C. Projected Resource Requirements for Production of Domestic Oil

Oil can only be produced with sufficient inputs of the resources of equipment, manpower, steel, and capital. Projections of these inputs under scenario HG3 are developed in this section.

1. Drill Rigs, Labor, and Steel

Table 3-6 shows the approximate annual requirements for drill rigs, labor, and steel for the reference case. Labor and steel requirements are shown later for synthetic fuel development in the maximum credible implementation (MCI) scenario, Chapter 6. The number of rigs determines many of the oil production impacts.

Several considerations were used in generating the annual resource requirements in Table 3-6:* (1) Since annual production under HG3 in 2000 corresponds closely to the Project Independence 1988 \$11/B Business-as-usual[4] scenario, no increase in the annual resource requirements beyond the Project Independence 1985 \$11/B Business-as-usual requirements is assumed except for investment and (2) this is based on the assumption that future production is closely correlated

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[*] Annual oil production depends on resource inputs and exploration activity. For example, it will take several years before a new offshore field reaches peak production. More than one production platform is likely for a large field.

Table 3-6

LABOR, DRILL RIG AND STEEL REQUIREMENTS FOR OIL PRODUCTION UNDER HG3

	1977[*]	1980[*]	1985[*]	1990[†]	1995[†]	2000[†]
Exploration Drill Rigs in Use Annually						
Onshore	930	1,100	1,250	1,250	1,250	1,250
Offshore	240	370	500	500	500	500
Alaska						
Onshore	125	125	150	150	150	150
Offshore	26	52	110	110	110	110
Offshore Production Platforms in Use Annually						
Offshore	90	150	200	200	200	200
Alaska-offshore	6	12	25	25	25	25
Labor--Rig and Platform Crewmen Employed Annually						
Onshore	22,000	25,000	29,000	29,000	29,000	29,000
Offshore	24,000	37,000	52,000	52,000	52,000	52,000
Alaska	3,000	5,000	8,000	8,000	8,000	8,000
(Offshore)	(1,600)	(3,100)	(6,500)	(6,500)	(6,500)	(6,500)
Total	49,000	67,000	89,000	89,000	89,000	89,000
Steel--Thousands of Tons Required Annually						
Onshore	1,400	1,600	1,700	1,700	1,700	1,700
Offshore	1,400	1,700	1,400	1,400	1,400	1,400
Alaska	200	200	400	400	400	400
Total	3,000	3,500	3,500	3,500	3,500	3,500

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[*] Data up to 1985 adapted from Reference 4, Tables VI-8, VI-9 and VI-10, by excluding the heavy crude oil and tar sands data.

[†] All requirements after 1985 held constant.
This reflects the correspondence between production by 2000 under HG3 and the FEA $11/B BAU scenario production by 1988 used in Appendix B to generate the regional production for HG3.

to exploration activity. The same drilling activity used to achieve the FEA production by 1988 is assumed to achieve the HG3 production by 2000. The correlation is generally valid--more drilling activity results in more future production, although according to those knowledgeable in the field, it is becoming increasingly difficult to find oil with the amount of oil discovered per foot of exploratory well drilled on the decline.[6] Since that trend can be expected to continue, the resource requirements in Table 3-6 are probably underestimated.

The factors that will mean less production per unit of investment toward the end of the century are:

- Exploration of deeper oil prospects, which entails more feet of drilling per well, fewer well completions per foot of drilling, slower drilling rates per foot of well, and greater expense per completed well.
- Exploration of more remote locations, which has characteristics of exploration of deeper prospects. Moreover, the drilling season is limited in such places as arctic offshore regions.
- Exploration of the "better" prospects will be completed.

a. Drill Rig Requirements

Oil production on land requires drill rigs for exploration--thereby the adage "the only true test for oil is the drill"--and for drilling development wells and the extra wells required by secondary and tertiary recovery or for workover. Onshore drill rigs are relatively mobile and are often truck-mounted.

Offshore oil production requires drill rigs both for exploratory drilling--jack-ups, semisubmersibles and ship-mounted rigs are the most common[7]--and for production at locations where permanent platforms complete the production wells and support the production equipment. In the future, more subsurface platforms (unmanned) are likely to be used because they are cheaper and lighter than surface platforms. The subsurface, unmanned platform is fixed to the ocean floor, and the wells are drilled by a mobile drillship, which moves on after placing the production tubing. The rig requirements shown for offshore production in Table 3-6 fall into these categories.

The rig requirement shown for Alaska in Table 3-6 includes both onshore rigs (rarely truck-mounted because of the severe environment of the North Slope tundra) and offshore rigs--similar to rigs used offshore in other areas with the exception of those designed for use in pack ice regions.[8,9] Many of the impacts on Alaskan offshore waters depend on the number of offshore rig requirements.

The HG3 scenario requires substantial drilling activity. Alaska, particularly, will see large increases in drilling activity. Because of much increased drilling for tertiary recovery under HG3, onshore continues to receive the most drilling activity.

b. Labor Requirements

The total number of rig crewmen required depends on the number of rigs in operation and whether they are operated on or offshore. Onshore rigs each require about 25 men, while offshore rigs each require about 50 men. Project Independence[4] estimates Alaskan rigs require somewhat fewer men than other onshore rigs--less than 20 men each; however, a backup crew is also required and a large number of support personnel are required, while in onshore production elsewhere support personnel are part of the general infrastructure.

Labor requirements for drilling and production grow substantially under HG3. The HG3 requirements in 2000 are double those in 1977. The rigmen required for offshore may be overestimated if subsurface production platforms become widely used toward the end of the century, as may be likely.

c. Steel Requirements

Steel is required for the construction of drill rigs and production platforms, for the production of the tubing used to support the drill during drilling, for the well casing, and for surface equipment such as storage tanks, equipment sheds, and pumps. The steel requirements shown in Table 3-6 reflect these needs and are probably underestimated since much of the steel required for tertiary production (the extra wells) is not included. Neither are steel requirements for oil transportation and distribution or refining included. These needs can be substantial, particularly for oil pipelines from remote regions. For example, the Trans-Alaska Pipeline (TAPS) will contain about 1.2 million tons of steel. Under HG3, the annual steel requirements are about 3,000,000 tons by 2000, with onshore production requiring the most steel (refer to Table 3-6).

An impact occurs during retirement of some production facilities--the irretrievable investment of steel. Offshore rigs may be left in place after their economic life is exceeded. During periods of falling prices, rigs may remain idle which represent a large energy investment in terms of the steel in the well pipe and rig. Some offshore rigs contain as much as 25,000 tons of steel. Whether this steel will be left in place forever remains an open question. To give some feeling for what this 25,000 tons of steel represents, we give the following illustrative calculation. An offshore production platform must produce about 30,000 B/D to be economically viable. This fuel rate will supply about 900,000 cars with each car using about 0.033 B/D (20 miles/gal and 10,000 miles/yr). At 1 ton each, these cars contain about 900,000 tons, or about 36 times as much steel as the offshore platform supplying their fuel.

2. Capital Investment

To our knowledge, Project Independence contains the most recent detailed estimates of investment in crude oil production,[4] and they have been adapted to form the basis of our projections. Unfortunately, these investments were based on the 1972 USGS resource estimates discussed in Appendix A. In order to create more realistic investment estimates for HG3, we have assumed that the investment projections in Project Independence cover only the annual investment necessary for primary and secondary recovery under HG3, and we have gone on to assume that additional investment is necessary for the substantial tertiary recovery required for oil production under HG3 (discussed in Appendix B).

Table 3-2 showed cumulative production by advanced recovery techniques necessary to support the HG3 production level from each region. For this production to take place, the resources in each region must first become economically producible reserves (Appendix A). The capital investment necessary to convert resources into economically producible reserves in each region is shown in Table 3-7. The Project Independence Oil Task Force Report shows the investment required per barrel of reserve added for 1974 and 1988. To estimate the minimum capital investment necessary to convert 70 billion barrels of resource into oil recovered by advanced techniques we have assumed that these

Table 3-7

CAPITAL INVESTMENT REQUIRED FOR SECONDARY AND TERTIARY RECOVERY

	Dollars (1973) per Barrel of Reserve Added	
	1974-1988	1988-2000
Secondary Recovery		
Region 1	$ 0.96	$ 1.92
Regions 2A, 6A, and 11A	0.64	1.28
Regions 2, 3-6, and 7-11	0.32	0.96
Tertiary Recovery		
Region 1	1.68	3.12
Region 2	1.50	3.00
Regions 2A, 6A, and 11A	1.12	2.14
Regions 3-6, 7-11	0.80	1.76

Source: Project Independence Blueprint,
Oil Task Force Report

investments pertain to the entire period to the year 2000 as shown in the table. The investments shown in the second column probably underestimate the necessary investment for HG3 since many of the better tertiary recovery prospects in each region will already be in production by the last decade of the century.

The approximate capital investment for recovery by advanced techniques is shown for onshore, offshore, and Alaska in Table 3-8. The investment estimates represent a probable lower limit to the necessary investment for reserves recoverable by tertiary methods since these estimates reflect only the tertiary recovery that is actually accomplished by 2000. In practice, there must be reserves of crude oil left after any given year; in the past, reserves have been about ten times annual production (Appendix C) so that additional investment, not shown in the Table 3-8, is required for the reserves left in the year 2000. We have assumed that the total investment for the two periods, 1974-1988 and 1988-2000, is divided uniformly on an annual basis. This probably will not be true in practice.

The approximate capital investment for all conventional oil recovery to the year 2000 is displayed in Table 3-9. Capital investment in constant dollars increases over two and half times between 1977 and 2000. Project Independence forecasts considerably less production from advanced recovery than is necessary for HG3 in the light of the 1975 USGS resource estimates.[2] Thus, we have assumed that the annual investment levels projected by Project Independence approximately cover the 60 billion barrels of production under HG3 that must come from primary and secondary recovery methods. The investment allocated for tertiary recovery in the Project Independence scenarios is probably comparable to the additional investment for the tertiary recovery reserves in 2000 left out of our analysis, so that any investment that

Table 3-8

APPROXIMATE CAPITAL INVESTMENT REQUIRED FOR ONSHORE, OFFSHORE, AND ALASKA OIL PRODUCTION BY ADVANCED RECOVERY TECHNIQUES

Region	Cumulative Production (10^9 barrels)	Investment per Barrel (1973 dollars)	Total Investment (10^9 1973 dollars)	Annual Investment (10^9 1973 dollars)
		1974-1988		
Onshore	17	$ 0.8	$ 14	$ 1.0
Offshore	7.5	1.1	8.3	0.6
Alaska	8.0	1.7	14	1.0
Total				2.6
		1988-2000		
Onshore	17	1.8	31	2.6
Offshore	7.5	2.1	16	1.3
Alaska	8.0	3.1	25	2.1
Total				6.0

Table 3-9

CAPITAL INVESTMENT IN CONVENTIONAL OIL PRODUCTION FOR HG3
(In 1973 dollars annually)

	1974	1977	1980	1985	1990	1995	2000
Onshore Recovery							
Primary and Secondary	1.3	1.4	3.3	3.9	3.9	3.9	3.9
Advanced*	1.0	1.0	1.0	1.0	2.6	2.6	2.6
Subtotal	2.3	2.4	4.3	4.9	6.5	6.5	6.5
Offshore Recovery							
Primary and Secondary	0.3	0.3	0.5	0.9	0.9	0.9	0.9
Advanced	0.6	0.6	0.6	0.6	1.3	1.3	1.3
Subtotal	0.9	0.9	1.1	1.5	2.2	2.2	2.2
Alaska							
Primary and Secondary	0.7	1.2	1.2	1.3	1.3	1.3	1.3
Advanced	1.0	1.0	1.0	1.0	2.1	2.1	2.1
Subtotal	1.7	2.2	1.2	1.3	3.4	3.4	3.4
Total	4.9	5.5	6.6	7.7	12.1	12.1	12.1

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*Primary and secondary recovery investment data up to 1985 adapted from Reference 4, Table IV-16, by excluding the heavy crude oil and tar sands data.

has been underestimated in Table 3-8 is probably made up by the over-investment in primary and secondary recovery implicit in Table 3-9.

The analysis in Appendix B leads to the conclusion that over 50 percent of the recovery should be coming from advanced recovery methods toward the end of the century. Because of the higher investment levels necessary for advanced recovery relative to primary or secondary recovery (refer to Table 3-7), the investment split between primary and secondary recovery and advanced recovery should be heavily weighted toward advanced recovery projects. Table 3-9 shows such an emphasis on advanced recovery. The estimates shown in Table 3-9 are designed largely for purposes of illustrating the necessary investment for HG3. We do expect, however, that the investment projections for advanced recovery and for overall recovery are approximately correct and reflect current expectation of investment for future recovery. Recent estimates[5] of future production and investment made by Texaco and published in the Oil and Gas Journal support the rough estimates and trends for investment and production shown here for HG3.

D. Projected Environmental Impacts

The scope of the research did not permit detailed assessment of the effect of oil extraction, distribution, and refining in the reference case on the environment; however, the material presented is sufficiently detailed to indicate the probable environmental consequences of an intensive and accelerated industry effort to extract the maximum amount of oil from onshore, offshore, and Alaskan sites. Only major impacts are treated here. They are broadly grouped into land use requirements, water requirements, employment and induced population, oil spill probabilities and quantities, and major air and water pollutant emissions. No attempt is made to rank the impacts in severity.

The environmental impacts of the reference case are determined by means of scaling factors for quantifiable characteristics of the oil extraction, transport, and refining processes. For example, operation of each barrel per day (B/D) of petroleum refining capacity is responsible for a volume of water effluent averaging 770 gallons per day. With a refining capacity of 20 million B/D, the water effluent would approximate $20 \times 10^6 \times 770$ gallons per day. This 15-billion gallon per day effluent volume is a quantitative indicator of the environmental impact of petroleum refining.

Scaling factors appropriate to the various activities involved in crude oil production, distribution, and importation are derived in Section 1, below. In Section 2, environmental impacts for onshore, offshore, and Alaskan production, and oil transport (domestic and imported) are developed by applying the scaling factors to the production estimates given in Section B and the equipment and labor requirements given in Section C, above.

1. Impact Scaling Factors

a. Crude Oil Production

The scaling factors necessary for evaluating the major environmental impacts of oil exploration and production on land use, air quality, and water quality are presented in four groups:

- Impacts of normal exploration activity
- Impacts of exploration accidents
- Impacts of normal production activity
- Impacts of production accidents.

(1) Normal Exploration Activities

Impact scaling factors for the major environmental impacts of normal exploration are shown in Table 3-10. The three major consequences of normal drilling activity[*] are qualitatively:

- "Boom towns," increased urban growth, increased automobile use, and increased demand for housing and recreation created by the presence of drilling crews, their families, and personnel in service industries. These impacts occur off the drilling site.
- Disturbed lands or ocean bottom, displaced species, water pollution, or road construction at or adjacent the drilling site.
- Solid waste produced by drilling, which may produce water pollution or undesirable land fill.

Many important impacts of exploration result from the normal human activities and demands of the exploration drillers, their families, and associated personnel in service industries. These impacts, of course, vary in severity depending on the degree of urbanization already existent in the region: the less the urbanization, the greater the impact.

Since individual environmental impacts that occur on the drilling site are too site-specific to quantify, Table 3-10 gives only the estimated land areas impacted by a typical drilling project onshore and offshore. Onshore exploration rigs, including storage ponds for drilling mud, occupy about one acre. Offshore rigs are considerably larger than onshore rigs, containing crew quarters, storage facilities

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[*] Other geophysical and exploration activity results in minimal environmental impact.

Table 3-10

IMPACT SCALING FACTORS FOR NORMAL EXPLORATION OPERATIONS

	Scaling Factor	
Impact	Quantity	Units[†]
Urban development, population growth consequences of human activity		People employed per exploration rig:[*]
	24	Onshore
	100	Offshore
	12	Alaska (onshore)
	60	Alaska (offshore)
Surface lands affected by drilling		Approximate land area disturbed by one drilling rig:
	1 acre	plus land for service road (onshore)
	1 acre	plus land for housing (Alaska onshore)
Submerged lands affected by exploratory drilling	3000 acres	Approximate offshore land area disturbed by an offshore drilling rig[11]
Solid waste produced by drilling rig--drill cuttings consisting of rock particles, sand, and drilling mud	63 tons	Weight of cuttings (tons) produced per 1000 ft of exploratory drilling[4]

[†] Approximate conversion factors: 1 acre = 4000 m^2, 1 ton = 907 kg, 1000 ft = 300 m.

[*] Inferred from Table 3-6

for equipment, and a processing area for drilling mud; their decks occupy 1 to 2 acres of surface area. Large semisubmersible exploration rigs have as many as 2 acres of surface area.[12]

Wells can be drilled as far as 6000 ft (slant range) from an offshore platform and may therefore tap an area of 4 square miles, or 2500 acres. About a 1 mile clear zone is maintained around offshore rigs, which is intended to prevent ships and tankers from colliding with the platform. Thus, an offshore platform impacts commercial fishing and navigation by the removal of about 3000 acres* of ocean surface from many alternative uses and by presenting a hazard to navigation.[7]

In Alaska, drilling sites entail greater acreage than do sites in the lower 48 states because large rigs, needed for the relatively deep wells, must also provide shelter from the weather for the workers. Moreover, onsite housing, airfields, and other facilities occupy considerable area. The Prudhoe Bay site consists of about 400 square miles, with only a small fraction occupied by exploration rigs.

Drilling produces considerable solid waste in the form of drill tailings--sand, rock particles, and some drilling mud. The average well is about 5000 ft (1.5 km) deep and would therefore produce some 300 tons (270,000 kg) of drill tailings. In exploratory drilling offshore, the USGS orders for OCS drilling allow onsite disposal of this material; other solid waste must be fully processed or returned to shore.[11] Little is known about the environmental effects of the disposal of drilling mud, although the unconsolidated sediment makes for a

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*Assuming 1 mile (1.6 km) distance between tankers and platform is maintained.

poor home for bottom-dwelling organisms.[13]

(2) Exploration Accidents

Table 3-11 shows the major scaling factor for the impacts of accidental or abnormal drilling operations. The environmental impacts of oil in the marine environment, mainly the death of large numbers of sea birds, the loss of aquatic life, have been widely discussed.[14-18]

Blowouts, a major source of oil entry into the environment, result from excessive uncontrolled pressure buildup in the well. During drilling, the drill mud composition and density are varied to assure that the weight of drilling mud equals or exceeds the pressure in the rock formation. An oil or gas pressure exceeding this weight can force the drilling mud back up the drill hole. The resulting excess pressure, if not controlled, forces mud and oil back up the well, which causes a blowout. Blowouts can cause loss of life, equipment failure, broken pipes, and other damage, and may result in fires as well as the uncontrolled release of oil into the environment.

Onshore, the probability of an oil blowout is much less than 1 in 2500, owing to the large number of high-pressure gas blowouts included in this estimate. In part, the reduced risks of onshore drilling come from the less sophisticated demands of onshore drilling and from the more frequent drilling in oil formations with known pressures.

Table 3-11

IMPACT SCALING FACTORS FOR EXPLORATION ACCIDENTS (BLOWOUTS)

Impact	Scaling Factor	
	Quantity	Units
Potential for human casualties, disruption and destruction of marine biota, and scenic losses from accidental discharge of oil into the environment (blowout)		Onshore probability of a blowout:
	1	well in 2500[19] (includes high pressure gas blowouts)
		Probability of a blowout offshore:
	1	well in 500[7] (includes high pressure gas blowouts)
	1	well in 3300 (not including gas blowouts)

(3) Normal Production Activities

Table 3-12 summarizes the impact scaling factors for the major environmental impacts from normal crude oil production activities. These impacts are:

- Disturbed lands or ocean bottom, displaced species, water pollution, or road construction at the drilling site.
- Increased urban growth, increased automobile use, and increased demand for housing and recreation caused by presence of production personnel, their families, and personnel in service industries. These impacts occur away from the production site.
- Water-related effects.
- Potential for air pollution.

The first two impacts are much the same as for exploration activities.

Much of the byproduct water from oil production is reinjected into the formation so that not all of the wastewater (which contains low concentrations of oil and perhaps chemicals used in advanced recovery) enters the environment. Water demands for secondary and tertiary recovery, although large, produce severe impacts only in regions with a scarcity of water. Water injection has a number of side effects. It can trigger seismic activity and the hydraulic pressure of water injection can cause surface deformation and faulting. The injection of chemicals into wells can result in contamination of the deep aquifers which are in contact with nearly all oil reservoirs.

Table 3-12

IMPACT SCALING FACTORS FOR NORMAL PRODUCTION OPERATIONS

	Scaling Factor	
Impact	Quantity	Units[*]
Urban growth, induced population and effects on the environment from human activity	13,000	Employees per million barrels per day of production[20]
Wastewater production from normal oil production operations	2×10^8	Gallons per million barrels per day of production[20]
Makeup water requirements--water injection for secondary and tertiary recovery	360×10^6	Gallons per million barrels per day of production[19]
Land use:		
Onshore	1/4	Acres per development well[10]
Offshore	3000	Acres per production platform[11]
Alaska--onshore	65,000	Acres per million barrels per day of production[21]
Alaska--offshore	3000	Acres per production platform[11]
Chemical requirements for tertiary recovery:		
Biopolymers and polyacrylamides	$1\text{-}6 \times 10^6$	Pounds per 10^6 barrels of oil produced[22]
Surfactants (sulfonates)	$7\text{-}15 \times 10^6$	"
Cosurfactants (isopropanol)	$4\text{-}10 \times 10^6$	"
Air pollutant emissions from tertiary recovery by thermal methods:		
Particulates	120	Tons per million barrels[†] of oil recovered
SO_2	1,000	"
NO_x	200-420	"
CO	21	"
Hydrocarbons	16	"
Solid waste production (drill cuttings and spent mud components)	63	Tons per 10^3 feet of well[‡]
Oil release into offshore environments from normal OCS operations	9	Barrels per million barrels per day of production[7]
Pollution from oil produced with onshore wastewater (untreated)	50	Barrels per million barrels per day of production[7]

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[*] Approximate conversion factors: 1 gal = 3.8×10^{-3} m^3, 1 ton = 907 kg, 1 barrel = 0.16 m^3, 1 pound = 0.45 kg, 1 acre = 4000 m^2.

[†] Thermal recovery of oil (steam injection) requires about 1 barrel of oil burned for steam for every four barrels produced.[23] Emissions are assumed to be the same as for burning residual fuel oil.[24]

[‡] Three times as many development wells are drilled as exploratory wells.[25]

Oil production can contribute to air pollution. In some regions in which it is uneconomical to transport oil's co-product, natural gas, by pipeline, the gas is flared. However, most gas is reinjected into the well if no gas transmission system is available. Tertiary recovery by thermal methods, particularly fire flooding or burning part of the oil underground to build heat and pressure in the well, can result in gaseous emissions from the formation. Recovery of high-sulfur crude may result in the release of highly toxic sulfurous gases.[26]

(4) Production Accidents

The impact scaling factors for abnormal production activities are listed in Table 3-13. The most important impact results from accidents to equipment, which release oil to the environment.

Most oil reservoirs contact groundwater aquifers. Many tertiary recovery projects will require the injection of large quantities of chemicals into oil formations and potentially can result in the exchange of water soluble chemicals with groundwater. In locations in which the hydrology is not well known, tracing the path of such chemicals into underground aquifers proves difficult.

About 98 percent of the oil entering the world's ocean environment results from man's activities.[7] Much of this oil results from accidents. To estimate a probability distribution from spills[27], we extrapolated historical data for the 25-year period between 1975 and 2000. These spill probabilities most likely represent upper limits for the number of large spills.

b. Crude Oil Distribution and Oil Imports

The crude oil distribution system has two main components—tankers and pipelines. At present, Alaskan oil flows from offshore

Table 3-13

IMPACT SCALING FACTOR FOR PRODUCTION ACCIDENTS

	Scaling	
Impact	Quantity	Units*
Major and minor offshore oil spills:		Mean number of spills per 10^6 barrels per day of production over 25 years[27]
More than 100,000 barrels	4.3	
Between 10,000 and 100,000 barrels	13	
Between 2,000 and 10,000 barrels	39	
Average amount of oil spilled in:		Barrels per 10^6 barrels of production[7]
Major accidents	140-530	
Minor accidents	25	

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*Approximate conversion factors: 10^6 B = 160,000 m^3

collector lines to onshore storage before being shipped by tanker to the lower 48 states. In the future, the Trans-Alaska Pipeline System (TAPS) will bring oil from Northern Alaska to Valdez for storage and tanker shipment to the lower 48 states. Pipelines transport most onshore oil, while tankers transport about 90 percent of the imported oil. Currently, most Canadian crude oil arrives by pipeline, but recent trends in Canadian policy make any significant crude oil shipments to the United States after 1982 unlikely.[28, 29]

The major impacts of the crude oil distribution system result from construction of pipelines, tanker ports, and storage facilities (tank farms), from the normal operations of tankers, and from the abnormal operations of tankers, pipelines, and onshore storage facilities.

(1) Pipelines

Table 3-14 presents the scaling factors for the major impacts of future pipeline construction. Since the present TAPS is limited in capacity to about 2.5-million B/D, a second pipeline would be required to increase production up to the 3.4-million B/D from the entire North Slope unde HG3.

The normal operation of pipelines results in minimal impact. Most onshore pipelines are buried and unobtrusive. Offshore pipelines at depths shallower than 200 ft are also buried and present minimal impact. Even the labor force necessary to operate a pipeline is small by comparison with employment for refining crude oil. For example, TAPS will employ only 300 people during its operation.[32] For the entire oil industry, only about 5 percent of the total employment is for pipeline operation--about 20,000 in 1973.[25]

Table 3-14

IMPACT SCALING FACTORS FOR THE PIPELINE DISTRIBUTION SYSTEM

Impact	Scaling Factor	
	Quantity	Units†
Pipeline construction: soil disturbance, vegetation removal[1]	8000	Miles per 10^6 B/D increase in crude oil supply
Air pollution from new pipelines onshore and offshore[3]		
Particulates	1.25	Tons/day per 1000 miles pipeline
SO_2	16	"
Hydrocarbons	0.38	"
NO_x	5-8.8	"
CO	0.50	"
Air pollution from a TAPS[4]		
Particulates	2	Tons/day per 1000 miles pipeline
SO_2	25	"
Hydrocarbons	2	"
NO_x	36	"
CO	11	"
Offsite impacts induced by employment, urbanization, and recreation demands		
Onshore[5]	> 0	Employees per 1000 miles of pipeline
Alaska[6]	300	Employees per Trans-Alaska Pipeline System

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[1] Assuming a second TAPS from Naval Petroleum Reserve Number 4 to Valdez.

[2] Assuming 50 percent of the total pipeline mileage of 220,000 miles[19] (AF 299, Table 20) is used for crude oil transportation and assuming 13 million barrels per day of crude oil transported by pipeline. Both numbers are for 1971.

[3] A 24-inch diameter crude oil pipeline requires 150 horsepower per mile of pipe.[30] Using distillate fueled pumps which use 0.064 gallons of fuel per horsepower hour, we calculate 0.3 x 10^5 gallons of distillate fuel per 1 mile of pipe per day. Emission factors for distillate fuel burning pumps are:

SO_2--142 lbs/10^3 gal, particulates--15 lbs/10^3 gal, NO_x--40-80 lbs/10^3 gal, CO--4 lbs/10^3 gal.

Source: Compilation of Air Pollutant Emission Factors, Third Edition, U.S. Environmental Protection Agency, 1973.[24]

[4] Summary Report Air Quality: "Stations and Related Facilities for the Trans-Alaska Pipeline," Alyeska Pipeline Service Company, April 1974, p. 6-3[31] We assume a second TAPS would have these same emission factors.

[5] Based on the average number of employees per mile of pipe (16,000 for 220,000 miles of pipeline).

[6] Permanent employment for TAPS is anticipated to be 300 people.

†Approximate conversion factors: 10^6B = 160,000 m^3
1 ton = 907 kg
1 mile = 1.6 km

(2) Tankers

Normal tanker operations have the potential to create more environmental impact than do pipeline operations. Table 3-15 highlights the major impacts and scaling factors for normal tanker operations. The two major impacts are oil releases to the marine environment and sewage disposal. Tankers, generally in port only a few days, produce little sewage in U.S. waters. The control of tanker ballast cleaning operations, which can be a major source of water pollution, cannot be controlled beyond the U.S. 12-mile limit.

Table 3-16 shows the major impacts from storage facilities. TAPS storage is the only storage facility included since most other oil storage is located at refinery sites.

(3) Tanker and Pipeline Accidents

Tanker groundings and collisions have resulted in major oil spills, for example, the Torrey Canyon. Dragged anchors have resulted in several pipeline breaks, which released large quantities of oil.[33] Table 3-17 indicates scaling factors for the tanker and pipeline accidents that are the most likely to occur.

c. Refineries

Many of the impacts of refineries come from the manpower, materials, capital, and water requirements for its construction and operation. To provide information on refineries, analagous to that presented in the MCI scenario (Chapter 6) for the synthetic fuels technologies, Table 3-18 shows the impact scaling factors for refinery

Table 3-15

IMPACT SCALING FACTORS FOR NORMAL TANKER OPERATIONS

Impact	Scaling Factor	
	Quantity	Units*
Oil releases to the marine environment from ballast cleaning		
Alaska to Pacific Coast[7]	13-270	Barrels/1,000,000 barrels transported
Sewage from tanker operation in coastal waters[†]		
Imports[11]	1.5	10^3 gal/tanker-day
Alaska[11]	1	10^3 gal/tanker-day

---

[*] Approximate conversion factors: 10^6 B = 160,000 m^3
10^3 gal = 3.8 m^3

[†] Tankers are in port about 36 hours.

Table 3-16

IMPACT SCALING FACTORS FOR TRANS-ALASKA PIPELINE STORAGE TERMINAL AND DEEPWATER TERMINAL

	Scaling Factor	
Impact	Quantity	Units[*]
Land disturbance and land withdrawn from alternative uses[34]	800	Acres per TAPS pipeline
Tankers[34]	3	100,000 Dwt[†] tankers/day
Potential oil spills from ruptured storage tanks during an earthquake[36]	44	510,000 barrels per tank
Permanent employment[34]	100	People

---

[*] Approximate conversion factors: 1 acre = 4000 m^2
1 ton = 907 kg
1 barrel = 0.16 m^3

[†] Dwt = Dead weight tons

Table 3-17

IMPACT SCALING FACTORS FOR CRUDE OIL PIPELINES AND TANKER ACCIDENTS

Impact		Scaling Factor	
		Quantity	Units*
Maximum oil spill from break in an offshore pipeline		3,000	Barrels/mile of 24-inch pipeline
Maximum oil spill from break in TAPS[35]		50,000	Barrels/break
Maximum oil spill from breakup of a 200,000-Dwt[†] tanker		1,400,000	Barrels/tanker
Maximum oil spill from rupture of storage tanks for TAPS		20,000,000	Barrels/TAPS storage facility
Major accidents:[7]	Imports	34	Barrels/million barrels transported
	Alaska	34-182	"
Minor accidents:[7]	Imports	1.5	"
	Alaska	3	"

---

*Approximate conversion factors: 1 barrel = 0.16 m^3
1 inch = 0.025 m

†Dwt = Dead weight tons

Table 3-18

SCALING FACTORS FOR RESOURCE REQUIREMENTS FOR 10^6-B/D REFINERY CAPACITY

Item or Resource Required	Scaling Factors	
	Quantity	Units*
Construction		
Capital[37]	2,000	10^6 1973 \$ (cumulative)
Labor[38]	37,500	Man-years (cumulative)
Land[10]	22,000	Acres
Steel[38]	850	10^3 tons
Operation		
Capital[37]	500	10^6 1973 \$/year
Labor[39]	9,500	Number permanent employees
Water[37]	60	10^3 acre-ft/year
Electric power[10]	250	MW

---

*Appropriate conversion factors: 1 acre = 4000m^2, 1 ton = 907 kg,
1 acre-ft = 1,200 m^3, 10^6B = 160,000 m^3

construction and operation. Table 3-19 shows the major environmental scaling factors for plant operation.

Refinery emissions are the major source of air pollution for the reference case, even when the average emission rates for the well-controlled, relatively low emission refineries of Los Angeles are used in the calculations. Thus, the scaling factors in Table 3-19 reflect well-controlled sources.

Refineries demand more water than any other element in the reference case system.

Refineries also account for about one-third of the necessary employment for the reference case, with crude oil production requiring most of the remaining two-thirds of the employment. Many of the offsite or indirect impacts from population in the reference case result from refinery employment.

2. Environmental Impacts

a. Onshore Production

The environmental impacts from tertiary recovery which will be the major source of new impacts onshore are shown in Table 3-20. These impacts will be the drilling activity necessary to begin tertiary recovery,* the growth of a chemical industry to produce the necessary chemicals for micellar flooding, and the air pollutant emissions from oil combustion to produce steam for injection.

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*We have assumed a relative recovery rate for tertiary recovery by various methods of:[40] Thermal: 29%, Micellar: 58%, CO_2: 8%, Hydrocarbon miscible: 5%

Table 3-19

IMPACT SCALING FACTORS FOR 10^6-B/D REFINERY CAPACITY

Impact	Scaling Factor	
	Quantity	Units*
Disturbed land or land removed from alternative uses	4400	Acres[10]
Solid waste production (sludge)	80	Cubic yards per day[20]
Wastewater production	420	10^6 gallons per day[20]
Water pollution[10]		
BOD	15	Tons/day
COD	55	Tons/day
Oil	4.0	Tons/day
Phenols	1.0	Tons/day
Suspended solids	10	Tons/day
Dissolved solids	250	Tons/day
Sulfides	1.5	Tons/day
Phosphorus	0.5	Tons/day
Nitrogen	2.0	Tons/day
Air pollution[10]		
Particulates	5.5	Tons/day
SO_2	76	Tons/day
Hydrocarbons	69	Tons/day
NO_x	34	Tons/day
CO	41	Tons/day
Offsite impacts induced by employment, urbanization, and recreation demands		
Permanent employees[39]	9500	People
Total population	32,500	Population multiplier (6.5) times the number of people†

---

[*] Approximate conversion factors: 1 acre = 4000 m^2, 1 ton = 907 kg, 1 cubic yd = 0.76 m^3.

[†] Population multipliers are discussed in Chapter 23.

Table 3-20

ENVIRONMENTAL IMPACTS FROM ONSHORE OIL PRODUCTION UNDER THE REFERENCE CASE

Impact Scaling Factors and Scenario Quantities											
Activity	Impact	Impact Scaling Factor		Scenario Quantity which Determines Impacts				Quantitative Indicator of Environmental Impact			
		Quantity	Units*	1975	1985	2000	Units*	1975	1985	2000	Units*
Exploration	Urbanization and induced population										
	Employees	24	People/rig	1,100‡	1,250	1,250	Rigs	25‡	29	29	10^3 people
	Total population	6.5	People/employee	25‡	29	29	10^3 employees	160‡	190	190	10^3 people
	Solid waste produced by drilling	63	Tons/10^3 ft		1975 - 2000 9.5		10^8 ft of exploratory well†		1975 - 2000 60		10^6 tons†
	Land area disruption by drilling	1	Acre/exploratory well		1975 - 2000 190		10^3 wells†		1975 - 2000 190		10^3 acres†
Production	Urbanization and induced population										
	Employees	13,000	People/employee	8.9	6.2	5.0	10^6 B/D	116	81	65	10^3 employees
	Total population	6.5		116	81	65	10^3 employees	750	520	420	10^3 people
	Wastewater production	210	g/water/B oil	8.9	6.2	5.0	10^6 B/D oil	1.9	1.6	1.1	10^6 g/D
Tertiary recovery by all methods								0	3.5	4.0	10^6 B/D
Tertiary recovery by chemical methods40		0.58	Total tertiary recovery	0	3.5	4.0	10^6 B/D Tertiary recovery	0	2.0	2.3	10^6 B/D
Chemical requirements	Chemical production										
	Biopolymer and Polyacrylamide	1-8	Lbs/B oil	0	2.0	2.3	10^6 B/D	0	0.7 - 5.8	0.8 - 6.7	10^9 lbs/yr
	Surfactants (Hydrocarbon Sulfonates)	7-15	Lbs/B oil	0	2.0	2.3	10^6 B/D	0	5.1 - 11	5.9 - 13	10^9 lbs/yr
	Co-surfactants (Isopropanol)	4-10	Lbs/B oil	0	2.0	2.3	10^6 B/D	0	2.9 - 7.3	3.4 - 8.4	10^9 lbs/yr

Table 3-20

ENVIRONMENTAL IMPACTS FROM ONSHORE OIL PRODUCTION UNDER THE REFERENCE CASE

Impact Scaling Factors and Scenario Quantities											
Activity	Impact	Impact Scaling Factor		Scenario Quantity which Determines Impacts				Quantitative Indicator of Environmental Impact			
		Quantity	Units*	1975	1985	2000	Units*	1975	1985	2000	Units*
Tertiary recovery by thermal methods[40]		0.29	Total Tertiary recovery	0	3.5	4.0	10^6 B/D	0	1.0	1.2	10^6 B/D
	Air pollution										
	Particulates	0.12	10^3 tons/10^6 B oil recovered	0	1.0	1.2	10^6 B/D	0	0.12	0.14	10^3 tons/D
	SO_2	1	"					0	1	1.2	"
	NO_x	0.2 - 0.4	"					0	0.2 - 0.4	0.24 - 0.48	"
	CO	0.02	"					0	0.02	0.02	"
	Hydrocarbons	0.02	"					0	0.02	0.02	"
Production	Land disruption	1	Acres/development well		1975 - 2000 570		10^3 development well†		1975 - 2000 570		10^3 acres†
	Solid waste production	3	Times the amount of waste produced by exploration		1975 - 2000 70		10^6 tons†		1975 - 2000 210		10^6 tons†

---

*Approximate conversion factors: 1 gal = 3.79 x $10^{-3} m^3$, 1 ton = 907 kg, 1 acre = 4.05 x 10^3 m^2, 1 ft = 0.305 m, 10^6 B = 160,000 m^3, 1 pound = 0.454 kg, 1 mile = 1.61 km

†Accumulative for period indicated.

‡Applies to 1980 only, not 1975.

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Tertiary recovery, which requires many new wells in fields already producing under primary and secondary recovery, will bring an influx of drill rigs and well development personnel. This influx of personnel and their families can be expected to produce boom-town conditions in small communities that border large oil fields. For example, West Texas and Rock Springs, Wyoming, currently experience considerable oil-related activity as a result of recent crude oil price increases.

The most significant potential for adverse environmental effect will result from the production and use of large quantities of chemicals necessary for tertiary recovery (up to 10 billion lbs/yr [4.5×10^9 kg/yr] of some of the chemicals). Many of these chemicals are hazardous; polyacrylamide, for example, is carcinogenic. The isopropanol production shown in Table 21 for example, will, in the year 2000, be at about the level of today's methanol production. At present, no large-scale commercial production capacity exists for manufacturing these chemicals.

With onshore production likely to begin a long-term decline sometime in the next few decades,[3,6,41] and with production unlikely to increase significantly up to the onset of long-term decline, little onshore construction directly related to production can be expected. For example, pipeline construction will be confined mainly to that necessary for the transport of oil from tanker ports and from new offshore and Alaskan oil fields.

Total oil industry employment directly related to onshore production should also remain constant or decline with production through the end of the century.

b. Alaska Production

Under the reference case, Alaska undergoes the most substantial increase in oil production since the current production of about 200,000 B/D (32,000 m^3/D) is projected to grow to over 3,400,000 B/D (540,000 m^3/D) by the year 2000--far greater than any increase projected for other regions. The environmental impacts from this production increase are shown in Table 3-21.

The large projected rise in oil production employment in Alaska, from the current 3,000 to 57,000 by the year 2000, suggests that this state, with a current population of only about 350,000, will experience considerably more population related impacts than any other region under the reference case. This is particularly true if the 6.5 employment multiplier can be used to estimate the total increase in population of over 370,000 people. These impacts will be concentrated along the coastline of the Gulf of Alaska, along the North Slope, and in the Fairbanks region since it is the only large city close to the North Slope.

With the largest area of unspoiled wilderness in the nation and the second largest volume of crude oil reserves of all the states (Texas has more), Alaska will likely become a legal and institutional battleground for advocates of wilderness values and advocates of resource development. Opening the road to Prudhoe Bay to the public will allow more people access to northern Alaska than ever before, and perhaps will result in more environmental damage than the current TAPS construction project or the construction of a second pipeline as required in the reference case.

Alaskan offshore production can be expected to result in oil spills off the coast. Two very large oil spills (over 100,000 barrels

Table 3-21

ENVIRONMENTAL IMPACTS ON ALASKA UNDER THE REFERENCE CASE

Impact Scaling Factors and Scenario Quantities

Activity	Impact	Impact Scaling Factor		Scenario Quantity which Determines Impacts				Quantative Indicator of Environmental Impact			
		Quantity	Units*	1975	1985	2000	Units*	1975	1985	2000	Units*
Exploration	Urbanization and induced population										
	Employment										
	Onshore	12	People/rig	$125^{\ddagger}$	150	150	Rigs	$1,500^{\ddagger}$	1,800	1,800	Employees
	Offshore	60	People/rig	$52^{\ddagger}$	110	110	Rigs	$3,100^{\ddagger}$	6,500	6,500	Employees
	Total population§	6.5	People/employee	$5,000^{\ddagger}$	8,000	8,000	Employees	$33^{\ddagger}$	52	52	10^3 people
					1975 - 2000				1975 - 2000		
	Solid waste production										
	Onshore	63	Tons/10^3 ft of well		6600		10^3 ft of well†		0.42		10^6 tons†
	Offshore	63	Tons/10^3 ft of well		3800		10^3 ft of well†		0.24		10^6 tons†
					1975 - 2000				1975 - 2000		
	Onshore land area disruption	5	Acres/well		660		Number of exploratory wells†		3300		Acres†
					1975 - 2000				1975 - 2000		
	Offshore	3,000	Acres/well		380		Number of exploratory wells drilled†		1.1		10^6 acres†
Production (normal)	Urbanization and induced population										
	Employees	13,000	Employees per 10^6 B/D	0.2	3.6	4.4	10^6 B/D production	2.6	47	57	10^3 employees
	Total population	6.5	People	2.6	47	57	10^3 employees	17	300	370	10^3 people
	Low-level oil releases to the offshore marine environment	9	B per 10^6 B/D production	0.2	0.5	0.96	10^6 B/D	1.8	4.5	8.6	B/D oil
	Wastewater production from onshore production	210	gal/B oil	0	3.1	3.4	10^6 B/D	0	0.65	0.71	10^9 gal/D
	Onshore land area disruption	65	10^3 acres per 10^6 B/D oil production	0	3.1	3.4	10^6 B/D oil	0	200	220	10^3 acres
	Offshore land area disruption	3	10^3 acres per production platform	$12^{\ddagger}$	25	25	Production platform	$39^{\ddagger}$	75	75	10^3 acres

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Table 3-21

ENVIRONMENTAL IMPACTS IN ALASKA UNDER THE REFERENCE CASE

Impact Scaling Factors and Scenario Quantities

Activity	Impact	Impact Scaling Factor		Scenario Quantity which Determines Impacts				Quantative Indicator of Environmental Impact			
		Quantity	Units*	1975	1985	2000	Units*	1975	1985	2000	Units*
					1975 - 2000				1975 - 2000		
Production (normal)	Solid waste production Onshore	3	Times total solid waste from exploration		0.42		10^6 tons†		1.3		10^6 tons†
	Offshore	3	"		0.24		10^6 tons†		0.72		10^6 tons†
Exploration (abnormal operations)	Blowouts and accidental release of oil into the environment. Bird losses, oiled beaches, fire, loss of life.				1975 - 2000				1975 - 2000		
	Onshore	0.4	per 10^3 wells drilled		660		Number of wells drilled†		0.3		Mean number of blowouts†
	Offshore	0.3	per 10^3 wells drilled		280		Number of wells drilled†		0.1		"
Production (abnormal operations)	Size of accidental oil spills from offshore operations				1975 - 2000				1975 - 2000		
	Greater than 100,000 B	4.3	Mean number of spills per 10^6-B/D production over 25 years		0.5		(Average production)10^6 B/D†		2.2		Mean number of very large oil spills†
	Between 10,000 B and 100,000 B	13	Mean number of spills per 10^6-B/D production over 25 years		0.5		(Average production) 10^6 B/D†		6.5		Mean number of large spills†
	Size of oil spills Between 2,000 B and 10,000 B	39	Mean number of spills per 10^6-B/D production over 25 years		0.5		(Average production)10^6 B/D†		19		Mean number of moderately large spills over 25 years†

Table 3-21

ENVIRONMENTAL IMPACTS IN ALASKA UNDER THE REFERENCE CASE

Impact Scaling Factors and Scenario Quantities

Activity	Impact	Impact Scaling Factor		Scenario Quantity which Determines Impacts				Quantative Indicator of Environmental Impact			
		Quantity	Units*	1975	1985	2000	Units*	1975	1985	2000	Units*
Pipeline construction over 1000 miles of terrain from Naval Petroleum Reserve Number 4 to Valdez.	Air pollution from second TAPS	1000	Miles/TAPS	0	3.1	3.4	10^6 B/D production	0	1,000	1,000	
	Particulates	2	Tons/day	0	1	1	Number of additional TAPS	0	2	2	Tons/day
	SO_2	25	Tons/day	"	"	"		0	25	25	Tons/day
	Hydrocarbons	2	Tons/day	"	"	"		0	2	2	Tons/day
	NO_x	36	Tons/day	"	"	"		0	36	36	Tons/day
	CO	11	Tons/day	"	"	"		0	11	11	Tons/day
	Induced urbanization population and employment										
	Employees	300	People/TAPS	0	2	2	Number of TAPS	0	600	600	Employees
	Total population	6.5	People/employee	0	600	600	Employees	0	4,000	4,000	People
	Land disruption through construction of new oil storage facility for TAPS Number 2.	800	Acres	0	1	1	Number of new TAPS	0	800	800	Acres
									1980 - 2000		
Pipeline and distribution system (abnormal operations)	Potential oil spill from rupture of storage tanks at Valdez	510,000	B/tank	0	44	44	Number of tanks		20		Maximum potential oil spill-10^6 B
	Potential oil spill from rupture of TAPS	50,000	B/rupture						0.05		"
	Potential oil spill from tanker grounding	1.5 x 10^6B	B/tanker						1.5		"

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*Approximate conversion factors: 1 gal = 3.79 x $10^{-3}m^3$, 1 ton = 907 kg, 1 acre = 4.05 x 10^3 m^2, 1 ft = 0.305 m, 10^6B = 160,000 m^3, 1 pound = 0.454 kg, 1 mile = 1.61 km.

†Cumulative for period indicated.

‡Applies to 1980 only, not to 1975.

§Employees plus associated population.

of oil) can be expected as the mean number over the next 25 years. All Alaskan crude oil will probably be shipped to the West Coast states by tanker; which implies oil spills and sewage production that occur from tanker operations may impact the Pacific coastline from Alaska to California.[11]

Oil spill from earthquake damage to the Valdez storage facility, with its 20-million barrel capacity, is possible, particularly with the frequency and severity of tremors along the Gulf of Alaska[*] (Valdez was destroyed by the 1964 earthquake).

A second TAPS for transportation of oil from Naval Petroleum Reserve Number 4 (NPR4) to Valdez is required sometime in the 1980s. Considerable impact will be associated with its construction although additional road construction would be needed only across the North Slope tundra from the present pipeline corridor to NPR4.

Many of the impacts in Alaska, although quantitatively less than for onshore production (compare similar categories in Tables 3-20 and 3-21), will be severe in Alaska because relatively few areas will be impacted due to the geographic concentration of resources. Oil production from Alaska will increase many fold under the reference case and the impacts can be expected to rise proportionately.

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[*] Between 1899 and 1973, 13 earthquakes with magnitude over 7.0 on the Richter Scale have occurred.[11]

c. Offshore Production with Attendant Transport and Refining Operations

The impacts from refinery construction under HG3 are given for two cases: (1) in which all imported oil is unrefined, and (2) in which 50 percent of the imported oil is already refined. If all imported oil is in the form of refined products, then no new refinery capacity is required. Table 3-22 shows the environmental impacts from offshore production, Tables 3-23 and 3-24 show the requirements for additional refinery construction and operation, and Table 3-25 shows the environmental impacts from refinery operation.

The coastlines receive a large share of the environmental impacts under the reference case, not only because considerable crude oil production will take place offshore, but because the possibility of large-scale oil spills from production and tanker accidents adds ecological disaster potential without analogy in onshore oil production. New refinery capacity is likely to be built along the coastlines at locations at which the increase in crude oil production under HG3 will be delivered. Unless all imports are in the form of refined products, additions to refinery capacity will be required under HG3. Expansion of existing refineries (already concentrated on the coastal regions, particularly the Gulf coast) will cover much of the projected needs.

The mean number of large oil spills (over 100,000 barrels) under HG3 is projected to be 13 over the next 25 years.

Employment-related impacts from offshore oil production will triple under HG3. Offshore-production-related employment will grow from 18,000 to 52,000. Of course, the impacts related to this employment will be dispersed over the Atlantic, Gulf, and Pacific coasts.

The coastal regions experience the most pipeline construction under the reference case. Offshore solid waste from well drilling will

Table 3-22

ENVIRONMENTAL IMPACTS FROM OFFSHORE DEVELOPMENT AND TANKER OPERATIONS UNDER THE REFERENCE CASE.

Impact Scaling Factors and Scenario Quantities											
Activity	Impact	Impact Scaling Factor		Scenario Quantity which Determines Impacts				Quantative Indicator of Environmental Impact			
		Quantity	Units*	1975	1985	2000	Units*	1975	1985	2000	Units*
Exploration	Urbanization and induced population along coastlines										
	Employees	100	Employees/rig	$370^{\ddagger}$	500	500	Rigs	$37^{\ddagger}$	52	52	10^3 employees
	Total population	6.5	People per employee	$37^{\ddagger}$	52	52	10^3 employees	$240^{\ddagger}$	340	340	10^3 people
	Tons of drill cuttings	63	Tons/10^3 ft of exploratory well		1975 - 2000 11		10^7 ft of well†		1975 - 2000 6.9		10^6 tons†
	Offshore land disruption	3,000	Acres per exploratory well		11		10^3 wells†		11		10^6 acres†
Production	Induced urbanization and employment										
	Employees	13,000	Employees per 10^6 B/D	1.4	3.0	4.0	10^6 B/D	18	39	52	10^3 employees
	Total population	6.5	People per employee	18	39	52	10^3 employees	117	254	338	10^3 people
	Tons of drill cuttings	3	Times that produced by exploration		1975 - 2000 6.9		10^6 tons†		1975 - 2000 21		10^6 tons†
	Offshore land disruption	3,000	Acres/production platform	$150^{\ddagger}$	200	200	Production platforms	0.5	0.6	0.6	10^6 offshore acres
	Low concentration oil releases to the marine environment										
	Atlantic OCS	9	B/10^6 B oil produced	0	0.04	0.6	10^6 B/D oil production	0	0.36	0.54	B oil per day
	Gulf OCS	9	B/10^6 B oil produced	1.3	2.3	2.0	10^6 B/D oil production	12	21	18	B oil per day
	Pacific OCS	9	B/10^6 B oil produced	0.058	0.6	1.2	10^6 B/D oil production	0.5	5.4	11	B oil per day

Table 3-22

ENVIRONMENTAL IMPACTS FROM OFFSHORE DEVELOPMENT AND TANKER OPERATIONS UNDER THE REFERENCE CASE.

Impact Scaling Factors and Scenario Quantities											
Activity	Impact	Impact Scaling Factor		Scenario Quantity which Determines Impacts				Quantative Indicator of Environmental Impact			
		Quantity	Units*	1975	1985	2000	Units*	1975	1985	2000	Units*
Exploration (Abnormal activities)	Blowouts and accidental oil releases to the marine environment: bird deaths, spoiled beaches, damage to fisheries, cleanup costs, fire and equipment damage	0.3	per 1000 exploratory wells drilled		1975 - 2000 11,000		Exploratory wells†		1975 - 2000 3		Mean number of blowouts expected†
Production (Abnormal activities)	Sizes and frequency of probable number of oil spills:										
	Greater than 100,000 B	4.3	Mean number of spills per 10^6 B of production per 25 years		3.0		Average over 25 years 10^6-B/D oil production		13		Mean number of very large spills over 25 years
	Between 10,000 B and 100,000 B	13	Mean number of spills per 10^6-B/D production over 25 years		3.0		"		39		Mean number of large spills over 25 years
	Between 2,000 B and 10,000 B	39	Mean number of spills per 10^6-B/D production		3.0		"		120		Mean number of moderately large spills over 25 years
Crude Oil Pipeline System	Offshore pipeline construction - seabed disturbance and potential navigational hazard	8,000	Miles of pipeline per 10^6 B/D increase in crude oil supply	0	1.7	2.7	10^6 B/D increase over 1974 production	0	14	22	10^3 miles of offshore pipeline

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Table 3-22

ENVIRONMENTAL IMPACTS FROM OFFSHORE DEVELOPMENT AND TANKER OPERATIONS UNDER THE REFERENCE CASE.

Impact Scaling Factors and Scenario Quantities											
Activity	Impact	Impact Scaling Factor		Scenario Quantity which Determines Impacts				Quantative Indicator of Environmental Impact			
		Quantity	Units*	1975	1985	2000	Units*	1975	1985	2000	Units*
Crude Oil Pipeline System	Air pollutant emissions increase from new offshore crude oil pipelines:										
	Particulates	1.25	Tons per 10^3 miles of pipeline	0	14	22	10^3 miles of pipeline	0	18	28	Tons/day
	SO_2	16					"	0	220	350	"
	Hydrocarbons	0.38					"	0	5.3	8.4	"
	NO_x	5-8.8					"		70-120	110-190	"
	CO	0.50					"		7	11	"
	Urbanization and associated population; recreation demands										
	Employees	70	Employees per 1000 miles of new pipeline	0	14	22	1000 miles new pipeline	0	0.9	1.5	10^3 employees
	Total population	6.5	People/employee	0	0.9	1.5	10^3 employees	0	5.9	10	10^3 people
Tanker Operations	Oil release to the marine environment from ballast cleaning operations										
	Alaskan Pacific Coast oil shipped to west coast ports	13-270	B/10^6 B transported from Alaska	0.2	3.6	4.4	10^6 B/D oil from Alaska	2.6 to 54	47 to 970	57 to 1200	B/D
	Sewage produced in coastal waters by tankers:										
	By imports	1.5	10^3 gal/tanker	4	7.5	12	200,000 dwt tankers/day	6	11	18	10^3 gal/D
	By Alaskan oil tankers	1.0	10^3 gal/tanker - day	3	40	50	Tankers	3	40	50	10^3 gal/D
	Probable oil spills										
	Major										
	Imports	34	B/10^6 B transported	6.0	11.5	18.4	10^6 B/D oil transported	200	390	630	B/D oil
	Alaskan oil	34-180	B/10^6 B transported	0.2	3.6	4.4	10^6 B/D oil transported	6.8 to 36	120 to 650	150 to 790	B/D oil

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Table 3-22

ENVIRONMENTAL IMPACTS FROM OFFSHORE DEVELOPMENT AND TANKER OPERATIONS UNDER THE REFERENCE CASE.

Impact Scaling Factors and Scenario Quantities

Activity	Impact	Impact Scaling Factor		Scenario Quantity which Determines Impacts				Quantative Indicator of Environmental Impact			
		Quantity	Units*	1975	1985	2000	Units*	1975	1985	2000	Units*
Tanker operations	Probable oil spills Minor Imports	1.5	$B/10^6$ B transported	6.0	11.5	18.4	10^6 B/D oil transported	9	17	28	B/D oil
	Alaskan oil	3	$B/10^6$ B transported	0.2	3.6	4.4	10^6 B/D oil transported	0.6	11	13	B/D oil

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*Approximate conversion factors: 1 gal = 3.79×10^{-3} m^3
1 ton = 907 kg
1 acre = 4.05×10^3 m^2
1 ft = 0.305 m
10^6B = 160,000 m^3
1 pound = 0.454 kg
1 mile = 1.61 km

†Cumulative for period indicated.

‡Applies to 1980 only, not to 1975.

Table 3-23

NEW REFINERY REQUIREMENTS FOR REFERENCE CASE OVER AND ABOVE 1975 REFINERY CAPACITY IMPORTS ARE CRUDE OIL ONLY

Data and Assumptions			Impact for Year		
			1975	1985	2000
Production Schedule: Refinery Capacity increase over 1975 in 10^6 Barrels per Day			0	12.0	19.0
Inputs and Outputs		Scaling Factors per 10^6 B/D of new capacity (in units specified)			
Items	Units*				
Construction					
Capital	10^6 1973 \$ (cumulative)	2,000	0	2.4×10^4	3.8×10^4
Labor	Man-years (cumulative)	38,000	0	4.5×10^5	7.1×10^5
Steel	10^3 tons (cumulative)	850	0	1.0×10^4	1.6×10^4
Land	10^3 acres	22	0	260	420
Operation					
Operating costs	10^6 1973 \$/year	500	0	6×10^3	9.5×10^3
Labor force	Number of people	9,500	0	1.1×10^5	1.8×10^5
Water	10^3 acre-ft/year	60	0	720	1,100
Electric power	MW	250	0	3,000	4,800

*Approximate conversion factors: 1 gal = $3.79 \times 10^{-3} m^3$, 1 ton = 907 kg, 1 acre = $4.05 \times 10^3 m^2$, 1 ft = 0.305 m, 10^6B = 160,000 m^3, 1 pound = 0.454 kg, 1 mile = 1.61 km

Table 3-24

NEW REFINERY REQUIREMENTS FOR REFERENCE CASE OVER AND ABOVE 1975 REFINERY CAPACITY (50 PERCENT OF IMPORTS ARE REFINED PRODUCTS)

Data and Assumptions			Impact for Year		
			1975	1985	2000
Production Schedule: Additional Capacity in Units of 10^6 B/D			0	5.9	9.3
Inputs and Outputs		Scaling Factors for a 10^6 B/D Plant (in units specified)			
Items	Units*				
Construction					
Capital	10^6 1973 $ (cumulative)	2,000	0	1.2×10^4	1.9×10^4
Labor	Man-years (cumulative)	38,000	0	2.2×10^5	3.5×10^5
Steel	10^3 tons (cumulative)	850	0	5.0×10^3	7.9×10^3
Land	10^3 acres	22	0	130	200
Operation					
Operating costs	10^6 1973 $/year	500	0	3×10^3	4.7×10^3
Labor force	Number of people	9,500	0	5.6×10^4	8.8×10^4
Water	10^3 acre-ft/year	60	0	350	560
Electric power	MW	250	0	1,500	2,300

*Approximate conversion factors: 1 gal = $3.79 \times 10^{-3} m^3$, 1 ton = 907 kg, 1 acre = 4.05×10^3 m^2, 1 ft = 0.305 m, 10^6B = 160,000 m^3, 1 pound = 0.454 kg, 1 mile = 1.61 km

Table 3-25

ENVIRONMENTAL IMPACTS FROM THE OPERATION OF NEW REFINERIES UNDER THE REFERENCE CASE.

Impact Scaling Factors and Scenario Quantities								Quantative Indicator of Environmental Impact				
Activity	Impact	Impact Scaling Factor		Scenario Quantity which Determines Impacts				Imports refined in U.S.				
		Quantity	Units*	1975	1985	2000	Units*		1975	1985	2000	Units*
Refineries	Wastewater production											
	Coastal regions	420	10^6 gal/D per 10^6B/D refined	0	5.9	9.3	10^6 B/D	50%	0	2.5	3.9	10^9 gal/D
				0	12	19		0%	0	5.0	8.0	
	Water pollution											
	BOD	15	Tons/D per 10^6 B/D	0	5.9	9.3	10^6 B/D	50%	0	89	140	Tons/D
				0	12	19		0%	0	180	290	
	COD	55	Tons/D per 10^6 B/D	0	5.9	9.3	10^6 B/D	50%	0	320	510	Tons/D
				0	12	19		0%	0	660	1,000	
	Oil	4	Tons/D per 10^6 B/D	0	5.9	9.3	10^6 B/D	50%	0	24	37	Tons/D
				0	12	19		0%	0	48	76	
	Phenols	1	Tons/D per 10^6 B/D	0	5.9	9.3	10^6 B/D	50%	0	5.9	9.3	Tons/D
				0	12	19		0%	0	12	19	
	Suspended solids	10	Tons/D per 10^6 B/D	0	5.9	9.3	10^6 B/D	50%	0	59	93	Tons/D
				0	12	19		0%	0	120	190	
	Dissolved solids	250	Tons/D per 10^6 B/D	0	5.9	9.3	10^6 B/D	50%	0	1,500	2,300	Tons/D
				0	12	19		0%	0	3,000	4,800	
	Sulfides	1.5	Tons/D per 10^6 B/D	0	5.9	9.3	10^6 B/D	50%	0	8.9	14	Tons/D
				0	12	19		0%	0	18	29	
	Phosphorus	0.5	Tons/D per 10^6 B/D	0	5.9	9.3	10^6 B/D	50%	0	3.0	4.7	Tons/D
				0	12	19		0%	0	6.0	9.5	
	Nitrogen	2.0	Tons/D per 10^6 B/D	0	5.9	9.3	10^6 B/D	50%	0	12	19	Tons/D
				0	12	19		0%	0	24	38	
	Air pollution											
	Particulates	5.5	Tons/D per 10^6 B/D	0	5.9	9.3	10^6 B/D	50%	0	32	51	Tons/D
				0	12	19		0%	0	66	100	
	SO_2	76	Tons/D per 10^6 B/D	0	5.9	9.3	10^6 B/D	50%	0	450	710	Tons/D
				0	12	19		0%	0	910	1,400	
	Hydrocarbons	69	Tons/D per 10^6 B/D	0	5.9	9.3	10^6 B/D	50%	0	410	640	Tons/D
				0	12	19		0%	0	830	1,300	
	NO_x	34	Tons/D per 10^6 B/D	0	5.9	9.3	10^6 B/D	50%	0	200	320	Tons/D
				0	12	19		0%	0	410	650	
	CO	41	Tons/D per 10^6 B/D	0	5.9	9.3	10^6 B/D	50%	0	240	380	Tons/D
				0	12	19		0%	0	490	780	

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Table 3-25

ENVIRONMENTAL IMPACTS FROM THE OPERATION OF NEW REFINERIES UNDER THE REFERENCE CASE.

Impact Scaling Factors and Scenario Quantities								Quantative Indicator of Environmental Impact				
Activity	Impact	Impact Scaling Factor		Scenario Quantity which Determines Impacts				Imports refined in U.S.				
		Quantity	Units*	1975	1985	2000	Units*		1975	1985	2000	Units*
Refineries	Employment, urbanization, and recreation											
	Employment	9,500	Employees per 10^6B/D capacity	0	5.9	9.3	10^6 B/D	50%	0	56	88	10^3 employees
				0	12	19		0%	0	114	180	
	Total population	6.5	People per employee	0	56	88	Employees	50%	0	360	570	10^3 people
				0	114	180		0%	0	740	1,200	

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*Approximate conversion factors: 1 gal = 3.79×10^{-3} m^3

1 ton = 907 kg

1 acre = 4.05×10^3 m^2

1 ft = 0.305 m

10^6 B = 160,000 m^3

1 pound = 0.454 kg

1 mile = 1.61 km

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create unconsolidated sediment and poor habitat around the sites of offshore drilling; the volume will be about 200 ft by 200 ft and 1 ft thick around the base of each drill site. However, this amount of solid waste is dwarfed by the amount of sludge produced by coastal cities (e.g., New York).

Employment-related impacts from refinery construction and operation could be more substantial than for crude oil production. Refinery employment under HG3 could double from 150,000 in 1975 to over 300,000 in 2000 if all imports are in the form of crude oil.

The coastal regions will experience impacts that are quantitatively similar to the impacts from onshore production (compare similar categories in Tables 3-21 and 3-22); however, the impacts will be concentrated in a smaller region. In addition, pipeline construction, refinery construction and operation, and increased tanker activity will bring impacts to the coastal regions unlike those in onshore production. Tables 3-22 and 3-25 support the conclusion that under the reference case the coastal regions will experience the most significant air pollution increases of the three reference case regions and the greatest potential for large oil spills, in addition to major employment-related impacts.

APPENDIX A

QUANTITIES OF OIL RESOURCES AND RESERVES

The distinction between resources and reserves is often misunderstood. In general, resources refer to physical quantities, while reserves implies recoverability of a fraction of the resource as determined by prevailing economics and technology. Figure A-1 illustrates the relationship of the various classes of oil resources and reserves. The quantities of the important classes of resources and reserves are:[2]

- 440×10^9 barrels of crude oil resources identified in the United States as of January 1975.
- 106×10^9 barrels of crude oil resources produced as of January 1975.
- 40×10^9 barrels of discovered crude oil resources classified as economically producible (demonstrated reserves) as of January 1975.
- 82×10^9 barrels of undiscovered oil resources estimated by the USGS as producible with 50 percent certainty at 1973 crude oil prices (assumes 32 percent recovery of the undiscovered resources).
- Up to an additional 130×10^9 barrels of oil of the resources (discovered and undiscovered), which may be recoverable with advanced recovery techniques (up to 50 percent recovery of the original resources both discovered and undiscovered) at much higher crude oil prices.

Much of the oil resource cannot be recovered because of the difficulties of extracting oil from the porous oil-bearing rock strata, which can lie up to 20,000 ft (6000 m) underground. Estimates of the percentage of the resource eventually producible generally vary between 30 and 50 percent.[40] Primary recovery (producing oil from self-pressured fields

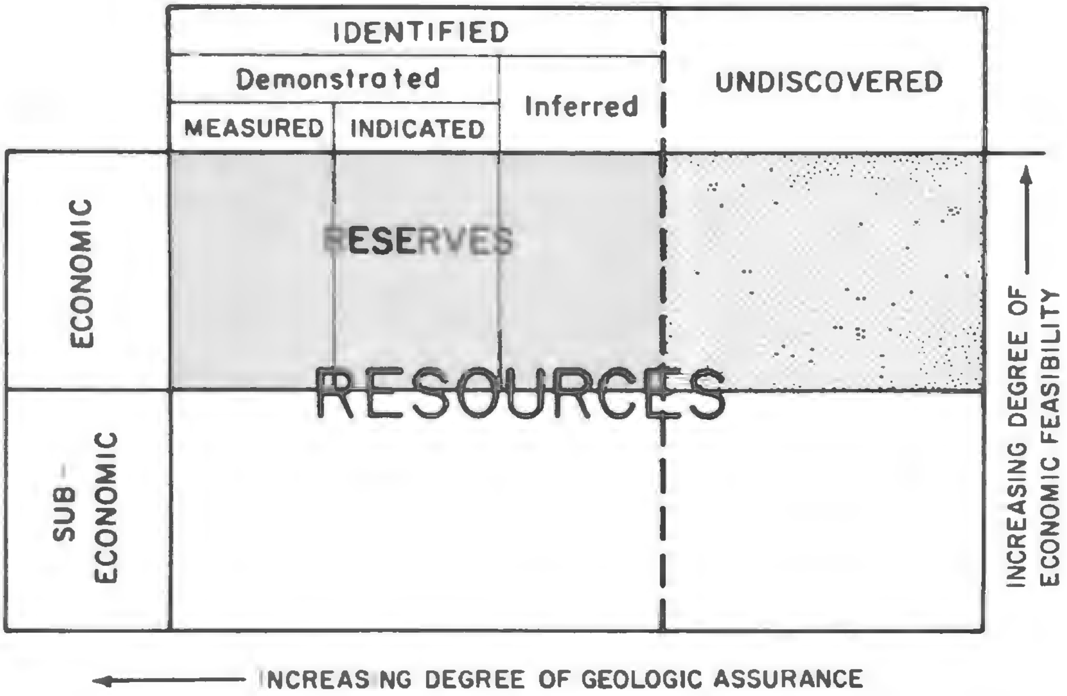
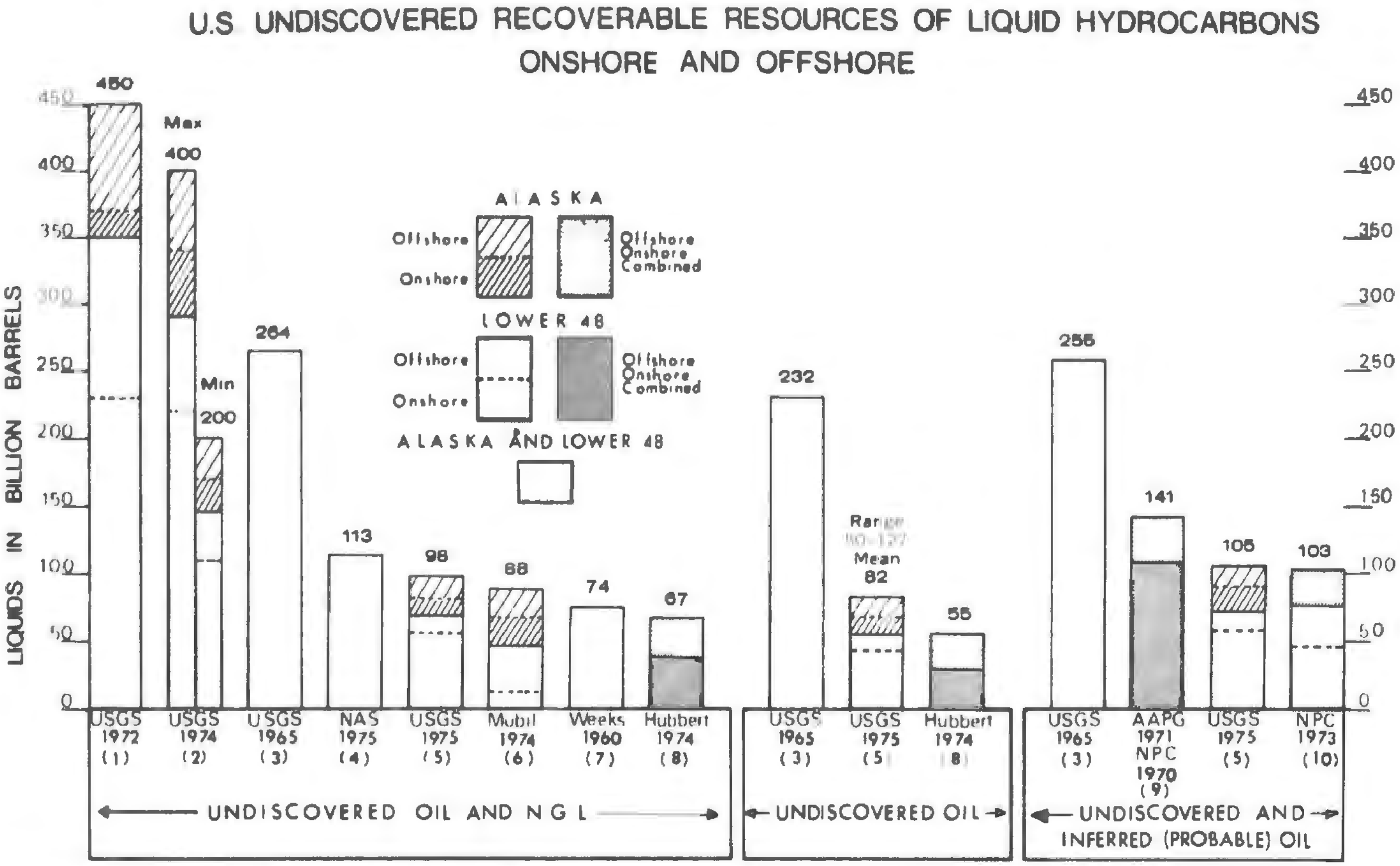


FIGURE A-1. DIAGRAMATIC REPRESENTATION OF PETROLEUM RESOURCE CLASSIFICATION BY THE U.S. GEOLOGICAL SURVEY AND THE U.S BUREAU OF MINES or from artificially pumped fields) and secondary recovery (producing oil by pressurizing the field through water injection or through natural gas injection) together generally achieve about 30 percent recovery of the original resource. Advanced recovery or tertiary recovery (producing oil by injecting solvents, steam, CO_2, or other chemicals or producing oil by any technique not classed as primary or secondary recovery) may achieve an additional 20 percent recovery of the initial resource. This additional recovery percentage varies considerably among actual fields--in some cases 90 percent recovery can be achieved. Unfortunately, however, no general agreement exists over the percentage of the resource that can be recovered by advanced recovery techniques.[40]

Today's technology and economics make 70 percent of the resources either too expensive to produce or impossible to produce. For future oil production, increased oil prices can make some of the last 70 percent of the resources available. However, it takes considerable time to bring advanced recovery into widespread use and significant production by advanced recovery cannot begin for at least a decade.

Considerable controversy surrounds the quantity of undiscovered oil resources, although recent estimates agree remarkably.[2] Figure A-2 shows several of the important estimates. In mid-1975, USGS estimated that undiscovered ultimately recoverable oil resources (at 1973 crude oil prices) consist of between 50 and 127 billion barrels with the mean estimate of 82 billion barrels (assuming 32 percent recovery of the undiscovered resources). A recent study by the National Academy of Sciences reports that about 113 billion barrels remain to be found and produced.[42] These estimates implicitly assume recovery at 1973 prices.



Source: U.S. Geological Survey, Circular 725

(1) Theobald and others, USGS Circ. 650 (1972). Includes water depth to 2,500 m (8,200 ft).
(2) USGS News Release (March 26, 1974). Includes water depth to 200 m (660 ft)
(3) Hendricks, USGS Circ. 522 (1965). Adjusted through 1974. Includes water depth to 200 m (660 ft).
(4) National Academy of Sciences, "Mineral Resources and the Environment," (1975). Water depth not indicated.
(5) USGS "Mean," Oil and Gas Branch Resource Appraisal Group (1975). Includes water depth to 200 m (660 ft).
(6) Mobil Oil Corp., "Expected Value," Science (12 July 1974). Includes water depth to 1,830 m (6,000 ft).
(7) Weeks, L.G., Geotimes (July-August 1960). Adjusted through 1974. Water depth not indicated.
(8) Hubbert, M. K., Senate Committee (1974). Includes water depth to 200 m (660 ft).
(9) American Association Petroleum Geologists Memoir 15, (1971); National Petroleum Council, "Future Petroleum Provinces of the United States," (1970). Some areas are excluded from this estimate. Includes water depth to 2,500 m (8,200 ft).
(10) National Petroleum Council, "U.S. Energy Outlook--Oil and Gas Availability," (1973). Includes water depth to 2,500 m (8,200 ft).

FIGURE A-2. COMPARATIVE ESTIMATES OF OIL RESOURCES IN THE UNITED STATES

Thus, taking into account reserves, the USGS estimates that, at 1973 prices, recoverable resources yet to be produced amount to about 120 billion barrels. If advanced recovery could be applied to the remaining discovered and estimated undiscovered resources so that 50 percent of the resource could be produced, the recoverable resource, which could actually be produced, would be about 250 billion barrels. More detailed estimates of the oil recoverable by advanced techniques are not available and the 250 billion barrels must, at this time, be viewed as the most credible upper limit to the amount of resources left to be produced. Furthermore, tertiary recovery is a slow process which takes many years to complete in a given field but it contributes to overall oil production by maintaining production rates higher and longer than possible under long-term primary and secondary recovery. If today's oil prices are maintained, then the limits of the reserves (120 billion barrels) virtually assure that U.S. crude oil production will begin a long-term decline in the early 1980s (completion of TAPS will stave off the decline in U.S. production rate for 5 to 8 years). Higher crude oil prices can extend the reserves to a maximum of 250 billion barrels, but because of the long time required to bring tertiary recovery projects up to full production and the generally slow rate of recovery by tertiary methods, production rates during the late 1980s and thereafter for the nation as a whole are unlikely to increase beyond those achievable in the early 1980s. Increasing crude oil prices will have the long-term effect of preventing declines in production, but because of the limits of the resource base now projected, substantial increases in future crude oil production rates would seem impossible.

APPENDIX B

METHOD FOR HG3 REGIONAL SUPPLY PROJECTION

The limitations of the oil resource base discussed in Appendix A help determine a credible upper limit to the future production rate from U.S. resources. Of the 120 billion barrels available at 1973 oil prices and producible by primary and secondary recovery, about half of this amount is physically producible by the year 2000 if prices remain constant in 1973 dollars. Thus, cumulative production of more than about 60 billion barrels by the year 2000 requires much higher crude oil prices and the application of advanced recovery to many fields. Indeed, physical considerations together with the new USGS estimates imply that crude oil production rates past the year 2000 cannot exhibit long-term increases, not even a constant production rate.

With these limitations imposed on the quantity and the rate at which oil can be recovered, we selected from among the EPP scenarios of domestic oil production in the absence of synthetic crude oils scenario HG3, which has the lowest cumulative production between 1975 and 2000 and a non-increasing rate of domestic production between 1985 and 2000. The remainder of the scenarios in Table 3-1 imply that the rate of domestic production increases to the year 2000 and beyond.

Scenario HG3 itself requires that about 70 billion barrels of oil be produced by advanced recovery techniques by the year 2000. Since cumulative production over the last 100 years has only been 106 billion barrels using conventional oil recovery techniques, the 70 billion barrels recovered in 25 years by applying advanced techniques probably represent the upper limit to domestic oil production, and indeed lower cumulative production and smaller production rates in the year 2000 than HG3 are more likely, particularly if the new USGS estimates of the domestic resources base are approximately correct. Thus, HG3 represents a scenario of maximum credible domestic oil production, even assuming much higher crude oil prices. (It is not possible to estimate at this time what price of crude oil would be necessary to bring about production of the 70 billion barrels of oil by advanced recovery techniques for HG3, since not enough is actually known about the economics of applying advanced recovery techniques on a wide scale.)

For analysis of the impacts of HG3, we have used the Project Independence scenarios in the Oil Task Force Report[4] for determining the percentage breakdown of regional oil supplies from national production under HG3 as shown in Table 3-1. Table B-1 shows the regional oil supply projected by HG3 and serves to illustrate environmental impacts. The supplies shown in Table B-1 may never be realized; they are intended to serve a similar function in this study to that served by the maximum credible implementation scenario, Chapter 6. One major difference in credibility between the two scenarios rests in the area of the resource estimated. No one really knows how much oil is left for discovery, where it is, or how rapidly it can be produced. However, the location and the quantities of the oil shale and coal resources for syncrude are known.

Table B-1

HISTORICAL GROWTH SUBSCENARIO 3--REGIONAL SUPPLY OF OIL AND NATURAL GAS LIQUIDS

(Millions of barrels per day)

Region or Source	1974	Percentage of Total Supply*	HG3 1985	Percentage of Total Supply†	HG3 2000
Prudhoe	0	13.4	1.80	8.6	1.20
North Slope	0	9.4	1.30	5.1	0.68
NPR4	0	0	0	11.7	1.60
NPR1	0	0	0	0.6	0.08
Military Reserves	0	0	0	1.2	0.16
1	0.201	4.0	0.54	7.2	0.96
2	0.792	4.4	0.59	2.8	0.38
2A	0.058	4.5	0.60	9.0	1.20
3	0.215	1.2	0.16	0.9	0.12
4	0.614	2.5	0.34	1.7	0.23
5	2.553	12.1	1.60	8.0	1.10
6	3.526	24.0	3.20	18.1	2.40
6A	1.311	17.4	2.30	15.2	2.00
7	0.994	6.4	0.86	4.2	0.56
8-10	0.213	2.1	0.28	1.4	0.19
11	0.007	0	0	0.1	0.013
11A	0	0.3	0.040	4.5	0.60
Totals*	10.50	100	13.400	100	13.400

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*Items may not sum to totals due to rounding.

†Percentages based on data on[4] Exhibit IV-2, Business-As-Usual, $7/B, 1985.

†Percentages based on data in[4] Exhibit IV-2, Accelerated Development, $7/B, 1988.

APPENDIX C

TRENDS IN PAST U.S. PRODUCTION AND THEIR IMPLICATIONS FOR FUTURE PRODUCTION

Hundreds of oil fields produce oil in the United States. Production into the rest of this century is certain to include oil from most of the existing fields, some of which have been producing for over 60 years, and presumably from fields yet to be discovered. Section 1 below presents a brief history of U.S. consumption of crude oil and crude oil prices. Declining annual discovery rates for new oil fields and declining crude oil prices (in constant dollars) characterize the 20 years prior to 1973. Dramatic crude oil price increases characterize the last two years.

1. A Brief History of U.S. Oil Production and Oil Exploration

Table C-1 summarizes the history of U.S. crude oil production and discovery. Column 2 of the table shows the annual U.S. crude oil production for the selected years. Each year, oil is produced from the economically proven reserves (Column 3 of Table C-1) remaining at the end of the previous year. Production increased nearly 3 percent per year on the average from 1890 until production peaked in 1970. After 1970, production began a decline, which continues (late 1975). This trend is expected to continue until TAPS is completed. In 1974, reserves were estimated to be about 34 x 10^9 barrels, and production was 3.0 x 10^9 barrels. Thus, if all else were constant, economically producible known reserves would be exhausted in only 11 years. However, each year brings new discoveries and new economic conditions, which change estimates of reserves. Increasing the real price of crude oil can result in new

Table C-1

HISTORICAL RECORD OF PRODUCTION AND PROVEN RESERVES: ALSO THE ULTIMATE RECOVERY AND ORIGINAL OIL IN PLACE BY YEAR OF DISCOVERY--TOTAL UNITED STATES FOR SELECTED YEARS

(Billions of barrels of 42 U.S. gallons)

	For All Fields Discovered to Date		For Fields Discovered During Year	
Selected Years (1)	Production During Year (2)	Proved Reserves at End of Year (3)	1974 Estimate of Ultimate Recovery (4)	1974 Estimate of Original Oil in Place (5)
Pre-1920	5.1		25.8	98.0
1925	0.8		1.0	4.0
1930	0.9		7.7	13.6
1935	1.0		2.5	7.1
1940	1.3		3.8	9.6
1945	1.7	19.9	2.2	7.0
1950	2.0	25.3	2.6	7.3
1955	2.4	30.0	1.5	5.6
1960	2.5	31.6	0.9	3.1
1965	2.7	31.3	1.3	4.5
1966	2.9	31.4	0.5	2.0
1967	3.0	31.4	0.7	2.9
1968	3.2	30.7	10.6	25.4
1969	3.2	29.6	0.6	2.3
1970	3.3	39.0	0.7	2.2
1971	3.3	38.1	0.4	1.3
1972	3.3	36.3	0.2	1.0
1973	3.2	35.3	0.2	1.0
1974	3.0	34.3	0.06	0.3
Total cumulative for all years	106		140	440

Source: Summarized from Tables III and IV of[43] Reserves of Crude Oil, Natural Gas Liquids in the United States and Canada; and United States, Productive Capacity as of December 31, 1974.

reserves. The following equation shows the relationship.

> (Proven reserves in previous year) - (Production that year) +
> (Discoveries in new fields) + (Extensions to old fields) =
> (Proven reserves at the end of the year).

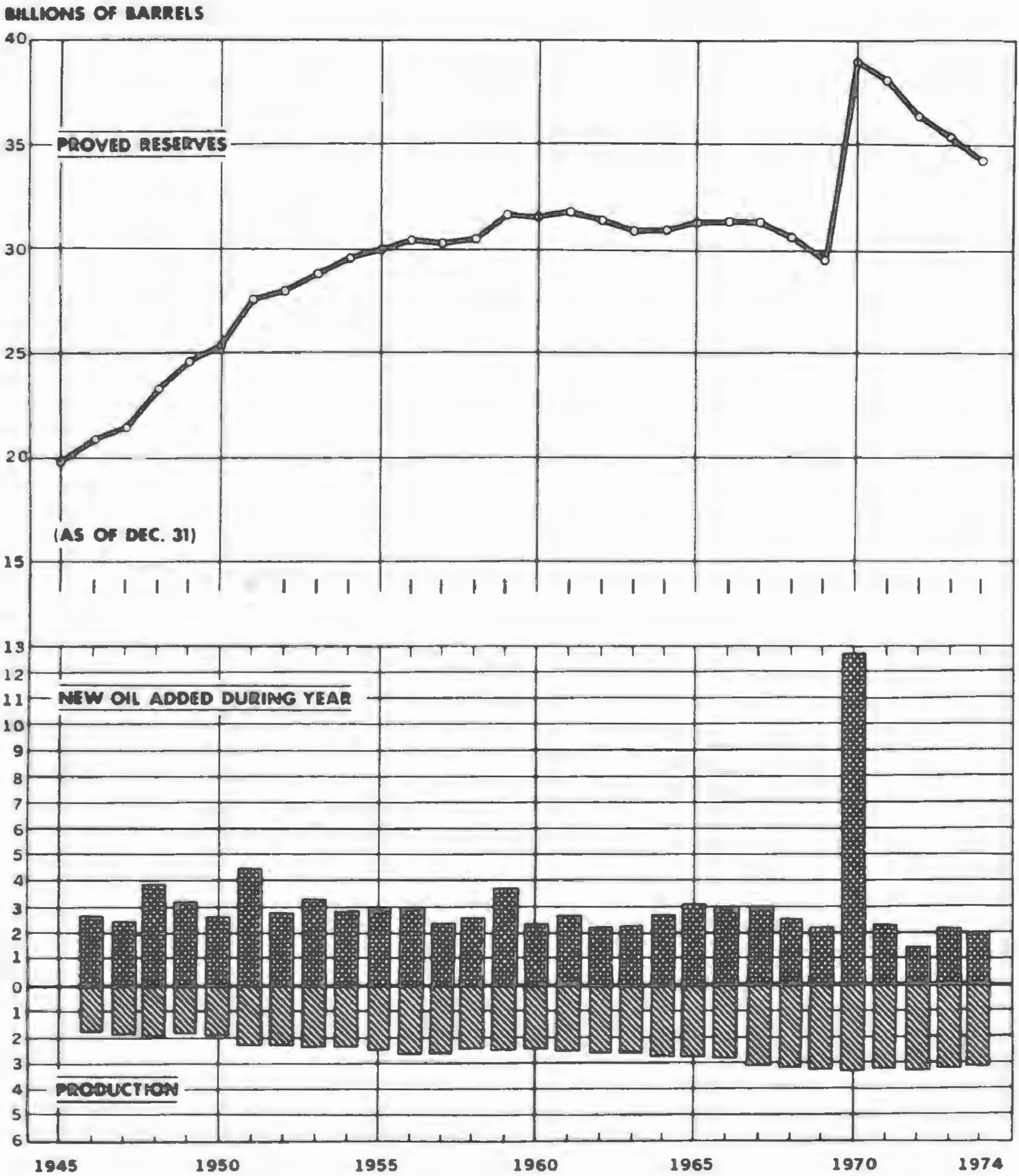
Indeed, since 1945, reserves have fluctuated around 10 times the annual production.

For the past 20 years, discoveries in existing oil fields exceeded discoveries of new fields--except for 1969 with 10×10^9 barrel discovery under the Alaskan North Slope. The year 1974 exemplifies this dominance trend. Discoveries in new oil fields (column 4 of Table C-1) added only 0.1×10^9 barrels to ultimately recoverable oil while extensions to old oil fields added approximately 1.9×10^9 barrels.

Column 4 of Table C-1 reflects the 1974 estimate of the ultimate recovery from all known oil fields at January 1974 crude oil prices--approximately 140×10^9 barrels, of which 106×10^9 barrels have been produced. Figure C-1 shows the history of U.S. reserves since 1945. A comparison of new field discoveries (column 4 of Table C-1) with the new oil added (cross-hatched histogram in Figure C-1) demonstrates the trend discussed in the previous paragraph.

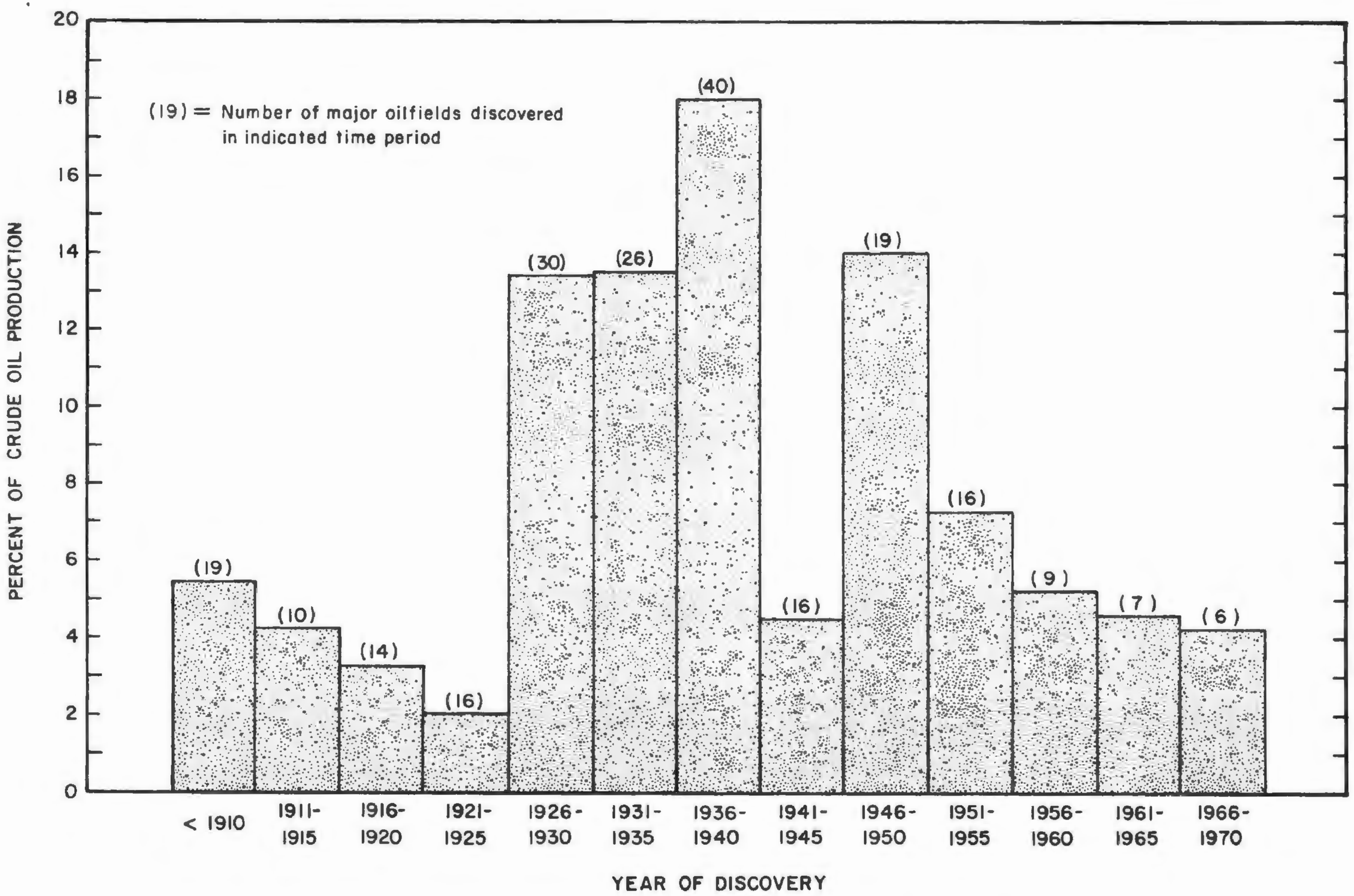
Not only does much of the exploration activity take place in known fields, but all production takes place in them as well. Figure C-2 shows the oil produced in 1973 from 228 major U.S. oil fields (fields which produced at least 1×10^6 barrels during the year). The data are tabulated by year of discovery of the field. Several apparent facts are:

- Approximately 80 percent of the oil from the 228 major fields was produced from 190 fields, all at least 20 years old.
- The 228 major fields accounted for almost 60 percent of all domestic production.



Source Amer can Gas Association

FIGURE C-1. PROVED RESERVES OF CRUDE OIL IN THE UNITED STATES, 1945-1974



Source : Based on data in 1974 International Petroleum Encyclopedia, p. 223.

FIGURE C-2. 1973 CRUDE OIL PRODUCTION FROM 228 MAJOR DOMESTIC OILFIELDS BY YEAR OF DISCOVERY

- Production from most of these major fields is likely to continue into the rest of the century.
- Any impacts already associated with these oil fields will continue.

A comparison of the statistics for 1968 on major U.S. oil fields (those producing over 10^6B per year)[44] with statistics for 1973[8] shows that production in many of these major fields increased substantially-most often due to more wells coming into production by 1973 (i.e., new wells were drilled).

Predicting future production from currently producing oil fields is difficult. Future production depends on the price of crude oil, on the existence of economic or other incentives for developing oil reserves which are uneconomic to produce at today's prices and, crucially, on the amount of oil left to produce.

2. A Brief History of U. S. Crude Oil Supply and Demand

Table C-2 shows the history of U.S. crude oil supply and demand between 1944 and 1973. While domestic supply was 11.3 million barrels per day in 1970, it declined to 10.5 million barrels per day in 1974; imports nearly doubled, from 3.2×10^6 barrels per day to 6.2×10^6 barrels per day. Total U. S. demand between 1944 and 1973 rose at about 4 percent per year, while imports grew from supplying 23 percent of domestic demand in 1970 to 36 percent of domestic demand in 1974. Table C-2 makes three important points:

- Domestic demand grew between 1944 and 1973 at 4 percent per year to 17.3×10^6 barrels per day in 1973.
- Imports grew between 1970 and 1974 to supply 36 percent of domestic demand.
- Domestic supply fell between 1970 and 1974 to only 10.5×10^6 barrels per day in 1974.

Table C-2

STATISTICS OF THE PETROLEUM INDUSTRY

YEAR	PRODUCTION			IMPORTS			OTHER SUPPLY'	TOTAL SUPPLY	PETROLEUM DEMAND		
	Crude Oil (1,000 B/D)	Nat. Gas Liquids (1,000 B/D)	Total (1,000 B/D)	Crude Oil (1,000 B/D)	Refined Products (1,000 B/D)	Total (1,000 B/D)		(1,000 B/D)	Domestic (1,000 B/D)	Export (1,000 B/D)	Total (1,000 B/D)
1945	4,695	315	5,010	203	108	311	—	5,321	4,857	501	5,358
1946	4,751	322	5,073	236	141	377	—	5,450	4,912	419	5,331
1947	5,088	364	5,452	266	170	436	—	5,888	5,452	450	5,902
1948	5,520	402	5,922	353	161	514	—	6,436	5,775	368	6,143
1949	5,047	431	5,478	421	224	645	—	6,123	5,803	327	6,130
1950	5,407	499	5,906	487	363	850	2	6,758	6,509	305	6,814
1951	6,158	562	6,720	491	353	844	7	7,571	7,060	422	7,482
1952	6,256	612	6,868	573	379	952	7	7,827	7,283	436	7,719
1953	6.458	655	7,113	648	386	1,034	20	8,167	7,624	401	8,025
1954	6,343	692	7,035	656	396	1.052	23	8,110	7,784	355	8,139
1955	6,807	772	7,579	782	466	1,248	34	8,861	8,493	368	8,861
1956	7,151	801	7,952	934	502	1,436	43	9,431	8,822	430	9,252
1957	7.170	809	7,979	1,023	552	1,574	42	9,595	8,860	568	9,428
1958	6.710	808	7,518	953	747	1,700	64	9,282	9,146	276	9,422
1959	7.053	880	7,933	966	815	1,780	86	9,799	9,494	255	9,749
1960	7.035	930	7,965	1,015	799	1,815	146	9,926	9,807	202	10,009
1961	7.183	991	8.174	1,045	871	1.917	179	10,270	9,985	174	10.159
1962	7,332	1,021	8,353	1,126	956	2,082	175	10,610	10,410	168	10,578
1963	7,542	1,098	8,640	1,131	992	2.123	202	10,965	10.753	208	10,961
1964	7,614	1,155	8,769	1,198	1,060	2.258	217	11,244	11,032	202	11,234
1965	7,804	1,210	9,014	1,238	1,230	2,468	220	11,702	11,523	187	11,710
1966	8,295	1,284	9,579	1,225	1,348	2,573	245	12,397	12.095	198	12,293
1967	8,810	1,410	10.220	1.128	1,409	2,537	292	13,049	12,569	307	12.876
1968	9.096	1,503	10,599	1,290	1,550	2,840	348	13,787	13,404	231	13,635
1969	9,238	1,589	10,827	1,409	1,757	3.166	340	14,333	14.148	233	14,381
1970	9.637	1,660	11,297	1,324	2,094	3.419	355	15,071	14,709	259	14,968
1971	9,463	1,692	11,155	1,681	2,245	3,926	439	15,520	15,225	224	15,449
1972	9.441	1,744	11,185	2,216	2,525	4,741	444	16,370	16,380	222	16,602
1973	9,208	1,738	10,946	3,244	3,012	6.256	485	17,687	17,321	231	17,552
1974	8,774	1,688	10.462	3.477	2,611	6,088	500	17.050	16,642	220	16,862

Source: Reference 25

Table C-3 shows a history of crude oil prices. Although prices in current dollars rose between 1954 and 1973, prices in constant 1973 dollars fell until 1974. The effective decline in crude oil prices made drilling and exploring for oil increasingly unprofitable. For example, the number of new oil wells drilled fell from 30,000 in 1954 to 9900 in 1973.[25] The total footage of wells drilled also declined from 220 x 10^6 ft in 1954 to 140 x 10^6 ft in 1973.[25] Recent increases in crude oil prices stimulated drilling activity and it remains to be seen if many new resources are added and if a net U.S. production increase takes place.

Table C-3

OIL PRICES

Year[25]	Crude Oil at Well (per barrel) Current $	Crude Oil at Well (per barrel) Constant 1973 $
1954	2.78	4.77
1955	2.77	4.69
1956	2.79	4.57
1957	3.09	4.88
1958	3.01	4.63
1959	2.90	4.39
1960	2.88	4.29
1961	2.89	4.25
1962	2.90	4.22
1963	2.89	4.15
1964	2.88	4.07
1965	2.86	3.97
1966	2.88	3.89
1967	2.91	3.81
1968	2.94	3.70
1969	3.09	3.71
1970	3.18	3.62
1971	3.39	3.38
1972	3.39	3.57
1973	3.89	3.89
1974	6.74	6.32
November 1975[45]	8.75	7.18

Source: References 25, 45

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4--SYNTHETIC LIQUID FUELS: THE TECHNOLOGY, RESOURCE REQUIREMENTS, AND POLLUTANT EMISSIONS

By Robert V. Steele

A. Introduction and Overview

To assess the impacts of large-scale production and use of synthetic fuels it is necessary to set forth the technological systems or networks through which these fuels proceed from resource extraction to end use. We have attempted to do this by examining the technologies that are likely to be utilized for synthetic fuels production, as well as associated mining, transportation, refining, and distribution technologies. We have attempted to quantify flows of energy, materials, and dollars through the systems and to identify specific areas where impacts may be expected.

The level of detail with which the various technological system elements have been discussed is sufficient to understand flows of materials, labor, dollars, and energy through the system, and to identify flows of residuals into the environment. We have not undertaken detailed engineering and economic analyses of these technologies since this work has been performed elsewhere, often by several sources.*

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*Specifically, two previous studies on the feasibility of alternative fuels for automotive transportation[1,2] are pointed out as sources of more detailed engineering and economic analysis.

The basic elements that make up the alternative fuels network are shown in Figure 4-1. This block flow diagram is sufficiently general that the particular energy conversion technologies and the transportation and distribution steps need not be specified. These will be discussed in detail later. The important thing to notice about the diagram is the way the alternative fuels are introduced into the conventional fuel production and distribution system. It is our judgment that methanol, because of its special properties, would have its own distribution network parallel to, but distinct from, the conventional gasoline and distillate fuel networks. On the other hand, for gasoline and distillate fuels derived from coal and oil shale, we expect that once the syncrude has been produced and introduced into the conventional pipeline/refinery system, its fate will be essentially indistinguishable from the natural crudes that are processed in the same system. The block flow diagram reflects these judgments and also allows for the additional alternative of introducing a methanol/gasoline blend at the last stage of fuel distribution, i.e., at the pump.

It becomes apparent from the above discussion that most of the social, economic and environmental impacts resulting from the development of alternative fuels, with the possible exception of methanol, will be in the extraction and conversion stages. For this reason, most of the subsequent discussion, as well as the identification of impacts, will center around these two stages. Since the production of methanol from coal and of synthetic crude oil (syncrude) from coal and oil shale are new technologies, they may have impacts that are qualitatively different from current types of energy conversion activities. In addition, new types of impacts from the distribution and end use of methanol are likely to occur. The extraction of coal for liquid fuels production is not likely to pose any new problems in addition to those already encountered with conventional coal mining methods. However, the scale of

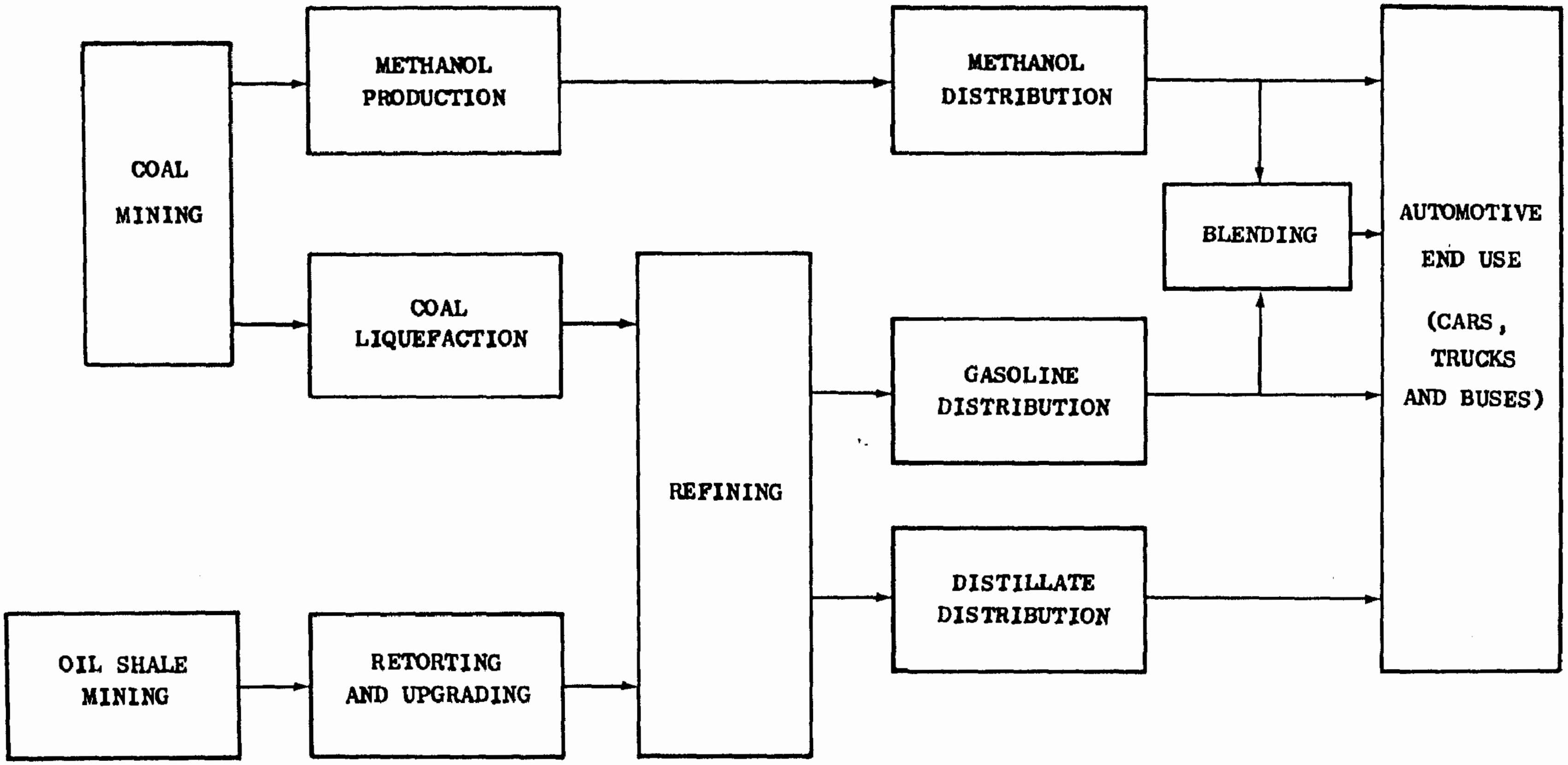


FIGURE 4-1. SYNTHETIC FUELS NETWORK

impacts is likely to increase in certain areas. The extraction and processing of oil shale will have significant new impacts in shale-bearing regions due to the very large amount of material that must be mined and disposed of.

Two important considerations in the development of a synthetic fuels industry are the cost and availability of the resource required for input into the conversion processes. In coal conversion processes, large quantities of coal are required by a single large plant (10 to 20 million tons per year), and this requirement contributes significantly to the cost of producing the final product. Since it is important to ensure a continuous supply of coal over the 20-year life of the plant, the companies that operate the plants will attempt to "block up" (i.e., acquire leases) at least a 20-year supply of coal for each plant. The large reserves required are more readily obtained in the western states than in the eastern states. In addition, the costs of western coal extraction are appreciably lower ($3-5/ton) than those for eastern coal ($8-10/ton) due the thick seams and low stripping ratios typical of western coal deposits.

A large part of the expansion of the coal industry can be expected to take place in the West. For this reason a large energy conversion industry may also be centered in the western United States, in which case many of the impacts due to synthetic fuels development would be specific to this region. Thus, the use of western coal to produce synthetic petroleum and methanol is emphasized in the following discussion. This emphasis does not rule out the use of midwestern and eastern coals for conversion to synthetic liquid fuels; in fact, there are strong reasons for utilizing these high sulfur coals to produce clean liquid fuels, and a major expansion of eastern coal production can be expected. However, the judgment that the greater part of the projected expansion of the coal and energy conversion industries is likely to take place in the West and that problems associated with this expansion are more likely to be serious in the western states than in the eastern states is reflected in this emphasis.

The technologies for converting coal and oil shale into liquid fuels can best be described as emerging technologies in the sense that bench scale, pilot plant, and, in some cases, demonstration plant, operation of the various processes have been carried out, but none of the technologies has yet been utilized in a commercial-sized plant. Of the three technologies considered--crude oil from oil shale, crude oil from coal and methanol from coal--it is widely accepted that the technology for extracting crude oil from shale is the most advanced and the one closest to commercial application. We judge the second most advanced of the technologies to be the conversion of coal to methanol, even though no pilot or demonstration plants have been built. The reason for this judgment is that the two steps for converting coal to methanol--production of synthesis gas and catalytic conversion of synthesis gas to methanol--are both well understood and developed sufficiently so that the combination of the two into a coal-to-methanol operation does not present serious technical difficulty. Coal liquefaction is the least advanced technology. Even though several processes have been tested through the pilot plant stage, serious difficulties remain in the large scale application of this technology, and the first commercial plants are not expected for at least ten years.

Synthetic liquids derived from coal and oil shale are expected to be expensive. Estimates of the market price range from $12 to $17 per oil-equivalent barrel[3] (two barrels of methanol have approximately the same energy content as one barrel of oil). Some estimates go even higher. A large fraction of the price of synthetic fuels is due to the high initial capital investment required for a synthetic fuel plant. This investment is of the order of $1 billion (1973) for a 100,000-B/D

(16,000 m^3/D) plant. Since construction costs have escalated at a rate significantly higher than the overall rate of inflation, the capital investment may be much higher (in constant dollars) over the next ten years. Ultimately technological improvements as well as standardization of some process components can be expected to reduce both capital investment and operating costs. The problems associated with generating the large amounts of capital required to build up the synthetic fuels industry constitute a significant economic and institutional impact, and are discussed in detail in Chapter 8.

Brief mention should be made of the kinds of products to be expected from synthetic fuels plants. In the conversion of coal and oil shale to liquid fuels, a variety of products can be produced, ranging from light oils and naphtha to fuel oil and synthetic crude oil. Some of these products may be used as fuel for power plants, heating oil, etc. However, since this study is directed toward the use of synthetic fuels in automotive transportation, we assume that the major end product of a coal liquefaction or oil shale plant is synthetic crude oil, which is suitable as a refinery feedstock, and which is ultimately converted to gasoline and distillate fuel as well as to other refined products consistent with the composition of the syncrude.

B. Discussion of Technologies

1. Liquid Fuels from Coal

a. Extraction

The various techniques for surface mining coal are discussed in detail in Chapter 13, and only brief mention is made here on the extraction stage of coal conversion. The techniques of area strip mining utilizing large "walking" draglines to remove overburden and electric shovels and heavy duty trucks to scoop out and remove the coal from the exposed seam are both well developed and well adapted to mining the large western coal deposits lying near the surface. These mines can be made rather large, in the 5- to 10-million ton per year (4.5×10^9 to 9×10^9 kg/Y) range, and thus it will be feasible to dedicate two or three large mines to a single large (100,000 B/D or 16,000 m^3/D) synthetic fuel plant, which will require 10 to 20 million tons per year (9×10^9 kg/Y to 18×10^9 kg/Y) of coal.

Although there are some large underground and surface mines in Illinois (up to 5 million tons per year or 4.5×10^9 kg/Y), most eastern mines are much smaller,[4] and many more of these mines will have to be dedicated to a single synthetic fuel plant operating in the East. It may be difficult to ensure a continuous source of supply from many small mines unless they are all controlled by the same company that operates the synthetic fuel plant.

Eventually western coal deposits lying near the surface will be depleted and technology will have to be developed to extract the much larger deep-lying coal resource. The presently used techniques such as room-and-pillar and longwall mining, which are used in the relatively narrow underground seams in the East, will have to be replaced by newer methods suitable for the much thicker deposits in the West. The long-term future of the western coal industry as well as the synthetic fuels industry may hinge on the successful development of such techniques.

b. Conversion

Coal is an organic material consisting primarily of carbon and hydrogen and secondarily of oxygen, nitrogen, sulfur and other inorganic constituents. The molecular constituents of coal are complex aromatic (ring) compounds in which the atomic ratio of carbon to hydrogen is about one. Typical carbon-to-hydrogen weight ratios are 11 to 15. Under the appropriate conditions, these large molecules can be broken down into smaller ones, with carbon-to-hydrogen weight ratios of the order of 6 to 8, and a liquid hydrocarbon fuel can be obtained. There are three distinct routes for carrying out the conversion of coal to liquid fuels, of which two are of interest for this study.

(1) Fischer-Tropsch Synthesis/Methanol Synthesis--Fischer-Tropsch synthesis was used extensively by the Germans during World War II to produce synthetic petroleum from coal when natural petroleum was in short supply. Through 1943, large quantities of gasoline were produced in this fashion. Even though this method of coal liquefaction is expensive and inefficient, it is the only coal liquefaction process currently being used in a commercial plant (South African Gas and Oil Company [SASOL]--operating at 6600 tons (6×10^6 kg) of coal input per day). The main product of this plant is synthetic gasoline, but significant amounts of diesel oil, liquefied petroleum gas (LPG), waxes and alcohols are also produced.[5] SASOL has recently announced plans to expand the plant to three times its present size.

Fischer-Tropsch synthesis is actually the second step of a two-step process for converting coal to liquid fuels. In the first step, the coal is gasified to produce a synthesis gas consisting mainly of carbon monoxide (CO) and hydrogen (H_2). There are several processes by which gasification can be accomplished. As an example, we will use the Lurgi process, which is both well developed and widely used. In the Lurgi process, coal is crushed and fed to a pressurized lock hopper from which it is admitted to the gasification vessel. Inside the vessel the coal moves from top to bottom by the force of gravity and is reacted with a counterflowing stream of oxygen and steam at 1100-1400°F (590-760°C) and 350-450 psi ($2.4\text{-}3.1 \times 10^6$ N/m^2). Ash is removed via another lock hopper at the bottom of the vessel. The gas produced by the reaction is bled off at the top of the vessel. It consists primarily of CO and H_2 along with carbon dioxide (CO_2), water vapor (H_2O), methane (CH_4), and contaminants such as hydrogen sulfide (H_2S). After leaving the gasifier, the hot gas is quenched with water to remove tars and oils, which are formed during gasification, and then purified to remove the acid gases CO_2 and H_2S.

The resulting synthesis gas containing H_2 and CO in the approximate molecular ratio of 2/1 is suitable for conversion to hydrocarbons via Fischer-Tropsch synthesis. This synthesis is carried out in a fluidized bed catalytic reactor at 430-490°F (220-250°C) and 360 psi (2.5×10^6 N/m^2). The two major reactions on which the synthesis is based are as follows, where $(CH_2)_n$ is the symbolic representation of a hydrocarbon containing n carbon atoms with n larger than about 4 or 5:

$$nCO + 2nH_2 \rightarrow (CH_2)_n + nH_2O$$

$$2nCO + nH_2 \rightarrow (CH_2)_n + nCO_2 \ .$$

The resulting liquid product is fractionated (distilled) to separate the various components described earlier. Depending on the conditions and catalysts employed, different product mixes can be obtained.

Although it is unlikely that this inefficient and obsolete process will be used to produce liquid hydrocarbon fuels from coal in the United States, a variation of this process will be of primary importance for the production of methanol. The synthesis of methanol from coal is similar in almost all respects to the Fischer-Tropsch synthesis of gasoline. The major difference is in the final synthesis step where the nature of the catalyst and the operating conditions determine the final product.

In methanol synthesis, a copper-zinc catalyst is used to convert purified synthesis gas to methanol at 500°F (260°C) and 1500 psi (1×10^7 N/m^2). The principal reactions involved are:

$$CO + 2H_2 \rightarrow CH_3OH$$

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O\ .$$

To achieve the maximum yield of methanol (CH_3OH) it is important to have the correct $H_2/(CO + CO_2)$ molecular ratio in the synthesis gas. This is accomplished by allowing some of the gas to undergo CO shift conversion, whereby steam and CO are reacted to form CO_2 and H_2. This step constitutes another difference between methanol synthesis and the Fischer-Tropsch process.

Figure 4-2 shows a block flow diagram for the conversion of coal to methanol. Nearly a third of the coal input to the plant is converted to low-Btu fuel gas in a gasifier operating with air instead of oxygen. This gas is burned on-site to provide steam and electricity to run the various plant processes.[6] This method of producing plant fuel is not as efficient as burning coal directly but does result in significantly lower emissions to the air.

Most of the processes associated with methanol production have been discussed previously. Other processes shown in Figure 4-2 are: methane reforming, wherein methane produced in the gasifier (methane is not suitable as a feed to methanol synthesis) is reacted with steam to produce additional CO and H_2; compression of the 300-400-psi ($2.1\text{-}2.8 \times 10^6$ N/m^2) synthesis gas to the 1500 psi (1.0×10^6 N/m^2) necessary for methanol synthesis--since less than 7 percent of the synthesis gas is converted to methanol during a single pass through the synthesis stage, the remainder is recycled to the compression stage; sulfur recovery, in

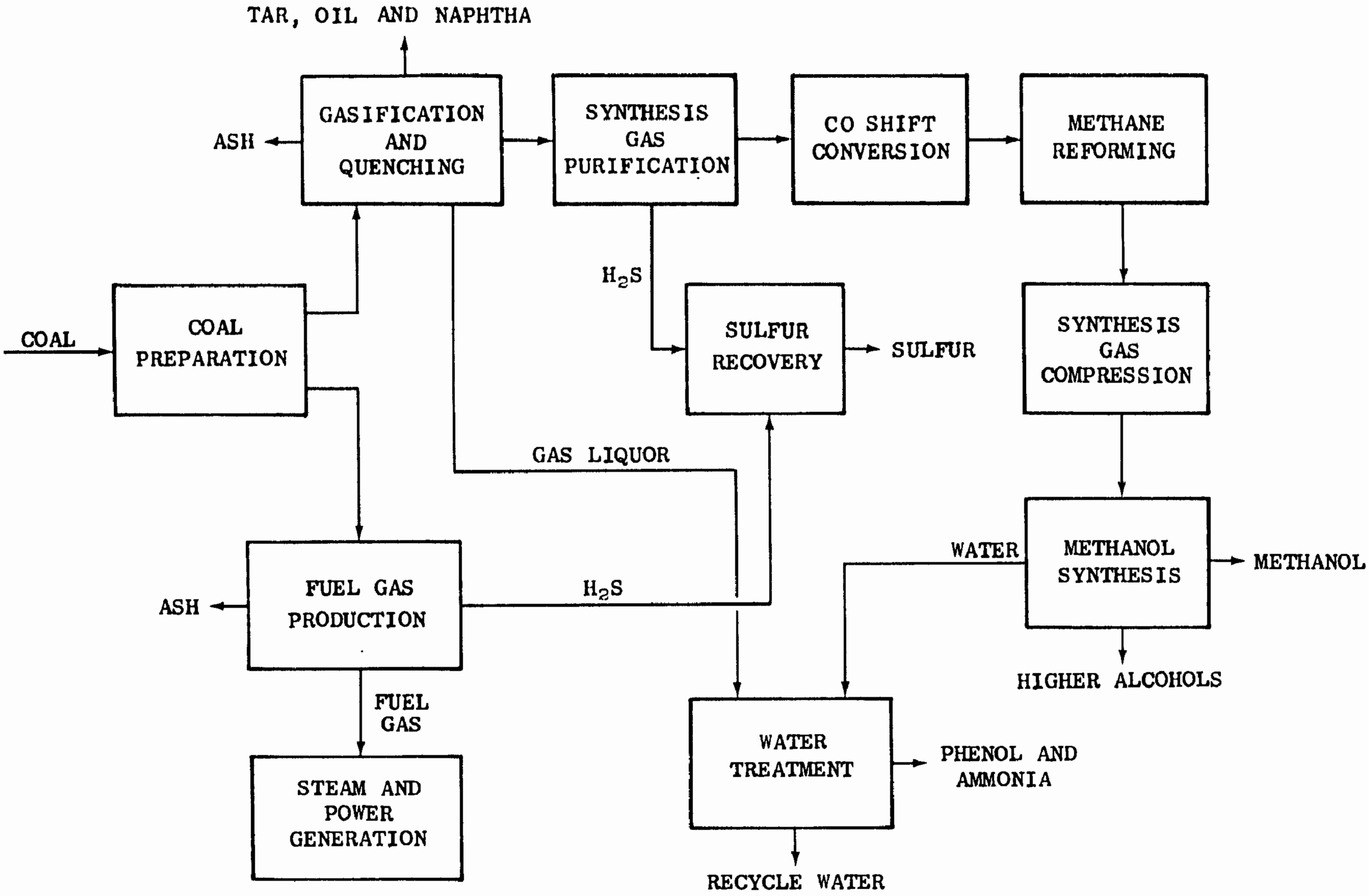


FIGURE 4-2. PRODUCTION OF METHANOL FROM COAL

which H_2S is a concentrated stream from the gas purification stage is reduced to elemental sulfur, which can be sold as a byproduct.

For the process shown in Figure 4-2, the thermal efficiency is rather low--56.6 percent if the heating value of all the byproducts is counted; 40 percent if only methanol is counted.[6] Certain changes in process components could result in a higher overall efficiency. Burning coal directly instead of converting it to low-Btu fuel gas has been discussed previously. This procedure increases efficiency but results in a higher environmental cost. Another process change would be to utilize a high-temperature gasifier, which would produce a negligible methane yield in the synthesis gas. This would eliminate the energy consumptive methane reforming step, and high temperature operation would produce far fewer byproduct tars and oils.

There are two commercially available gasifiers that have low direct methane yields--the Winkler and the Koppers-Totzek. These gasifiers also have the advantage of producing practically no tars and oils, thus eliminating an additional separation step. However, both gasifiers have the disadvantage of operating at atmospheric pressure, thus requiring a large degree of compression of the gas before methanol synthesis. In the Koppers-Totzek process, the additional energy savings brought about by low tar and methane yield is offset by the large compression energy requirement, resulting in an overall coal to methanol efficiency of about 40 percent,[2] the same as when the Lurgi gasifier is used.

A number of advanced gasifiers suitable for producing synthesis gas have been tested. These include the Bureau of Mines Synthane process, the CO_2 Acceptor process of Consolidation Coal Company, the Westinghouse fluidized bed process and various <u>in situ</u> gasification processes, developed by the Bureau of Mines, Lawrence Livermore Laboratory, and others. All of these processes incorporate design features which promote increased synthesis gas yields and other process improvements that will eventually render the Lurgi and Koppers-Totzek processes obsolete. However, none of these processes are commercially available at present. First generation methanol plants will undoubtedly be designed around current technology, while second and third generation plants will incorporate the more advanced gasification technologies mentioned above, as they become available.

(2) Pyrolysis--Pyrolysis is a technique for extracting the volatile material in coal by heating it to high temperatures (about 1600°F) in successive stages. The volatile material driven off contains most of the hydrogen in the coal, and consists of medium-Btu gas and a high-density synthetic crude oil. A portion of the gas can be reformed to produce hydrogen, which can then be used to hydrotreat the liquid product, thus upgrading it to a crude oil suitable as a refinery feedstock. The material left behind after pyrolysis is called char; it consists mostly of carbon and ash. This material may be usable as fuel if the sulfur content is low enough.

Pilot plant tests made by FMC Corporation on its COED (Char Oil Energy Development) coal pyrolysis process indicate that just slightly over one barrel (0.16 m^3) of synthetic crude oil is obtained per ton (910 kg) of coal input.[6] Thus, the coal-to-oil thermal efficiency is only about 25 percent. The remainder of the product energy is in the form of char or gases. Since this study is directed toward the production of liquid fuels from coal, and other processes are capable of liquid fuel yields of three barrels per ton (0.53 m^3 of oil per 1000 kg of coal) or more, we do not consider that coal pyrolysis is of sufficient interest to warrant further analysis.

(3) Coal Dissolution--The process by which coal is dissolved in a solvent, hydrogenated, and converted into a liquid hydrocarbon

fuel is known as coal dissolution. It is also referred to as solvent hydrogenation or solvent extraction. This appears to be the most promising technology for converting coal into synthetic crude oil (syncrude). It has the advantage of achieving a high liquid product yield (approximately three barrels per ton or 0.53 m^3 per 1000 kg of bituminous coal) with relatively high thermal efficiency (up to 75 percent). In addition, most of the sulfur in the coal is removed during the process. Although several variations of this process have been developed, there are some steps common to all processes including the dissolution of the organic matter in the coal in a process-derived solvent and hydrogenation of the resulting product to yield synthetic crude oil. These are shown in the block flow diagram of Figure 4-3. The dotted lines indicate the different stages at which hydrogenation can take place, depending on the process.

The three variants of the coal dissolution technique that have been the most extensively evaluated are the Solvent Refined Coal (SRC) process of Pittsburgh and Midway Coal Company, the Consol Synthetic Fuel (CSF) process of Consolidation Coal Company and the H-Coal process of Hydrocarbon Research, Inc. (HRI).

In the SRC process, the crushed coal is first slurried with the solvent and then reacted with hydrogen at 815°F (435°C) and 1000 psi (6.9×10^6 N/m^2), causing complete dissolution of the organic matter. After separating unreacted solids and solvent, a low-sulfur, ash free product, which is a solid at room temperature, is obtained. It must be further upgraded by hydrotreating to yield synthetic crude oil. Two pilot plants have been constructed to test the SRC process. A six ton per day (5400 kg/D) plant producing a clean boiler fuel recently completed a 75-day test run at Wilsonville, Alabama. Sponsors are the Electric Power Research Institute (EPRI) and the Southern Services

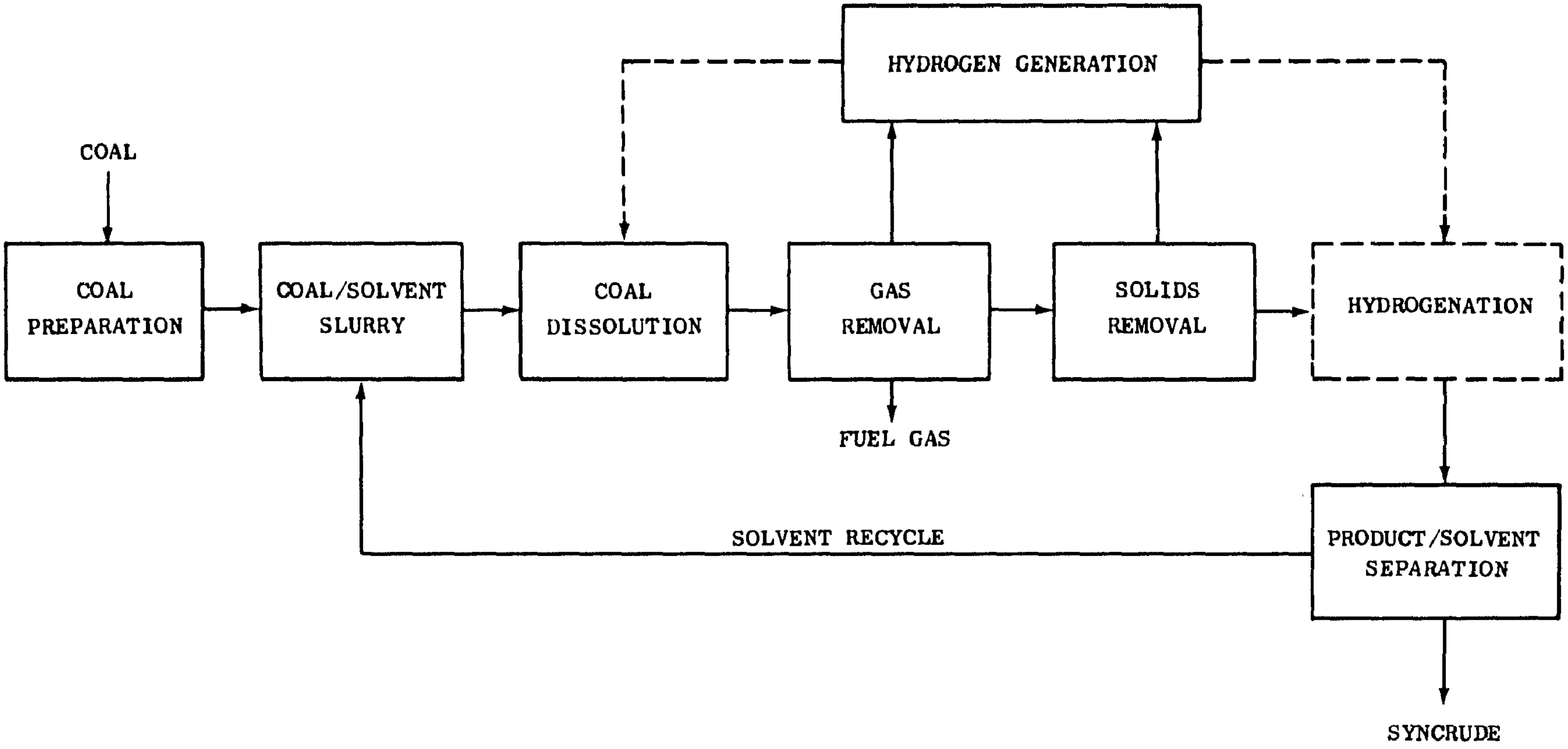


FIGURE 4-3. COAL LIQUEFACTION VIA DISSOLUTION AND HYDROGENATION (FROM REFERENCE 7)

Company. In Tacoma, Washington, a 75 ton per day (68,000 kg/D) pilot plant has been built for Pittsburgh and Midway under ERDA sponsorship.

The CSF process separates the dissolution and hydrogenation steps. The crushed, dried, and preheated coal is first slurried with a hydrogen donor solvent. Then it is passed through a tubular furnace at 150 psi (1.0×10^6 N/m^2) and 765°F (410°C) to an extraction vessel where dissolution of the organic matter is completed. After unreacted solids are separated, the resulting liquid is fractionated. The low-boiling fraction is recovered as solvent, and the heavy bottom product is further hydrogenated at 800°F (430°C) and 3000 psi (2.1×10^7 N/m^2) to yield synthetic crude oil.

A 70 ton per day (6.4×10^4 kg/D) pilot plant based on the CSF process was operated at Cresap, West Virginia, for 40 months, ending in 1970. Because of recurring equipment failures, the plant was shut down for a detailed study of problem areas. However, it was concluded that the process, as designed, is technically feasible. This plant is scheduled to be reactivated by the Fluor Corporation; several coal-to-liquid-fuels processes will be tested.

A third variant of the solvent refining method, the H-Coal process, carries out dissolution and hydrogenation in the same step in the presence of a catalyst. The slurried coal is reacted with hydrogen in an ebullating bed reactor at 850°F (450°C) and 2700 psi (1.9×10^7 N/m^2). Cobalt-molybdenum catalyst is continuously added to the reactor as spent catalyst is removed. After separating gases and unreacted solids, synthetic crude oil is recovered from fractionation of the resulting liquid.

Initial testing of the H-Coal process has been carried out in a three ton per day (2700 kg/D) pilot plant at the HRI facilities at Trenton, New Jersey, under the sponsorship of Ashland, ARCO, Standard of Indiana, and Exxon. In addition, ERDA and HRI are planning a 600 ton per day (5.4×10^5 kg/D) pilot plant at Catlettsburg, Kentucky, to test the commercial feasibility of the H-Coal process. Industrial sponsors include the ones mentioned above (except Exxon), EPRI and Sun Oil.

Several additional variants of the coal dissolution method are being tested. Gulf Research and Development recently began testing a catalytic process in a one ton per day pilot plant. The Bureau of Mines has contracted Foster-Wheeler Corporation to design an eight ton per day pilot plant to test its Synthoil process, which is similar to the H-Coal process, and has been tested through the one-half ton per day (450 kg/D) pilot plant stage.

In all the above processes, large amounts of hydrogen (15,000-20,000 cubic ft per ton of coal or 470-620 m^3/1000 kg of coal) are consumed. In most cases, sufficient hydrogen can be produced by a combination of gasification of unreacted coal solids (char) and heavy distillation products, and steam reforming of high-Btu byproduct gases. If necessary, some of the feed coal itself can be gasified to provide additional hydrogen.

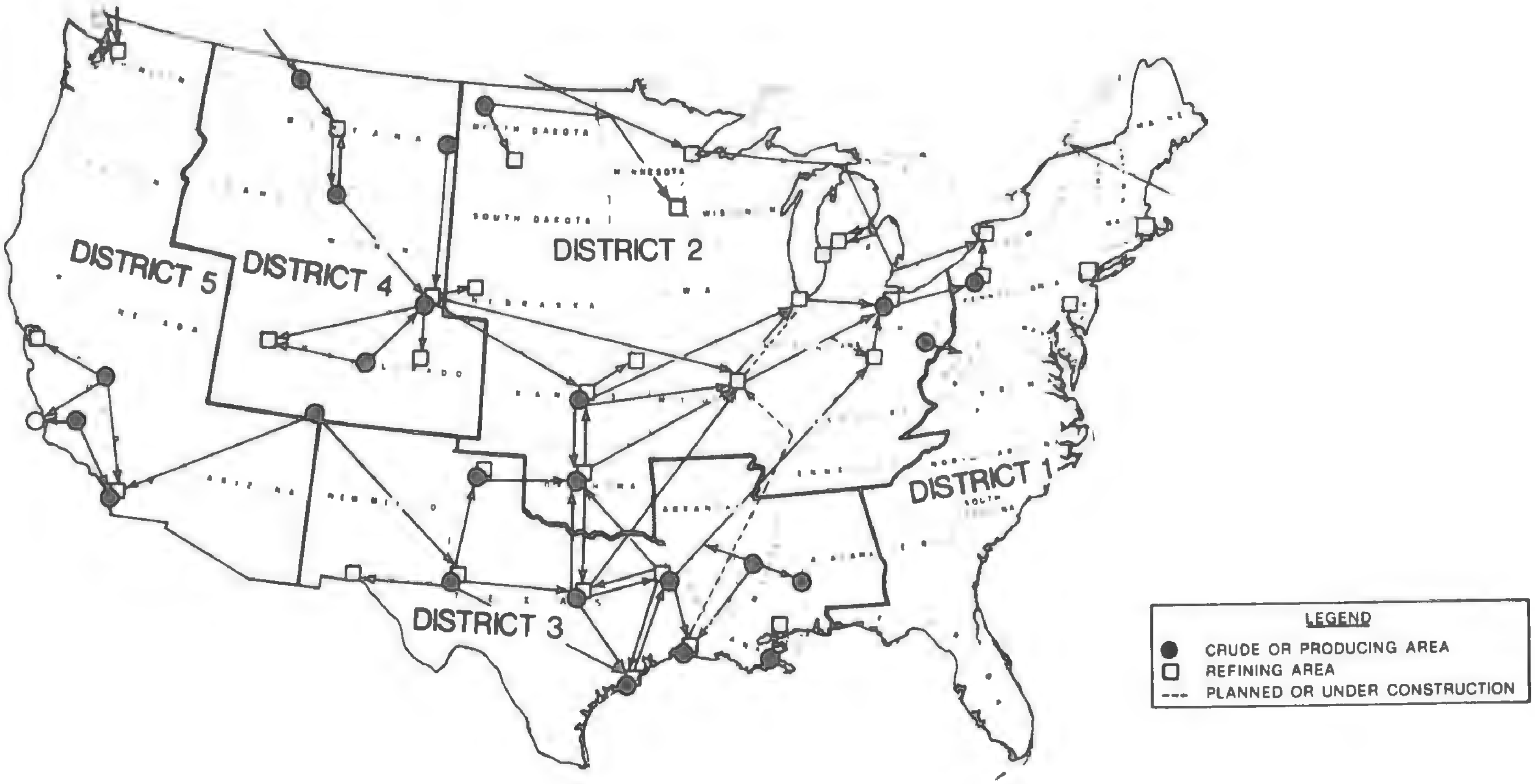
At present no coal liquefaction processes are suitable for incorporation into a commercial-size plant. Several processes have been tested at the pilot-plant level as indicated above. However, considerable research and development remains before the first commercial coal liquefaction plants can be built and operated successfully. In particular, areas in which further R&D are required are coal slurrying and pressurization, durability of reactor materials under severe operating conditions, separation of unreacted solids from liquid products, and maintenance of the activity of hydrogenation catalysts.

It is widely believed that a single-step catalytic hydrogenation process, such as the H-Coal process, is the one most likely to achieve rapid commercialization for the production of synthetic crude oil from coal.[1,7,8] While other processes, such as the SRC process, may be utilized to provide clean boiler fuels for power plants, it appears that the H-Coal or a similar process is the most suitable for providing refinery grade crude oil in terms of cost, efficiency, and technological readiness. Other promising processes are currently undergoing development, including the Union Carbide process, which has been chosen by the Office of Coal Research to be used in a 2600 ton per day (2.4×10^6 kg/D) demonstration plant. However, details of this process are largely proprietary, and furthermore half of the product output of the plant (on a Btu basis) will be in the form of high-Btu gas--the liquid yield is only 1.5 barrels per ton ($0.26\ m^3/1000$ kg) of coal.

Due to the substantial amount of analysis that has been carried out on the H-Coal process,[1,8] its suitability for producing syncrude, and its advanced stage of technological development, we have chosen it as the basis for scaling the impacts from coal liquefaction.

c. Distribution

Due to the similarity between coal-derived syncrude and natural crude oil, the most likely mode of distribution is through the presently existing crude oil pipeline system shown in Figure 4-4. Depending on the location of the syncrude plants, some new pipeline additions or extensions will undoubtedly be built. However, it is likely that the location of crude oil pipelines, as well as the availability of coal, water, etc., will be taken into account in siting the plants. Once the syncrude has entered the pipeline distribution system, it will probably be treated as another source of "sweet" (low sulfur) crude, as



SOURCE: NATIONAL PETROLEUM COUNCIL

FIGURE 4-4. CRUDE OIL PIPELINE NETWORK

is presently done with syncrude from Canadian tar sands, and distributed to refineries as a supplement to natural crude supplies.

Once the syncrude has entered the refinery and is blended with natural crudes, its fate will become indistinguishable from that of other crudes, and products derived from refining the blended syncrude will enter the product distribution network along with other refined products. Due to the high aromatic content of H-Coal syncrude, it is relatively more suitable for the production of gasoline than distillate fuel or other products.[8] Thus, refineries that process significant fractions of syncrude will undoubtedly produce an even larger proportion of gasoline, relative to distillate fuel, than the 2 to 1 ratio that characterizes the present average refinery product slate.

The distribution of methanol derived from coal presents a different problem. There is no pipeline network suitable for transporting methanol. Presumably such a pipeline system could be built, but in the early days of the industry there would not be the financial incentive to do so. Thus, it is likely that methanol will be transported to major distribution centers in the same manner as other liquid chemicals, via railroad tank car. If the industry grows to a large size and firm markets are established, both volume requirements and economic incentives would probably induce the construction of product pipelines to the regions of highest consumption.

The distribution of methanol to final consumption (cars, trucks, and buses) poses additional problems of handling and storage. Since methanol is compatible with gasoline as a blend, it is likely to be consumed initially as a 10-15 volume percent methanol/gasoline blend.[9] However, small amounts of water in the methanol tend to cause phase separation in the gasoline/methanol mixture. To mitigate this problem, the methanol should be stored and handled with special equipment designed to keep moisture out of the system, and blended with gasoline at the last stage of distribution when the fuel is pumped into the vehicle. Thus, methanol is likely to be distributed through the same network as gasoline, but with separate storage and handling facilities.

Ultimately, assuming new engines are designed to operate with pure methanol, some distribution facilities may be built solely to handle methanol sales, but most of the methanol would probably continue to be sold through gasoline distribution facilities (service stations) either in the pure form or as a blend.

An alternative to locating a coal liquefaction or methanol plant near the mine and shipping the product to refining or distribution centers is to locate the plant near these centers and ship the coal to the plant. In coal liquefaction, this is undoubtedly a more expensive alternative than shipping syncrude via pipeline. However, the tendency of some western states, such as Montana, to encourage resource extraction, while discouraging energy conversion activities within the state, will cause increased attention to be directed toward this alternative.

To transport the large quantities of coal required by synthetic fuel plants, either unit trains or coal slurry pipelines will be utilized. A single coal slurry pipeline could supply one or two 100,000-B/D (16,000 m^3/D) plants. Four to five unit trains per day of 100-car length would be required to supply a single plant of the same size. Assuming a two-day transit time between the mine and the plant, about 20 to 25 unit trains would be required to be dedicated full time to a single plant. Assuming several plants will be located in a particular area, say northern Illinois, an enormous supply problem can be envisioned. Coal slurry pipelines will undoubtedly help relieve these problems. However, at least one limiting factor will be the large amounts of water that are required for slurrying the coal--about 750 acre-ft per million tons (100 m^3/1000 kg) of coal.[10] Many western states are reluctant to have scarce water supplies leave the state in this fashion.

Further discussion of coal slurry pipelines and railroads and problems involved in the large scale transport of coal can be found in Chapter 19.

2. Oil Shale

a. Extraction

The production of synthetic crude oil from oil shale involves mining and processing an enormous amount of material--1.4 tons of shale per barrel of oil recovered, on the average. This means that an oil shale retorting and upgrading plant producing 100,000 barrels (16,000 m^3) of syncrude per day must process about 50 million tons (4.5×10^{10} kg) of shale per year. The mining operation for this plant would be ten times larger than the largest underground coal mines now in operation.

It is anticipated that most of the oil shale lying in underground deposits will be mined via the room-and-pillar technique.[11] This is a conventional, well-established mining technology whereby large underground "rooms" (about 60 ft × 60 ft or 18 m × 18 m) are blasted and dug from the resource bed, and large "pillars" are left standing between the "rooms" to support the roof of the mine. With this method, about 60 percent of the resource in-place can be extracted and 40 percent is left in the form of "pillars."[12]

When oil shale lies in deposits near the surface, open pit mining can be carried out. The overburden is first stripped away and stored, then the shale is recovered, crushed, and retorted. After all the resource is removed from the mine area, the overburden is replaced, contoured, and revegetated. The feasibility of surface mining oil shale is determined by the overburden-to-resource ratio and the availability of an area for overburden storage.

A more complete discussion of oil shale mining and spent shale disposal and reclamation can be found in Chapter 14.

b. Conversion

Conceptually, the technology of obtaining liquid hydrocarbons from oil shale is simple. The crushed shale is heated in a closed vessel (retort) to a temperature of 900°F (480°C) or greater, at which point the kerogen (the organic portion of the oil shale) vaporizes and is separated from the solid inorganic portion of the rock. After retorting, the shale oil is upgraded by means of hydrotreating (chemically reacting with hydrogen) to yield a synthetic crude oil, which is suitable for transport via pipeline and can be used as a refinery feedstock.

The various methods for retorting oil shale differ in the manner in which heat is generated and transferred to the shale. The simplest method is the Fischer assay technique in which heat from an external source is transferred to the shale through the wall of the retort. Any fuel may be used to supply the heat. Due to large capital and operating costs, this method is unsuitable for commercial development. However, it is commonly used on a laboratory scale to measure the kerogen content of the shale.

There are four additional methods for retorting oil shale, which are in various stages of development and which have the potential for commercial application. These are discussed in the following paragraphs.

(1) Hot Solids or Solids-to-Solids Heating Method--The TOSCO II process is the most advanced version of this technique. In this process ceramic balls are heated by the combustion of byproduct gases and liquids and transferred to the retort where they are mixed with crushed, preheated shale. Shale oil vapor is driven off and recovered. The ceramic balls are separated from the spent shale (on the basis of size) and subsequently reheated. A high efficiency of energy recovery is achieved; however, capital and operating costs are high.

In the Lurgi-Ruhrgas version of this technique which has been tested in a 12 ton per day pilot plant in West Germany, spent shale is used as the heat carrier. The spent shale is heated by combusting the carbon residue which remains after retorting, together with additional fuel as needed.

The TOSCO II process is essentially ready for commercial application. Colony Development Operation (a joint venture of ARCO, Ashland, Shell, and The Oil Shale Corporation) has successfully completed tests on a 25 ton per day test unit and an 1100 ton per day semiworks plant at Parachute Creek, Colorado. Colony had announced plans to begin construction in April 1975, of a 50,000-B/D commercial plant based on the TOSCO II process. These plans were later postponed, with Colony citing rapidly inflating construction costs and uncertainties in U.S. energy policy as the basis for its decision.[13]

There are several other planned commercial operations in which the TOSCO II retort will be used. These include the following: a 50,000-B/D (8000 m^3/D) plant planned to begin operation in 1982 by ARCO, TOSCO, Ashland, and Shell as a joint venture on Colorado Tract C-b; the Rio Blanco Oil Shale Project, a joint venture on Colorado Tract C-a by Gulf Oil and Standard of Indiana with 50,000-B/D (8000 m^3/D) initial production planned for 1980; the 75,000-B/D (12,000 m^3/D)

Sand Wash Project in Utah planned by TOSCO with start-up expected in 1981-83.

(2) Gas-to-Solids Heating/Internal Gas Combustion Method--Crushed shale is fed to the top of a vertical retort and low-Btu byproduct gas is injected at the bottom. The gas is combusted in the retort along with residual carbon on the spent shale, and the hot combustion gases heat the shale, driving off the oil vapors that are condensed at the top of the retort. The noncondensible gases are recycled for combustion. Due to the lack of external heating equipment, this method is less costly than other types of retorts. Energy recovery efficiency is somewhat lower, however.

The Bureau of Mines tested a version of this technique, called the Gas Combustion process, in 1966-67. No tests have been carried out on this process since then.

The Union Oil Company version of the process utilizes a unique "rock pump" which injects shale at the bottom of the retort while combustion gases are drawn down from the top by blowers, and retorted shale oil is collected at the bottom. A 1000 ton per day (9×10^5 kg/D) pilot plant was successfully demonstrated in 1957-58. A more advanced version of this retort, called the steam gas recirculation (SGR) process, was recently announced and a 1500 ton per day (1.4×10^6 kg/D) demonstration plant based on this process will be built on private land in Colorado. (The SGR retort is actually an example of the gas-to-solids, external heat generation method discussed in the next section.) Union reportedly plans to have a 50,000-B/D (8000 m^3/D) commercial plant operating by 1980.

A third variation on the process has been constructed by Development Engineering, Inc. (DEI), the operating arm of Paraho Development Corporation (a consortium of 17 firms). This process, usually referred to as the Paraho retort, utilizes patented shale-feed and spent shale-discharge grates, which provide a uniform flow of shale through the retort. Multilevel gas injectors are also used to carefully control the level of incoming gases. DEI recently completed a successful 30-day run on its 500 ton per day (4.5×10^5 kg/D) test plant near Rifle, Colorado, as part of a 30-month R&D program. Paraho has also proposed to construct and test a commercial size retort on the Naval Oil Shale Reserve in Colorado.

Both of the planned commercial operations on federally leased tracts in Utah have proposed to use primarily the Paraho retort. However, since the Paraho retort can operate only on coarse shale, the TOSCO II process will also be used to deal with the 10 to 20 percent of the crushed shale that is too fine for the Paraho process. Sun Oil and Phillips Petroleum have leased the U-a tract and propose to have a 50,000-B/D (8000 m^3/D) plant operating by 1978. The White River Shale Corporation (a joint venture of Sun, Phillips, and Standard of Ohio) has leased the other Utah tract (U-b) and is also planning a 50,000-B/D (8000 m^3/D) operation. Due to the continguous nature of the two tracts, and overlapping ownership in the two ventures, it is likely that these operations will be carried out jointly by all the participants.

(3) <u>Gas-to-Solids Heating/External Heat Generation Method</u>--Recirculated byproduct gas is used as the medium of heat transfer; however, heating of the gas is carried out in the external furnace, rather than by combusting the gas and spent shale within the retort. Some of the byproduct gas, carbon residue on the spent shale, or any other suitable fuel may be combusted to supply heat to the furnace. During 1975, Paraho will begin testing a version of its retort which operates with externally heated gases.

The Brazilian national oil company (Petrobras) has tested a 2200 ton per day (2.0×10^6 kg/D) version of the external gas heating retort called the Petrosix process. The tests were successful; however, there are no plans for commercial application in the United States.

(4) In-Situ Retorting--Shale rock is fractured in place by explosives to form an underground retorting chamber. Air is injected to combust part of the shale, and retorting is carried out via heat transfer from the hot combustion gases. Shale oil is collected from a hollow mined at the bottom of the shale column.

Numerous tests of this method have been made by various companies. Commercial feasibility has not yet been demonstrated, although recent tests by Garrett Research and Development, a subsidiary of Occidental Petroleum, appear promising. A 30 × 30 × 70-ft (9 × 9 × 21-m) shale column was successfully retorted, resulting in a shale oil yield of about 60 percent. Further tests are planned on a 100 × 100 × 250-ft (30 × 30 × 76-m) column, with yields in excess of 70 percent expected. If the Garrett or other tests demonstrate the commercial feasibility of in-situ retorting, the use of this method could considerably reduce water consumption, spent shale disposal, and other problems presently associated with aboveground retorting. However, new problems, such as surface subsidence and the release of large quantities of combustion gases, would be created, and these would need to be carefully managed. This method is expected to be less costly than any aboveground retorting technique.

The TOSCO II process is the most advanced retorting method for which a sufficient amount of information is available to provide the scaling factors required for analysis. In addition, it has been incorporated into the plans of a majority of the companies which will be actively developing oil shale. Thus, we have chosen to use it in our analysis of oil shale conversion. A block flow diagram showing the steps in oil shale processing, from crushing through upgrading is shown in Figure 4-5.

Subsequent to retorting, described previously, the shale-derived gases and liquids must be processed to remove sulfur and nitrogen, and produce a syncrude that is suitable as a refinery feedstock. The raw shale oil is separated into naphtha, gas oil, and residual fractions. The naphtha and gas oil are sent to separate hydrotreaters where they are upgraded and desulfurized. The residual oil is sent to the coker unit, where coke is produced along with additional naphtha and oil, which are sent to the hydrotreaters. During hydrogenation of the naphtha and gas oil sulfur and nitrogen compounds are converted to H_2S and ammonia, which are separated in the sour water waste stream and subsequently recovered as ammonia solution and elemental sulfur.

The hydrogenated naphtha and gas oil are recombined and leave the plant as synthetic crude oil. The high-Btu byproduct gases from the retort are purified to remove H_2S and ammonia impurities, and to remove uncondensed liquids (naphtha). All of these gases are then consumed on site, either as plant fuel to provide steam and heat, or as feed to the steam reforming furnaces, where they are reacted to form hydrogen for the hydrotreaters.

Although it is conceivable that the raw shale oil upgrading could be carried out elsewhere, transporting it via pipeline would pose severe problems due to its high viscosity. The viscosity is reduced in the process of upgrading and the syncrude product is suitable for shipment via pipeline.

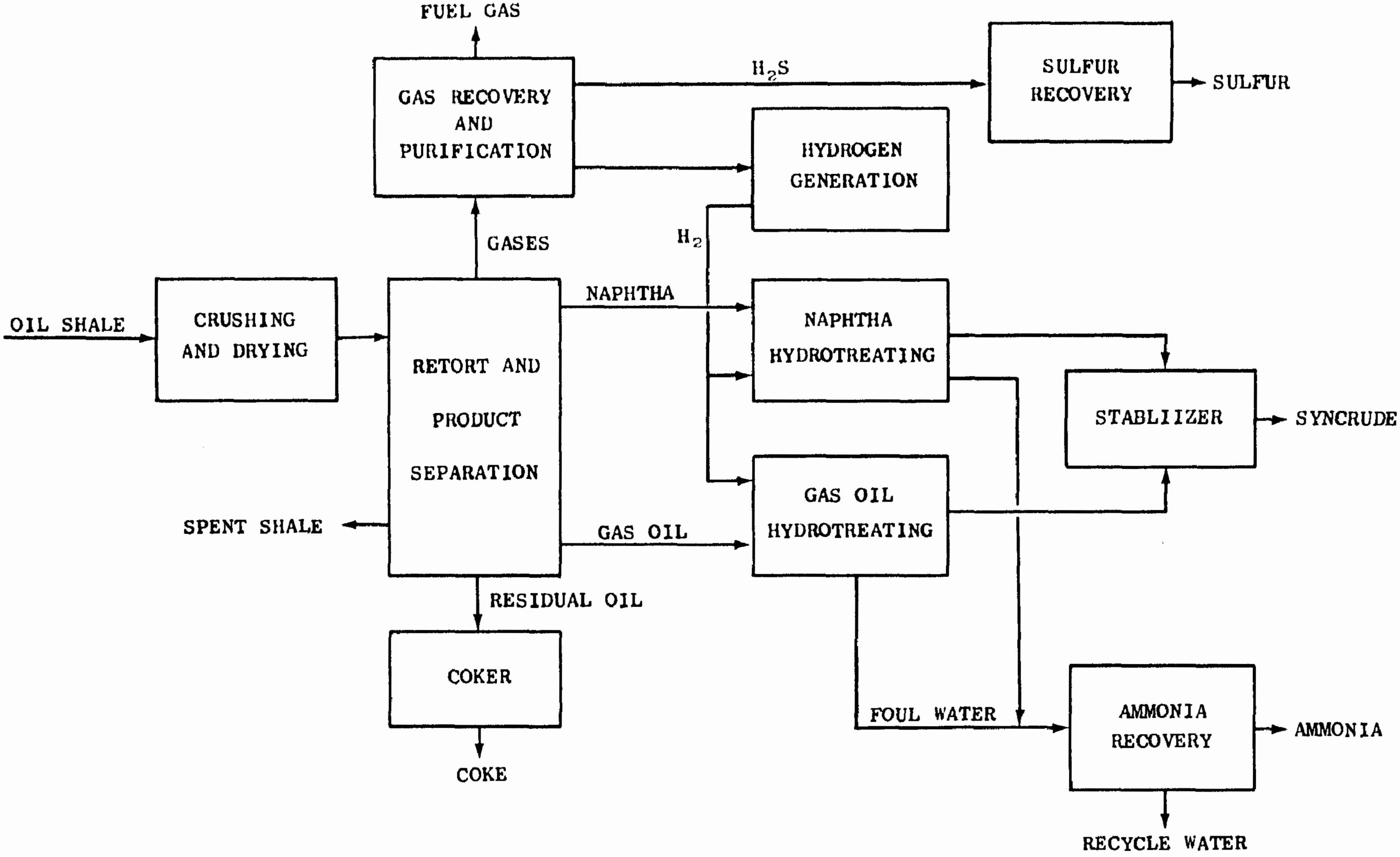


FIGURE 4-5. OIL SHALE RETORTING AND UPGRADING

c. Distribution

As in coal-derived syncrude, the distribution of upgraded shale oil will undoubtedly be done via the present crude oil pipeline network. Colony Development Operation has proposed a pipeline system that would originate in the Piceance Basin of Colorado and connect with existing crude pipelines to carry shale syncrude to refinery centers. Other pipeline connectors will undoubtedly be built as the oil shale industry develops. Figure 4-6 shows the location of the existing crude oil pipeline network in relation to the oil shale-bearing regions of Utah, Wyoming, and Colorado.

3. Building Block Sizes

The sizes of building blocks which will make up the production and transportation systems for synthetic liquid fuels from coal and oil shale will be determined by many interacting factors. Among these are the limiting physical size of the components of each building block, the capacity at which economies of scale are achieved, and the level of production or throughput that best fits into the regional energy supply/ demand picture. For the first generation of synthetic liquid fuel plants there is another constraint on size--the amount of capital that private companies are willing to risk in a venture based on technology that has not been previously tested on a commercial scale.

An inspection of the literature on current energy industry practices and future plans for synthetic fuel plants quickly reveals that there is a range of sizes that characterizes building blocks in the synthetic fuels system. Table 4-1 shows the higher and lower sizes in the range typical of each building block. These figures are not meant to indicate absolute limits on sizes; rather they are meant to indicate what "large" and "small" building blocks look like in the

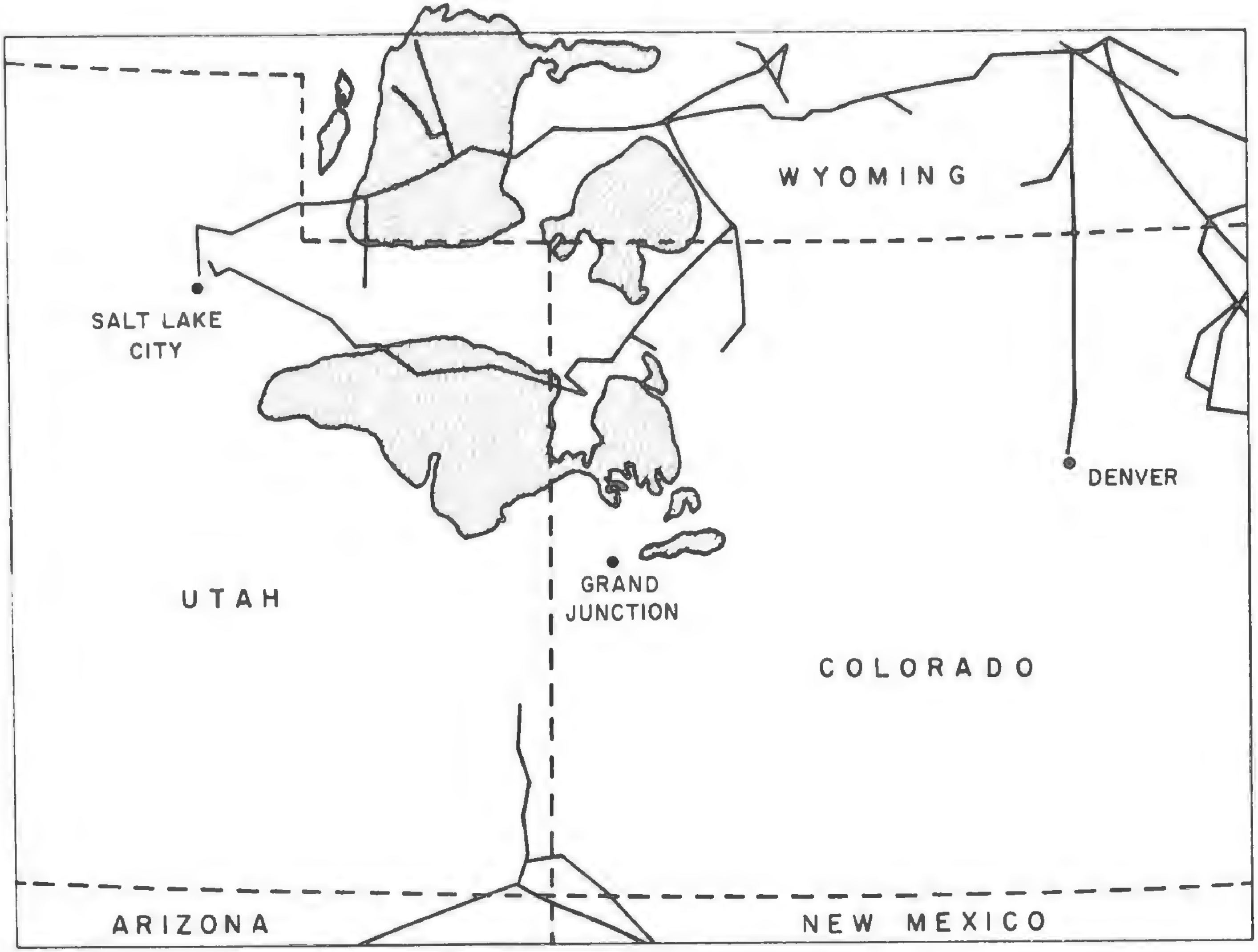


FIGURE 4-6. EXISTING CRUDE OIL PIPELINES IN RELATION TO OIL SHALE AREAS

context of a synthetic fuel supply system. For example, there are many Appalachian coal mines that produce less than 100,000 tons (9×10^7 kg) per year. However, these are not considered to be viable building blocks in the synthetic fuel system.

Table 4-1

BUILDING BLOCK SIZES IN THE SYNTHETIC LIQUID FUELS PRODUCTION SYSTEM

		Building Block Size	
Building Block	Units*	Small	Large
Western surface coal mine	tons/yr	1 million	10 million
Eastern underground coal mine	tons/yr	0.1 million	5 million
Unit train (coal)	tons of capacity	--	10,000
Coal liquefaction plant	B/D	25,000	100,000
Methanol plant	B/D	35,000	200,000+
Oil shale mine	tons/yr	25 million	75 million
Oil shale retort and upgrading complex	B/D	50,000	150,000
Crude oil pipeline	B/D of capacity	25,000 (8 in.)	1.5 million (48 in.)
Refinery	B/D	50,000	400,000

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*1 ton/yr = 910 kg/yr
1 B/D = 0.6 m^3/D
1 in. = 2.54 cm.

In spite of the range of sizes possible for the different building blocks, there tend to be certain nominal or "typical" sizes that characterize industry plans for synthetic fuels. For coal liquefaction, the earliest commercial plants will probably be in the range of 25,000 to 40,000 B/D (4000-6400 m^3/D). As the industry matures, the plant sizes will probably increase to about 100,000 B/D (16,000 m^3/D). There are few indications that plants larger than this will be built.

The first planned commercial oil shale complexes are of the order of 50,000 B/D (8000 m^3/D). Later complexes of 100,000 B/D (16,000 m^3/D) or larger are contemplated. Plants larger than 100,000 B/D (16,000 m^3/D) will probably be combinations of smaller units.

Consideration of methanol plant size is usually made by analogy with substitute natural gas (SNG) plants. A plant using Lurgi gasifiers, which processes the same amount of coal as a 250 million cubic ft per day (7.1×10^6 m^3/D) SNG plant (typical size) can produce about 81,200 B/D of methanol. This is the approximate energy equivalent of a 40,000-B/D (6400 m^3/D) syncrude plant. Although conceptual designs have been carried out for much smaller coal-to-methanol plants, it appears that economy of scale will favor the larger plant sizes. Plants with capacities in excess of 200,000 B/D (32,000 m^3/D) are conceivable.

Recent trends in construction of the other building blocks in Table 4-1 have been toward the higher end of the scale. However, to a large extent synthetic fuel plants will have to interface with existing facilities, which tend to be at the lower end of the scale. The country abounds with 8-in. (20 cm) pipelines and refineries with capacities well under 100,000 B/D (16,000 m^3/D).

C. Material and Energy Flows

In this section the quantities of raw materials, resource energy, labor and capital required to produce a given quantity of synthetic fuel are given and flows of these quantities are traced both through the extraction-conversion-distribution systems and to areas external to the systems. Tracing the flows of these quantities is important to the assessment of the social, economic, and environmental impacts of synthetic fuels development.

1. Energy Efficiency

Since the processes for converting solid resources into synthetic liquid fuels are themselves energy intensive activities, it is important to identify both the sources of energy loss during conversion and the requirements for external sources of energy to operate the conversion plants. Additional energy will be consumed in the extraction, transportation, refining, and distribution stages as well. By dividing the energy available for end use by the initial resource energy plus all the external energy inputs into the system, we can obtain an overall efficiency for the production of each alternative fuel.

We are concerned here only with the efficiency with which resource energy can be converted into product energy. We do not address the larger question of net energy, in which the energy required to manufacture and deliver the materials that go into the plant along with secondary energy inputs are considered. Net energy calculations are carried out and discussed in Chapter 5.

a. Methanol from Coal

Figure 4-7 shows the energy balance for converting 39,000 tons per day (3.5×10^7 m^3/D) of 8870 Btu/lb (2.1×10^6 J/kg) Navajo coal into 100,000 barrels (16,000 m^3) of methanol.[14] All energy consumed in the plant is derived from the initial coal input--no external energy source is required. Of the 692 billion Btu per day (7.3×10^{14} J/D) entering the plant as the heating value of the coal, 272 billion Btu (2.9×10^{14} J) exit the plant as methanol, 120 billion Btu

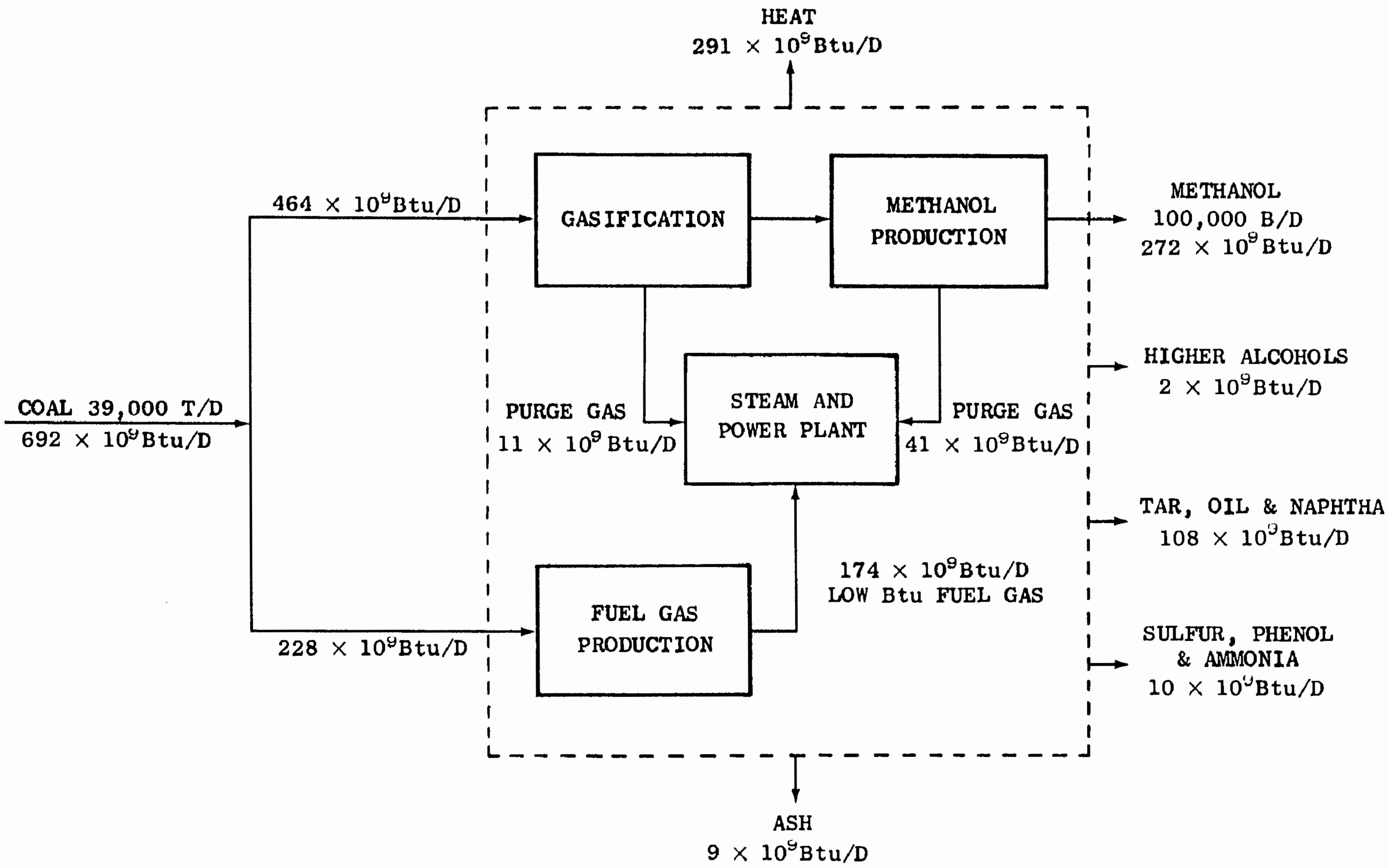

FIGURE 4-7. METHANOL FROM COAL ENERGY BALANCE

(1.3×10^{14} J) are in the form of byproducts, and 300 billion Btu (3.2×10^{14} J) end up as waste heat, endothermic reaction heat or in the ash.[14]

There are several ways to define thermal efficiency, all of which are useful in difference contexts. For this study we wish to know the efficiency with which the energy in the initial resource (coal in this case) can be converted into energy in the form of the alternative fuel of interest. With this definition, we simply divide the heating value of the methanol by the heating value of the coal to obtain:

$$\text{Efficiency (coal-to-methanol)} = \frac{272 \times 10^9}{692 \times 10^9} = 39.3 \text{ percent.}$$

(If the byproduct higher alcohols (ethanol, propanol, etc.) are not separated but remain blended with the methanol, the product is called "methyl fuel." The coal-to-"methyl fuel" efficiency is only slightly greater, however, 39.6 percent.)

It is important to note that in this case significant quantities of combustible byproducts are produced along with the methanol--about 110 billion Btu per day (1.2×10^4 J/D). If these byproducts are counted as part of the total useful product energy we have

$$\text{Efficiency (coal-to-products)} = \frac{272 + 110}{692} = 55.2 \text{ percent.}$$

One final accounting method that is useful in comparing one alternative fuel with another and in computing net energy is the primary resource energy/ancillary energy method. Primary resource energy is defined as the initial energy content (heating value) of the resource that is actually processed into the final product. The ancillary resource energy is the energy content of the resource which is required to provide the electricity, steam, or general fuel to run the process. This concept is especially useful when the resource from which the ancillary energy is derived is different from the primary resource.

In the coal-to-methanol conversion, 228 billion Btu (2.4×10^{14} J) of ancillary resource energy are required to convert 464 billion Btu (4.9×10^{14} J) of primary resource into 272 billion Btu (2.9×10^{14} J) of methanol. The 52 billion Btu (5.5×10^{14} J) of off-gas from methanol production are not counted in the ancillary energy requirement since they are generated internally and do not place any demand on external resources.

The primary and ancillary resource energy requirements for producing 10^{12} Btu (1.1×10^{15} J) of methanol are tabulated in Table 4-2 below.

Table 4-2

COAL-TO-METHANOL ENERGY REQUIREMENT

	10^{12} Btu	10^{15} J
Methanol energy	1.00	1.06
Primary resource energy	1.71	1.80
Ancillary resource energy	0.84	0.89

b. Syncrude from Coal

The energy balance for converting 55,200 tons per day (5.0×10^{7} kg) of 7800 Btu per lb (18×10^{6} J/kg) Powder River coal into 100,000 barrels (16,000 m^3) of synthetic crude oil via the H-Coal process is shown in Figure 4-8.[15] This process has been designed to produce only plant steam and heat on-site. An additional 144,000 kW of purchased electricity is required to operate the plant. The 35 billion Btu per day (3.7×10^{13} J/D) of ancillary resource energy required to produce this quantity of electricity (assuming 33 percent conversion efficiency) must be taken into account in the energy balance.

Unlike the coal-to-methanol process, this plant has been designed to utilize all byproducts within the plant. The coal char and vacuum bottoms (derived from fractionation of the coal hydrogenation product) are gasified to produce hydrogen, and part of the high-Btu byproduct gas is steam reformed to produce hydrogen. The remaining gas is burned to provide process steam and heat (93 billion Btu per day or 9.8×10^{13} J/D).[8] All the usable product energy is in the form of syncrude.

The efficiency for converting the initial coal resource into synthetic crude oil is:

$$\text{Efficiency (coal-to-syncrude)} = \frac{567}{861 + 35} = 63.3 \text{ percent.}$$

We have assumed that the 35 billion Btu per day (3.7×10^{13} J/D) of resource input into electric power generation are in the form of coal.

The primary and ancillary resource energy required to produce 10^{12} Btu of syncrude are shown in Table 4-3.

c. Syncrude from Oil Shale

The energy balance for oil shale mining, TOSCO II retorting and upgrading is shown in Figure 4-9.[16] Mining is included in this balance since it is considered to be an integral part of the oil shale operation. All the process energy requirements are generated

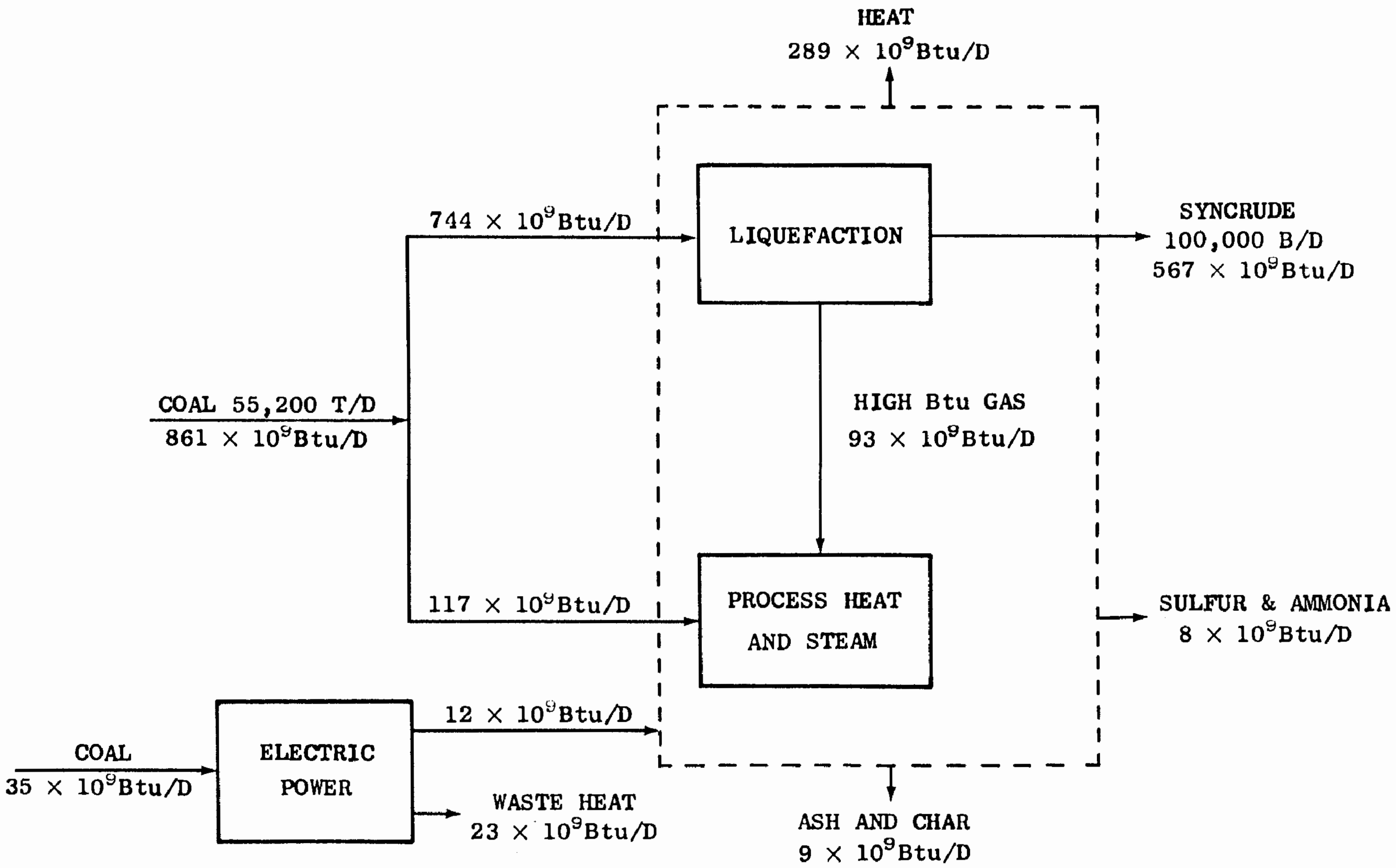

FIGURE 4-8. H-COAL LIQUEFACTION PROCESS ENERGY BALANCE

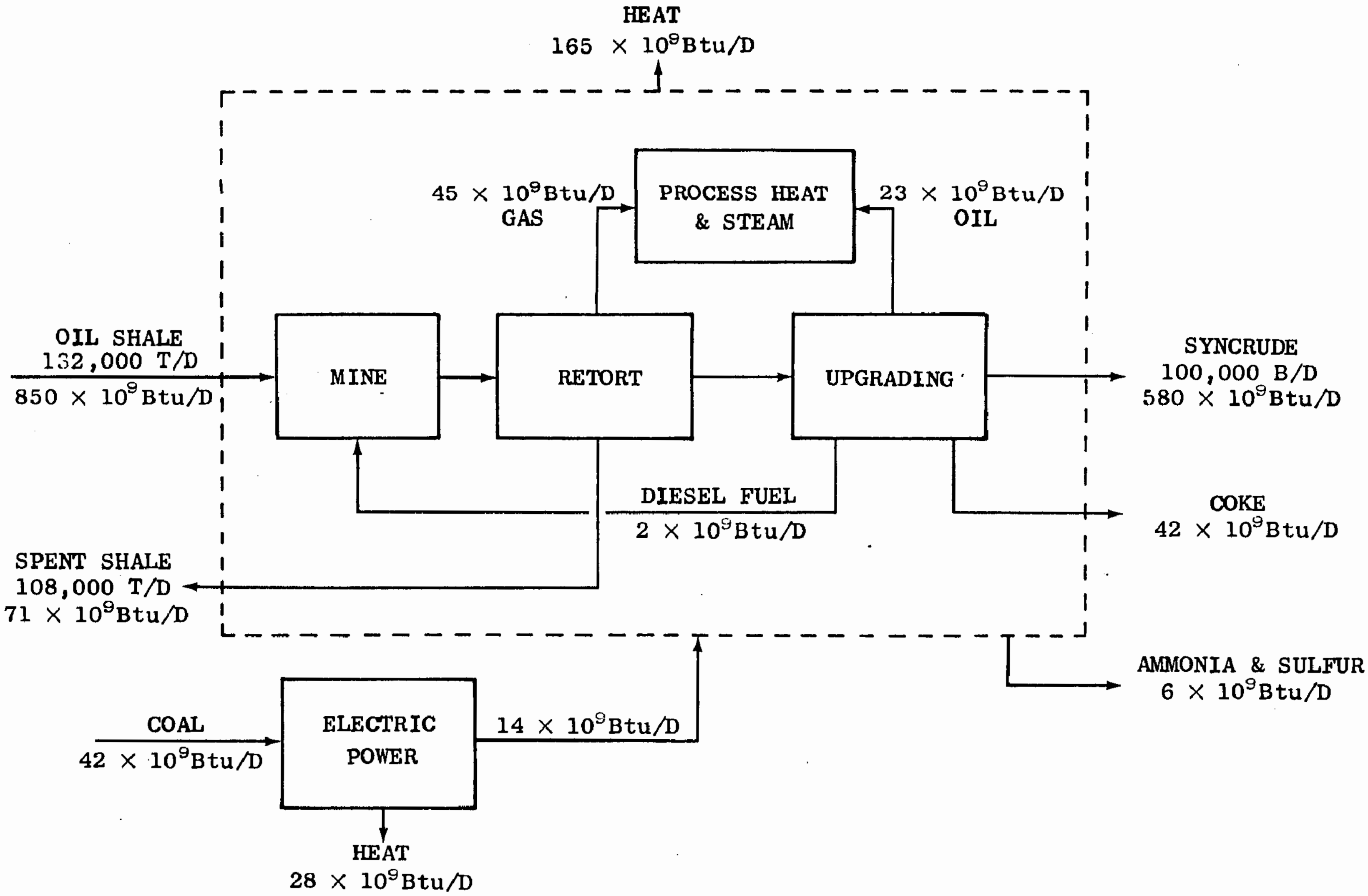

FIGURE 4-9. TOSCO II OIL SHALE RETORTING AND UPGRADING ENERGY BALANCE

on-site by the combustion of byproduct gases and fuel oil except for 170,000 kW of purchased electricity.[12]

Table 4-3

COAL-TO-SYNCRUDE ENERGY REQUIREMENT

	10^{12} Btu	10^{15} J
Syncrude energy	1.00	1.06
Primary resource energy	1.31	1.38
Ancillary resource energy	0.27	0.28

The thermal efficiency for converting oil shale to syncrude is:

$$\text{Efficiency (oil-shale-to-syncrude)} = \frac{580}{858} = 67.6 \text{ percent.}$$

Strictly speaking, the resource (probably coal) required to produce the electric power for the plant should be included, so that the resource-to-syncrude efficiency is:

$$\text{Efficiency (resource-to-syncrude)} = \frac{580}{858 + 42} = 64.4 \text{ percent.}$$

The efficiency for conversion of resource to useful product energy, including byproduct coke, is:

$$\text{Efficiency (resource-to-products)} = \frac{580 + 42}{858 + 42} = 69.1 \text{ percent.}$$

The calculation of primary and ancillary resource energy requirements has somewhat more meaning for oil shale than for the liquid fuels from coal technologies, since without the investment of a certain amount of ancillary energy from another resource, no useful products could be produced from oil shale. Coal is already a useful form of energy, and energy is invested only to convert it to another form. Table 4-4 shows the primary and ancillary resource energy requirements for converting oil shale into 10^{12} Btu of synthetic crude oil.

Table 4-4

OIL SHALE-TO-SYNCRUDE ENERGY REQUIREMENTS

	10^{12} Btu	10^{15} J
Syncrude energy	1.00	1.06
Primary resource energy	1.48	1.56
Ancillary resource energy	0.07	0.07

2. Resource Consumption

We have defined resource in a broad way to include not only the primary resources coal and oil shale but also the quantities of water, land, labor and steel necessary to build and operate synthetic fuels plants. In addition we consider briefly the consumption of catalysts, chemicals, and other such materials. The reason for defining resources in this way is to be able to examine a broad range of social and economic impacts from synthetic fuels development as well as impacts on the natural environment. We therefore use the concept of societal/industrial resources as well as natural resources. Strictly speaking, capital should also be included as a resource, but due to the somewhat greater complexity of analyzing capital and operating costs, we defer the discussion of capital to Section 4.

a. Coal and Oil Shale

The consumption of primary resources in a given synthetic fuel conversion process depends on both the particular process design and the energy content of the resource. We will maintain consistency with our previous discussion by assuming here and in subsequent sections that coal is converted to syncrude via the H-Coal process; coal is converted to methanol via Lurgi gasification followed by intermediate pressure methanol synthesis; and oil shale is converted to syncrude via TOSCO II retorting followed by coking and hydrotreating.

The quantity of oil shale consumed is determined by its kerogen content. Colony Development Operation has designed its first commercial plant to operate on 35 gal/ton (0.15 m^3/1000 kg) shale.[12] Other processes have been designed to operate on shale with oil content down to 27 gal/ton (0.11 m^3/1000 kg) and we include this for comparison. The coal requirement is the amount of western subbituminous coal which must be burned to provide electric power for the shale plant.

The two U.S. coal types which we consider for liquefaction are western subbituminous (8000-9000 Btu/lb (1.9 × 10^7-2.1 × 10^7 J/kg) and eastern bituminous (11,000-12,000 Btu lb or 2.6 × 10^7-2.8 × 10^7 J/kg). The amount of coal consumed is calculated on the basis of both the primary resource required and the amount of coal necessary to provide plant fuel and electricity. The considerably lower requirement for eastern compared to western coal is due not only to the higher heating value of eastern coal but also to the significantly larger amount of byproduct gases recovered during eastern coal liquefaction which can be used in place of coal as plant fuel.[8]

In methanol produced from coal, we consider in addition to bituminous and subbituminous coal, North Dakota lignite (about 6500 Btu lb or 1.5×10^7 J/kg), which is an excellent feedstock for coal gasification, and would thus be suitable for methanol production as well. The production of methanol from bituminous coal requires technology other than the Lurgi gasifier, which has not operated well with U.S. eastern coals. We assume that either a modified Lurgi gasifier or another type of gasifier such as the Koppers-Totzek will be used with bituminous coal.

The coal and oil shale requirements for the three technologies under consideration are shown in Table 4-5. These annual requirements are based on daily resource inputs, assuming the plant is operating 90 percent of the time over a period of one year.

b. Water

The water requirement for synthetic fuels production arises mainly from the need for cooling water to dispose of waste heat, and the chemical need for hydrogen in the conversion process. The chemical hydrogen requirement is more or less fixed for each process, while the cooling requirement is variable depending on the degree to which wet cooling versus dry cooling is used in the plant, and the level to which heat given off during each process step can be recovered for useful purposes. Other uses of water within the plant may be quenching of gaseous products to remove oil and particulates, dust suppression, solid waste disposal, and the generation of steam to drive turbines or gas compressors.

In the conversion of coal to methanol, about 3300 acre-ft of water per year (as steam) is consumed in chemical reactions (gasification, shift conversion and methane reforming).[6] For the H-Coal liquefaction process, the chemical consumption of water is about 3500 acre-ft

Table 4-5

ANNUAL COAL AND OIL SHALE REQUIREMENTS FOR 100,000-B/D SYNTHETIC FUELS PLANTS

	Oil Shale (million tons)	Oil Shale (10^9 kg)	Coal (million tons)	Coal (10^9 kg)
Syncrude from oil shale				
35 gal/ton (0.15 m^3/1000 kg)	43	39	0.8	0.7
27 gal/ton (0.11 m^3/1000 kg)	55	50	1.0	0.9
Syncrude from coal				
Bituminous	--	--	13	12
Subbituminous	--	--	18	16
Methanol from coal				
Bituminous	--	--	10	9
Subbituminous	--	--	13	12
Lignite	--	--	18	16

per year (4.2×10^6 m^3/Y) using either western or eastern coal.[8] This water is utilized as steam in the partial oxidation plant and steam reformer to convert solid and gaseous byproducts, respectively, into hydrogen for the coal hydrogenation process. The chemical consumption of water in oil shale processing is in the steam reforming furnaces, where hydrogen is produced for use in hydrotreating raw shale oil products. This use of water amounts to 1500 acre-ft per year (1.8×10^6 m^3/Y).[11]

Other uses for water in oil shale mining, retorting and upgrading have been fairly well established and are shown in Table 4-6 below.

Table 4-6

ANNUAL WATER REQUIREMENTS FOR A 100,000-B/D OIL SHALE MINING, RETORTING, AND UPGRADING OPERATION

Process	Water (acre-ft)	Water (10^6 m^3)
Mining and crushing	900	1.1
Retorting	1300	1.6
Upgrading	3600	4.3
Spent shale disposal	7300	8.8
Power generation	1800	2.2
Revegetation	700	0.8
Total	15,600	18.7

Source: Reference 11.

Of the above total, about 3800 acre-ft per year (4.6×10^6 m^3/Y) are consumed as makeup water to the evaporative cooling towers. This quantity could be reduced significantly if more costly dry cooling were utilized. There are relatively few additional areas where water consumption could be reduced. Essentially all process waste water will be reused within the plant.

Information on nonchemical water requirements for producing methanol from coal is somewhat sketchy. Depending on the extent to which air cooling is used, makeup water for cooling is in the range of 12,000-24,000 acre-ft per year (14 × 10^6-28 × 10^6 m^3/Y). Much of the water requirement for steam generation and cooling can be made up by treating and recycling process waste water. We estimate the total water requirement for a 100,000-B/D (16,000 m^3/D) plant to be 10,000-20,000 acre-ft per year (12 × 10^6-24 × 10^6 m^3/Y).

Coal liquefaction via the H-Coal process consumes 22,000 acre-ft of water per year (26 × 10^6 m^3/Y) in evaporative cooling losses.[8] The total requirement is 26,000-29,000 acre-ft per year (31 × 10^6-35 × 10^6 m^3/Y) with no waste water recycling. To the extent that dry cooling and internal cleanup and recycling are used, this figure could be reduced by about half.

c. Land

Land use for synthetic fuels production includes permanent uses such as the plant site itself, roads, pipeline and utilities corridors, and water storage areas. Temporary uses include areas disturbed by mining and solid waste disposal, assuming the disturbed land can be rehabilitated for other uses. To the extent that the land is disturbed so that restoration or rehabilitation is not possible, these uses of the land become permanent.

The permanent land requirement for a 100,000 B/D (16,000 m^3/D) oil shale mining, retorting, and upgrading operation is about 600 acres (2.4 × 10^6 m^2).[12] In addition, about 150 acres per year (6.1 × 10^5 m^2/Y) are disturbed by the disposal of spent shale in deep canyons, assuming the disposal pile is 250-ft (76 m) high.[11] Revegetation of spent shale has not been convincingly demonstrated at this time, and it remains to be seen whether canyons which have been filled with spent shale can be reclaimed for other uses.

By analogy with synthetic natural gas plants, a coal-to-methanol conversion facility will occupy about 1000 acres (4×10^6 m^2).[17] Solid waste in the form of ash will be returned to mined-out areas for burial. A coal liquefaction plant and associated facilities will occupy about 1000 acres (4×10^6 m^2).

The land disturbed by surface coal mining depends strongly on the area of the country in which the coal is mined and is a function of the coal seam thickness and the method used for mining, i.e., contour stripping versus area stripping. Table 4-7 shows the average amount of land disturbed by area strip mining in several western states.[18]

Table 4-7

AVERAGE LAND AREA DISTURBED PER MILLION TONS OF COAL RECOVERED

State	Land Area (acres)	Land Area (10^3 m^2)
Arizona	78	320
North Dakota	65	260
New Mexico	62	250
Montana	47	190
Wyoming	25	100

Source: Reference 18.

Combining this information with data from Table 4-5, we find that the land disturbed annually to supply coal to a 100,000-B/D (16,000 m^3/D) methanol plant ranges from 325 acres (1.3×10^6 m^2) for Wyoming subbituminous coal to 1170 acres (4.7×10^6 m^2) for North Dakota lignite. For liquefaction of subbituminous coal at the 100,000-B/D (16,000 m^3) level, the land disturbed ranges from 450 to 1400 acres per year (1.8×10^6-5.7×10^6 m^2/Y).

In the Midwest, coal seams are much thinner than in the West; consequently, more land must be disturbed per unit of coal recovered. The average land area disturbed in the Midwest per million tons of coal recovered is 144 acres (5.8×10^5 m^2).[19] Thus, 1440 acres (5.8×10^6 m^2) must be disturbed annually to supply a 100,000-B/D (16,000 m^3/D) methanol plant and 1870 acres (7.6×10^6 m^2) must be disturbed to supply a 100,000-B/D (16,000 m^3/D) coal liquefaction plant.

In Appalachia, most surface coal mining is done by contour stripping, in which land is disturbed not only in the area of overburden removal but also by covering the downslope region with a spoil bank and to a lesser extent by drainage ditches and induced landslides. The average land area disturbed in Appalachia per million tons of coal recovered is 415 acres (1.7×10^6 m^2) for the contour stripping method.[19] This means that 4150 acres (1.7×10^7 m^2) must be disturbed annually to supply a methanol plant and 5400 acres (2.2×10^7 m^2) must be disturbed to supply a coal liquefaction plant.

The reclamation potential for surface mining in the major coal-bearing regions of the United States is discussed in detail in Chapters 13 and 15. Generally speaking, it is possible in almost all areas for some form of reclamation to take place and is in fact now required by law in many states. Therefore, we may consider land disturbed by surface mining to supply synthetic fuels plants a temporary land use.*

Land disturbance from eastern underground coal mining is mostly in the form of surface subsidence. The degree to which subsidence occurs will depend on the mine depth, the strength of the rock formation above the mine, and the type of mining which is employed. For example, long-wall mining results in greater subsidence than room-and-pillar mining. The effect of subsidence is more or less permanent but does not necessarily remove the land from other uses. Using an average figure of 0.1 acres (400 m^2) of subsidence per 500 tons (4.5×10^5 kg) of coal mined,[20] we find that 2000 acres (8.1×10^6 m^2) could be disturbed annually to supply a methanol plant, and 2600 (1.1×10^7 m^2) acres could be disturbed to supply a coal liquefaction plant.

d. Labor

To assess impacts due to the buildup of population in rural areas where much of the synthetic fuels development is expected to occur, it is necessary to know the manpower requirements for construction and operation of the plants. The influx of personnel required for plant construction will represent a temporary population buildup lasting three to four years, while the plant operation and maintenance personnel will represent a stable long-term population increase in the area. However, in oil shale development, where synthetic fuels plants and mines are concentrated in a small area and there is a gradual build-up of large productive capacity, the population increase due to the

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*The reclamation potential of many arid regions of the West has not been established, and surface mining in some areas may result in permanent land disturbance.

construction labor force will be spread out over a longer time period--perhaps 10 to 15 years.

Colony Development Operation has estimated that 40 months will be required for construction of its 50,000-B/D (8000 m^3/D) oil shale complex, and that the construction force will rise from several hundred at the beginning of construction to a peak of 1200 halfway through the project.[12] Assuming a model for the buildup and fall-off of construction personnel as shown in Figure 4-10, we calculate about a 3000 man-year construction requirement. For a 100,000-B/D (16,000 m^3/D) complex we estimate a 5000-6000 man-year requirement, with a peak construction force of about 2000. Colony estimates that operation,

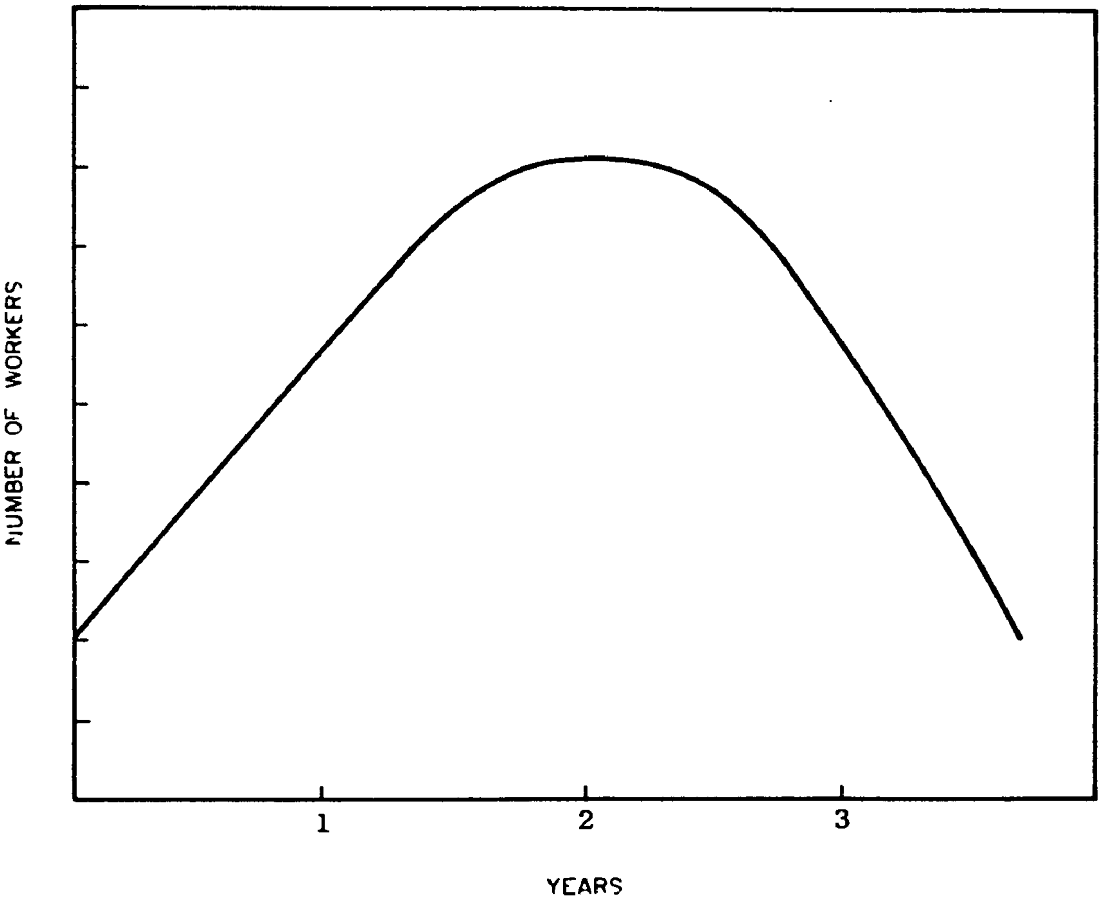

FIGURE 4-10. TYPICAL CONSTRUCTION LABOR PROFILE FOR LARGE PROPOSED FUEL CONVERSION PROJECTS

maintenance, and administrative personnel will total 900-1000 for its 50,000-B/D (8000 m^3/D) complex. A mining, retorting, and upgrading operation twice this size might be expected to employ 1500-1800 people.

Labor requirements for a coal-to-methanol plant can be estimated by comparison with El Paso Natural Gas Company's 288 million SCF per day (8.2×10^6 m^3/D) SNG plant.[17] Construction time will be about three years with a peak construction force of 3500. Assuming that the labor force at the beginning and end of the project is about one-fourth the peak force, we estimate that 7500 man-years are required to build a 100,000-B/D (16,000 m^3/D) methanol plant. Operating personnel requirements will total about 900.

Labor requirements for coal liquefaction plant construction are difficult to estimate. Estimates range from about 5000[8] to about 12,000 man-years of effort[21] over a period of three to four years. On the basis of the total plant investment cost, we estimate the level of construction effort to be 7000-8000 man-years, with a peak labor force of 2000-3000. The number of workers and supervisors involved in operating the plant will be about 1400.

Construction of a 5 million ton per year (4.5×10^9 kg/Y) surface coal mine in the western United States requires a 250 man-year effort over a period of two years with a peak labor force of about 150. Operating personnel required to run such a mine number about 100.[22]

e. Steel

The principal material requirement in the construction of synthetic fuels plants will be steel. This will be in the form of equipment and machinery, piping, girders for building construction, etc. A rough estimate of the total steel requirement for a synthetic fuels plant can be made through a breakdown of plant investment costs (shown in Section C-4) using some average cost for fabricated steel. We have used the figure \$1 per pound (\$2.20/kg) for fabricated carbon steel and \$2.50 per pound (\$5.50/kg) for fabricated stainless or alloy steel. We have also assumed that approximately one-quarter of the fabricated steel is stainless. Construction steel is assumed to be carbon steel. With these rough estimating methods, we obtain a figure of about 100,000 tons (9.1×10^7 kg) of steel as the requirement for a coal-to-methanol coal liquefaction, or oil shale plant of 100,000-B/D (16,000 m^3/D) capacity.

The Oil Shale Task Force Report and Synthetic Fuels from Coal Task Force Report of Project Independence Blueprint estimate that about 130,000 tons (1.2×10^8 kg) of steel will be used in a 100,000-B/D (16,000 m^3/D) oil shale mining, retorting, and upgrading plant or coal liquefaction plant.[23,24] By way of comparison, the MIT Energy Laboratory has estimated that 170,000 tons (1.5×10^8 kg) of steel are required for construction of a 200,000-B/D (32,000 m^3/D) petroleum refinery.[25]

f. Other

The second most critical material will probably be copper, primarily in the form of electrical wiring, instrumentation, windings for electric motors, etc. Based on the percentage of plant facilities investment spent for major equipment and for electrical supplies and materials and using the figures 3.7 tons (3.4×10^3 kg) of copper per million dollars of output and 23 tons (2.1×10^4 kg) of copper per million dollars of output[26] for the Industrial Equipment and Machinery sector and Electrical Equipment and Supplies sector of the economy, respectively, we estimate that about 1500 tons (1.4×10^6 kg) of copper will be utilized in a 100,000-B/D (16,000 m^3/D) synthetic fuels plant. The Synthetic Fuels from Coal Task Force Report of Project Independence

Blueprint estimates that about 1200 tons (1.1×10^6 kg) of copper are required for a 100,000-B/D (16,000 m^3/D) Fischer-Tropsch synthesis type gasoline-from-coal plant.[24]

In addition to the metals requirements, there will be other materials requirements such as concrete (several hundred thousand cubic yards or several hundred thousand m^3 for foundations, parking areas, etc.), insulation and paint.

Major equipment components will probably be fabricated elsewhere and shipped to the construction site, although the largest items, such as pressure vessels, may be fabricated on site due to the difficulty in shipping such large objects. Numerous smaller pieces of equipment such as pumps, motors, valves and conveyor belts will be needed as well. Most of these items are not unique to synthetic fuels plants but, due to the possible remote location of some of the plants, there may be difficulties and delays in supplying equipment and materials. Delays in equipment deliveries can contribute to increased costs due to the necessity of keeping construction personnel on-site for longer periods of time.

Once the plant has been constructed, the materials requirements for operation and maintenance are much smaller. Other than coal or oil shale, water and fuel, the main requirements are for the chemicals and catalysts consumed in various chemical processes and in water cleanup and air pollution control equipment. A large supply of spare parts, lubricants, tools, and other maintenance equipment will be needed. Again, the supply of these materials presents no special problems other than those imposed by the remote location of some of the plants.

The catalysts and chemicals requirement will vary with the types of chemical processes employed in the production of each synthetic fuel. In coal liquefaction, about 5500 tons (5.5×10^6 kg) of cobalt-molybdenum catalyst are consumed annually in the coal hydrogenation process,[7] as well as 230 tons (2.1×10^5 kg) of nickel oxide catalyst in the steam reforming plant.

In the coal-to-methanol conversion process, 875 tons (7.9×10^5 kg) of copper-chromium-zinc catalyst for methanol synthetic must be replaced every 1-2 years. Other catalysts such as the nickel oxide catalyst for methane reforming and copper-zinc or iron-chromium catalysts for CO shift must be replenished every 2-5 years.

Colony Development Operation has set forth requirements for the processing and treating steps in the production of oil from oil shale. These are listed in detail in Table 4-8. The replacement time written after each quantity of catalyst is roughly the lifetime of the catalyst.

Some additional chemicals that may be required in synthetic fuels plants for water treating and cleanup, fuel gas cleanup, stack gas scrubbing, etc. include lime (CaO), alum, salt, methanol, isopropyl ether, sulfuric acid, and sodium hydroxide.

3. Byproducts and Residuals.

In addition to the production of end products--syncrude and methanol--for which synthetic fuel plants are designed, there will be byproducts and residual materials generated which will be sold or disposed of. Usable byproducts which can be sold on the open market bring in additional revenue to the plant and help defray the production costs of synthetic fuels. Solid, liquid, or gaseous waste materials generated during synthetic fuels production must be considered environmental contaminants. The manner in which these wastes are disposed governs the degree of environmental acceptability of the plant. At present,

Table 4-8

CATALYST AND CHEMICAL REQUIREMENTS FOR A
100,000-B/D OIL SHALE RETORTING AND UPGRADING PLANT

Naphtha and gas oil hydrotreaters
  670 tons (6.1×10^5 kg)/2 yr (max) hydrodenitrogenation catalyst

Steam reformer
  270 tons (2.4×10^5 kg)/4 yr cobalt-molybdenum hydrodesulfurization catalyst
  5 tons (4.5×10^3 kg)/day caustic soda (NaOH)
  30 tons (2.7×10^4 kg)/2 yr zinc oxide sulfur guard
  100 tons (9.1×10^4 kg)/5 yr iron-chromium CO shift catalyst
  100 tons (9.1×10^4 kg)/3 yr copper-zinc CO shift catalyst

Sulfur conversion
  300 tons (2.7×10^5 kg)/2 yr bauxite claus plant catalyst
  200 tons (1.8×10^4 kg)/5 yr cobalt and nickel molybdate tail gas hydrotreater catalyst

Fuel gas treating
  17.5 tons (1.6×10^4 kg)/2 wk diatomaceous earth filter
  17.5 tons (1.6×10^4 kg)/2 wk activated carbon sulfur trap

Source: Reference 12.

there are no federal standards that govern emissions from synthetic fuels plants, although there are standards which govern individual processes which may occur in the plant, such as combustion of fuel in steam boilers. New Mexico has promulgated emission standards for coal gasification plants, and undoubtedly other states as well as the federal government will direct increasing attention towards synthetic fuels plants as the industry develops.

a. Salable Byproducts

A variety of byproducts is produced from the conversion of coal to methanol. These generally are produced during purification processes in which impurities are removed from the synthesis gas or methanol product. Tar, oil, and naphtha are removed during quenching of the synthesis gas exiting the gasifier. The quench water dissolves ammonia and phenols which are recovered in the water treatment plant. Sulfur is a product of the sulfur recovery plant which treats the acid gas stream which results from synthesis gas purification. Finally, a small quantity of higher alcohols (ethanol, propanol, butanol, etc.) are formed during methanol synthesis, and these are separated from the final product by distillation.

The quantities of different byproducts generated by a 100,000-B/D (16,000 m^3/D) methanol plant utilizing western coal are listed in Table 4-9.

Table 4-9

BYPRODUCTS FROM A 100,000-B/D
COAL-TO-METHANOL PLANT
(Western Coal)

Tar, oil, and naphtha	15,200 B/D (2400 m^3/D)
Phenols	840 B/D (130 m^3/D)
Higher alcohols	405 B/D (64 m^3/D)
Ammonia	450 T/D (4.1×10^5 kg/D)
Sulfur	170 T/D (1.5×10^5 kg/D)

Source: Reference 6.

All of these products have commercial value and could be sold if a market could be found for them. Otherwise they would have to be stored or disposed along with the solid wastes.

The H-Coal liquefaction process is designed to maximize syncrude production and to minimize the production of byproducts.[8] The large quantities of high-Btu gases generated are utilized as plant fuel or as feed to the steam reformer. The heavy bottoms product, which is separated from the syncrude, is fed to the partial oxidation plant for hydrogen production. The only usable byproducts generated from this process are 320 to 420 tons per day (2.9×10^5-3.8×10^5 kg/D) of ammonia and 200 to 1300 tons per day (1.8×10^5-1.2×10^6 kg/D) of sulfur.[8] A small amount of char is also produced, but it is not of commercial value and will be disposed of with the ash.

As in the case of coal liquefaction, oil shale processing will result in a minimum of byproducts. All gases and C_4 liquids (butane and butene) produced from retorting will be consumed on-site as plant fuel. The main byproduct will be 1600 tons per day (1.5×10^6 kg/D) of coke, derived from the heavy residual shale oil fraction.[12] This product may or may not be of commercial value. Other byproducts are 400 tons per day (3.6×10^5 kg/D) of elemental sulfur and 300 tons per day (2.7×10^5 kg/D) of ammonia.

b. Solid Waste

The main solid waste resulting from coal liquefaction and methanol production is the ash that remains after the organic portion of the coal is converted to liquid and gaseous products. The amount of ash produced depends on the original ash content of the coal. Typically, 3000 to 4000 tons (2.7×10^6-3.6×10^6 kg) of ash and char (mostly ash) will be generated per day by a 100,000-B/D (16,000 m^3/D) coal liquefaction or coal-to-methanol plant. If the plant is located near the mine, then this waste material can be disposed of in the mine--either buried in a mined-out area in the case of an underground mine, or added to the spoil piles and buried under topsoil during reclamation operations for a surface mine. If it is not feasible to return the ash to the mine, it must be stored in waste piles or used as landfill.

The major solid waste from oil shale retorting and upgrading is, of course, the spent shale which results from retorting the oil shale, amounting to 100,000 to 150,000 tons per day (9.1×10^7-1.4×10^8 kg/D). The enormity of this disposal problem is reflected in the plan proposed to deal with it--filling in a 250-ft (76 m) deep canyon. The land area required for such an operation was discussed earlier in Section 2c.

It may be possible to dispose of some of the spent shale in areas of the mine where recovery operations have been completed. There is general reluctance in the industry to do this, however, since lower grade deposits that might be economically recoverable at a later date would be made inaccessible. In any case, not all the spent shale could be disposed of in this way since the total shale volume expands 10 to 30 percent in crushing and retorting.[11]

Other minor solid wastes generated by synthetic fuel plants include coal and shale dust, spent catalysts, and char and coke if these cannot be sold commercially. In general, these wastes will be disposed of along with the spent shale and ash.

The potential for recovering valuable minerals or metals from spent shale or coal ash has yet to be assessed. At present there are no plans to process spent shale. Of the major constituents of spent shale, the only ones of value are magnesium, aluminum, and iron oxides. Valuable trace metals such as gold, silver and platinum are present in quantities less than 0.1 part per million. There is about 1 part per million of uranium. The spent shale itself may have potential uses as filler in concrete and building blocks, or as road substrate. However, only a tiny fraction of the total spent shale generated by a mature industry could be used in this way.

Coal ash also contains aluminum, magnesium and iron oxides, and perhaps trace quantities of valuable metals. The possibility has been raised of recovering uranium from North Dakota lignite ash. In general the uranium content of western coal ash is from 1 to 10 parts per million.

c. Effluents to Water

In principle, the effluents to water from synthetic fuels plants can be reduced effectively to zero. This can be done by treating and recycling all boiler and cooling tower blowdown water, process waste water, etc., and discharging to on-site evaporation ponds any remaining water that is too highly contaminated to be recycled. All discharges to streams and rivers can thus be eliminated. Furthermore, the raw water requirement for plant operation can be considerably reduced. This is particularly important in arid western regions where water supplies are limited.

Colony Development Operation has designed its first commercial 50,000-B/D oil shale retorting and upgrading plant so that no waste streams from the plant are discharged to natural sources.[12] Most of the process water waste streams are treated and used for cooling or processed shale moisturizing. This results in considerable water consumption savings. The overall water use and treatment plan for the Colony plant is shown in Figure 4-11. Although not all the steps in this scheme are directly applicable to other synthetic fuels processes,

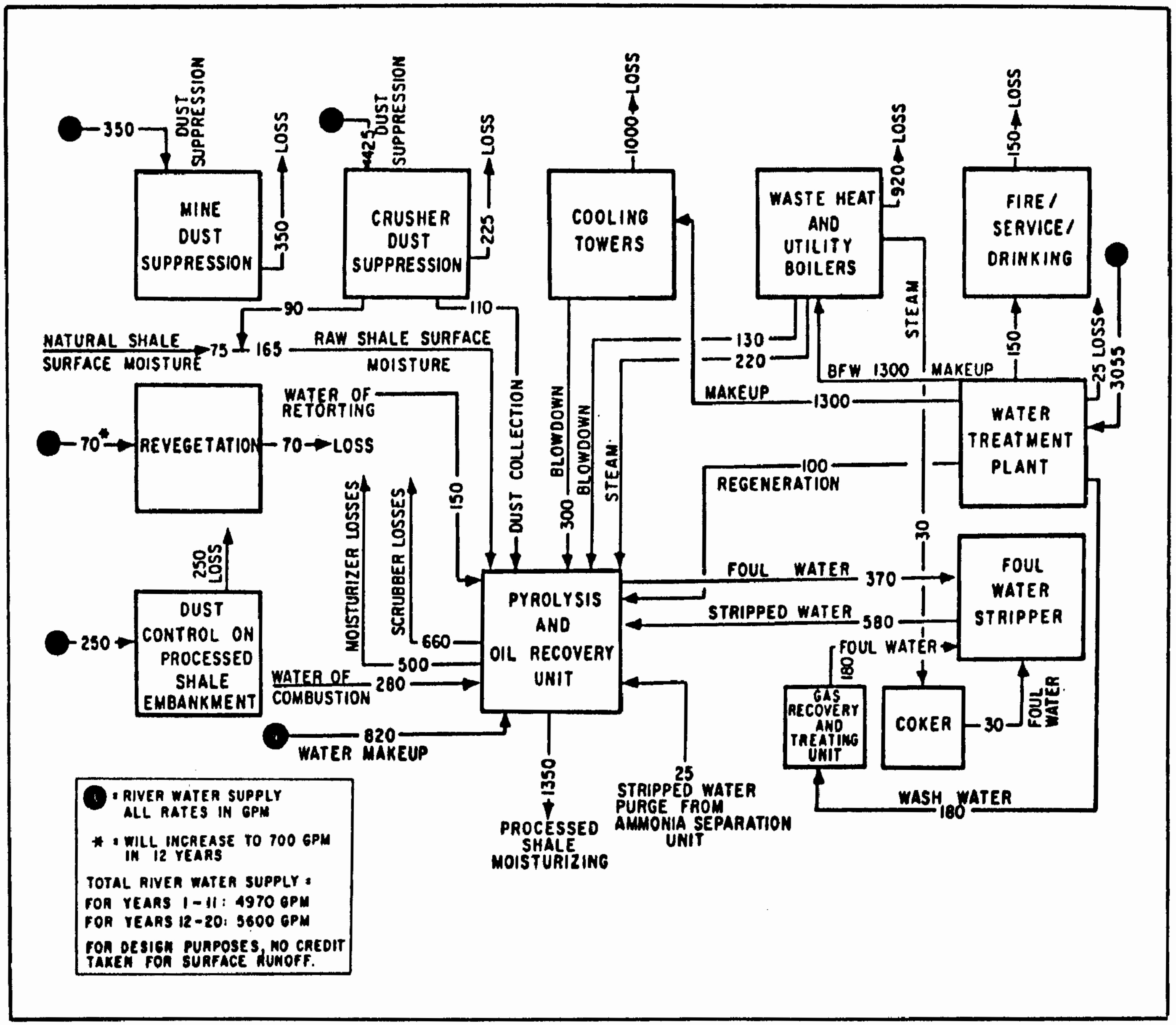

FIGURE 4-11. RIVER WATER UTILIZATION (from Reference 11)
(50,000-BPD TOSCO II OIL SHALE PLANT)

it does serve to illustrate the kinds of steps which may be taken to reduce aqueous emissions to zero.

El Paso Natural Gas Company has also developed a waste water treatment and recycling plan for its Burnham, New Mexico, coal gasification project.[17] In this scheme, most of the treated waste water is used to replace water lost in cooling tower evaporation--the single largest consumptive use of water in the plant.

The sources and ultimate disposition of aqueous contaminants are different for each synthetic fuel process. In the conversion of coal to methanol, most of the contaminants originate in the coal gasification process. In addition to the tar, oil, naphtha, and phenols formed from volatile matter in the coal, the nitrogen and sulfur compounds are converted to ammonia, hydrogen cyanide (HCN), hydrogen sulfide, carbon disulfide (CS_2) and carbonyl sulfide (COS) in the gasifier.[27] Subsequent to gasification, during the synthetic gas quenching step, the tar, oils, and naphtha are condensed, decanted, and recovered as byproducts. The remaining quench water (called gas liquor) contains dissolved phenols and ammonia, which are recovered by the (proprietary) Phenosolvan process. The remaining water containing small amounts of all the above contaminants is sent to the water bio-treating plant and recycled for use as cooling water and boiler feedwater.

The sulfur compounds and hydrogen cyanide remaining in the synthesis gas are removed by the Rectisol process (cold methanol scrubbing) and sent to a Stretford sulfur recovery unit where the HCN, CS_2, and COS are converted to sodium thiocyanate (NaSCN) and sodium thiosulfate (NaS_2O_3). The contaminated Stretford solution is periodically replaced with fresh solution and sent to water bio-treating.[27]

In coal liquefaction, aqueous contaminants are produced during coal drying and coal hydrogenation in which the oxygen, nitrogen and sulfur in the coal are converted to water, ammonia, and hydrogen sulfide, respectively. The contaminated water is sent to the ammonia stripper unit where aqueous ammonia is recovered as a byproduct and a concentrated H_2S stream is generated and sent to the Claus sulfur recovery plant. The remaining water can be sent to a bio-treating unit along with the waste water from coal drying, cooling tower and boiler blowdown and other process waste water.[28]

The levels of contaminants expected in the effluent water from a biological treatment pond in which waste water from coal liquefaction is treated is shown in Table 4-10. A 100,000-B/D coal liquefaction plant produces about 5 million gallons of waste water per day; this weighs about 21,000 tons (1.9×10^7 kg). Therefore, the concentrations shown in Table 4-10 multiplied by the above figure give the amounts of these contaminants discharged daily if the waste water is not recycled or sent to on-site evaporation ponds.

Table 4-10

COAL LIQUEFACTION PLANT BIOLOGICAL
TREATING POND WATER EFFLUENT

Constituent	Concentration (wt ppm)
Sulfide	< 0.005
Ammonia	0.11
Oil	0.68
Biological oxygen demand (BOD)	10.5
Suspended solids	12.9
Phenol	0.38
Chemical oxygen demand (COD)	45
Phosphate	0.11
Chromate	7.1
Zinc	3.5

Source: Reference 28.

During the retorting and upgrading of oil shale, waste water is generated as excess moisture from the retorting process and the gas recovery unit, as process water and condensed moisture from the coking unit and boiler and cooling tower blowdown, as well as fuel gas and stack gas scrubbing water. Waste water containing H_2S and ammonia is recovered in the foul water stripper and recycled. Most of the treated waste water is disposed of by using it to moisturize the spent shale generated during retorting. This use amounts to about 4 million gallons per day (1.5×10^4 m^3/D)[12] which weighs about 17 tons.

The water used to moisturize the spent shale will consist of any mine drainage water and spent shale runoff water that has been collected in addition to process waste water. The approximate concentrations of contaminants expected in this water are listed in Table 4-11. A potential source of water pollution is leaching or runoff from the spent shale disposal pile into local aquifers. Except in catastrophic failure of the pile or flash flooding, catchment dams will probably be sufficient to retain any runoff water. The potential for water contamination due to leaching depends on several factors, such as the degree of compaction of the spent shale, and has yet to be fully assessed.

In addition to direct plant discharges, there are possible indirect water contamination problems. For example, the withdrawal of low salinity water from the Upper Colorado River Basin for use in oil shale processing will result in an increase in salinity in the Lower Colorado, due to a decreased dilution effect. The salinity increase resulting from a 1-million B/D oil shale industry would be about 10 parts per million (out of a present level of 860 ppm) at Imperial Dam.[12] Even though this increase is small, the fact that the United States is planning to build a desalination plant on the lower Colorado River to meet its treaty obligations with Mexico indicates that some additional costs will be incurred (and paid for by the taxpayers) due to this additional--indirectly caused--salinity increase.

Table 4-11

COMPOSITION OF WASTE WATER USED IN
SPENT SHALE MOISTURIZING

Constituent	Concentration (wt ppm)
Sulfates	510
Thiosulfates	60
Carbonates	520
Phosphates	15
Chlorides	330
Cyanides	50
Hydroxides	30
Phenol	60
Ammonia	30
Amines	1900
Organic acids	1000
Chelates	3
Chromates	130
Arsenic	0.03

Source: Reference 12.

d. Effluents to the Air

Sufficient information on plant design and emission sources has been set forth in the literature so that quantitative estimates can be made of the emissions of air pollutants. Generally speaking, there are two major sources for the emission of contaminants to the air from synthetic fuels production--the combustion of fuels to provide heat, steam and electricity to drive the various plant processes and the emission of sulfur-containing waste gas (tail gas) from sulfur recovery operations. In almost all cases, some sort of emission controls, direct or indirect, have been incorporated into the plant designs. Although there are presently no federal performance standards for synthetic fuels plants, it is generally assumed that combustion of fuel in boilers, for example, will be required to meet federal standards. It is likely that standards for such plants will be promulgated as the industry develops.

Since a more detailed discussion of air pollutant emissions and controls will be given in Chapter 16, only a summary of the relevant emission data is given here. Table 4-12 shows the quantities of SO_2, particulates, NO_x and hydrocarbon emissions that may be expected to result from the liquefaction of Montana-Wyoming coal and eastern coal via the H-Coal process,[8] the conversion of Navajo coal to methanol[6] and the retorting and upgrading of 35 gal/ton oil shale to syncrude,[12] all at the 100,000-B/D level. The emission levels shown in Table 4-12 are those resulting from application of the "best available" emission controls appropriate to each technology. The types of controls applied are discussed in detail in Chapter 16.

All the emissions and NO_x shown in Table 4-12 result from the combustion of gaseous, liquid, or solid fuels to power the various plant processes. The total includes the combustion of fuel necessary to provide purchased electricity when it has been incorporated into the plant design. All particulate emissions are from fuel combustion or coal drying, except for oil shale processing where one-fourth of the particulate emissions are in the form of fugitive dust.[12] We have assumed a level of control of 99.5 percent using electrostatic precipitators or Venturi scrubbers for reducing stack gas emissions from

Table 4-12

EMISSIONS OF AIR POLLUTANTS FROM
SYNTHETIC FUELS PRODUCTION
(Tons per 100,000 Barrels of Product)

	SO_2	Particulates	NO_x	Hydrocarbons
Coal liquefaction (H-Coal)				
Montana/Wyoming coal	11	7.1	96	1.6
Illinois No. 6 coal	16	2.7	28	0.4
Coal-to-methanol (Lurgi)				
Navajo coal	15	2.0	25	0.4
Oil shale retorting and upgrading (TOSCO II)				
35 gal/ton shale	40	10	72	7.6

coal combustion. Fugitive dust control is assumed to be 98-99.8 percent effective (see Chapter 16).

The SO_2 emissions shown in Table 4-12 result from both fuel combustion and sulfur recovery plant tail gas. We have assumed a level of control for stack gas emissions from burning high sulfur fuels of 90 percent, while for tail gas emissions a control level resulting in SO_2 emissions of 250 ppm by volume (equivalent to about 95 percent SO_2 removal) has been assumed. The relative proportions of SO_2 emissions from fuel combustion and tail gas are as follows: eastern coal liquefaction, 59 percent from combustion, 41 percent from tail gas; western coal liquefaction, 86 percent from combustion, 14 percent from tail gas; methanol from Navajo coal, 94 percent from combustion, 6 percent from tail gas; syncrude from oil shale, 96 percent from combustion, 4 percent from tail gas.

e. Trace Elements

The question of the fate of toxic trace elements in coal and oil shale conversion processes has received considerable attention due to the potential for highly toxic metals such as mercury, lead, beryllium, arsenic, cadmium, selenium, and fluorine to enter the air, water, or soil and ultimately to create a health hazard. At present, few pathways of trace elements through energy conversion activities have been identified. It is known, for example, that volatile elements, including those listed above, will be discharged to the air during combustion. Other nonvolatile elements will end up primarily in the ash. However, the fate of these elements during coal gasification and liquefaction and oil shale retorting is not as clearly defined.

The quantities of toxic trace elements which are found in oil shale and coal are shown in Tables 4-13 and 4-14, respectively. The oil shale determinations were made on 35-gallons per ton (0.15 m^3/ 1000 kg) Green River oil shale. The coal analyses were based on a variety of coals found in both the eastern and western United States. Typically, as seen from Table 4-14, eastern coals have a somewhat higher trace element content than western coals.

During the coal gasification step of methanol production, volatile elements in the coal are vaporized and may exit the gasifier along with the raw synthesis gas. During gas quenching these elements are condensed and separated out along with the tar, oil, and naphtha or as part of the gas liquor stream. It is unlikely that any significant fraction of the trace elements in the coal make their way to the final methanol product.

In tests made on the Bureau of Mines Synthane gasifier,[29] it was determined that 20 trace elements were present in the raw gas quench water in the range of 2 parts per billion to 4 parts per million.

The concentration of selenium was 360 parts per billion and that of arsenic was 30 parts per billion. Byproduct tar was found to contain 3 parts per billion of mercury and 0.7 parts per million of arsenic. Only 0.01 parts per billion of mercury could be detected in the cleaned synthesis gas, and none could be detected in the final product (methane).

Table 4-13

CONCENTRATION OF TOXIC TRACE ELEMENTS IN OIL SHALE

Element	Concentration in Oil Shale (wt ppm)
Arsenic	7.2
Beryllium	35
Cadmium	0.14
Fluorine	1700
Lead	10
Mercury	< 0.1
Selenium	0.08

Source: Reference 12.

During coal liquefaction, coal is exposed to considerably different conditions than in gasification, the primary differences being the presence of a solvent (and perhaps a catalyst) and hydrogen at high pressures. These conditions strongly affect the fate of trace elements. A large portion of the trace metals will remain with the ash and unreacted solids that are separated from the liquid product. Gasification of this solid material to produce hydrogen will produce trace elements in waste streams in a fashion similar to coal gasification.

Table 4-14

MEAN TRACE ELEMENT CONCENTRATIONS (ppm, Moisture Free) OF VARIOUS COALS

		Western Region					Eastern Region			
Element	S	Colorado, Valmount Power Station, Boulder	Montana and Dakotas	Wyoming Powder River	Montana Colstrip	Utah	Illinois	Penn.-Ohio-W. Va.	Tenn. Allen Power Plant	Maryland Chalk Pt. Power Plant
Beryllium	Be		0.12-3.9	0.25*	Trace	1.0	1.9	2.0-3.1	0.3	
Fluorine	F		65	56.5	31.6	66	42-134	50-120		
Arsenic	As			2.1	Trace	0.5	14	3-59	5	25
Selenium	Se	1.9		1.1	0.016	1.2	2.2			5.1
Cadmium	Cd			0.11†	0.23	≤0.2	≤0.2-22	(0.39)	0.46	
Mercury	Hg	0.07	0.07	0.12	0.15	0.04	0.24	0.12-0.21	0.12	
Lead	Pb	≤5	7	5.3‡	4.8	5	49	4-14	4.9	9.6
Bromine	Br				21.0	23	15		4.3	41
Zinc	Zn	7.3		6.6		10	342	(24.8)		80
Copper	Cu	9.6	15	13.7	≤100	10	15	14-17		
Nickel	Ni		7	4.0		4	23	9.7-20		25
Chromium	Cr		7	7.7	2.9	7	17	11-15		29
Vanadium	V		16	20.9	2.5	10	34	19-25		40
Barium	Ba			206.3						150
Strontium	Sr	120		92.6						86

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*44 percent of the coal samples contained less than 0.15 ppm beryllium.
†70 percent of the coal samples contained less than 0.1 ppm cadmium.
‡8 percent of the coal samples contained less than 1.5 ppm lead.

Source: Reference 31.

Trace elements such as arsenic and selenium, which can react with hydrogen, may enter the gas phase during liquefaction.[30] Those that are not removed during cooling and scrubbing of the gas will enter the atmosphere if byproduct gases are combusted to provide plant steam and heat.

Finally, some trace elements, especially those which are bound to organic molecules in the coal, will be carried through into the synthetic crude oil product.

During oil shale retorting, trace elements are carried over into the raw shale oil product. Twenty-nine trace elements have been detected in raw shale oil,[12] including all of those listed in Table 4-13. Undoubtedly, a large fraction of the trace elements will remain with the spent shale. Further processing and upgrading of the raw shale oil may result in the introduction of some elements into waste streams. The ultimate disposition of all solid and liquid waste streams will be in the spent shale pile. Therefore, the major potential source of environmental contamination will be from leaching from this pile or failure of a catchment dam.

Although it is certain that some of the trace constituents in the raw shale oil will remain in the syncrude product, there has been no quantitative measurement of their concentrations. In general, few quantitative assessments of the presence of trace elements in synthetic fuel products or waste streams have been made. Much more research must be carried out in this area before any realistic evaluation of potential health hazards from trace element emissions from synthetic fuel plants can be undertaken.

4. Costs and Dollar Flows

a. Investment and Operating Costs

The Arab oil embargo of late 1973 and the subsequent increases in world oil prices brought about a renewed interest in the possibility of using synthetic crude oil from coal and oil shale to augment declining domestic oil reserves. One of the greatest areas of concern has been the question of whether synthetic liquid fuels can be economically competitive with conventional fuels even at high prevailing world prices.

During 1974, a number of studies were carried out in which new cost estimates were made, or previous estimates revised, to determine the costs at which synthetic fuels could be produced from coal and oil shale, and the prices at which they would have to be sold to achieve a reasonable return on investment. Table 4-15 summarizes some of the estimates of costs and prices made during this period. All dollar figures are in 1973 dollars.

Unfortunately, these estimates were made during a period of rapid inflation, and few knowledgeable sources would consider the figures shown in Table 4-15 to be representative of current costs. The figures do, however, provide a relative basis of comparison for the costs of synthetic fuels.

From mid-1973 to late 1975 chemical plant construction and operating costs have increased by nearly 30 percent. Thus, the synthetic fuel prices shown in Table 4-15 would be at least 30 percent higher if estimated using current cost figures. However, even if inflation is properly accounted for in making cost estimates, there is another reason why the resulting figures are likely to be low. As new technologies move from the R&D stage through the pilot plant and demonstration plant level and approach commercialization, the bases for making

Table 4-15

COST ESTIMATES FOR SYNTHETIC LIQUID FUELS (1973 COSTS)

Type of Plant	Size (B/D)	Capital Cost ($\$10^6$)	Operating Cost ($\$10^6$/yr)	Byproduct Credits ($\$10^6$/yr)	Cost of Coal ($/ton)	Rate of Return (% DCF)	Price of Product ($/B)
H-Coal[a] (Navajo coal)	100,000	1014	160	113 (Sulfur, 1.8; ammonia, 9.5; fuel gas, 102)	3	10	8.00
						15	10.70
			199		5	10	8.70
						15	11.40
H-Coal[b] (Powder River coal)	100,000	668	133	12 (Sulfur, 1.5; ammonia, 10.5)	3	10	7.80
						15	9.80
H-Coal[b] (Illinois coal)	100,000	685	188	20.3 (Sulfur, 7.6; ammonia, 13.7)	9	10	9.30
						15	11.40
H-Coal[c] (Bituminous coal)	30,000	260	61	33 (Fuel gas)	8	10	8.08
						15	10.70
Methanol[a] (Navajo coal; Lurgi gasifier)	81,200	475	63	28 (Tar, tar oil, naphtha, phenol ammonia, and sulfur, 18; methane, 10)	3	10	5.10
						15	6.70
			79		5	10	5.70
						15	7.30
Methanol[d] (Navajo coal; Lurgi gasifier)	81,200	517	82	36 (Tar oil, naphtha, phenol, ammonia, sulfur and higher alcohols)	3	15	4.10
Methanol[c] (Illinois coal; Koppers-Totzek gasifier)	35,800	353	50	1 (Sulfur)	7.30	12	9.80
Oil shale,[a] mining, retorting & upgrading (TOSCO II retort; 35-gal/ton shale)	100,000	643	70	5 (Coke, sulfur and ammonia)	--	10	4.70
						15	6.00

(continued)

Table 4-15 (concluded)

Type of Plant	Size (B/D)	Capital Cost ($\$10^6$)	Operating Cost ($\$10^6$/yr)	Byproduct Credits ($\$10^6$/yr)	Cost of Coal ($/ton)	Rate of Return (% DCF)	Price of Product ($/B)
Oil shale,[f] mining, retorting & upgrading (gas combustion retort, 30-gal/ton shale)	100,000	522	82	8.6 (Coke, sulfur and ammonia)	--	12 15 20	5.20 6.10 7.90
Oil shale,[g] mining, retorting & upgrading (gas combustion retort; 30-gal/ton shale)	54,500	421	82	7 (Coke, sulfur and ammonia)	--	12	8.70

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a. From Reference 1.

b. From Reference 8.

c. From Reference 25. Capital recovery factors of 20 and 30 percent were used to calculate prices in the table instead of 15 percent used in this reference.

d. From Reference 6. Methanol price based on utility financing, assuming a 75/25 debt-to-equity ratio and a 9 percent cost of capital.

e. From Reference 2.

f. From Reference 32.

g. From Reference 33.

accurate cost estimates become more concrete. Cost estimates made early in the developmental stage of a technology are simply not able to anticipate the cost factors that are realized at later stages of development.

Oil shale retorting and upgrading is currently closer to commercial development than any of the other synthetic liquid fuels considered in this paper, and recent cost estimates have tended to confirm the above discussion. When Colony Development Operation announced suspension of its plans to develop the first commercial oil shale facility (October 1974), the capital cost estimates for a 50,000-B/D plant had increased 45 percent (from $435 million to $630 million) in six months. This sort of cost inflation, due to actual increases in components of construction costs plus more realistic estimates of total costs, will undoubtedly continue to characterize the synthetic fuels economic picture.

b. Dollar Flows for Plant Construction and Operation

To understand the disposition of money spent for the construction and operation of synthetic fuel plants it is not necessary to display the total cost of construction or plant operation but only the relative sizes of the components of the total costs. Figures 4-12 and 4-13 show breakdowns of the capital cost and operating expenses for a 100,000-B/D H-Coal plant. These breakdowns were derived from actual costs presented in Reference 8 and the capital cost estimating techniques discussed in Reference 34. The relative costs of construction shown in Reference 34 were updated from 1969 to 1973 using components of plant cost indices published in Chemical Engineering.

Figure 4-12 shows that equipment and materials constitute the largest source of capital expenditure, contributing nearly 50 percent of the plant construction cost. The next largest single item is

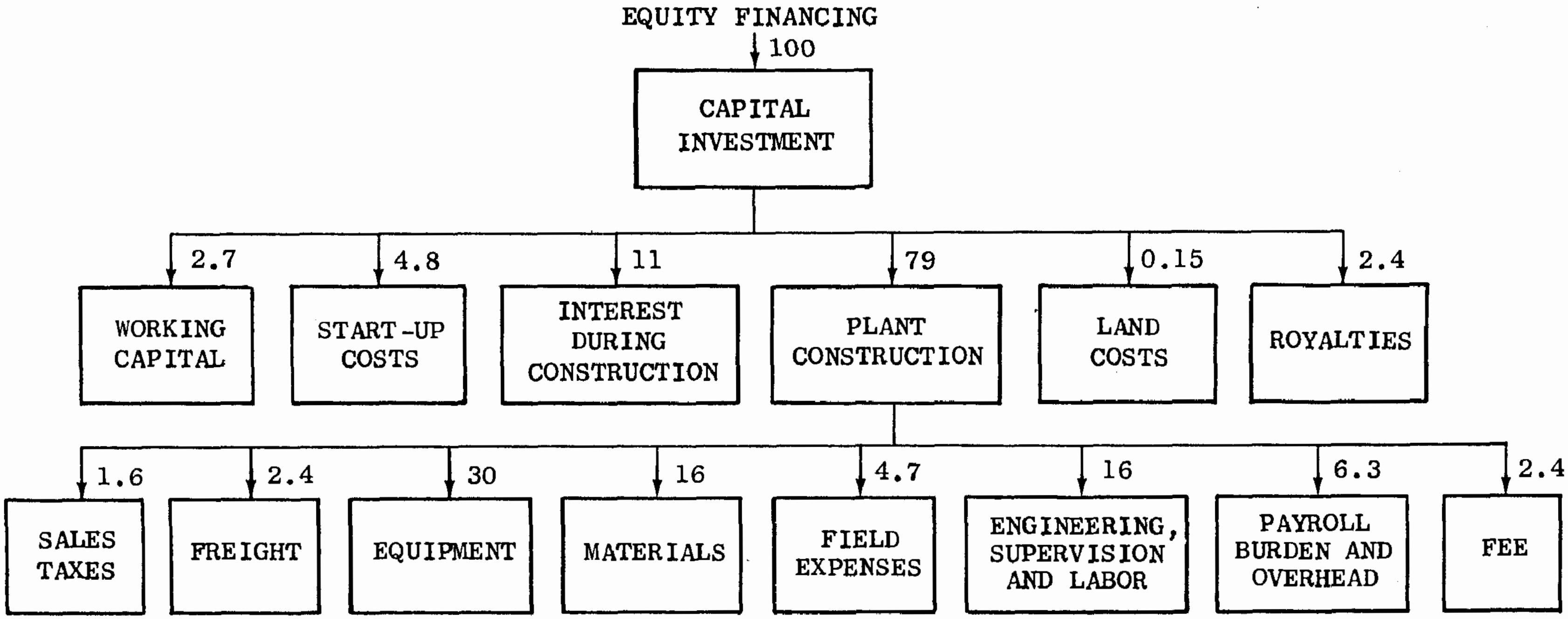

FIGURE 4-12. CAPITAL INVESTMENT DOLLAR FLOWS FOR H-COAL LIQUEFACTION PLANT

labor (including engineering and supervision) which contributes over 20 percent of the cost if payroll burden (fringe benefits) is counted.

In the operation of a coal liquefaction plant, the single largest expense item is the coal. The operation is not particularly labor intensive. On the other hand, the coal mining operation is considerably more labor intensive, with salaries and associated benefits consuming 30 percent of the mine revenue.

As shown in Figure 4-13, capital recovery and profit--the sum of depreciation, net income, and income taxes--contribute an overwhelming amount to the price of syncrude--nearly two-thirds if the operation of both mine and liquefaction plant are counted. These figures are proportional to the capital cost of the plant and mine so that in the long run it is mainly the initial capital investment in synthetic fuel facilities that will determine the viability of the industry. This is true, of course, not only because of the effect of capital costs on product prices, but also because of the difficulty in marshalling sufficient capital for the development of the industry.

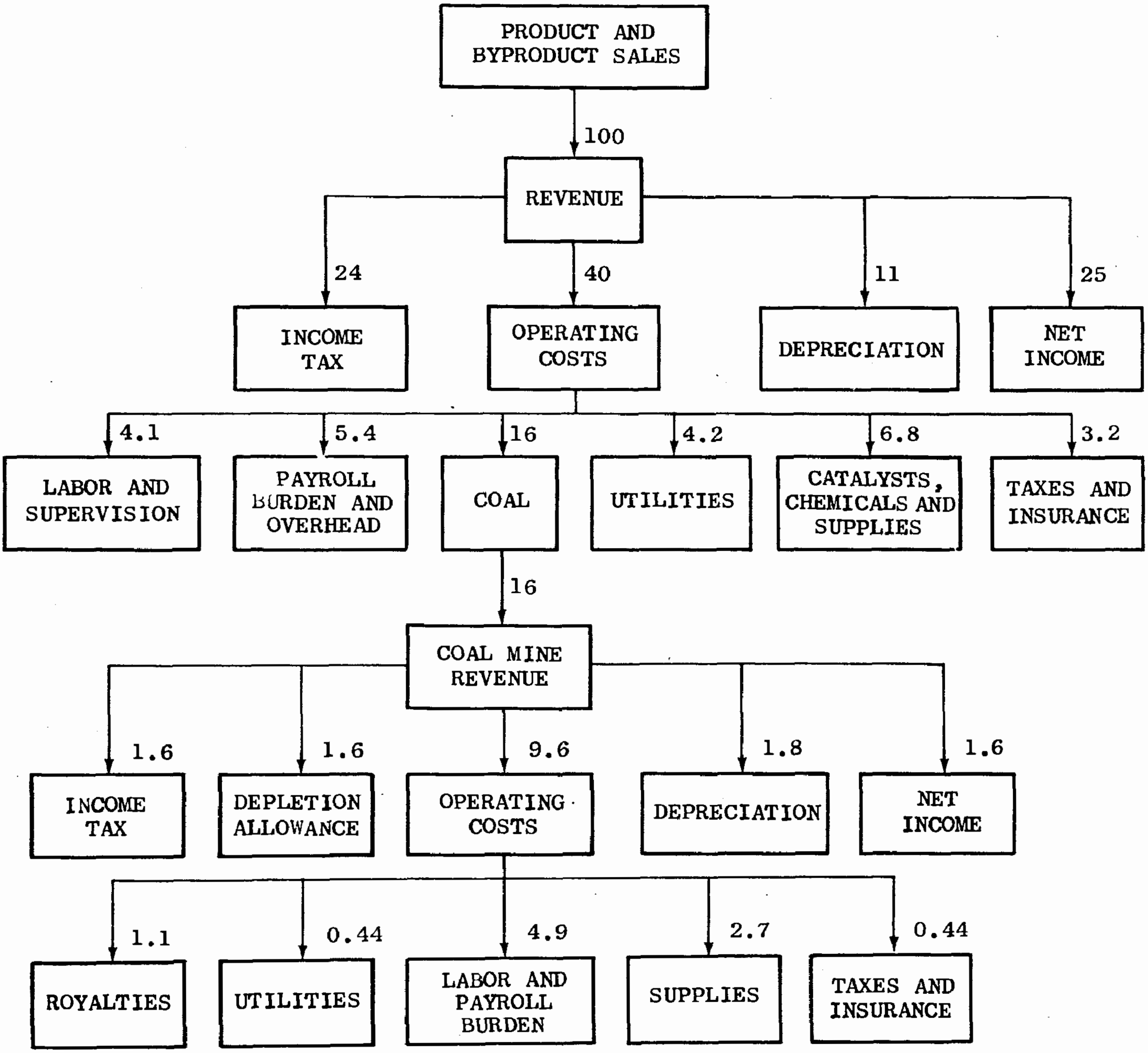

FIGURE 4-13. OPERATING DOLLAR FLOWS FOR WESTERN COAL LIQUEFACTION VIA THE H-COAL PROCESS (BASED ON 15% DCF RETURN ON INVESTMENT AND COST OF COAL AT $3.00/TON)

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15. Quantities shown in Figure 4-8 were derived from the process description and flow diagrams in Reference 8.

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5--NET ENERGY ANALYSIS OF SYNTHETIC LIQUID FUELS PRODUCTION

By Robert V. Steele

A. Introduction

The concept of net energy has recently been introduced into the area of energy policy in an attempt to understand the efficiency with which society uses energy in obtaining new energy supplies. Net energy can be expressed as a measure of the energy return that is obtained per unit of energy invested in the energy-producing sectors of the economy, although analogies with capital investment are not strictly appropriate.

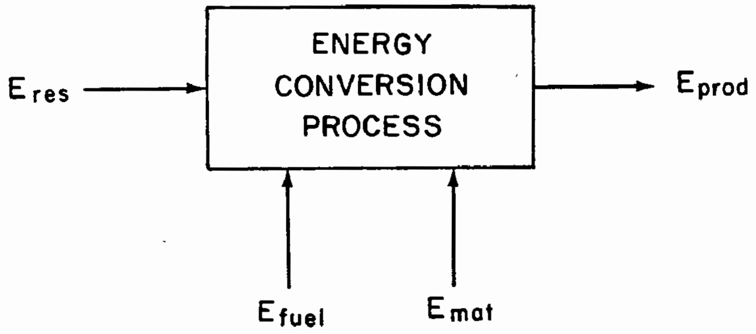
The concept of net energy can be illustrated by the use of an input/output analysis[1] to calculate the energy cost of producing different forms of energy. For example, the petroleum refining sector of the economy provided 44 percent of U.S. energy needs in 1963. However, this sector also consumed 6.4 percent of the petroleum products, 1.3 percent of the electricity, and 5.6 percent of the natural gas produced in the United States during that same year,[1] as well as various chemicals and materials. Consequently, approximately 0.2 unit of resource energy (coal, crude oil, natural gas, and nuclear and hydro-power equivalents) was consumed for each energy unit of petroleum products delivered to the U.S. economy. Thus, the energy return per unit of energy expended in the petroleum refining sector was approximately 5-to-1 in 1963.

The rationale behind the concept of net energy is that new sources of energy or new energy conversion activities can be examined to determine those that provide the highest return per unit of energy invested. If there are two or more competing technologies for accomplishing the same result, then net energy analysis provides a basis for choosing one over another. There are, of course, other basic considerations such as cost, environmental impact, social disruption, and so forth, which will be taken into account in deciding the technology that should be employed. However, in an age in which energy resources are in great demand and supplies are dwindling, net energy analysis can be an important policy consideration in determining how energy resources can be used wisely.

In principle, net energy analysis should clarify discussions of the resource utilization efficiency of various energy technologies. In practice, however, probably as much confusion has been generated as understanding. This is due, in part, to the varying definitions of net energy used by different sources, and in part to the various advocacy positions that net energy calculations are called on to support. In this chapter, we will attempt to define carefully what is meant by net energy and to set forth clearly the processes by which numerical values are obtained.

Often, net energy is defined as the energy value of the products delivered to society by an energy-producing or conversion process minus the energy required to carry out the production or conversion. The intent of this definition is to allow one to determine how much energy is actually made available to society by a process if one also counts the energy that is consumed, or made unavailable, as a result of carrying out the process. It has been common practice to express the energy consumed in carrying out the process in terms of the energy value of the energy resources that are consumed to provide fuel, materials, and so forth, to run the process. Thus, the net energy figure is expressed as the difference between energy in the form of deliverable products and energy in the form of raw resources. This is somewhat akin to subtracting apples from oranges, although both energy figures are expressed in Btu or the equivalent. The problem has to do not so much with the thermodynamic "quality" of the energy form (expressed as availability, or the ability to do work), although this may occasionally be an important factor, as it does with the "quality" of the energy form as measured by its usefulness to society. The social utility of a Btu of gasoline is obviously much higher than that of a Btu of crude oil in the ground. Thus, it is desirable to express net energy in a way that makes clear the nature of the units specified.

The mathematical formulation of net energy used throughout this chapter is explained with the help of the energy flow diagram shown in Figure 5-1. In this diagram, the quantity E_{res} is defined as the energy content or heating value of the resource that is converted to a useful product. It is sometimes called the "primary" resource energy. E_{prod} is defined as the energy content or heating value of the product that is produced by the conversion process. Since there is always some energy



$$\text{NET ENERGY RATIO} = \frac{E_{prod}}{(E_{res} - E_{prod}) + E_{fuel} + E_{mat}}$$

FIGURE 5-1. FLOW DIAGRAM FOR DEFINITION OF NET ENERGY RATIO loss during conversion, E_{prod} is always less than E_{res}. (The conversion efficiency of a process is sometimes referred to as the ratio of E_{prod} to E_{res}.) The quantity (E_{res} - E_{prod}) represents the resource energy lost during the conversion process. Other energy inputs to the process include any externally supplied fuel, which is consumed to provide steam, heat and electricity for running the process, and the energy consumed in building the plant and in fabricating the materials used in operating and maintaining the plant facilities. These energy inputs are represented by E_{fuel} and E_{mat}, respectively. (The quantity E_{fuel} is sometimes called the ancillary energy.) It is important to note that E_{fuel} includes, in addition to the energy value of the fuel itself, all the energy consumed in extracting and processing the fuel as well as distributing it to the point of use.

With these definitions we have the tools to formulate a working relationship for the net energy ratio of a process: it is defined simply as the useful product energy output of the process divided by the resource energy that has been lost during conversion or consumed in the form of fuel or materials input to the process.

$$\text{Net energy ratio} = \frac{E_{prod}}{(E_{res} - E_{prod}) + E_{fuel} + E_{mat}} .$$

As an example, if 20 billion Btu per day are consumed in the form of fuel and materials to convert 130 billion Btu per day of primary resource energy into 100 billion Btu per day of product energy, then the net energy ratio is:

$$\text{Net energy ratio} = \frac{100}{30 + 20} = 2.$$

This result tells us that for every two units of product energy produced, one unit of resource energy was expended. Thus, the net energy ratio is merely a measure of the quantity of energy that is made available to society in a particular form per unit of resource energy consumed in the conversion process.

It is clear from the discussion above that the net energy ratio can have any value between zero and infinity. Higher net energy ratios are more desirable than lower net energy ratios since a greater energy return on energy investment is achieved. Net energy ratios less than one mean that the break-even point for return on investment has not been attained; more energy was consumed than was produced as product energy. However, this does not necessarily mean that the technology in question should not be employed. For example, the production of electricity, which supplies a large fraction of the nation's energy needs, has a net energy ratio of about 0.36 (1967 data).[2] Society is willing to expend nearly three units of resource energy to obtain one unit of electricity since electricity is a convenient, clean, transportable, and efficient energy form relative to the resources from which it is obtained. Thus, net energy considerations have a relatively small impact on society's judgment about the development and use of this energy source.

With respect to the development of new technologies (such as those for producing synthetic fuels for automotive transportation) in which several different processes are capable of meeting the same end-use needs, net energy analysis can provide a valuable input to decision making regarding the most efficient use of resources.

B. Methodology

With the definition of net energy established, there remains the task of obtaining the appropriate data to calculate numerical values of the net energy ratios for coal liquefaction, methanol from coal, and oil shale processing. These data are generally available in the literature or from published reports on conceptual designs for synthetic fuel plants. The data are generally of two types. One is simply the energy value of the resource input, ancillary fuel requirement, and product output of the process in question. These values can be used directly in the net energy calculation with one exception: any fuel that must be purchased from external sources (i.e., is not generated within the process itself) must have its energy content multiplied by the appropriate factor to account for the resource energy that is required to extract, process, and transport that particular fuel. External energy sources to which this correction applies are natural gas, refined petroleum products, and electricity. The fuel-to-resource conversion factors are shown in Table 5-1.

Table 5-1

FACTORS FOR CONVERTING ENERGY CONTENT OF PURCHASED FUELS OR ELECTRICITY INTO RESOURCE ENERGY*

Fuel	Conversion Factor (Btu/Btu)
Refined petroleum products	1.208
Natural gas	1.101
Electricity	3.796

Source: Reference 2.

The second class of data is that in which inputs of materials into the construction or operation of a plant are given in dollar values. These values can also be converted to resource energy equivalents by using the energy input/output table in Reference 2. This table lists the energy input (in the form of direct fuel and materials purchases from all other sectors of the economy) per unit dollar output for each of 360 sectors in the U.S. economy for 1967 (the latest year for which complete input/output data are available). To account for inflation, the appropriate deflator is applied to convert from costs applicable to the year in which the dollar estimates were made to 1967 costs. These deflators are obtained from the Plant and Equipment Cost Indices published monthly in Chemical Engineering.

It would be preferable to obtain the energy embodied in materials inputs by knowing the quantities of materials involved and multiplying by the appropriate value of resource energy required to produce a unit quantity of material. However, in many cases either the quantities of materials are not readily available or the energy required for producing the materials is not known. This is why the input data in Reference 2 are particularly useful. However, it is important to realize that the Btu per dollar figure for a given sector averages over many different types of products whose energy inputs per unit quantity and dollar values per unit quantity may vary widely. Thus, these numbers should be considered only a gross estimate for a given type of material input. The roughness of this estimation is considerably mitigated, however, because the energy embodied in material inputs is generally a small fraction (2 to 5 percent) of the total energy input to synthetic fuels production. Thus, considerable error in these estimates leaves the net energy ratio hardly affected.

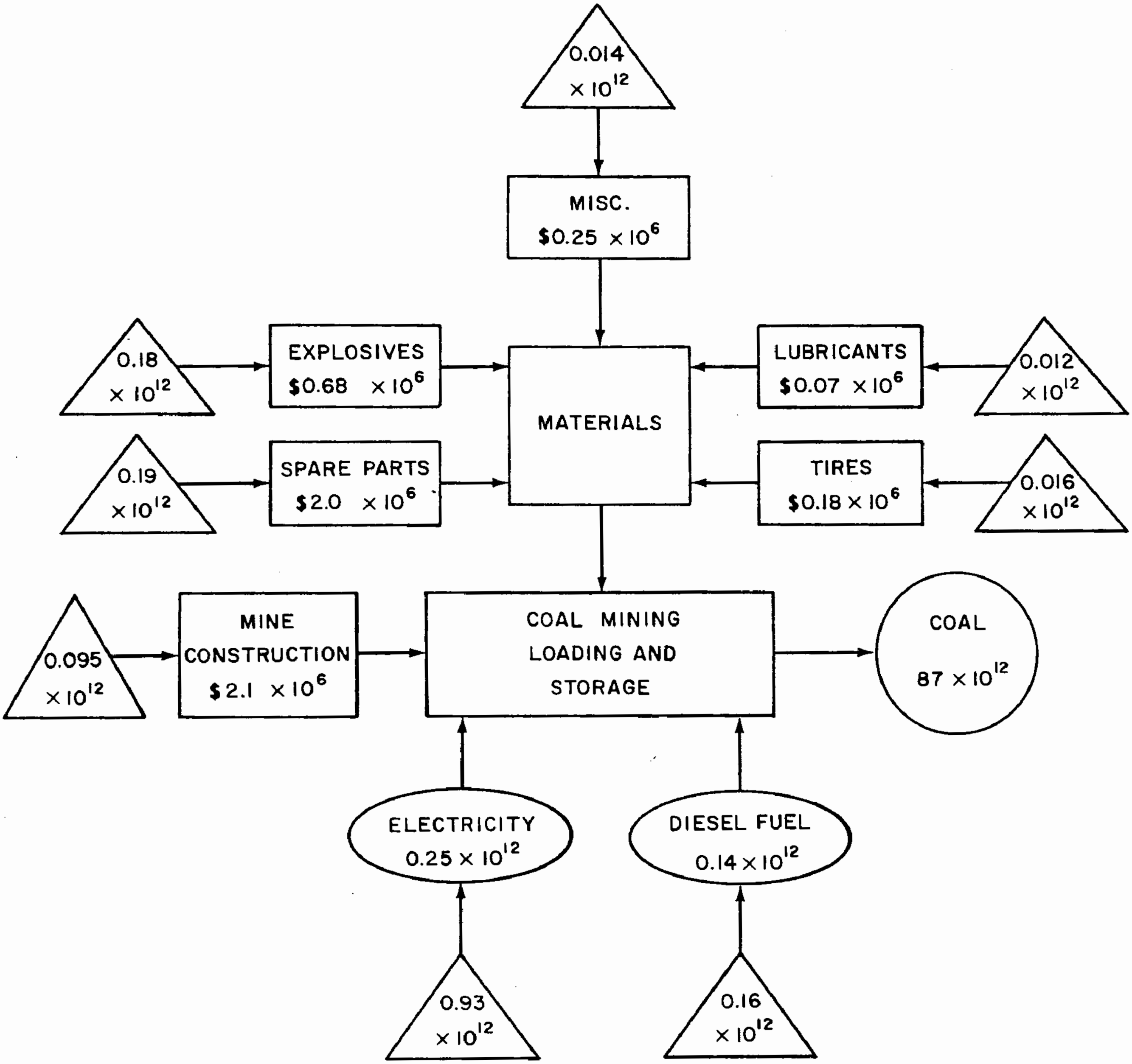
The method of performing net energy calculations can be illustrated by calculating the net energy ratio for surface coal mining in the southwestern United States.

The net energy of surface coal mining is important for synthetic fuels net energy calculations since this is the first step in the set of activities by which coal is converted to methanol or synthetic crude oil. The data for surface coal mining were obtained from Bureau of Mines information[3] as well as from plans by El Paso Natural Gas Company for supplying coal to its proposed Burnham, New Mexico, coal gasification plant.[4]

Since the coal seam thickness tends to be lower, and stripping ratios higher, for southwestern coal deposits than those in the Northern Great Plains area, the energy required to extract a given quantity of coal is significantly higher for the Southwest than for other major western coal areas. Thus, the net energy ratio calculated for surface coal mining may be considered to be at the lower end of the range of possible values for western coal.

Figure 5-2 shows all the annual material and fuel inputs required for the operation of a 5-million ton/year (4.5×10^9 kg/yr) surface coal mine. The electricity figure includes the electric power required to operate the dragline, conveyor belts for coal loading and all other electrical equipment. The diesel fuel figure includes the fuel requirements for coal trucks, bulldozers, reclamation equipment, and all other mine vehicles. Both of these energy requirements have been converted to resource energy using the conversion factors shown in Table 5-1. In Figure 5-2 and in subsequent figures, fuel inputs are shown as ellipses, materials inputs are shown as squares, and resource energy inputs are shown as triangles.

To calculate the resource energy embodied in the materials utilized in the coal mining operation, dollar figures for these quantities (shown in the appropriate squares in Figure 5-2) were taken from Reference 3 and subsequently converted to resource energy inputs by using the 1967 input-output table of Reference 2. Since this table is broken down into



NOTES: All resource energy inputs and product outputs are in Btu
All dollar figures are in 1969 dollars per year

FIGURE 5-2. ANNUAL ENERGY INPUTS FOR CONSTRUCTING AND OPERATING A 5 MILLION TON/YEAR SURFACE COAL MINE IN THE SOUTHWESTERN UNITED STATES only 360 sectors, it is not always possible to find a sector that exactly matches a particular material. In this case, the Btu-per-dollar figure for the sector that seemed the most appropriate was used. For example, the spare parts input has no exact equivalent in the table since the nature of the parts is not specified. However, there is a fabricated metal products sector, and this was deemed appropriate for this case.

In Figure 5-2 the dollar figure and resource energy figure for mine construction are both based on the total mine capital investment amortized over the assumed 20-year life of the mine. The capital investment for mine construction includes both the initial capital investment of $28.6 million (1969) and a deferred investment of $0.716 million (1969) yearly.[3] The resource energy associated with the various material inputs or other energy consuming activities are shown in Table 5-2. These inputs or activities were derived from total capital cost estimates in Reference 3 using a module approach to capital cost estimation[5] to break out dollar values of individual components of the total cost such as equipment, labor, and so forth.

Other costs not included in the table are labor, engineering, overhead, various indirect costs, interest, fees, etc. Resource energy inputs due to deferred investment contribute another 0.64×10^{12} Btu (0.68×10^{15} J) to the total shown in Table 5-2.

Using all the resource energy inputs to the coal mining operation shown in Figure 5-2, it is possible to calculate a net energy ratio for this activity. The breakdown of energy inputs and the results of the calculations are shown in Table 5-3. There is no entry for energy lost during "conversion." For example, coal left in the ground due to inefficiencies of the extraction process is not counted as "lost" energy. The calculated net energy ratio of 54 indicates that surface coal mining is a very efficient activity, requiring slightly less than 2 percent of

Table 5-2

ENERGY INPUTS FOR CONSTRUCTION OF A 5-MILLION TON/YEAR SURFACE COAL MINE*

Components of Construction	Resource Energy	
	10^{12} Btu	10^{15} J
Mining machinery		
Equipment ($11.4 million)	0.75	0.79
Materials ($3.1 million)	0.28	0.30
Exploration, roads and buildings ($2.2 million)	0.14	0.15
Unit train loading facilities ($0.75 million)	0.046	0.049
Freight ($0.73 million)	0.052	0.055
Total	1.27	1.34

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*Investments in 1969 dollars.

Table 5-3

ANNUAL ENERGY INPUTS AND OUTPUT FOR A 5-MILLION TON/YEAR SURFACE COAL MINE

	Resource or Product Energy	
	10^{12} Btu	10^{15} J
External energy inputs		
Electricity	0.93	0.98
Diesel fuel	0.16	0.17
Materials	0.41	0.43
Construction and equipment replacement	0.10	0.11
Total	1.60	1.69
Mined coal output	87	92

$$\text{Net energy ratio} = \frac{87}{1.6} = 54$$

the resource energy made available to be consumed in extraction. However, this does not include the energy consumed in transporting the coal away from the mine or otherwise making it available for end use.

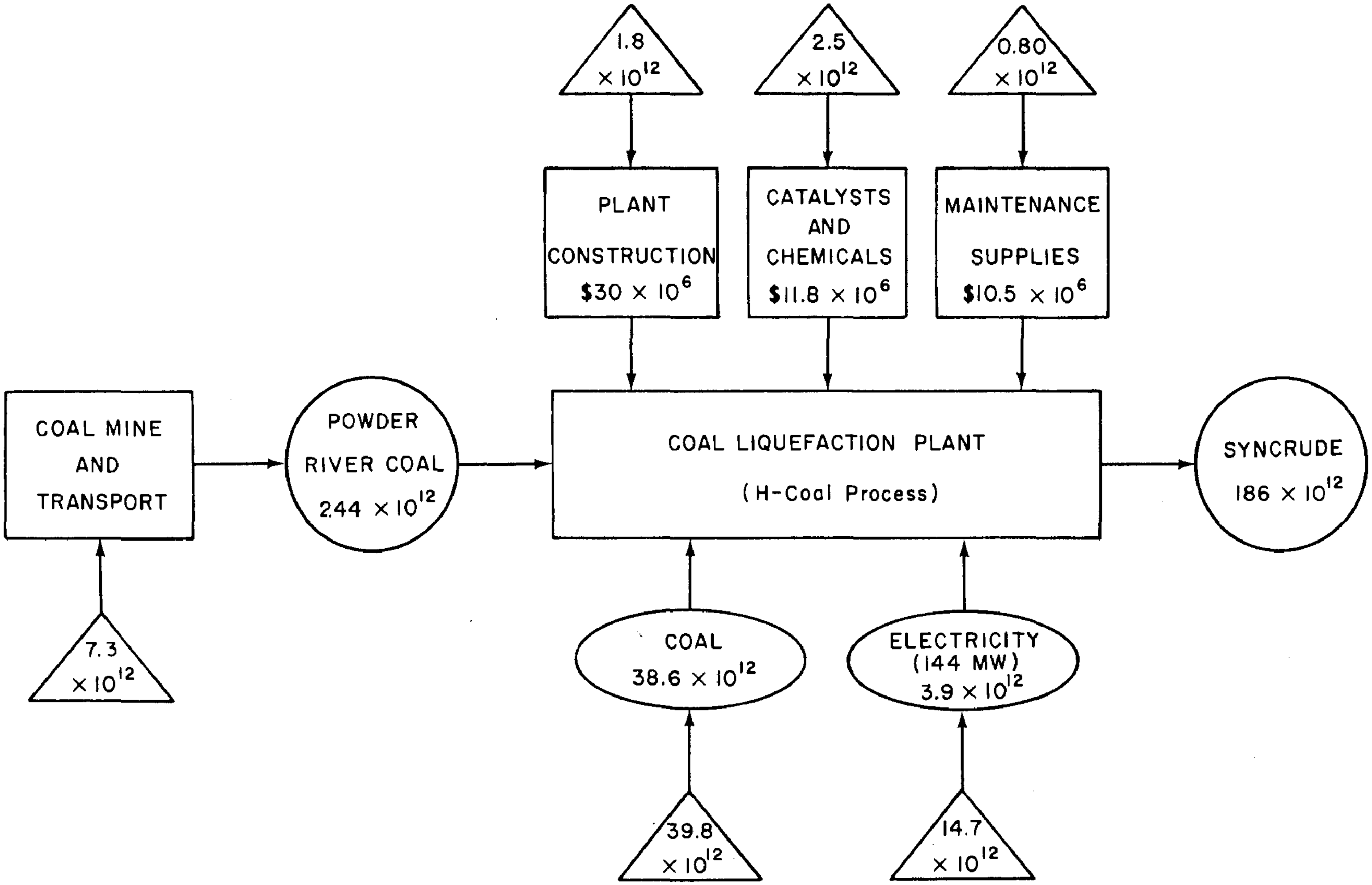
C. Analysis of Synthetic Fuel Processes

1. Coal Liquefaction (H-Coal Process)

The conversion of western coal to synthetic crude oil via the H-Coal process is an energy intensive activity characterized by approximately a 25-percent loss of resource energy during processing and consumption of ancillary resource energy equivalent to nearly 30 percent of the product energy output.[6] Much of the energy lost during processing is in the form of byproduct gases, which are consumed as additional plant fuel or steam reformed to provide hydrogen for liquefaction. Additional loss occurs in the form of char and vacuum bottoms (derived from fractionation of the product), which are gasified to produce hydrogen.

Relatively little of the ancillary energy contribution is in the form of materials or plant construction. The coal input, product output, and energy inputs from all other sources are shown in Figure 5-3. The resource energy input for coal mining and transport is derived from the data in Figure 5-2 and the additional assumptions that the coal is hauled by trucks 5 miles (8 km) to the plant, and that 1 percent of the coal is lost during loading and unloading. The resource energy inputs for catalysts, chemicals, and maintenance supplies have been calculated as previously described.

Two different methods were used to calculate the resource energy inputs for plant construction. The first method was similar to that used to calculate the coal mine construction energy inputs. Capital costs from Reference 6 were used in conjunction with plant construction module data from Reference 5 to break out dollar figures for various



NOTES: All resource energy inputs and product outputs are in Btu
All dollar figures are in late 1973 dollars per year

FIGURE 5-3. ANNUAL ENERGY INPUTS FOR CONSTRUCTION AND OPERATION OF A 100,000 B/D H-COAL PROCESS COAL LIQUEFACTION PLANT equipment, materials, and other construction components. The total construction energy input calculated by this method was 21 × 10^{12} Btu (22 × 10^{15} J). The second method simply involved taking the total plant capital investment figure (late 1973 dollars deflated to 1967 dollars by a factor of 1.35) and multiplying by the conversion factor in the table of Reference 2 for the public utilities construction sector. This sector was chosen since it most nearly represents the construction of the type of energy conversion facility required for a coal liquefaction plant. The energy input obtained by this method is 36 × 10^{12} Btu (38 × 10^{15} J). Since the first method of energy accounting tends to underestimate the construction energy input due to the inability to account for all categories, it was decided to use the figure derived from the second method. This provides a simple and direct method of computing construction energy inputs and is probably a more complete one since the input/output method takes into account energy inputs from all sectors that contribute to the construction of the plant.

Table 5-4 shows the resource energy lost during conversion, along with the breakdown of ancillary resource energy inputs and the calculation of the net energy ratio for coal liquefaction.

The table indicates that the liquefaction of western coal is a fairly energy consumptive process, returning only about 50 percent more useful product energy than was invested in the conversion process. However, for midwestern coal, the more favorable composition of the organic portion of the coal results in a somewhat lower ancillary energy consumption during liquefaction;[6] the net energy ratio in this case is about 1.8.

2. Methanol from Coal

The conversion of coal to methanol is a two-step process which involves the gasification of coal by reaction with steam and oxygen followed by the catalytic conversion of the resulting synthesis gas to methanol. Due to inefficiencies in both steps, the overall conversion efficiency for the process is only about 59 percent. In addition, a considerable quantity of coal is consumed as fuel to provide heat, steam, and electricity to run the process. In the process design on which the net energy calculation was based,[7] it was assumed that to meet environmental regulations the coal is gasified to form a clean, low-Btu fuel gas, rather than being burned directly. This method of utilizing coal as an ancillary fuel requires the consumption of about 50 percent more coal than would burning it directly.

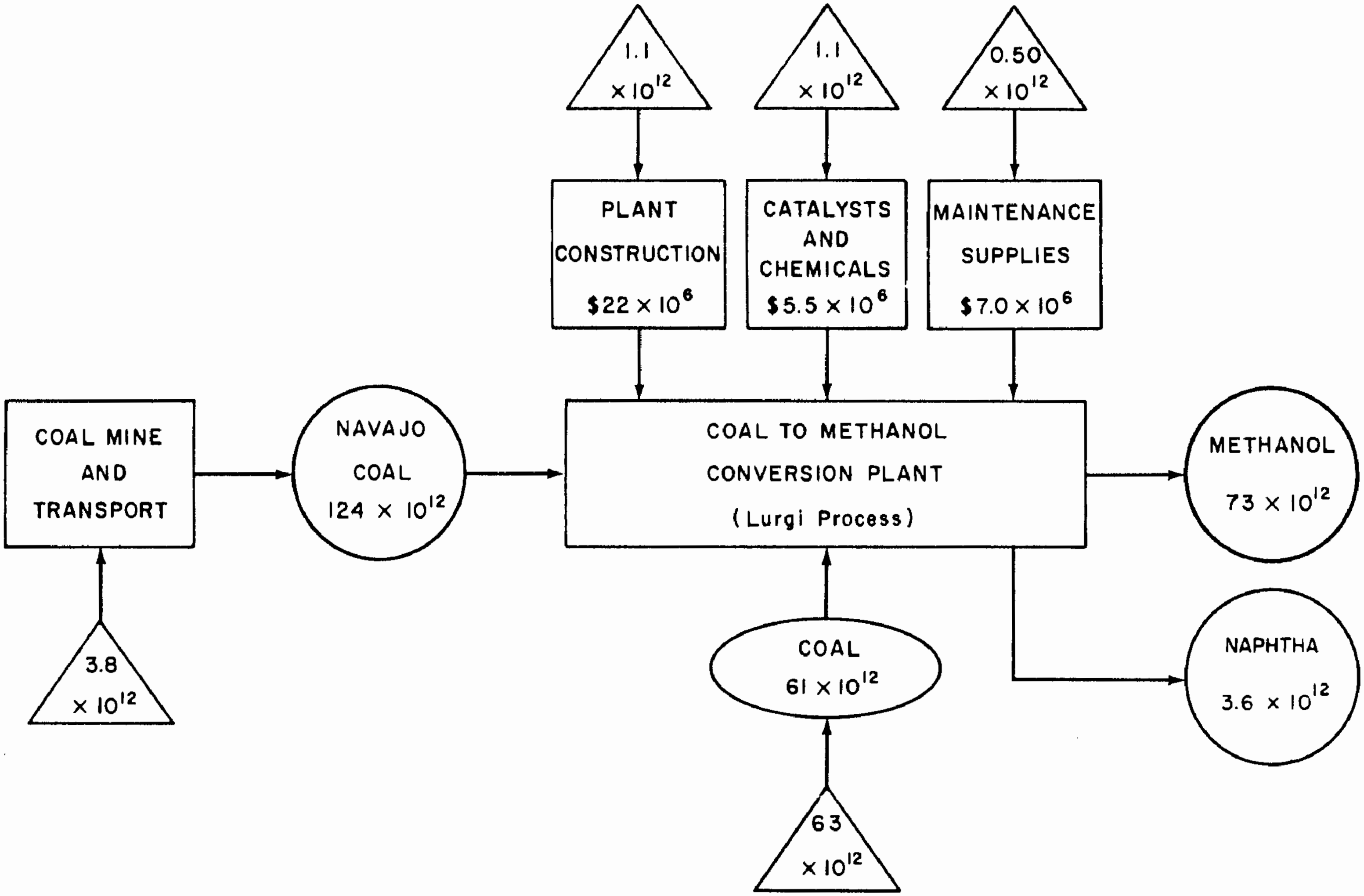
Table 5-4

ANNUAL ENERGY INPUTS AND OUTPUT FOR A
100,000-B/D COAL LIQUEFACTION PLANT

	Resource or Product Energy	
	10^{12} Btu	10^{15} J
Internal conversion loss	58	61
External energy inputs		
Coal	40	42
Electricity	15	16
Materials and construction	5.1	5.4
Coal mining and transport	7.3	7.7
Total	125	132
Syncrude output	186	196

$$\text{Net energy ratio} = \frac{186}{125} = 1.5$$

The energy inputs required for the production of 81,400-B/D (13,000 m^3/D) of methanol from Navajo coal are shown in Figure 5-4. The



Notes: All resource energy inputs and product outputs are in Btu
All dollar figures are in 1974 dollars per year

FIGURE 5-4. ANNUAL ENERGY INPUTS FOR CONSTRUCTION AND OPERATION OF AN 81,433-B/D COAL-TO-METHANOL PLANT types of inputs are the same as for coal liquefaction, except that all the electricity required to run the process is produced on-site, and the energy requirement is included in the ancillary coal input. The production of 2000 B/D (320 m^3/D) of byproduct naphtha is included in the output since this is a high quality product suitable for refining to gasoline and other fuels.

Not shown on the output end of methanol production in Figure 5-4 is the 25×10^{12} Btu/yr (26×10^{15} J/yr) of tar and tar oil, which are produced as additional byproducts of Lurgi gasification. These products are of low quality and are not suitable for refining to other fuels. Although there is some possibility that they could be used as boiler fuel, it is more likely that they will be used in nonfuel applications. Other gasification technologies, such as the Koppers-Totzek process, yield essentially no byproducts. Nearly all of the coal is converted to synthesis gas. However, an analysis of methanol production using the Koppers-Totzek gasifier has shown that the overall coal-to-methanol conversion efficiency is roughly the same as that of the Lurgi gasifier.[8] The ancillary fuel requirement, however, is slightly less.[8]

Table 5-5 shows a tabulation of the conversion energy losses and external energy inputs along with the calculation of the net energy ratio for the conversion of coal to methanol. The fact that the net energy ratio is less than one for this process indicates that more energy is consumed in conversion than is provided to society as methanol product. By comparison with coal liquefaction, the conversion of coal to methanol appears to be a relatively inefficient use of resources. However, the coal liquefaction product must be further refined before it can be used as an automotive fuel, while methanol can be used directly. The net energy ratio for the entire coal-to-refined products system is examined in a later section.

Table 5-5

ANNUAL ENERGY INPUTS AND OUTPUT FOR
AN 81,000-B/D COAL-TO-METHANOL PLANT

	Resource or Product Energy	
	10^{12} Btu	10^{15} J
Internal conversion loss	47	50
External energy inputs		
Coal	63	66
Construction and materials	2.7	2.8
Coal mining and transport	3.8	4.0
Total	117	124
Methanol output	73	77
Naphtha output	3.6	3.8

$$\text{Net energy ratio} = \frac{77}{117} = 0.66$$

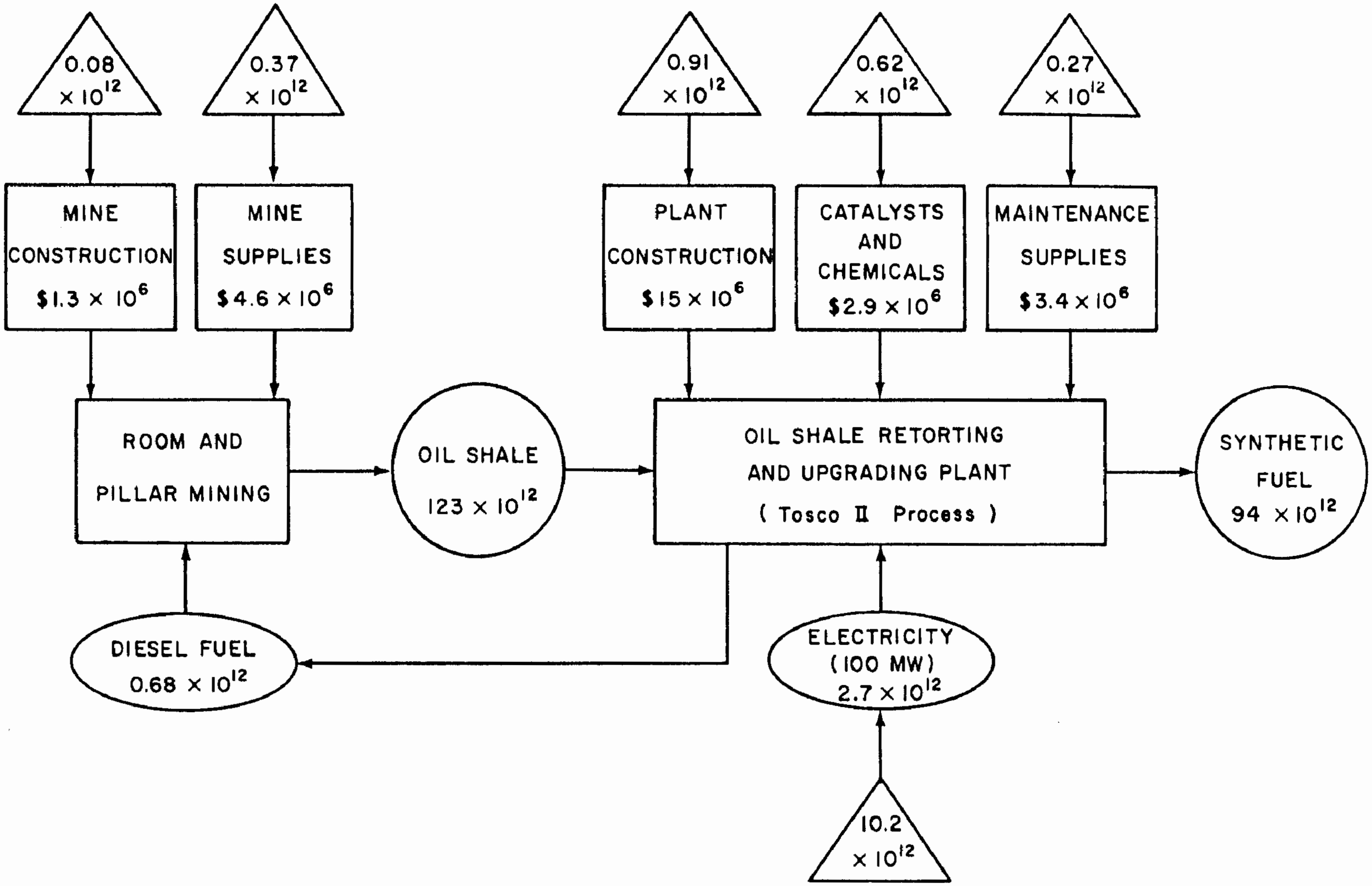
3. Oil Shale

Oil shale is a resource that is not used directly as a fuel. It must first be processed to extract the organic portion of the shale rock (about 11 percent by weight for 35 gal/ton shale), which must then be upgraded to be suitable as a refinery feedstock or fuel oil. The retorting process by which shale oil is extracted is very energy intensive and involves the heating of large quantities of shale to 900°F (480°C). However, much of the organic material in the shale can be recovered; the TOSCO II retorting process recovers essentially all of it.

Because oil shale is unusable in its raw form, a certain amount of care must be taken in computing the net energy ratio for mining, retorting, and upgrading. Unprocessed oil shale has a heating value that can be measured, but in computing the energy loss during retorting and upgrading this value is not used as the energy content of the resource. Instead, the energy content of the products of retorting is used as the basis for the energy loss because the energy contained in the shale is not useful until it has been extracted as a liquid or gaseous hydrocarbon. In practice, the only energy-containing material that cannot be extracted from the shale is a carbon residue which remains on the spent shale after retorting.

Figure 5-5 shows the annual energy inputs for oil shale mining,[9] retorting,[10] and upgrading.[10] As mentioned above, the resource energy input for oil shale includes only the heating value of the hydrocarbon products actually recoverable by retorting. As shown in Figure 5-5, the diesel fuel consumed by the mining equipment is obtained as a byproduct from shale oil upgrading.[10] This fuel consumption is counted as a conversion loss. Other conversion losses occur mainly in the form of the combustion of retort gases as well as some fuel oil to provide heat and steam for retorting and upgrading. The product from oil shale retorting and upgrading is simply called synthetic fuel since the process design on which the analysis is based was for the production of fuel oil and liquified petroleum gas (LPG) rather than synthetic crude oil.[10] The production of synthetic crude oil probably would not result in a significantly different net energy ratio.

Table 5-6 shows the breakdown of conversion energy loss and external energy inputs, as well as the computation of the net energy ratio, for a 50,000-B/D (8000 m^3/D) oil shale complex. The net energy ratio of 2.3 for oil shale processing is the highest of the three different alternatives that have been examined for producing synthetic fuel, probably because oil shale (or at least the organic portion of it) in its raw form is closer in composition to the final product that is coal, which results in less severe (less energy consumptive) processing. In



Notes: All resource energy inputs and product outputs are in Btu
All dollar figures are in 1973 dollars per year

FIGURE 5-5. ANNUAL ENERGY INPUTS FOR CONSTRUCTION AND OPERATION OF A 50,000-B/D OIL SHALE MINING, RETORTING, AND UPGRADING COMPLEX addition, it appears that retorting methods such as gas combustion or in-situ may have been even higher net energy ratios, although the calculations have not been fully carried out due to insufficient data.

Table 5-6

ANNUAL ENERGY INPUTS AND OUTPUT FOR A 50,000-B/D OIL SHALE MINING, RETORTING, AND UPGRADING COMPLEX

	Resource or Product Energy	
	10^{12} Btu	10^{15} J
Internal conversion loss	29	31
External energy inputs		
Electricity	10.2	10.8
Plant construction and materials	1.8	1.9
Mine construction and materials	0.45	0.47
Total	41.5	43.8
Synthetic fuel output	94	99

$$\text{Net energy ratio} = \frac{94}{41.5} = 2.3$$

D. Coal-to-Refined Products System

The production of synthetic crude oil from coal, of course, is not the final step in converting coal into liquid fuels usable by society. The syncrude must be transported to a refinery to be processed to yield gasoline, diesel oil, heating oil, and other products. Both the transport and the refining process are energy consumptive and consequently decrease the net energy ratio of the final products.

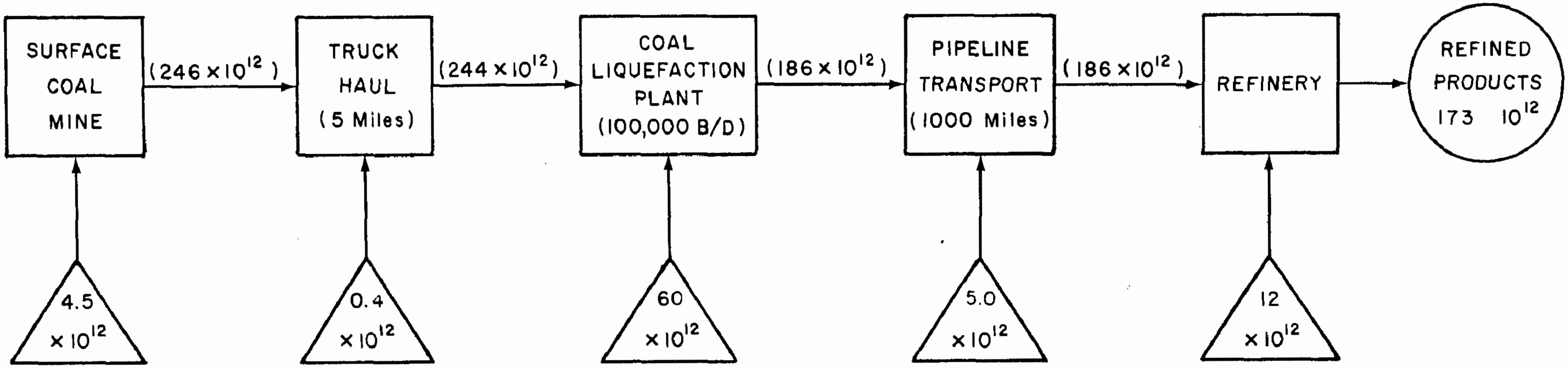
The energy consumed in transporting crude oil via pipeline has been calculated assuming a 24-inch (61 cm) diameter pipeline 1000-miles (1600 km) long, corresponding to shipment of syncrude from eastern Montana or Wyoming to the Midwest for refining. The motive power requirement for this diameter pipeline is 151 horsepower/mile (70 kW/km), corresponding to a capacity of 14 million tons per year (1.3×10^8 kg/yr).[11] The resource energy requirement is calculated to be 780 Btu/ton-mile (560 J/kg-km) for diesel engines or 1020 Btu/ton-mile (740 J/kg-km for electric motors. An average figure of 900 Btu/ton-mile (650 J/kg-km) has been used in the net energy calculation. In addition, the energy required to produce the 500,000 tons (4.5×10^8 kg) of steel used in the pipeline has been included in the pipeline energy requirement (assuming a 20-year pipeline life). This contribution represents about 10 percent of the total.

The energy losses (due mostly to internal use) and external resource energy consumption during refining are calculated from data in Reference 2 as 7.1 percent and 6.5 percent of the crude oil energy input, respectively. These figures correspond closely with the figures of 6.8 percent and 6.7 percent obtained from nationwide refinery energy efficiency and external energy use data.*[12]

The annual resource energy inputs required for the entire coal-to-refined products system are shown in Figure 5-6. The size of the system is scaled to a 100,000-B/D (16,000 m^3/D) coal liquefaction plant. Table 5-7 tabulates the data from Figure 5-6 and shows the net energy

---

*The results of a recent SRI study[6] indicate that the internal loss is 2 percent and the external resource energy use is 12 percent for refining a 50-50 blend of syncrude and natural crude. The total energy consumption is about the same as quoted above, however.



Note: All resource energy inputs and product outputs are in Btu

FIGURE 5-6. ANNUAL ENERGY INPUTS FOR CONVERTING WESTERN SURFACE-MINED COAL TO REFINED PRODUCTS IN THE MIDWEST ratio calculations for the system. The net energy ratio of 1.1 indicates that nearly as much energy is expended in obtaining refined fuels from coal than is contained in the fuels themselves.

Table 5-7

ANNUAL ENERGY INPUTS AND OUTPUT FOR A
COAL-TO-REFINED PRODUCTS SYSTEM
(Based on a 100,000-B/D Coal Liquefaction Plant)

	Resource or Product Energy	
	10^{12} Btu	10^{15} J
Internal conversion loss		
Coal transport	2.4	2.5
Coal liquefaction	58	61
Refinery	13	14
External energy inputs		
Coal mine	4.5	4.7
Coal transport	0.4	0.42
Coal liquefaction plant	60	63
Pipeline	5.0	5.3
Refinery	12	13
Total	155	164
Refined products output	173	183

$$\text{Net energy ratio} = \frac{173}{155} = 1.1$$

A similar calculation for the oil shale-to-refined products system results in a net energy ratio of 1.6. For methanol the only additional step required in the system is transportation since no further refining is necessary. Adding transportation reduces the net energy ratio for methanol only slightly, to 0.65.

E. Summary

The net energy ratios for three different synthetic fuel processes, as well as for coal mining and the entire resource-to-end products systems, have been calculated. These ratios are a measure of the product energy that is made available per unit of resource energy consumed in the synthetic fuel conversion process. The net energy ratio calculations for the three synthetic fuel processes are summarized in Table 5-8 along with the calculations for the three resource-to-fuels systems.

The main conclusion to be drawn from Table 5-8 is that the conversion of coal to automotive and other fuels via coal liquefaction is a more efficient use of resources than is the conversion of coal to methanol. This remains true even when the additional energy inputs and losses incurred in refining the syncrude product are taken into account. On the basis of converting western subbituminuous coal, about 1.8 times as much resource energy is consumed in converting coal to methanol as there is in converting coal to refined products via coal liquefaction.

In considering the conversion of oil shale to refined products, the comparisons are not as straightforward. On the basis of total resource consumption, oil shale conversion is clearly the most efficient use of resources. However, due to the distinctly different nature of the resource, it is difficult to draw conclusions regarding the attractiveness of oil shale with respect to coal liquefaction on the basis of total resource utilization. Unlike coal, oil shale has no other practical uses, and some energy penalty must be exacted just to convert the shale to a usable form. However, most of the energy consumed in this conversion is provided by the oil shale itself, in the form of products of retorting. On the basis of the consumption of resources other than oil shale, the conversion of oil shale to synthetic crude oil appears to be especially attractive compared with the coal conversion technologies.

Table 5-8

SUMMARY OF NET ENERGY CALCULATIONS FOR SYNTHETIC LIQUID FUELS

	Conversion Process*				Resource-to-Fuels System†			
Technology	Internal Loss (10^{12} Btu/yr)‡	External Input (10^{12} Btu/yr)‡	Product Yield (10^{12} Btu/yr)‡	Net Energy Ratio	Internal Loss (10^{12} Btu/yr)‡	External Input (10^{12} Btu/yr)‡	Product Yield (10^{12} Btu/yr)‡	Net Energy Ratio
Coal liquefaction								
H-Coal process, Powder River coal, 100,000 B/D	58	67	186	1.5	71	84	173	1.1
H-Coal process, Illinois coal, 100,000 B/D	81	27	195	1.8	98	42	182	1.3
Methanol from coal								
Lurgi process, Navajo coal, 81,433 B/D	47	70	77	0.66	47	72	77	0.65
Oil shale								
TOSCO II process, 35-gal/ton shale, 50,000 B/D	29	12.5	94	2.3	35	20	88	1.6

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*Includes mining of resource.

†Includes 1000 miles of pipeline for shipment of syncrude or methanol.

‡10^{12} Btu/yr = 1.06 × 10^{15} J/yr.

There are several sources of error in computing the values displayed in Table 5-8. First, it is impractical to account for all the energy inputs into a given system. However, since it is possible to account for the most important inputs, the net energy ratios quoted above are expected to be in error by no more than 5 to 10 percent due to such oversights. Several inputs or activities such as research and development, engineering, etc., which are energy consumptive were not added into the total simply because the insignificance of the contributions (much less than 1 percent of the total) was not worth the additional effort expended in deriving the numbers. Neglecting such contributions represents a real, though very small, source of error.

Moreover, errors may occur in assigning energy values to aggregated dollar values for certain types of inputs such as construction or maintenance. Whenever possible, these figures were compared with calculations of energy inputs associated with a known subcategory of input as a check on the reasonableness of the total value. For example, the energy consumed in the production of roof bolts for room-and-pillar oil shale mining might be expected to contribute significantly to the total energy consumption for this activity since large numbers of roof bolts are required for such a mine (nearly 1000 tons per year or 9×10^5 kg/yr or a mine supplying a 50,000-B/D plant or 8000 m^3/D). The energy required for producing steel roof bolts is about 0.05×10^{12} Btu/yr (0.05×10^{15} J/yr). This compares with the total energy input calculated for mine supplies of 0.37×10^{12} Btu/yr (0.39×10^{15} J/yr).

Much more work needs to be done on expanding the data base for net energy calculations to provide straightforward data on as many types of energy inputs as possible. More information is needed on other types of synthetic fuel processes as well to facilitate the comparison of different processes that accomplish the same objective. The net energy calculations in this chapter provide a starting point for understanding the total energy picture for synthetic fuels development.

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6--MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO FOR SYNTHETIC LIQUID FUELS FROM COAL AND OIL SHALE

By Evan E. Hughes, Robert V. Steele

A. Introduction

Many speculations have been advanced in recent years concerning future levels of production of synthetic fuels from coal and oil shale. To set an upper limit on the possible impacts that would result from production of these fuels, this study requires an implementation scenario that sets forth the maximum credible rate at which the synthetic fuels industry (coal and oil shale syncrudes, methanol from coal) could be expected to develop. This maximum implementation scenario is the subject of this chapter. It is extremely important to recognize that this scenario is *not a prediction of what will occur* but is an attempt to elucidate the maximum possible impact situation.

B. Implementation Schedule

The maximum credible implementation scenario is derived from a hypothesized growth schedule for a synthetic liquid fuel industry presented in Table 6-1.* The growth schedule indicates a slow start for synthetic

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*Approximate conventional-to-metric unit conversion factors relevant to this chapter are the following:

100,000 B/D is about 16,000 m^3/D
1000 AF/Y is about $1.2 \times 10^6 m^3$/Y
10^6 tons/Y is about 900×10^6 kg/Y
1000 acres is about $4.0 \times 10^6 m^2$.

Table 6-1

HYPOTHESIZED GROWTH SCHEDULE OF SYNTHETIC LIQUID FUELS INDUSTRY

	Number of Plants Producing				
	Year				
Fuel Description*	1980	1985	1990	1995	2000
Syncrude from coal					
30,000 B/D plant	0	3	7	7	0
100,000 B/D plant	0	0	3	13	40
Total production (10^6 B/D)	0	0.09	0.5	1.5	4.0
Syncrude from oil shale					
50,000 B/D plant	2	2	2	0	0
100,000 B/D plant	0	4	14	20	20
Total production (10^6 B/D)	0.1	0.5	1.5	2.0	2.0
Methanol from coal					
50,000 B/D plant	2	2	2	0	0
100,000 B/D plant	0	5	19	50	80
Total production† (10^6 B/D oil equivalent)	0.05	0.3	1.0	2.5	4.0

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*Note that 100,000 B/D is about 16,000 m^3/D.

†To a close approximation, the energy content of a barrel of methanol is half that of a barrel of oil.

liquid fuels with negligible production before 1985, followed by a rapid growth until the year 2000. The relatively slow start stems from the present situation in the oil industry: (1) the increased activity to find and produce energy from conventional petroleum sources, and (2) the steady increase in cost estimates for synthetic fuel plants. As a result, the oil industry can be expected to postpone construction of synthetic liquid fuel plants in favor of investment in more familiar resources.

The scenario projects accelerated growth for oil shale processing after 1980 and for the coal-based fuels after 1985. Such growth, of course, assumes that the first plants are successful, both technically and economically. This assumption is made solely to facilitate construction of a scenario that depicts the maximum rate at which an industry could be deployed subject only to physical and general economic constraints. Of course, other real world constraints, such as water availability, would lead to a lower actual rate of deployment.

The rapid increases in synthetic fuel production shown in Table 6-1 have been derived on the basis of several considerations:

- The impact study would be most instructive if it included a scenario that showed synthetic liquid fuels playing a major role in meeting U.S. requirements for liquid fuels.
- The rates of growth projected during early years of the commercial production of the alternative fuels should be reasonable for a new industry.
- The requirements for economic and physical resources to build and operate the plants should be realistic.

The maximum credible implementation scenario reflects several judgments regarding the relative states of development of the three basic synthetic liquid fuel technologies: Oil shale technology is ready for commercial deployment. Tests have been made on a scale large enough to confirm the feasibility of the technology and guide the design of a large plant. Future improvements in the technology (excluding the possibly significant case of in-situ technology) are not expected to be pronounced enough to render obsolete a plant begun today. Hence, our maximum credible scenario for oil shale shows two 50,000 B/D plants in 1980 and an addition of four 100,000 B/D plants by 1985. The commercial production of methanol and syncrude are restrained relative to oil shale to reflect the anticipated benefits of further research, development, and demonstration work on processes of making syncrude from coal and the market uncertainties concerning introduction of methanol for large-scale use as a fuel. The status of the technology for production of methanol from coal is similar to that of syncrude from shale--basically ready for first generation commercial production. The more advanced development of methanol compared with coal syncrude production derives from the similarities of producing methane and methanol from coal, and the greater attention that SNG technology has received in the last decade compared with coal liquefaction technology. Oil shale production is shown leveling off as a reflection of anticipated water shortages.

C. Comparison with the National Academy of Engineering Scenarios

The National Academy of Engineering (NAE) projection of the maximum production of synthetic fuels possible in the next 10 to 12 years[1] is compared with those of this study in Table 6-2.

Table 6-2

MAXIMUM POSSIBLE PRODUCTION OF SYNTHETIC LIQUID FUELS IN 1985: NAE AND SRI PROJECTIONS

Fuel	NAE (million B/D oil equivalent)*	SRI (million B/D oil equivalent)*
Syncrude from coal	0.3	0.09
Methanol from coal	0.3	0.3
Syncrude from shale	0.5	0.5
Total synthetic liquid fuel in 1985	1.1	0.89

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*Note that one million B/D is about 160,000 m^3/D.

The NAE projections were based on the lead times required to plan and construct the facilities and on the resources of capital and labor that must be mobilized to build and operate them. The lower level of production of syncrude from coal reflects the need for more prototype plant testing of coal liquefaction plants before beginning the commitment to commercial plants. Oil shale technology is taken to be well enough developed to justify commitment to a commercial facility now. Although the NAE Task Force on Energy viewed the technology for producing methanol from coal as adequately developed to justify commitment to commercial sized plants, it, too, apparently felt that uncertainties in the uses of methanol as a fuel on a commercial scale would limit the estimated maximum production in 1985 to a level comparable to the estimate for syncrude from coal and below the estimate of syncrude from oil shale.

As Table 6-2 shows, the SRI study's schedule for the maximum credible implementation of syncrude from coal is lower than the NAE level for 1985 reflecting our judgment that the expectation of great improvement in technology, combined with the uncertainties inherent in all of the synthetic fuels, makes the postponement of commitments to commercial-scale coal liquefaction facilities inevitable. The situation was succinctly described by a vice president of Exxon Research and Engineering Company in a talk at Stanford University: Coal liquefaction differs from other synthetic fuel processes (coal gasification and oil shale production) in that substantial savings are expected from second generation technology compared to that presently available. In particular, while the 10 or 15 percent savings expected from improvements in gasification technology over the next five years are not sufficient to justify postponement of construction, the larger (but unspecified) savings expected from advanced liquefaction technology warrant a go-slow attitude. Because it is technologically reasonable to deploy present technology for production of methanol from coal or syncrude from oil shale, these are suitable levels for a maximum credible implementation scenario. Therefore, our schedule in Table 6-1 puts methanol and oil shale production at the levels projected in the NAE study.

In both the oil shale and the methanol cases the actual realization of the schedules of Tables 6-1 and 6-2 requires that present uncertainties be resolved soon in a way that encourages development of the synthetic fuels. Several recent events make it questionable whether the maximum credible production levels for 1985 can still occur: (1) The recent announcement by the Colony Development Company that it will not start the construction originally planned for spring 1975 on its 50,000 B/D oil shale plant at Parachute Creek in Colorado, (2) the lack of enthusiasm for oil shale displayed in the "Project Independence Blueprint" recently published by the Federal Energy Administration (FEA),[2] and (3) commercial scale uses of methanol as a fuel will have to be apparent soon to justify the deployment of the 300,000 B/D (oil equivalent) production level by 1985. The most likely candidate uses of methanol emerging before 1985 are fuel for electric utilities (especially as fuel for gas turbine or combined cycle generators) and automotive fuel for fleet vehicles.

D. Scenarios and Scaling Factors

The projected fuel production schedules shown in Table 6-1 have been assigned the hypothetical locations shown in Table 6-3 in proportion to reported reserves of surface and underground minable coal and have been used to derive the scenarios in Tables 6-4 through 6-7. The scaling factors shown in the tables are used to account for the quantities of capital, labor, steel, and land required for the construction and operational phases of each of the building blocks used in these scenarios.

Table 6-3

HYPOTHESIZED LOCATIONS OF PLANTS FOR PRODUCING SYNTHETIC LIQUID FUEL FROM COAL

Units for table entries are as follows:

Coal syncrude plants: S = 30,000 B/D
L = 100,000 B/D*

Methanol plants: S = 50,000 B/D (methanol)
L = 100,000 B/D (methanol)

Surface mine: 5 million tons/year

Underground mine: 1 million tons/year*

Water: 10^3 acre-ft/year*

	Cumulative Quantities				
	Year				
State	1980	1985	1990	1995	2000
Wyoming					
Coal syncrude	0	2S	3S, 2L	3S, 5L	13L
Methanol	0	0	2L	8L	13L
Surface mines	0	2	14	42	81
Water	0	58	116	297	584
Montana					
Coal syncrude	0	0	1S	1S, 3L	11L
Methanol	0	0	1L	5L	10L
Surface mines	0	0	4	25	66
Water	0	0	24	174	479
North Dakota					
Methanol	1S	1S, 2L	1S, 5L	13L	21L
Surface mines	2	9	20	47	76
Water	8	39	86	202	326
New Mexico					
Methanol	0	1L	3L	4L	4L
Surface mines	0	3	8	10	10
Water	0	15	46	62	62
Illinois					
Coal syncrude	0	1S	1S, 1L	1S, 3L	7L
Methanol	0	1L	4L	9L	14L
Surface mines	0	1	3	8	14
Underground mines	0	9	40	93	161
Water	0	29	98	231	415
Kentucky					
Coal syncrude	0	0	1S	1S, 1L	4L
Methanol	1S	1S, 1L	1S, 3L	7L	10L
Surface mines	1	1	3	7	13
Underground mines	0	10	23	52	87
Water	8	23	62	144	266
West Virginia					
Coal syncrude	0	0	1S	1S	2L
Methanol	0	0	1L	3L	5L
Surface mines	0	0	1	2	4
Underground mines	0	0	9	24	56
Water	0	0	24	54	134
Ohio					
Coal syncrude	0	0	0	1L	3L
Methanol	0	0	0	1L	3L
Surface mines	0	0	0	1	4
Underground mines	0	0	0	18	49
Water	0	0	0	44	133

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*Note that 100,000 B/D is about 16,000 m^3/D, 1 million tons/year is about 900 million kg/year, and 1 acre foot is about 1200 m^3/year.

Table 6-4

SYNCRUDE FROM COAL: MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO

	Scenario for Year				
Data and Assumptions	1980	1985	1990	1995	2000
Production Schedule					
Cumulative capacity (million B/D)	0	0.09	0.5	1.5	4.0
Number of Plants					
Small (30,000 B/D)	0	3	7	7*	0
Large (100,000 B/D)	0	0	3	13	40

Inputs and Outputs		Scaling Factors for a 100,000 B/D Plant	Year				
Items	Units	(in units specified)	1980	1985	1990	1995	2000
			Cumulative Amount				
Construction							
Capital	10^9 1973 $	0.67	0	0.60	3.4	10	27
Labor	10^3 man-years	7.3	0	6.6	37	110	290
Steel	10^3 tons	110	0	100	560	1700	4400
Land	10^3 acres	1	0	0.9	5.1	15	40
			Annual Amount				
Production							
Operating costs	10^6 1973 $/year	130	0	120	650	2000	5200
Labor force	10^3 people	1.4	0	1.3	7.0	21	56
Coal (Western)	10^6 tons/year	18	0	16	90	270	720
Water	10^3 acre-ft/year	29	0	26	145	435	1160
Electric power	MW	140	0	130	700	2100	5600

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*Arrow indicates that small plants are enlarged and enter large plant classification.

Table 6-5

SYNCRUDE FROM OIL SHALE: MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO

Data and Assumptions	Scenario for Year				
	1980	1985	1990	1995	2000
Production Schedule					
Cumulative capacity (million B/D)	0.1	0.5	1.5	2.0	2.0
Number of Plants					
Small (50,000 B/D)	2	2	2*	0	0
Large (100,000 B/D)	0	4	14	20	20

Inputs and Outputs		Scaling Factors for a 100,000 B/D Plant (in units specified)	Year				
Items	Units		1980	1985	1990	1995	2000
			Cumulative Amount				
Construction							
Capital	10^9 1973 $	0.75	0.75	3.8	11.3	15.0	15.0
Labor	10^3 man-years	5.4	5.4	27	81	108	108
Steel	10^3 tons	90	90	450	1350	1800	1800
Land	10^3 acres	0.6	0.6	3.0	9.0	12	12
			Annual Amount				
Production							
Operating costs	10^6 1973 $/year	80	80	400	1200	1600	1600
Labor force	10^3 people	1.7	1.7	10.2	25.5	34.0	34.0
Shale	10^6 tons/year	54	54	270	810	1080	1080
Water	10^3 acre-ft/year	16	16	80	240	320	320
Electric power	MW	170	170	850	2250	3400	3400
Land	10^3 acres/year	0.15	0.15	0.750	2.25	3.0	3.0

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*Arrow indicates that small plants are enlarged and enter large plant classification.

Table 6-6

METHANOL FROM COAL: MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO

	Scenario for Year				
Data and Assumptions	1980	1985	1990	1995	2000
Production Schedule					
Cumulative capacity (million B/D oil equivalent)[*]	0.05	0.3	1.0	2.5	4.0
Number of Plants					
Small (50,000 B/D)	2	2	2[†]	0	0
Large (100,000 B/D)	0	5	19	50	80

Inputs and Outputs		Scaling Factors for a 100,000 B/D Plant[*]	Year				
Items	Units	(in units specified)	1980	1985	1990	1995	2000
			Cumulative Amount				
Construction							
Capital	10^9 1973 $	0.59	0.59	3.5	11.8	29.5	47.2
Labor	10^3 man-years	7.5	7.5	4.5	150	375	575
Steel	10^3 tons	100	100	600	2000	5000	8000
Land	10^3 acres	1	1	6	20	50	80
			Annual Amount				
Production							
Operating costs	10^6 1973 $/year	70	70	420	1400	3500	5600
Labor force	10^3 people	0.9	0.9	6.4	18	45	72
Coal (Western)	10^6 tons/year	13	13	78	260	650	1040
Water	10^3 acre-ft/year	15	15	90	300	750	1200
Electric power	MW	100	100	600	2000	5000	5000

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[*] The energy of a barrel of methanol is half that of a barrel of oil.

[†] Arrow indicates that small plants are enlarged and enter large plant classification.

Table 6-7

SURFACE COAL MINES NEEDED FOR SYNCRUDE PLUS METHANOL PRODUCTION*

Data and Assumptions	Scenario for Year 1980	1985	1990	1995	2000
Production Schedule					
Cumulative capacity (million tons/year)	13	94	350	920	1760
Number of mines (5 million tons/year)	3	19	70	184	352

Inputs and Outputs Items	Units	Scaling Factors for a 5 Million Ton/Year Surface Mine (in units specified)	Year 1980	1985	1990	1995	2000
			Cumulative Amount				
Construction							
Capital	10^3 1973 $	0.03	0.09	0.57	2.1	5.5	10.6
Labor	10^3 man-years	0.25	0.75	4.75	17.5	46.0	88.0
Steel	10^3 tons	3	9	57	210	552	1060
Land†	Acres	10	30	190	700	1840	3520
			Annual Amount				
Production							
Operating costs	10^6 1973 $/year	12	26	228	840	2210	4220
Labor force	10^3 people	0.1	0.3	1.9	7	18	35
Water	10^3 acre-ft/year	0.15	0.45	2.85	10.5	27.6	52.8
Electric power	MW	10	30	190	700	1840	3520
Land	10^3 acres/year	0.25	0.75	4.75	17.5	46	88

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*Assumes all of the coal requirements for syncrude and methanol plants are supplied by surface mines.

†Land for buildings, storage and handling facilities, parking, etc.; this is not land for mining.

E. Resources

By far, the majority of the commercially significant oil shale reserves (25 to 30 B/ton of shale or 4.4 to 5.3 $m^3/10^3kg$) are found in the Piceance Basin in western Colorado. Unlike oil shale, coal is widely distributed in the nation. Table 6-8 shows a recent tabulation of strippable coal reserves and the number of coal liquefaction plants that these reserves could sustain. Since synthetic fuels will require low cost feedstocks to be economically competitive (at least initially) with conventional petroleum fuels, strippable coal has been emphasized. Clearly, strippable reserves would be able to sustain this study's maximum credible production scenario for several plant lifetimes. However, when other coal demands are also taken into account, there is a good chance that early in the 21st century, strippable reserves will be nearing depletion.* This suggests the need to develop both in-situ recovery techniques and improved methods of underground mining (especially since present methods cannot efficiently mine the very thick, deep seams of coal found in the West).

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*However, it is important to note that distinction between resources and reserves. Reserves are the fraction of resources that are economically recoverable with state-of-the-art technology at any given time. Hence, both changes in the market price of a mineral, and the technology available can alter estimates of reserves, while resource estimates can be changed only with new discoveries.

Table 6-8

STATES AND REGIONS WITH STRIPPABLE COAL RESERVES SUFFICIENT TO SUPPORT A LARGE SYNTHETIC FUELS INDUSTRY

States and Regions	Strippable Reserves 10^9 Tons*	Number of 100,000 B/D Plants Sustainable for 20 Years at 20 MT/Year
Montana	43	110
Wyoming	24	60
North Dakota	16	40
Illinois/Western Kentucky	16	40
West Virginia/ Eastern Kentucky	8.7	22

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*Note that one ton is about 900 kg.

Source: Reference 3, "Demonstrated Reserve Base," U.S. Bureau of Mines (1974).

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7--LEGAL MECHANISMS FOR ACCESS TO COAL AND OIL SHALE

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Edited by R. Allen Zink

A. Introduction: Principles

Access to mineral deposits is governed first by the obvious question, "Who owns the land?" Actually, the question should be "Who owns the minerals under the land?" There is an ancient maxim of law that the owner of the soil owns as well the air above and the earth below--all the way up and all the way down. The owner of land may dispose of it as he wishes; he may sell, lease, or otherwise dispose of his rights to the land, and he may carve up his interest in any way which pleases him. The principal importance of this in mineral law is that a landowner may sever the surface and mineral estates (rights), selling or leasing one and retaining (or selling or leasing to someone else) the other. He may, in other words, divide his land both vertically (by dividing the surface) and horizontally (by severing the mineral estate, or even by severing different mineral strata and disposing of or retaining them separately). It is common for land to be conveyed with a reservation of mineral rights, or vice versa.

However, if the mineral estate is severed, the mineral estate becomes the "dominant" estate and the surface of the "servient" estate (that is to say, secondary in right to the mineral estate), which means that the owner of the surface may not use his ownership to interfere with the use of the mineral estate beneath. Use of the mineral estate means doing what is necessary to remove desired minerals from beneath the surface of the land and carry them away. The owner of a mineral estate has the right of access to it, and the right of entry onto the surface as is necessary to exploit his mineral estate. He may build such improvements (roads, buildings, etc.) as are necessary to his use of the mineral estate. What he does must be "reasonable," and must not unreasonably injure the surface estate (for example by removing coal in a way that causes subsidence); a bond may be required to protect the surface owner's estate. The same rule applies in theory to strip mining--as generally understood, a lease or other interest in the mineral estate does not entitle its owner to devastate the surface. However, the damage "reasonably" necessary to conduct strip mining operations may be very extensive indeed. While it may be true that the owner of the dominant estate may not destroy the usefulness of the servient estate without being liable to compensate the surface owner, even such compensation may be inadequate from the standpoint of the owner of the surface. If the owner of the mineral estate decides to exploit his estate by strip mining, and in the process of so doing utterly destroys the surface, and is required to pay to the surface-owner the full market price of the surface, what has happened in effect is that the mineral-owner has exercised a sort of private eminent domain. This may be unsatisfactory to the people who live above the mineral, but that is the way it is in the absence of overriding state laws to the contrary.

The extent of the interest conveyed in a mineral-land transaction (severance, ownership, leasehold, etc.) and the terms of the transaction (in the case of a lease rent, royalty, duration, etc.) are matters of agreement between the parties. Even general common law principles may be altered by their mutual agreement, subject to the general rules of contract law on unconscionable contracts, equity, and the like. State and federal police power is, of course, paramount in the areas where it properly applies. A state strip mining law is an exercise of police power, and overrides any agreement between the parties. Under the Commerce clause of the U.S. Constitution, any coal mines producing coal, for example, which enters the stream of commerce (and just about all coal mines are covered by this provision) are subject to the federal coal mine operating safety laws, as well as to state laws of similar effect. But beyond this, insofar as access to and rights in the land are concerned, it is the intentions of the parties which govern any transaction involving rights to minerals. As will be seen, this is true whether the proprietor of the land is a private citizen, a state, or even the federal government.

So the first question is "Who owns the mineral estate?" If the answer is that title to the mineral estate is held by a private individual, or by a corporation, or by any entity other than a state or the United States (holding title either for itself or in trust for an Indian or Indian tribe), the law which governs access is private law, the law of contracts and real property. Most of the law regulating the relations between vendors and vendees, or lessors and lessees, of mineral estates in private ownership is the result of the common law process. It has grown out of the decisions of the courts in individual deeds and leases, in which the object is always to determine and give effect to the intentions of the parties and to do justice in terms of realizing those intentions and in terms of basic equity. They have general application only in that they govern the interpretation of language in other private agreements in the same jurisdiction. The term of any future agreements involving access to coal or oil shale lands in private ownership will depend largely on what is worked out between the lawyers for the owners and the lawyers for the developers. There are no regulations to be complied with (environmental protection restrictions are exercises of police power and are another story).

Essentially the same principle governs lands in public (state or federal) ownership. In permitting access to mineral deposits on land, the mineral estate of which it owns, the state (or the United States) acts not as sovereign but as proprietor. The whole elaborate mechanism of the federal Mineral Leasing Acts, for example, is not an attempt to regulate access to mineral lands in general but only governs the "intentions of the lessor" when the lessor is the United States. What the law determines and what the regulations regulate is the terms that the owner of the mineral estate will insist on in what is essentially still a private law transaction. The regulations bind the government, but the lease incorporating the terms the regulations require (and whatever other terms not required by the regulations but thought wise to insist on by the Bureau of Land Management) is what binds the lessee. In understanding any state or federal mineral leasing program it is essential to remember this basic fact: the end product of the whole process is a lease binding the government as lessor and the developer as lessee. We are accustomed to thinking of regulations as governing citizens directly, but the mineral leasing regulations are nothing at all like, say, the Selective Service regulations. The regulations may require, for example, an annual rent of not less than $1 an acre, but the lease offered by the government may require an annual rental of $6 an acre. Even if no state law requires reclamation of strip-mined lands, a stipulation may be inserted in the lease as offered by the given state requiring such reclamation and setting forth in detail what will be required as compliance, and this binds the lessee not as a matter of public law but as a matter of the private law of his lease. A prospective lessee bids on a lease as offered by the government, and it is the lease the government offers, when signed by the lessee, that is the controlling factor in his access to the lands.

B. Federal Lands

Figure 7-1 shows the multiple aspects of land generally necessary to an understanding of the problems of access to mineral lands. Private lands may be leased or sold at the will of the parties, and state lands may be leased under the provisions of state law applicable in each case, as discussed above. But where the federal government is the proprietor of lands valuable for coal or oil shale, or where (as, for example, under the Stock Raising Homestead Act) the United States has reserved the mineral estate underlying the surface, the land (or mineral estate) may not be alienated under any circumstances. Title will remain in the United States, that is, one cannot buy federal coal lands. Access to coal and oil shale under federal lands may be had only through license, lease, or permit under the Mineral Leasing Laws, principally the Mineral Leasing Act of 1920 and the Mineral Leasing Act for Acquired Lands of 1947, both as amended and amplified by the regulations issued under their authority.

In the days before the Mineral Leasing Act of 1920, access to federal mineral lands was governed by the General Mining Law of 1872. There was a separate act for coal, the Coal Land Act of 1873, which is still carried on the books at 30 USC §§71 et seq., but which has been effectively superseded by the Mineral Leasing Act, as described below. The compilers of the U.S. Code state their doubt that the laws codified as 30 USC §§71 et seq. should even be carried in the Code.) Under the Mining Law (which still governs access to minerals other than those specifically mentioned in the Mineral Leasing Act*) land "chiefly valuable for minerals" was reserved from sale or distribution under the

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*The Mineral Leasing Act covers coal, phosphate, sodium, potassium, oil, gas, oil shale, native asphalt, solid and semisolid bitumen, and bituminous rock (including oil-impregnated rock or sands from which oil is recoverable only by special treatment after the deposit is mined or quarried). 30 USC §181

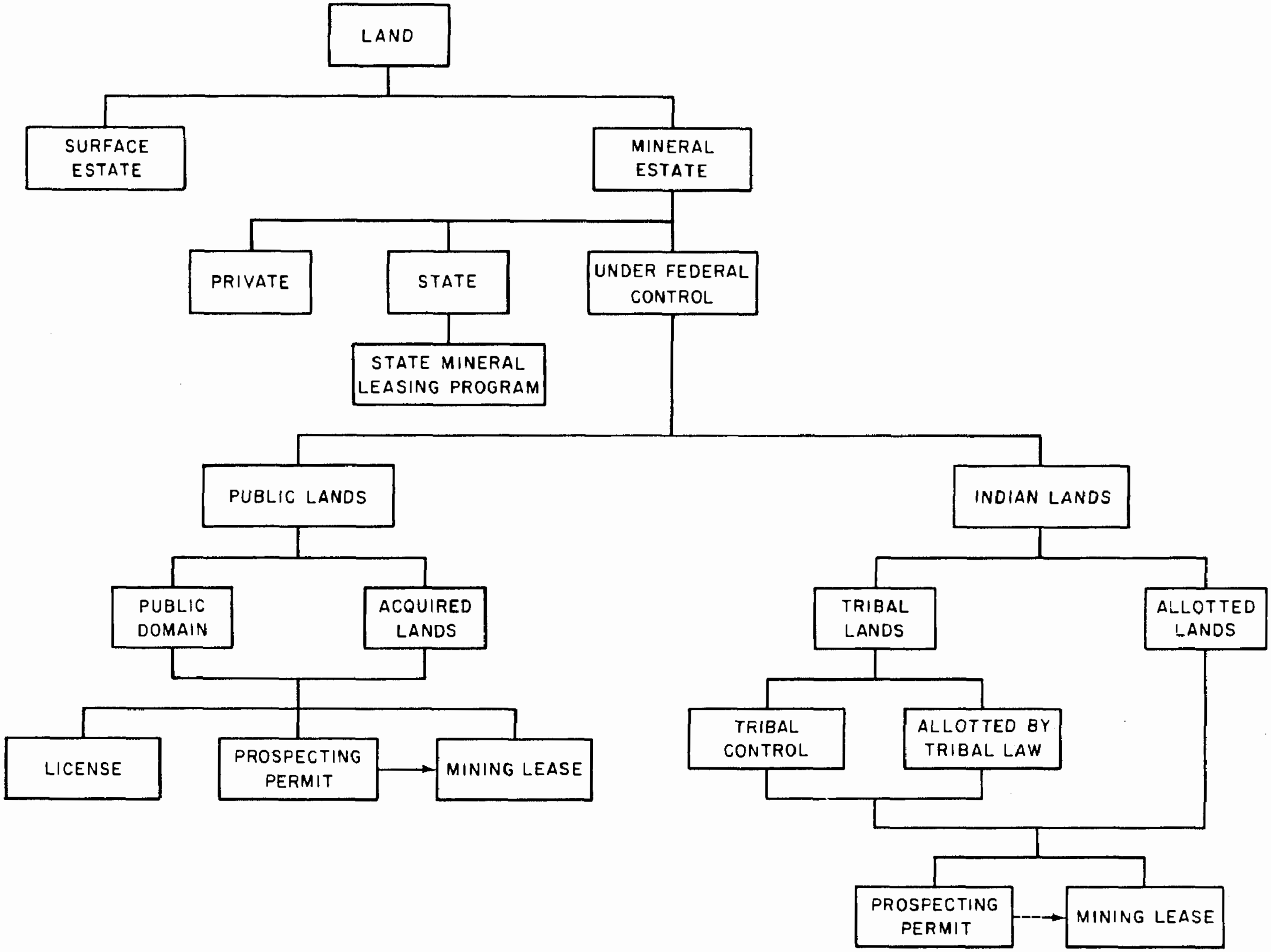

FIGURE 7-1. MECHANISMS OF LEGAL ACCESS TO MINERAL ESTATES

general land laws. Entry for prospecting purposes was, however, generally permitted at will onto public lands. When a prospector discovered a mineral deposit, he could file a mineral location or claim. He was then entitled to the exclusive right to extract the minerals and dispose of them as his own even though he did not hold title to the land. This practice had its origin in the customs of the early western miners, whose customs in the absence of any other law in the mining camps of those days took on the force of law themselves and were more or less recognized and legitimated by the Mineral Location Act of 1872. Although the Coal Lands Act of 1873 differed from this model in some respects, it was similar in approach, and because it is no longer in use, and because the change to the current leasing system was made with reference to the philosophy of mineral development exemplified in the 1872 Act, this part of the discussion does not attempt to distinguish between the practices under the 1872 and 1873 laws.

A prospector who filed a mineral location under the old law had an exclusive right of possession of the surface of the land included within his location, and the right to the minerals beneath it. There were certain limits on acreage covered by each claim (although there was no limit to the number of claims each prospector could file), and to protect his rights against those of a subsequent locator, a certain dollar amount of improvements was required of him to ensure that the mineral deposits were in fact developed and not simply held for speculative purposes. But as long as he was engaged in mining activity, the fruits of his labor were available to him without charge.

Title to land worked under a mineral location remained in the United States unless an application was made for a patent. Frequently, since the location was sufficient to secure exclusive possession of the surface and access to the minerals beneath it, miners proceeded under these locations until their mines were worked out, at which point they simply abandoned their claims and moved on. If, however, a miner wishes to acquire title to the lands from the government, he could do so easily. His proof of mineral discovery (which he needed in any case for his location) and proof of improvements totalling $500 in five years usually sufficed to secure him, if he wished, a patent on the lands. In return for $2.50 an acre for placer claims, and $5.00 an acre for lode claims, the United States would patent to the miner a fee simple estate (absolute ownership) in the lands.

The purpose of these liberal mining laws was to encourage the development of the mineral resources in the public lands of the West. But in the early years of the 20th century it began to be called into question whether this encouragement was any longer needed, whether this policy of permitting almost unlimited transfer of public mineral lands was any longer serving the public interest. At the time, the conservation movement was gaining political power in the United States. In addition, there were massive oil strikes in California, all of which were subject to patenting under the Oil Placer Act of 1897. The freedom given all citizens, discoverers of oil and (under the Oil Placer Act) those who had sense enough to file locations on land adjoining known strikes, promised a rapid transfer of the California oil fields into private control. In 1909 the Director of the U.S. Geological Survey (USGS reported to the Secretary of the Interior that at the rate public oil lands in California were being located and patented by private parties, it would

> "be impossible for the people of the United States to continue ownership of oil lands for more than a few months. After that the government will be obliged to repurchase [for the Navy and other government purposes] the very oil that it has practically given away."

The Director of the USGS asked that the filing of claims on the California oil lands be suspended pending legislation on the subject. On September 27, 1909, President Taft issued a proclamation "in aid of proposed legislation" withdrawing over 3,000,000 acres of public domain oil lands in California and Wyoming from location, entry, or disposal under the mining laws. There was some question of the constitutionality of the executive withdrawal of public domain lands from entry and location* and authority was sought and obtained from Congress for this sort of withdrawal. The law granting this authority was known as the Pickett Act (43 USC §§141-3).† The Pickett Act gave to the President authority

> "at any time in his discretion, temporarily [to] withdraw from settlement, location, sale or entry any of the public lands of the United States. . .and reserve the same. . .for public purposes. . .and such withdrawals shall remain in force until revoked by him or by an Act of Congress."

During the years 1910-20, most of the public domain land was withdrawn by executive action from location for nonmetalliferous minerals, and there was a vigorous debate in the Congress on what the new federal policy should be in this area. In 1920 it was decided and enacted that public domain land valuable for coal, oil, phosphate, oil shale, gas and sodium should be developed only by lease, reserving title (and such control over its development that the leasing method would provide) to the United States, rather than permitting the alienation of mineral lands by patent. From the enactment of the Mineral Leasing Act on February 25, 1920, forward, the older Mining, Coal, and Oil Placer Acts ceased (except in situations relating to claims filed before enactment) to have application to coal and oil shale development, and the Mineral Leasing Act

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*Resolved in favor of its constitutionality in United States v. Midwest Oil Company, 236 U.S. 459 (1915).

†(The constitutionality of the Pickett Act has never been decided by the Supreme Court, but the Attorney General has ruled in its favor, 49 Op. Atty.Gen. 73 [1941]. Especially in light of the Midwest decision cited, however, there is not really any serious doubt of the constitutionality of withdrawal of public mineral lands.)

became the keystone of the law relating to development of coal and oil shale on the vast public domain.

The phrase "public domain" requires some explanation. It will be noted in Figure 7-1 that a distinction is made between public domain land and acquired lands. The Mineral Leasing Act of 1920 itself only covers public domain lands, which are not coextensive with the lands owned by the federal government. Public domain lands are those lands to which title has never been in state or private hands since the land became subject to United States sovereignty by conquest or treaty, but which have been in federal ownership since the beginning of American dominion.* A great portion of the lands in Montana, Colorado, and Wyoming are public domain lands, never having been alienated by the United States. The Mineral Leasing Act of 1920 also applies to the mineral estate of public domain lands where the surface estate was severed and conveyed but the mineral estate retained, as was the case under the Stock Raising Homestead Act.

West Virginia, on the other hand, was formed from Virginia during the Civil War and Virginia was one of the original states. <u>Title</u> to (as opposed to sovereignty over) nonprivate land in Virginia was not originally in the United States, having been transferred from Crown to Commonwealth at the time of independence or before. There are, therefore, no public domain lands in West Virginia.

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*Lands that were in private ownership at the time of cession to the United States remained in private ownership; sovereignty changed but proprietorship did not. In some cases, however, depending on the law which applied before cession, only the surface estate was in private ownership and the mineral estate, or part of it, was in the possession of the former sovereign and therefore passed to the United States and is in the public domain. This is an intricate problem of title which has to be resolved on an individual basis for the lands in question.

The situation whereby the Mineral Leasing Law, and its underlying policy, applied to some federal lands and not to others was an anomalous one to say the least, and it was cured by the passage of the Mineral Leasing Act for Acquired Lands (30 USC §§351 et seq.) in 1947. Under the Mineral Leasing Act for Acquired Lands, provision is made for lands acquired by the United States in other ways to be administered and leased in the same way as are public domain lands.

There are several surviving applications of the difference between public domain lands and acquired lands for federal mineral leasing purposes. First, not all acquired lands are covered. As with public domain lands, some lands are excluded from disposition under the Act, including lands in incorporated cities, towns and villages, lands in national parks or monuments, lands in military petroleum or oil shale reserves, etc. Lands acquired for development of their mineral deposits and land acquired by foreclosure or otherwise for resale are excluded from the Acquired Lands Act. Also, there are certain technical differences in the wording of the two Acts. For example, the 1920 Act excludes "lands within the naval petroleum and oil shale reserves," whereas the Acquired Land Act excludes "lands set apart for military or naval purposes, including lands within the naval petroleum and oil shale reserves." It therefore becomes important, if there is coal discovered beneath some vast military gunnery range in Utah, whether the lands are public domain (in which case they would be subject to leasing under the Act if the decision was made to switch the use of the land from gunnery to mining) or later acquired (in which case they would be excluded from the leasing program by the language of the statute). These are concerns that matter only as to individual tracts, but the distinction is still important for this reason.

Second, acquired lands may be sold. This is not to say that patents can be awarded as under the old system, but public domain lands chiefly valuable for Leasing Act minerals may not be sold.

Third, acquired lands are frequently under the jurisdiction of some agency of government other than the Bureau of Land Management. If that is the case, the head of the government agency having control over the lands is to be called to report whether he has objections to the lease being granted. If he recommends a special stipulation be inserted into the lease to protect the interest of the United States, that will be done. If the lands are segregated for a special purpose, that purpose is to be considered the dominant purpose of the land, and mining operations under lease will be permitted only insofar as they are consistent with the primary purpose of the land. The point is that acquired lands acquired for mineral purposes are excluded from the application of the Mineral Leasing Act for Acquired Lands, and acquired lands acquired for some other purpose may well be being used for that other purpose or at least be administratively segregated for another purpose, and fall under the jurisdiction of some other agency, in which case additional steps must be taken to involve the administering agency in the terms of a proposed lease, to protect the primary purpose of the land, and so on. (Public domain lands may also be administratively segregated.)

Fourth, lands leased under the 1920 Act and lands leased under the Acquired Lands Act are computed separately for purposes of acreage limitations on coal leases, and those held under one Act are not credited against the limitation of the other Act. The acreage limitations for each Act are the same--it is the intention of the Acquired Lands Act that the acquired lands subject to the Act be administered in the same way as the public domain lands--but the separate computation provides a loophole to permit a lessee to go the limit in a given state twice.

Beyond these differences, however, the distinction between public domain and acquired lands does not have much significance. The lines on the chart now rejoin, and we turn our attention to the three methods of disposition--license, permit, and lease--without further reference to the distinction. It should be noted that the following discussion applies to coal only. Although oil shale is a Leasing Act mineral, access to oil shale on federal lands presents special problems and will be dealt with separately at the conclusion of the discussion of coal.

1. Licenses

A license is a permission to enter on land and do something which would otherwise be unlawful--for example, a license to remove coal--which conveys no interest in the land is (unlike a lease) terminable at the will of the licensor. There is provision in the law for licenses to remove coal from public land without charge. These are of no real economic importance as matters now stand, but they merit a brief discussion because the license concept has great potential for federal aid to cities in providing for their own energy needs at no cost to the municipal budget.

43 CFR §3530.0-1, issued under authority of 30 USC §208, provides as follows:

> "Coal licenses may be issued for a period of 2 years [renewable] to individuals and associations of individuals to mine and take coal for their own local domestic need for fuel, but in no case for barter or sale, without the payment of any rent or royalty. [No corporations, except municipal corporations as follows.] Licenses may be issued to municipalities to mine and dispose of coal without profit to their residents for household use. Under such a license a municipality may not mine coal either for its own use or for nonhousehold use such as for factories, stores, other business establishments and heating and lighting plants."

Usually such licenses to individuals or associations are limited to 40 acres, and licenses to municipalities to various acreages are dependent upon their populations. Provision is also made for four-year coal licenses to be issued to established state relief agencies to take coal for distribution to families on their rolls who need the coal for fuel and cannot pay for it.

As the law now stands, the licensing authority is very limited and the Act specifically prohibits municipalities from taking coal under a license for any other purpose than the household use of its residents. If the law were to be changed, however, it could permit licenses to be issued to municipalities to take public coal for municipal purposes--city power plants, street lighting, public buildings, etc. This would amount to a nonbureaucratic, noncash direct grant of energy to muncipalities, and could be of great benefit to them. Whether the utility company lobbies would permit its application is another question. The existence of provision and precedent for coal licenses is something to think about in forming energy policy in the areas in the West where public coal lands are close enough to allow their use.

On February 17, 1973, Secretary of the Interior Morton announced a moratorium on all coal permits and leases, with certain exceptions, to permit the formulation of a new coal leasing policy, primarily with reference to environmental concerns but also, presumably, with reference to other defects in the present system. (The moratorium had been in effect *de facto* since 1971.) This action was similar in intent to the executive withdrawals of the 1909-19 period discussed above, in that it stops most further disposition of the public mineral lands pending development of a program to reflect new policies. Under the moratorium, prospecting permits, one of the two major forms of access to federal coal lands, are not being granted at all, and new coal leases are being offered only where they are needed to maintain an existing operation or where coal is needed as a reserve for production in the near future. In this "short-term leasing program," as it is referred to, the words "short-term" apply to the program and not to the leasing, since under the law, new coal leases must still be for an indeterminate term. But these leases are being offered only on an individually negotiated basis, with extensive environmental stipulations. Very few are being offered at all. The moratorium is expected to extend until the completion and adoption of a programmatic statement on the new coal leasing program. When the new program is completed and approved, it will go into force and the moratorium will be over. The present situation is confused. The new leasing program proposal imposes reclamation and performance standards upon operations mining federal coal. Moreover, there is a bill being considered in Congress that would also modify coal leasing on federal lands. Entitled "Federal Coal Leasing Amendments Act of 1975" (S391), the bill would make six basic changes in the provisions of the 1920 Mineral Leasing Act.

2. Permits

Under the premoratorium system, prospecting permits were awarded in the following way. To begin with, as with public land leases there was a requirement of citizenship. This is not likely to change. Under the Mineral Leasing laws, prospecting permits and mining leases could be held only by U.S. citizens. They might be held by such citizens individually, in associations (if the federal or state laws under which the association was formed and the instrument establishing the association permitted it), or by corporations (subject to the same restrictions).

An alien might participate only as a stockholder of a corporation, and then only if the country of which the alien was a citizen afforded reciprocal rights to U.S. citizens.

Once this requirement was satisfied, the Secretary of the Interior was authorized to issue prospecting permits to qualified applicants (by which was meant applicants who met the citizen requirements, did not hold permits or leases in excess of the acreage limitations, were in fact capable of performing prospecting operations, etc.). The purpose of the permits was to allow entry and prospecting for coal on unclaimed and undeveloped areas of the public lands. Since that was the purpose of the prospecting permit, permits were not granted to prospect areas where the minerals sought were already known to exist in workable quantities.

Permits were issued to prospect areas in 40-acre units not in excess of 5120 acres (eight square miles), or for an amount not to exceed 36,080 acres in combination with other permits and leases in a single state. The permit ran for two years and could be extended for up to two additional years if necessary. Coal lands did not have to be surveyed for prospective purposes, but could be described by metes and bounds, the actual surveying to be done at the expense of the government. The two-year permit granted the permittee an exclusive right of entry and prospecting in the permit area, although no coal was to be removed other than what was needed for experimental purposes or to demonstrate the existence of commercial quantities of coal. A plan of operations had to be submitted and approved. Permit tracts had to be contiguous or at least reasonably compact in form. An advance rental fee was required of not less than 25¢ an acre for the first year, and 50¢ an acre for the next year (or years, if the permit was renewed). There were, of course, no royalties, because no coal was to be extracted for commercial purposes.

As with ordinary mining leases, if the lands were under some other authority than the Bureau of Land Management, stipulations required by the other authority to protect the primary purpose of the land were to be inserted in the permit. (To protect the interests of the United States as potential royalty-owner in the most economical and fruitful development of the lands, there was also required a demonstration that there was a need for additional coal which could not otherwise be met, and that a new coal mine was needed in the area. In practice, however, these additional need requirements were not enforced.)

If, during the two-year period of the permit (or its extension), the prospector demonstrated that he had found coal deposits in his permit area sufficiently extensive and workable to permit commercial exploitation, he was entitled as a matter of right to a regular mineral lease. This was called a preference right lease, and was the incentive and the payoff for prospecting. The concept of the preference right lease is under great criticism at the moment. Among other objections, it is contended that it deprives the government of the bonus it could otherwise expect if it were to conduct a competitive offering, that it is not necessary to the encouragement of prospecting (the price of coal being on the way up), and that it locks up more land in the leasing program without sufficient government control. Preference right leases are not awarded on the successful conclusion of prospecting under a prospecting permit on Indian lands.

During the moratorium, no new prospecting permits have been awarded and the future of the system is in doubt. Since the preference right is included in the law (30 USC §201[b], either the law will have to be changed or the department can simply adopt the policy of denying applications for prospecting permits in the future as it has during the moratorium. This can be justified on the ground that there are already great areas of public land under coal lease that are not producing coal and that there is at present no need to look for more. It seems likely that the present prospecting permit system will not be a major practical factor in the new leasing program. However, at the moment at least 147 preference right applications are filed and pending, and it is more than questionable, if they meet the requirements of the law, whether they may legally be denied.

The leases awarded under a preference right were, except in the manner of their awarding, similar to ordinary mineral leases to which we now turn our attention.

3. Leases

Procedure. Again, the law and the regulations bind the government, but it is the lease that binds the lessee. Federal coal leases (other than preference right leases) are offered on a competitive basis by advertising the lease it is proposed to offer in a local newspaper of general circulation in the county where the lands lie. The terms of the lease are set forth in the offering and are not subject to negotiation; the competitive bidding has reference to a "bonus" bid that is for the privilege of signing the lease. These leases may be offered either on the motion of an applicant or on the motion of the Bureau of Land Management (BLM), but it appears that in the entire history of the coal leasing program there has never been a Bureau motion lease sale. It has been the practice in the past to await a request from the industry and then to offer the area the industry asks for. A great proportion of "competitive" lease sales did not attract more than one bidder. Sometimes sealed bids were solicited, and sometimes the lease was sold at public auction; latter practice permitted even the original applicant not to bid and to have the lease awarded without paying any bonus at all. Sometimes the two methods were combined. Of course, the awarding of these leases was discretionary, and the right of the Secretary to reject even the highest bid is preserved in the law, but according to the figures in the Council on Economic Priorities' (CEP) Leased & Lost, single-bid and no-bid awards were not uncommon, and there is an inverse relationship between number of bidders and amount of bonus. The frequently noncompetitive nature of the competitive bid process, the awarding of leases without bonus, and the practice of offering leases on industry demand are all matters which, it can be expected, will be reviewed by the department. Although these practices may well continue as a matter of fact, their continuation should not be counted on in the new leasing program.

Duration. 30 USC §207 sets the duration of federal coal leases as follows:

> "Leases shall be for indeterminate periods upon condition of diligent development and continued operation of the mine or mines, except where such operation shall be interrupted by strikes, the elements, or casualties not attributable to the lessee, and upon the further condition that at the end of each twenty-year period succeeding the date of the lease such readjustment of terms and conditions may be made as the Secretary of the Interior may determine."

This means, essentially, that "coal leases are forever." The requirement of diligent development and continuous operation has not been enforced in the past, although this is likely to change under the proposed rules discussed below. Twenty years must pass before even such basic matters as rents and royalties can be adjusted to conform to current economic conditions. A lease may be surrendered, with the agreement of the Secretary of the Interior, but the government may cancel it for nonperformance of terms only by bringing an action against the lessee in federal court, something which apparently has never happened in the history of the coal leasing program. The result of the indeterminate term and the nonenforcement of the diligent development and continuous operation requirements has been that very large numbers of coal leases, including those awarded under the preference-right system, are not producing coal. The land is being held unproductive. The Council on Economic Priorities believes that a lot of this is due to developers holding the land for speculative purposes, waiting for the price of coal to rise. Vice-President William Hynan of the National Coal Association takes violent exception to this. He says (and his point is supported by CEP Leased and Lost figures, pp 36-47) that a lot of these leases were awarded in the 1960s, and the time it takes to go from lease to producing mine is quite long. He says that at the time a lease is executed (other than a preference right lease) the developer does not really know where the coal is, or even where to look. This seems surprising, since competitive leases are supposed to be offered on land where the USGS has determined there is coal. Nevertheless, Hynan says that extensive exploration is required, and that before a mine can be operated economically 35 years' worth of coal reserves have to be located, and that in some cases the remoteness of the coal fields requires construction of railroad spurs up to 60 miles long. The whole question of nonproductive leases is the result of ignoring the "diligent development and continuous operation" requirements of the law and the leases which include these requirements. It is an indication of how seriously these requirements have been taken over the years that no definition of "diligent development" or of "continuous operation" had been thought necessary for 54 years after the passage of the act.

New rules were proposed by the BLM in the Federal Register on December 11, 1974. If the new rules are adopted, they will clarify these definitions, and more conscientious applications of the rules can be expected. The original closing date for comments on the new rules was January 10, 1975, but it was extended on January 14 to February 3. Bureau of Land Management deliberations pertaining to these regulations must now be underway. Mr. Hynan of the National Coal Association objects to the new rules. The scheme the new rules propose for enforcement of these statutory lease terms seems to be a sound one, however little it appeals to coal companies holding unproductive leases, and while it is not possible to predict the outcome of the political process involved in making these proposed rules effective, a statement of the proposed new system will probably be a fair guide to what the new system will be.

Under the new system as set forth in the proposed rules, within two years of the effective date of the new regulations, all federal coal leaseholders must have their leases included in what will be called a "Logical Mining Unit" (LMU). An LMU is defined in the new regulations as

> ". . .a compact area of coal land that can be developed and mined in an efficient, economical and orderly manner with due regard to conservation of coal reserves and other resources and in accordance with an approved Mining Plan."

An LMU may include one or more federal leaseholds and intervening or adjacent nonfederal coal lands under the effective control of the same operator or joined by an approved contract for collective development. Future leases will be predicated on the LMU concept, and existing leases must, within two years, be transformed into LMUs unless that proves impossible, in which case the existing leases will still be considered as if they were LMUs and will thus be included in the new system. This amounts to a reorganization of the existing leasing patterns, and this reorganization is taken as the opportunity to require a new mining plan to be submitted and approved by the Mining Supervisor of the USGS. "Diligent development" is now defined as

> ". . .preparing to extract coal from an LMU in a manner and at a rate consistent with a Mining Plan approved by a Mining Supervisor. . . ." [emphasis supplied]

and a long list of activities that may constitute diligent development is included in the proposed rule.

> "Activities that may be approved as constituting diligent development of an LMU include: environmental studies, including gathering base-line environmental data and design and operation of monitoring systems; on-the-ground geological studies, including drilling, trenching, sampling, geophysical investigation and mapping, engineering feasibility studies, including mine and plant design, mining method survey studies; and research on mining methods, contracting for purchase or lease of operating equipment and development and construction work necessary to bring the LMU into production. The work performed and the expenditure of monies may take place on or for the benefit of the leased land, or on other lands within the LMU, or at a location remote from the land so long as they are undertaken for the purpose of obtaining production from the LMU." [emphasis supplied]

"Continuous operation" is defined in the proposed rules as

> ". . .extraction, processing, and marketing of coal in commercial quantities from the LMU without interruptions totalling more than six months in any calendar year, subject to the exceptions [strikes, elements, etc.] contained in 30 USC §207 and in the lease, if any."

A coal lease will therefore in the future, as in the past in theory only, be maintained only on a showing of diligent development or, when required by the Mining Supervisor, continuous operation. New leases will be let on the LMU basis, and old leases will be transformed (or will be considered as having been transformed) into LMUs within two years. A mining plan must be submitted and approved. Within 30 days from the anniversary of the establishment of the LMU in even-numbered years (i.e., every two years) the operator must report to the Mining Supervisor his work and expenditures for the period just past and advise him of his plans for development in the two years to come, to meet to the Mining Supervisor's satisfaction the requirements of diligent development (if the mine is not in production) or continuous operation (if it is). The Mining Supervisor is responsible for determining whether the lessee is in compliance with the diligent development and continuous operation conditions of the lease, and, presumably, if he is not, action can be taken to recover on his bond or even to terminate the lease on the ground of failure to perform duties required under it. At the moment a lease may be cancelled only by suit in federal court, but it may be that administrative measures can be devised subject to appeal to federal court. Certainly this is possible by stipulation in new leases.

The intent, and certainly the effect if actually enforced, will be to require all holders of federal coal leases to file an approvable plan for immediate beginning of development of coal lands, to get the plan approved, to do what the plan calls for (under the supervision of the Mining Supervisor) to get the mine ready for production, and then to keep the mine in production in commercial quantities at least six months of the year, all under penalty of losing the lease. If the new rules go into effect and are enforced, the new system has the potential for eliminating the problem of leased tracts being unused and will ensure that leases granted for the development of public mineral holdings will actually ensure such development. It is a very ingenious system in the way it brings existing leases under the new system by requiring their conversion into LMUs.

30 USC §208 permits the Secretary of the Interior, in his discretion, to accept in lieu of the continuous operation provision of the lease, an advance royalty on a minimum number of tons of coal. The regulation issued under authority of this provision allows for a payment of such royalties, less rental in lieu of actual production. Section 2(d) of the standard-form coal lease provides that this minimum royalty be equivalent to a royalty of $1 an acre. Since the rental after the fifth

year is also $1 an acre, and since rentals are credited against royalties, this section of the lease in effect gives the Secretary the authority to forget entirely about the continuous operation provision of the lease. That is what has been done in the past. But it is inconsistent with the policy of the proposed rules to permit this in the future. It will be interesting to see whether the Secretary permits this statutory loophole to be used on an _ad hoc_ basis by holders of coal leases to avoid the requirements of the new system.

All federal coal leases are subject to maximum acreage requirements. No one may hold permits or leases in excess of 46,080 acres in any one state except as described below. Partial interests, direct and indirect holdings, percentage of holdings of corporations holding leases, and the like are all calculated and prorated so that no one holds more than the maximum, except that ownership of less than 10 percent of the stock in a corporation is not chargeable, so that in theory it is possible to hold 9 percent interest in 20 corporations, each holding the maximum of 46,080 acres, and avoid the limitation.

As noted above, acreage held in separate states and acreage held on public domain lands as opposed to acquired lands are computed separately and are not charged one against the other. Applications for leases or permits in excess of the maximum will be denied, and if it is discovered that anyone holds acreage in excess of the limit, the leases or permits on the excess land will be cancelled or forfeited.

Cooperative mining, involving pooling of separate leases by separate leaseholders, is permitted with the approval of the Secretary of the Interior subject to restrictions against apportionment of production or royalty to ensure that the cooperative agreements really are cooperative enterprises for the more economical and efficient utilization of the coal resources. They may be exempted from the acreage requirements by the Secretary of the Interior.

Furthermore, a lessee who wishes to secure leases or permits in addition to the prescribed limit of 46,080 acres in a given state may be allowed additional acreage. He must make a showing that the additional acreage is necessary to "carry on business economically" and that it would be in the public interest to grant him more acreage. His application must disclose any interest the applicant (who may be a corporation) has in other federal or nonfederal coal leases and permits within the state, and the estimated coal reserves he has within the state. Additional permits or leases, if granted, will be in multiples of 40 acres, but not more than an additional 5120 acres. The filing of an application for additional lands will cause those lands to be withdrawn from disposition under the Mineral Leasing laws until a ruling on the application is made. Public hearings are required before the additional lands may be let. The new lease may require a cash bonus higher than that required for the original lease, and/or higher rent and/or royalty, and any additional terms the Secretary may wish to impose.

Moreover, a holder of a lease may apply for a modification of his existing lease to include contiguous coal lands or deposits if the appropriate federal official considers such an extension to be in the interest of both parties to the existing lease. If it is simply a matter of tacking on some odd extra land, that is one thing, but if it appears that the lands sought to be included in the modification are capable of independent operation, and that there is a competitive interest in them, those lands are supposed to be offered on a competitive basis.

If a showing is made by a lessee that within three years the deposits of coal in a given 40-acre tract covered by a lease will be "exhausted, worked out, or removed," an additional tract may be leased. An application must include a proposed plan of operation, method of entry, and an estimate of recoverable reserves. Upon a determination that the proposed additional lands constitute an acceptable leasing unit, they will be offered on a competitive basis and if the applicant is the successful bidder and the new lands can practicably be operated with the lessee's existing leasehold as a single mining operation, the lease may be modified to include them.

Bonds. Under the coal leasing program in force before the moratorium, various bonds were required of holders of federal mining leases. First, there was a "compliance bond" to ensure compliance with the terms of the lease, which for coal was set at $1000 minimum per lease, or $25,000 for coverage of all leases held on a statewide basis, or $75,000 for nationwide coverage. In addition, other bonds could be required in the terms of the lease, including bonds for surface protection in strip mining operations, special bonds for work done on Forest Service lands, bonds to protect the surface interest of a holder of the surface estate under a stock raising homestead patent, and so on. It seems likely that the bonding requirements will be substantially increased, especially with reference to environmental protection, and that the bond will be a substantial factor in access to federal coal lands.

Rents and Royalties. The statutory minimum for rental of coal land is as follows:

For the first year, not less than	$0.25 an acre
For the second year through fifth years, not less than	0.50 an acre
For each succeeding year, not less than	1.00 an acre

Although it has apparently been the practice in the past for the BLM to set rents at the statutory minimum in setting forth the terms of the leases it offers, this need not be the case, and indeed there have been efforts in recent years to set the rates at a higher level. This can be expected to continue, and is especially important when you remember that these terms, once set, are not adjustable for 20 years under present law.

A rental once due becomes a debt to the United States, and the United States can sue for its recovery. Rentals are credited against royalties, which more or less eliminates the problem for producing mines when the rents are set at the statutory minimum.

The statutory minimum for royalties on federal coal leases is 5¢ a ton. Recent practice has apparently been to set the royalties at a considerably higher rate, as follows:

Underground mining: 15¢ a ton for the first 10 years
17-1/2¢ a ton for the next 10 years

Surface mining: 17-1/2¢ a ton for the first 10 years
20¢ a ton for the next 10 years

In addition, government offerings have been made incorporating a royalty calculated as a percentage of the value of the mine run, again differentiated according to method (strip or auger versus deep mining). There is nothing in the regulations to prevent this, and it seems to be a better deal from the standpoint of the United States as lessor, especially in view of the statutory 20-year period that must elapse before lease terms can be adjusted and of the increasing price of coal. Since the terms of a lease are determined by the BLM as offering agency, subject only to the statutory minimum, there is nothing to stop the government from devising other methods of computing royalties such as the sliding-scale royalties now applicable to oil shale. Royalties could be set at a rate inversely proportional to the sulfur content of coal as a way of encouraging extraction of low-sulfur coal. There are all sorts of things that might be done. The statute only specifies a minimum royalty of 5¢ a ton, and the regulations state specifically that royalties are to be determined on an individual basis before a lease is issued. The regulations also require that the leases be conditioned on the payment of the royalty, whatever it is, on a minimum annual production beginning with the sixth year of the lease. The royalty thus fixed may be paid, or could be paid under the system in effect before the new LMU rules come into effect in lieu of the continuous production required statutorily under the lease. But since rentals were required anyway and could be credited against royalties, the net amount paid over the rental on nonproducing leases under the old system often turned out to be very little if at all. Thus, a lessor, for payment of a small amount, could hold onto a nonproducing lease for speculative or other purposes. The new rules should more effectively guarantee genuine continuous operation.

On application by a leaseholder, the Secretary of the Interior may determine that the subject mine cannot be economically operated because of the royalty terms, or he may find that further promotion of coal recovery is desirable. In either case he is empowered under the regulations to waive, suspend, or reduce all or part of the royalties. If the government finds a lessee cheating on the mine run and reporting for royalty purposes less than was actually mined, the lessee is liable to a penalty of twice the royalty on the part withheld.

Assignments and Overriding Royalties. A federal mining lease, or any part of the rights held thereunder, may be assigned or subleased with the prior approval of the Secretary of the Interior, provided the assignee, sublessee, or whoever the succeeding party in interest is meets the requirements of being capable of running the mining operation, being in conformity with the citizenship and acreage requirements, and so on. The arrangement between the assignor and the assignee is a matter of private law between them, as are the arrangement between joint holders of federal mining leases, and the mineral leasing laws do not provide a federal common law to regulate the relations between parties. The supreme Court has held to this effect in Wallis v. Pan American Petroleum Corp., 384 US 63 (1966). There is a requirement, however, that an assignment of a coal lease not create an overriding royalty to be paid by the sublessee to the sublessor in excess of 50 percent over the royalty to be paid to the United States under the primary lease, unless it can be shown that the sublessor has made significant improvements, which justify a higher rate.

Easements. It may be that the land contained within a federal leasehold does not communicate directly with roads or railroads. If the intervening land is also held by the government, it is the policy of the BLM to grant on application an easement over the intervening public lands, for the purpose of building a road or a rail spur or a tramway, etc., subject to stipulations on where the road (or whatever) is to be built, with appropriate environmental restrictions. If the intervening land is is in private hands, it is the government's policy to acquire the easement at government expense and include it in the lease, the thought being that this adds to the value of the leasehold and that this added value will be reflected in the bonus bids. As we have seen, reliance on bonus bids to assure that the government receives maximum or fair economic benefit is not, nor has it been, an effective device. In certain cases an easement will be condemned by the government. In the oil shale leases more recently offered, for example, easements were condemned to make the prototype lease sale easier. This is not ordinary policy, however, but it can be done.

Nondiscrimination in Employment. Federal mining leases are subject to a requirement of nondiscrimination in employment on grounds of race, creed, color, or national origin, as well as various other provisions for the protection of mineworkers (workers must be paid twice a month, there are restrictions on hours worked, etc.).

Adjustment of Terms. The right reserved in the lease (and in the statute) to adjust "reasonably" the terms of the lease after 20 years poses some difficult problems. In the past the practice has been to adjust the terms of the lease to conform to the leases being issued at the time of the adjustment. But as appear likely, the terms of new leases contain rent and royalty provisions considerably above those of the past, and the reclamation and environment restrictions in new leases differ dramatically from those of 20 years ago, there may be some conflict as the meaning of the term "reasonable." Before the expiration of the 20-year term, the BLM may set forth new terms, and the lessee is deemed to have agreed unless he files objections. If he files objections, there may be no compromise possible.

One suggested remedy is for the government to sue for cancellation, and for the lessee to defend on the ground of illegality of the new terms.* This seems cumbersome at best, and has not been done in the past; it seems likely that in most cases administrative appeals channels will provide an acceptable compromise. Since the Secretary is entitled by the lease to adjust the terms subject only to a requirement of "reasonableness," and since courts are very unwilling to find abuses of discretion or unreasonable conduct on the part of responsible officers of government, a lessee would be well advised in most cases to accept the best deal he can get, and if he cannot live with it, to take advantage of the other terms of the law that permit the Secretary to waive royalties or give other indulgences if it appears that the mine cannot be run economically otherwise. As a last resort a lessee can apply for suspension of operations or surrender his lease. It seems unlikely that the department would impose ruinous terms on a lessee in any other than the environmental area. However, should a federal lessee feel that "ruinous

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*Parr, J. F., "Terms and Conditions of Federal Mining Leases," Rocky Mountain Mineral Law Foundation Institute on Federal Mineral Leasing (non-oil and gas), (1971).

terms" had been imposed in the environmental area, he would be unlikely to find relief in the courts because they would be inclined to find the Secretary's action "reasonable."

4. Federal Requirements in Pricing

There exists a provision in 30 USC §187 stating:

> "Each lease shall contain. . .such. . .provisions as [the Secretary of the Interior] may deem necessary to insure the sale of the production of such leased lands to the United States and to the public at reasonable prices, for the protection of the interests of the United States, for the prevention of monopoly, and for the safeguarding of the public welfare."

So let the developers beware: there is a provision that can be used to regulate coal prices. If it is the lease it can be used, and if it is not the lease the validity of the lease is open to question.

C. Indian Lands

The rules governing mineral leasing on Indian lands are essentially the same in outline as those governing mineral leasing on public lands, but differ in several important particulars. Distinction must be made among lands that are tribal lands, owned by the tribe as a corporate or quasi-corporate unit, lands that are allotted to individual Indians, and lands that, although held by Indians, are not subject to restrictions on alienation by the Bureau of Indian Affairs (BIA).

Tribal lands may be leased by the tribal council or other authorized representative of the Indian's tribe, with the approval of the Secretary of the Interior. Indian leases may, with the permission of the Secretary of the Interior, be negotiated separately and privately on an individual basis. This method is coming into increasing favor since it permits lease provisions requiring, e.g., employment of Indians in the construction of mining improvements, building of a health care center for Indians in the area (provisions such as this have been included in negotiated leases in the Southwest), and so on. Concern that the BIA is lax in representing the interests of the Indians in negotiating leases is eased where the lease is negotiated by an informed and hard bargaining representative of the tribal council. In such a case the possibilities are good for the Indians to get something substantial in return for access to the mineral deposits under their tribal land. The potential developer should be aware that much may be required from him, including some form of economic partnership in the production of the mine and his doing things for the benefit of the Indians, which have no counterpart in other mineral leases. It depends, of course, on what the negotiators for the developers and the negotiators for the Indians decide between them.

When the negotiated lease method is not used, the terms of the lease will be somewhat parallel to those of a regular mining lease. The lease tract must be advertised for sale and bids taken for bonuses in addition to the usual rents and royalties. There is a requirement, for a 25 percent deposit in advance, to be forfeited if the lease is disapproved by the Secretary of the Interior (whose agreement is required to all Indian leases) through no fault of the lessor. The lands are held in trust for the Indians by the United States, and the United States acts as lessor of the lands, as trustee. The Secretary may reject the highest bid, if he believes it is in the interest of the Indians to do so. The BIA takes the role occupied in public land leases by the Bureau of Land Management.

Bonds may be required in varying amounts, but these may be reduced with the consent of the Indians if circumstances appear to warrant it and the rights of the Indians will be protected. The schedule is as follows:

Acreage	Bond
Less than 80 acres	$1000
80 to 120 acres	1500
1200 to 160 acres	2000
For each additional 40 acres	500

A "statewide bond" of $15,000 may be offered, even though lands within the offering may be Indian reservation lands which in fact extend beyond state boundaries. Nevertheless, the bonded land may not exceed 10,240 acres. The bond may be increased when the BIA officer in charge feels it necessary.

The lands must be in a reasonably compact form, and no lease may be offered for a tract extending more than one mile along the outcrop. No operator may hold more than 2560 acres, but a combination of leases, or a lease in excess of the maximum, may be allowed if the Commissioner of Indian Affairs finds it in the interest of the Indians and necessary to permit the establishment of thermal electric power plants or other industrial facilities on or near the reservation. He may insert into the lease a requirement of relinquishment if the facilities are not constructed, and may require advance rental and/or minimum royalty as a condition of the lease.

Indian leases run for 10 years, "and as much longer as the substances specified in the lease are produced in paying qualities." In time of war or national emergency, the U.S. government reserves the right to buy all or part of the output of the leased land at the market price. (There are similar provisions in public land leases.)

Unless otherwise authorized, rents are not less than $1 per acre, royalties not less than 10¢ a ton of coal of the mine run, including slack, and there is a required yearly development expenditure of not less than $10 an acre. In the event of discovery of minerals in paying quantities, all advance payments may be credited against stipulated royalties for the year for which such advance payments have been made.

On Indian leases, the rent is due for the period of the lease even if the lease has been surrendered or cancelled. Suspension of the rent is permitted with the consent of the tribe and the Secretary of the Interior "whenever during the primary term of the lease [10 years] it is considered that marketing facilities are inadequate or economic conditions unsatisfactory."

Written permission is required from the U.S. Geological Survey (USGS) to begin operations on an Indian lease. Failure to comply with the terms of an Indian lease or the regulations or orders of the BIA Superintendent or the USGS Mining Supervisor subjects the lease to cancellation by the Secretary and the lessee to a penalty of up to $500 for each day the lessee is in violation. The lessee gets notice and a hearing by the Mining Supervisor, with a right of appeal to the Secretary, but proceedings in federal court are not required as they are in an ordinary federal mining lease.

Assignments are subjected to the requirement that the lessee's entire interest be assigned, and not just a partial interest. In ordinary federal leases partial assignments are permitted.

Leases may be surrendered, subject to proceedings against the bond, and cancelled by the Secretary of the Interior if the lessee is in violation of the terms, or cancelled on application of the lessee if a satisfactory showing is made of provision for the protection and conservation of the land. Prospecting permits are allowed, subject to the same requirement that no minerals may be removed except that quantity necessary for experimental or other such work, but a prospecting permit does not entitle a successful prospector to a preference right lease.

The regulations in 25 CFR Part 171, governing the leasing of tribal lands for mining, may be superseded by tribal constitution, charter, or law issued pursuant to the Indian Reorganization Act of 1934 (25 USC §461-79), or an ordinance issued thereunder. Insofar as not superseded, these regulations apply to all leases not privately negotiated, the validity of which requires the approval of the Secretary of the Interior.

Allotted lands, i.e., those that have been allotted to individual Indians in severalty (alone) are let on much the same rules, with certain exceptions. Permission to negotiate privately is for 30 days only, subject to reasonable extension separately applied for, but privately negotiated leases are still subject to rejection by the Secretary and to being offered for competitive bids. There are slightly different rules for disclosure by corporations who seek leases. Allotted lands are held by individual Indians, and although they are still subject to restrictions on alienation and the BIA is still involved to some extent in the title to the lands, they may be passed on by inheritance, which causes some problems if all the heirs cannot be found. The regulations provide for procedures by which leases of allotted lands can still be auctioned even if all the heirs cannot be located. This makes acquisition easier than if the lands were in private hands, or were in the hands of Indians but not subject to BIA supervision, in which case the usual complicated problem of providing clear title to lands to which all the heirs cannot be found would apply. The rule requiring that assignments of leaseholds be of the entire interest of the assignor does not apply to allotted lands. Other than that, the rules are for all practical purposes the same.

It should be noted that the allotments mentioned here are allotments by the United States to individual Indians. Such lands are not tribal lands. Tribal lands may also be allotted by the tribal council to Indians within the tribal system. Such lands are not allotted lands for the purpose of the law, but these tribal allotments may be leased by the Indians to whom the mineral rights have been so assigned, subject to the terms of the tribal constitution and the approval of the Secretary. Preference is to be given to Indian cooperative associations and individual Indians in making such leases.

When lands are removed from the control of the BIA and restrictions against alienation have been removed, the lands are treated as private lands and neither the Secretary of the Interior nor the BIA is involved at all.

D. Access to Oil Shale on Public Lands

Of the worthwhile oil shale land in the West, 10 percent is in private hands, either because the land is just plain private land or because it was transferred by mining patents or under old homestead laws, which did not reserve mineral rights to the United States. Another 5 percent may or may not have been transferred under patents granted under the grandfather clause in the Mineral Leasing Act covering claims made under the old mining laws before the Mineral Leasing Law came into force. There is, and has been for many years, an incredibly complex debate on the subject of these old claims, some of which do not seem to have been made in compliance with the law in force at the time. The actual result of the dispute is not of major importance, however, since only a small portion of the oil shale land is involved. If the lands return to government hands, they will not be made available for leasing in any event for a long time, as will be seen below. If they are in private hands, either the development will be done by the owners of the patents or the lands, or the use of them, or some interest in them will be assigned by the patentholder on a private law basis.

The remaining lands are public domain lands or Indian lands. These contain the best and richest of the deposits. After the Mineral Leasing

Act went into effect in 1920, there were a few leases given out in the early 1920s, but these have lapsed. In 1930, oil shale reserves on public lands were withdrawn from leasing by Executive Order No. 5327.

The section of the Mineral Leasing Act of 1920, which deals specifically with oil shale is codified as 30 USC §241. There are no regulations issued under authority of this section, and the regulations that do exist under the general authority of the Mineral Leasing Act or other associated statutes scarcely ever mention oil shale. There were regulations initially governing oil shale leasing, and a few leases, since lapsed, were issued in the 1920s. But when some hopeful developers attempted to have some of the land made available for lease in the mid-1960s, the government revoked the regulations. There was another attempt in 1968, as Secretary Udall was leaving office. The Secretary, under conflicting pressures, agreed to accept bids for oil shale leases around Christmas of 1968. However, all of these bids were rejected.

The next attempt was made in 1973, and this was successful. Six tracts were offered, two each in Colorado, Utah, and Wyoming. No one bid on the Wyoming oil shale. The leases in Colorado and Utah went for enormous bonuses. Since there were no regulations covering the oil shale leases, and since the offering of these leases was in the nature of a prototype, the terms of these leases were also the nature of a prototype. The terms were published in the Federal Register of November 30, 1973, along with the order modifying the Executive Order, which had withdrawn the oil shale lands from the public domain. Because this was a prototype program, no further oil shale leases can be expected for quite a few years. The prototype time table is as follows:

● Two years for gathering baseline data and another year for producing a mining plan, as required by the lease	end of 1976
● Two years for study	end of 1978

● Two to three years after study is approved for building of plant	end of 1981
● Two more years for production and evaluation of results	end of 1983.

It is in the nature of a prototype program to see how it turns out before going ahead. This means that it will be 1983 before more oil shale leases will be offered on public lands. This prediction may, of course, be altered by a number of factors. There may be litigation of some sort, which will permit earlier awarding of other leases (although it is doubtful that anyone could sue to be awarded a lease to develop public lands under withdrawal.* There is the possibility that the results of development on private or state lands may accelerate the date on which a sensible decision can be made on the practicality and usefulness of more oil shale leasing on public lands. There also is the possibility that the need or alternative domestic sources of energy may prompt this Administration or another to award more leases without waiting for the results of the prototype program. Even so, with all the environmental requirements, it will be some time before anything can be accomplished on public lands.

Since it is a prototype program, it is questionable how much general application the terms of the four leases actually offered will have. They take up 12 pages of small print in the Federal Register, but they apply only to the parties involved. They are not regulations.

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*See Boesche v. Udall, 373 U.S. 472 [1963], which holds very strongly for the discretion of the Secretary, and effectively removed the word "temporary" in withdrawals as a basis for forcing leases to be issued.

E. Summary of Federal Oil Shale Leases

Although by no means exhaustive, the following summary includes many of the principal terms of the government oil shale leases awarded in 1973. It is essential to remember that these leases were prototype leases and were made on an *ad hoc* basis. There is no assurance whatever that future federal oil shale leases, if any, will follow these terms.

1. Acreage

The acreage is determined by the offering. There were six leases offered, and each one was specific as to the lands included within it. The rules were only one lease to a customer. Since there are no other federal oil shale leases being offered, the question of acreage restrictions has not yet come up.

2. Duration

The leases were for terms of 20 years and for so long thereafter as *production is had* in paying quantities. This is to be distinguished from the intermediate coal lease, in that if the mine is not in production on the 20th anniversary the lease will lapse by its own terms. There is a provision for readjustment after 20 years; this is done by the government proposing changes to which the lessee is deemed to agree if he does not object within a stated time. If he does object, a compromise is to be worked out, and if that is not possible (there are elaborate appeal procedures) the lease can be terminated by either party at that time. There are provisions for suspension and earlier surrender, but cancellation still requires action in federal court.

3. Bonuses

The applicants bid by means of offering bonuses and the leases in fact went for millions of dollars. The bonuses were to be paid in a first installment with the balance to be paid in four equal annual installments. There is provision, however, for crediting improvement costs against the bonuses. Expenses attributable to operations on the leased property in the first three years may be credited against the fourth installment, and credit for expenses so attributable in the first four years not claimed against the fourth installment may be claimed against the fifth and final installment. After that, credits are allowed against minimum royalties, as set forth below.

4. Rents and Royalties

Rent is set at a flat 50¢ an acre and can be credited against royalties for the lease year (the year from one anniversary of the effective date of the lease to another).

The royalty scheme for oil shale leases is very complex. It begins with a division between oil shale obtained by mining methods as opposed to that obtained by _in situ_ methods. For mined oil shale, the basic royalty is 12¢ a ton, varying up or down by 1¢ a ton as the amount of oil recoverable from a ton of oil shale varies up or down from a base of 30 gallons a ton. Thus, at 30 gal/ton, the basic royalty is 12¢ a ton; at 29 gal/ton, it is 11¢; at 31 gal/ton, it is 13¢, etc. In no case, however, is it allowed to go below 4¢ a ton. For oil shale processed by _in situ_ methods, the royalty is 12¢ a ton, and there is a very complicated formula for arriving at the proper amount.

The basic royalty is adjusted as a function of the combined average value per barrel of _all crude oil and crude shale oil produced in Colorado, Utah, and Wyoming_ (the three states in which leases were offered). As the combined average value of all this oil goes up or down a percentage point over the year before, the royalties are adjusted by the same percentage. In this way the royalties are tied to oil on other leaseholds, oil in private production, etc., in these three states. In no case may the royalty go below 4¢ a ton.

Credits are allowed against royalties in the sixth through tenth lease years for expenditures attributable to operations on the lease site not claimed against bonus installments. However, if the facility is in actual production, there is no credit allowed against the first $10,000 annual minimum royalty.

The minimum royalty payable on each tract is set separately and individually in the lease offering. There is one figure for the sixth through fifteenth lease years and another for the years thereafter. This can be excused in whole or in part and for as long as the Secretary decides is necessary if the expenditures necessary to meet the reclamation and other requirements of the regulations exceed those in the contemplation of the parties at the time the lease was signed. There are various discretionary provisions allowing the Secretary to make things easier if necessary. This minimum royalty is, by its nature, payable whether there is production or not, but, as an incentive to get into production early, if there is production prior to the eighth anniversary of the lease, and the royalty payable exceeds the minimum royalty payable in any event as stipulated in the lease, the lessee is excused from payment of one half the royalty in excess of the minimum.

5. Bonds

To begin with, there is a compliance bond of $20,000. Then there is a reclamation bond, set for the first three years at $2000 an acre for spent shale disposal sites and $500 an acre for other areas, and renewable at three-year intervals at a figure to be determined by the lessor as necessary for reclamation and restoration of the site. This may be increased even during the three-year period if there is a change in the development plan, which, in the opinion of the lessor (speaking through the USGS Mining Supervisor), increases the risk and amount of environmental damage. The bond may be released as to land reclaimed and restored to the satisfaction of the government. There is a third bond required in an amount not less than $20,000 conditioned on faithful compliance with 30 CFR Part 231 (Mine Operation Regulations) and 43 CFR Part 23 (Reclamation), the environmental stipulations in the lease, and observation of all federal environmental standards, the development plan, and anything else which might affect the environment. This may be modified as is thought necessary.

A development plan must be filed, setting forth the plan for exploration, development, production, processing and reclamation, a detailed statement of how the lessee intends to comply with the operating and reclamation regulations mentioned earlier, and a requirement that the lessee use "due diligence" to attain, as early as he can in light of the environmental restrictions placed on him, production in an amount equal to the rate on which the minimum royalty stipulated in his lease is computed. The USGS Mining Supervisor looks into the plan, holds hearings on it, and finally, after whatever changes are necessary have been made, approves it. It becomes the basic document; any change in the lessee's plan of operations requires a corresponding change in the approved development plan, etc. There is a requirement of annual reporting of operations.

6. Other Requirements

Other provisions of the oil shale lease require fair employment practices (e.g., hours worked) nondiscrimination and nonsegregation, and one which reserves to the United States the right to promulgate and enforce orders and authorities pursuant to 30 USC §§187 and 189 to ensure sale of mine output at reasonable prices, to prevent monopoly, and "to safeguard the public welfare."

Assignment is permitted at the option of the lessee, subject to disapproval by the lessor only if the assignee is unqualified to hold a lease or unable to post an adequate bond, or where the assigned or retained portion would, in the opinion of the lessor, be too small to permit economic development. Overriding royalties, except where improvements warrant more, are limited to 25 percent over the royalty fixed in the primary lease.

There are provisions covering surrender and relinquishment, disposition of property on termination, protection of proprietary information, and so on. It is a very comprehensive document, not at all like the four-page standard coal lease. It must be remembered that these are prototype leases; future leases, if any, may be quite different.

Following the lease itself, there is a set of "Environmental Stipulations." These consist of about 15 or 16 columns of Federal Register type; the Table of Contents is reproduced as Table 7-1 to give an idea of the scope of the stipulations. The technique of environmental stipulations included by reference in the lease and thus binding the lessee directly as a matter of private law is a very novel and effective one, which may be considered as a coming idea.

Land in state ownership is sold or leased according to the provisions in the appropriate state code governing disposition of state land. Most of the land that comprises the oil shale and coal-rich western states was originally owned by the United States. When these states entered the Union, certain of the public lands in the states were given by the United States to the state governments. The most important

Table 7-1

ENVIRONMENTAL STIPULATIONS TO PROTOTYPE FEDERAL OIL SHALE LEASES

Sec.

- 1 General
  - (A) Applicability of Stipulations
  - (B) Changes in Conditions
  - (C) Collection of Environmental Data and Monitoring Program
  - (D) Emergency Decisions
  - (E) Environmental Briefing
  - (F) Construction Standards
  - (G) Housing and Welfare of Employees
  - (H) Posting of Stipulations and Plans
- 2 Access and Service Plans
  - (A) Transportation Corridor Plans
  - (B) Regulation of Public Access
  - (C) Existing and Planned Roads and Trails
  - (D) Waterbars and Breaks
  - (E) Pipeline Construction Standards
  - (F) Pipeline Safety Standards
  - (G) Shut-off Valves
  - (H) Pipeline Corrosion
  - (I) Electric Transmission Facilities
  - (J) Natural Barriers
  - (K) Specifications for Fences and Cattleguards
  - (L) Crossings
  - (M) Alternate Routes
  - (N) Off-Road Vehicle Use
- 3 Fire Prevention and Control
  - (A) Instructions of the Mining Supervisor
  - (B) Liability of Lessee
- 4 Fish and Wildlife
  - (A) Management Plan
  - (B) Mitigation of Damage
  - (C) Big Game
  - (D) Posting of Notices
- 5 Health and Safety
  - (A) In General
  - (B) Compliance with Federal Health and Safety Laws and Regulations
  - (C) Use of Explosives
- 6 Historic and Scientific Values
  - (A) Cultural Investigations
  - (B) Objects of Historic or Scientific Interest

Sec.

- 7 Oil and Hazardous Materials
  - (A) Spill Contingency Plans
  - (B) Responsibility
  - (C) Reporting of Spills and Discharges
  - (D) Storage and Handling
  - (E) Pesticides and Herbicides
- 8 Pollution--Air
  - (A) Air Quality
  - (B) Dust
  - (C) Burning
- 9 Pollution--Water
  - (A) Water Quality
  - (B) Disturbance of Existing Waters.
  - (C) Control of Waste Waters
  - (D) Cuts and Fills
  - (E) Crossings
  - (F) Road Surfacing Material
- 10 Pollution--Noise
- 11 Rehabilitation
  - (A) In General
  - (B) Management Plan
  - (C) Stabilization of Disturbed Areas
  - (D) Surface Disturbance on Site
  - (E) Areas of Unstable Soils
  - (F) Materials
  - (G) Slopes of Cut and Fill Areas
  - (H) Impoundments
  - (I) Flood Plains
  - (J) Land Reclamation
  - (K) Overburden
  - (L) Revegetation
- 12 Scenic Values
  - (A) Scenic Considerations in General
  - (B) Consideration of Aesthetic Values
  - (C) Protection of Landscape
  - (D) Signs
- 13 Vegetation
  - (1) In General
  - (2) Timber
  - (3) Clearing and Stripping
- 14 Waste Disposal
  - (A) Mine Waste
  - (B) Other Disposal Areas
  - (C) Disposal of Solid and Liquid Wastes
  - (D) Impoundment of Water
  - (E) Slurry Waste Disposal

portions of these grants are the so-called school sections. Land was divided into rectangular divisions by the public land surveys, and such a division six miles by six miles (36 sq mi) is called a township. Each of these townships is subdivided into 36 sections of one square mile (640 acres), and numbered consecutively. Of the sections in each township, it was the practice in these areas to allocate to the new states sections 16 and 36, or two square miles in each 36, to provide revenue for the support of the state school system. These are the school sections; they comprise a major portion of the state lands in these states. (No such system, of course, existed in coal-rich West Virginia, which is not a public land state, but which was formed from Virginia during the Civil War.) The administration of these and other public lands in the states are under the jurisdiction of State Boards and Land Commissioners (there are various local practices), who have the authority under certain restrictions to lease state lands for mineral purposes.

F. State Lands

1. Colorado

The disposition and control of state lands in Colorado is vested by the state constitution in the State Board of Land Commissioners, who have the right to sell, lease, or otherwise dispose of state lands, whether derived from the school sections or not. It has been the policy in Colorado since 1911 not to sell mineral rights to state lands, but to make them available only through lease.

Coal. The rules for leasing state coal lands are as follows. Prospecting is permitted only with the approval of the Board. Leases are issued by the Board on application, and the Board may, of course, reject any application. The regulations specify that leases are to be issued only "in the name of one party" unless there is a specific provision of joint tenancy with right of survivorship. While on the face of it, this might raise a question as to the eligibility of associations and corporations, the statutes make regular reference to such organizations.

Leases are let in 40-acre units. The amount of acreage to be included in a single lease is subject to limitation by the Board, but there is no limitation on the number of leases that any one party can hold. If the surface is already leased (for grazing purposes, for example), the Board can, and often does, cancel that surface lease.

Leases usually run for ten years, subject to renewal; renewal is at the option of the Board and is not a right. If, however, a mine is in continuous production (by which is meant production not interrupted for more than six months at a time without an extension granted by the Board), the lease is continued in force as long as there is continuous production. Thus, in contrast to the federal system, if a mine is actually producing, the lease will continue in force but if not it will lapse.

Rentals are set at $1 an acre, yearly, and unlike the federal system, rentals are not credited against royalties.

There is a statutory minimum royalty of 15¢ a ton, a ton being defined as 27 cubic feet of coal. Royalties by statute may be adjusted after five years if the royalty is on a fixed (i.e., not a percentage) basis. In practice, however, royalties are now set at 15¢ an acre or 5 percent of the value of the mine run, whichever is greater, so the opportunity for adjustment after five years is not used. The opportunity comes at the expiration of the lease. There is provision for the setting of minimum royalties due, but if in the year following one exceeds one's minimum, one's payment of royalty for *this* year *over* that due on *actual* production may be credited against one's excess royalty payment for the next year.

There is an interesting wrinkle in the statute, interesting for the purposes of the synthetic fuels study. The 15¢ a ton statutory minimum has a statutory exception. If the coal is to be used for the production of chemicals, or synthetic fuels, or power at the plant of operation, and not less than 250,000 tons a year are mined, the Board is permitted to set the royalties at 5¢ a ton instead of 15¢. (If fewer than 250,000 tons a year are mined, the reduced statutory minimum does not apply.) In practice, this provision is not used.

The Land Commissioners require a $2000 bond for the protection of the <u>personal</u> property of the surface owner (cow killed by a truck, etc.). The major bond, and it can be quite substantial, for the protection of the land itself is required by the Department of Natural Resources' Division of Mines.

Assignments are permitted with the approval of the Board, which will then issue an assignment lease to the assignee.

Surrender is permitted in whole or in part.

<u>Oil Shale</u>. There is no oil shale to speak of in Colorado state lands. There is apparently a little in Moffatt County, but it is of such low grade that it is not worth considering commercially. The Piceanse Valley, one of the world's major oil shale deposits, is in Rio Blanco and Garfield counties, and there is oil shale in Mesa, Delta, Montrose, and Gunnison counties as well, but unfortunately for the state of Colorado at the time of statehood this land was part of the Ute Indian Reservation and so no school sections were granted the states in this area, but other, so-called "indemnity" lands in other parts of the state were granted instead. The result is that "The State of Colorado doesn't own

an inch of oil shale."* As a consequence, there is no state oil shale leasing policy or program whatever.

Since the public lands in Colorado are vested in the Board of Land Commissioners by provision of the state constitution and since in theory they can sell whatever they like, there is a provision in the law to get around this. If it appears that certain state lands that have "unique economic or environmental value for the public" are, because of their control by the Board of Land Commissioners (which is now an agency of the State Department of Natural Resources), subject to sale, the Director of the Department of Natural Resources may acquire these lands from the Board by condemnation _via_ an intricate interagency transaction.

2. Montana

Coal leasing in Montana has been under a moratorium since 1971, according to the Mineral Leasing Bureau of the Department of State Lands. The Montana legislature is presently considering new legislation on coal leasing, and until that process is completed there will be no new regulations issued.

The old statute (the one presently in force but not being used) provides that the State Board of Land Commissioners be in charge of the leasing of Montana state lands or mineral estates however acquired, that leases have a maximum length of 20 years, and that royalties be individually set by mine depending on local conditions but in no event to be less than 12-1/2¢ a ton.

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*Tom Bretz: Colorado State Board of Land Commissioners.

3. Wyoming

Lands in the possession of the state of Wyoming may be leased for mining purposes by the State Board of Land Commissioners. There are some lands to which title is held not by the State Board of Land Commissioners but by the Wyoming Farm Loan Board. These lands came into state possession during the Great Depression as a result of foreclosures. Some were resold, but in compliance with the state law, mineral rights were reserved. Depending on ownership, the land (or mineral estate) is leased by the Land Commissioners or the Farm Loan Board, and the regulations make reference to both Boards, but in practice leasing is administered in both cases by the Land Commissioners and action by the Wyoming Farm Board is *pro forma*.

State law provides that any patent of state lands be with a reservation to the state of rights to minerals, whether known at the time or not, along with rights of access for mining or prospecting purposes, so that access to minerals in state lands must be by lease.

The Board has "wide discretion," expressly given in the regulations, to lease to such parties and upon such terms as "shall, in the judgment of the Boards, insure to the greatest benefit to the State."

To qualify as an applicant for a lease, one must be 21 years of age, a U.S. citizen (or have declared the intention to become one), or an association or corporation permitted by law and charter to engage in mining activities. There is no competitive bidding; applicants get priority on vacant land for which they submit lease applications until a decision is reached on their application. If a lease that is not producing comes up for renewal, there is a competition (in which the leaseholder may participate) but it is done on a lottery basis and there is no bonus involved.

Coal. Rents are set at a yearly minimum of $1 an acre, and minimum is what is charged in practice. After discovery of coal in commercial quantity (called "commercial discovery"), rents can be credited against royalties.

Royalties are set by a statutory minimum of 5¢ a ton of the mine run. In practice, however, the Board has adopted a percentage royalty of 7 percent of the value of the mine run, but in no case less than 25¢ a ton.

Acreage restrictions are as follows: A lease must generally be of contiguous or cornering lands, but variances may be granted by the Board if necessary, provided the lands fall within a 6 sq mi area (or six surveyed sections, which amounts to the same thing) in the Board's discretion. Only one class of lands (state lands, school, farm loan lands, or individual institutional lands) may be included in any one lease, and each lease may include no more than 1280 acres (2 square miles). The number of leases any single party may hold is within the discretion of the Board to decide "in the interest of fair trade, proper competition, and prevention of monopoly."

Duration of leases is to be up to 10 years, with a preference right of renewal for additional 10-year periods if the mine is in production. If it is not in production, as stated above, the lease is made available to the leaseholder and other applicants on a lottery basis.

Although the provision of the statute requiring bonds was removed in 1965, bonds may still be, and are still, required by regulation. At present, the bond requirement is a compliance bond of $5000 per lease, or $25,000 statewide. There is also an environmental bond in an amount equal to 100 percent of the potential damage development may do to the land.

Only one producing state coal lease is presently in effect in Wyoming, although there are a million acres leased for prospecting (there is no essential difference between the two prospecting and producing leases for there is no prospecting permit system comparable to the bifurcated federal system. A lease is a lease, and if it produces, it is a producing lease, with royalty and renewal preference rights).

Assignment of lease interests is permitted with the approval of the Board. Overriding royalties (the royalty paid the sublessor by the sublessee), however, are limited to 5 percent over that in the primary lease.

Relinquishment of leases, or parts of them, is permitted. Modification of lease terms while the lease is in force is by agreement between the Board and the lessee. A lease may be cancelled for noncompliance or nonpayment, but there is a right of recourse to the courts.

Oil Shale. At present there is no oil shale leasing in Wyoming, state or federal. The Wyoming Mining Rules and Regulations booklet states on the cover "except oil and gas and oil shale." There has not been any state oil shale leasing in Wyoming for a long time, if ever. The state's primary holds are the school sections, and it seemed unlikely that anyone would be interested in oil shale development of 640-acre plots. The Board of Land Commissioners thought the market for state oil shale lands would be among holders of federal oil shale leases, to tack adjacent lands onto their federal leaseholds. There was excitement about this prospect when the two federal oil shale tracts were offered in 1973. However, the federal oil shale leases in Wyoming did not sell. So everyone drew back to consider what to do next. There are now rules being drafted for oil shale leasing on Wyoming state lands, but they will not be ready until midsummer, 1975, at the earliest. Until then there is no oil shale leasing to be done on Wyoming state lands.

4. West Virginia

Mr. George Wise, the Land Agent with the West Virginia State Land Corporation, states that there is no body of leasing regulation. The Land Corporation uses as a reference the statute itself, Chapter 20 of the Laws of West Virginia. He states that there has been no coal land leased since 1967.

According to Mr. Wise, all applications for coal leasing must go first to the Director of the Department of Natural Resources, who then refers the application to the appropriate Division Chief, if the land comes under his jurisdiction. No mining is permitted in state parks, which means that strip mining is not to be permitted and deep mining is allowed only if the shaft is begun outside the state park boundary and then tunneled underneath. Applications concerning other lands under the jurisdiction of the Department of Natural Resources go to the appropriate Division Chiefs: forests, parks and recreation, and hunting and fishing areas. The State Auditor's Office handles land that has come to the state through escheat or default of taxes. The Highway Department handles lands they control. The Public Land Corporation has title to all land not assigned elsewhere, including specifically land in the beds of navigable streams.

West Virginia state lands are not sold, but may only be leased. And it is provided by statute that all leases must have the written approval of the Governor of West Virginia. In theory, bids are submitted to the Director of Natural Resources (or other responsible officer), who may reject them all or take the highest bid from a responsible bidder subject to the Governor's approval. Unlike the federal system in which all the terms are set in advance by the lessor and the bidder is only for bonuses, in West Virginia the system preserves more of the private law character, and lease bids are considered in their entirety. Thus, one bid may have a higher rent but a lower royalty than another, and this calls for judgment on the part of the Director (or other responsible officer). It is to be expected that when (and if) West Virginia state coal leasing resumes there will be a new set of guidelines on acceptable rents, royalties, and other terms and procedures.

G. Vetoed Strip Mine Act

The Surface Mining Control & Reclamation Act of 1974 contained a fairly comprehensive regulatory system covering surface mining and the surface effects of underground mining of coal. The bill would have had a marked impact on the coal situation had it gone into law, but it was vetoed by President Ford. This year a similar bill has been vetoed, and attempts in the House to override the veto failed. The major provisions of the vetoed bills will be described.

The basic premises were that, climate and terrain and local conditions being what they are, the best way to administer a program governing and limiting the effects of strip mining and mandating and supervising reclamation would be to have it done by the states. Accordingly, the framework that was established provided the states with primary administrative responsibility. The regulatory agencies created by the state were to demonstrate to the satisfaction of the Secretary of the Interior that they were capable of establishing and enforcing programs containing criteria no less stringent than those put forth in the Act. If they did so, then their programs would govern, and they could indeed be more severe than the federal program. If the states were unable to satisfy the Secretary that they could set up programs capable of this enforcement, or if, having set them up, the Secretary determined that the state programs were not properly enforcing the minimum criteria of the Act, he could establish a federal program in the area to preempt state enforcement, and keep it in force until such time as a satisfactory state program was put forth. The Secretary was also to enforce these requirements in federal leasing programs, or on federal lands generally, except Indian lands, which were considered separately. Among the principal elements of the program were stiff and explicit requirements for protection of the environment during the mining, and similarly stiff and explicit requirements for reclamation. The benchmark for restoration was to be the uses the land was capable of supporting before <u>any</u> mining was done on it, whether that mining was done by the present or proposed operator or by someone else 30 years before. It is to be noted that the present BLM regulations in 43 CFR Part 23 (Surface Exploration, Mining and Reclamation of Lands) and USGS regulations in 30 CFR Part 211 and 231 (Operating Regulations) have been or are being revised by the Department to reflect the wording and intention of the vetoed strip mine bills.

The first major reform would have been the removal of supervision and enforcement of surface mining and reclamation procedures from the BLM and the USGS and the placing of them in a new office in the Department of the Interior, to be called the Office of Surface Mining Reclamation and Enforcement. By law, no federal authority, program, or function having as its purpose the promotion of the development of any mineral resource shall be transferred to this office. The idea was to protect the new office from any conflicts of interest.

The states would have had 18 months from enactment to submit a program if they wish to assume exclusive jurisdiction to regulate surface mining and reclamation in their states (this does not include activity on federal leaseholds). The Secretary would have had 6 months to review the program and approve or disapprove it. If he disapproved it, the state would have had 60 days to resubmit, and the Secretary 60 days more to redecide. If a state did not submit a program within the 18 months, or resubmit a disapproved one in the required time, or if the Secretary determined that a state program in operation did not meet the requirements of being able to enforce, at a minimum, the standards for operation and reclamation specified in the Act, he would then put a federal program in operation in that state. There would have been, of course, complicated hearing requirements. A state that did not apply or qualify in time could try for approval at any time; conversely, a state program deemed not to be working could be superseded in whole or in part at any time by a federal program. The idea was to have state programs for those states that want exclusive jurisdiction and can demonstrate that their programs would be sufficient in fact, not just on paper, to ensure that surface mining (and the surface and hydrological effects of underground mining) would be regulated and kept at least within the standards provided in the Act. States would have been quite free, in their own programs, to require a higher standard of performance from operators, but if it appeared that a lower standard would in practice be required, the federal program would have substituted to ensure this minimum compliance. And the "minimum" would not have been easy, either; the criteria in the federal program were rather stiff. A state program would have to incorporate, at a minimum, the environmental protection criteria discussed below, would have to provide sanctions, including bond forfeiture, suspension and revocation of permits, and civil *and criminal* penalties no less stringent than the federal program, would have to demonstrate the existence of sufficient personnel with sufficient expertise to enforce the requirements of the Act, would have to include a permit system that met the requirements of the Act, a procedure for designating areas unsuitable for any surface mining at all, and coordination procedures to prevent federal/state duplication. If it worked, the system would ensure that the *provisions* of the Strip Mine Act applied everywhere without the necessity of direct federal supervision or enforcement if the states would do it (or more) themselves.

Approval of a state program would require the approval of the Administrator of EPA as to air and water pollution regulation, and the input of EPA, Agriculture, and other federal agencies, a public hearing, and a finding by the Secretary that the state had the legal authority and personnel to enforce its program. (There was a provision suspending introduction of a federal program if implementation of the state program was held up by an injunction, such suspension not to exceed one year.)

Permits granted by a state program later superseded by a federal program are valid, but reviewable by the new authority, and vice versa.

Since it was in the contemplation of the Act that the same standards, at minimum, would be enforced by a state program or a federal program, the Act used the words "regulatory authority" to refer either to the federal Office of Surface Mining Reclamation and Enforcement or to an approved state authority, depending on the circumstances. This is helpful word usage, and for the sake of clarity it will be used here.

The so-called Environmental Protection Performance Standards stated:

1. Recovery of the coal is to be maximized so as to prevent the necessity of remining.
2. The land is to be restored to a condition at least fully capable of supporting the uses which it was capable of supporting before any mining was done, or "higher and better" uses if it is consistent with a local land-use plan, etc. The important thing is that an operator could be held responsible for returning land, which was mined before he arrived, to the condition it was in before anyone mined it. In other words, he could be required to leave the land better than he found it.
3. The approximate original contour of the land must be restored. This means backfilling, compacting where necessary because of volumetric expansion of spoil and mine waste, eliminating all highwalls (to prevent isolation of the land above the highwall), getting rid (in specifically approved ways) of spoil piles, depressions (unless needed for water

for revegetation), etc. Mountaintop mining is permitted under certain circumstances. Grading is required until the original contour is restored. If there is too much overburden and spoil, a contour so arranged to prevent slides, erosion, etc., must be created. Drainage of and covering of all acid-forming or toxic substances. A lot of complex technical requirements were given, but the crux was that the original contour must be restored unless there were too much overburden, in which case a contour would have to be created, which did not exceed the angle of repose.

4. Surface areas including spoil piles must be stabilized to control air and water pollution or erosion.

5. Topsoil must be segregated when removed so it (or a superior stratum if one is discovered) may be put on the top when the reclamation begins, and the topsoil or best available subsoil must be stored to preserve it, and it must be put back on the top of the restored contour. If the topsoil has to be segregated for so long that it would deteriorate, it may be necessary to plant vegetation on it to preserve it. It must be kept free of acid or other soil contaminants. The topsoil must be restored when mining is finished.

6. Offsite areas must be protected from slide or damage, and no spoil or waste may be put there.

7. Permanent impoundments of water may be created if called for in the reclamation plan (see below) subject to a number of severe requirements on size, dam construction, quality and level of impounded water, etc. Quality of water of surrounding users may not be impaired.

8. Auger holes must be filled with impervious and noncombustible substances.

9. The hydrologic balance must be preserved by avoiding acid or other toxic mine drainage, preventing contribution of suspending solids into stream flow or runoff above the level as measured before <u>any</u> mining in the area, removing siltation structures from drainways after revegetation, restoring aquifer capacity, protecting alluvial valley floors (if any), and so on.

10. Waste must be disposed of in compacted layers, etc.

11. Surface coal mining within 500 feet of active or abandoned underground mines is not allowed, subject to variances.

12. Groundwater must be protected from acid or other toxic leachates.

13. Conditions lending themselves to sustained combustion must be avoided.

14. The use of explosives is subject to restrictions.

15. Placement of access roads is subject to environmental restrictions (erosion, siltation, damage to wildlife habitat, water pollution, damage to private property, etc.).

16. Drainage channels or stream beds must not be blocked.

17. Regraded areas must be revegetated, using native species if possible, and the operator is responsible for seeing to it that the revegetation takes hold. His responsibility would have lasted 5 years after the last year of augmented seeding, fertilization, irrigation or whatever, or 10 years if the annual precipitation averages less than 26 inches. If the post-reclamation use is intensive agriculture, his period of responsibility would start with the initial planting.

18. Reclamation must be done in an "environmentally sound manner" and as contemporaneously as possible with the mining activity.

19. No debris on the downslope, etc.

This list gives a general idea of the breadth of the requirements; these requirements were stated in a much more complex manner in the bill itself. Certain variances are allowed, subject to restrictions and safeguards, and keyed to the post-mining land use plan. Thus the program was very comprehensive, with enforcement measures built in.

The Act required that, from date of enactment, anyone opening a new or previously abandoned mine must have a permit if the mine is within a state with an existing state program. There were initial regulatory procedures. Beginning with the date of enactment, any mining on a permit granted on or before enactment would have to meet some of the standards of the bill, those relating to restoration to condition capable of supporting before <u>any</u> mining, those relating to restoration to original contour, to segregation of topsoil, to hydrological balance, to water retention facilities, to revegetation, and to deep slopes. Work on permits issued before the date of enactment would have to meet these standards within 135 days. By the time 20 months had elapsed operators must have a permit from the state agency if they contemplate future work under the state program.

Federal or approved state programs would have to provide for random inspections, unannounced, to be held at least every three months. Later the inspection requirements are escalated to every month. It might be pointed out that the Environmental Impact Assessment Project study of the Proposed Coal Leasing Program EIS has noted that there are not enough agents available in the department now to cover even the minor inspection duties currently that would have been required. Although the bill contemplated establishment of a new office, there was doubt that even the new office would be able to obtain sufficiently trained manpower to do the inspection the bill would require. More important, it is equally or more doubtful that the states would have been able to obtain enough inspectors, and if they cannot demonstrate that they would have sufficiently trained people to carry out the requirements of the program they could not have gotten a state program approved, and a federal program would have to have been instituted.

Permit applications would have to have been accompanied by extensive documentation, a lot of it highly technical and expensive. Furthermore, the application fee for a permit under the new system "shall be based. . . upon the actual or anticipated cost of reviewing, administering, and enforcing such permit. . .," which is also likely to have been very expensive.

The strip mine bill also included an ambitious program of restoring abandoned strip mine sites not related to present operations: the scars of Appalachia, and so forth. This was to be paid for in large measure by fees from operators. The reclamation fee was, in the 1974 Act, set at 35¢ a ton for surface mining and 25¢ a ton for underground mining. It is interesting that, first, present operators would have been required to pay to reclaim land the destruction of which they had nothing to do with, and second, that the reclamation standards would have required restoration of the land to its use potential before <u>any</u> mining was done. Thus, in at least these two ways, present operators would have been required to pay for the sins of their predecessors. It is an interesting public policy to require coal operators to clean up a mess they themselves did not create.

An applicant for a mining operation permit under the Act would have had to present a reclamation plan, setting forth past and projected future land use, the capacity of the land to support a variety of alternative land uses, a detailed description of how the reclamation would be accomplished, intricate technical data of many sorts, results of test borings, a timetable, and a host of other information. One of the objections that the coal industry had to the Strip Mine bill was the immense amount of paperwork it would have imposed on them; at almost every step detailed reports and proposals would have been submitted. These would be expensive and would have added substantially to the cost of operating a coal mine.

A performance bond would have to have been posted, which is sufficient to pay for the cost of putting into effect the approved reclamation plan if done by a third party. This includes recontouring, compacting, construction of water retention facilities, revegetation, etc., a very complicated and expensive business. Not only would this have been paid by the operator, but he would also have to post a bond of 100 percent of the cost. Surety premiums can be substantial, especially since the responsibility for revegetation extends 5 or 10 years after everything else is over and the bond can be increased during the term of the permit if necessary. Cumulatively, there appeared to be merit to the industry complaint that this bill would drive up their costs spectacularly.

There were also coal exploration permits, which would have required less elaborate information but which would have required an application fee similar to that described above for operating permits and the written consent of the surface owner.

Another important provision of the bills related to areas unsuitable for surface mining. The federal program provided, and the state programs to be approved would have to have provided, for procedures to declare certain areas unsuitable for any surface mining and therefore to prohibit surface mining at all on the area. On petition by any interested party, which can include agencies of government, areas could be declared unsuitable if the regulatory agency determined that reclamation pursuant to the requirements of the Act was not "feasible." Moreover, if the mining operations themselves would be incompatible with existing land use plans or programs, if they would affect "fragile or historic lands" in which the operations could result in damage to historic, cultural, scientific, or aesthetic values, if the operations could affect renewable resource lands and could result in substantial damage to water supply or food or fiber products or aquifers, or if the lands are "natural hazard lands" (floods, "unstable geology," etc.). In federal lands, the Secretary was directed to survey the federal lands and withdraw from leasing any such unsuitable lands. A public hearing was required. Withdrawn also were coal areas in the National Parks, National Forests, National Wildlife Refuges, National Trails, National Wilderness Areas, National Wild and Scenic Rivers, and National Recreation Areas. Withdrawn also were publicly owned parks or places included in the National Register of Historical Places, if an adverse impact was anticipated, unless the regulatory agency and the agency having authority over the park or place agreed, near roads (subject to permission to move the road), etc. In these areas surface mining permits would simply not be issued at all.

Another provision of interest: although the principal focus of the bills were on surface mining, there was also provision for protection against the harmful surface effects of underground mining. Permits would have to be issued for these effects, too, and would include provision for measures to prevent subsidence, maximize stability, maintain the surface value of the lands, make proper provision for disposal of mine waste of all sorts, keep leachate from the ground and surface waters, revegetate regraded areas, protect the hydrological balance, seal portals, and do various other things, which would be expensive and time-consuming.

Penalties could have been severe. There was a sort of graduated schedule, beginning with show-cause orders, proceeding through cease and desist orders and permit revocation, finally arriving at civil penalties for violations of the Acts, the state or federal program or their regulations, or the lease terms incorporating these restrictions, up to $5000 for each violation, each day being considered a separate violation. These civil penalties might be sought in any violation, but matters of past history, good faith attempts at abatement, seriousness of violation and consequencies, size of business (capability of absorbing the penalty), and negligence could all be taken into account. Hearings and appeals were provided. Willful or knowing violations could lead to criminal penalties, up to a $10,000 fine or a year in prison, or both. For approval, state programs had to include penalty provisions at least as stringent as these. False statements on any application, report, or other document involved in the program could also draw a $10,000 fine and/or a year in prison. There was nothing in the federal mining law up to this point that provided any of these sorts of penalties.

Protection of surface-owner interests: these provisions were defeated in the Senate markup of the latest bill. These would have required the written consent of the surface-owner for any mining of federal coal beneath his land that involved other than underground operations. In addition to this, the developer was required to pay the full money value of the surface-holder's interest as fixed by three appraisers, one appointed by the Secretary, one by the surface-owner, and one by the other two appraisers. The amount began with the fair market value of the surface estate, and then added to loss of income to the surface-holder during the mining operations, the cost of livestock, crops, water and so on, the cost of any other damage that might be done, and an additional amount related to the length of tenure of the surface-owner (uprooting long-established holdings, etc.), not to exceed the amount of the four additions listed or $100 an acre, whichever was less. This amount, if paid in installments, might be adjusted according to increases in the consumer price index. And it appears that the surface-owner would have gotten to keep his title to the surface estate.

To quality for this protection a surface-owner would have had to hold title, legal or equitable, to the surface estate, have a principal residence on the land or personally farm or ranch it or derive a significant portion of his income from such farming or ranching, and he would have had to have met these conditions for three years, provided, however, that if three years had not elapsed the Secretary could hold up putting the land into a leasing tract until the three-year period had been satisfied. This applied only to split-fee lands where the mineral estate is owned by the United States. Consent was not required under this section if the coal was not federal coal. There was also a provision that anyone who offered anything of value to a surface-owner to induce him to consent, or any surface-owner who accepts anything of value for his consent, was liable to a civil penalty of 1-1/2 times the value of the item of value. Consequently, no private deals were permitted. Federal lessees of surface interests (e.g., for grazing) were entitled to protection in the form of a consent requirement and the requirement of a bond against damage to the surface estate.

There were a number of other provisions to the bills of which the most interesting include:

1. Provision, in the case of checkerboards or other closely related federal and nonfederal lands, for cooperation between the state and federal authorities to avoid duplication. Since either one could delegate authority to the other, operators would have only one authority and set of rules and forms to deal with, instead of two.

2. Extensive provisions for hearings, public participation and public standing to sue in many of the stages of the program.

3. Special exemptions and provision for other arrangements for certain bituminous coal mines located west of the 100° meridian, and for anthracite mines, principally in Pennsylvania.

4. Exemption from the Act of people who took coal from their own land for their own use, and commercial operations limited to two acres or less.

5. Exemption of Indian lands from this program, pending a study. The idea of the study was to see if it can be arranged to have the Indian tribes act as states, running their own programs subject to federal preemption in the same fashion as state programs are.

It should be noted that these programs covered only coal, pending a study of extending the program, or devising a different program, for other minerals presumably including oil shale.

H. Existing Environmental Regulations

Three bodies of regulations deal with the environmental impact of coal exploration and mining: 43 CFR Part 23, which details the procedures of the BLM prior to issuance of a lease or permit, 30 CFR Part 211 ff., which details the responsibilities of the USGS for enforcement of the restrictions included in a lease or permit by the operation of 43 CFR Part 23, and 25 CFR Part 177, which covers Indian lands.

The Department of the Interior overhauled the first two of these sets of regulations with the intention of including in them as much as possible of the language of the 1974 Strip Mine bill. The title of 43 CFR Part 23 is "Surface Exploration, Mining and Reclamation of Lands." The principal provisions of the current regulations include the following:

1. No one may explore, test or prospect for Leasing Act minerals in such a way as to disturb the surface of the earth without a permit.

2. In connection with an application for a permit, the District Manager of the BLM must make or cause to be made a technical examination of the effects of the proposed exploration or surface mining on a variety of environmental elements, including:

    - Recreational, scenic, historical and ecological values.
    - Control of erosion, flooding and water pollution.
    - Isolation of toxic materials.
    - Prevention of air pollution.
    - Reclamation prospects, by revegetation, replacement of soil, or other means.

- Prevention of slides.
- Protection of fish and wildlife, and their habitats.
- Prevention of hazards to public health and safety.

3. Based on this technical examination, the BLM District Manager formulates general requirements for environmental protection that must be included in the lease or permit. Participation of other agencies, if they have the primary responsibility for the land, is provided for.

4. The District Manager may limit or prohibit operations on land where "previous experience under similar conditions has shown that operations cannot feasibly be conducted by any known methods or measures" to avoid:

   - Dangerous rock- or landslides.
   - Substantial deposition of silt or sediment into streams, lakes, or reservoirs.
   - Lowering of water quality below levels established by the state water pollution control agency, or by the Secretary.
   - Lowering of the quality of waters that exceed minimum standards, absent a certification that it will not preclude assigned uses of the water and that such lowering is "necessary to economic and social development."
   - Destruction of "key" wildlife habitat.
   - Destruction of "important" scenic, historic, natural, or cultural features.

   Water quality objections bring into force a requirement of consultation with the Federal Water Pollution Control Administration and a finding by them that the proposed activity will not violate the Federal Water Pollution Control Act.

5. Before disturbing the surface to explore, test, or prospect for Leasing Act minerals, an exploration plan must filed and approved by the USGS Mining Supervisor in consultation with the BLM District Manager. The exploration plan must include information on the land, proposed operating methods, and methods proposed to prevent fire,

erosion, pollution, damage to wildlife, public safety and natural resources both during and after exploration activities. There are provisions for negotiation if the plan is not initially acceptable.

6. Before beginning any mining operations under a federal permit or lease, a mining plan must be filed and approved by the USGS Mining Supervisor with the consultation of the BLM District Manager, as in an exploration plan. This proposed mining plan must include much information, including information about the land and

   - A statement of proposed operating methods, with information on proposed roads, trails, and structures.
   - An estimate of proposed water use and pollution.
   - A design for impoundment and treatment of runoff water, to prevent erosion, sedimentation, and pollution.
   - Description of methods to prevent fire, soil erosion, water pollution, damage to fish and wildlife, and dangers to public health and safety.
   - If revegetation is required, a detailed plan must be provided.
   - If regrading and backfilling is required, a detailed plan must be provided.

   There are provisions for negotiations and for approval of a partial plan, and similar administrative measures.

7. A performance bond is required sufficiently large to satisfy the reclamation requirement of the approved exploration or mining plan, but not less than $2000.

8. Elaborate reporting is required of the operator, detailing his progress in performing each of his obligations under the approved plan.

9. There is a provision headed "Notice of Noncompliance; Revocation," which provides for issuance of notices of noncompliance by the USGS or the BLM but does not mention revocation. As noted earlier, revocation of

a federal mining lease is not as easy as perhaps it should be.

10. There are appeals procedures.

25 CFR Part 177 governs Indian lands. It is very similar to 43 CFR Part 23, except:

1. In place of the BLM District Manager there is substituted the Superintendent of the BIA or his representative.
2. This will be superseded, since the Strip Mine bill does not apply to Indian lands, pending a study of the feasibility of having Indian tribes set up their own programs on a par with state programs.
3. There <u>is</u> provision for suspension and cancellation by the Mining Supervisor in case of noncompliance.
4. The Superintendent must consult with Indian landowners on actions he plans to take concerning technical examination, granting or denial of permits, exploration plans, noncompliance actions, etc.

30 CFR Part 211 provides Coal Mining Operating Regulations. It is principally concerned with the responsibilities of the USGS during the process of approval of exploration and mining plans and the supervision and enforcement of the statutes, regulations, and environmental protection restrictions incorporated into the terms of permits or leases. It applies to all federal leaseholds regardless of surface ownership, and to Indian lands. It provides, however, that (except with respect to §211.37, Surface Mining) in case of conflict with 43 CFR Part 23 and 25 CFR Part 177, discussed above, those regulations shall be considered superior to these.

The latest available text is that of a proposed revision, published in the <u>Federal Register</u> on January 30, 1975, but yet to be officially promulgated. This revision is part of the effort mentioned above to bring the existing federal regulations in line with the language of the

Strip Mine bill. Section 211.37 incorporates much of that language, and there are numerous other instances of strengthening of provisions in the existing Part 211.

There seems little point in detailed recitation of the provisions of this Part. Section 211.1(b), however, sums up the purpose of the provisions:

> "The purpose of the regulations in this part is to promote orderly and efficient prospecting, exploration, testing, development, mining, preparation and handling operations and production practices, without avoidable waste or loss of coal or other mineral deposits or damage to coal or other mineral-bearing formations; to encourage maximum recovery and use of coal resources; to promote operating practices which will avoid, minimize or correct damage to the environment--land, water and air--and avoid, minimize or correct hazards to public health and safety; to require effective reclamation of lands; and to obtain a proper record and accounting of all coal produced."

(The last purpose--that of a record--is there because the USGS has the responsibility for assessing and collecting royalties.)

The responsibilities of the USGS Mining Supervisor are enumerated. He is to inspect to prevent waste or damage, and regulate operations to conserve mineral resources. He is to require that operators obey the law and the regulations and conform to the requirements in their lease or permit, and in their approved exploration or mining plans. He is to require that work be performed in an environmentally sound manner, and that reclamation be done as contemporaneously as possible with the mining itself. He is to obtain and check production records and assess and collect rent and royalty money. He is to decide on applications for suspension of operations or termination of suspension (and on Indian lands transmit such applications to BIA officials). He is to determine whether operations that have ceased or that have been abandoned have conformed to reclamation and other requirements. He is to inspect and determine the adequacy of air and water pollution control methods, and require that they be sufficient to meet the requirements of the law, the lease or permit, and the operations plan. He is to determine the amount of reclamation bonds. He is to prescribe or approve methods of protection of water from leakage from wells and prospect holes drilled through coal. He is authorized to issue mining operations orders as necessary to assure compliance with the rules.

There is included in the next section a series of obligations of permittees and lessees, which obligations the USGS Mining Supervisor may also enforce, since they are made obligations by the regulations. Operators must conform with the laws, the regulations, the terms of leases and permits, the terms of approved plans, and the orders and instructions issued by the Mining Supervisor. They must take precautions to prevent waste and damage to mineral formations. They must "take such action as may be needed to avoid, minimize or control" soil erosion, air pollution, water pollution, alteration of water flow, damage to crops, vegetation or timber, injury to fish and wildlife and their habitat, unsafe conditions, damage to improvements, by whomever owned, and damage to recreational, scenic, historical, archaeological, and ecological values. All of which is purposefully vague; it is the responsibility of the Mining Supervisor to determine questions arising under these obligations, and his word is (subject to appeal procedures) the final one. He may issue mining operations orders to enforce any of these obligations as he sees fit ("Don't build the road here, build it there." "Install a mine drainage discharge monitoring device here, here and here," etc.).

There follow a number of highly complex and technical requirements dealing with reporting, maps and plans, requirements for the contents of proposed exploration and mining plans, surveillance wells and blowout control devices, etc. One thing of importance, which is not dealth with elsewhere, is a provision that production must be conducted in a manner to yield the maximum recovery of coal deposits consistent with environmental values, and that a lessee shall not "leave or abandon any coal which otherwise could be safely recovered by approved methods of mining when in the regular course of mining the time shall arrive for mining such coal." This is for the purpose of conserving natural resources, protecting the government's royalty interest, and preventing the environmental consequences attendant upon secondary or tertiary recovery attempts.

There is also provision in this part for such things as permission to mine narrow isolated strips of nonleased coal to prevent their loss, and other similar minor housekeeping matters.

Section 211 deals only with coal. Oil shale is included in the coverage of Part 231. However, there is no need to examine these provisions, which are very similar to those in Part 211, because the only federal oil shale leases that are likely to be let for some time have already been let, with elaborate environmental protection provisions of their own, and the study of the differences between USGS enforcement of coal leases and plans and oil shale leases and plans is not, at this point, very profitable.

It should be noted, however, that both parts of the regulations stipulate that if the orders of the Mining Supervisor are not obeyed, after due notice of noncompliance and so on, the Mining Supervisor may order suspension of operations. Appeals from Mining Supervisors' decisions go to the Director of the USGS (or, on Indian lands, to the Commissioner of the BIA), and from there to the Board of Land Appeals in the Office of Hearings and Appeals in the Office of the Secretary of the Interior.

I. State Reclamation Statutes and Regulations

It seems likely that in the light of federal action, state systems will be revised and/or will be superseded by the federal/state system outlined in the section on the Strip Mine bill. By and large, the state laws do not rise to the level that will be expected of them under the Strip Mine bill. Two things should be kept in mind, however. The first is that in Montana, contour mining is prohibited. The second thing to bear in mind is that in West Virginia the legislature has passed, for the third time in a row, a two-year moratorium on surface mining in counties in which there has been no surface mining in the past. If the Governor has not yet signed the bill, he is expected to.

J. Other Regulations

There are other agencies of government that have impact on coal mining. In addition to the Environmental Protection Agency (air and water pollution standards), there is also the Mining Enforcement and Safety Administration (Department of the Interior), which enforces the Federal Coal Mine Health and Safety Act of 1969. There is enforcement of nondiscrimination provisions of federal leases. These are tax issues. There are state mining safety laws, and requirements for licenses from state authorities to open and operate mines (which are primarily concerned with safety and competence of personnel). There are zoning and local land use regulations. The law on the subject is indeed a seamless web. This paper has endeavored to give the background of coal and oil shale leasing, and has attempted to shed some light on the principal environmental restrictions which affect rights under leases.

8--FINANCING THE SYNTHETIC LIQUID FUELS INDUSTRY BY THE U.S. CAPITAL MARKETS

By Ronald L. Cooper, John W. Ryan,
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A. Introduction

The future outlook for investment in the U.S. domestic energy industry must be considered within the framework of capital expenditure requirements for other sectors of the economy. Capital requirements for the aggregate economy in turn depend on the future growth of the GNP and the rate of inflation.

The discussion in this chapter begins by outlining the framework in which the capital expenditures requirements for the aggregate economy and the domestic energy industry are generated. First, the projections for the aggregate economy are based on the Ford Foundation Energy Policy Project (EPP), A Time to Choose: America's Energy Future,[1] as well as other sources.[2-7] Projections for the energy industry to 1985 rely heavily on the study carried out for the Ford Energy Policy Project by Hass, Mitchell, and Stone.[8] Projections for 1985-2000 are based on the extrapolation of past trends and the 1973-1985 relationships between capital expenditures and energy output. Second, the capital expenditures for the energy industry are discussed for two main scenarios: Historical growth (HG), and technical fix (TF). HG assumes that the growth of energy consumption continues in the future at rates close to historical rates, with little or no conservation. TF assumes a much greater amount of demand conservation which, in turn, significantly lowers the growth of energy consumption over the 1975-2000 period. Under HG, three subscenarios are considered: (1) accelerated development of domestic petroleum supplies (HG1); (2) accelerated nuclear development (HG2); (3) continued heavy reliance on imports of crude oil (HG3). The domestic capital requirements for the energy industry differ for each scenario. Third, the capital requirements of the petroleum industry with and without synthetic fuels are compared to the petroleum industry's sources and uses of funds.

B. Outlook for Total Business Fixed Investment and Other Related Macroeconomic Variables

Business fixed investment represents one use of total savings in the aggregate economy. Other competing uses of savings funds are financing increases in business inventories, residential construction, and federal, state, and local debt financing. Total savings comes from two main sources: business savings, and personal savings of households. Another source of savings, when funds flowing into the country exceed funds flowing out, is net foreign investment. The total sources and uses of savings and investment funds for 1973 are shown in Table 8-1. Projections of the total sources and uses of funds are made for 1975-2000, and funds statements for 1985 and 2000 are presented in Table 8-2 for illustration. Also shown are the cumulative totals for the sources and uses of funds over the 1975-2000 period. The projections are made in two stages. First, predictions of "desired" capital are made for the 25-year period for each sources and uses component. The methodology behind these projections, which covers each category in Table 8-2, is explained in Appendix A, Tables A-1 through A-5. Since the total sources of funds must balance the total uses, Table 8-2 includes both the "desired" and "realized" projections. For each year over the 1975-2000 period, the total use of funds exceeds the total supply of funds on a "desired" basis. The equality between the total sources and uses of

Table 8-1

SOURCES AND USES OF FUNDS--1973
(Billions of Current Dollars)

Sources of Funds		
Business savings	136.5	
Personal savings	74.4	
Net foreign investment	0.1	
Total sources	211.0	
Uses of Funds		
Business fixed investment	136.8	
Residential construction	57.2	
Inventory investment	15.4	
Federal deficits	5.6	
State and local government borrowing	-9.2	(surplus)
Credit agency borrowing	9.5	
Statistical discrepancy*	-4.3	
Total uses	211.0	
Savings Gap	0	

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*The statistical discrepancy arises from the inability to measure the uses of funds with precision.

Source: Reference 6.

funds in each year is accomplished by interest rate adjustments in the capital markets. To eliminate the discrepancy between total investment and total saving, the total sources have been increased by half the amount of the gap, and the total uses have been similarly decreased. The total amounts within the sources and uses are allocated to each component on the basis of historical shares.

Table 8-2

PROJECTED SOURCES AND USES OF FUNDS
(Billions of Current Dollars)

	1985		2000		Cumulative 1975-2000	
	Desired	Realized	Desired	Realized	Desired	Realized
Sources of Funds						
Business savings	$378	$417	$1326	$1453	$14,639	$15,910
Personal savings	139	153	535	586	5,696	6,191
Net foreign investment	0	0	0	0	300	326
Total sources	$517	$570	$1861	$2039	$20,635	$22,427
Uses of Funds						
Business fixed investment	446	408	1623	1492	17,413	16,126
Residential construction	135	123	475	437	5,223	4,837
Inventory investment	27	25	96	88	1,053	975
Federal deficits	4	3	4	3	91	84
State and local government borrowing	3	2	5	5	103	95
Credit agency borrowing	10	9	15	14	335	310
Total uses	$625	$570	$2218	$2039	$24,218	$22,417
Savings Gap	108	0	357	0	3,538	0

Current dollar projections of business fixed investment are converted to constant 1973 dollar projections by dividing the current dollar figure by the projected implicit price deflator corresponding to business capital expenditures. The methodology for projecting the capital expenditures price deflator is explained in Appendix A, Table A-3.

C. Investment in the Energy Industry

Energy investment is projected in Table 8-3 for the five major energy groups--domestic petroleum, electric utilities, natural gas, coal, and nuclear--for 1975-2000 for the three options under the HG scenario. Energy investment projections are also developed for the TF scenario.*

In the reference case, synthetic fuels are excluded from energy investment over the 1975-2000 period. The EPP energy projections are adjusted to exclude synthetic fuels by shifting synthetic fuel entries to the imports category. Table 8-3 shows capital expenditure projections at 5-year intervals for 1975-2000 for the three options under HG. The average annual growth rates of capital expenditures in 1973 dollars for HG1, HG2, and HG3 are, respectively, 4.79, 4.72, and 4.53 percent. The corresponding average annual growth rate for total business fixed investment (Appendix A, Table A-3) over the same time span is 4.3 percent. Thus, because investment in the energy industry under HG is projected to grow at a faster rate than for the economy as a whole, the <u>share</u> of total investment devoted to the domestic energy industry must increase significantly for the projected domestic supply options to be met. Under HG, the increasing shares of energy investment reach a maximum

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*In the Ford study,[1] a third main scenario is considered--zero energy growth (ZEG). However, insufficient information is provided in that study for SRI to develop energy investment projections for ZEG.

Table 8-3

PROJECTIONS* TO 2000 OF CAPITAL INVESTMENT IN U.S. DOMESTIC ENERGY INDUSTRY UNDER HISTORICAL GROWTH: BILLIONS OF 1973 DOLLARS

(Excluding Synthetic Liquid Fuels)

	1975	1980	1985	1990	1995	2000
HG1						
Domestic petroleum and natural gas production and refining	13	18	23	25	28	30
Electric utilities, including nuclear facilities	21	30	42	57	72	87
Natural gas distribution	5	5	5	5	6	6
Coal production (excluding coal for synthetic gas)	2	2	2	2	3	3
Nuclear fuel production	0	2	2	3	5	6
Total	41	57	74	92	114	132
HG2						
Domestic petroleum and natural gas production and refining	13	18	23	24	25	26
Electric utilities, including nuclear facilities	21	31	43	59	75	92
Natural gas distribution	5	5	5	5	6	6
Coal production, excluding coal for synthetic gas	2	2	2	2	2	3
Nuclear fuel production	0	2	2	4	6	8
Total	41	58	75	94	114	135
HG3						
Domestic petroleum and natural gas production and refining	13	14	16	18	20	22
Electric utilities, including nuclear facilities	21	30	42	57	72	87
Natural gas distribution	5	5	5	5	5	6
Coal production, excluding coal for synthetic gas	2	2	2	2	3	3
Nuclear fuel production	0	2	2	3	5	6
Total	41	53	67	85	105	124

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*Appendix B describes the methodology underlying the projections.

in 1995 and somewhat decline between 1995 and 2000. For example, under option HG1, as shown in Table 8-4, the energy share of investment increases from about 29 percent in 1975 to 34 percent by 1995, and 32 percent in 2000.

Table 8-4 shows the increases in the energy share of total investment with the introduction of synthetic fuels for automotive transportation. The synthetic fuels investment projections are taken from Chapter 6.* It is observed from Table 8-4 that the required shares of investment in energy increase much more significantly with the introduction of synthetic fuels. For example, under option HG1, the share of energy in total investment increases from about 29 percent to a maximum of 36 percent in 1995, and then falls back to 35 percent in 2000.

Table 8-5 presents capital expenditures at 5-year intervals for 1975-2000 under the technical fix scenario (TF1). Because of the much greater amount of energy conservation in TF than HG, energy investment requires much lower shares of total business fixed investment.

Under both historical growth and technical fix scenarios, energy industry investment has to increase relative to total business fixed investment because of increased reliance on domestic energy sources. Past growth in energy demand has been met by larger imports while domestic production has declined.

Under all scenarios electric utility investment requires a major portion of the total energy industry investment--roughly 60 percent or more. Therefore, the funds and interest rates available to other industries are quite sensitive to events concerning electric utilities.

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*It is assumed that the production of synthetic fuels for automotive transportation will replace an equivalent amount of crude oil imports, and it will not substitute for domestically produced oil. Table B-3 summarizes the annual synthetic fuels investment for the maximum credible implementation scenario.

Table 8-4

CAPITAL EXPENDITURES FOR ENERGY INDUSTRY COMPARED TO TOTAL U.S. BUSINESS FIXED INVESTMENT UNDER HISTORICAL GROWTH

(Percent)*

		1975	1980	1985	1990	1995	2000
Excluding synthetic fuels	HG1:	29	31	32	33	34	32
	HG2:	29	31	32	33	34	33
	HG3:	29	29	29	30	31	30
Including synthetic fuels†	HG1:	29	32	33	35	36	35
	HG2:	29	32	33	36	36	35
	HG3:	29	30	30	32	33	33

---

*Defined by dividing energy investment from Table 8-3 by "desired" business fixed investment for the appropriate year from Table A-3.

†Annual investment for synfuels from the maximum credible implementation scenario (Table 6-8, Chapter 6) was added to investment in Table 8-3.

Investment required for coal production is less than 5 percent of the electric utilities investment. Since electric utilities are a regulated industry, the government can (through a liberal treatment of rate requests) provide the utilities with an internal source of funds financed by the general public. Thus, while historical financial markets will play a role, the ultimate outcome to financing energy production will be dominated by politically dictated policies.

Table 8-5

CAPITAL INVESTMENT IN U.S. DOMESTIC ENERGY INDUSTRY FOR TECHNICAL FIX SCENARIO (EXCLUDING SYNTHETIC FUELS) (Billions of 1973 Dollars)

	1975	1980	1985	1990	1995	2000
Domestic petroleum and natural gas production, refining, excluding gas pipelines	$13	$17	$21	$21	$22	$22
Electric utilities, including nuclear facilities	21	25	30	34	38	43
Natural gas pipelines	5	5	5	5	5	5
Coal production, excluding coal for synthetic natural gas	2	2	1	1	2	2
Nuclear fuel production	0	1	2	2	2	3
Total	$41	$50	$59	$63	$69	$74

ENERGY'S SHARE OF TOTAL INVESTMENT (Percent)*

Excluding synthetic fuels	29	28	25	23	20	18
Including synthetic fuels†	29	28	27	25	23	20

Note: Appendix B describes the methodology underlying the projections.

*Defined by dividing energy investment from the upper part of the table by business fixed investment for the appropriate year from Table A-3.

†Annual investment for the maximum credible scenario Table A-8 was added to energy investment.

D. Capital Availability in the Petroleum Industry

To assess the impact of synthetic fuels industry on capital markets, the sources and uses of funds within the petroleum industry were calculated for the HG1 scenario with and without synthetic fuels. The analysis was carried out to the year 2000, using the methodology of Hass, et al.;[8] the data and details of the financial relationships are presented in Appendix C. Briefly, the industry assets are used to project the internal sources of funds based on a rate of return after taxes and a depreciation rate. The uses of funds are annual investment and dividends. The annual investment data are shown in Table C-1. Assumptions made in the calculations are as follows:

1. The historical after-tax return applies to new investments as well as existing investments.*
2. Depreciation rates will approximate recent levels as a percent of assets.
3. External funds will be available to maintain historical debt-equity ratios.
4. Historical payout rates will be maintained.

The initial calculations were carried out using constant 1973 dollars for investment and cash flow calculations. The cash flow for the domestic petroleum industry are depicted in Figures 8-1 and 8-2 (see Table C-2 for basic data) for no synthetic liquid fuels and with synthetic liquid fuels. In both cases, after 1985 there are excess funds available, which are assumed to be paid out in dividends. Prior to 1985,

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*This assumes that federal energy policy concerning synthetic fuels will both establish conditions making synthetic fuels as profitable as conventional fuels and also mitigate business risks to the extent that a rate of return on investment higher than conventional fuels would not be justified.

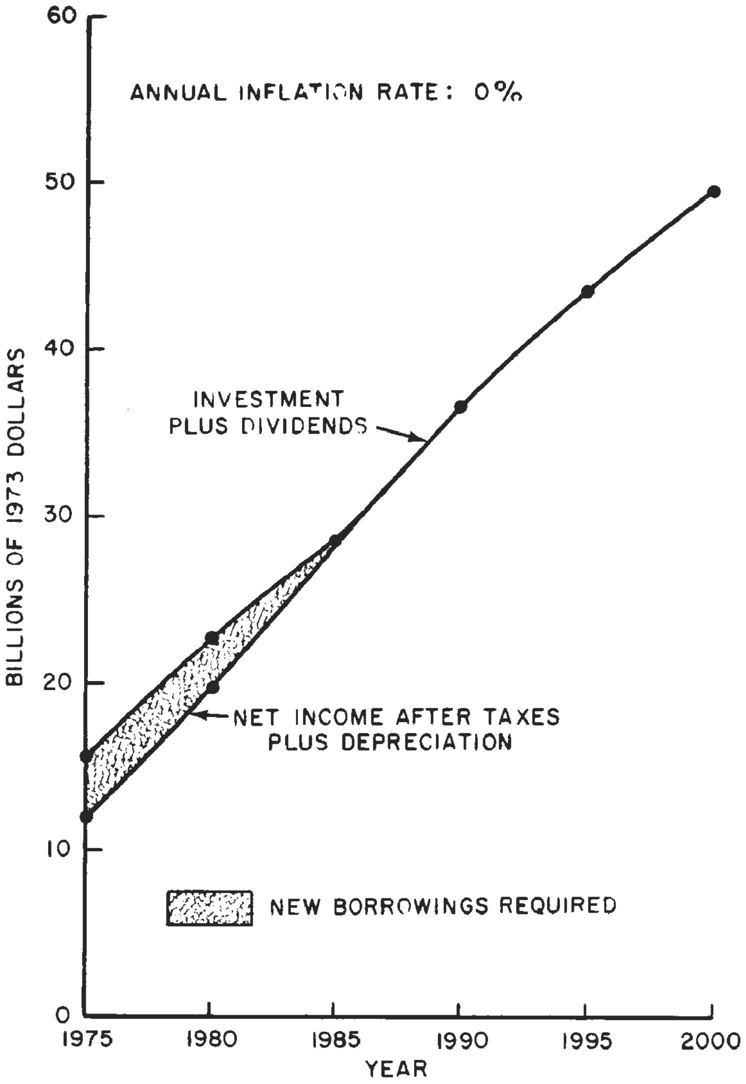

FIGURE 8-1. PROJECTED CASH FLOW FOR DOMESTIC OIL AND GAS INDUSTRY— NO SYNTHETIC LIQUID FUELS—AT A ZERO RATE OF ANNUAL INFLATION

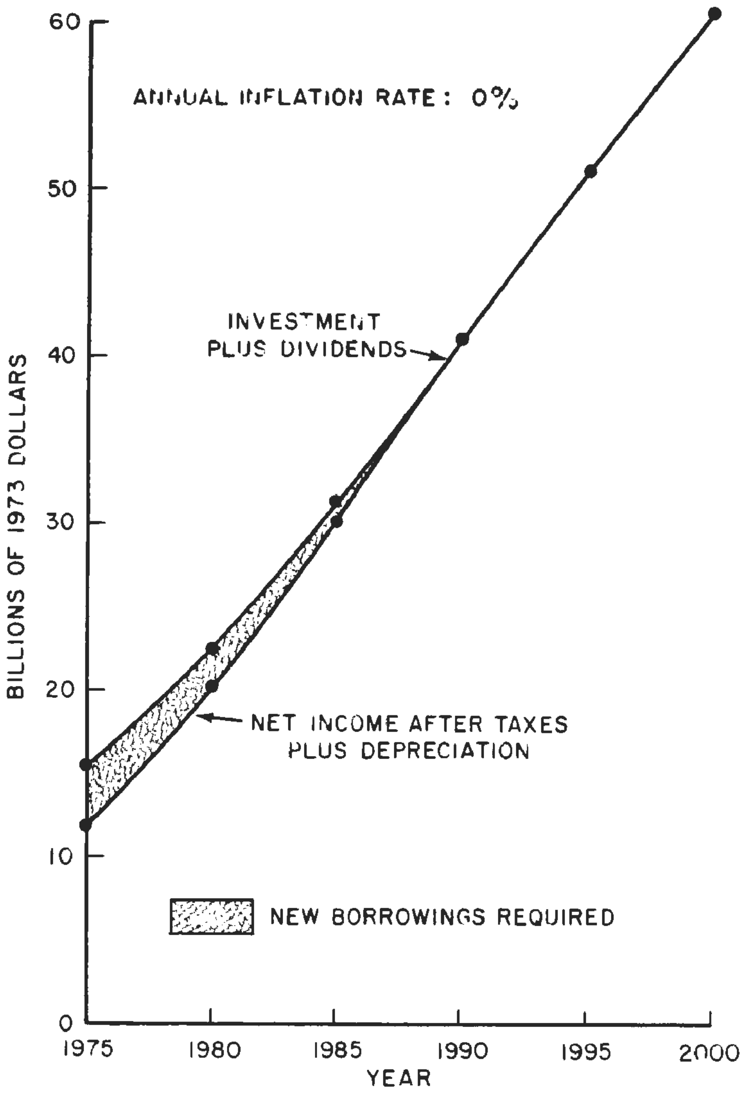

FIGURE 8-2. PROJECTED CASH FLOW FOR DOMESTIC OIL AND GAS INDUSTRY— CONVENTIONAL ACTIVITIES PLUS SYNTHETIC LIQUID FUELS —AT A ZERO RATE OF ANNUAL INFLATION

there is a shortage of internally generated funds shown by the shaded gap between the sources and uses levels in the figures.

This constant dollar analysis implies no large impact of synthetic fuels on capital markets since the petroleum industry generates more cash than it needs. This occurs in spite of the low productivity of assets employed. In 1973, total assets were \$80 billion and output was 45×10^{15} Btu;* according to the balance sheet figures as projected in Appendix C, the productivity of assets diminishes as follows:

	Total Assets	Energy Output	Productivity
1985	\$247 billion	63×10^{15} Btu	0.25×10^{6} Btu/\$
2000	\$417	82×10^{15} Btu	0.20×10^{6} Btu/\$

This implies that the assumptions of a constant rate of return on assets is important, since lower productivity requires more assets which, under constant return, generate more net income as well as more depreciation funds. It is implicit in the rate of return assumption that the petroleum companies are able to maintain prices at a level high enough to generate a 10 percent return on total financing.

The analysis was extended to consider the future flow of funds under inflation at 5 and 8 percent per year. The results show that in an inflationary environment, borrowed funds are needed whether or not synthetic fuels are assumed. Figures 8-3 to 8-6 show the necessary borrowings in these cases. Under 8 percent inflation, the petroleum industry with synthetic fuels must borrow \$58 billion in 2000; however, this

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*A quadrillion (10^{15}) Btu is about 10^{18} J.

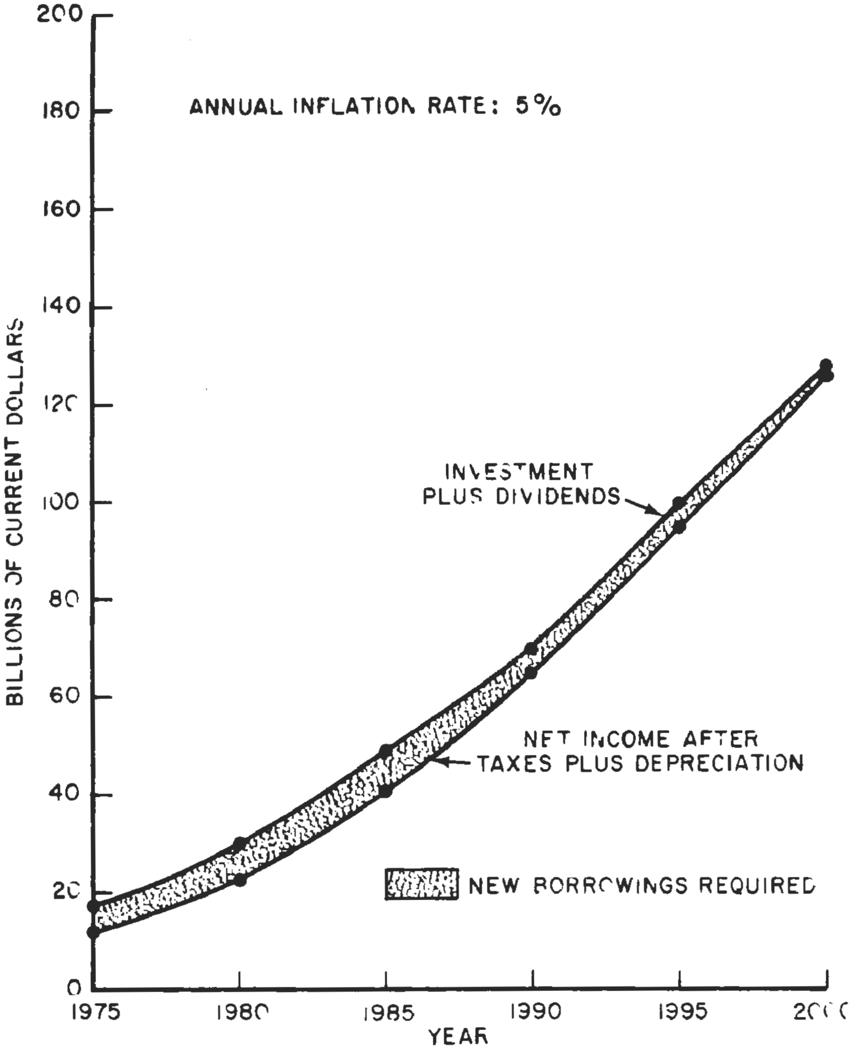

FIGURE 8-3. PROJECTED CASH FLOW FOR DOMESTIC OIL AND GAS INDUSTRY – NO SYNTHETIC LIQUID FUELS – AT A FIVE PERCENT ANNUAL RATE OF INFLATION

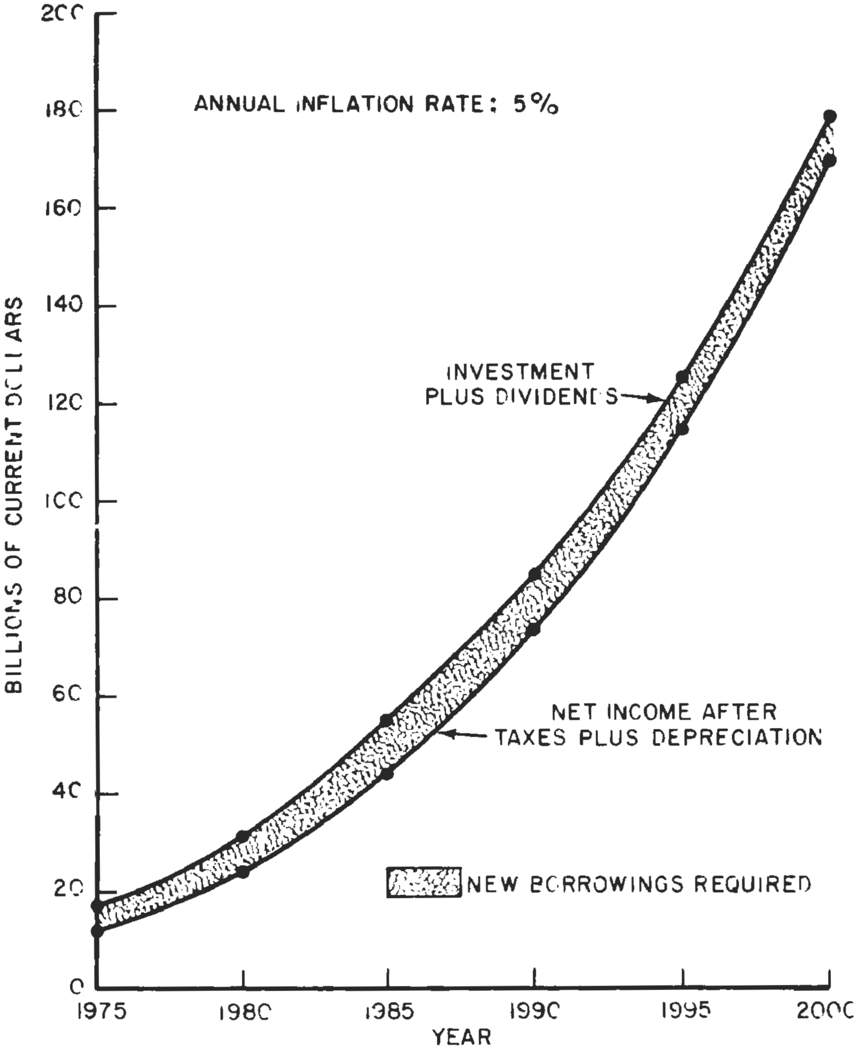

FIGURE 8-4. PROJECTED CASH FLOW FOR DOMESTIC OIL AND GAS INDUSTRY – CONVENTIONAL ACTIVITIES PLUS SYNTHETIC LIQUID FUELS – AT A FIVE PERCENT ANNUAL RATE OF INFLATION

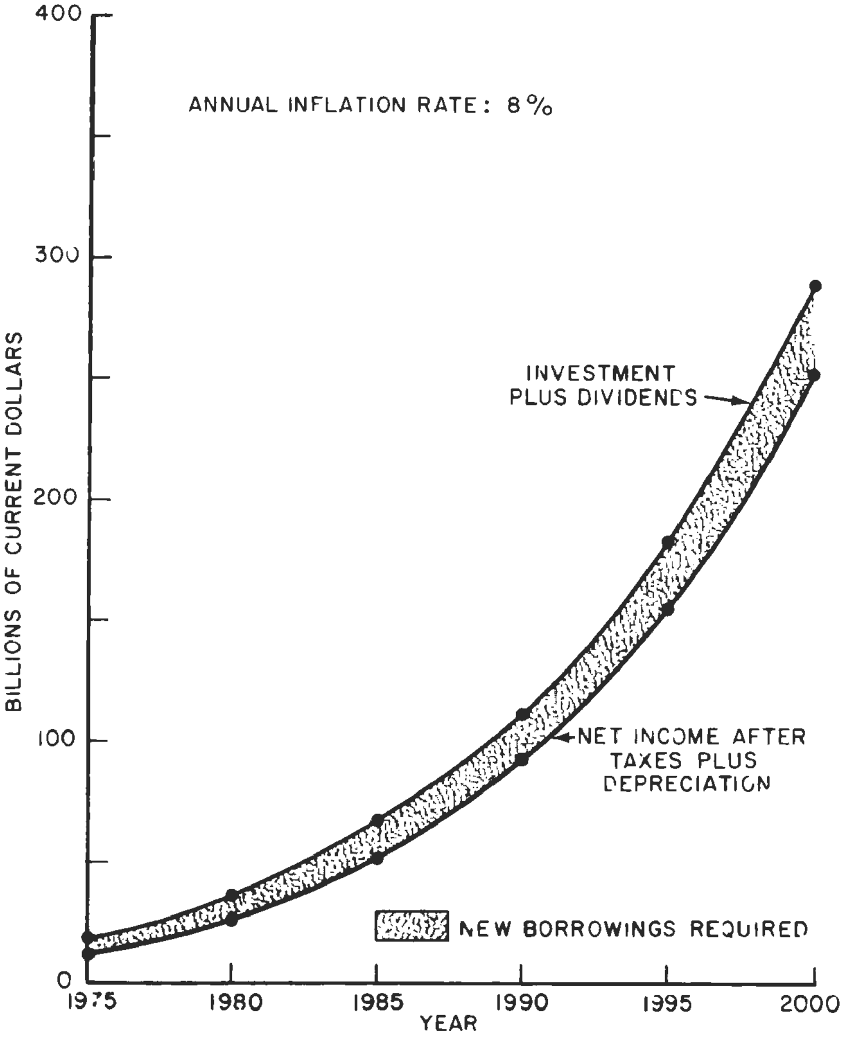

FIGURE 8-5. PROJECTED CASH FLOW FOR DOMESTIC OIL AND GAS INDUSTRY—NO SYNTHETIC LIQUID FUELS—AT AN EIGHT PERCENT ANNUAL RATE OF INFLATION

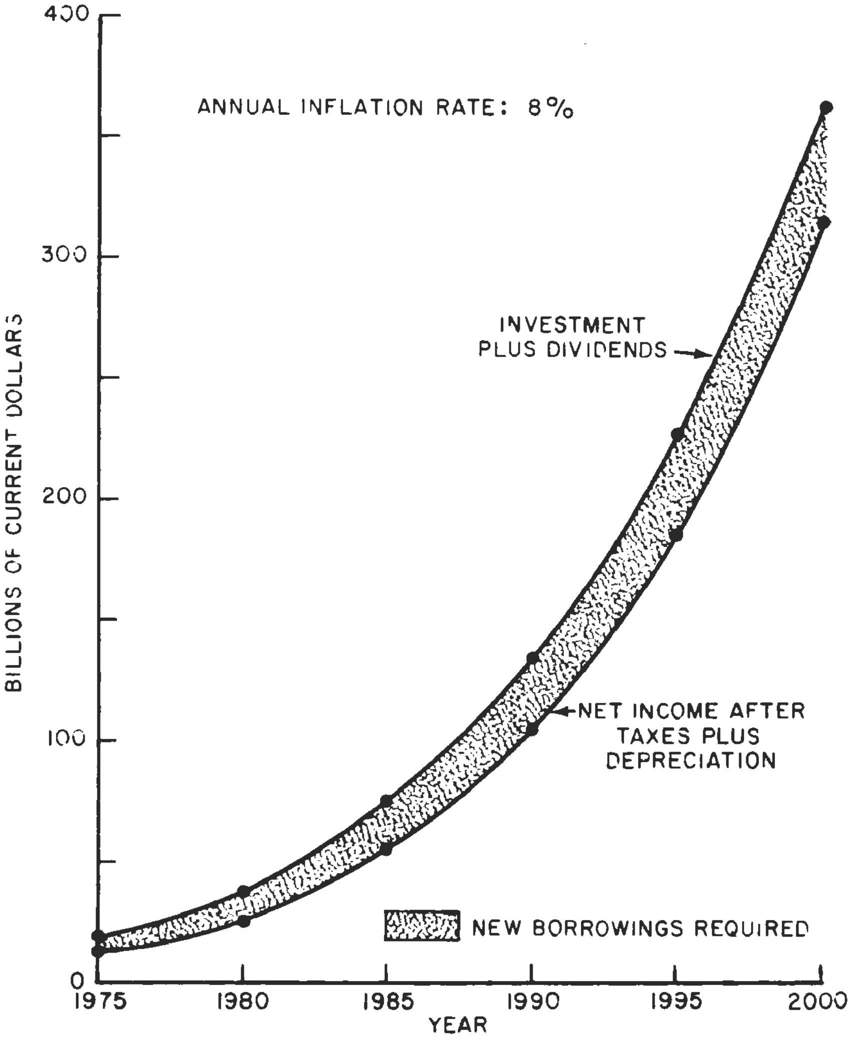

FIGURE 8-6. PROJECTED CASH FLOW FOR DOMESTIC OIL AND GAS INDUSTRY—CONVENTIONAL ACTIVITIES PLUS SYNTHETIC LIQUID FUELS—AT AN EIGHT PERCENT ANNUAL RATE OF INFLATION

is a small fraction of its total cach flow of $315 billion in 2000 and less than the dividend payout (see Table C-4).

The reason for the shortage of internal funds under inflation is that depreciation of fixed assets is based on historical rather than replacement cost. Consequently, cash flow from depreciation does not generate sufficient cash to replace existing assets and to add to assets as well.

E. Conclusions

The findings of this flow of funds analysis of the petroleum industry demonstrate the importance of inflation rates and governmental policy on industry cash flow. Fiscal policies that result in inflation prevent depreciation credits from providing enough cash flow to actually replace existing assets at the higher prices. As a result, industry must use a portion of its after-tax income to maintain existing asset levels. Funds for growth are thereby diminished and the need to attract funds from external sources is increased. In the petroleum industry, funds for growth have been hurt by recent changes in the tax laws affecting depletion allowances and foreign tax credits.

The results of this chapter project faster growth for petroleum industry investment than for total business fixed investment. In the early 1970s the petroleum industry accounted for 7.5 to 9 percent of total business fixed investment while our projections are that the percentage will double to 18 percent by 1995. There will be much competition from other sectors of the economy for capital that will work against realizing such growth.

Within the energy industry itself, for example, electric utilities will require vast amounts of new capital. Likewise, other basic industries need large amounts of capital for expansion, modernization and pollution control. Such needs will likely cause intense competition for newly formed capital.

However, the projections of this chapter show the petroleum industry able to provide internally for an increased fraction of its investment funds by the year 2000.* Our model (and assumptions) project that in an 8 percent inflation economy, new borrowings by the petroleum industry would fall from 31 percent down to 15 percent of cash flow by the year 2000.

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*The projections of this chapter are based partly on the assumption that real GNP will grow at an average annual rate of 3.6 percent. This assumption may be valid only if energy prices remain relatively cheap. It was, unfortunately, beyond the scope of this effort to also attempt to model the dependency of GNP on energy prices.

Appendix A

PROJECTIONS OF GNP, AND SOURCES AND USES OF FUNDS

Table A-1

GROSS NATIONAL PRODUCT -- HISTORICAL AND PROJECTIONS TO 2000
(Billions of Dollars)

Historical	Current Dollars	Constant 1973 Dollars	Gross National Product Deflator 1973 = 100
1967	$ 790	$1,060	74.7
1968	860	1,100	78.1
1969	920	1,130	82.0
1970	970	1,130	86.4
1971	1,050	1,160	90.8
1972	1,160	1,220	94.9
1973	1,300	1,300	100.0
1974	1,397	1,267	110.3
Average annual change 1967-1974	8.5%	3.3%	5.0%
Projections			
1975	1,480	1,220	121
1980	2,340	1,590	147
1985	3,560	1,890	188
1990	5,420	2,260	240
1995	8,270	2,700	306
2000	12,590	3,220	391

Sources: Historical data. Constant 1973 dollars were obtained from Survey of Current Business, Bureau of Economic Analysis, Sept. 2974, p. 6, Table A; current dollars are from Table 1, various issues. Deflators were derived by dividing current dollars by 1973 constant dollars.

Projections. Real GNP was projected at an annual growth rate of 3.6 percent, taking off from 1974. The deflators were projected at 5 percent annually for the period 1975-2000. Current GNP was obtained by multiplying real GNP by deflators.

Table A-2

SOURCES OF FUNDS--HISTORICAL DATA AND PROJECTIONS TO 2000
(Billions of Current Dollars)

Historical	Business Savings*	Personal Savings	Net Foreign Investment
1967	$ 93	$ 40	$ 2.2
1968	97	38	-0.3
1969	97	38	-0.9
1970	97	55	1.2
1971	110	61	-2.1
1972	126	53	-9.1
1973	137	74	0.1
Projections			
1975	165	65	20
1980	249	95	40
1985	378	139	0
1990	574	218	0
1995	872	342	0
2000	1,326	535	0
Cumulative 1975-2000	14,639	5,696	300

---

*Business savings is equivalent to the sum of undistributed corporate profits, corporate inventory valuation adjustment, corporate and noncorporate capital consumption allowances, and wage accruals less disbursements in the Survey of Current Business.

- Business savings

Sources: Historical. Survey of Current Business, National Income and Product Table 15, various issues.

Projections. The equation 3.5 + 0.105 (GNP) was used to project business savings. (See Reference 3.)

(continued)

Table A-2 (concluded)

- Personal savings

Sources: Historical. Survey of Current Business, National Income and Product, Table 10, various issues.

Projections. Personal savings was projected using a ratio of personal savings to GNP (on a sliding scale of 0.0425-0.039 for 1975-1985 and 0.039-0.0425 from 1985-2000). (See Reference 3.)

- Net foreign investment

Sources: Historical. Survey of Current Business, National Income and Product, Table 12, various issues.

Projections. Net foreign investment (NFI), which historically has fluctuated around zero, is assumed to increase to $20 billion in 1975, to continue to grow, reaching a high of $40 billion in 1980, and then to fall to zero again by 1985. The sharp rise in NFI expected over the 1975-85 period is due to recycling of "petro-dollars." In 1975, it is estimated that OPEC surplus revenues (i.e., the difference between oil exports and total imports) will be about $65 billion. Currently, about 31 percent of these funds are returning to the United States. OPEC surplus revenues are expected to increase to about $130 billion by 1980, and assuming the 31 percent share for the United States persists, a NFI in 1980 of about $40 billion results. NFI is anticipated to decline steadily between 1980 and 1985 as the dollar value of imports to OPEC countries gradually overtakes the dollar value of oil exports. By 1985 it is assumed that the oil surplus will disappear.

Table A-3

BUSINESS FIXED INVESTMENT*--HISTORICAL AND PROJECTIONS TO 2000

(Billions of Dollars)

Historical	Current Dollars	Constant 1973 Dollars	Business Fixed Investment Deflator 1973 = 100
1967	$ 88	$ 106	78.5
1968	89	110	81.1
1969	99	116	85.0
1970	101	113	89.7
1971	106	111	95.1
1972	117	121	96.3
1973	137	137	100.0
1974	149	136	109.4
Average annual change 1967-1973	8.6%	4.3%	4.1%
Projections			
1975	167	142	118
1980	273	181	151
1985	446	232	192
1990	686	280	245
1995	1,055	337	313
2000	1,623	407	399
Cumulative 1975-2000	17,413	6,775	

---

*Business fixed investment is equivalent to nonresidential fixed investment in the Survey of Current Business.

Sources: Historical data. Survey of Current Business, National Income and Product, Table 1 (various issues) for current dollars; Table 16 for deflators. 1958 base year deflators were converted to 1973 base year by dividing deflators by the year 1973 deflator. Constant 1973 dollars were obtained by dividing current dollars by the deflators.

(continued)

Table A-3 (concluded)

Projections. Current dollars were projected at an annual growth rate of 10.3 percent for the period 1975-1985 and 9 percent from 1985-2000. Deflators were projected using an average ratio (0.9588) of business fixed investment deflators to GNP deflators (1958 = 100) and converted to a 1973 base year. Constant 1973 dollars were calculated by dividing current dollars by the deflators.

Table A-4

RESIDENTIAL CONSTRUCTION*--HISTORICAL AND PROJECTIONS TO 2000
(Billions of Dollars)

Historical	Current Dollars	Constant 1973 Dollars	Residential Construction Deflator 1973 = 100
1967	$ 25	$ 36	70.7
1968	30	40	74.6
1969	32	40	79.2
1970	31	39	80.4
1971	43	51	84.2
1972	54	60	90.5
1973	57	57	100.0
Average annual change 1967-1973	14.7%	8.3%	6.0%
Projections			
1975	58	53	109
1980	88	63	139
1985	135	76	178
1990	205	90	227
1995	312	108	290
2000	475	129	370
Cumulative 1975-2000	5,223	2,224	

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*Residential construction is equivalent to residential structures fixed investment in the _Survey of Current Business_.

Sources: _Historical_. Current dollars are from _Survey of Current Business_, National Income and Product, Table 1, various issues. Deflators (1958 = 100) from Table 16 were converted to 1973 base year and divided into current dollars to obtain constant 1973 dollars.

(continued)

Table A-4 (concluded)

Projections. Projections of constant prices were made by taking an average ratio (0.0354) of residential construction (1958 prices) to GNP (1958 prices) for the years 1967-1973 and multiplying by real GNP projections for 1975-2000. Deflators were projected by the same method (using average ratio of deflators) and converted to a 1973 base year. Current dollars were obtained by multiplying constant dollars by the deflators.

Table A-5

SELECTED USES OF FUNDS--HISTORICAL AND PROJECTIONS TO 2000
(Billions of Current Dollars)

Historical	Inventory Investment*	Federal Deficit	Credit Agency Borrowing	State and Local Borrowing†
1967	$ 7.4	$12.7	$ 8.2	$ 1.8
1968	7.3	5.2	7.7	1.5
1969	8.5	-9.2 (surplus)	8.6	0.6
1970	4.9	12.9	--	-2.8 (surplus)
1971	3.6	21.7	--	-4.8 (surplus)
1972	8.5	17.5	--	-12.3 (surplus)
1973	15.4	5.6	9.5	-9.2 (surplus)
Projections				
1975	12	4	10	3
1980	18	4	10	3
1985	27	4	10	3
1990	41	4	15	5
1995	63	4	15	5
2000	96	4	15	5
Cumulative 1975-2000	1,053	91	335	103

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*Inventory investment is equivalent to change in business inventories in the Survey of Current Business.

- Inventory investment

Sources: Historical. Survey of Current Business, National Income and Product, Table 1, various issues.

Projections. Current dollars were projected by taking an average ratio (0.0076) of inventory investment to GNP for the period 1967-1973 and multiplying by projected GNP in current dollars.

- Federal deficit

Sources: Historical. Survey of Current Business, National Income and Product, Table 13, various issues.

Projections. The federal deficit is assumed to average about $3.5 billion per year over the 1975-2000 period the same as the average for the nonwar years of 1954-1963. This projection was used in the New York Stock Exchange study for the 1975-1985 period and is assumed to continue in the 1985-2000 period. It is important to recognize that the $3.5 billion annual deficit projected for 1975 is only an average over the 1975-2000 period. The actual deficit in 1975 may be anywhere between $50 and $80 billion because the economy is current in a recession. However, part of the 1975 deficit is expected to be offset in future years by a government surplus when the economy is operating close to full employment again.

(continued)

Table A-5 (concluded)

- Credit agency borrowing

Sources: Historical. Federal Reserve Bulletin, Total New Issues table under Federally Sponsored Credit Agencies, various issues.

Projections. Credit agency borrowing is taken from the New York Stock Exchange study over the 1975-1985 period and extrapolated to year 2000.

- State and local borrowing

†State and local borrowing is equivalent to state and local surplus or deficit in the Survey of Current Business.

Sources: Historical. Survey of Current Business, National Income and Product, Table 14, various issues.

Projections. These projections are taken from the New York Stock Exchange study for the 1975-1985 period and extrapolated to 2000.

Appendix B

PROJECTIONS OF CAPITAL INVESTMENT IN THE OIL AND GAS INDUSTRY

Appendix B

PROJECTIONS OF CAPITAL INVESTMENT IN THE OIL AND GAS INDUSTRY

The capital investments in the five categories of energy investment shown in Table 8-3 were projected using the data through 1985 from Hass, Stone and Mitchell in Financing the Energy Industry (FEI),[8] and converted into 1973 constant dollars using the deflator from Table A-3.

Table B-1

ENERGY INDUSTRY INVESTMENT FOR 1975, 1980, AND 1985 FOR HG1
(Billions of Constant Dollars)

	1970 Dollars			1973 Dollars		
Energy Sector	1975	1980	1985	1975	1980	1985
Domestic petroleum and natural gas production and refining, excluding chemical plants	$12.0	$17.0	$22.0	$13.4	$19.0	$24.5
Electric utilities, including nuclear capacity	18.6	26.8	37.6	20.7	29.9	41.9
Natural gas pipelines and distribution	4.0	4.0	4.0	4.5	4.5	4.5
Coal production	1.5	1.5	1.5	1.7	1.7	1.7
Nuclear fuel production	0.0	1.4	1.4	0.0	1.6	1.6
Totals	$36.1	$50.7	$60.5	$40.3	$56.7	$74.2

To obtain investment in the domestic petroleum industry without synthetic fuels, it was assumed that energy output per dollar invested is identical for conventional petroleum and synthetic fuels.

The ratio of energy output from conventional oil and gas, and synthetic gas from coal (including conversion losses) to energy output from conventional oil and gas, and synthetic liquid fuels from coal and oil shale from the HG1 scenario (Table B-2) was used to scale down the investment in conventional oil and gas plus synthetic from FEI to exclude synthetic liquid fuels. It is assumed that the investment schedule from FEI, Table 6-1, applied to the HG1 scenario shown in Table B-2. The resulting investment in 1973 constant dollars under HG1 for the domestic petroleum industry fuel is:

1975	$13.4 billion
1980	18.2
1985	23.0

These projections are used for the HG1 projections through 1985 shown in Table 8-3. The investment requirements for HG1 through 2000 and the investment requirement for HG2 and HG3 shown in Table 8-3 and for TF1 shown in Table 8-5 are generated by scaling the HG1 investment. First, HG1 is extended to 2000 based on the ratio of energy output in 1990, 1995, and 2000 to energy output for 1985. For other scenarios, the HG1 investment figure was scaled using the ratio of energy output relative to the HG1 energy output for the same category and year. Table B-2 shows the energy outputs from the various energy investment categories which are used for the scaling. Table B-3 gives the annual investment requirements for the maximum credible implementation scenario.

Table B-2

ENERGY SUPPLY SCENARIOS
(Quadrillion Btu)*

	Actual	HG1		HG2		HG3		TF1	
	1973	1985	2000	1985	2000	1985	2000	1985	2000
Domestic Oil and Gas									
Domestic oil (no synthetics)	22	32	40	32	34	27	27	30	36
Domestic gas	23	29	37	29	31	26	27	27	32
Synthetic gas from coal	0	1	3	1	3	1	3	0	1
Conversion losses, coal to synthetic gas	0	0.5	1.5	0.5	2	0	1.5	0	1
Total domestic gas and oil†	45	63	82	63	70	54	59	57	60
Natural Gas for Distribution									
Domestic gas	23	29	37	29	31	26	22	27	32
Synthetic gas	0	1	3	1	3	1	3	0	1
Imported gas	1	1	0	1	2	4	5	1	0
Total gas consumption†	24	31	40	31	36	31	35	28	33
Nuclear fuel produced†	1	10	40	12	50	10	40	8	11
Coal production† (excluding use for liquid synthetics)	13	25	33	23	33	20	38	16	22
Energy input to electricity generation‡	21	41	85	41	85	41	85	29	42

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*Note a quadrillion (10^{15}) Btu is about 10^{18} J.

†Reference 1, Tables 3 and 13.

‡Reference 1, Tables F-2, F-3.

Table B-3

INVESTMENT REQUIREMENTS FOR SYNTHETIC FUELS UNDER THE MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO

Year	Billions of 1973 Dollars
1975	$0.0
1980	0.7
1985	2.6
1990	5.6
1995	7.2
2000	9.0

Appendix C

PROJECTIONS OF CASH FLOW FOR THE PETROLEUM AND GAS INDUSTRY

Appendix C

PROJECTIONS OF CASH FLOW FOR THE PETROLEUM AND GAS INDUSTRY

The following gives financial accounting relationships used to derive cash flow for the petroleum and gas industry, summarized from Hass, Stone and Mitchell,[8] Appendix B and Table 3-4.

<u>Assets</u>

$$TA(t) = TA(t-1) + \Delta CA(t) + \Delta OA(t) + INV(t) - DEP(t)$$

where

t = year

$TA(t)$ = total assets in year t.

$\Delta CA(t)$ = change in cash assets ($CA(t)$) from the previous year.

$\Delta OA(t)$ = change in other assets ($OA(t)$) from the previous year.

$INV(t)$ = investment in year t.

$DEP(t)$ = depreciation on total assets in year t.

and

$CA(t) = a\ TA(t) \qquad a = 0.32$

$DEP(t) = d\ TA(t-1) \qquad d = 0.064$

$OA(t) = \phi\ TA(t) \qquad \phi = 0.08$

then

$$TA(t) = \frac{(1-a-\phi-d)\ TA(t-1) + INV(t)}{1-a-\phi}$$

$$TA(t) = \frac{0.54\ TA(t-1) + INV(t)}{0.60}$$

The base year taken was 1973, and total assets were derived from total fixed assets given by Reference 4, excluding chemical plants and pipelines, of \$48.3 billion. The total assets for 1973 are therefore \$80 billion.

Total Financing

TF(t), total financing, is defined as

$$TF(t) = TA(t) - CL(t) - OL(t)$$

where

$CL(t)$ = current liabilities in year t.

$OL(t)$ = other liabilities in year t.

and

$$CL(t) = c\ TA(t), \quad c = 0.20$$

$$OL(t) = \alpha\ TA(t), \quad \alpha = 0.24$$

then

$$\begin{aligned} TF(t) &= (1-c-\alpha)\ TA(t) \\ &= 0.56\ TA(t) \end{aligned}$$

Cash Flow

Sources (cash flow in) = uses (cash flow out)

Cash flow in = NIAT(t) + DEP(t) + net new borrowings

where

NIAT(t) = net income after taxes

New borrowings = net new debt financing issued plus new equity financing (all common stock-assuming no preferred stock).

$$NIAT(t) = 0.10\ TF(t)$$

assuming a 10% rate of return after taxes on total financing

DEP(t) = 0.064 TA(t-1)

Cash flow out = INV(t) + DIV(t)

INV(t) = annual investment

DIV(t) = dividend payments on common shareholder equity

DIV(t) = PO · ECS(t)

PO = dividend payout rate

= 0.50

ECS(t) = equity share of the total financing

= 0.10 TF(t) - 0.08 DEBT(t)

DEBT = total debt financing in year t.

= 0.04 TF(t) (assumes a constant debt/equity ratio).

Table C-1

ANNUAL INVESTMENT SCHEDULE FOR HG1
(Billions of 1973 Dollars)

Year	HG1 (no synthetic liquid fuels)	HG1 (with MCIS synthetic fuels)
1973	$ 9.8	$ 9.8
74	12.0	12.0
1975	13.0	13.0
76	14.0	14.2
77	15.0	15.3
78	16.0	16.5
79	17.0	17.6
1980	18.0	18.7
81	19.0	20.1
82	20.0	21.5
83	21.0	22.8
84	22.0	24.2
1985	23.0	25.6
86	23.4	26.6
87	23.8	27.6
88	24.2	28.6
89	24.6	29.8
1990	25.0	30.6
91	25.6	31.4
92	26.2	32.4
93	26.8	33.4
94	27.4	34.3
1995	28.0	35.2
96	28.4	36.0
97	28.8	36.7
98	29.2	37.5
99	29.6	38.2
2000	30.0	39.0

Sources: Table 8-3 and Table 6-8 (in Chapter 6).

Table C-2

HG1 CASH FLOW--NO INFLATION
(Billions of 1973 Dollars)

	Cash Flow In			Cash Flow Out		
Year	NIAT(t)	DEP(t)	New Borrowings	INV(t)	DIV(t)	Excess Funds
			No Synthetic Fuels			
1975	$ 5.9	$ 5.9	$3.6	$13	$ 2.4	
1980	9.6	10.1	2.1	18	3.8	
1985	13.8	14.8		23	5.5	$ 0.1
1990	17.5	19.2		25	7.0	4.7
1995	20.6	22.8		28	8.2	7.2
2000	23.4	26.1		30	9.3	10.2
	With Maximum Credible Implementation Scenario Synthetic Fuels					
1975	5.9	5.9	3.6	13	2.4	
1980	9.9	10.3	2.5	18.7	4.0	
1985	14.7	15.6	1.2	25.6	5.9	
1990	19.7	21.4		30.6	7.9	2.6
1995	24.4	26.9		35.2	9.8	6.3
2000	28.8	32.0		39.0	11.5	10.3

Table C-3

HG1 CASH FLOW--5 PERCENT ANNUAL INFLATION
(Billions of Current Dollars)

	Cash Flow In			Cash Flow Out	
Year	NIAT(t)	DEP(t)	New Borrowings	INV	DIV
		No Synthetic Fuels			
1975	$ 6.0	$ 6.0	$ 4.7	$ 14.3	$ 2.4
1980	11.6	11.7	6.6	25.3	4.6
1985	20.3	20.9	8.2	41.3	8.1
1990	31.6	33.3	5.0	57.3	12.6
1995	46.3	49.1	5.0	81.9	18.5
2000	65.8	70.3	2.2	112	26.3
	With Maximum Credible Implementation Scenario Synthetic Fuels				
1975	6.0	6.0	4.7	14.3	2.4
1980	11.9	11.9	7.3	26.3	4.8
1985	21.7	22.1	10.9	46.0	8.7
1990	36.1	37.5	10.9	70.1	14.4
1995	55.8	58.7	10.8	103.0	22.3
2000	82.4	87.4	9.2	146.0	33.0

Table C-4

HG1 CASH FLOW--8 PERCENT ANNUAL INFLATION
(Billions of Current Dollars)

	Cash Flow In			Cash Flow Out	
Year	NIAT(t)	DEP(t)	New Borrowings	INV	DIV
		No Synthetic Fuels			
1975	$ 6.1	$ 6.0	$ 5.5	$ 15.2	$ 2.4
1980	13.0	12.9	10.1	30.8	5.2
1985	25.7	25.8	16.7	57.9	10.3
1990	45.4	46.7	18.6	92.5	18.2
1995	76.0	78.5	28.1	152.2	30.4
2000	123.4	128.3	37.7	240	49.4
		With Maximum Credible Implementation Scenario Synthetic Fuels			
1975	6.1	6.0	5.5	15.2	2.4
1980	13.3	13.1	10.9	32.0	5.3
1985	28.0	27.5	20.0	64.5	11.0
1990	52.2	52.9	28.8	113	20.9
1995	92.2	94.3	41.8	191.4	36.9
2000	155.4	160.4	57.9	311.5	62.2

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9--MARKET PENETRATION OF SYNTHETIC LIQUID FUELS--THE KEY ROLE OF THE DECISION-MAKING PROCESS LEADING TO DEPLOYMENT

By Edward M. Dickson

A. Introduction

For most new product offerings, the manufacturer is properly concerned with obtaining an estimate of the share of the market that his new product may capture. It would seem appropriate, therefore, to ask what fraction of the consumer market gasoline produced from oil shale, for example, might ultimately capture. However, discussions with energy industry experts* and stakeholders† have revealed that the question of market penetration of the final consumer product is less fundamental to the impact study than is the question of how and why decisions to deploy synthetic liquid fuel production technologies will be made.

B. Synthetic Liquid Fuels and the Natural Petroleum System

The nature of the synthetic fuel production processes and of the existing fuel production and distribution infrastructure with which synthetic fuels must mesh is at the root of this. Figure 9-1 shows a simplified block representation of a synthetic fuels production process and Figure 9-2 shows a simplified representation of the existing automotive fuels production system. Two markets are involved in both cases:

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*Exxon Research and Engineering and Stanford Research Institute.
†Atlantic Richfield, Shell Oil, Carter Oil (a subsidiary of Exxon), Texaco, and Chase Manhattan Bank.

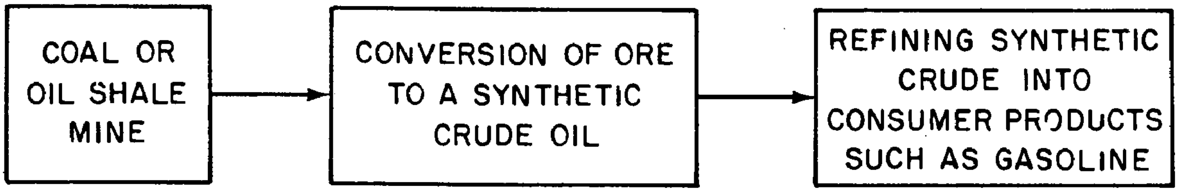

FIGURE 9-1. SYNTHETIC LIQUID FUELS PRODUCTION SYSTEM

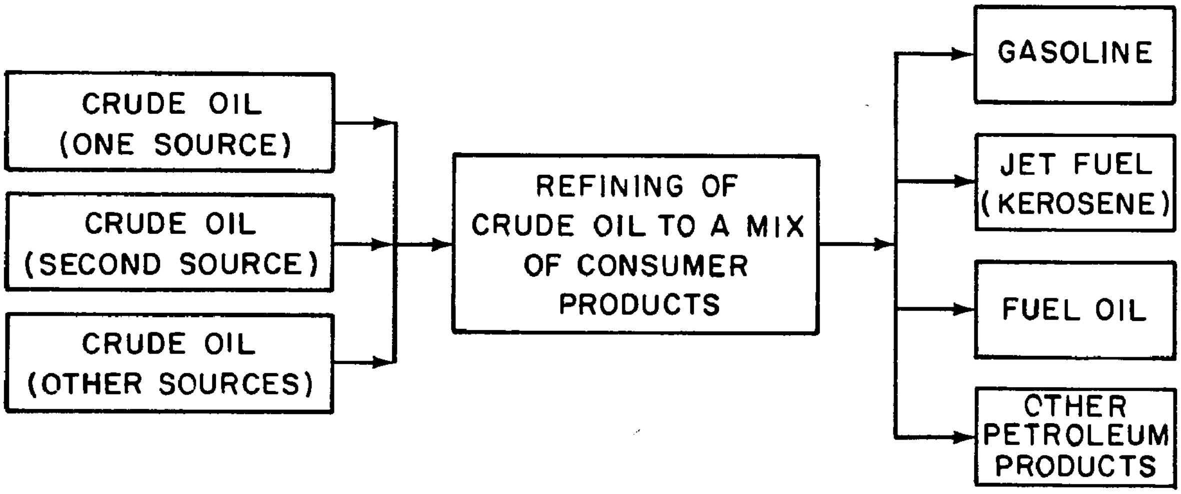

FIGURE 9-2. NATURAL PETROLEUM PRODUCTS PRODUCTION SYSTEM

crude oils and refined products. The synthetic fuels and natural petroleum fuels systems could be joined or could compete at either of the two points.

If the two systems were to join in the market for refined products, there could be two alternative market forms (not mutually exclusive):

(1) The synthetic gasoline could be sold separately through a distinct distribution system in direct competition with conventional gasoline.

(2) The synthetic and conventional gasolines could be mixed together to be marketed and sold through the existing distribution system.

Both alternatives allow the possibility of either new or established corporate entities, with no previous association with the automotive fuels market, making and selling synthetic gasoline. The first alternative would require creation of a new marketing network and competitive pricing of the product. Since it is expected that synthetic gasoline cannot be made as cheaply as conventional gasoline,[1] this market will be difficult to enter competitively. The second alternative avoids the establishment of a new network and expenditures on advertising, and allows the product to be sold at the average price of all the inputs that are blended together, rather than at the actual marginal price of the synthetic gasoline. Of course, if the synthetic gasoline were to cost more to produce than the conventional gasoline, there would be little enthusiasm for using this cost averaging mechanism to create a market for synthetic gasoline. Nevertheless, provided that synthetic gasoline did not cost too much more than conventional gasoline and that it was not too large a share of the total product to be marketed, the second alternative would offer this "roll-in" mechanism that could be employed if a fallback proved necessary because of a poor business decision. However, if the synthetic gasoline were produced by organizations outside the existing natural petroleum based industry, such synthetic gasoline would have to wholesale competitively with conventional gasoline before existing oil companies could be expected to purchase it and absorb it in their existing marketing system.

The first alternative, the competitive approach of a fully integrated synthetic fuel company, is clearly the more risky course and because of the very strong position of existing oil companies in the automotive fuels marketplace there has been apparently no serious contemplation of this approach of potential corporate producers outside this existing industry. Indeed, for excellent reasons that are rooted in the chemical engineering of the processes, even the second alternative, the consumer product blending approach, has not been taken seriously even by those corporations* expressing interest in synthetic liquid fuels.

The product mix shown as a single refinery output in Figure 9-2 results not simply from the consumer demand for diverse products, but also from the nature of crude oil and the chemistry and engineering associated with its processing. Crude oil consists of a mixture of hydrocarbon molecules that cover a wide range of physical and chemical properties. The first step in refining is the distillation of the oil into its various components (fractions). Some of these are processed fairly directly into consumer products while other components that are present in quantities that exceed their market demand are chemically altered into products that are in more demand. Although it would be possible to convert crude oil entirely into a gasoline product, this would entail so much chemical reforming that it would be economically prohibitive as well as costly in terms of process energy (largely supplied from the petroleum stream itself). Consequently, it is standard practice to design modern, large refineries so that they can be tuned to yield an optimal product mix for any (sensible) blend of crude inputs.†

Because it is standard for refineries to accept and utilize a blend of crude inputs and the natural intermediate output of a synthetic liquid fuels plant is a synthetic crude oil rather than refined product, the

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*Such as a large chemical company.

†Some old, small refineries do, however, accept crude from a single field. These represent an historical artifact.

the corporate interests and governmental research elements involved in synthetic liquid fuels development have emphasized joining the synthetic liquid fuels and the existing fuels system at the synthetic crude node rather than at the synthetic consumer product node. The natural industry approach to synthetic liquid fuels is to produce a synthetic crude and to add that product to the pool of all available crudes. Thus, the key market is not the consumer market but is the intra-industry market for crude oil.

Once this mixture occurs, of course, it is extremely unlikely that, on an atom-to-atom basis, the carbon derived from either the fossil coal or oil shale deposits would actually all be consumed in the form of automotive fuel. Instead, as in a game of musical chairs, a carbon atom previously destined to become fuel oil might end up as kerosene, while an atom previously headed for kerosene might end up as gasoline, and the atom from the coal or oil shale might end up as fuel oil. Thus, whether the coal or oil shale is made straight into gasoline or into a syncrude that is blended with natural crudes, the net result is the same: Development of coal or oil shale resources has resulted in gasoline being made available. In either event, the consumer would be no more aware that any given purchase of gasoline came from coal or oil shale than he is now aware whether his gasoline came from domestic or foreign crude, or from a particular oil field.

Depiction of the series of synthetic fuels product events as a single chain from coal to gasoline is a useful heuristic device to demonstrate that coal or oil shale could provide energy for automotive uses, but this device does not reflect reality adequately to serve as a basis for impact analysis. Through discussion with people well informed about the petroleum industry and with energy industry stakeholders, the SRI study team has verified that the key element is the process by which decisions will be made to produce synthetic crudes. Once these decisions are made, synthetic crude will become available for blending into the pool of total crude and this, in turn, will facilitate the production of automotive fuels. A key element in the decision to deploy synthetic liquid fuels technology will be the decision maker's perception of the risks of synthetic crude production compared with his perception of the risks of alternative investments in conventional crude exploration and production. Moreover, both of these alternatives will be compared to investment opportunities outside the fuels arena.

The petroleum business is inherently very complex, but myriad governmental regulations make it even more complex. Nevertheless, the analysis below captures the essential features, although not the nuances, of the decision-making process concerning synthetic liquid fuels. Corporate stakeholders have verified that the major thrust of the description is correct.

C. Common Misconceptions About the Petroleum Industry

Before the decision-making process can be discussed properly, it is essential to dispose of some commonly held misconceptions about the oil industry.

First, there is no single price for crude oil. There are many sources of crude oil, each possessing different chemical and physical properties--some more highly valued than others. For example, some oils are rich in the less viscous hydrocarbons and are called "light," while others are rich in more viscous hydrocarbons (such as asphalt or bitumen) and are termed "heavy;" some oils have low sulfur content (less than 1 percent) and are called "sweet," while others with higher sulfur content are called "sour." In general, American refiners prefer the light, sweet crudes because these can most easily and economically be used to produce the mix of products desired by American consumers; their use also permits environmental standards to be met most readily. Consequently, there are price differentials for crude oils of different qualities; at the extreme, these variations approach $2 per barrel ($\$12/m^3$).* The common practice of referring to the market price of crude oil is merely a shorthand for speaking of a representative price of a major crude oil or of the government controlled price of domestic crude.

Second, there is no single cost of producting natural crude oil. Since there are many wells (some 500,000 in the United States at the end of 1973) in many different fields at different stages of depletion, producing oils of many different qualities, recovery costs are highly variable. Some fields are self-pressured and the oil flows to the surface naturally, while some wells require pumping. Wells that produce less than 10 B/D (1.6 m^3/D) are termed "stripper wells." In 1973, nearly 14,000 stripper wells became uneconomic to operate and were closed down; the size of this number shows that many stripper wells are on the verge of being phased out at any given time. Many wells are very old but still producing; for these, the exploration and development costs have been fully written off long ago so only operating costs are now pertinent. Clearly, therefore, the costs of producing crude oil vary widely, and thus so does oil well profitability.

Third, the market for crude oil is far from a "free market," owing to the cartel of the Organization of Petroleum Exporting Countries (OPEC) and complicated federal government price controls.[1] For example, "old" oil comes both from new wells and from increased production from old

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*The raw oil shale and coal syncrudes can be upgraded to superb quality (sweet and light) and, therefore, could command a premium price over most natural crudes.

wells,* and can be sold at whatever the market will bear. There is also "released" oil, that is, old oil that has been reclassified as new in accord with a government exploration incentive that allows reclassification of one barrel of old oil for each barrel of new oil produced. Stripper wells are exempt from the "old" classification. The complex price structure is further complicated by an "entitlements" program by which the federal government guarantees to all refiners the equivalent of an equal percentage access to low price old oil. Companies with ownership or contract rights to old oil in excess of the industry average must purchase entitlements from companies with less old oil than the average. By this strategem, the government seeks to spread the blow of the suddenly higher cost of imported oil over all petroleum companies. These governmental interventions were temporary expedients stimulated by the Arab oil embargo; they are subject to change at any time.

D. Example of the Decision-Making Process

The recent rise in world oil prices caused by the strong position of the OPEC cartel is an excellent example of the decision-making process concerning synthetic crude. The description that follows is simplified; in particular, the extreme complications caused by U.S. oil price regulations and the entitlements program are suppressed in the interest of providing a readily intelligible picture of the decision-making process.

Figure 9-3 is a snapshot in time that shows a hypothetical† curve depicting the spectrum of natural crude oil production costs, relative

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*Relative to the pertinent monthly reference period in 1972 for each producing property.

†The shape of the curve and the breadth do not represent actual data. Such data is proprietary to the producer and therefore not available to this study.

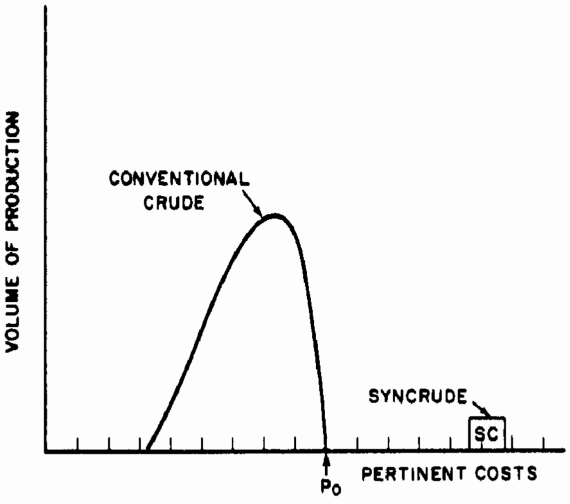

FIGURE 9-3. EARLY 1973 PERCEPTION OF A HYPOTHETICAL SYNCRUDE PLANT BEGINNING TO PRODUCE IN 1973

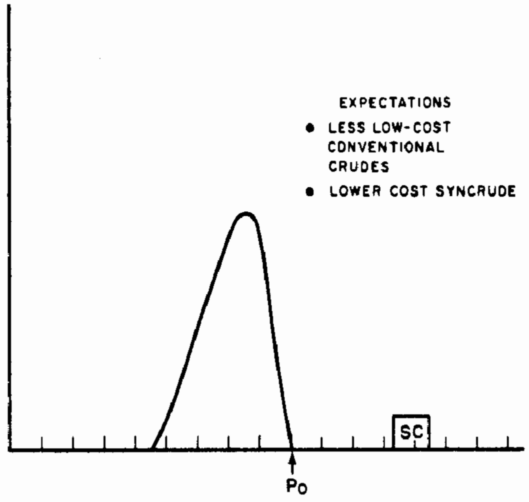

FIGURE 9-4. EARLY 1973 PERCEPTION OF A SYNCRUDE PLANT BROUGHT ON STREAM IN 1980

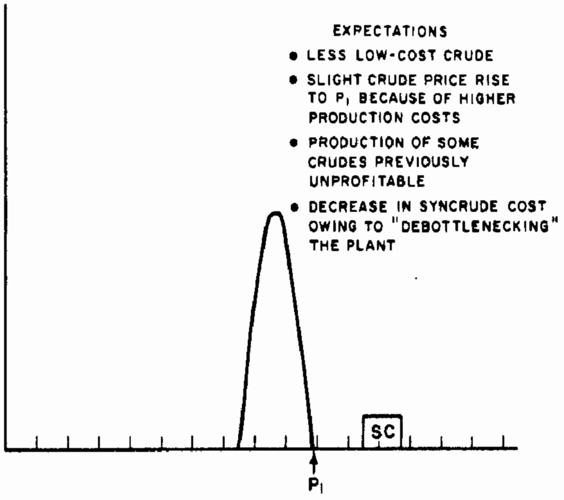

FIGURE 9-5. EARLY 1973 PERCEPTION OF THE 1985 STATUS OF A SYNCRUDE PLANT BROUGHT ON STREAM IN 1980

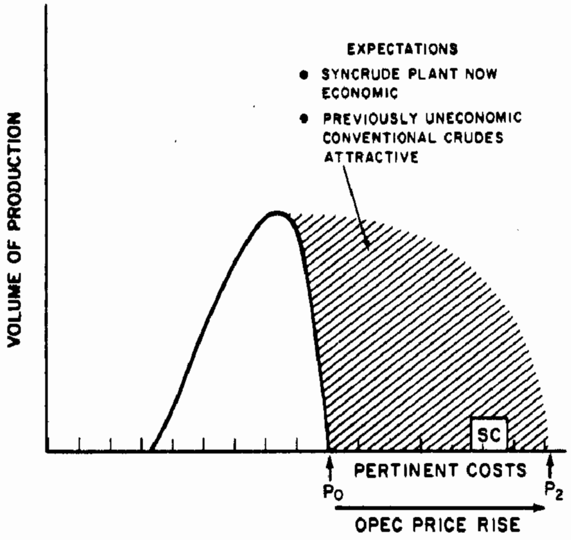

FIGURE 9-6. LATE 1973 PERCEPTION OF THE HYPOTHETICAL SYNCRUDE PLANT PRODUCING IN 1973

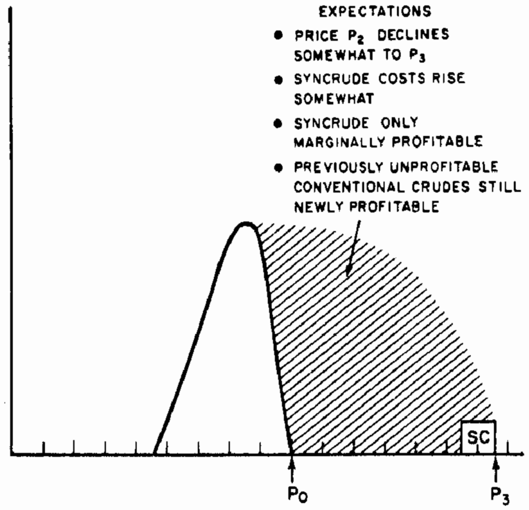

FIGURE 9-7. MID-1974 PERCEPTION OF A HYPOTHETICAL 1974 SYNCRUDE PLANT, AFTER EXAMINATION OF INVESTMENT COSTS

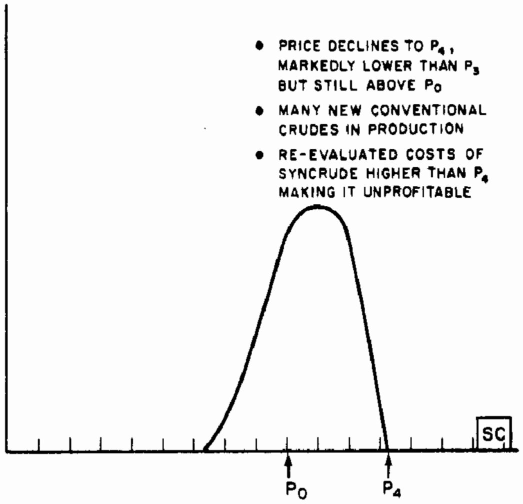

FIGURE 9-8. LATE 1974—EARLY 1975 PERCEPTION OF SYNCRUDE PLANT ON STREAM IN 1980

to the average market price, P_O, for crude oil. The portion just to the left of P_O is largely composed of stripper wells. Whenever the pertinent costs of a particular well rise above P_O, that well is shut down. During the lifetime of a well, or ensemble of wells, producing from a particular field, the tendency is for the costs to be at the leftward end of the spectrum when the well or field is young and progressively shift to the right as production rate declines with increasing depletion until finally the wells enter the category of stripper wells. Figure 9-3 also shows how a hypothetical, newly producing commercial-scale syncrude plant would have looked to a decision maker in early 1973. At that time there was no actual producing syncrude plant, but if there had been, it would have represented the technology at 1965, when its design would have begun. In early 1973, the best estimates for the syncrude plant showed that production would cost considerably more than the going crude oil market price, and, hence, the plant would have lost money. In 1973, then, it was apparent that petroleum companies had made the correct decision years earlier when they chose not to build syncrude plants.

Figure 9-4 shows how, in early 1973, the same decision maker would have perceived a syncrude project begun that year but not scheduled to produce crude until 1980. Thus, the curves represent his perception of the state of affairs that would pertain in 1980. First, the conventional crude production spectrum would have narrowed somewhat as the easier-to-find-and-produce conventional crudes were depleted, thereby eliminating the lowest cost crudes (at the farthest left portion of the production spectrum). The price, P_O, was left essentially unchanged, because the weight of the historical evidence favored basically a stable price expectation for crude oil. Although the production cost for syncrude is shown to be slightly lower than in Figure 9-3 (because there would have been some improvement in technology), the costs were still expected to exceed the market price in 1980; consequently, in early 1973 the decision still would have been not to build a syncrude plant.

Figure 9-5 represents the same decision maker's perception of 1985--still from his vantage point in 1973. All the trends described for Figure 9-4 continued and this led to an expectation that there might be a slight price increase in crude (to P_1), reflecting the increased difficulty of providing the supply. Nevertheless, a syncrude plant scheduled to begin production in 1985 still looked like a poor investment.

Then, however, OPEC initiated a series of stunning price increases for crude oil, which opened an unprecedented gap between the then-operational production spectrum and the new crude oil market price, P_2. This event is shown in Figure 9-6, which shows that from a late 1973 vantage point it suddenly looked as if the hypothetical syncrude plant of Figure 9-3 (producing in 1973) would then be profitable if only it had been built. The sudden price increase, however, also meant that many conventional crude production possibilities, which had previously been unprofitable, would now also be profitable if only they were in operation. In fact, any activity and activities in the range of production costs between P_0 and P_2 now could be taken seriously as profitable investment opportunities. Thus, during the initial period following the OPEC price rises, the price rise stimulated interest in many new sources of crude oil--including synthetics and advanced recovery techniques from old fields.

Often, alternatives that seem very unattractive after only a coarse analysis are set aside without performing a more costly, more refined analysis. This was largely true of the analysis of synthetic crude plants. As shown in Figure 9-7, between late 1973 and mid-1974, when the possible syncrude investment option was examined more closely, cost estimates were revised upwards, and once again it appeared that a syncrude investment would be only marginally profitable. This conclusion was enhanced by the prospect that the OPEC price would not hold at P_2 and would shift downward somewhat, to at least P_3. Thus, within the spectrum of new options lying in the range P_0 to P_3, syncrude seemed to be one of the costlier crudes to produce and therefore one of the least profitable. Moreover, there seemed to be many conventional crude exploration and production opportunities that could still be undertaken that would be more profitable than production of syncrude. Indeed, even some previously shut down stripper wells could justifiably be returned to operational status. Moreover, many difficult conventional crude production activities such as deep offshore, arctic offshore, and tertiary recovery might all prove profitable.

By late 1974 and early 1975, reevaluation of the expectations of the future and the costs of options had improved further. Figure 9-8 indicates how the same decision maker generally thought the situation would appear in 1980. First, the syncrude plant was found to produce an even (slightly) more costly product than last thought, and conviction that the OPEC price would fall to P_4 grew stronger. Thus, once again, syncrude looked like it would lose money. In addition, the conviction that much more conventional crude could be produced at costs between P_0 to P_4 led to rekindled interest in extensions of the conventional approach to oil production and away from the temporary, but heady, enthusiasm for syncrudes. Important to this rekindled interest was the fact that the decision maker felt more comfortable with the historical conventional approach than he did with the syncrude approach to obtaining his supplies of crude.

It must be emphasized that the above analysis concerns <u>commercial</u> scale plants, not demonstration or pilot plants, and not research and development activities. All of these activities are in progress and will continue in spite of unfavorable expectations for commercial plants.

Indeed, there may be so much publicity given to pilot or demonstration plants built to further the research and development efforts that the public could easily leap to the premature conclusion that the day of synthetic fuels had dawned. The tempo of research and development activity will, of course, be modulated by the decision maker's expectation of when synthetic fuels will be competitive with future alternatives.

E. Comparison of the Risks

Besides a straightforward (although difficult to calculate) comparison of the relative profitability of alternative ways to gain new crude supplies based on the pertinent costs of production and market price, other factors enter into the decision-making process. Foremost among these is the risk involved.

Building a synthetic crude plant, although it requires much capital and complex engineering, carries very little risk concerning the ultimate existence of the product. In that respect the risk is very much like an oil refinery or a chemical plant where the major risk is the likelihood of a misestimate of the cost of the feedstock and of making the product, not the actual existence of the product. Thus, a synthetic crude plant very much resembles many other manufacturing type activities. Basically, there is a single decision to "go ahead" and there are no major intermediate decision exit points between the start and the finish.

Exploring and developing oil resources, by contrast, involves risks of a completely different nature, and there are several crucial intermediate decision exit points between the initial exploration go-ahead and the actual production of oil. First, there are geological explorations to determine formations likely to contain commercially significant accumulations of oil and gas. Second, based on these geological data, there are decisions to be made about whether and where to drill. Third, based on the findings of the exploration wells, there are decisions to be made about whether the discoveries (if any) are sufficiently large to justify drilling of production wells. At each decision-making juncture there are risks associated with proceeding to the next juncture, but it is important that there be a series of exit points should the project begin to look unfavorable.

The salient feature of the synthetic crude plant risk* is the uncertainty in production costs, while the major risk* in oil exploration investments is the actual presence of the oil. As conventional production shifts increasingly to offshore areas and distant, unfamiliar, hostile environments (e.g., Alaska, or deep waters of the outer continental shelf), experience on which decision makers can base their estimates of the inherent risks diminishes. Ultimately, rational investors will decide that the risks of oil exploration exceed the risks of synthetic fuels production--but today there is much disagreement over when synthetic fuels will become commercially competitive.

In a very real sense, the world has just embarked on an oil exploration experiment. Never before has there been such a large sudden jump in the market price of crude oil. As a result, there is no historical experience to show how much additional oil can really be located and produced under the stimulus of such an incentive. By 1980 the indications will be strong and by 1985 the results of this experiment will be

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*The comparison of risks on just the basis of crude production is incomplete because much of the natural gas used in the United States is found associated with oil, thus there is a byproduct credit involved; similarly synthetic crude plants also produce byproducts with value such as gas (which may however be consumed internally to power the plant), sulfur, and ammonia.

known. The success rate of finding and producing new oil will have a profound effect on decision makers concerned with synthetic crude because, as shown in Figures 9-3 to 9-8, their perception of the future of conventional petroleum strongly affects their perception of the need and profitability of synthetic fuels.

Besides risks associated with the nature of the fuel production methods themselves, there are substantial uncertainties about the institutional setting. In particular, corporate interests in the petroleum business translate uncertainties about governmental policies into risks. Examples of uncertainties affecting the decision-making process and the sphere of influence include:

Federal Government

- Domestic and international actions to establish a stable crude oil market price.
- Future domestic oil price regulations.
- Environmental regulations on extraction of coal by strip mining, oil shale refuse disposal, and production of oil from offshore leases.
- Resource leasing policies.
- Environmental restrictions that affect direct burning of coal and oil (mainly control of sulfur compound emissions).
- Policies concerning the degree of energy independence to be achieved.
- Policies affecting the development of alternative energy technologies.*

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*Since oil is the "swing fuel," or the one that has historically taken up the slack in the availability of other energy forms, the role of oil is especially sensitive to the total national energy mix, or interfuel balance.

- Rate of inflation.*
- Stability of governmental policies and regulations.

State Governments

- Growth policies.
- Water allocation policies in the energy resource-rich portion of the West.
- Environmental restrictions on development.
- Stability of state policies.

Foreign Governments

- Stability of foreign ownership rights, export policies, and taxes.
- OPEC price-setting actions.

Perhaps the most crucial risk element--recurring over and over again in discussions with synthetic fuels corporate stakeholders--was the one of stability of governmental policies.[3] When there is expectation that policies will be stable, even when the policies are unfavorable to the stakeholder and greatly restrict their freedom of action, there is a feeling that the investment decisions can be made with a tolerable degree of risk.

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*Rapid inflation increases risks of investment in capital intensive projects for several reasons: First, the continual escalation of costs during construction diminishes the purchasing power of the initial financing. Second, because depreciation is based on the initial (book) value of the plant but the depreciation tax deductions are always in current dollars, the capital actually recovered fails to meet the true replacement costs.

F. Comparison of Economic Risk

The investment in synthetic crude oil plants is very large--of the order of $0.5 to 1 billion (in 1973 dollars) for a production of 100,000 B/D (16,000 m^3/D). The size of this investment can be compared to the net worth of the corporations that might make the investment and the size of alternative crude production investments.

Data obtained from a standard financial reference[4] concerning oil company assets are shown in Table 9-1. A decision to invest $0.5 to 1 billion in a synthetic crude plant is a very grave event for even the largest companies. For example, such an investment would amount to some 4 to 7 percent of Exxon's net worth in 1973, and 25 to 50 percent of Phillips' net worth in 1973. To contemplate having such a large fraction of their shareholders equity riding on such a risky single project is especially sobering to the smaller companies, and not taken lightly by the large ones either.

Table 9-1

ASSETS OF SELECTED MAJOR OIL COMPANIES, DEC. 31, 1973
(Billions of Dollars)

Company	Gross Assets	Net Worth
Exxon	25.1	13.7
Gulf	10.1	5.6
Mobil	10.7	5.7
Phillips	3.6	2.0
Shell	5.4	3.1
Standard of California	9.1	5.8
Standard of Indiana	7.0	4.1
Standard of Ohio	2.0	1.1
Sun Oil	3.4	1.9
Texaco	13.6	8.0
Atlantic Richfield	5.1	3.1

Source: Reference 4.

By contrast, the investment in individual exploration and development projects for conventional crude oil, although considerable, is not as large. Moreover, the step-by-step decision process allows several exit points. For example, a 3-company consortium obtained offshore drilling rights in 6 contiguous tracts off the Florida Panhandle. On the basis of geophysical exploration by many companies, this region had been expected to be a large producer of oil. The $632 million cost[5] of rights to explore this so-called Destin Anticline is summarized in Table 9-2. This bid is about 10 times as large as the usual successful lease bid. Exxon is reported to have spent $15 million drilling 7 dry holes.[6,7] Other companies, drilling in the vicinity, have also failed to strike meaningful accumulations of oil. The consortium has surrendered the leases and will have to write off a $632 million lease bid.[7] This example illustrates that while oil exploration is costly and carries the risk of complete failure, the initial stakes of even an extreme example are not as high as with synthetic crudes.

Table 9-2

OFFSHORE LEASES IN THE DESTIN AREA OFF
FLORIDA'S PANHANDLE
(Millions of Dollars)

Company	Share
Exxon	311
Mobile	211
Champlin	111
Total*	632

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*Total does not add because of rounding.

Source: Reference 5.

It is noteworthy that for large contemporary conventional crude activities, such as the Destin venture, companies find it prudent to spread the risk by forming consortia. The same approach has been applied to the development of the tar sands resource in Canada and to the development of oil shale technology and oil shale lease bids (Table 9-3). Besides spreading the risk, this group approach allows the smaller oil companies to participate. Naturally, however, the participation of several companies complicates the decision-making process because they do not possess common perceptions of the future and the risk to each differs in proportion to their total assets. However, coal leases are not, generally, being acquired by consortia, apparently because, unlike oil shale, there are many alternative uses of coal besides liquid fuels, and, therefore, the risks are much smaller.

If the disappointing Destin exploration experience in the eastern Gulf of Mexico should be repeated in other frontier offshore areas--where much of the future domestic oil is expected to originate--corporate decision makers will reevaluate the relative attractiveness of the gamble on conventional exploration compared to synthetic crude production. This would result from their reevaluating the expected marginal cost of new conventional crude and its effect on the market price. Added to the comparison between the future of domestic crude discovery and production and synthetic fuels is the future of foreign activity in conventional crude. Most oil companies feel that worldwide there is still much oil to be developed, but after recent experiences with nationalization they must weigh the risk of foreign investment against those of domestic investment--including synthetic crude. Companies now generally insist on higher rates of return in foreign countries where political instabilities threaten their investments.

Foreign governments affect the decisions of U.S. oil companies in another important way. As Figure 9-8 showed, any activity that could

Table 9-3

GROUP PARTICIPATION IN OIL SHALE LEASES AND VENTURES

Oil Shale Leases	Share (percent)
Colorado-a	
Gulf	50
Standard of Indiana	50
Colorado-b	
Atlantic Richfield	25
TOSCO	25
Ashland	25
Shell	25
Utah-a*	
Phillips	50
Sun	50
Utah-b*	
White River Oil Shale	
Sun	33
Phillips	33
Standard Oil of Ohio	33
Colony Development (as of July 1974)	
Atlantic-Richfield (ARCO)	25
Shell	25
TOSCO	25
Ashland	25

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*To be operated jointly.

produce a crude at a cost between P_0 and P_4 would prove profitable. Yet, if companies commit investment capital to these activities they run the risk of OPEC cutting the price of their oil, thereby pulling the rug out from under the investments that produce crude at a cost above the new price. The fear of this possibility inhibits investments in synthetic crudes.

G. The Decision-Making Climate for Synthetic Liquid Fuels

Published information and our discussions with corporate stakeholders revealed that today the indicated poor profitability (even loss) of synthetic crudes, coupled with guarded optimism about the success of redoubled efforts to find new reserves of conventional crude, tip the scales against deployment of commercial synthetic crude production facilities. The outlook for decisions being made to go ahead with synthetic liquid fuels is very poor without either direct risk mitigation or indirect risk mitigation through the stabilization of policy and, most probably, some concomitant--direct or indirect--economic subsidy.[2] A high level of synthetic liquid fuels production will probably not be attainable without the creation of strong incentives; with a governmental hands-off policy, it is most likely that hardly any synthetic liquid fuels will be produced in this century.

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10--GOVERNMENT POLICIES TO ENCOURAGE THE PRODUCTION OF SYNTHETIC LIQUID FUELS

By Ernest C. Harvey

A. Introduction

In the past, various government policies have been adopted to encourage investment in specific industries, to protect industries from foreign competition or domestic overproduction, and to generate rapid increases in the output of particular products. Measures such as investment incentives provided through the tax structure, price support formulas, import quotas or tariffs, and investment grants or loans have been employed. At the time it was initiated, each of these policies was regarded as appropriate for the industry for which it was adopted. Whether any of these or other policies would be appropriate for a synthetic liquid fuels industry, or would be regarded by the Administration or Congress as politically feasible, depends on the specifics of national energy policy, on the contribution that might be made by this industry to the objectives of this policy, and on the cost to the public of achieving this contribution--not only in dollars but in environmental degradation, disruption of local economies, and other costs.

To assess alternative policies in this context, it is necessary first to examine the characteristics of this industry and to identify the principal features of a policy that could be expected to stimulate the commercialization of synthetic liquid fuels. Industry characteristics have been described in detail in other chapters, as well as the factors that would affect the decisions of private sector companies to commit resouces to the production of synthetic liquid fuels. These characteristics and factors are summarized and policy requirements are identified in the next section. The principal policy mechanisms that might be considered are examined in the following sections along with the assessment of their applicability to synthetic fuels.

B. Required Features of Federal Policy

There are two principal characteristics of a new synthetic liquid fuels industry that would influence both business decisions to commit resources to the industry and government decisions to provide incentives or other support:

- Large investment relative to output.
- High level of uncertainty regarding major factors that determine potential profitability.

Investment costs of producing synthetic liquid fuels have escalated rapidly in the last few years. For this analysis it is accurate enough to know that investment would be in the neighborhood of $1.0 billion (1973 dollars) for an output of 100,000 B/D.* As has been pointed out in other chapters, this is a very large investment even for large companies, an investment with none of the exit points that exist for exploration and development activities and involving techniques with which oil companies are not familiar.

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*Colony Development Operation is currently estimating more than $800 million for a 50,000-B/D (8,000 m^3/D) oil shale facility; other companies are hesitant to make any firm estimate. The exception seems to be Occidental's _in situ_ oil shale process, which is expected to require about $100 million investment for a 50,000-B/D output. Industry experts are skeptical at this point about Occidental's estimates.

The uncertainty is not limited to investment requirements. There are sharp differences between the Administration and the Congress on the specifics of a federal energy policy, and the future world price of oil is highly uncertain in view of the apparent instability of OPEC and the large discoveries that have been made around the world.

It is clear that the commercial production of syncrude is a high-risk venture* and that the short-term contribution to domestic self-sufficiency in crude production would be negligible. Without some form of federal incentive, it is unlikely that investments of the size required to achieve significant output will be made by the private sector, particularly if relatively high rates of inflation persist. It is also unlikely that the federal government will consider costly incentive programs unless they can be relied on to significantly reduce the nation's dependence on foreign sources of oil.

Under these circumstances the most appropriate federal policy would appear to be one that limited itself to determining, and, to the extent possible, reducing, the costs of commercialization of synthetic liquid fuel production. The time required to accomplish this would permit more careful analysis of energy demand/supply prospects and development of energy policy guidelines within which a longer-term incentive program for synthetic fuels could be established.

C. Incentive Policy Options

For purposes of analysis, incentive policies can be grouped into several categories that reflect increasing levels of government involvement:

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*With the possible exception of Occidental's in situ oil shale process and a proposed venture by Superior Oil Company that includes recovering nahcolite and dawsonite along with kerogen from the oil shale.

- Removal of constraints
- Tax incentives
- General price supports
- Specific price supports
- Government participation in investment.

These incentives are discussed briefly below, with comments regarding their applicability to synthetic liquid fuels.

1. Removal of Constraints

In a study of incentives recently completed by the National Science Foundation (NSF) and the Federal Energy Administration (FEA) 23 companies were asked if the removal of a number of constraints would constitute an incentive.[1] The constraints related primarily to the lack of a firm government policy with respect to independence from foreign sources of oil and to the current "excessive" government involvement in the energy market.

There was a consensus that a comprehensive national energy policy should encompass policy decisions in a variety of areas, provide for improved coordination among the many government agencies involved in regulation or approval of synthetic fuels development, and incorporate a commitment that these policies will remain in effect at least through 1990. The areas most in need of firm policy determination were listed as availability of federal land (on which most of the best oil shale is located) and clarification of environmental regulations.

In view of the controversial nature of these and other identified policy areas, it is unlikely that such a comprehensive energy policy will be developed in the near future. It is also unlikely, given the short-term perspective of most members of Congress, that the type of commitment felt to be necessary will, in fact, be made.

With respect to government involvement in the market, the major constraints are price controls on crude oil and regulation of the price of natural gas. Although the Administration favors removal of these constraints, Congress is reluctant to do so; proposals have, in fact, been made to roll back the price of old oil and place a ceiling on the price of new and released oil. However, respondents to the NSF/FEA survey were not consistent: although they called for a free market, they gave high priority to guaranteed procurement of synthetic liquid fuels and to loan guarantees and direct grants.

It was the conclusion of the NSF/FEA study that removal of constraints, although important, would not be sufficient to ensure commercialization of synthetic liquid fuels production. The key to such development is the assurance of profitability. Current statements by the industry, as reported in trade journals, recognize the importance of uncertainties surrounding government policy but also place major emphasis on cost and the uncertain future course of crude oil prices as major deterrents to commercialization.

2. Tax Incentives

Historically, a variety of tax incentives has been used to stimulate investment generally or in specific industries. Investment tax credits and rapid write-off provisions have been offered; minerals industries are allowed depletion allowances and the timber industry is accorded capital gains treatment. These policies are effective only where profitability can be assumed, even if it is marginal. The objective in such cases is to raise potential profitability of the activity receiving special treatment to a level that would make it competitive with alternative uses of funds, without recourse to a direct, overt subsidy.

An investment tax credit was given relatively high priority by respondents to the NSF/FEA survey, ranking 9th out of 45. However, most of the companies surveyed indicated that a credit significantly greater than that suggested (7-10 percent) would be required--perhaps as large as 50 percent--although it was recognized by many that credits in excess of 10 percent probably would not be politically acceptable. A tax credit of 7 percent was available for new investment at the time of the survey. This had been increased to 10 percent under the new tax law. Therefore, the 7-10 percent range for synthetic fuels investment does not constitute a special incentive.

In practice, the effectiveness of a tax credit of a given size will vary with the characteristics of the companies considering synthetic liquid fuels production and the specific application of the credit. If the credit is applicable only to synthetic fuels production it will not constitute an incentive unless there is reasonable assurance of profitability. If it is not restricted in application, considerations include the cash flow and profitability implications of initiating synthetic fuels production and taking advantage of the credit relative to other investment alternatives.

It should be pointed out that current congressional sentiment is to eliminate special tax "privileges." The oil depletion allowance has already been eliminated and elimination of other special tax provisions has been discussed. It seems clear that if production of synthetic liquid fuels were determined to be required in the national interest Congress would prefer to direct subsidy rather than the indirect and somewhat uncertain route of tax incentives. Congress has already expressed concern about the profits of oil companies, which are prime candidates for development of synthetic liquid fuels production, has taken action to constrain these profits by removing the depletion allowance and retaining controls on crude oil prices, and has considered an excess profits tax. A new tax incentive is unlikely.

3. General Price Support

Price support programs of various types have been used in agriculture for years. The general approach was to set floor prices for the various farm crops. At harvest time farmers could store their crops and receive payment, on a loan basis, at the support price. If the market price rose above that level he could sell the crop and repay the loan; if it declined title passed to the Commodity Credit Corporation. The Sugar Act provided for maintenance of the domestic sugar price by limiting imports of foreign sugar by means of a quota system. Crude oil and petroleum products received similar support before March 1973. Imports were restricted through quotas and duties,* which made possible the continued existence of a relatively high-cost domestic oil industry.

Programs of this type are effective in large-output situations in which the problem is one of overproduction relative to market demand. In agricultural price supports, acreage limitations were also imposed to restrict output and reduce the downward pressure on prices. The objective is to maintain the market price at a level sufficient to ensure reasonable profitability. However, such a program would not be applicable to synthetic liquid fuels because, at least in the near and medium term, the output would not be large enough to affect the price of crude oil. Other measures, such as restrictions on imports, would be required to force up the price of conventional crude to the level required to

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*Imports of No. 4 distillate and residual fuel oil into the East Coast were exempt from quota.

make synthetic fuels profitable. Largely because of consumer pressure, Congress has not accepted Administration proposals to free the price of old oil, and as stated earlier, it is considering a rollback of the old oil price and a ceiling on the price of new and released oil. Therefore, Congress is not likely to support a program that would induce significantly higher price increases, with its potential impact on the rate of inflation and on profits of the oil companies.

The general price-support approach could, of course, be used to provide a price guarantee to producers of synthetic liquid fuels, recognizing that, for the foreseeable future, the government would have to assume title to the output and sell it at a loss. This program would become a specific price support program; such programs are discussed in the next section.

4. Specific Price Supports

Several types of specific price support have been suggested and are under study by FEA. These include government procurement at cost plus a fixed fee, at a fixed price, or under a contractual arrangement with adjustments for inflation. Another mechanism, which is not technically a price support but which is similar in effect, is the payment of direct subsidies to producers of synthetic fuels.

Each of these proposals would require industry to provide the necessary capital funds unless capital expenditures were also subsidized. Rate of return on these funds would depend on the fee or fixed price negotiated or on the level of the subsidy provided. The cost plus fixed-fee arrangement would probably be the fastest way to achieve commercialization unless the rate of return implied by the negotiated fee were perceived to be less than could be obtained from other uses of funds. Furthermore, this approach would provide no incentive for efficiency unless provision were made for renegotiation of the fee upward to reflect substantial reductions in cost.

Although the fixed-price and contractual approaches would tend to encourage efficiency, many of the uncertainties--e.g., future world crude prices and government import and tariff policies--that have prevented commercialization to date would remain. The negotiated price would have to include a substantial allowance for these uncertainties to ensure even a reasonable prospect of profitability, even if provision were made for inflationary adjustments. If the negotiated price were high enough the impact on efficiency might be minimal, but, if it were significant, it would probably generate government pressure for renegotiation.

A direct subsidy would contain elements of several of the above approaches. It could be a fixed amount negotiated in advance or an amount sufficient to cover the excess of costs over revenues, with or without allowance for profits. Advantages and disadvantages similar to those indicated above apply, depending on specifics.

Any of these schemes could be handled on a levy/subsidy basis. An extra tax collected on gasoline could be distributed to synthetic crude producers to reduce the sales price of syncrude to the market level. The amount required would depend on government policy with respect to the pricing of domestic oil and the levying of tariffs on imported oil and on the future world price of oil. However, as long as the supplies of syncrude remained small, a relatively small tax would be sufficient. Presumably, a large increase in the proportion of syncrude produced would be accompanied by, and would indeed be conditional on reductions in its relative cost of production. In that event, the levy/subsidy arrangement could be adapted without undue hardship to the consumer to accommodate a proportion of the order of 10 percent of total supplies in the form of syncrude.

An alternative to a levy/subsidy mechanism would be to allocate a proportion of any extra costs entailed in the production of syncrude to each refiner in proportion to output. This type of approach is currently employed in the oil "entitlements" program to eliminate disparities in cost among companies with varying proportions of old oil, new and released oil, and imported oil in their refinery mixes. Its application to syncrude production, given its administrative complexity and the small quantities involved initially, does not seem appropriate in the short run.

There has been no discussion in recent articles in trade magazines of the mechanics and cost of marketing syncrude. Incentive programs entailing government purchase would presumably leave the marketing function to the government; either party could be responsible under a direct subsidy program. So long as the output remained small, marketing should not present serious problems. However, if relatively large quantities of syncrude were produced ultimately, substantial investment in new pipeline links would almost certainly be required. More generally, to the extent that syncrude replaces imports (which would be the logical limit on making it, unless and until it becomes cheaper than conventional crude) it will be necessary to contemplate adding to the pipeline network sufficient capacity to transport it where it is needed for refining. If syncrude served as a replacement for imports, one important destination would be the northeastern states that presently have about a million barrels a day of refinery capacity supplied by imports, but no crude pipelines other than one from Portland, Maine, to Montreal. This problem of transportation should be carefully evaluated before an incentive policy contemplating a significant long-run expansion of syncrude production is formulated.

5. Government Participation in Investment

The government can stimulate the development of specific industries by participating in investment in varying degrees. The most direct participation in investment is government ownership of industrial plants. The government can participate to a lesser extent by sharing investment costs with private enterprise or by guaranteeing private loans.

a. Government Ownership

Under a program of direct government ownership of industrial plants, the plants are constructed and operated by private enterprise under contracts with the federal government. After the development of the industry or, as the national need for the industrial output decreases, private firms would have the option of leasing or purchasing the facilities.

This approach to the rapid development of an urgently required industry is illustrated by the U.S. synthetic rubber industry in World War II. The rapid Japanese advance early in 1942 cut off the greater part of Allied supplies of natural rubber. Over the next two and a half years, to late 1944, 51 plants for producing various types of synthetic rubber and their ingredients from petroleum were built in the United States. The capital cost, some $600 million, was funded by the federal government; running costs and profits of sales were for government account. The plants were run by large private firms (because large firms alone possessed the necessary technical knowledge) on a fee basis which was, in effect, a substitute for profits. Of course, in war time there was a ready market for all the synthetic rubber that could be produced; indeed, the United Kingdom, which had agreed to take rubber from the United States rather than produce it for itself, remained somewhat short of supplies.[2]

After the war, 22 of the synthetic rubber plants were disposed of in fairly short order, but the others remained in federal ownership. A market for synthetic rubber was assured by regulating by law the amount of natural rubber that might be used in various finished goods. As time went on, and the quality of the synthetic rubber improved, manufacturers became willing to take more than was legally obligatory, and in 1953 the obligation was ended. In the same year an act was passed (P.L. 205, 83rd Congress, 1st Session, Chapter 338) establishing a Disposal Commission to sell off the remaining 29 rubber-producing facilities, and by the middle of 1955 this process was virtually complete. The plants were disposed of mainly by sale to the companies that were operating them on behalf of the government, although there were one or two exceptions, and one or two unsalable plants that had to be put on a care and maintenance basis. Particular care was taken to ensure that the purchasers would reserve part of their production for small business. The proceeds of the sales realized the federal government more, on paper, than the cost of building the facilities in the first place (if no allowance is made for the fall in the value of the dollar between 1942 and 1955). The day-to-day conduct of the businesses was also profitable.

Aluminum is another example of this approach. During World War II, the output of aluminum was greatly enlarged through the mechanism of government-owned plants constructed and operated by private enterprise under contracts with the U.S. Reconstruction Finance Corporation. At the end of the war, aluminum production was sharply curtailed and uneconomically located capacity was retired. Government aluminum plants were declared surplus for lease or sale. The lease or sale program was designed to dispose of facilities to producers other than Alcoa, which until 1940 was the sole producer of aluminum in the U.S. and had been subject to antitrust action.

However, the analogy between either synthetic rubber or aluminum and any prospective synthetic liquid fuel is not close. Both rubber and aluminum were required urgently for wartime needs in large quantities; the raw material was plentiful, and the technology was known. By contrast, synthetic crude would be a marginal addition to total energy supplies at best for many years, if only because of actual availability of the raw material, be it coal or shale.* Moreover, the investment required per unit of output is many times greater than that required for synthetic rubber or aluminum. The approach used in synthetic rubber to assure a market after World War II could be applied to synthetic crude, either by requiring acceptance of syncrude or purchase of an entitlement. However, this procedure does not seem justified, given its administrative complexities and the relatively small syncrude output involved in the near term.

b. Grants-in-Aid

The government could participate in investment to a lesser extent than in either synthetic rubber or aluminum by sharing, on a grant basis, the investment costs with private enterprise. Direct or convertible grants, if they are large enough, and if they can be used, in effect, to offset costs in excess of market price, might provide the necessary incentive for commercialization of synthetic fuels production.

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*These limitations are most likely to arise from environmental restrictions; from shortages of labor and transport facilities; from demand for more urgent needs, such as electricity generation; and from political opposition in the western states.

However, this indirect approach to subsidy has political drawbacks and would require extensive government surveillance; furthermore, under this arrangement, it would be difficult to assess the potential for production of syncrude on a private enterprise basis.

c. Loan Guarantees

A third way the government can participate in investment is through loan guarantees, which could be provided for some percentage of the required amount. Unlike the other types of participation, a loan program does not require a direct commitment of federal funds; federal funds are only committed in the event of default on the loans. Although loan guarantees are not direct government investments, they do allow the private market to invest under conditions of risk and uncertainty. Such guarantees have been used to stimulate home, farm, and small business loans. There is usually a limit on the rate of interest, and in times of tight money the margin to lenders is not particularly attractive. Furthermore, unless there is a 100 percent guarantee, the lender must assume a portion of the risk and in any event he is usually required to exercise prudent lending practices. In addition, the reporting and paperwork required under these programs is regarded by many as inordinate. The specific requirements of a loan guarantee program established for synthetic crude production, therefore, would govern its acceptability to lenders. However, given the current level of uncertainty, such a program is unlikely to provide sufficient incentive to potential procedures of syncrude to stimulate commercialization of synthetic fuels production.

There have been two recent proposals for government action to stimulate the development of a synthetic fuels industry. The first is a loan guarantee program applicable only to the development of a synthetic fuels industry. The second is contained in a broader program designed to supplement and encourage private capital investment to meet the energy needs of the nation.

The Senate version of the ERDA Authorization Bill (HR3474) included a $6 billion loan guarantee program for the development of a 350,000 B/D (56,000 m^3/D) synthetic fuels industry. Since the addition of this provision, ERDA has requested an additional $5.5 billion: $600 million for plant construction; $4.5 billion for price supports; and $400 million for loan guarantees to communities that would have to cope with the new industry.

Legislation creating an Energy Independence Agency (EIA) was submitted to Congress by the President in October 1975. The EIA, which will have a 10-year life, would have financial resources of $100 billion, consisting of $25 billion of equity and $75 billion of debt. Financial outlays are intended to be recovered by the government and would be used to support projects that would contribute directly and significantly to energy independence and that would not be financed without government assistance. Financing could take a variety of forms including direct loans, loan guarantees, guarantees of price, purchase and leaseback of facilities, and purchase of convertible or equity securities. Emphasis would be placed on loans and loan guarantees, and government ownership is authorized only for limited periods and under specified conditions.

These proposals indicate an awareness, at least on the part of the Administration, that significant investment in synthetic fuels is unlikely in the near term without government assistance. However, there appears to be little support for these programs on the part of many legislators and industry spokesmen. There is considerable controversy concerning the size, scope, and timing of a synthetic fuels program, which is itself part of the larger controversy regarding a national energy policy. Any decision with respect to financial involvement by the government must await resolution of these controversies.

D. Conclusions

The combination of high cost seemingly irremedial uncertainty make synthetic fuels investment unsuitable for private business. If synthetic fuels are to be produced in significant amounts in the near future, government assistance will probably be necessary. There is considerable disagreement among Congress, the President and industry regarding the degree of government participation in the synthetic fuels industry. Even if a variety of inducements could be provided, it is not clear whether private investment could be attracted, especially since most inducements are subject to considerable uncertainty in that they can be modified or eliminated at short notice. The need for long-term commitment to firm energy policies was emphasized by respondents to the NSF/FEA study. Such commitment would be particularly important for synthetic liquid fuels production because of the large investment requirements and uncertain future market. However, by its very nature, Congress cannot commit itself to firm, long-term policies, and its record with "long-term" policies in the past does not instill confidence.

If the government decides that development on a commercial scale is desirable, it would seem appropriate for it to finance a commercial plant or plants. The government has already become heavily involved in the financing of a demonstration plant under the terms of a contract between the Energy Research and Development Administration (ERDA) and Coalcon*

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*Coalcon is a joint venture formed by Union Carbide and Chemical Construction and has recruited members of a consortium being formed to build and operate the demonstration plant.

of New York. The initial funding for plant design and engineering will be provided by the government and costs of construction, evaluation, and operation will be shared equally by the government and industry. Total government funding will be $137 million, and the private sector will contribute $100 million. The plant is expected to be operating by 1983 and will convert 2600 tons/day (2.4×10^6 kg/D) of coal into 3900 B/D (4100 m^3/D) of liquid product and 22 million cubic ft (620,000 m^3/D) of pipeline-quality gas per day.* This plant is very small compared with the sizes considered suitable for commercialization elsewhere in this study.

If commercialization is determined to be required before the results of this demonstration are in, the government will probably have to furnish the capital to build the plant (and possibly to open an associated mine), arrange for the transportation of the product to refineries (building pipelines if necessary) and enter into contracts with a firm or firms for the day-to-day management of the plant on a fee basis, and for the purchase of the product at a range corresponding to the difference in quality between it and competing conventional crude. Although this rate might represent a premium over the market price, it seems clear that it would have in it a large element of subsidy. These tasks would have to be carried out by one or more of the big companies in the industry.

This undertaking would inevitably involve the government in the industry in a variety of complicated ways that it would doubtless prefer to avoid. As the NSF/FEA report makes clear, government involvement would also be unpopular with the oil companies. For example, one of the

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*This represents about an equal division of energy in liquid and gaseous forms.

companies surveyed observed that it would be a disincentive to synthetic fuels development activities by the private sector, although it is difficult to believe that anyone making this observation had looked carefully into the question of comparative cost. Another company observed that the most likely outcome would be that "the government would end up as the sole owner of an unprofitable plant," which is perhaps much nearer the mark. However, government financing of a commercial plant would provide a firmer basis than now exists for estimating the likely costs of synthetic liquid fuels production and for establishing a policy regarding the role of these fuels in the future supply of domestic oil. If successful, the experience gained in the synthetic rubber program could be used to turn the activity over to the private sector.

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11--NATIONAL ECONOMIC IMPACTS OF THE SYNTHETIC FUELS INDUSTRY

By John W. Ryan

A. Introduction

The production of synthetic fuels from coal or oil shale results in impacts at several levels in the economy. The chief impacts are those associated with the employees (and their families) of the mining and processing facilities. The secondary economic impacts are those that result, in turn, from the primary development. These include the induced growth of and competition with other industries. Most commonly discussed are the supporting industries that gather around the primary development. However, there are many supporting and supplying industries that will provide goods and services from a distance; many of these are already established and are unlikely to relocate. The demands for the goods and services of these supporting sectors will be substantial under the levels of resource development required by the SRI scenarios.

This chapter discusses the availability of materials and equipment and describes the impacts in geographic regions distant from the location of the primary mining and processing facilities. The nature of the impact and general magnitude of the demand are discussed, along with the geographic location of the major supplying industries. Specific forecasts of impacts are not attempted because there are too many influences outside of the system of synthetic fuels production.

B. Interindustry Relationships

The principal sectors supplying the coal mining industry (and by inference the future oil shale mining industry) can be determined from the total requirements table of the 1967 input-output (I-O) matrix of the U.S.[1] The coefficients in this table specify the direct plus indirect output of other industries needed to produce a dollar's worth of coal delivered to final demand. For example, the coefficient for mining machinery (sector 45.02) is 0.026; this means that for every thousand dollars of coal sold in 1967 to final demand, purchase of $26 of mining machinery is required. Table 11-1 lists the 20 coal supplying sectors with the largest total requirements coefficients.

The largest coefficient in Table 11-1 belongs to the coal industry itself; for every dollar of coal delivered to final demand, another 0.15 dollar's worth is consumed by sectors that in turn supply the coal mining industry. Nonindustrial sectors with large coefficients are real estate and miscellaneous business services. These reflect the importance of land purchases and leases and of repair services, such as welding and armature rewinding. Legal services are classified under sector 73.03, miscellaneous professional services, with a coefficient of 0.010.

Several manufacturing sectors appear in Table 11-1. Blast furnaces and basic steel products (sector 37.01) have the largest coefficient and, therefore, can be expected to be of utmost importance for expanded coal production. Other sectors that one would expect to be important are construction and mining machinery. Chemical industries (sectors 27.01 and 27.04) appear primarily because of the importance of blasting materials in mining.

Petroleum refining is classified as a manufacturing sector according to I-O classifications, although it actually represents oil as a

Table 11-1

ECONOMIC SECTORS PROVIDING INPUTS TO THE COAL MINING SECTOR, RANKED BY SIZE OF 1967 TOTAL REQUIREMENT COEFFICIENT

Source: Reference 1.

Rank	Industry Title	Coefficient	Input/Output Sector Code
1	Coal mining	1.148	7.00
2	Real estate	0.075	71.02
3	Blast furnaces and basic steel products	0.037	37.01
4	Wholesale trade	0.034	69.01
5	Miscellaneous business services	0.034	73.01
6	Electric utilities	0.031	68.01
7	Mining machinery	0.026	45.02
8	Petroleum refining	0.020	31.01
9	Screw machine products and bolts, nuts, rivets, washers	0.017	41.01
10	Miscellaneous chemical products	0.017	27.04
11	Maintenance and repair construction	0.016	12.02
12	Construction machinery	0.015	45.01
13	Industrial chemicals	0.014	27.01
14	Imports	0.013	80.00
15	Reclaimed rubber and miscellaneous rubber products	0.012	32.03
16	Railroads and related services	0.011	65.01
17	Crude petroleum and natural gas	0.011	8.00
18	Miscellaneous professional services	0.010	73.03
19	Insurance	0.010	70.04
20	Logging camps	0.009	20.01

source of energy analogous to the coal, natural gas, and electric utility sectors. The coefficient for petroleum refining is 0.020, while that for electric utilities is 0.031. These high values reflect the direct importance of petroleum products and electricity to coal mining, as well as their importance to all sectors supplying the coal mining industry.

Input-output tables reveal the relative contribution of various sectors to the output of coal mines. However, potential constraints on the expansion of the coal industry depend largely on the size of coal industry demand compared with other demands for the capacity of each supplying sector.

The level of aggregation in the input-output table is a source of difficulty. The aggregation can obscure key parts of selected industries. One attempt to overcome this problem is reported in Bureau of Mines Information Circular 8338, "The Interindustry Structure of the U.S. Mining Industries - 1958," which contains detailed tables listing materials and purchased services for coal and other mining industries. For example, this more disaggregated table reveals that the reclaimed rubber and miscellaneous rubber products sector is important because of the miscellaneous rubber products (SIC 3069) component, which includes conveyor belting and rubber hoses.

Thus, in summary, the interindustry relationships given in input-output tables are useful to identify the major inputs needed by the coal mining sector, especially from indirect suppliers of the coal mining sector that could easily by overlooked otherwise. The next section expands the analysis to discuss the demand levels for specific equipment and the potential for bottlenecks.

C. Materials and Purchased Services Used by the Coal Industry

The availability of goods and services used in energy production was analyzed by the Materials, Equipment, and Construction (MEC) Task Force of Project Independence,[2] which covered all energy sectors; this paper, however, is concerned only with coal and oil shale. Other demands on supplying sectors from other energy sectors cannot be discussed in detail but may have an effect on the availability of materials for coal production.

1. MEC Task Force Projections

The MEC Task Force considered two scenarios in their analysis:

1. BAU, "Business-as-Usual" scenario of the Project Independence Coal Task Force.
2. AD-C, "Accelerated Development" scenario of the Coal Task Force, as constrained by the availability of walking draglines.

Figure 11-1 shows coal production for the maximum credible implementation scenario (MCIS) developed for this study added to that of the Ford Energy Policy Project's Historical Growth scenario (HG1) without synthetic liquids from coal. Together, the scenarios call for 3.6 billion tons of coal consumption in 2000. The 1990 production for the BAU and AD-C scenarios of the MEC Task Force are shown in Figure 11-1 as two points at 1.3 billion tons and 1.8 billion tons, respectively. Because the AD-C scenario is approximately equal to the total for HG1 plus MCIS in 1990, the conclusions of the MEC Task Force can be applied directly--assuming (1) that the split between underground and surface mining remains approximately the same between 1990 and 2000, and (2) that trends in capacity expansion continue to 2000.

The future availability of the selected items was based on Department of Commerce analyses of production capacity for the commodities

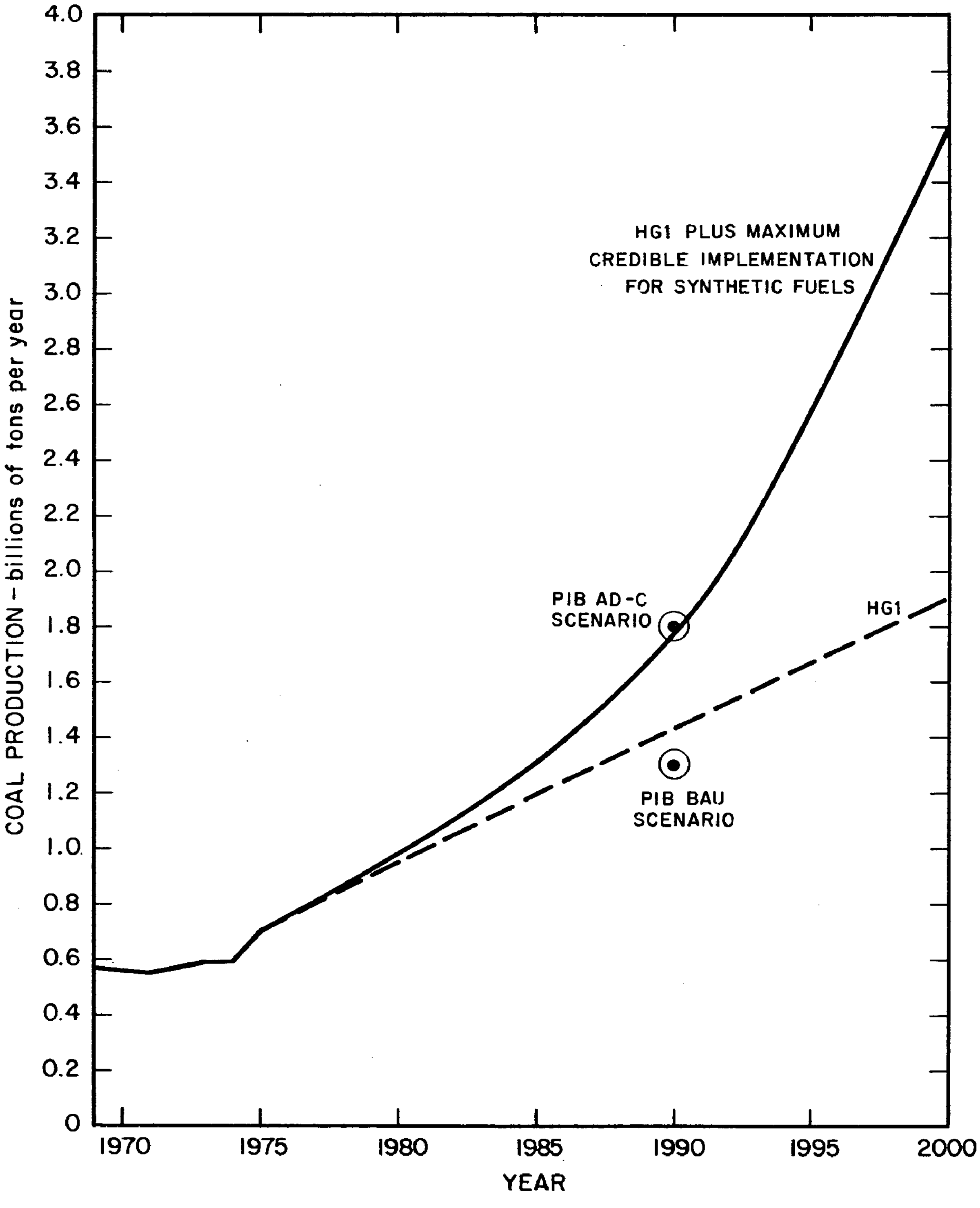

FIGURE 11-1. FUTURE COAL PRODUCTION LEVELS FOR PROJECT INDEPENDENCE SCENARIOS AND THE SRI MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO (PIB: Project Independence Blueprint; HG1: Ford Energy Policy Project Historical Growth 1)

involved. Export demand (a fraction of capacity) was assumed to continue at current levels, with the remainder of production available for domestic consumption. MEC estimated the portion sold to the energy sectors by techniques such as trend line extrapolation, input-output, and contacts with manufacturers.

The MEC investigated basic materials, such as steel and cement; intermediate materials, such as forgings, castings, and explosives; equipment components, such as compressors, pumps, and valves; and major equipment, such as continuous miners and draglines. Potential problems for the future expansion of coal mining were found in:

- Steel
- Walking draglines
- Castings and forgings.

However, problems are not expected for:

- Continuous miners
- Construction equipment
- Crushers
- Explosives
- Mine roof bolts
- Power shovels.

Before discussing the problem areas further, however, the analysis behind other coal-related categories will be considered.

The MEC Task Force made various assumptions in its analysis.* For example, although the demand for continuous miners depends on the coordinate availability of horizontal and vertical boring machines, the

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*To fully understand the MEC assumptions about the supply situation, the reader should refer to the MEC Task Force Report for each category.

latter two were not analyzed or discussed in detail. It should be noted that continuous miners are made to mine specifications and not available from open inventory. About 94 percent of the continuous miners produced in 1973 and 1974 were shipped to the coal mining industry, but in the period to 1990 the MEC estimates that the percentage will drop to 86 percent. About 95 percent of mine roof bolts will go to coal mines. Assuming that roof bolt supplies are not again disrupted by price controls, as they were in 1972 and 1973, the MEC foresees sufficient flexibility to expand roof bolt production in existing facilities. This should remain true even if legislation greatly curtails surface mining and forces an increase in underground mining. The estimates for categories that sell to end users besides mining are not as critical because productive capacity that has historically gone to other sectors could, in principle, be diverted to the coal industry. This is true of construction equipment,* explosives, crushers, and power shovels, where less than 50 percent of output goes to coal mining.

a. Steel

The MEC Task Force found that there would be a shortage of steel supplies available in the energy sector if no more than the historical percentage of steel output went to energy industries. Based on the historical distribution of steel between energy and nonenergy uses, a 7.3 percent availability to energy industries was selected as a conservative estimate, while an upper value of 11.1 percent was chosen on the basis of figures for the first half of 1974. The results are summarized from the MEC report in Table 11-2.

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*Especially now that the interstate highway system is nearing completion.

Table 11-2

PROJECTED STEEL AVAILABILITY
(Millions of Tons)*

	1980	1990
Steel mill capacity	125.9	150.2
Available to energy sector:		
@ 7.2%	9.1	10.8
@ 11.1%	14.0	16.7
Requirements:		
Scenario BAU	10.3	13.4
Scenario AD-C	11.6	14.6

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*Note 1 ton is about 907 kg.

Source: Project Independence Materials, Equipment and Construction Task Force.

Table 11-2 shows that the requirements for scenarios BAU and AD-C of the MEC fall between the 7.2 percent and 11.1 percent production values. Thus, with synthetic liquids included, the energy sector will need to purchase a greater proportion of steel output than it has averaged historically. Steel for the coal industry, including production allocated to liquid synthetic fuels, reaches 6 percent of energy sector requirements in 1980. This is such a small portion of total steel demand that it is unlikely that coal mining will be seriously affected by shortages of gross steel capacity; however, as discussed below, specialty products may prove constraining.

b. Ferrous Castings and Forgings

Castings and forgings are usually discussed together because of the similarity of their production. Production capacity is fragmented among several industries producing diverse products, which leads to great difficulties in estimating current capacity for castings and forgings.[2] Clearly, future capacity depends on availability of steel, capital, labor and energy, but a major portion of future capital expenditures must be oriented towards compliance with regulations on health, safety, and environmental quality. Unfortunately, the small size and low profitability of many firms in these industries make them unattractive to capital sources. Even though the MEC Task Force was unable to develop quantitative estimates of availabilities and requirements for castings and forgings--because it found that even though the industry is operating multiple shifts, delivery times are growing and shortages are developing--it concluded that expansion of energy production was likely to be constrained.

c. Walking Draglines

The MEC Task Force concluded that walking draglines would be the limiting item in accelerating coal output. Indeed, their AD-C was derived by scaling the "Accelerated Development" scenario of the Coal Task Force of Project Independence that called for 2.8 billion tons of coal in 1990. The MEC concluded that in 1990 only 1.8 billion tons could be produced because the availability of draglines would constrain future development of surface mines. Thus, since the sum of HG1 and MCIS scenarios correspond to the AD-C scenario, walking draglines can be expected to inhibit synthetic fuels development.

Behind this conclusion are the following facts:[2]

- Orders now on the books are sufficient to keep the industry at full production through 1979.

- Producers plan to ship 45 draglines in 1977--up from 21 in 1974. (MEC Task Force estimates 1980 annual capacity at 50 to 55 units.)
- Historically, 25 percent of the walking draglines have been exported (helping to balance capital outflows from the United States).
- Manufacturers have been able to raise capital for expansion in the past.

Unfortunately, the MEC Task Force does not present the details of its supply/demand estimates, so the basis for its conclusion is not readily apparent. In fact, a simple analysis of the supply situation compared with the number of mines necessary to meet the 1990 production levels of the AD-C scenario suggests that dragline production should be more than sufficient. The details of the estimate made for this study are given in Appendix A.

2. Overview

The level of economic activity of the moment can influence an analyst's views of material shortages. The work of the MEC Task Force was conducted in mid-1974 during a period of material shortages and long delivery times. The recessionary situation of early 1975 was quite different; except for the energy sector, there was considerable idle capacity and unemployment. It might be expected that the fraction of future production capacity available to energy sectors is likely to increase as suppliers turn to that market, seeking to cultivate stable and growing markets. Thus, historical relationships are likely to change as the economy shifts back to growth, with more emphasis on capital goods sectors and less on consumer durables, such as automobiles.

D. Conversion Facilities

Possible constraints on the construction of three processing operations for the production of synthetic liquid fuels are considered here:

- Coal liquefaction plants
- Oil shale retorts
- Methanol plants.

The input-output approach used above cannot be used to identify the major supplying industries to the future synthetic fuels industry since the data do not exist. Moreover, after exploring possible parallels with the petroleum refinery sector in the input-output data, it was concluded that the analogy was not strong enough to justify elaboration. However, engineering analyses have provided estimates of the needed materials and equipment. Liquefaction plants and oil shale retorts require similar amounts of steel for large-scale operations; however, methanol production requires almost twice the steel per unit of output (see the construction scaling factors in Chapter 6).

Coal liquefaction is a highly complex process requiring large pressure vessels and high-quality piping; both require numerous pumps and compressors. Consequently, the construction of coal liquefaction plants is more likely to meet with materials and equipment shortages than construction of oil shale retorting facilities.

Availability of steel plate for pressure vessel construction is limited. According to the Project Independence Task Force Report on Synthetic Fuels from Coal, only one steel company presently has the capability to produce steel plate in large widths;[3] lead times in 1974 were reported to be 2 years.

Even if the necessary steel plate were available, fabrication of pressure vessels poses another bottleneck. Most of the capacity able to produce heavy-walled pressure vessels needed in coal liquefaction is currently committed to nuclear power facilities, and it is unlikely that large amounts of capacity will be available for coal liquefaction without substantial additions to capacity.[3] The major fabricators are currently committed through the 1970s. The present competition for materials is not likely to change significantly over the long term under current U.S. policy. Even in the 1990s when the scenarios of this study show rapid growth in coal liquefaction, the demand for nuclear power is expected to remain a strong competitor for steel suitable for pressure vessels.

Future production of pumps and compressors depends on the availability of castings and forgings as opposed to plant capacity. The engineering lead times for synthetic fuels plants is longer than the time needed to tool up for increased production of these goods.[2]

Material constraints on oil shale retorts and methanol plants seem less critical. While large amounts of steel are required, the necessary pressure vessels are smaller and easier to fabricate. Consequently, there are more mills capable of producing the necessary steel products. The availability of castings and forgings is a possible bottleneck in this portion of the synthetic fuels production chain as well.

E. Transportation

The impacts in the transportation sector depend very much on the location of mines and conversion facilities. Coal liquefaction may either be done at the mine (mine-mouth) or the coal may be shipped to a remote liquefaction plant by rail or slurry pipeline. (See Chapter 19.) There is no transportation problem for the oil shale industry because processing must be performed at the mine to be economic, and the synthetic crude can be shipped by pipeline using relatively short branch lines to connect with existing crude pipelines.

Regulatory policies will be a key factor. Present air quality standards will increase demand for low sulfur western coal, and the distance to utility markets will increase the demand for rail facilities. If western states pass regulations prohibiting development of conversion facilities, then rail shipments or slurry pipelines will be necessary to move coal to distant liquefaction plants.

1. Railroad Equipment

Presently, railroads haul 78 percent of all coal, and this amounts to approximately 20 percent of all rail traffic.[4] Under their "Base Case" scenario, Project Independence calculations show that rail shipments of coal will more than double by 1985 to a level of 730 million tons per year.[4] The resulting supply/demand balance for locomotives and hopper cars for 1985 is shown in Table 11-3.

Table 11-3

CUMULATIVE DEMAND AND SUPPLY ESTIMATES FOR LOCOMOTIVES AND HOPPER CARS TO 1985--PROJECT INDEPENDENCE BASE CASE

		Manufacturing Capacity	
	Required	Minimum	Maximum
Locomotives	10,465	14,600	19,100
Hopper cars	274,800	180,000	310,000

Source: Reference 4.

Table 11-3 indicates that there would be sufficient locomotives if all new production could be used to move coal. Total requirements are over two-thirds the estimated minimum productive capacity to 1985, leaving only one-third of the new locomotives to be used by the other 75 (or more) percent of rail traffic. Hopper cars are in even tighter supply according to Project Independence; the projected requirements for coal shipments are 88 percent of the maximum production through 1985, and 50 percent greater than the minimum.

Because of slight differences in coal production rates and time horizons assumed in the MEC and this study, it was necessary to adjust the MEC's railway equipment projections upwards by 22 percent. This yields an upper-bound estimate of locomotive and hopper car requirements. This gives a requirement for 335,000 hopper cars and exceeds the maximum estimated production capacity shown in Table 11-3.

The production of railroad equipment requires that steel goods be available in sufficient quantities. For example, a typical 100-ton hopper car requires 30 tons of steel, but castings and forgings needed for wheels and axles, truck side frames, and couplings are likely to be in limited supply. Thus, the gross availability of steel may not constrain coal car production as much as the lack of specialty products.

Financing of new equipment will be a definite problem for deficit-plagued railroads. However, institutional changes affecting the ownership of rail cars are occurring; in particular, utilities and other large coal users are now purchasing cars directly to guarantee their shipments. This trend, coupled with equipment leasing, will alter the nature of railroad financing in the future.

2. Coal Slurry Pipelines

The use of slurry pipelines will not drastically alter the materials and equipment requirements for coal transport. Indeed, the Project Independence analysis concluded that slurry pipelines ". . . are not going to offer major savings in total dollar investment, steel or in labor."[4] However, they may drastically alter the institutional structure of the coal transportation industry. (See Chapter 19.)

F. Geographical Distribution of Sectors Supplying Synthetic Liquid Fuels Industry

The impacts of rapid development of coal and oil shale resources to make synthetic liquid fuels will extend to most of the major manufacturing areas of the United States. However, the magnitude of the impacts is not likely to be large compared with the total economic activity in an area--in contrast to the situation in western mining areas where rapid growth rates are expected because of the small current base population.

1. Mining and Construction Equipment

Firms manufacturing mining and construction equipment will be considered together, since many construction equipment items, such as power shovels and front-end loaders, are used by the coal mining (and future oil shale) industry.

Two-thirds of the total employment in the construction machinery (SIC 3531) and mining machinery (SIC 3532) industries is located in the 6 states listed in Table 11-4. Within these states, plants are concentrated in the vicinity of Chicago, Cleveland, and Milwaukee; smaller metropolitan areas of importance in Illinois are Peoria and Springfield; and in Ohio, Bucyrus and Marion. The manufacture of mining equipment is a much smaller industry having only 22,000 employees versus 132,000 for construction equipment. Only four states are major producers--Ohio, Wisconsin, West Virginia, and Pennsylvania. As coal mining in the West grows, some new plants will be opened. For example, Bucyrus Erie, one of the three firms that manufacture walking draglines, has opened a plant in Pocatello, Idaho.

Table 11-4

EMPLOYMENT IN CONSTRUCTION EQUIPMENT AND MINING EQUIPMENT INDUSTRIES BY STATE, 1972

State	Employment (thousands of employees) Construction Equipment	Mining Equipment
Illinois	45.7	0.9
Ohio	13.7	2.2
Iowa	12.1	n.a.*
Wisconsin	10.7	2.8
Pennsylvania	5.9	5.0†
West Virginia	n.a.	1.8
Total U.S.	132.1	21.7

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*n.a. = not available.
†Estimated for this study.

Source: Dept. of Commerce, Bureau of the Census, 1972 Census of Manufacturers.

There are a few items of mining equipment that are currently produced by a limited number of firms. Two prominent examples are draglines and continuous miners having, respectively, only three and five producing firms. A third example is off-highway trucks; the 1974 Buying Directory of Coal Age lists 20 manufacturers, but only 10 are major factors in the manufacture of large coal hauling trucks used at surface mines.

2. Explosives

Approximately 45 percent of the U.S. output of explosives is used by the coal mining industry, and the vast majority (96 percent) is consumed by surface mines.[2] In 1967, the eight largest companies accounted for 91 percent of total shipments. The only significant concentration of plants is in New Jersey, where Hercules, Inc., has three plants and duPont has one.

3. Railroad Equipment

The manufacture of and market for locomotives in the United States is shared by General Electric Co., and the Electro Motive Division of General Motors Corp., with plants located at Erie, Pennsylvania, and Chicago, Illinois, respectively. GM captured over 75 percent of domestic orders in 1974, but GE supplied 100 percent of the foreign orders for locomotives.[5]

Freight cars are manufactured by several companies, including divisions of the railroads themselves. On December 1, 1974, order backlog stood at nearly 91,000 cars.[5] Open hopper cars suitable for coal represented 27 percent of this backlog, although they constitute only 20 percent of the total current fleet of cars. Thus, the fraction of hopper cars (both open and covered) in the freight car fleet is increasing.

Ten firms dominate the freight car manufacturing industry, but not all of them manufacture open hopper cars.[2] The conversion of other car production lines to coal hopper cars could be accomplished readily if demand warranted. Moreover, Pullman-Standard, a major manufacturer of coal cars, has recently completed a new production line in Butler, Pennsylvania (employing 3,000), to make hopper cars for the Burlington Northern; this company is planning a similar production line at its plant in Bessemer, Alabama.[6]

The impact of increased demand for railroad equipment will most likely be concentrated in current producing areas. These are the Chicago-Gary-Hammond region of Illinois and Indiana and medium-sized towns in the western Pennsylvania region. These Pennsylvania producers are all within the sphere of influence of Pittsburgh (although not in the SMSA itself). Other regions that can expect impacts less concentrated than the above are St. Louis, Missouri; Seattle, Washington; and Bessemer, Alabama (near Birmingham).

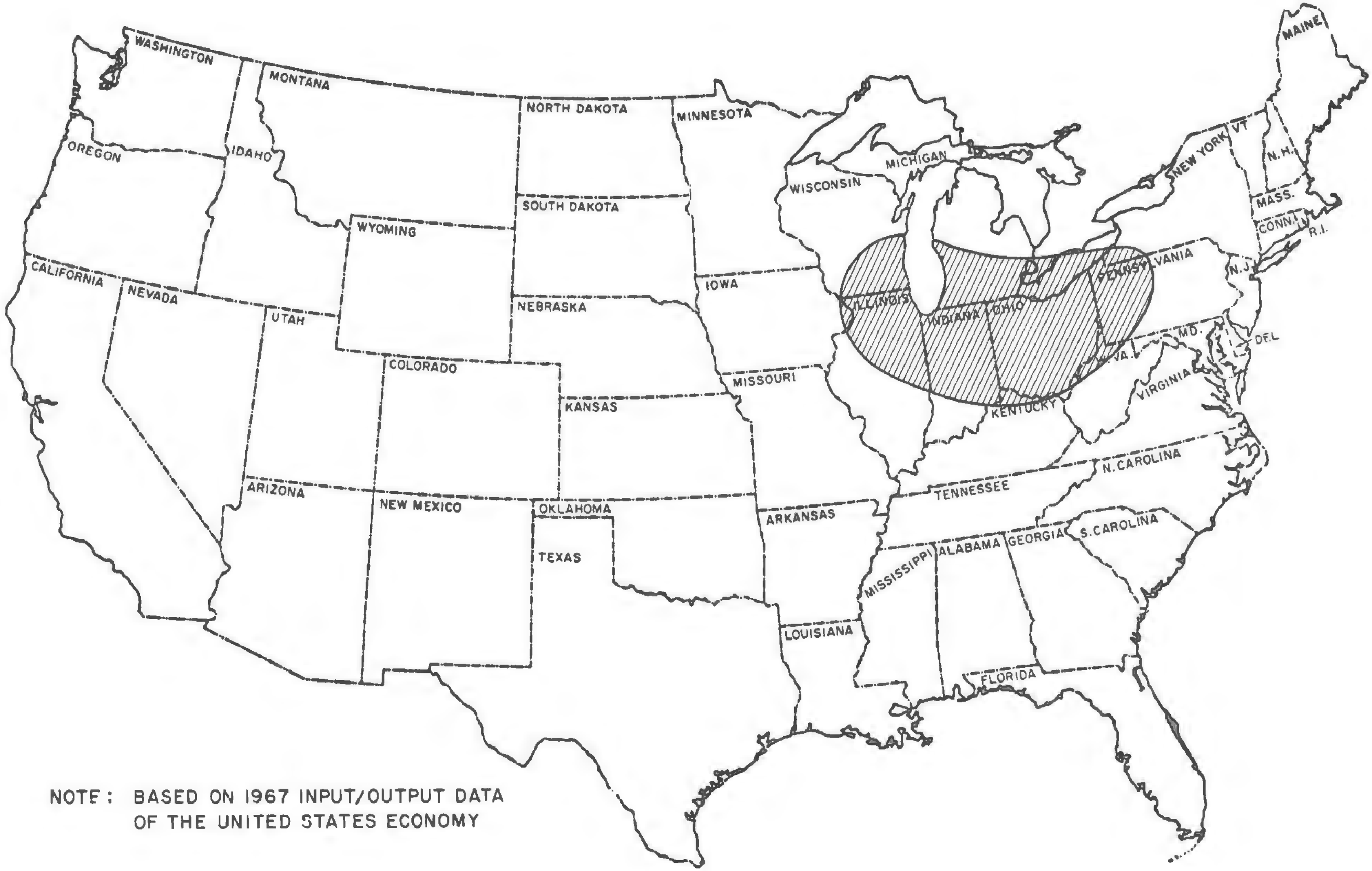
4. Steel

In the above discussion of the relationship of energy growth and steel demand, the main conclusion was that energy-related steel demand will be a relatively small portion of total capacity. Consequently, the geographical impacts will be minor and can only be discussed in general terms. Assuming no rapid shutdown of aging facilities to meet environmental regulations, the current steel producing centers will probably be dominant to the end of the century. These major production centers are Pittsburgh, Pennsylvania; E. Chicago/Gary, Indiana; Baltimore, Maryland; Buffalo, New York; and Youngstown, Ohio. All are in highly developed metropolitan economies, so that any growth will have little percentage impact. If traditional steel markets diminish in the future (such as might result from smaller cars using increased fractions of plastic), then energy-derived demand could help to maintain steel industry output and employment. In general, however, the state of the steel industry will depend more on the nation's overall economic strength than on demand derived from energy industries.

5. Summary

Although little can be said to pinpoint future changes in the locational patterns of the four industries that are important to the future development of coal resources, it is unlikely that any rapid changes will take place. Heavy industrial centers in the United States have developed where raw materials, labor force, energy, and transportation are available; once established, institutional inertia slows the pace of change.

For the most part, the supplying industries discussed throughout this paper are located in a crescent-shaped region around the southern edge of the Great Lakes, stretching from Milwaukee on the west to Pittsburgh, as shown in Figure 11-2. Historically, this is the region that has supported coal mining and heavy industry, and it appears that it will continue to do so in the future.



NOTE: BASED ON 1967 INPUT/OUTPUT DATA OF THE UNITED STATES ECONOMY

FIGURE 11-2. PRIMARY CONCENTRATION OF MAJOR INDUSTRIAL SECTORS EXPECTED TO SUPPLY THE COAL AND OIL SHALE INDUSTRY

Appendix A

ESTIMATION OF DEMAND FOR WALKING DRAGLINES

Appendix A

ESTIMATION OF DEMAND FOR WALKING DRAGLINES

Using data from the MEC Task Force and assuming sufficient materials are available, as shown in Table A-1, about 400 draglines should be available from 1975 to 1990, even assuming no expansion beyond the MEC estimate of 1980 production levels.

The number of surface coal mines that would have to be opened to produce 1.8 billion tons of coal was estimated as follows. Underground production is assumed to double from 0.3 billion tons in 1974 to 0.6 billion tons in 1990. The 1.2 billion tons of surface production was assumed to come from 300 mines: 100 east of the Mississippi River, each producing 2 million tons annually; and 200 western mines, each producing 5 million tons annually. (The estimate of draglines needed will be conservative if it is assumed that all these mines are new.)

Without delving into details concerning overburden thickness and stripping ratios, a straightforward comparison shows that an average of 1.33 (400/300) draglines per mine could be produced to 1990. According to a Bureau of Mines cost analysis,[7] more than one dragline would be necessary only in rare cases, such as a 5-million-ton per year lignite mine in North Dakota. Most of the model mines described have only one dragline for removing overburden and use power shovels for mining coal and loading trucks. Moreover, in some mines, such as the open pit Belle Ayre mine in Wyoming, draglines are not used.

However, a large increase in power shovel production cannot be expected since they are manufactured mainly by the same firms that make walking draglines.

Table A-1

ESTIMATION OF DRAGLINE PRODUCTION
1975-1990

Year(s)	Annual Production (units)	Total Units
1975	25	25
1976	30	30
1977-79	45	135
1980-89	50	500
Total produced 1975 to 1990		690
Exports @ 25%		-175
Noncoal @ 20%		-103
Total available for coal		412

Source: Reference 2.

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12--ECONOMIC IMPACTS IN RESOURCE DEVELOPMENT REGIONS

By John W. Ryan

A. Introduction

The development of oil shale and coal resources for synthetic liquid fuels will create employment opportunities at mines and processing facilities. In the Midwest, such employment opportunities will result in relatively little population migration because of the underemployment of the existing labor force and existence of a substantial base population. In the Northern Great Plains and the Rocky Mountain West, however, the indigenous population is not nearly sufficient to meet the labor demand. The result will be a large immigration into the relatively small towns of the western coal and oil shale areas. Judging from past oil and uranium booms, as well as the present beginnings of a coal boom, the influx of new workers and their families will cause substantial economic changes.

The purpose of this paper is to describe the economic impacts of such induced growth under various assumptions. The analysis concentrates on two western regions: (1) for coal, Campbell County, Wyoming, the center of the Powder River Basin coal field and the location of nearly all the strip-minable coal in the Basin; and (2) for oil shale, Rio Blanco and Garfield counties, Colorado, the counties that encompass most of the high-grade oil shale resources in the Piceance Basin. Impacts in these regions will be compared and contrasted with the expected impacts in other resource regions, namely, western North Dakota, southern Illinois/western Kentucky, and Appalachia. The location of all these regions is outlined in Figure 12-1.

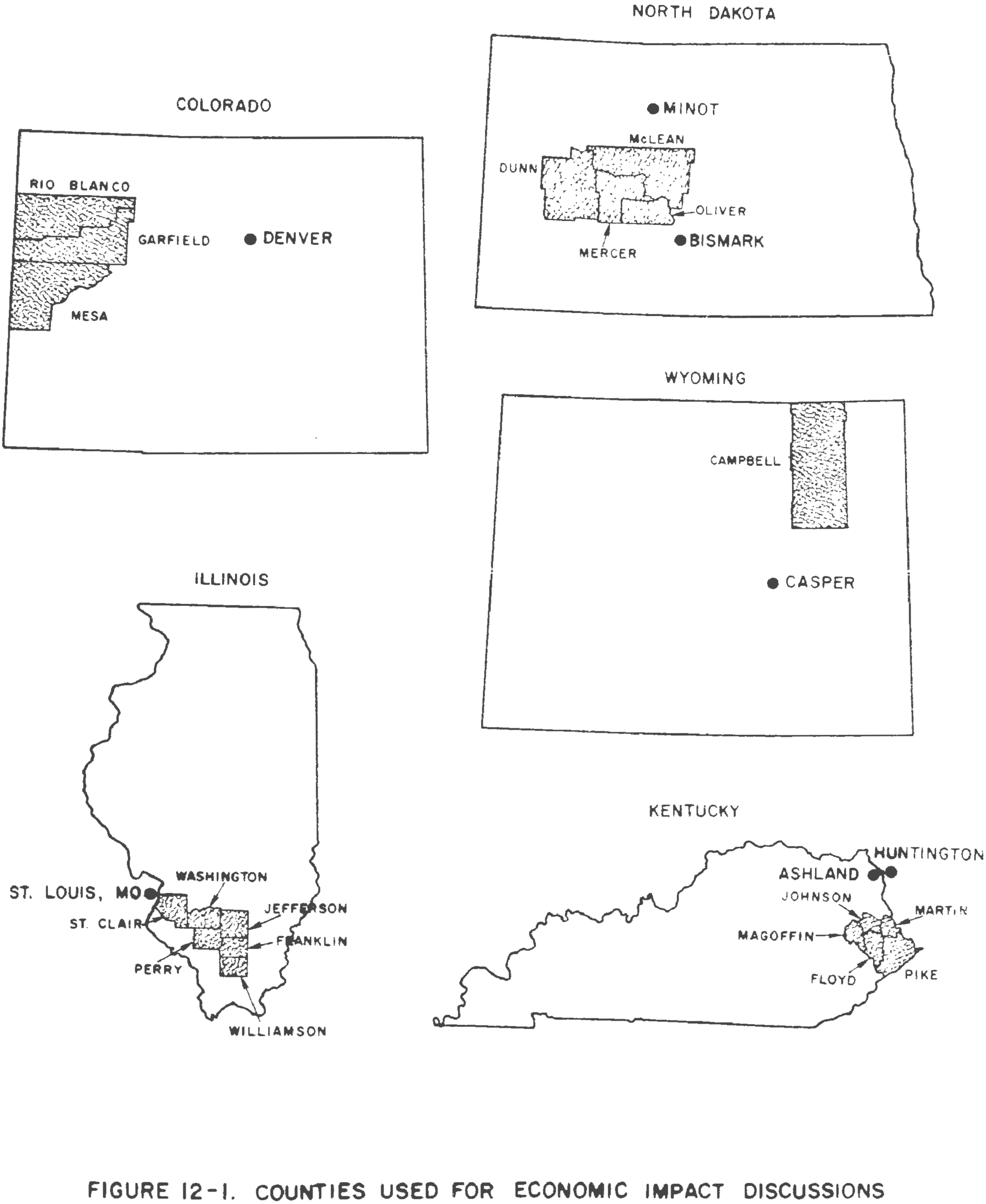

FIGURE 12-1. COUNTIES USED FOR ECONOMIC IMPACT DISCUSSIONS

B. Regional Employment Growth

1. Background Theory

The classical approach to regional economics is to distinguish between basic or export employment and secondary employment. The theory is that basic employment generates income by exporting goods to other regions;* this income is then able to support local service industries, such as wholesale and retail trade. Regional growth projections are made by projecting basic employment and then adding secondary employment based on a ratio of secondary to basic employment. Population totals are derived by assuming some labor force participation rate or average family size.

2. Population Estimates for Coal Development

The population that is likely to result from coal mining and processing has been estimated for portions of the western coal regions in many previous reports.[1-5] The method of approach is basically the same in all cases. Employment in coal mining and related activities (gasification, liquefaction, and power generation) is estimated on the basis of the number and sizes of facilities. The employment in service or derivative sectors is estimated using a ratio of total employment to basic coal-related employment. In one instance,[2] income is used as the basis for the predictive relationship. Total population is then estimated using labor force participation ratios and family size. Several refinements are possible:

- Secondary-to-basic employment ratios may be distinguished by basic industry: mining, manufacturing, construction.

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*Additional income is generated by imports of mortgage money to finance construction.

- Secondary-to-basic employment ratios may be distinguished by size of town (i.e., scale effects are assumed to exist).
- Secondary-to-basic employment ratios may differ by the distance between the basic industry and trade centers.
- Labor force participation rates may be broken down by age and sex to allow for varying age characteristics of the immigrants.

The result is that by judicious choice of ratios, a wide range of total population estimates can result from any assumed basic employment number. Thus the casual use of multipliers or ratios derived from historical relationships in the study areas has drawbacks.

Additional forecasting difficulties arise because there are problems in defining the base area and obtaining data. Regional economies rarely adhere to the political boundaries for which data are usually published. Another problem--one that often confronts local planning officials--is accounting for time lags in growth. Secondary development often lags growth in basic industries because service industries are usually not attracted to an area until the initial employment growth has already occurred. On rare occasions--as in the recent Alaskan oil finds--substantial investments in service industries are made before large-scale primary development occurs.

The large construction projects usually contribute another element of uncertainty because much construction labor is transient and creates service industry demands resulting from its family and age characteristics that are different from those of permanent residents.

3. Coal-Related Development in Campbell County, Wyoming

The population in Campbell County for 1975 to 2000 was calculated for two basic scenarios:

- Maximum credible implementation (MCI) of synthetic liquid fuels technology.
- Growth constrained (GC) at 5 percent compound growth rate annually.

In the growth-constrained scenario, five combinations of coal mines and processing facilities were outlined to assess the implications of peaks in the construction labor force:

- Mines only--coal exported from the county
- Mines plus large and small liquefaction plants
- Mines plus small liquefaction plants
- Mines plus methanol plants--3-year construction periods
- Mines plus methanol plants--5-year construction periods.

For these cases, the coal development that can be accommodated within various growth constraints is depicted in Figure 22-2 through 22-7 (Chapter 22). Figure 22-2 shows the growth in Campbell County population implied by the maximum credible implementation (MCI) scenario. The coal mines and facilities for the MCI scenario were derived by assigning 25 percent of the Wyoming portion of the MCI to Campbell County.

First, the base population of Campbell County was estimated at 17,000 in 1975, using Bureau of Census data and information from discussions with county planning officials. Then, a 5 percent annual growth rate curve was derived as shown in Figures 22-2 through 22-7. The population levels consistent with a 5 percent growth rate were divided by a population-to-basic employment multiplier of 6.5 to determine the basic construction and plant operating employment possible each year. Then an appropriate level of coal mines and processing facilities was devised that would (more or less) utilize the basic employment allotment for the year.

A ratio of 6.5 for total population-to-basic employment is a reasonable approximation of the product of (1) primary-to-total employment ratio, and (2) population-to-total employment ratio (the inverse of the labor force participation rate). For example, a primary-to-total employment ratio of 2.6 and a population-to-total employment ratio of 2.5 are multiplied to obtain a composite multiplier of 6.5. According to data from Matson and Studer,[6] the 1970 multiplier for Campbell County was 5.9. Matson and Studer use multipliers in the 6.7 to 7.3 range in their growth scenarios for Campbell County. The higher ratios used for future growth are justified because the anticipated population influx will be able to support a wider range of service activities than is currently available in Campbell County. Thus, by the standards of Matson and Studer, the population growth forecasts of this study are conservative; or conversely, the level of resource development that is consistent with a 5 percent growth rate is optimistic.

Figures 22-2 to 22-7 show only coal processing facilities to make synthetic liquid fuels. But there are good correspondences in plant sizes that will allow these scenarios to depict other coal development as well. In particular, a 100,000-B/D liquefaction plant has the same effect as a 250 million cubic-foot-per-day coal gasification plant; the permanent labor force at a 1,000-MW, coal-fired, electric generating plant closely matches that of a 5 million ton-per-year coal mine. However, the construction force for a 1,000-MW electric generating station would be much larger than for a mine and the work would be spread over a 5-year period rather than a 2-year period.

There is some room for alteration in the scenarios shown in Figure 22-2 to 22-6 concerning the timing of new construction projects depending on what short-term growth rates one might be willing to accept. Figures 22-2 and 22-6 for large liquefaction or methanol plants illustrate the conflict between the objectives of local planning agencies and resource developers. Planners want slow, smooth changes in population levels so that the community can develop necessary facilities for a growing population. On the other hand, investors want to minimize no-income construction time so that revenue producing operations can begin as soon as possible. Construction delays increase the interest costs on invested funds and are especially costly as a project nears completion when the most capital is tied up. The economics of these large-scale developments imply that communities must have mechanisms to prepare for short periods of rapid growth.

The obvious economic impact on Campbell County of 5 percent annual population growth will be to transform it from a relatively rural area with less than 2,000 basic employees in 1972 to a much more highly industrialized area with roughly 8,500 basic employees in 2000, and a total population of 56,000. Agricultural employment is already in decline and a gradual decline is expected to continue until agriculture becomes an insignificant factor in the county's economy in 2000. At that time, agricultural employment will number approximately 500, less than one percent of the population.

The other basic employment would be concentrated in the coal mining and processing industries. Some small manufacturing operations would probably be established to provide repair parts for the construction and mining industries, such as machine shops that make special order items. No large-scale influx of manufacturing plants is likely to follow coal development since many of the regional disadvantages (such as distance to markets and shortages of skilled labor) that discouraged past development will remain.

At present, Gillette is the only community of note in Campbell County; its population in 1975 is estimated at 13,000. It will continue to serve as the economic hub of the county; however, it is possible that a new community will be built in the southern area of the county as coal development in that region proceeds. As the county grows, more wholesalers and warehousing would probably locate in Gillette; however, major support would be expected to continue from Casper 130 miles to the south (the largest city in Wyoming) and from Denver, Colorado. The only other regional trading center near Gillette is Billings, Montana; impacts there would accrue from growth in both the Wyoming and the Montana portions of the Powder River Basin. Alone, growth in Campbell County would not exert any appreciable impact on Billings.

In the environmental impact studies recently prepared for resource developments in the area, the construction phase is carefully distinguished from the operation phase of proposed facilities. This is a very important distinction for geographically isolated, one-time developments, because the construction work force attracted to rural areas has different family characteristics and is more transient than operating labor. However, the almost continuous development patterns envisioned in the MCI should be able to attract and hold a stable construction labor force. Construction activity will still have peaks, but substantial construction activity will exist continuously.

Secondary construction activity will be required for the housing, commercial, and public works needed for new population. In the past, because of time and cost advantages, mobile homes have been used to fill a large part of the demand for new housing units. Consequently, the mobile home industry in the area will probably grow.

4. Oil Shale Development in the Piceance Basin, Colorado

Mesa, Garfield, and Rio Blanco counties in northwestern Colorado (see Figure 12-1) are expected to receive the bulk of the impacts of any oil shale development in the region. The 1970 total and urban population are shown in Table 12-1.

Table 12-1

POPULATION IN COLORADO OIL SHALE REGION, 1970

County	1970 Population	Percent Urban
Mesa	54,400	47.8%
Garfield	14,800	27.7
Rio Blanco	4,800	0.0
Total	74,000	40.7%

Grand Junction with 20,200 people in Mesa County is the only city of note in the region. It lies on Interstate 70 and is some distance from the center of the oil shale deposits. Farther up the Colorado River in Garfield County are Glenwood Springs with 4,100 people in 1970 and Rifle with 2,150. Meeker in Rio Blanco County had 1,600 people in 1970 and is not considered urban by Census Bureau definition.

Primary development is expected to concentrate in Garfield and Rio Blanco counties because it is there that the richest oil shale lies. Access to and from the center of the mining/processing region to Grand Junction will be about 50 or 60 miles over some very rugged terrain. Consequently, it is expected that Mesa County will become only a secondary trading center for the region. Towards the end of the century, under pressure of development, the access from Grand Junction to the producing region would probably be improved by new roads.

Population growth of 5 percent annually would raise the combined 1975 population of Garfield and Rio Blanco counties from 23,000 in 1975 to 79,000 in 2000. Shale oil production would be 400,000 B/D according to a 10 percent growth scenario depicted in Chapter 22. Under MCI, shale oil output is predicted to reach 2 million B/D in 2000. If the associated population were restricted to Garfield and Rio Blanco counties, the population growth rate would have to average 17 percent annually. In reality, such a scenario would result in great disorder because the existing transportation network and other elements of the infrastructure could not expand as rapidly as needed to accommodate such growth.

Currently, Garfield and Rio Blanco counties export agricultural and mining products and depend on other regions for wholesale and retail goods. New development in Garfield County is expected to result in population increases primarily in the existing small communities along the Colorado River--Glenwood Springs, New Castle, Rifle, and Grand Valley. The rugged topography of the area eliminates much of the county from consideration for urban development; thus, future immigrants can be expected to settle in much the same geographic pattern as the present population. Of course, this may be altered should resource companies decide to develop their own land for new communities.

Although some spillover effects from Garfield County would be felt in Mesa County, there would be little spillover to Rio Blanco County because of the poor existing highway network (constrained by terrain). Denver, on the other side of the Rockies, is the center of the major trading area, serving western Colorado, and has already begun to feel the impact of the current interest in energy resources as companies have established or enlarged regional offices. Distributive sectors will be affected as development increases; however, the impact will be slight until demonstration projects have proved the feasibility of oil shale development.

Compared with Gillette, Wyoming, the economic impacts of resource development in Colorado will most likely be felt by several existing communities rather than only one. However, coordinated planning would be required to prevent one community from bearing the brunt of the adverse impacts. Yet, because so much of the U.S. oil shale resources are in this corner of Colorado, development would doubtless result in a concentration of impacts in just a small region. By contrast, coal development will take place in many states from Appalachia to Utah; very little such flexibility is possible for oil shale development--there are other small reserves only in eastern Utah and southwest Wyoming.

Agriculture in this 3-county area of Colorado consists primarily of livestock grazing. Thirteen percent of farm acreage is cropland and lies in the valleys that are also most desirable for new housing. Crop revenues in Rio Blanco and Garfield counties were $1.2 million in 1969--10 percent of total 1969 agricultural* revenues in those counties. Whatever the level of development, there is likely to be considerable impact on the small amount of existing cropland, thereby insuring the decline in agriculture.

C. Comparisons with Other Resource Regions

1. North Dakota Lignite

Western North Dakota contains considerable lignite reserves that have been mined on a small scale for years. The local economy is much like the areas of Wyoming and Colorado described above but with more prosperous agriculture. Most counties in southwestern North Dakota lost population between 1960 and 1970; many lost 20 percent or more. A large fraction of the reserves in North Dakota lie in Dunn, McLean, Mercer, and Oliver counties, having a total population of 24,600 in 1970. Their collective population loss between 1960 and 1970 was over 5,000 or

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*Livestock accounted for most of the other 90 percent.

17 percent. The setting is basically rural, with a few small towns sprinkled about; per capita income in the region was less than 75 percent of the national average in 1970.

Development of lignite mines in Dunn, McLean, Mercer, and Oliver counties will impact the current regional centers of Bismarck and Minot; next in the hierarchy of trading centers is Minneapolis, Minnesota, some 500 miles away. The state, local, and federal governments are the largest employers in the 4-county area, with over 35 percent of total employment in 1971;[7] agriculture was roughly 10 percent and declining. Impacts on agriculture will be greater than in the arid, high plateau areas of Wyoming, because the land is more productive. In 1969, these 4 counties accounted for 6 percent of the value of agricultural products sold in North Dakota; approximately half of the sales came from crops. Since most lignite is surface mined, cropland will be disrupted in North Dakota, and the impacts of resource development on agriculture can be expected to be more costly than in Wyoming or Colorado.

Lignite development will reverse the population decline in these counties by providing jobs for the indigenous population as well as to newcomers. In many ways, southwestern North Dakota is more amenable to development in general than Campbell County, Wyoming, because transportation links with the Midwest are shorter. Nevertheless, in the main, development over the foreseeable future is expected to be energy-related because the disadvantages of remoteness tend to discourage other industries from moving so far from (nonenergy) raw material sources and markets.

2. Appalachian Coal Development

Discussion of economic impacts in the Appalachian region will be based on the Big Sandy Area Development District (BSADD), which consists of the following 5 counties of eastern Kentucky: Floyd, Johnson, Magoffin, Martin, and Pike. Population in the BSADD declined 12 percent between 1960 and 1970 to 134,000. Unemployment in 1972 was 9.3 percent versus 3.6 percent for Kentucky as a whole.[8] Mining employment stood at 8,000 in 1970, down from 20,000 in 1950. The situation has been reversed in 1974 due to surging demand for coal; in Martin County, for example, the unemployment rate has declined from 8.4 percent in 1972 to 3.2 percent in January 1975.[9] Employment in agriculture and forestry has all but disappeared--in 1970 it stood at 338 or 4 percent of the 1950 level. Sectors registering employment gains between 1960 and 1970 were construction, manufacturing, and public administration.[8] Transfer payments, such as social security and welfare benefits, are a large source of personal income in the area; in Martin County alone, 26 percent of per capita income came from transfer payments in 1973.[9]

Compared with the impacts of expanded coal mining in western coal regions, impacts in BSADD will be less disrupting because of the larger existing base population. In addition, the region has the basic infrastructure to provide services for a larger population, as well as service industries for coal mining equipment repair. Because the rural population is spread about in small clusters, expanded coal mining is disrupting existing population differently than in the West. Mining operations are carried out closer to residences, making them vulnerable to noise and shock from blasting, to say nothing of landslides. In addition, coal is sometimes hauled by truck on county roads, increasing maintenance costs and decreasing safety.

The outlook for a diversified economy in the BSADD is not much improved by coal development. The area will remain relatively remote unless rail and highway links are improved. In addition, areas suitable for development of industrial parks are limited due to the lack of level land. Land ownership and use are complicated because mineral rights have often been sold separately from surface rights. Eastern Kentucky counties receive major wholesaling and financial support from the Ashland, Kentucky-Huntington, West Virginia, metropolitan area. It is a major support center for coal mining, and any additional mining activity for synthetic fuels is unlikely to have a large fractional impact.

3. Southern Illinois Coal Regions

The economy of counties in southern Illinois provide a distinct contrast to the regions discussed above. Much of the remaining coal reserves lie in the 6 counties listed in Table 12-2 and outlined in Figure 12-1. Perry and St. Clair each have over one billion tons of strippable reserves and another billion tons of deep reserves remaining.[10] The remaining 4 counties combined have over 17 billion tons of deep reserves remaining. St. Clair, Washington, and Franklin counties were identified in a recent study[12] as likely sites for coal gasification plants. These same counties could serve as sites for coal liquefaction plants.

Compared with other regions discussed above, the area is relatively urban and has a relatively large population. The high urban population in St. Clair County shown in Table 12-2 is due to the city of East St. Louis, a suburb of St. Louis, Missouri; however, the eastern areas of the county are more rural in character. Of the other counties, only Washington is more than 50 percent rural; together, the 6 counties presently contain 437,500 people--far more than in the other regions discussed.

Except for Washington, the counties are currently major producers of coal; collectively, they accounted for 57 percent of the Illinoise production in 1972.[11] Their existing reserves will insure that this role will continue into the future.

Table 12-2

POPULATION AND COAL PRODUCTION IN SELECTED COUNTIES OF SOUTHERN ILLINOIS

County	1970 Population	Rural (percent)	Operating Coal Mines (1973)	1972 Coal Production Millions of Tons	1972 Coal Production Rank in State
Franklin	38,300	50%	3	7.3	4
Jefferson	31,400	49	4	7.4	2
Perry	19,800	49	5	11.2	1
St. Clair	285,200	17	2	7.3	3
Washington	13,800	78	0	0.0	NR*
Williamson	49,000	43%	6	4.0	7

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*NR = no rank.

Sources: Bureau of the Census, Census of Population 1970, "General Characteristics" - Illinois.

Reference 10 and 11.

Agricultural output in southern Illinois consists of both livestock and crops--corn and soybeans. However, the 6 counties are not major producers--accounting for only 1 percent of the Illinois corn output and 3 percent of soybeans in 1972.[11-12] In Franklin, Jefferson, Perry, Washington, and Williamson counties, 1972 yields per acre of both crops were 80 percent of the statewide average.[11-12] Further development of Illinois coal will disrupt land more valuable per acre than in the other resource regions discussed; however, it will not be prime agricultural land; and as discussed in other working papers, there is good prospect for reclamation.

Even ignoring St. Clair County, the population impacts will be considerably less severe on a percentage basis than in the West. Developed urban areas already exist in these counties, and basic economic activity is more diversified than other resource regions discussed. In Franklin, Jefferson, Perry, Washington, and Williamson counties combined, manufacturing employment was 21 percent of total employment in 1970. Service industries are currently well established in the region so that secondary employment multipliers for future energy developments should be lower than places like Gillette, Wyoming. St. Louis, Missouri, is the nearest large metropolitan area and serves as a manufacturing, wholesale, and service center for southern Illinois.

D. Overview

In differentiating the impacts of resource development for typical regions, the obvious conclusion is that economic impacts in western regions will tend to be greater than elsewhere because of the smaller economic base, which requires substantial secondary development and structural change to accommodate even low levels of development. Growth constraints would help to mitigate any adverse consequences by allowing local areas to plan for change and adjust as circumstances dictate. By conventional measures of economic welfare (such as personal income and gross area product), economic well-being would rise in the regions discussed. However, by more comprehensive, but more ambiguous, measures (such as the "quality of life"), the direction of change is not so clear.

Production of liquid fuels from coal and oil shale will reorder the economic hierarchy of communities because most of resource regions discussed would not grow economically otherwise. The changes that will occur manifest a process that has been taking place throughout history; namely, the comparative economic attraction and advantage of regions and nations depends on their resources and the needs of human activity.

Today, the need is for energy, and, worldwide, the regions that have energy sources are growing in economic power.

As resource concentrations are depleted until they are no longer profitable to exploit, regions once rich in resources begin to decline in economic power, and population is attracted elsewhere. Often, such decline is gradual. Appalachia is only now beginning an upswing after a long period of decline in coal consumption persisting since World War II. Many areas of the West still exhibit remnants of the gold and silver industries of the last century. Boom and bust cycles are common; Gillette, Wyoming, itself went through a rapid cycle in the 1960s, caused by oil exploration. Thus, there is a need to consider the longer run consequences and, in particular, the likelihood of a rapid decline in economic activity caused perhaps by a technological breakthrough in nuclear or solar power that reduces the importance of coal resources.

In decline, the West is likely to have a considerable problem because, to provide civic services for an expanding population, localities will probably have to resort to bonded indebtedness, which might well still exist when the boom is over. If decline comes too soon or is rapid, the eroding tax base could force communities into bankruptcy. This does not mean that these synthetic fuel developments should not occur, but it does mean that the planning process must include not only an expansion phase but have built-in capability for an orderly contraction phase should the need arise.

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13--COMPARATIVE ENVIRONMENTAL EFFECTS OF COAL STRIP MINING

By Edward M. Dickson

A. Introduction

The question of strip or surface mining inevitably arises in any discussion of the impacts of synthetic fuels production from coal or oil shale.[1-7] The methods and environmental effects of these mining activities are very different and must be considered separately. The practice of strip mining for coal and the potential and procedures for reclamation also differ so much that it is necessary to discuss this issue on a regional basis. For this report we have selected three areas with abundant coal resources for illustration (see Figures 13-1 to 13-3):

- Appalachian coal as typified by West Virginia and eastern Kentucky.
- Midwestern coal as typified by the coal field in southern Illinois, western Kentucky, and western Indiana.
- Western coal as typified by the Powder River Basin in northeast Wyoming.

These three suffice to demonstrate that there are few valid generalizations about strip mining for coal.

These days almost any discussion of coal strip mining becomes emotionally charged and polarized into camps of proponents and opponents and usually includes reasoning by questionable analogies. In particular, industry emphasis is often placed on the reclamation success in the Midwest as a model for the arid West or on the steep slopes of Appalachia, while environmentalists have used imagery describing the aesthetic impact of the disturbed and unreclaimed lands in Appalachia to convey a forecast

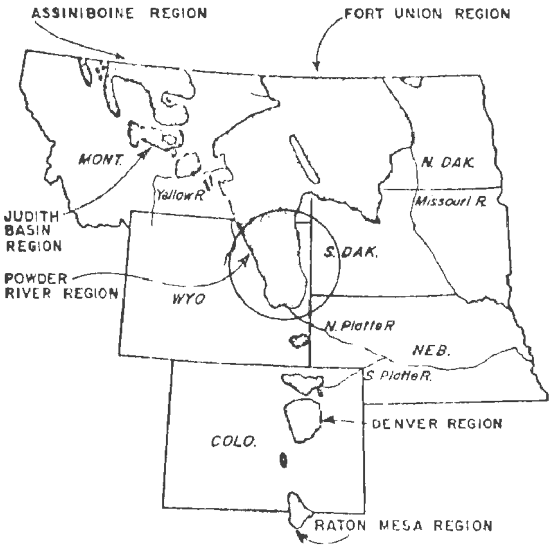

FIGURE 13-1. NORTHERN GREAT PLAINS PROVINCE

FIGURE 13-2. INTERIOR PROVINCE

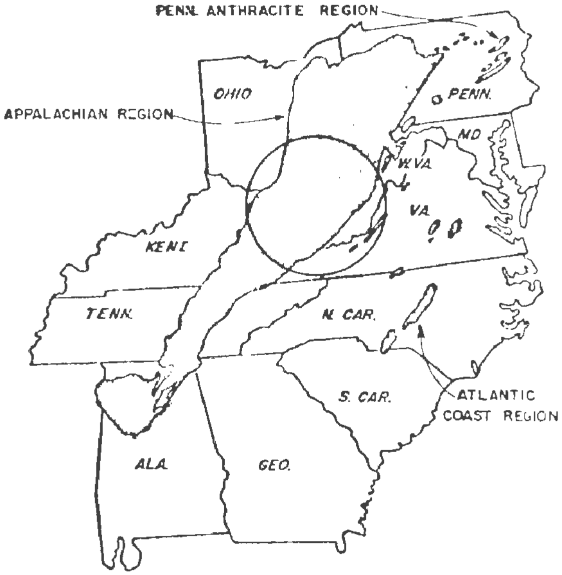

FIGURE 13-3. EASTERN PROVINCE

ADAPTED FROM "DRAFT ENVIRONMENTAL IMPACT STATEMENT PROPOSED FEDFRAL COAL LEASING PROGRAM," U.S DEPARTMENT OF THE INTERIOR (U.S. GOVERNMENT PRINTING OFFICE, WASHINGTON D.C.) 1974 of the effect in Wyoming. Neither is appropriate. Moreover, the very language chosen by the opposing groups is indicative of their perceptions and biases. The following matrix illustrates how the connotations of language depend on the user and his intentions.

Concept	Coal Industry	Environmentalists
A mine consisting of tunnels and shafts	Deep mine	Underground mine
A mine consisting of a broad shallow hole	Surface mine	Strip mine
Material that lies over the coal when still in place	Overburden	Soil Spoil
The same material when displaced from above the coal	Spoil	Waste Spoil

For example, to the lay person, a "surface" mine sounds more benign and less violent than a "strip" mine; "underground" mine conveys, in contrast to a "strip" mine, the image of a tidy, nondisruptive activity. Likewise, "overburden" has a built-in disregard for distinctions such as topsoil, subsoil, and bed-rock and conveys the notion that it is all merely something to be moved out of the way. Without attempting to take sides or further dispute the accuracy of the terms, this chapter uses the following technology for the four concepts outlined because we feel that it offers the most succinct phraseology:

- Underground mine
- Strip mine
- Overburden
- Spoil.

The following pages first describe modern mining in the three regions and then describe reclamation potential in the regions. It should be noted, however, that in the past, and even today, the land recontouring activity described is not always performed by some companies.

B. Mining and Environmental Effects

1. Appalachia

The coal country of Appalachia is characterized by low mountains and hills with many valleys and hollows. The coal lies in a plane that is more or less level, but geological weathering over the ages has cut away the landscape so that the valley floors lie beneath the coal seam. As a result, the coal seam is present in the hills but not in the valley bottoms. The area is well watered, receiving about 45 (110 cm) inches of precipitation annually, almost evenly spread throughout the year. Winters are cold and snowy, and summers are humid with frequent rains.[8-10]

Figure 13-4 shows a cross-sectional view of typical coal deposits in Appalachia. The coal often outcrops on the side of a hill, and usually is in seams 3 to 5 ft (1 to 2 m) thick and overlain by 100 ft (30 m) or more of material. In general, strip mining is uneconomic when the overburden is greater than about 10 times the thickness of the coal seam. This is measured by the "stripping ratio."* Thus, strip mining the coal from the side of the hill penetrates only a small distance into the hillside, and the extraction follows the contours of the hillsides. Thus, strip mining in Appalachia is usually termed "contour mining." The origin of other common terminology such as "highwall" and

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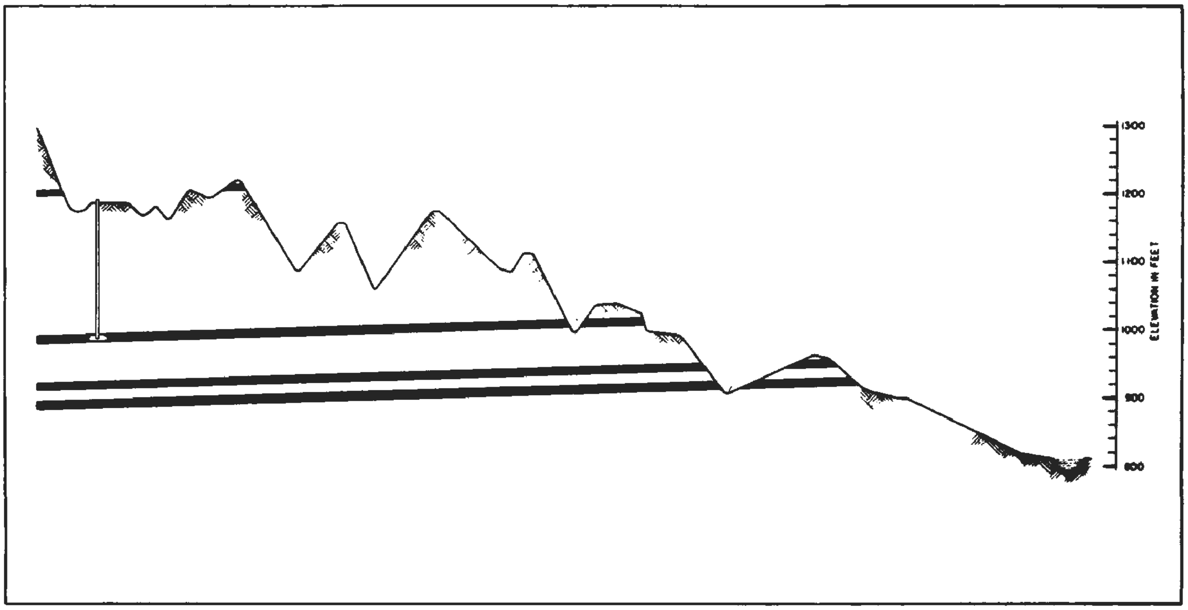
*The stripping ratio is actually defined in terms of the volume (cubic yards) of overburden per ton of coal.



ADAPTED FROM REFERENCE 8

FIGURE 13-4. TYPICAL CROSS SECTION (DENTS RUN WATERSHED, MONONGALIA CO., W. VIRGINA)

"bench" can be seen from Figures 13-5 and 13-6. Contour mining is, by far, the most common form of coal strip mining in the East. Between 80-90 percent of the coal is usually recovered by this method.[9]

"Auger" mining is an adjunct to contour mining designed to increase the coal obtained from a given unit of stripping. Once the stripping ratio becomes too high to justify further excavation of the hillside, the coal on the bench is removed leaving a highwall with an exposed coal seam. Large augers are then used to bore horizontally into the coal seam still lying under the hill for distances of 120 to 150 ft (35 to 45 m), as shown in Figure 13-7. To lessen the chance of collapse of the overburden, these holes are separated by 1/6 an auger diameter. Because such a long auger sags as it penetrates the hill, the diameter auger used is about 30 percent smaller than the seam thickness. Wherever the highwall executes a turn, pie shape segments are left unaugered.

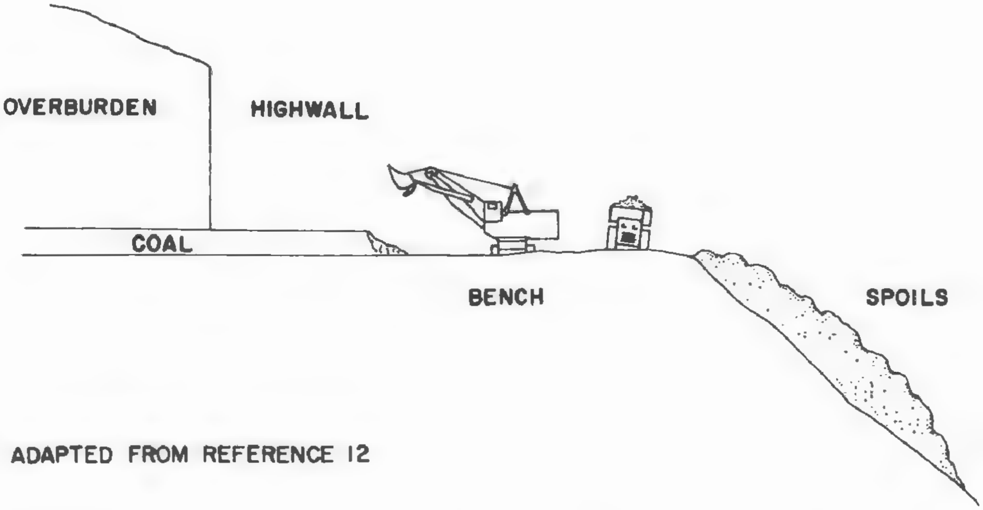


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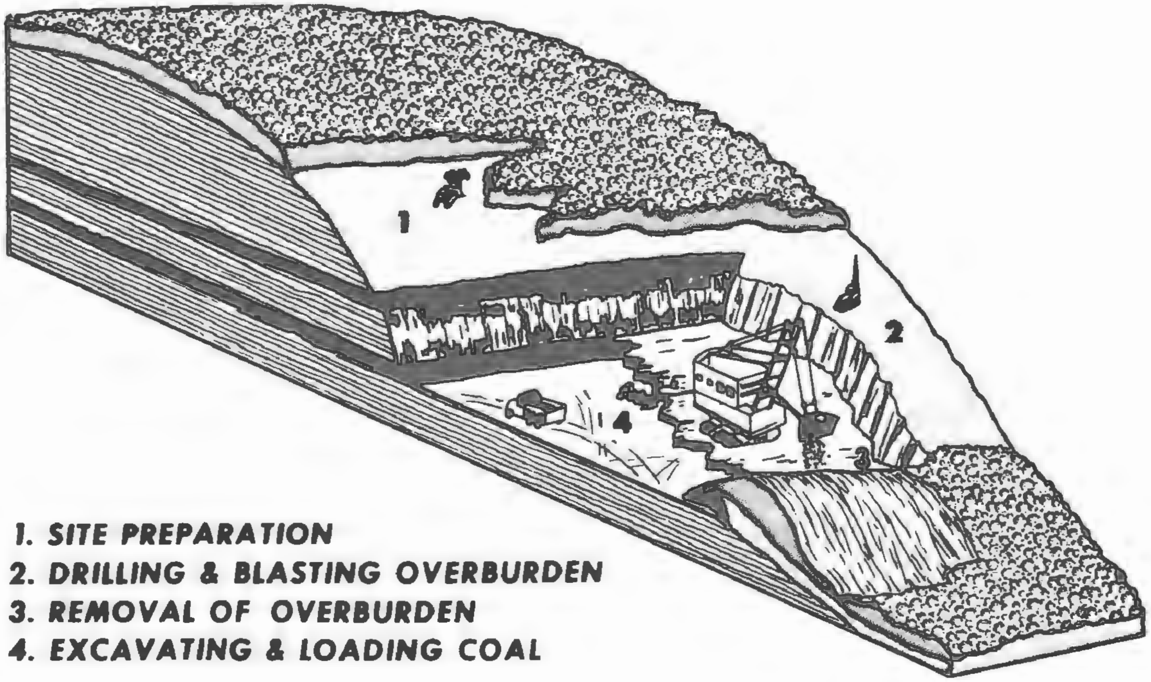
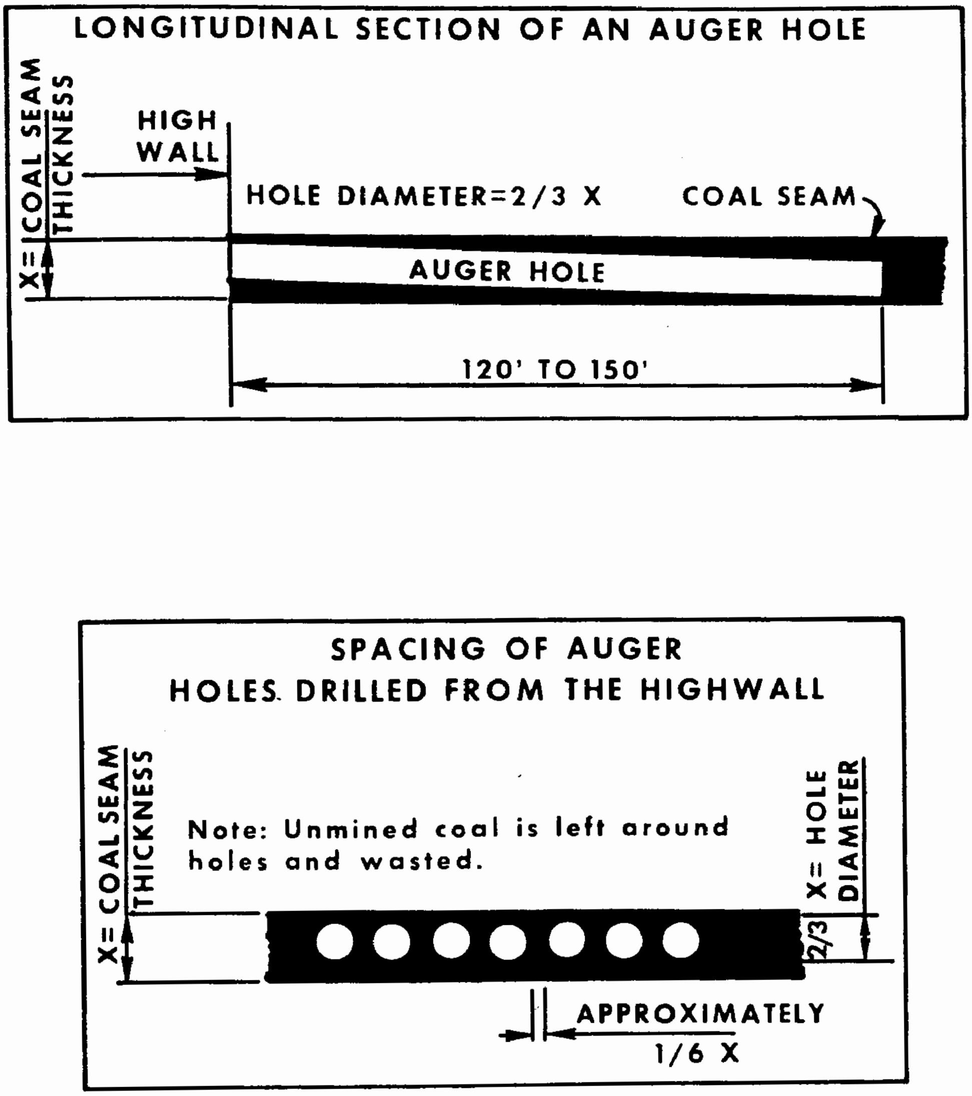
FIGURE 13-5. DIAGRAM OF A CONTOUR MINE



1. SITE PREPARATION
2. DRILLING & BLASTING OVERBURDEN
3. REMOVAL OF OVERBURDEN
4. EXCAVATING & LOADING COAL

SOURCE: REFERENCE 9

FIGURE 13-6. CONTOUR STRIP MINING



SOURCE : REFERENCE 9

FIGURE 13-7. AUGER HOLE SECTION AND SPACING

Clearly, auger mining leaves behind a large portion (about 65 percent) of the coal penetrated.[9]

As might be expected from Figures 13-5 to 13-7 and the configuration of contour and auger mining coupled with abundant precipitation is an open invitation for severe environmental problems in Appalachia. In the past, when no significant reclamation attempt was made, great environmental disruption has indeed resulted from contour mining. These impacts have included

- Sheet erosion
- Sliding of unstable spoil ranks
- Acid drainage
- Siltation of streams
- Loss of vegetative cover.

In addition, there has been significant aesthetic loss from the creation of highwalls, benches, and spoil banks in the place of wooded hillsides and turbid or acidic streams in the place of clear streams.[8,9,11]

Once the soil is exposed, erosion of the highwall, the benches, and the spoil bank occurs. However, with no attempt to contour, terrace, or compact the spoil bank, the most severe erosion occurs on the bank of loose spoil. Large volumes of silt frequently move into streams by this mechanism or by the collapse and sliding of portions of the bank. The rate of erosion is enhanced by the increased runoff rate caused by the removal of vegetation, topsoil (however thin), and plant litter, which normally serve to reduce the impact of rain and to absorb precipitation slowing runoff. Thus, unreclaimed contour mining activity serves to increase the amount of runoff, to compress it in a shorter time, and to increase the turbidity of the runoff streams. As a result, the water quality effects of contour mining are felt for large distances downstream.[8,9,11]

Acid mine drainage is another, and very severe, cause of water quality degradation in or downstream from areas where contour mining is practiced. Handling of the overburden results in the exposure and scattering of pyritic material (FeS_2). Exposed to moisture and oxygen, chemical reactions convert the pyrite to sulfuric acid and dissolved iron sulfate. In addition, other metals, notably manganese, copper, and zinc, dissolve in the acid water. Few plants and no fish can survive in this acid water that also corrodes immersed structures. The cumulative effect of acid mine drainage on streams has often been so great that beneficial uses of the water are greatly impaired.[8,9,11]

When the spoil is heaped on the downhill side of the bench, it smothers the vegetation under the spoil bank. Subsequent erosion and sliding disrupt the vegetation further downhill. Thus, contour mining disturbs more vegetation than that immediately over the coal. In spite of the abundant moisture, the removal of topsoil, and frequently the absence of other fertile soil on the spoil bank slows (for decades) the natural establishment and succession of vegetation on the scarred hillside. Reestablishment of a natural and stable ecosystem without human intervention is generally a poor prospect.

Access and haul roads also involve earthmoving disturbances. In Appalachia, the serpentine aspect of contour mining and short period of time spent mining in any particular spot requires frequent additions and changes in roads. Since the use of these roads is short lived, they are frequently poorly constructed and are an additional major source of land surface disturbance and erosion.[9]

The thinness of the strippable coal deposits and their occurrence partway up the hillsides, means that, in Appalachia, large-scale production of coal causes the disruption of many hillsides. As early as 1965, before strip mining became so common, there were already about 25,000 linear* miles (40,000 km) of disruption in Appalachia.[9] It is no wonder, then, that to many people the effect of strip mining on the aesthetics of the countryside in Appalachia is appalling.

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*Because contour mining results in a relatively narrow but long bench, the use of linear rather than area measurement is appropriate. However, in the West, area measurement is appropriate.

2. Midwest and West

Mining operations in the relatively flat regions in the Midwest and West are quite different from those in Appalachia. In both regions the coal seams lie in flat beds roughly parallel to the surface although the thickness of the seam varies. The slight tilt of these seams relative to the surface means that in places the coal has dipped too deep to be mined economically with present stripping methods. Coal occurs in the Midwest in multiple seams about 5 ft (2 m) thick, often separated by "partings" 50 to 100 ft (15 to 30 m) thick. In the Powder River Basin, seams are generally 30 to 100 ft (10 to 30 m) thick with a few as much as 250 ft (75 m) thick.* Because the current limit on the stripping ratio is about 10/1, strip mining in the Midwest is restricted to much shallower depths than in the Powder River Basin.[9,12,13]

The activity that characterizes strip mining in the Midwest and part of the Powder River Basin is shown in Figures 13-8 and 13-9. In some parts of the Powder River Basin the thick seams facilitate a type of strip mining that resembles open pit or quarry operations (Figure 13-10). Because the nature of the terrain and coal deposit facilitates the complete mining of large tracts of land, both of these approaches are called "area" mining. These methods recover about 95 percent of the coal in the seams.[9,12]

Area strip mining is inherently less environmentally disruptive than contour mining because it is efficient to place the overburden from one cut in the hole left by the previous cut. Roads have a long useful lifetime and are therefore well constructed. Moreover, the relative

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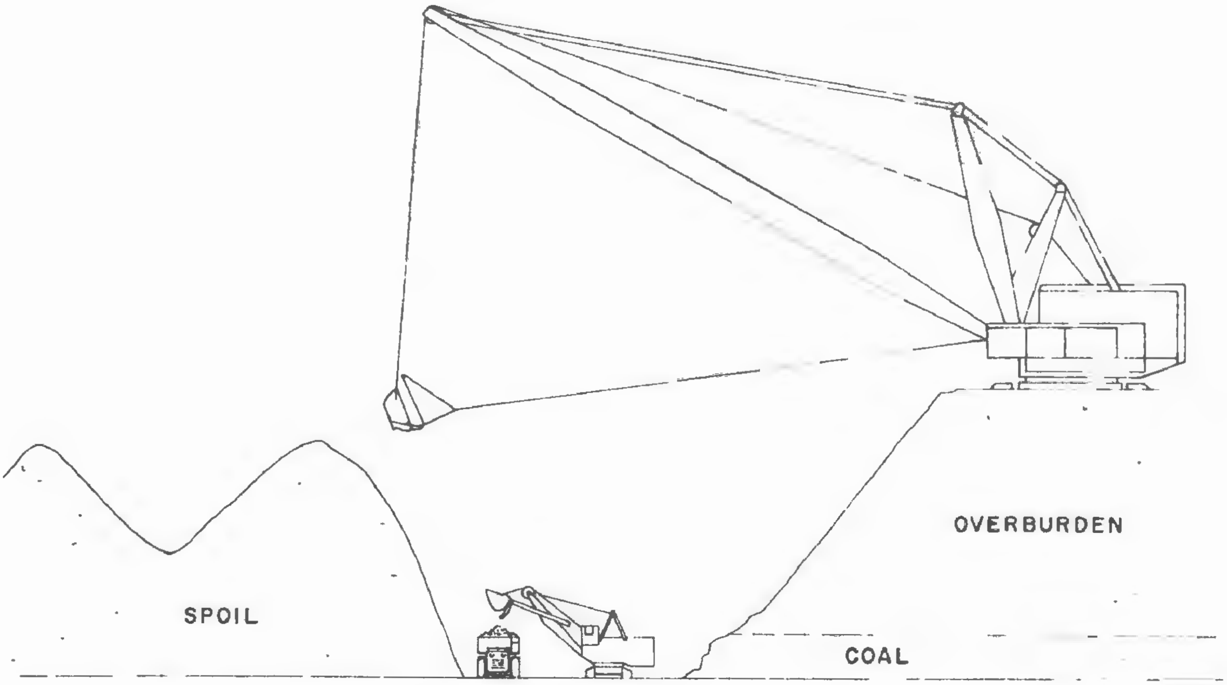
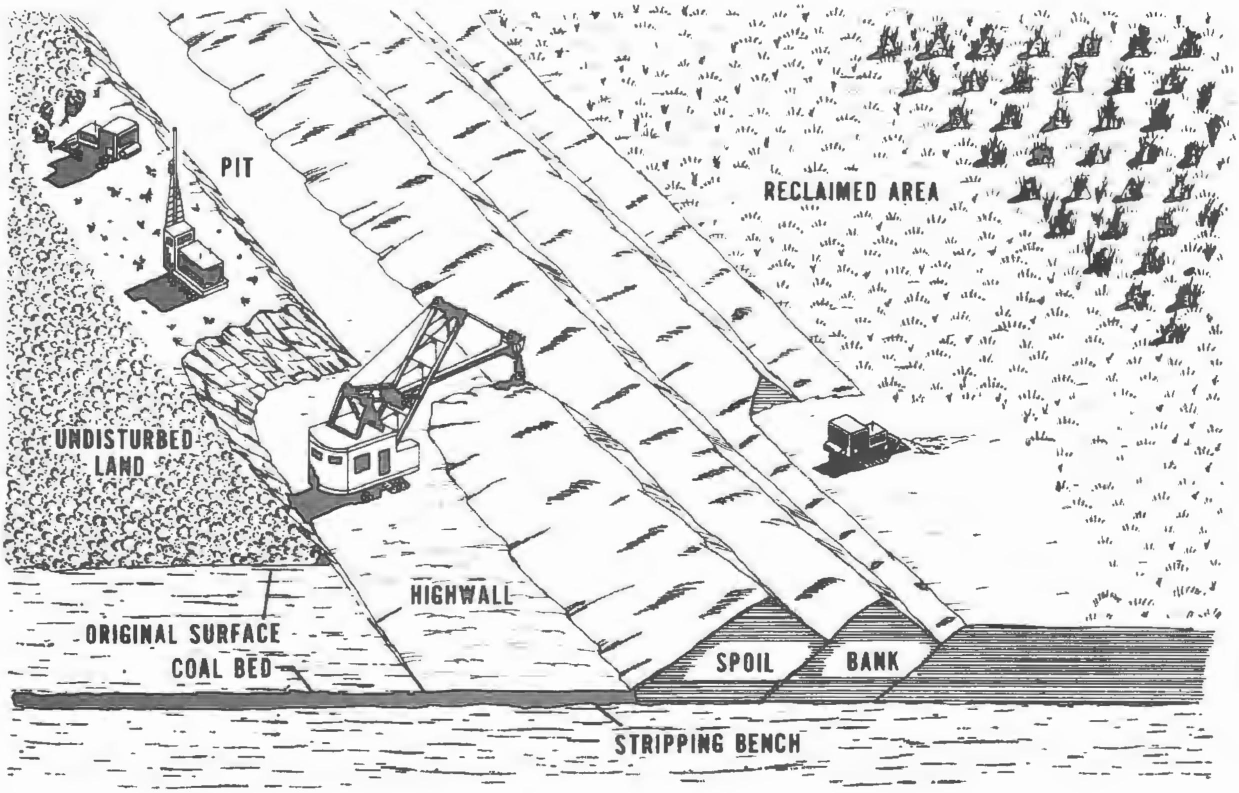
*Such thick seams are not found everywhere in the West.



ADAPTED FROM REFERENCE 12

FIGURE 13-8. DIAGRAM OF AN AREA MINE

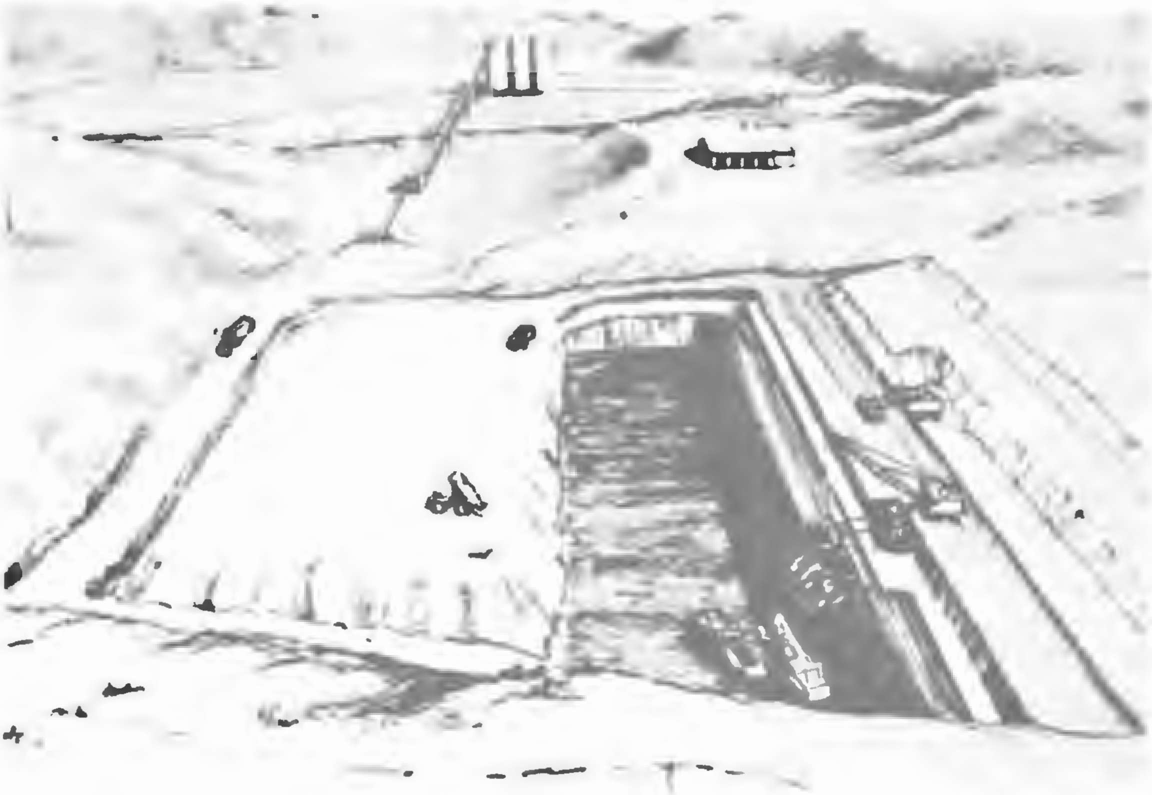


SOURCE: REFERENCE 9

FIGURE 13-9. AREA STRIP MINING WITH CONCURRENT RECLAMATION flatness of the terrain leads to less erosion of the roads, highwall, and spoil pile. Nevertheless, without efforts to reclaim the land, the result of area mining is the creation of a corrugated artificial terrain caused by the heaping of spoil in rows for each cut. At the starting edge of the area, a line of spoil remains piled on the surface of unmined land while at the final edge of the area a trench and highwall remain. Figures 13-9 and 13-11 show this very well. In open pit mining (Figure 13-10), the overburden from the initial large cut is either stored in a pile or deposited in a depression nearby. Subsequent spoil is then deposited in a mined-out part of the pit. At the end of mining, the spoil from the initial cut is either returned to the pit or other spoil is contoured to reduce the highwall. For thick coal seams, the reclaimed land surface is much lower than the original level.[9,12]

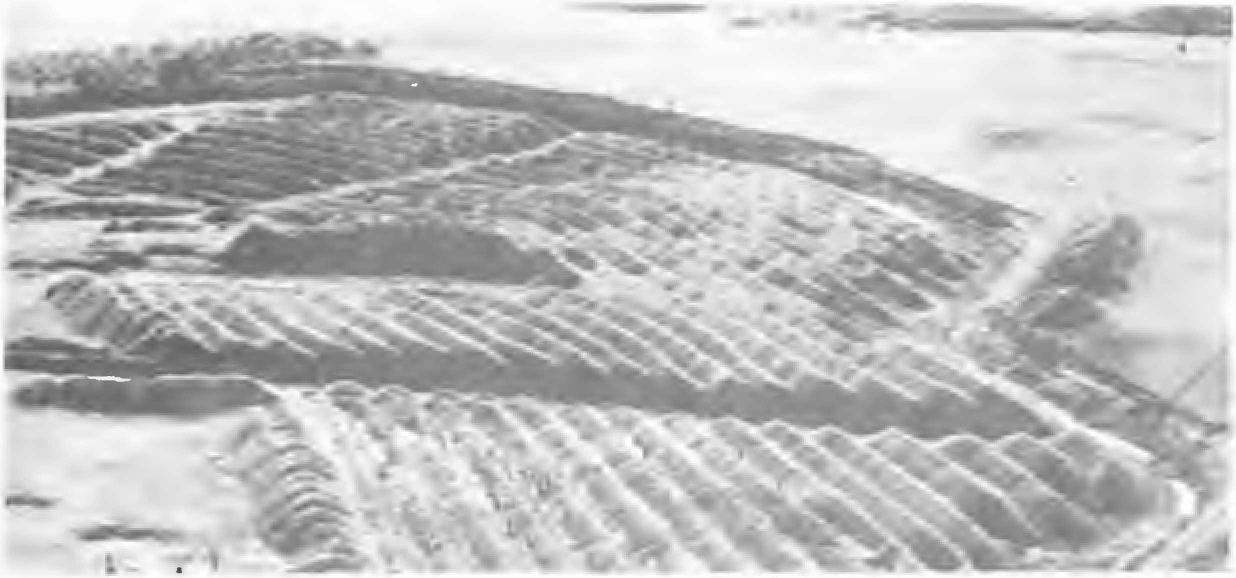
In the Midwest, although the coal has a high sulfur content and the precipitation is high (about 40 inches or 100 cm per year), the formation of acid drainage is less of a problem than in Appalachia.[9] In much of the West, however, especially the arid Powder River Basin, the combination of very low precipitation (about 13 inches or 33 cm per year) and low sulfur content of the coal almost eliminates acid mine drainage as an environmental problem.[9,14] For the same reasons of terrain and precipitation, erosion and siltation from area mining in the Midwest are less severe than from contour mining in Appalachia; in the Powder River Basin erosion and subsequent siltation are periodically moderate to severe from flash flooding from thunderstorms.

In the Midwest, the precipitation is ample enough and the surface stable enough that some natural revegetation of spoil piles occurs in a few years. In the very arid Powder River Basin, however, where the undisturbed vegetation is itself sparse, recovery of natural vegetation is extremely slow[14]--although the noxious imported annual weed called Russian Thistle, or tumbleweed, establishes quickly on the spoil piles.



SOURCE : REFERENCE 4

FIGURE 13-10. PERSPECTIVE OF TYPICAL MINING FACILITIES, HAULAGE ROADS, PIT OPERATION, AND RECLAMATION



SOURCE : REFERENCE 5

FIGURE 13-11 STRIP-MINED TERRAIN

Concern with moisture is not limited to the land surface, however. In some places in the West, the coal seam is part of the aquifer. The mining of large areas disrupts the continuity of the aquifer, thereby affecting nearby groundwater resources and sometimes the water in seasonally dry streams. In arid country, disruption of the groundwater is a matter of importance to residents. Disruption of the aquifer usually results in the accumulation of water in the mine itself. This water is often used to control the dust stirred up by the earthmoving machinery.

Aesthetically, most people find unreclaimed area strip mining in the West less objectionable than contour strip mining in the East. There are several apparent reasons for this. First, and foremost, is the manner in which area mining concentrates the effect to a well-defined tract and affects essentially only the area from which the coal is removed (e.g., there is no deposit of spoil down the hillside), while contour mining leaves a long, linear scar along the hillside. Second, the presence or absence of sight lines linking the observer and the disruption is important. Area mining is less visible because in relatively flat terrain there are few vantage points to see the disruption while contour mining can be seen readily from nearby hills or even from the valleys.

3. Summary

The foregoing descriptions illustrate the differences in methods and environmental effects of strip mining in Appalachia, the Midwest, and the West (Powder River Basin). The effects are sufficiently different that it is equally erroneous for environmentalists to maintain that Wyoming could become another West Virginia or for mining companies to assert that reclamation success in the Midwest provides the knowledge base for reclamation in the West.

C. Reclamation Potential

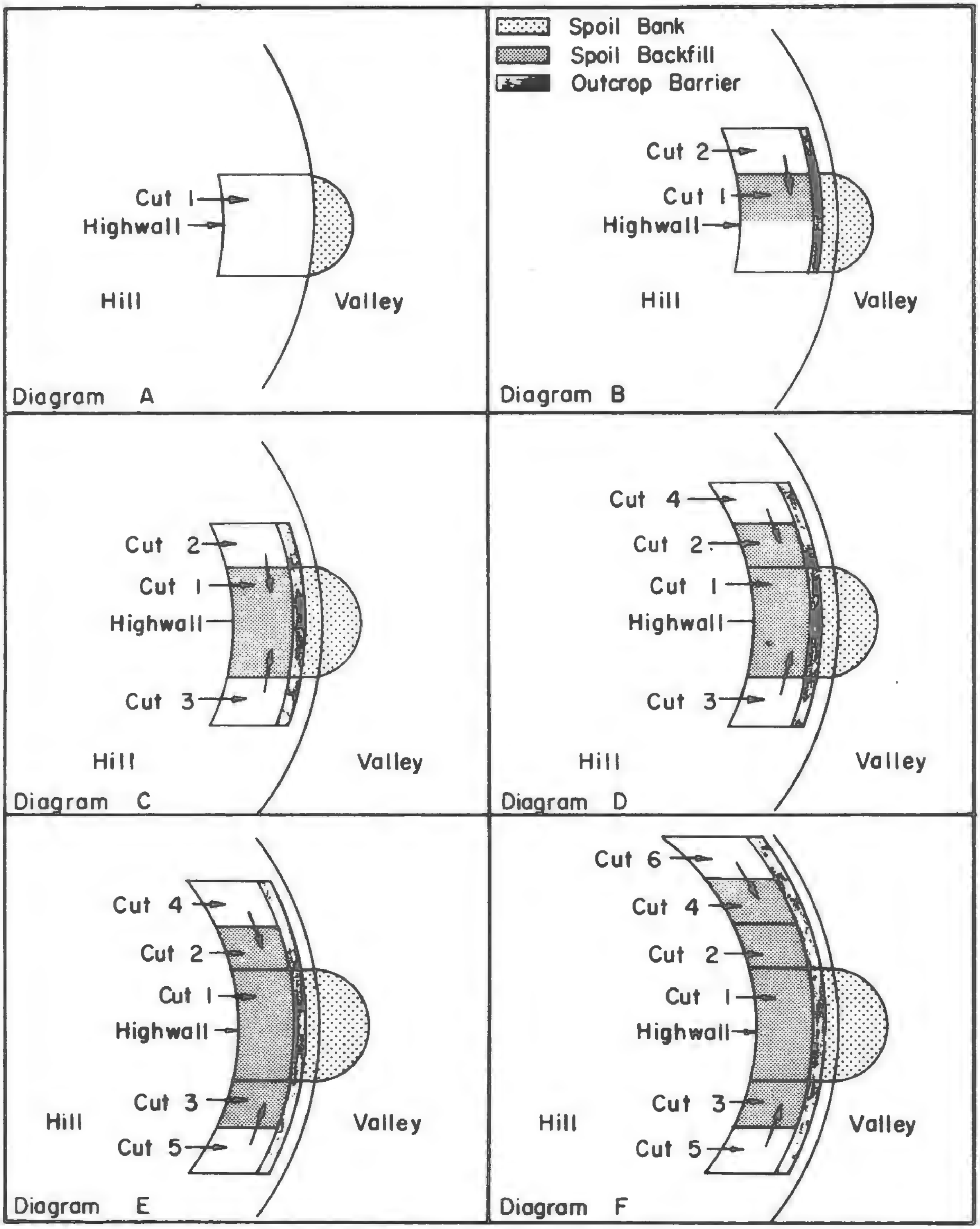
1. Introduction

Just as approaches and effects of strip mining were seen to differ in major ways from region to region, so do the potentials for reclamation. The most critical single parameter is available moisture, which is clearly related to precipitation and its annual pattern. The amount and timing of precipitation affect the stability of man-made slopes, and the erosion from slopes. These in turn affect the ability to return lands to agriculture or to reestablish, in a reasonable time span, a facsimile of the natural vegetation and thereby permit recovery of the wildlife populations. Once disrupted, ecosystems are not necessarily easily restored and it can take a long time before the ecology is returned to equilibrium.

It is important to make clear that "restoration," meaning a return to original conditions, is generally not possible while "reclamation," or "rehabilitation," implying a return to some stable, productive state, but not necessarily the original one, is generally possible.[14] However, reclamation requires a conscious and careful effort on the part of man, including a degree of land husbandry for a number of years.[14]

2. Appalachia

Reclamation is far simpler if it is an integral part of the mining plan, for then the spoil can both be placed behind the line of advancement rather than downslope and can be segregated into true topsoil, fertile subsoils, benign subsoils, and toxic or infertile materials. To create conditions conducive to plant growth, it proves important to layer the recontoured spoil so that the best soils are placed on top with the infertile and toxic materials underneath. Figures 13-12



SOURCE: REFERENCE 11

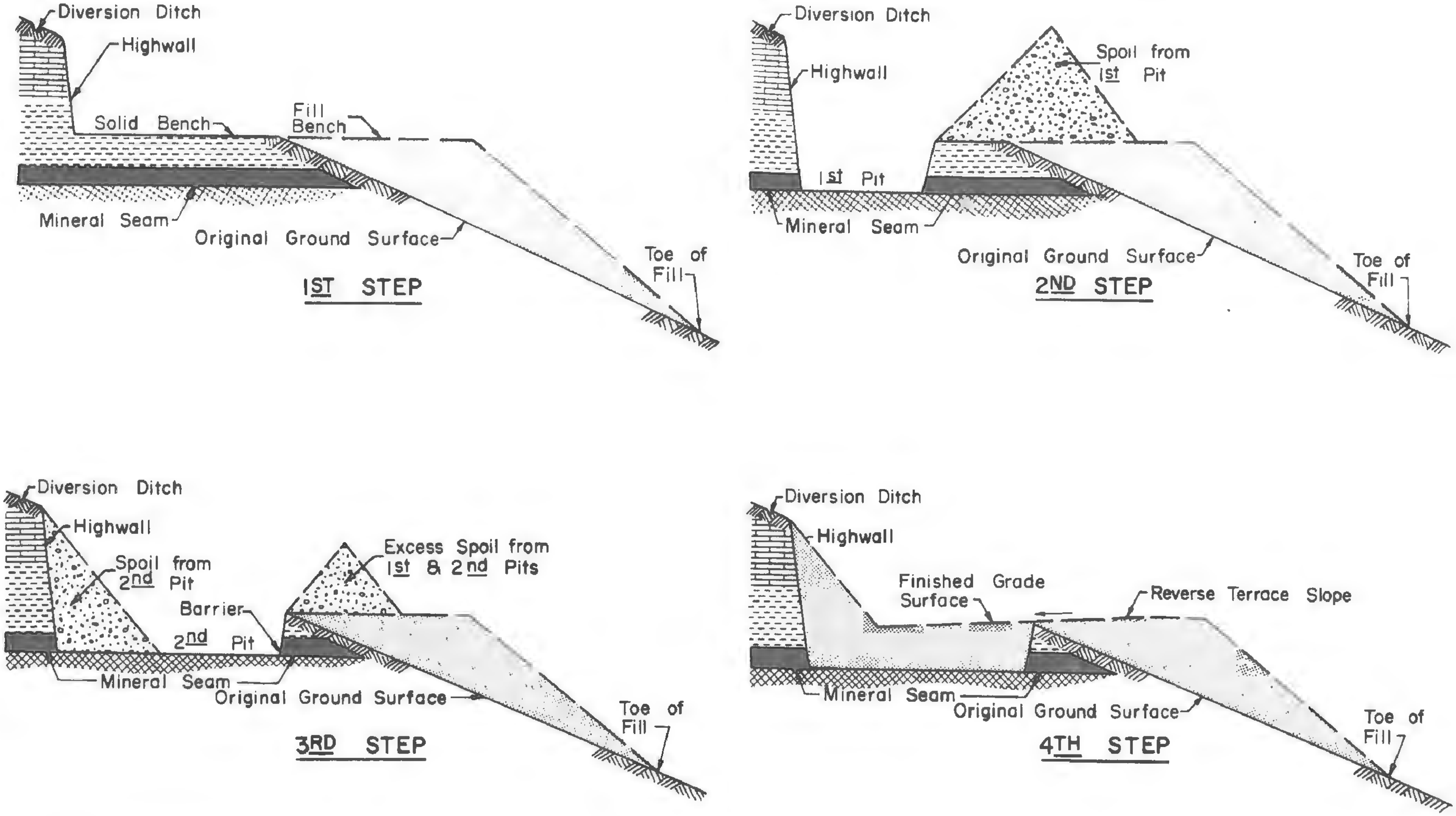
FIGURE 13-12. MODIFIED BLOCK CUT

to 13-14 show some of the techniques that have been used to recontour the land following mining.[9,12,14,15,16]

One of the important steps in the reclamation process following auger mining is the plugging of the auger holes in a manner that prevents drainage of acidic water. Clearly, this must precede the recontouring of the spoil.[9]

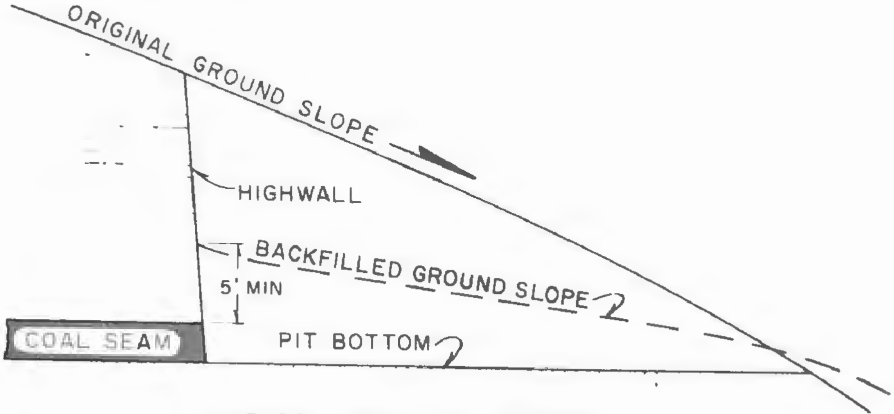
In Appalachia, seeds of native species are abundant and the ample moisture leads to relatively rapid reestablishment of a vegetative cover on reclaimed contour mines, although artificial seeding speeds recovery. Once the soil is protected from erosion by the initial growth of any species, natural species replacements (succession) can be allowed to proceed or other species can be introduced. For example, rather than waiting for the native hardwood forest species to reinvade the area, faster growing conifers may be planted to speed reforestation. Recent work in nonmined areas has shown, however, that the runoff from a dense stand of native hardwoods is significantly greater and different in temporal characteristics than the runoff from a dense woods of young (about 15 years old) conifers.[17] Thus, although reclamation with conifers may seem to be an environmental success from the point of view of aesthetics, erosion, and siltation, the question always remains whether the alteration in stream flows is within acceptable limits.

Pursuit of such a reclamation activity requires chemical analyses of the soil and subsoil and the attention of personnel trained in reclamation. Reclamation can be achieved at reasonable costs when the goal of reclamation is integrated from the start into the mining plan.[9] On the basis of cost-per-unit weight of coal, reclamation in Appalachia is more costly than in the other two regions because less coal is recovered per area disturbed.

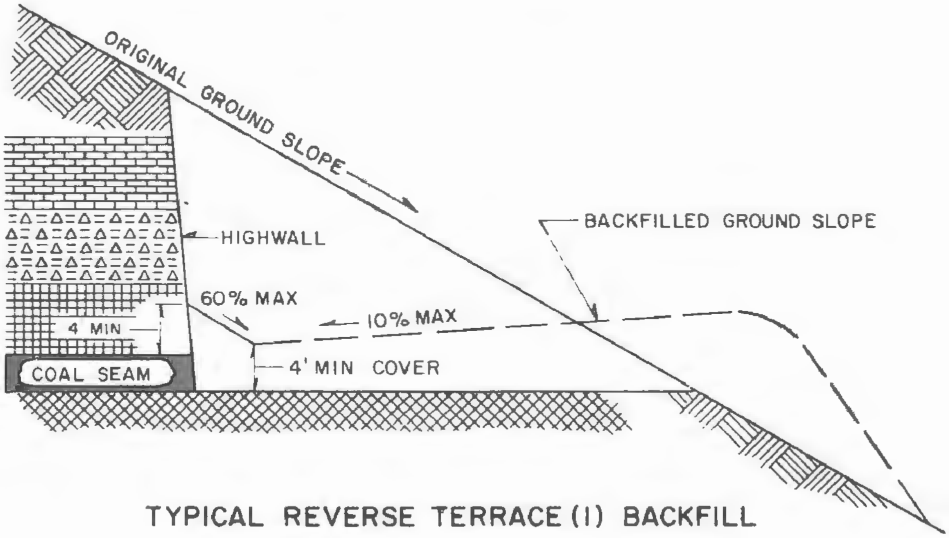


SOURCE: REFERENCE 11

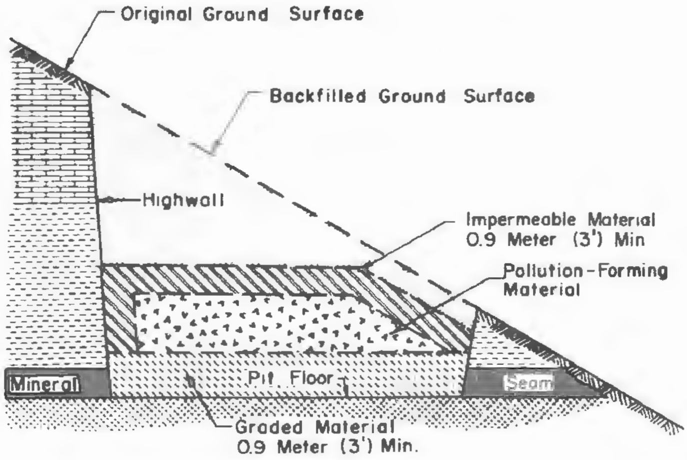
FIGURE 13-13. BOX-CUT MINING



TYPICAL PASTURE BACKFILL



TYPICAL REVERSE TERRACE (1) BACKFILL



CROSS SECTION OF
STRIP MINE SHOWING POLLUTION-
FORMING MATERIAL BURIAL

SOURCES: REFERENCES 8 AND 11

FIGURE 13-14. SOME LAND RECLAMATION TECHNIQUES FOR CONTOUR MINING

3. Midwest

Reclamation in the Midwest is made relatively easy by the facility with which materials can be handled in area mining. Without difficulty, the topsoil--usually very rich and often several feet thick--can be removed and stockpiled easily and so can the other materials capable of supporting vegetation. In area mining, it is a straightforward matter to smooth off and recontour the corrugations left by different cuts and to spread subsoil and topsoil.[13,18,19] This can be quickly followed by plantings. The area of coal deposits in the Midwest is a farming region, and Meadowlark Farms, a subsidiary of AMAX Corporation, has had notable success in farming reclaimed strip mine lands in the Midwest for many years. Without doubt, for successful reclamation, the most favorable combinations of terrain, soil, and moisture are found in the Midwest.

4. West

The development of western coal resources has been the subject of growing discussion in recent years and a dominant component of that discussion has been the potential for reclamation of strip mined lands in the arid West.[14-16] One of the more definitive examinations of this issue was prepared by the National Academy of Sciences,[14] which concluded that the success of reclamation with native species in areas receiving less than 10 inches (25 cm) per year of precipitation was in doubt. Although the total precipitation in the coal region of Wyoming is about 13 inches (33 cm), some of it is in the form of snow. In these areas of low humidity, as much as 60 to 80 percent of the snow may sublime (go directly into the vapor state without passing through the liquid state), thereby reducing the amount of precipitation that actually moistens the soil. The length of the growing season is also important. The Powder River Basin is at a high altitude (about 4500 ft or 1.4 km) and the frost-free period is only about four months (from late May to late September).[4]

The natural vegetation in the Powder River Basin is sparse, consisting of low clumps of grass and small desert shrubs ("sagebrush" types of plants such as fourwing saltbush). However, in many places, overgrazing has reduced this vegetation below its natural level. Because of the aridity, the native plants have extensive shallow, wide-spreading root systems with the majority of their total tissues underground. These roots effectively absorb moisture from a wide radius, and, as a result, competition among plants leads to a spacing between major plants of a foot (0.3 m) or more. It is frequently not appreciated that the root systems of this apparently sparse vegetation serve as a soil binder that retards erosion.[4]

In such arid areas, it is difficult to farm and consequently little cultivation (cropping) is practiced. Instead, the major agricultural activity is cattle ranching and about 50 acres (200,000 m^2) are required to sustain a single animal.[4] As a result, ranches usually consist of many thousands of acres.

To date, reclamation attempts that appear most successful are those that do not seek to restore the natural vegetation but that rather to seek to introduce nonnative but well-adapted species (often grasses), which are compatible with the natural ecosystem and are more productive.* In general, however, the experimental reclamation plots have either been too small or have not been established long enough (only a few years) to

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*One of the difficulties preventing more vigorous attempts to reestablish the natural ecosystem is the nearly total lack of a commercial source for native seeds. If this were to become a goal, a small seed industry would have to develop.

yield quality information about the long-term stability of revegetation attempts. It is widely held that decades may be needed before it will be known whether even the apparent success will survive the occasional several-year periods of drought (above and beyond the normal aridity) common to the area, and whether a stable, although nonnative, ecosystem will develop.[14]

There have been some notable revegetation successes in the region such as at the Big Horn Mine near Sheridan, Wyoming (owned by Peter Kiewit and Sons) and the Belle Ayre Mine owned by AMAX Corporation and rehabilitated by Meadowlark Farms.[1,18] These two efforts illustrate the benefits that accrue from a constructive attitude towards reclamation, which includes complete integration of reclamation within the mining plans. Yet, impressive as the reclamation at these two mines is, the reclamation is only a few years old and the object of considerable attention including watering and initial fertilization. It remains to be seen what will happen to the reclaimed areas when the coal is mined out and the attention of the reclaimers is turned elsewhere.

The successes at Big Horn and Belle Ayre have depended on soil chemistry and expertise in agronomy. The arid conditions and the slow growth of low density plants have not been conducive to the buildup of a deep topsoil with much humus. The true topsoil is very thin on the average (3 or 4 inches or about 7 to 10 cm) and is not evenly distributed because the almost continuous winds in the region have scalped some high spots and deposited the soil in depressions. At Belle Ayre, for example, before mining begins, the true topsoil is removed by a scraper under the supervision of an agronomist and is stockpiled. When there is no true topsoil, nothing is scraped off, but when a pocket is found, it is all taken. The scraper then proceeds to collect all subsoil that chemical tests indicate would sustain plant growth and stockpiles it separately. Some of this is later used as a substitute for the true topsoil.[20] The rest of the overburden, judged too poor to serve as true or substitute topsoil, is left for the regular mine equipment to handle as spoil.

During backfilling, care is taken to place rock and the toxic subsoil on the bottom. This is then followed first by a layer of the acceptable subsoil and then by a layer of the true or substitute topsoil. With agronomists participating in the reclamation, there is recognition that topsoil is not just a collection of lifeless physical dust particles but that it consists of a complete ecosystem of micro flora and fauna that are essential to plant growth and decay.[20] Stockpiling the topsoil can, through lack of air, kill off some of these organisms although most persist as spores. To reestablish this soil micro ecosystems, it is often necessary to add some plant matter--such as straw--for decay followed by moisture.[20] Cognizance of these biological facts and a concerted effort to make intelligent use of agricultural knowledge appears to result in successful rehabilitation (at least in the short term).

Agricultural practice, such as the dimpling of the raw soil surface to lessen wind erosion until a plant cover is established, increasing moisture retention by making use of stubble to catch and prevent snow from drifting away, and the use of a "nurse crop,"* has played a role in revegetation successes with nonnative plants. For example, at Belle Ayre, steps (1) and (3) in the following sequence have been completed:[20]

(1) Recontour the land
(2) Plant winter wheat
(3) Harvest, leaving straw as mulch and stubble to catch winter snow

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*A crop planted solely to provide cover for a more desirable crop planted as an understory. As the desired crop becomes established, the nurse crop is crowded out.

(4) Plow under mulch leaving summer fallow

(5) Plant a full crop of legumes and grass with a nurse crop of oats

(6) Pasture cattle on legumes and grass.

While there is good reason to expect that reclamation of the surface can be successful, serious efforts to restore disrupted aquifers have not been made. This may not be possible. As long as western strip mining is confined to a few isolated mines, the disruption of aquifers is unlikely to be serious. But a high level of mining activity, spread around the countryside in disconnected blocks, will increase the proportions and importance of this problem.

5. Summary

Reclamation is possible in all regions. It is far less costly when the effort is begun by including provision for it in the mining plan itself. Reclamation is probably easiest in the Midwest, where a combination of terrain and natural moisture simplifies the task, and most difficult in Appalachia, where the steep slopes and excess moisture make soil control and acid drainage difficult, and in the West, where a lack of moisture retards reestablishment of vegetation. However, in the West, the chances are good that revegetation can succeed if the reclaimed land is given careful attention over a long period and nonnative plants are accepted. The ease of reclamation is indicated by Figure 13-15, which relates environmental parameters to potential for success. In all cases the attention and responsibility of the restorers must extend over many years (or decades) and not terminate as soon as some seed are sown.

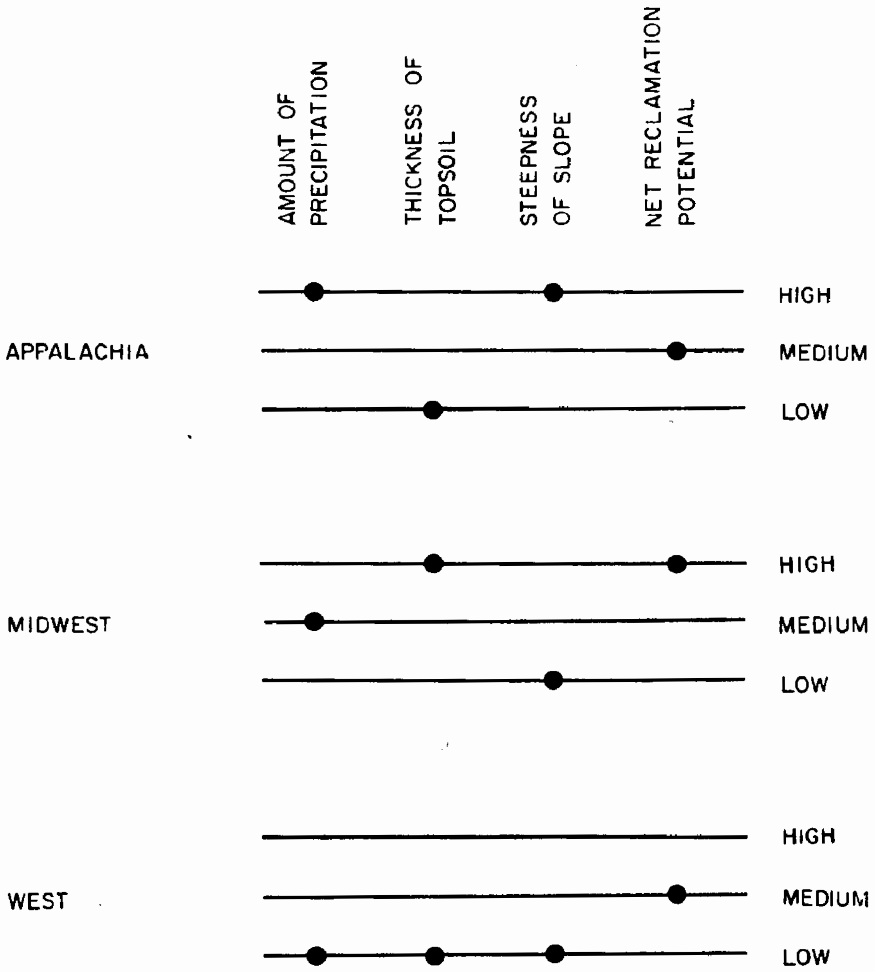

FIGURE 13-15. RECLAMATION POTENTIAL

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14--OIL SHALE MINING AND SPENT SHALE DISPOSAL

By Robert V. Steele

A. Introduction

An important aspect of the recovery of oil from the oil shale resources of the western United States is the large amount of material that must be mined, processed and ultimately disposed of if a large-scale oil shale industry is developed. Many of the adverse environmental consequences likely to result from oil shale development are directly related to the large volumes of material that are involved, as well as the nature of the material itself. This chapter presents the techniques and problem areas of oil shale mining and spent shale disposal, and provides background for the discussion of more specific environmental impacts in Chapter 15.

It has been estimated that 1.5 trillion barrels (240 billion m^3) of oil are contained in the oil shale deposits of the Green River Formation in Colorado, Utah, and Wyoming, although a much smaller quantity is practicably recoverable. The amount of recoverable oil contained in 25-gal/ton (0.1 m^3/1000 kg) grade or higher shale (suitable for above ground retorting) is estimated to be 240 billion barrels (38 billion m^3), of which 83 percent is located in the Piceance Basin of Colorado.[1] A 1 million B/D (160,000 m^3/D) industry operating for 20 years would only recover about 3 percent of this amount, however.

The physical form of the resource is not liquid oil but a solid organic material called kerogen, which is imbedded in a marlstone matrix. Only about 15 percent by weight of the oil shale is kerogen (for 30-gal/ton or 0.13 m^3/1000 kg shale). The remaining marlstone component of oil shale is a relatively useless material, which must be disposed of after the kerogen has been converted to liquid form and recovered. The fact that the organic portion of the shale constitutes such a small portion of the resource has important implications for the future of oil shale development. The recovery of even a small portion of the oil shale of the Green River Formation would bring about the largest mining operation in the history of mankind.

A mature oil shale industry of 1 million B/D (160,000 m^3/D) would involve the mining of 1.4 million tons of oil shale per day, and the disposal of 1.2 million tons (1.1×10^9 kg) of spent shale per day. The mining operation to support a single 100,000-B/D (16,000 m^3/D) retorting and upgrading plant (140,000 tons/day or 1.3×10^8 kg/D) would be larger than the largest mine now in operation in the United States--the 110,000 ton/day (1.0×10^8 kg/D) Bingham Canyon open pit copper mine in Utah.[2]

The disposal of spent shale is in itself an enormous problem. If the spent shale is disposed away from the mine, a 1-million B/D industry would fill the equivalent of a box canyon one-mile long (1.6 km), 1000-ft wide (0.3 km), and 250-ft deep (76 m) every 1.5 months. The enormity of this problem indicates that the methods chosen to deal with it will be crucial to the future of the oil shale industry.

B. Oil Shale Mining

1. Underground Mining

Mining the oil shale from the thick deposits characteristic of Colorado's Piceance Basin presents no special technical problems. The most suitable underground mining method is the "room and pillar" technique, which has been widely used in coal mining and has been established as a reliable method for oil shale mining in prototype operations by the Bureau of Mines. The numerous outcroppings of the kerogen-rich Mahogany

Zone along the canyons of the Piceance Basin provide ready access to deep-lying oil shale deposits.

The first step in the development of a room-and-pillar mine is to excavate the entrances, or adits, through which mining equipment is transported. The nature of the oil shale deposits will permit horizontal adits to be used generally, which will allow easy passage of equipment and the use of trucks to haul out the mined shale. Vertical adits may also be used, however, when horizontal adits are impractical.

Once the adits have been established, the development of the mine proceeds as follows. First, horizontal holes 30-ft (9 m) deep are drilled along the width of a "room" to be excavated. The holes are filled with an ammonium nitrate-fuel oil (ANFO) mixture, which is then detonated. The shale rubble is loaded onto large ore trucks with front end loaders for delivery to the primary crushers outside the mine. Next, a hydraulic backhoe scrapes away the remaining shale, which was fractured but did not fall away. After all the shale is removed from the room, roof bolts are installed to strengthen the roof against failure. Mining proceeds from room to room, with pillars of solid shale rock left in place to support the roof of the mine. Prototype mine experience has indicated that the optimum room size for an oil shale mine is 60 × 60-ft (18 × 18-m) with rooms separated by 60 × 60-ft (18 × 18-m) pillars.

Since the oil shale zone varies in quality, a 60- to 80-ft (18- to 24-m) thickness has to be mined to yield an average grade of shale (about 30 gal/ton) suitable for retorting. Generally, this width of deposit will be mined in two steps. First the "upper bench," 30- to 40-ft (9- to 12-m) high, will be developed as described above. Then the "lower bench" will be developed in a similar manner, with the exception that the blast holes will be drilled vertically instead of horizontally.

Figure 14-1 shows the room-and-pillar mining plan envisioned by Colony Development Operation.[3] Using 60 × 60-ft (18 × 18-m) rooms and pillars, and developing two 30-ft (9-m) benches of 35/gal/ton (0.13 m/1000 kg) average oil shale grade, Colony anticipates that 60 percent of the in-place resource can be extracted. To supply a 50,000-B/D (8000-m^3/D) plant for 20 years the mine would eventually occupy an area of 4100 acres (6.4 sq miles or 17 km^2) underground.[3]

2. Surface Mining

Surface mining of oil shale deposits that lie close to the surface will be an economical alternative to underground mining. The economy of surface mining is determined by the stripping ratio, which is a measure of the amount of overburden that must be removed relative to the amount of resource recovered. On the basis of a ratio of the thicknesses of overburden and resource, oil shale deposits may be economically surface mined up to a stripping ratio of about 2.5.[4] Thus, even some areas of the Piceance Basin, which have 1000 ft (300 m) of overburden, are amenable to surface mining due to thickness of the recoverable resource (up to 2000 ft or 600 m).

There are two kinds of surface mining--strip and open pit. For the very lowest stripping ratios (less than about 0.5), strip mining is the appropriate method of resource recovery. In this type of surface mining, which is commonly used to extract coal in the west, explosives are used to loosen the overburden and large draglines are used to remove it. Power shovels are used to excavate the exposed resource seam and load the shale onto trucks (see Chapter 13). The overburden is stored at a nearby site until a large enough area is mined to allow backfilling operations to begin.

Strip mining will probably be suitable only for oil shale deposits lying considerably nearer the surface than 1000 ft (300 m) because

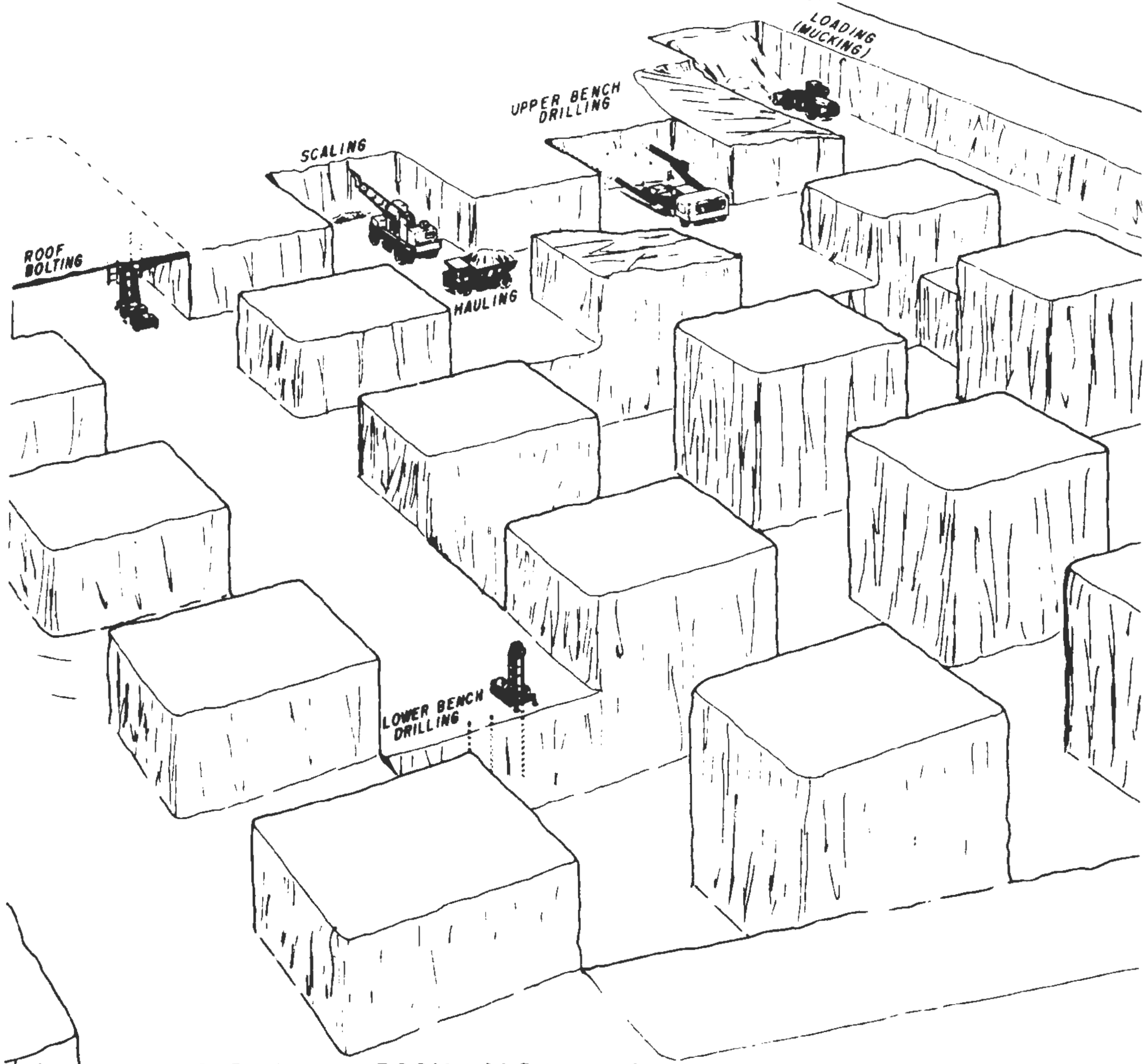


FIGURE 14-1. ROOM-AND-PILLAR MINING CONCEPT

Source: Reference 3

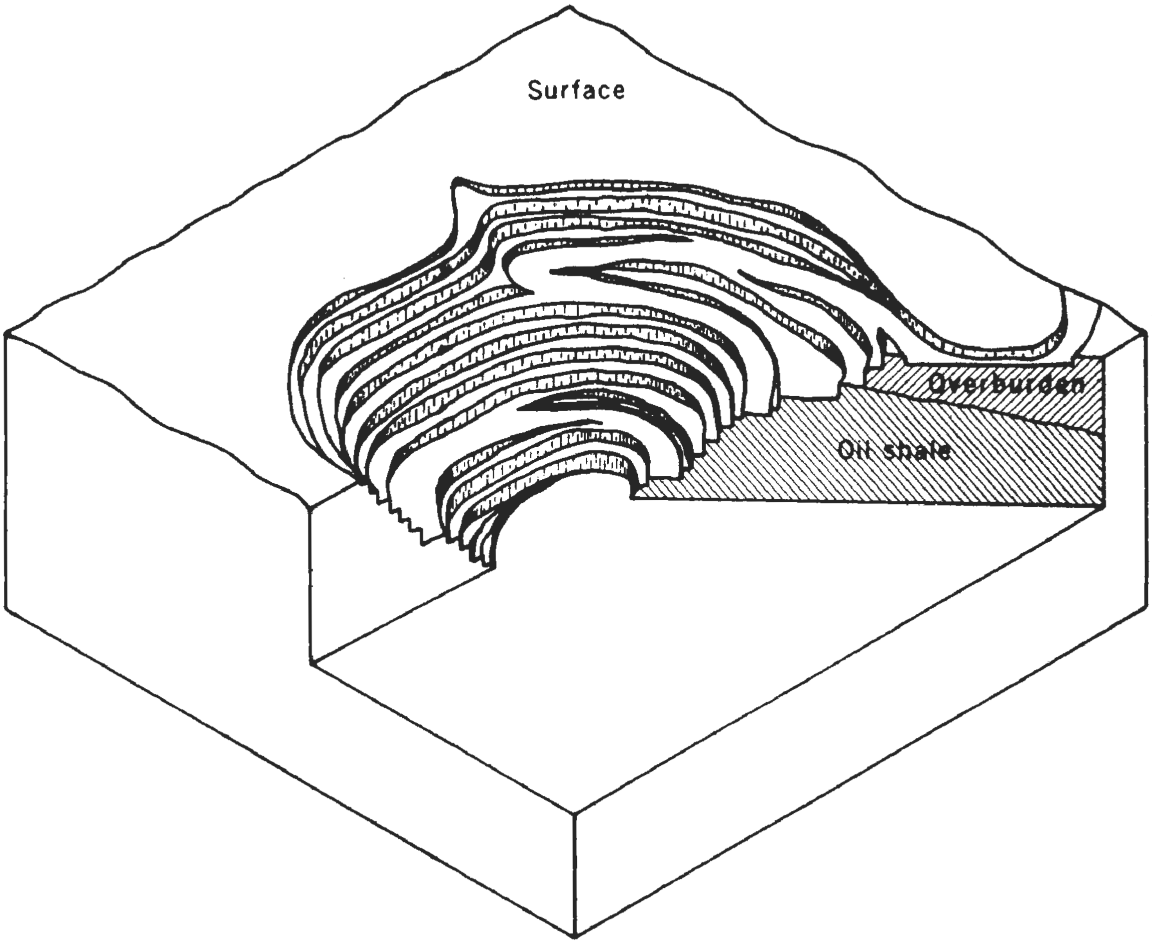
of the difficulty of excavating such a large depth of overburden with draglines. Open pit mining can be used for deeper deposits, and deposits with stripping ratios of 0.5 to 2.5 can be extracted economically.[4] In open pit mining, the overburden is also loosened by blasting; however, the ore is removed by power shovels and trucks rather than by draglines. As the pit is deepened, a series of benches are established, which provide stability for the sides of the mine. When the desired shale deposit is reached, it is loosened by blasting, loaded onto trucks, and conveyed to the crusher. Figure 14-2 illustrates the characteristics of an open-pit mine.

In open pit mining, as in strip mining, large amounts of overburden are generated, and a suitable site for storage must be found. Eventually, all the overburden can be returned to the mine and reclamation can take place.

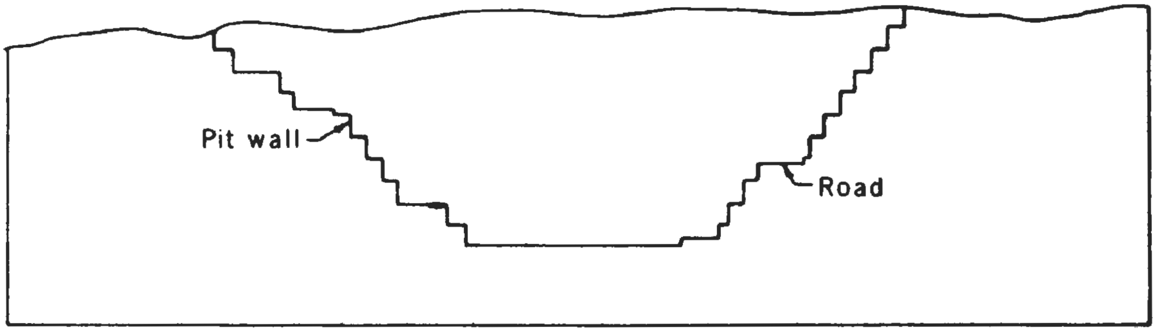
C. Spent Shale Disposal

After the oil shale has been mined, crushed, and retorted, approximately 85 percent of the original shale mass remains for disposal. The consistency of the spent shale may be of a fine granular form covered by carbonaceous residue if TOSCO II retorting is used, or a chunky material similar to agglomerated ash if the Paraho or another gas-combustion-type retort is used.[5] In either case, the spent shale is a relatively uselesss material, the disposition of which poses a major problem in oil shale development.

Most plans for oil shale development call for the disposition of the spent shale in canyons near the retorting operation. The plan is to spray the hot shale with water as it exits the retorts to cool it and control the dust, and then to transport the waste by conveyor belt to the disposal site.[3] There it will be graded, compacted, contoured



Isometric



Section

Source: Reference 5

FIGURE 14-2. SCHEMATIC OPEN PIT DEVELOPMENT and eventually revegetated, once the pile has reached its final height. Compaction will be required to minimize erosion and leaching of the pile, and to prevent the collapse of the pile's leading edge. In addition, the slope of the sides of the pile can be no greater than a three- or four-to-one grade if sliding is to be prevented.[5]

Runoff from the pile due to melting snow and rain will be highly saline due to the high concentration of salts in the spent shale. Therefore, a catchment dam must be constructed at the foot of the pile to collect runoff so that local streams are not contaminated.

Some of the spent shale can be returned to the mine. This is most readily accomplished if surface mining is employed, since it can be done in conjunction with the return of overburden to the mined-out areas. Spent shale can also be returned to the mine if underground mining is employed, but it will be more difficult because it will interfere with mining operations. In addition, the return of spent shale prohibits future recovery of shale contained in the pillars or in lower grade deposits.

In either case, disposal problems will remain since the volume of shale expands under retorting (10 to 30 percent, depending on the retorting process used) and not all the spent shale can be returned to the mine. Furthermore, temporary disposal sites will still be required since several years of mine development are needed before backfill operations can begin.

D. Environmental Problems

1. Mining

The environmental disruption associated with oil shale mining is typical of that of any large surface or underground mining operation, except that the sheer size of the operation will mean that the scale of the disruption will be much greater than any previously encountered.

Clearly, underground mining will cause the least ecosystem disruption. The major surface disturbance is the construction of roads for mine access. Surface subsidence should not be severe if pillars are properly placed within the mine.

Potentially serious is the contamination of aquifers in the mine area. The Mahogany Zone in which the richest shale occurs, forms an impermeable layer between the relatively pure aquifers that lie above this zone and the saline aquifers that lie beneath it in the Leached Zone. Shale mining will disturb this layer, permitting the saline aquifers to contaminate the upper aquifers, which recharge the streams of the region.[6] Furthermore, groundwater will seep into the mine from this highly saline zone, and dewatering the mine will produce large quantities of saline wastewater for disposal. To avoid the contamination of nearby streams, this wastewater must be eliminated through deep well injection or evaporation from lined ponds.[5]

Surface mining will cause similar disturbances of aquifers and saline water contamination problems. However, the major environmental disruption will be the disturbance of the area being mined and the resulting need to dispose of large quantities of overburden. Although the overburden will eventually be returned to the mined-out area for reclamation, a total of 2000 acres (8×10^6 m^2) could be disturbed per 100,000-B/D (16,000 m^3/D) operation before any reclamation would take place.[5]

2. Spent Shale Reclamation

Even under the best reclamation strategies, the naturally occurring ecosystems of the canyons in which the spent shale may be deposited will be completely covered and destroyed. The goal of reclamation is to establish a new ecosystem on the spent shale piles, which can be self-sustaining long after human involvement has ended. This goal involves stabilization of the pile against erosion and sliding, establishment of a suitable plant cover, and ultimately the generation of a plant succession system similar to other systems in the area.

Stabilization of spent shale from TOSCO II retorting appears to be possible with the appropriate amount of compaction and careful grading of the pile. After one or two years of natural weathering, the surface layers may be leached enough to reduce the salt concentration to a point where plant life can exist.

Research carried out by Colony Development Operation, and others, has indicated that a wide variety of plants can be grown if the spent shale pile is carefully fertilized and watered. However, only a few types of wheat-grass will survive on unattended spent shale.[7] Revegetation of the type of spent shale created by other types of retorts may be more difficult due to its clinker-like quality.

In general, the prospects for achieving a long-term stable ecosystem on massive spent shale piles have still not been fully assessed and it remains one of the major problems of oil shale development. Additional discussion of spent shale revegetation problems can be found in Chapter 15.

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15--REGION SPECIFIC BIOLOGICAL IMPACTS OF RESOURCE DEVELOPMENT

By Buford R. Holt

A. Powder River Basin

1. Introduction

Three significant classes of biological impacts can be important in the Powder River Basin of Wyoming:

- Retardation of revegetation by drought, erosion, heavy grazing, and spreading of toxic spoils.
- Adverse behavioral modification of big game and small game predators by mining and coal transport activities.
- Destruction of locally rare habitats.

The sections that follow focus on the environmental setting, major sources of impacts, and the potential for mitigation. Accounts of lesser impacts and additional biological detail can be found in the Final Environmental Impact Statement for the Eastern Powder River Coal Basin of Wyoming.[1]

2. Environmental Setting

The Powder River Basin is a broad, shallow topographic depression superimposed on a structural basin. The landscape consists of low, gently rolling hills, interrupted by broad flood plains containing shallow braided streams. Buttes, mesas, and rough, hummocky terrain add minor but significant diversity to the generally featureless terrain.

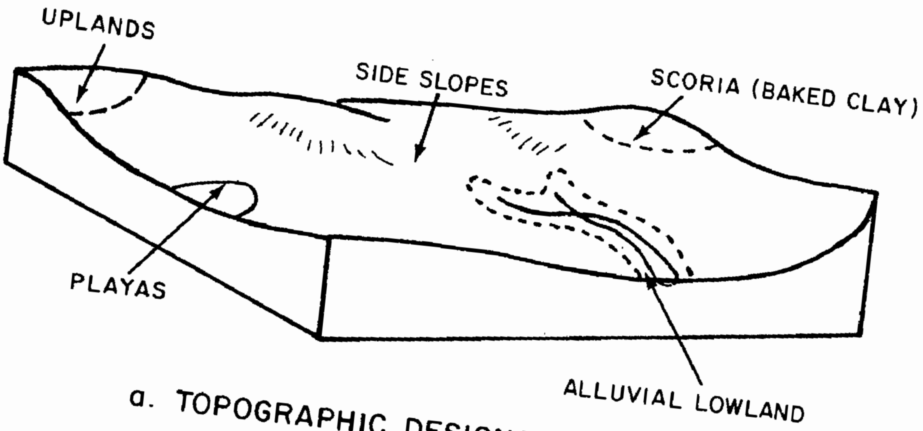
The climate is typically arid with frequent, unpredictable droughts. Most of the precipitation is derived from summer thunderstorms.

The winter snows are light and the snowmelt usually runs off before the ground thaws. Soil moisture is sufficient in the wettest years to support dryland farming, and lands near the Powder River Basin were plowed after the First World War, contributing to the subsequent dust bowls of the thirties. Comparable abuse by overgrazing has also been fostered by a tendency to be misled by the relatively high forage yields of the wettest years, resulting in substantial overstocking in the drier years. Consequently, the range in the basin has been severely degraded by decades of overgrazing.

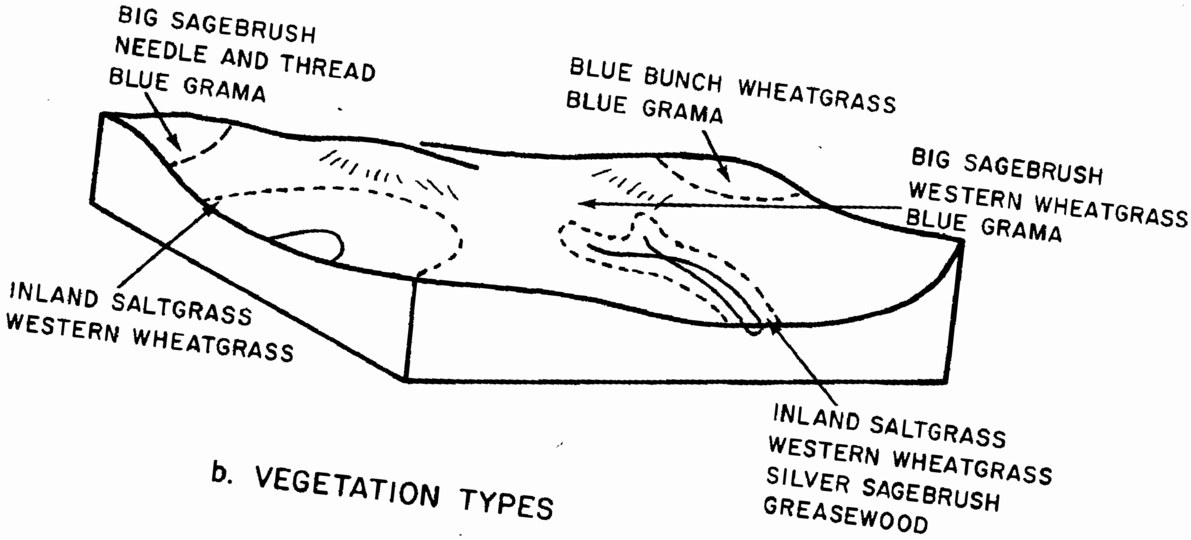
The soils are generally clayey, with slow to moderate internal drainage. Contrary to experience in humid regions, these clayey soils have less available water than sandy soils and are dominated by the more drought-tolerant species of the short grass prairie and elements of the cold deserts to the west. Water infiltrates more slowly into the fine textured soils and is more readily lost since even the fraction which penetrates below the first few inches can move to the surface by capillary action and is subsequently lost. On sandy soils water penetrates quickly and deeply, with loss only of that fraction in the surface layers. Correspondingly, the soils with the best moisture relations are the coarse textured soils of the scoria (baked shale) outcrops and the fine textured soils along stream courses. However, although they are deep and moist, the latter are generally either saline or alkaline and could be troublesome to rehabilitate if the underlying coal is strip-mined.

The vegetation of the basin is chiefly stunted plants of big sagebrush and sparse stands of blue grama, a drought-tolerant grass. Desert shrubs and arid grassland species dominate the overgrazed uplands and gentle slopes that prevail in the Basin, but pine forests cover the hills bordering the basin, and tall shrub communities line the larger, intermittent streams. Within the shrub and grassland communities, these conspicuous patterns are paralleled by significant variations in species composition even though the local variation in elevation is generally less than 100 ft as shown in Figure 15-1. The scoria outcrops are covered mainly by bluebunch wheatgrass and blue grama but contain several of the grasses characteristic of the wetter prairies to the east, including little bluesteam, prairie sandreed, and Indian ricegrass. Some of these more demanding grasses such as needle and thread are also found on the loamy upland soils where relatively good infiltration and storage of water can be expected. The big sagebrush-blue grama mixture predominates on the drier, clayey soils on the prevailing sideslope terrain (Figure 15-1a, 1b). Western wheatgrass and other salt-tolerant species dominate the relatively moist and productive alluvial lands. The dominant grasses within each vegetation type consistently include both cool and warm season grasses, designations based on the periods of maximum growth. However, these differences in the seasonality of growth are also correlated with differences in water loss during photosynthesis and may make the warm season grasses slightly more suitable for initial reclamation efforts. The establishment of both groups of grasses is necessary to maximize productivity over the entire growing season and to maximize the availability of the nutritionally superior new foliage throughout the calving period.

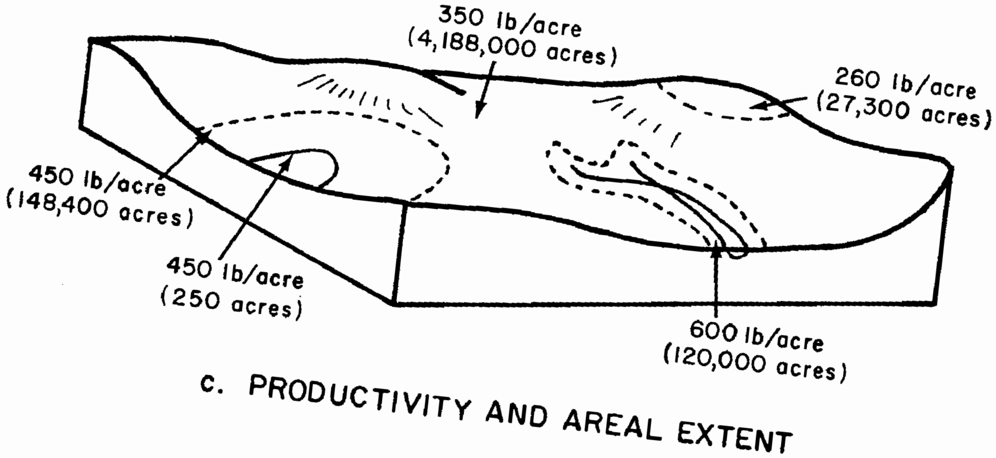
The dominant vertebrate land animals are small mammals and birds, with a conspicuous lack of large predators. Coyotes, badgers, foxes, and bobcats are the largest native predators in the Basin, but smaller ones also occur, including weasels, raccoons, and the black-footed ferret (an endangered species).[1] The big game species are limited to elk, mule deer, antelope, and white-tail deer. Small game species include sage grouse, wild turkey, sharp-tailed grouse, ring-necked pheasant, and cottontail rabbit.



a. TOPOGRAPHIC DESIGNATIONS



b. VEGETATION TYPES



c. PRODUCTIVITY AND AREAL EXTENT

FIGURE 15-1. NATURAL LAND UNITS OF THE POWDER RIVER BASIN

Invertebrate animals (insects, spiders, snails, etc.) have been little studied in the Basin, apart from surveys of species important to game fishes. Even so, these data on aquatic invertebrates should be useful as indicators of changes in water quality, and the available baseline data should be augmented.

The aquatic vertebrates are mostly warm-water fishes, reflecting the shallowness of the sparsely shaded streams and the consequent high summer temperatures and the fluctuations in water level and turbidity, which result from irrigation use. Most of the fish species are small, nongame species, but game species include large and small mouth bass, bluegills, and catfish, and, where water quality permits, various species of trout.

3. Immediate Impacts

It is unlikely that adverse effects on the animal population will be significant early in the exploitation of the Powder River Basin, but those that do occur will probably result from changes in the movement and distribution of game species or their predators.

The causal mechanisms are likely to arise from seemingly innoculous barriers such as sheeptight fencing, which antelope can leap over but frequently do not.[1] (Paradoxically, the antelope typically crawls under fencing rather than jumping it even though it is a conspicuously good jumper.)[2] Similarly, erection of utility poles may significantly increase the intensity of predation on small mammals or breeding grouse by providing perches for predatory birds, although large raptors are frequently killed when over-extended nests get wet, droop, and cause shorts. An analogous impact of fencing on songbird distributions, however, probably will not be important since shrubs provide an abundance of perches for songbirds. Conversely, some of the more conspicuous landscape changes, such as the fragmentation of shrubland corridors by mining activity, may not affect game movements in the Powder River Basin because the big game species are either highly local in their movements, such as the white-tail deer, or exceptionally wide ranging, such as the mule deer and elk, species which readily travel across grassland.

4. Cumulative Impacts

The most extensive impacts will derive from the destruction of habitats during mining and the subsequent replacement of the present shrub-grass mixtures with predominantly herbaceous vegetations of potentially lower productivity, thereby removing deer and antelope winter browse plants.

The magnitude of the potential productivity changes of these mined landscapes is the subject of dispute.[1] It is unlikely that the productivity of the reestablished vegetation will be much larger than the overgrazed range which they replace, without routine irrigation and reductions in the grazing intensity. The upper limit of productivity on these lands, even if well managed, probably will be less than the current maximum of 600 pounds of forage per acre characteristic of the wettest sites and may, as the Powder River Environmental Impact Statement (EIS) suggests, be as low as 200-500 pounds per acre, approximately the present productivity of scoria lands. This lower estimate is markedly below the present productivity of 350 pounds of cattle forage per acre of the dominant sagebrush vegetations and if the estimate is accurate it represents a long-term reduction in productivity of 25-50 percent.

Impacts attributable to modifications of productivity and the species composition of the vegetation will be greatest for the deer populations and least for the elk, which inhabit the pine forests just to the east of the strip-mine areas. The elk, however, are expected to be heavily affected by the increased human activity in the vicinity of the mines with a consequent reduction in the acceptability of an otherwise usable habitat.[1] Impacts of increased human activity should be minor for most small game; this may possibly cause declines in rabbit populations, and possibly long-term increases in prairie dog abundance. If the latter is true, the vegetation changes set forth in the EIS might enhance the survival probabilities of the black-footed ferret, an endangered predator of prairie dogs.

However, impacts on wildlife should be greater than productivity reductions alone would indicate since shifts in the species composition of the vegetation are probable and may be drastic. Deer and antelope depend on shrub forage much of the year, and elk utilize shrubs seasonally.[1,3] Correspondingly, deer and antelope utilize little grass, mostly in the spring when the carotene, digestible protein, and phosphorous contents are adequate. However, the magnitude of the effect of shrub removal will depend partially on the species removed and their location, for the shrublands comprising the winter range are the most critical, and their removal would most heavily affect the big game populations.[1]

The greatest long-term impacts on rare and upland game species will probably derive from the destruction of winter ranges, mating grounds, or tall shrub-woodland habitat. With the exception of the tall shrub and woodland habitats, which are essential for white-tail deer and elk throughout the year, these impacts involve the destruction of environments needed during restricted, but crucial portions of the organism's life cycle. For example, it is not clear that man can reproduce the environmental conditions necessary for the formation of a grouse dancing or strutting ground. However, it is probable that winter range for deer and antelope can be recreated by replanting shrubs,[4] although economic pressures may preclude this in private lands.

Restoration of stream habitats to their original mix of meanders, pools, and riffles, is improbable and certainly the thin shade provided by greasewood will not be quickly restored. Consequently, it is probable that mining activities in the Powder River Basin will severely affect local fish populations, may seriously impact local upland game species, and may reduce or eliminate at least the elk herd in the hills immediately to the east of the mines. The latter impact is perhaps the most serious, for the other species are widespread. The elk is largely confined to the western mountains and portions of the Canadian wilderness, even though it was once widespread throughout the North American woodlands east of the Rockies.[2]

5. Mitigation

Presently anticipated mitigation of the impacts of fencing, stream diversions, mining, and urbanization is largely limited to restoration of the original gently rolling topography and the reestablishment of vegetation in the mined areas.[1] No mention is made in the EIS of any plans to rehabilitate streams, possibly reflecting their minor economic importance of the wildlife which they contain.[1]

The probability of successful rehabilitation of terrestrial vegetation is moderate if the mine spoils are carefully layered and appropriate steps are taken to facilitate vegetation establishment.[5] Rehabilitation efforts have been moderately successful in areas receiving at least 10 inches of rain, even in the absence of irrigation.[5]

However, the rehabilitation programs are still young, and it is too early to appraise their success in the face of the recurrent droughts characteristic of the western plains. Moreover, appraisals to date have focused on the mass of plant material produced to the exclusion of their nutritional value. Since the species used typically provide good forage, the implicit assumption of high nutritional quality is probably sound, but the possibility remains that deficiencies of biologically essential elements in the new soils, and hence in the forage, may necessitate the addition to the soil of trace elements such as cobalt or copper. However, the data base on rehabilitation covers a broad enough range of sites to permit eventual refinement of appraisals of rehabilitation steps that will be necessary on the most difficult sites.[5]

The preliminary data from these rehabilitation experiments are sufficient to rank the rehabilitation probabilities of various sites within the West. The most difficult sites to rehabilitate are really the least extensive but most are in the Powder River Basin.[5]

The principal, universal constraints on rehabilitation in the West appear to be drought, inadequate seed sources, excess salinity, premature grazing, and the necessity for reshaping and appropriately layering the spoils.[5] In some areas instability of the soil surface must be added to the list,[5] as must frost-heaving on clay-rich soils during the relatively wet winter months.[6] Mitigation of all these constraints is feasible for small areas, but the prospect of mitigation of drought and grazing constraints over the large areas that would be involved over the 5-25 years variously estimated as the minimum duration of "post rehabilitation" is questionable. Indeed, the magnitude of the rehabilitation, irrigation, and fencing operations under those conditions probably would warrant an environmental appraisal in themselves.

Availability of suitable seed stock is considered to be a significant constraint for floodplain and badlands (severely eroded) sites,[5] but it should not be an unsolvable problem since cottonwood and willow are easily propagated by cuttings in the East, and research with mechanized planting techniques for upland shrubs is well advanced in the West.[4] Similarly, the greater availability of seeds of tall and mid-grass prairie species[5] probably owes more to the development of commercial markets for them in recent years than it does to any inate superiority over western grasses for successful seed production.

The salinity problems cannot be easily avoided in all cases, but they can be minimized by reliance on sandy soils as top-dressings. Use of sandy top-soils would have the subsidiary benefit of good soil-moisture relations, for in arid regions sandy, not clay-rich soils contain the maximum amount of water that is available for plant growth. In arid regions, clay soils are seldom wetted deeply and the deeper bodies of water are readily lost through capillary movement and subsequent envaporation. In contrast, water infiltrates fairly deeply into the sandier soils, and is retained in all but the upper two to three centimeters due to the absence of capillary movement.[7] The moderately sandy soils also tend to be less erosion-prone than the salinized clay-rich soils[5] and should minimize the probability of frost-heaving of young plants.[6]

Protection of young plants during the establishment phase will be consistently difficult because new tissues are typically the most nutritious and most highly favored by grazers.[3] Erection of sheeptight fencing around the newly revegetated areas should reduce this hazard, but it will be at best an expensive, partial solution. To the extent that it is effective, however, it reduces the winter range of antelope in the short run.

In all cases, however, the addition of top soil as surface coating (top-dressing) enhances success of vegetation establishment.[8] In the absence of irrigation and fertilization, native species can be expected to yield 2-3 times as much forage as introduced species. If ample fertilization and irrigation are available, the introduced species yield perhaps 10-20 percent more than the native species.[8]

In summary, successful rehabilitation appears to be feasible in wet years on sites recovered with the regional soils, but the success of rehabilitation programs in drought years is yet to be appraised.

B. Piceance Basin

1. Introduction

Environmental impacts in the Piceance Basin are dominated by three factors.

- Unsuitability of shale residues for plant growth without intensive supplemental management.
- Chronic drought and meager supplies of water for supplemental irrigation.
- Instability of many of the ungullied riverbottoms, causing substantial risks of heavy erosional damage and downstream sedimentation.

On balance, reclamation costs are likely to be higher in the Piceance than in any of the western or eastern coal fields because acid wastes and acid drainage excepted, the factors that most strongly limit reclamation in the coal fields are present. In addition, there is an immense problem of saline drainage.

The sections that follow focus on the environmental setting, the major sources of impacts, and the potential for mitigation. Additional detail can be obtained from the Environmental Impact Statement for the Colony Development Operation[9] and the Colorado State University report on surface rehabilitation potential.[10]

2. Environmental Setting

The Piceance Basin is a tectonic feature in arid, northwestern Colorado, which is overlain by a topographically diverse landscape. The "basin" is divisable into a rugged southern section, cut by thousand-foot canyons, and a more subdued northern plateau. The southern portion is characterized by dendtritic drainage patterns with deeply incised streams and marginally stable valley bottoms.[10] Although these streams apparently are not transporting significant sediment loads out of the basin now, any action that significantly increases runoff would trigger massive and rapid erosion with consequent sedimentation downstream, which would cause biological impacts well outside the oil shale region itself.

The soils in the Piceance Basin are typically shallow, weakly developed, and stony. The surface horizons are thin and lack conspicuous organic layers except in the forested regions. The subsurface temperatures are quite low, reflecting the low mean annual temperature. The soils are typically dry during all or most of the warm season, when growth would otherwise be most favorable.[10] A fairly broad spectrum of soils occurs within the region, but the more fertile ones are rare and typically restricted to the canyon bottoms and the floodplains of the major streams.

The climate is characterized by cold winters, warm summers, and chronic drought. Annual precipitation ranges from 12-15 inches with approximately two-thirds occurring as snow, and the rest as thunderstorms.[10] The frost-free season ranges from 90-120 days.[10] Snowmelt occurs as late as June[11] and initiates the period of highest runoff. Minimum stream flows occur in February when the soils are frozen and the snowmelt is mimimal.

Surface runoff averages less than an inch per year,[11] but is strongly pulsed, such that the erosion and flash flood hazards are great throughout the region. The dissolved solids content of the surface waters is moderate, as is water hardness.[11] The ground waters are meager and saline at shallow depths.[11]

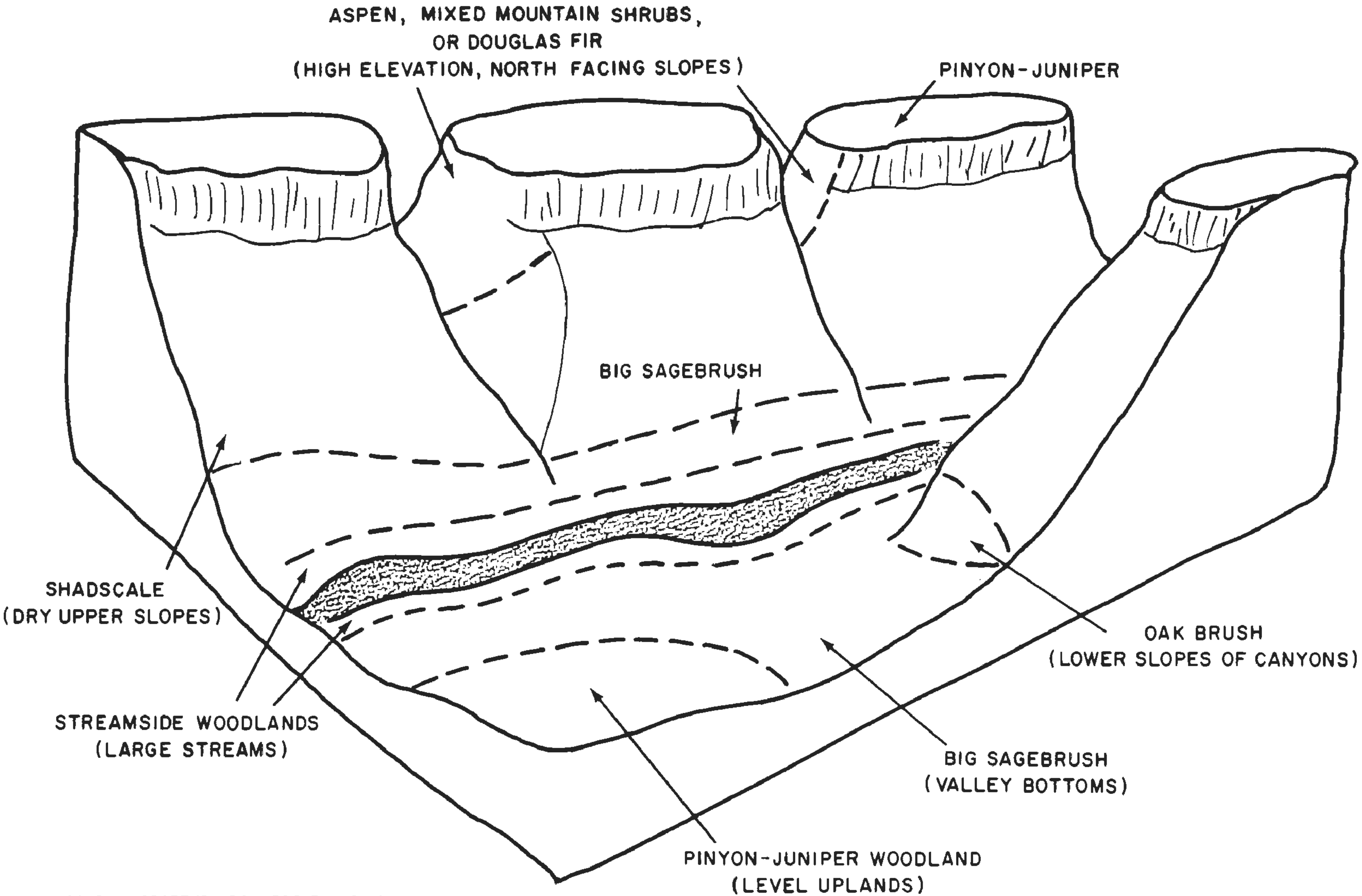
The vegetation of the basin is dominated by pinyon-juniper woodlands on the plateaus, tall shrub communities in the highly dissected southern region, and sagebrush communities on the fine textured, seasonally moist stream bottom soils in both regions. Riparian or gallery forest occurs along the larger streams in the south where water is available throughout the warmer months.[10] These gross characterizations are explicable in terms of the seasonality of water availability and the amount of water that is available during the respective growing seasons. The region as a whole is arid, but the lower temperature prevailing at the higher elevations lowers the loss rates from both plant and soil surfaces, rendering the higher elevations effectively wetter. The dominant plants are pine, juniper, and sagebrush. There are shallow-rooted species, which are metabolically active at the relatively low temperature prevailing in the spring and can effectively utilize the relatively abundant water supplies available just after the snowmelt. In contrast, the tall shrub communities of the lower elevation southern region are tap-rooted species that are metabolically active slightly later in the spring but that are able to utilize the deeper subsurface reservoirs of water that occur on the coarse textured soils of the lower valley slopes. The sagebrush species dominate the seasonally wet, fine textured alluvium in both regions, due to their tolerance of the extreme dryness of these soils during the summer months and their ability to utilize the moisture available in the late spring. On sites where the water supplies are dependable in the warm summer months, relatively rapidly growing deciduous trees such as cottonwood, boxelder, and chokecherry become dominant. Small areas of Douglas fir and aspen occur on the cooler, moister north facing slopes in the canyons at high elevations and shadscale, a desert shrub, covers the driest, steeper slopes as shown in Figure 15-2.

The terrestrial fauna of the area has received little attention to date, but as many as 100 mammalian species might be expected in the region, including 15 species of bats.[12] However, mule deer, coyotes, rabbit, and rock squirrels are the most conspicuous segment of this diverse fauna, although a number of familiar but rare species such as cougar and wild horses are to be expected in the region.[13] The reptilian fauna should be similarly diverse, with an abundance of lizards and snakes, but the amphibians are probably poorly represented. At least 62 species of birds are known to frequent the area,[14] but the total is probably at least twice that number.[15] Among these are a number of rare and endangered species such as the golden eagle, the bald eagle, the peregrine falcon, the Yuma Clapper rail, and the prairie falcon, most of which are favored targets of unthinking hunters.

The aquatic fauna is very poorly known,[13] but does include several rare species including one of potential interest as breeding stock for game fish hatcheries, the Colorado cutthroat trout.

3. Immediate Impacts

The immediate impacts of development will probably be felt most strongly in the aquatic ecosystems of the basin itself, with lesser impact on the biota of the Colorado River, and minor impacts on the upland communities. The principal hazards in the short run will probably be those associated with routine construction, particularly erosion and sedimentation.



SOURCE: ADAPTED FROM REFERENCE 10

FIGURE 15-2. VEGETATION OF THE PICEANCE BASIN

4. Cumulative Impacts

The principal long-term impacts will be associated with the mining and oil extraction processes themselves and will derive largely from the alternations in runoff, water quality, and the deposition of waste materials. An additional effect may be felt in lease tract C-a where strip mining is feasible since this tract stretches across the migration route of the White River mule deer herd, a group of possibly several thousand animals, which, unlike most deer populations, is migratory.[13] Extensive mining operations potentially could disrupt this normal pattern of movement, leading to overgrazing of portions of the herd's range and consequent long-term decreases in the herd size.

At full production (as the maximum credible implementation scenario), with approximately 20 retorting plants in operation, there is a possibility that the water flowing through the major streams in the area, Piceance, Parachute, Roan, and Yellow Creeks, may be significantly increased from runoff derived from disposal of spent shale.* However, the relative importance of evaporative losses and surface drainage are very sensitive to the disposal practices used. Losses are only likely when the spent shale deposits are watered with more water than needed simply to keep the surface wetted, which in this water-deficient region is most likely to occur during efforts to reestablish vegetative cover. If a water surplus is not added, or steps taken to provide a barrier to upward movement of capillary water, salt will accumulate to toxic concentrations in the surface soils. If these soils are rich in clays,

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*The estimated 8000 acre-ft per year of water that will be needed to wet down the spent shale and reestablish vegetation for a single oil shale processing plant represents the runoff from a square area approximately 14 miles on a side; for the basin as a whole with 20 plants operating, the water needed would be about twice the runoff occurring naturally.

salinization will cause dispersion of the soil particles, making the soil impervious and causing substantial increases in runoff. If simple overwatering is used as an inhibitor of salinization of the surface soils, substantial leaching of the underlying deposits of spent shale can be expected. Either method of water manipulation alone may consequently destabilize the stream bed deposits and cause massive erosion.[10] If this occurs rapidly, the biota of these streams will probably be decimated, although eventual recovery should follow the development of enlarged channels.

Impacts on stream biota can also be expected if local streams are used as water sources for dust control programs on roads and waste dumps. Removal of substantial fractions of water would tend to cause replacement of the biota of permanent streams by organisms characteristic of intermittent streams. Particularly strong reductions in the larger sized classes of those species that are most susceptible to human or avian predation due to restriction to isolated pools, lead to reductions in their breeding stocks.

Changes in salinity or in the suspended sediment concentrations will significantly affect the biota of the streams within the "basin," and, if sufficiently large, also within the Colorado River. Moreover, the latter impact is more difficult to appraise because the salinity and sediment concentrations are both high now and the percentage change expected is small.[16] Nonetheless, small increments have enormous biological and economic significance when the baseline values are near the limits of tolerance of the species at risk. One must also factor this into evaluations of the economic utility of energy extraction when the increased salinity requires that an energy intensive desalinization be undertaken downstream to meet international treaty obligations.

The prognosis for the probable impacts on terrestrial biota is less ambiguous but equally grim. The overburden in strippable areas consists of mixtures of limestone, siltstone, shale, and sandstone that yield rather coarse particles under the handling conditions that appear economically feasible.[10] While sand-sized particles enhance moisture availability for plants in arid regions by allowing rapid, deep penetration of the water, the larger particle sizes to be expected in the overburden spoils will retain too little water to sustain early growth. The spent shales, on the other hand, are almost wholly comprised of small particles, ranging in size from that of sand (< 2mm diameters) down to silt and clay (< 0.002 mm). As a substrate for plant growth, they are particularly unfavorable due to the previously mentioned aridity of the region, their dark coloration, and the lethally high temperatures that occur at the surface of spent shale piles. Moreover, spent shale is highly resistant to wetting, a property of some arid soils in the West, soils which are notably slowly revegetated following disturbances.

5. Mitigation

The basic mitigation steps for reclamation of spoil heaps and spent shale dumps broadly parallel those described for the western coal fields. It is essential that care be given to the stockpiling of soils and weathered rock, in strip-mined areas, for use as top dressings on the spoil heaps; that care be taken in the selection of the plants used for revegetation; that operations be planned whenever possible to capitalize on the relative moistness of north facing slopes; and that reclamation proceed closely behind the stripping or dumping operations. Spent shale will probably require additional steps to prevent wind erosion during the disposal process and to prevent subsequent salinization of the upper layers of the reclaimed waste piles. The former objective can be achieved by continual wetting of the surface, although at enormous costs in water consumption, but it might also be achieved by spreading a layer of gravel on the surface to form an artificial desert pavement at the end of any given dumping program. The second problem might be solved by laying a sufficiently thick layer of gravel on the spent shale before adding the top dressing of soil to prevent upward movement of salt-laden water by capillary processes. Such a coarse layer would prevent salinization of the surface soil and, by reducing the volume of water needed for revegetation, should reduce the impact of leached salt on the surface waters of the region. Soil for the reclamation of the spoils resulting from underground mining could be obtained from the meta-stable deposits of the streambeds with the side-benefit of reduced hazard of mass erosion, but these soil and weathered rock supplies may be grossly inadequate. If so, dredging in the Colorado River may be environmentally and economically acceptable as an alternative.

Impacts on streams within the "basin" can best be mitigated by pacing development to preclude abrupt changes in water quality and quantity but some impact seems unavoidable.

C. North Dakota Coal Fields

1. Introduction

The principal impacts in the North Dakota lignite fields should resemble those of the Powder River Basin but should be much less intensive. The principal differences are:

- Rehabilitation potential in North Dakota is higher due to greater water availability and soil fertility.
- Less disruption of wildlife habitat will occur in North Dakota due to prior conversion of substantial acreage to cultivation.

Destruction of regionally rare aquatic and streamside habitats remains a potential impact, although these mining impacts are dwarfed by the impacts of the dams constructed by the Corps of Engineers on the adjacent Missouri River.

The sections that follow focus on the environmental setting, the major impacts, and the probability of successful rehabilitation of the land assuming appropriate layering and reshaping of the soils.[1]

2. Environmental Setting

Broad, level uplands and gentle slopes dominate the topography although occasional hills and broad river valleys provide some diversity. To the east and north, the region is bounded by the bluffs and broad floodplains bordering the Missouri River, and to the west, by the badlands of the Little Missouri. Southward, the gentle terrain of the coal fields continues to South Dakota without interruption. Wetlands are rare southwest of the Missouri, but the regions eastward and downwind of the mining and industrial region are dotted with small ponds that are heavily utilized by migrant and breeding waterfowl.[11,17]

The climate in the coal fields is characterized by extremes of temperature and precipitation similar to those in the Powder River Basin, although the temperature range in North Dakota is larger and the moisture range is generally less than in the Powder River Basin. Precipitation is more strongly concentrated in the summer in North Dakota than in the other western coal fields, which, combined with the slightly lower summer temperatures, makes the effectiveness of precipitation in North Dakota greater than in the Powder River Basin.[18]

The soils of the region are loamy, slightly alkaline, moderately deep (up to 2 ft), with relatively high sodium concentrations.[5,19] As a consequence of the relatively high sodium and clay contents, formation of large soil particles (aggregates) is impeded in these soils and they are consequently readily eroded, particularly following repeated freezing and thawing.[1,5]

The vegetation of the Dakota fields is a mosaic of rangeland and small grain fields, with rare strips of woodlands along the major streams. The western border contains a small forest of ponderosa pine and the Little Missouri National Grasslands, which consists of farms that were abandoned during the dust bowl years of the 1930s. The woodlands along the Missouri, the Knife, the Little Missouri, and the Spring rivers consist of cottonwoods, elms, green ash, and boxelder, with small amounts of bur oak on the better drained river terraces.[20] These are rapidly being cleared for cultivation, now that the flood frequency has been greatly reduced by the construction of major dams on the Missouri, but they still provide extensive deer habitat.[20] The rangeland vegetation resembles that of the Powder River Basin with the exception of the greatly reduced incidence of shrubs[20,21] and the significantly higher productivity of even the poorest of the North Dakota sites. The range of forage production in the North Dakota is 980-1600 lb/acre,[21] roughly three times the productivity of the Powder River grasslands where approximately 50 acres are needed to support one cow.[1] The uplands are typically characterized by silty soils covered by stands of buffalo grass and needle and thread, while needle grass and little bluestem cover the relatively moist slopes of the steep-sided ravines that occur at the ends of the local drainage systems. Prairie dropseed and needlegrass dominate the sandiest ravine bottom soils.[21]

The vertebrate fauna of the fringes of the lignite fields are quite diverse due to the diversity of habitats provided by the mixture of urban, riverine, agricultural, and range environments. Approximately 150 species of birds are reported for the Missour Valley Region of North Dakota, including substantial numbers of woodland and aquatic species.[20]

Although censuses do not appear to be readily available, the number of species actually occurring in the lignite fields should be substantially smaller, due to the rarity of wetlands and forest. The major wetlands, and consequently the major waterfowl breeding areas are to the north and east of the Missouri River,[17] but there are four wildlife refuges within the lignite region.[22] Similar but less pronounced declines in species diversity with distance from the Missouri River may occur among the mammals and will surely occur within the amphibians, while reptiles may increase in diversity. In general, diversity among North American mammals increases with aridity, and particularly with increased variability in rainfall; extrapolating from these general patterns, it would appear that the mammalian fauna reported for the region do not reveal their true diversity.[23] Mule deer are the largest common mammals although cougar and black bear have been sighted in recent years.[20] The fish fauna is fairly well known, with preponderance of warm or turbid water species (i.e., species tolerant of low oxygen levels during the hottest months). As a whole, vertebrate fauna are dominated by small, geographically widely dispersed species, apparently lacking notable populations of rare or endangered species.

Invertebrate fauna have received exceptionally little attention apart from the grasshoppers which are economically important pests regionally.[20]

3. Immediate Impacts

Significant impacts are unlikely in the short run except in the highly localized areas of activity. Certainly, immediate impacts associated with road construction and mining should be less than in the Powder River Basin where the existing network of roads and fencing is less dense. Nor is significant restriction of the movement of game likely since the species present are either small or readily jump fences.[20]

4. Cumulative Impacts

The most significant impacts in the North Dakota coal fields are likely to be the destruction of the less common habitats such as steep slopes, which would be extremely difficult to reestablish. Such sites are characterized by locally unique combinations of microclimate and water availability, and consequently maintain distinctive plant communities. Apart from the eradication of these western representatives of the eastern prairies, the ultimate impact of mining should be modest if reclamation proceeds closely behind the stripping operations and is conducted with care. The soils are somewhat saline and become increasingly so with increasing depth, and spoils from the deeper layers rapidly become impermeable to water. Raw spoils particularly from the deeper layers are consequently exceedingly difficult to reclaim, but sites treated to a topdressing of material from within 10 ft of the surface typically have the highest reclamation potential of any within the Great Plains coal fields, due to the relatively favorable water balance prevailing in the region.[5] Disruption of lands along the river fringes due to coal development is likely to be minor relative to the changes already occurring in species composition in the floodplain forest in response to changes in the flooding regime caused by the major dams on the Missouri.[24]

5. Mitigation

Mitigation measures applicable in North Dakota are the same as those described in the appraisal of the Powder River mining operations. Their application in North Dakota is facilitated, however, by the greater availability of suitable seeds and water, and an academic base of experience in prairie reestablishment. However, care must be taken in those portions of both regions that have stony soils not to create gravel layers too close to the soil surface since they form an effective barrier to root penetration in arid regions.[25]

D. Illinois Coal Fields

1. Introduction

Three impacts dominate the Illinois coal region:

- Destruction of prime agricultural land.
- Production of acid drainage.
- Potential destruction of the floodplain forests of the Wabash River.

Impairment of wildlife habitat and destruction of natural ecosystems are generally not problems in Illinois due to the prior impacts of agricultural land uses, which have left only rudimentary fragments of the original prairies in cemetaries and along railroad rights of way. The dominant wildlife species are typified by Virginia deer and ring neck pheasant, both of which depend on the habitat fostered by man, and consequently tend to increase with increased human activity in humid regions.

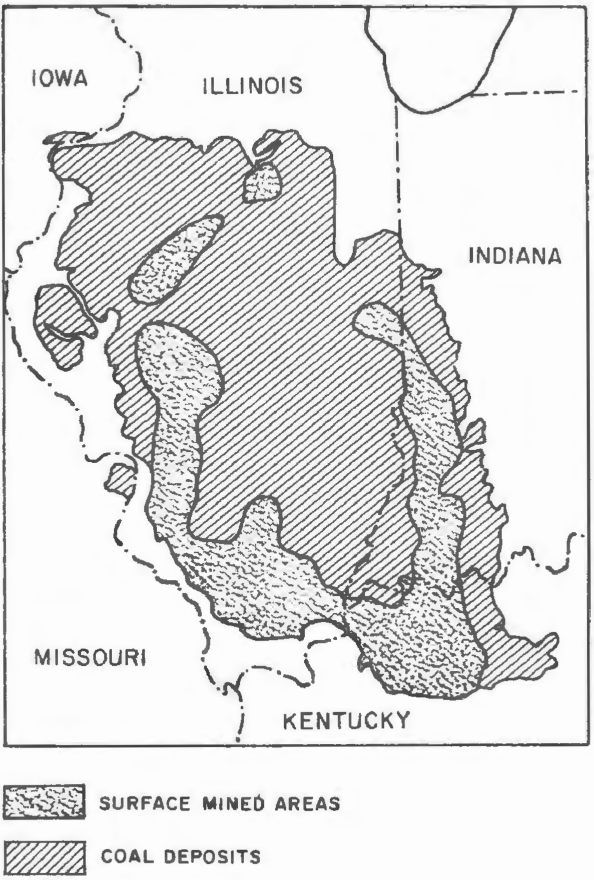
Rare or endangered species are unlikely to be threatened throughout northern and central Illinois, but do warrant consideration along the extreme southern fringe of the Illinois coal basin where the unglaciated terrain is characterized by usually rugged topography and underlain by extensive cave systems. This combination of topographic diversity and absence of glaciation have permitted the persistence of a number of endemic plant species as well as a number of broadly distributed species, which reach their northern distributional limits in southern Illinois. The vegetation of the southern fringe of the coal basin is consequently distinctive and rich.[26] The Wabash floodplain represents a special case of this general pattern, and, while heavily logged, still represents a unique extension of the rapidly disappearing southern floodplain forests of the Mississippi River.[27]

The sections that follow focus on the environmental setting, the major impacts, and the probable potential for rehabilitation. Additional biological detail and extensive bibliographies of pertinent literature are available in the Missouri Botanical Garden's report on the biota of the St. Louis region.[28]

2. Environmental Setting

The Illinois coal basin straddles the eastern extension of the tallgrass prairies and shares the climatic variability characteristic of the great plains but in a much milder form. Minimum monthly rainfall in Illinois is roughly equivalent to the maximum rainfall of the Powder River Basin and the average annual rainfall in Illinois is three times that of the Powder River Basin.[29] Approximately half of the precipitation in Illinois occurs during the growing season as a consequence of thunderstorm activity, and the remainder is precipitated as either rain or snow during winter storms associated with larger atmospheric movements (frontal storms). Floods occur primarily in the winter when the soil is frozen and in the early spring as the seasonal rainfall within the region is augmented by snowmelt.[30]

The topography of the midwestern coal fields is essentially featureless except for the gentle hills and low cliffs of their southern fringe. The major portion of the Illinois coal region is a level plain of glacial debris overlain by windborne sediments, which is transected by a few small rivers that meander through broad floodplains.[30] As shown in Figure 15-3 the southern boundary of the region is comprised of low, unglaciated hills underlain by an extensive cave system. The drainage system is well developed and lakes are consequently rare throughout the region.[30]



SOURCE: ADAPTED FROM REFERENCE 31

FIGURE 15-3. ILLINOIS COAL REGION

Streams in the region are typically alkaline but generally less so than in the western coal fields.[11] Hardness expressed as ppm of $CaCO_3$ ranges from 120-240 ppm in the Illinois basin, while it is at least 180 ppm in the Powder River Basin and typically over 240 ppm. Similarly both regions have exceeding hard groundwater, with concentrations in excess of 240 ppm except in the southern portions of the Illinois coal fields where a steep gradient in water hardness marks a transition to soft waters south of the Ohio River.[11] Sediment concentrations in the western and midwestern fields are similar, reflecting the easily eroded nature of the Illinois soil and the heavy use of row cropping in the Midwest. The water pollution potential from commercial fertilizers and domestic sewage is considerably greater in the midwestern region where fertilizer use is the heaviest in the nation.[11] Groundwater aquifers are absent in the central Illinois coal region, except for narrow aquifers along river courses. Moreover, since groundwater use is generally small, groundwater depletion is a problem only in the northern portion of the coal region.[30]

The soils of the region are generally 4 to 5 ft deep and exceptionally fertile, although soils in the southern portion of the region are characterized by impervious clay layers, which impede drainage.[30,32]

The structure and to some degree the fertility of the soils still reflect the nature of the original plant cover, the more strongly leached soils being those that developed under forest cover, which occurred in patches throughout the region. The soils are easily eroded and erosion to date has been characterized by the USDA as moderate to severe.[30]

The current vegetation of the northern and central portions of the Illinois coal basin is essentially a matrix of corn interspersed by roadside weeds such as giant ragweed, sunflowers, goldenrods, asters, marijuana, and assorted grasses. Remnants of the original prairies are found only in older cemetaries and along railway rights of way and presently consist of major prairie grasses such as little and big bluestem, Indian grass, and switchgrass, along with a number of broad leaved herbs which superficially resemble the weeds of abandoned croplands. The original woodlands are likewise rare, since the woodlands were settled before the prairies.[33] Woodland species are consequently found predominantly within the vicinity of homesites and along streams. In virtually all cases, woodland must be regarded as second growth, heavily disturbed stands.

The vegetation of the southern portions of the coal region is predominantly oak-hickory forest, a forest type widely distributed throughout the eastern United States.[34] The principal exceptions to this are the extensive floodplain forests of the Wabash River along the eastern edge of the coal field, which represents the northernmost extension of the rapidly disappearing floodplain forests of the alluvial plains of the Mississippi River. These forests have been logged, but still represent a unique resource even though the mammoth trees recorded in early photographs, including bald cypress, swamp gum, and sweet gum[35] are gone. A number of locally rare variants of these lowland forest vegetations have been described[26] for areas lying along the southern fringe of the coal area, many of which will be disturbed by mining if acid drainage is uncontrolled. The upland forest of oak and hickory have been repeatedly logged and burned, and most postdate the heavy logging of the 1890s and endured a second wave of logging during the 1920s.[36] It is of interest that the oaks of these forests fall into two groups reminiscent of the cool season-warm season distinction of the grassland dominants. Unpublished data from Brookhaven National Laboratory suggest that these groups, the red and the white oaks, are differentiated with respect to elemental composition and it is intuitively plausible that the distinctions between the two groups extend to other physiological properties. While significance of these distinctions is not clear, it is probable that they enhance the productivity of mixed forests and may have nutritional significance for browsers such as deer.

The flora and the vertebrate and invertebrate faunas of the major portion of the coal region probably contain few rare or endangered species given the extensive prior manipulation by man. However, the areas bordering the southern mining region contain a number of endemic and locally rare plant species such as French's Shooting Star in the unglaciated uplands bordering the Ohio River, and large numbers of rare animals are to be expected in the cave ecosystems underlying this region. While these probably will not be extensively impacted by mining, it is possible that they will be damaged by drainage waters from the strip-mined regions if adequate care is not taken to bury the toxic spoils to retard oxidation of sulfur containing overburden. The impact of mining warrants appraisal, but the greatest hazard to rare species in the region probably is associated with a proposed waterway development project on the Wabash.

The vertebrate animals of the uplands are typical of species found in the fringes of woodland, abandoned fields, and roadsides throughout the eastern half of the United States. Deer are the largest of the wild game, which includes the usual mixture of small game such as rabbit, raccoon, possum, squirrel, pheasant, quail, and dove. The total vertebrate fauna in the uplands consist of perhaps 40 species of reptiles, 10 species of amphibians, and 80 species of mammals,[32] and 115 species of birds.[15] The region borders the Mississippi flyway and a modest number of transient species pass through the area.

The vertebrate fauna of streams contain several additional species of reptiles and amphibians, as well as a large number of fish, including such game species as largemouth and smallmouth bass, crappie, bluegill, and catfish.[28,33] Individual streams draining the study area may have as many as 30 species of fish.[28]

Enormous numbers of invertebrates such as insects, leeches, snails, sowbugs, and crayfish are present in both upland and aquatic habitats, and they have been relatively well studied by the Illinois Natural History Survey. Indeed, as a consequence of the long continued efforts of the Natural History Survey and the state and federal soil conservation services, the biota and soils of Illinois are exceptionally well known, and the appraisals of impacts for this region can be defined with greater precision than for any other coal region.

The productivity of the region is high and diverse cropping is biologically feasible, although corn production dominates. In contrast to the Powder River Basin where as many as 50 acres may be needed per cow, approximately one acre per cow is sufficient in Illinois.[30]

3. Immediate Impacts

The immediate impacts of substantial expansion of the present mining activities should be much less than in the Powder River Basin or the North Dakota coal fields. The road and fencing networks are already substantial, and the game species involved are less strongly affected by fencing, both negating the impact of additional fencing. All impacts in the short term will be the consequence of increases in the areal extent of active mining itself.

4. Cumulative Impacts

The long-term impacts of strip mining will be relatively minor if reasonable care is taken to restore the land surface by layering and grading the spoils as outlined in the Environmental Impact Statements for the Powder River Basin.[1] Indeed, the restoration process is easiest here due to the presence of adequate rainfall during the growing season in all but the most exceptional years, the presence of deep layers of topsoil throughout much of the strippable region (up to 4 ft in thickness),[38] and the ready availability of seeds for both native and commercial plant species.[5] It is unlikely that destruction of shrub cover at any one time will be sufficient to substantially affect the game populations, and the rates of recovery of shrub cover should be high if reclamation is attempted.[39] Slow but uneven recovery can be expected even without reclamation,[39,40] although the erosion hazard is enormous in the western portion of the coal field where the loess deposits are deep.[11]

Indeed, the greatest impacts will probably be seen in the aquatic environments in response to increased turbidity and acidity of surface waters and the silting of spawning beds. However, with care, these impacts can be kept to relatively low levels, and the probability of exposure of sulfur rich deposits appears to be fairly low in much of the basin.[38] The principal problems with acid mine drainage can be expected in the southern fringe of the strip-mineable area.

5. Mitigation

The necessary mitigation measures are the same as those described for the Powder River Basin but are much easier to implement. Indeed, rehabilitation should be easier in Illinois than in any other coal field in the United States.

E. Appalachian Coal Fields

1. Introduction

The Appalachian coal fields are characterized by four environmentally significant features:

- Acid mine drainage is frequent from both surface and underground mines.
- Surface disruption of strip mining is exceptionally severe due to the rugged topography.
- Restoration of the land surface to the original contours is rarely feasible, although partial restoration is practical.
- Erosion is severe on sites which are not reclaimed.

These problems are not unique but are exceptionally frequent and severe in Appalachia.

The sections that follow focus on the environmental setting, the potential for mitigation, and the probable range of responses to attempted rehabilitation.

2. Environmental Setting

The Appalachian coal field occupies a southwest-northeast trending series of ridges and valleys and adjacent plateaus. The region as a whole is an intricate network of deeply incised streams, most of which empty into the Ohio River or its tributaries.[30] Topographically, the plateau consists of broad tableland, which grades into dendritically dissected hill land on both the northern and southern extremities and is underlain by horizontal or gently warped strata. The ridge and valley region is characterized by ridges up to 1500 ft high and tens to hundreds of miles in length, underlaid by strongly folded and faulted strata;[41]

The soils are thin to moderately deep, well drained, and easily eroded. Throughout much of the region, the uplands are too steep to farm, and the narrow floodplains are often plagued with poor drainage or frequent flood damage. The dominant land use is consequently forestry, with mixtures of pasture and cropland on the gentler terrain. As is generally true in the nation as a whole, the best agricultural soils are also the best soils for construction and are preferentially occupied by roads and urban areas.[41]

The climate is continental, with cold winters and hot, humid summers. The rainfall varies from 38 to 66 inches per year. The frost-free season averages 165 days and ranges from 150-200 days.[41] Precipitation is evenly spread throughout the year but varies in form from the cloudbursts of summer to the gentle, steady rains or snows of winter. Snowfall ranges from 2 to 60 inches, with between 10 and 40 inches being typical of most of the region. Soils in the northern portions regularly remain frozen throughout the winter but are subjected to sporadic freezes and thaws in the south. Frost penetration ranges from 3 to 20 inches and generally extends through the most densely rooted portions of the soil (the upper 6 inches).[11]

Surface water runoff is high, varying from 10 to 20 inches per year. Minimum stream flow occurs in late summer and early fall, and maxima occur in late winter or early spring when the soils are frozen or saturated and the transpiration losses are low. Groundwater supplies are typically marginal and are unimportant water sources throughout the region as a whole. Dissolved solids and salinity values are typically low, and the water quality in unmodified waterways is the best of the four coal regions considered. Surface waters are soft and, consequently, weakly buffered relative to those of the other regions--roughly half the hardness of water in Illinois--a factor that makes them particularly susceptible to change in response to acid mine drainage. Pollution from agricultural sources is low due to the topographic restrictions on mechanized agriculture, but urban pollution is locally severe.[11]

Streams in the region are generally shallow with frequent alternation of pools and riffles and a variety of bottom types. Typically, they are densely shaded during the warmer months and exhibit peaks of phytoplankton productivity in early spring and late fall when sunlight at the stream surface is maximal. Reproduction of both invertebrate and vertebrate fauna typically occurs in the spring when the decomposition of the accumulated tree litter accelerates and the phytoplankton production peaks. Most of the fishes migrate upstream to spawn, rendering the head waters critical to the maintenance of diversity in the larger streams.

The terrestrial vegetations are predominantly forests and include the most diverse forests of the continent in the highly dissected rim of the Cumberland Plateau and the Smoky Mountains. These forests frequently contain as many as 20 commercial species and several species of understory trees such as redbud, serviceberry, and hawthorn. This rich assemblage of sugar maple, white and red oak, hickories, ash, basswood, birches, magnolias, elms, beech, cherry, buckeye, and tulip-popular grades into less diverse stands of oak and hickory on the drier sites, and ultimately into stands of red cedar on dry limestone outcrops. On the shale barrens of Pennsylvania and the more acid, nitrogen-deficient mine spoils, black locust, which possesses a nitrogen fixing symbionic, becomes dominant. The wetter sites are dominated by sycamore, willows, red maple, elms, hackberry, black walnut, and assorted shrubs. The undisturbed forests on most, well-drained sites characteristically have relatively few shrubs but possess an exceptionally diverse herbaceous flora, which is metabolically most active before closure of the tree canopy in the late spring. As sites become either wetter or drier, and the tree canopy more open, the understory vegetations become more dense with a shift towards shrubs and ultimately drought-tolerant herbs on the drier sites such as ridge top and rock outcrops and a shift towards tall shrubs on the wetter, more poorly drained sites.[42]

Terrestrial vertebrates of recreational interest include gray squirrel, turkey, bear, deer, grouse, raccoon, possum, woodcock, and rabbit, but in general the fauna parallel the diversity of the vegetation, and the number of organisms of biological interest is large.[41] The southern Appalachians are a center of diversity for salamanders and other amphibians, while the region as a whole is moderately rich in mammalian species, with roughly 50 species of quadrupedal mammals and 10-15 species of bats.[23] Birds are likewise well represented, with perhaps 115 species in the region as a whole.[15]

Aquatic vertebrates include the species to be expected in Illinois but also include assorted cold-water species, although the trout populations are significantly augmented yearly with hatchery stock in all but the most remote cold-water streams. Smallmouth, stripe, spotted, rock, white, and largemouth bass; walleye, catfish, crappie, and bluegill constitute the major warm-water game fishes of the region[41] but a rather small portion of the total fish population, which includes minnows, suckers, and other nongame species.

Invertebrate fauna, both aquatic and terrestrial, are very diverse but as usual are unlikely to be endangered, with the possible exception of cave dwellers along the fringes of the mining regions.

3. Immediate Impacts

The immediate impacts of strip mining and the associated dirt roads are severe and, without considerable care, are both persistent and widespread. The coal seams are thin and the amount of overburden is extremely high. The spoils typically include substantial amounts of large rock fragments. As this overburden is first blasted and then shoved away from the seam, large rocks frequently roll down the adjacent hillsides, creating a swath of disruption somewhat larger than that caused by simple excavation and displacement of soils and other loose material. The resulting scars are often 50 to 100 ft high, including the terrain buried by displaced fill, and may stretch for miles. Severe as these impacts of the mining cut are, however, they may have only slightly more local impact on terrestrial biota than the less controversial interstate highway system, which has left equally permanent, if less vivid, scars on the landscape.

The immediate impacts of underground mining are modest, but the eventual impacts through waste disposal or acid drainage are often severe, even if less extensive than stripping.

In contrast to the impacts on land animals, the immediate- to long-term impacts of both strip and deep mining activity on aquatic organisms are persistent and often more severe than routine earth-moving activities such as highway construction. The increments to the silt load of streams is often severe in both mining and construction, but the mine wastes have the additional impact of significantly altering the acidity of streams by the continual release of extremely acid waters. In effect, acid mine drainage preempts the headwaters spawning grounds for many fishes, leading to inadvertent changes in the species composition of the biota downstream of the areas of immediate kill and this means a replacement of species that spawn in headwaters by those that spawn in the shallows of large streams, which in turn implies displacement of cold-water species, such as trout, by warm-water species, such as bass, catfish, or carp.

4. Cumulative Impacts

The long-term impacts scarcely differ qualitatively from those characteristic of the short term. The biological productivity of the land is lowered, life is often excluded from small streams, and more subtle changes in the biota of the intermediate-to-large streams are probable.

5. Mitigation

The mitigation steps applicable to Appalachia are similar to those of the midwestern and western coal fields but are far more difficult to implement. The thinness of the layers of weathered bedrock and soil combined intensify the need for careful analysis and handling of the overburden, while the steepness of the topography makes such painstaking work exceedingly difficult and expensive. Even in the best of circumstances, it is improbable that it will be economically feasible to restore the land to its approximate original contours, although it should generally be possible to greatly lessen the incidence of acid drainage and to speed the reestablishment of vegetation. The methodology is basically in hand to reclaim spoils[43,44] and, given adequate incentives for implementation, should be effective.

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16--AIR POLLUTION CONTROL FOR SYNTHETIC LIQUID FUEL PLANTS

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A. Introduction

1. Organization of the Discussion

In the assessment of the need for new technology for air pollution control in a future synthetic liquid fuel industry, the major steps are the following: (1) description and evaluation of the processes, emissions, and controls that can be used in the production of synthetic liquid fuels from coal and oil shale, (2) modeling the dispersion of pollutants emitted to the atmosphere, (3) comparing calculated ambient concentrations of pollutants with air quality standards that could apply in regions where the plants may be built, and (4) drawing conclusions regarding the adequacy of air pollution control technology for synthetic fuel plants. These steps are amplified in Sections B through E of this chapter, as indicated in the following paragraphs.

Section B identifies the sources of emission of air pollutants from various synthetic fuel processes by unit operation within the process and specifies the emissions that could be expected with best available control applied to each unit. Explicit assumptions about what constitutes the best available control are given and some of the choices that must be made in selecting the control technology to be applied to various unit operations within the process are discussed. Tables are given to summarize the resulting emission characteristics of each of the processes considered. Two processes for making synthetic crude oil are emphasized: TOSCO II retorting of oil shale and H-Coal liquefaction of western coal.

Section C uses the emission characterization of Section B to specify the source terms for atmospheric dispersion modeling. Reasonable assumptions regarding stack configurations and parameters are combined with meteorological data from energy resource regions in Colorado and Wyoming to calculate ambient concentrations of air pollutants. The calculated values are compared with various ambient air quality standards. Finally, the results of a preliminary sensitivity analysis are presented as an indication of the range of control requirements that could be derived from such calculations.

Section D summarizes the two preceding sections by presenting our best estimates of the percent additional control required to meet the Class II nondegradation standards. These standards are expected to apply in the oil shale and coal regions of Colorado and Wyoming, as well as to other energy resource regions of the western United States.

Section E presents conclusions and recommendations based on this analysis of air pollution control for synthetic liquid fuel plants.

2. Background

The assessment reported is a continuation of SRI work for EPA* in which the environmental implications of the development of solar, geothermal, oil shale, and solid waste energy sources were studied.[1] Phase II of that work focused on determination of the requirements for additional air pollution control for an oil shale industry[2] and is the

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*Under contract No. 68-01-0483.

prototype for the analysis presented here on the broader problem of air pollution control for synthetic liquid fuel plants.

The context for this discussion of air pollution control is established in Chapters 4, 6, and 9 of this report. Chapter 4 on the technology of alternative fuel production is most closely related to the air pollution problems and is referred to for some description of the processes. However, Chapter 6, on maximum credible implementation scenarios, and Chapter 9, on decision making for synthetic fuels, while not referred to explicitly here, help to set the stage for this discussion by indicating the possible magnitude of a major shift to synthetic liquid fuel production.

3. Air Pollution Standards

Standards play a key role in this assessment of air pollution control requirements.

Emission standards regulate the quantities of pollutants that can be emitted to the atmosphere from various specific processes or facilities. Such standards may be expressed as the amount of pollutant allowed per unit weight or volume of the total emission stream or as the amount of pollutant allowed per unit level of operation of the facility. Examples of the former are (1) the Colorado emission standard of 500 parts per million (ppm) of SO_2 relative to the total flue gas emitted from a stack and (2) the so-called "new source performance standard" for municipal incinerators of 0.18 g/m^3 (0.08 gr/SCF*) of

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*Grains per standard cubic foot. One pound equals 7000 grains. A standard cubic foot of any gas is the amount of gas that occupies a cubic foot at a standard temperature and pressure, in this case a temperature of 15°C (60°F) and a pressure of 1 atmosphere.

particulates in the exit flue gas. The latter type of emission standard is expressed in units used for "emission factors," such as pounds of sulfur dioxide (SO_2) released to the atmosphere per ton of copper ore processed in a smelter or kilograms of nitrogen oxides (NO_x) per gigajoule (GJ) of energy consumed in a boiler.

The emission standards referred to in this chapter are among the "new source performance standards" promulgated by EPA. These regulations set maximum emission rates for a number of industrial processes and facilities. "New source" is used to designate the fact that these standards apply only to facilities begun after some date specified in the notice of the standard. When new source performance standards are set by EPA, the nature of the processes employed in the industry and the availability of control measures that can be applied at reasonable costs are taken into account. New source performance standards for industrial boilers that consume solid, liquid, or gaseous fossil fuels are variously referred to in this chapter as power plant emission standards, utility boiler standards, or fossil fuel-fired boiler standards.

Air quality standards regulate the concentration of pollutants found in the "ambient" air that the general population breathes or could breathe. Ambient air is that found in the ordinary environment beyond the plant boundary, usually at ground level. Concentrations of pollutants are expressed either in parts per million (a volume of pollutant to volume of air ratio) or in mass per unit volume. The latter expression is now preferred, and all of the federal ambient air quality standards are expressed in units of micrograms per cubic meter of air ($\mu g/m^3$). The atmospheric dispersion model used in this work uses emission rates, which could themselves be compared directly only to emission standards, and calculates from them the ambient air quality, in $\mu g/m^3$, at various points in the vicinity of the emission source. These calculated concentrations can be compared directly to ambient air quality standards.

Ambient air quality standards used in this chapter include: (1) national primary standards, set by the federal government at concentration levels intended to be low enough to prevent adverse effects on human health, (2) national secondary standards, also set by the federal government acting under the same law, but set at lower levels of concentration intended to prevent economic damage, especially to living plants, (3) state air quality standards, in particular those of Colorado and Wyoming, and (4) three classes of ambient air quality standards intended to prevent significant deterioration of air quality in regions in which air pollutant concentrations are currently well below the national standards.

Standards in the last category are frequently referred to as "nondegradation standards." The specific classes and levels of standards in this category have been promulgated by EPA recently.[3] EPA proposed that the states be responsible for designating the clean air regions within their borders as belonging to one of three classes. Ambient air quality standards, expressed as increases in levels of concentrations of air pollutants to be allowed within the region, were set by EPA for each of the three classes. Of the three, Class I is the most strict, intended to keep air quality virtually unimpaired and consistent with very minimal industrial development of the regions so classified. Class II standards are strict but generally not so strict that substantial development is precluded, provided the development includes appreciable effort directed toward air pollution control. Class III standards allow the air quality in a region to meet the national primary or secondary levels, whichever is the strictest.

The complete specification of an ambient air quality standard includes, in addition to a level of concentration, the time interval over which the concentration is to be averaged. Standards mentioned in this chapter involve annual averages, 24-hour averages, and 3-hour averages. To completely specify standards tied to a daily or hourly average, the statement of the standard must also name the number of times per year that the specified level may be exceeded. Thus, the 24-hour or 3-hour levels of concentration are viewed as "worst-case" situations, with worst-case defined as the number of days per year a situation that severe is to be allowed under the standard. All such standards referred to in this chapter are to be exceeded no more than one day per year.

Table 16-1 is a summary of the ambient air quality standards referred to in this chapter. The standards are listed in the order of lenient to strict. Because background concentrations (pollutant levels present in the absence of any industrial activity in a region) must be added to the contributions from synthetic fuel plants for comparisons with all the standards other than Class I and Class II, it is possible that Class II, and perhaps even Class I, standards may not be as strict as a state standard in some cases. For example, due to background levels of SO_2 present in the Piceance Basin of Colorado, it would be easier for an oil shale industry to comply with the Class I nondegradation standard for SO_2 than with the corresponding state standard.

B. Synthetic Liquid Fuel Plants: Processes and Emissions of Air Pollutants

Emissions of air pollutants are estimated for three principal synthetic fuel processes:*

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*These and other competitive processes are described and discussed in Chapter 4.

Table 16-1

AMBIENT AIR QUALITY STANDARDS

		Concentration Level for Different Averaging Times ($\mu g/m^3$)		
Standard	Pollutant	1-yr	24-hr	3-hr
Federal[*] primary	Particulates	75	260	--
	SO_2	80	365	--
	NO_2	100	--	--
	Hydrocarbons (HC)	--	--	160
Federal[*] secondary	Particulates	60	150	--
	SO_2	--	--	1300
Colorado[†] (nondesignated areas)	Particulates	45	150	--
	SO_2	--	15	--
Wyoming[†]	Particulates	60	150	--
	SO_2	60	260	1300
	NO_2	100	--	--
	HC	--	--	160
Class II[‡]	Particulates	10	30	--
	SO_2	15	100	700
Class I[‡]	Particulates	5	10	--
	SO_2	2	5	25

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[*] Federal primary and secondary from The Federal Register, quoted in Environment Reporter, The Bureau of National Affairs, Inc. (1975).

[†] Colorado and Wyoming standards from The Federal Register, quoted in Environment Reporter, The Bureau of National Affairs, Inc. (1975).

[‡] Class I and II from The Federal Register, Vol. 39, No. 235, Part III (5 December 1974).

- TOSCO II production of oil from shale
- H-Coal production of oil from coal
- SASOL production of methanol from coal.

As cited earlier (Chapter 4), these processes were selected for study because of the advanced or proven development of the process, the suitability of the product for further refinement into automotive fuels in substantial proportion, and the availability of process data. In addition, data that were available on emissions associated with the Solvent Refined Coal (SRC) and Consol Synthetic Fuel (CSF) coal liquefaction processes have been included for comparison.

The relatively rich shale deposits of the Piceance Basin in Colorado are the source of raw material for the TOSCO II process. The H-Coal process emissions are estimated for two representative coals--a relatively high sulfur midwestern (Illinois No. 6) coal and a low sulfur subbituminous western (Powder River, Wyoming) coal. The data cited for the SRC and CSF processes pertain to the use of a "northwest" coal, similar to the Powder River coal, and a "central" coal, which is similar to the Illinois coal. The SASOL process consumes a low sulfur "western" coal similar to Powder River coal. Two process variations are also considered in the SASOL case: (1) the "design" process in which plant heat demand is met with a fuel gas manufactured from the coal and (2) an alternative process in which the necessary coal is burned directly. The latter process conserves energy but increases emissions.

In each case emissions from the production of electricity needed by the plant are estimated. These emissions are ascribed to the process regardless of plans to purchase the electricity or generate it on-site. However, the ambient concentration modeling in Section C excludes emissions ascribed to generation of electricity.

1. Syncrude from Oil Shale

The process of extracting the organic material from oil shale and of converting and upgrading the material to a suitable product is described in Chapter 4 and the analysis of air pollution control necessary for the TOSCO II process[3] is summarized here. Also included here are emissions that result from the generation of electricity supplied to the plant. Plans for the first TOSCO II installation by Colony Development Operation[4] call for purchase of electricity; other installations may generate electricity on-site. In either case the resulting emissions are attributable to the plant. Comparisons with the other synthetic fuels, those derived from coal, will then include emissions from all combustion needed for the plant. In all cases it is assumed that coal is consumed to generate electricity.

In addition, the TOSCO II plant is considered to produce a synthetic crude oil rather than a fuel oil. The difference in product does not have a significant effect on the air pollution expected from the plant. The dominant emissions from the plant are from the ore-preparation system and the pyrolysis and oil recovery unit, and these processes are the same for either product. Emissions from the product-upgrading units could vary with product changes, but these units consume relatively little fuel and therefore are relatively minor contributors to emissions. The crude shale oil must be upgraded to some degree in any case to permit transport by pipeline.

a. Control of Emissions

Emissions of a TOSCO II plant producing 16,000 m^3/day (100,000 B/D) of syncrude are summarized in Tables 16-2 through 16-5. Table 16-2 lists emissions attributed to the generation of electricity. Tables 16-3 through 16-5 summarize emissions of each major pollutant

Table 16-2

ELECTRIC POWER GENERATION* EMISSIONS ATTRIBUTABLE TO A TOSCO II OIL SHALE PROCESSING PLANT

(16,000 m^3/day of syncrude)

	Emissions Without Control Devices		Control Methods		Emissions Remaining With Best Control	
Type Emission	Factor (kg/10^3kg)†	Rate (g/s)	Device	Efficiency (%)	Factor (kg/GJ)‡	Rate (g/s)
Particulates	46.4	1280	Electrostatic precipitator	99.5	0.013	6.4
SO_2	9.5	260	Flue gas desulfurization	90	0.052	26
NO_x	9	245	None		0.50	245
HC	0.15	4.2	None		0.0083	4.2

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*Assumes use of Powder River Coal (see Section B-2).

†Refers to kg of pollutant per 10^3 kg of coal burned in the boiler.

‡Refers to kg of pollutant per 10^9 joules (about 10^6 Btu) of heat input to the boiler.

Table 16-3

PARTICULATE EMISSIONS FOR TOSCO II OIL SHALE PROCESSING PLANT (16,000 m^3/day)

	Emissions Without Control Devices		Control Methods		Emissions Remaining With Best Control	
System	Loading (mg/m^3)	Amount (g/s)	Device	Efficiency (%)	Loading (mg/m^3)	Amount (g/s)
Ore preparation						
Primary crusher	2,300	540	Baghouse	98.0	46	11
Final crusher	26,000	7,400	Baghouse	99.8	46	13
Fine-ore storage	21,000	1,600	Baghouse	99.8	46	3.3
Pyrolysis and oil recovery						
Raw shale preheat	16,000	18,000	Venturi scrubber	99.7	46	53
Steam superheater--ball stacks	5,900	1,400	Cyclone and Venturi scrubber	99.2	46	11
Processed shale moisturizer	8,200	970	Venturi scrubber	99.4	46	5.6
Product-upgrading						
Hydrogen unit	9	2.7	None		9	2.7
Naphtha hydrogenation	7	0.05	None		7	0.05
Gas oil hydrogenation						
Feed heater	7	0.23	None		7	0.23
Fired reboiler	7	0.20	None		7	0.20
Delayed coker	9	0.39	None		9	0.39
Utility boilers	50	2.5	None		50	2.5

Table 16-4

SO_2 EMISSIONS FOR TOSCO II OIL SHALE PROCESSING PLANT (16,000 m^3/day)

System	Emissions Without Control Devices		Control Method		Emissions Remaining With Best Control	
	Factor (kg/GJ)	Amount (g/s)	Device or Other Method	Efficiency (%)	Factor (kg/GJ)	Amount (g/s)
Pyrolysis and oil recovery						
Raw shale preheat	27	295	Treated fuels[†]	--	24	255
Steam superheater--ball stacks	6.0	5.3	Treated fuels	--	6.0	5.3
Product upgrading						
Hydrogen unit	22	81	Treated fuels	--	22	81
Naphtha hydrogenation	22	1.3	Treated fuels	--	22	1.3
Gas oil hydrogenation						
Feed heater	6.0	1.8	Treated fuels	--	6.0	1.8
Fired reboiler	6.0	1.5	Treated fuels	--	6.0	1.5
Delayed coker	22	11	Treated fuels	--	22	11
Utility boilers	43	23	Treated fuels[†]	--	34	19
Sulfur plant	4-5,000[*]	320	Tail-gas scrubber	95	250[*]	16

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*Units for sulfur plant emission factor--ppm by volume.

†Treated fuels include fuel oil meeting federal new source performance standards for power plants instead of fuel oil planned by Colony.

Table 16-5

NO_x EMISSIONS FOR TOSCO II OIL SHALE PROCESSING PLANT (16,000 m^3/day)

	Emissions Without Control Devices			Emissions Remaining With Best Control	
System	Factor (kg/GJ)	Amount (g/s)	Control Methods	Factor (kg/GJ)	Amount (g/s)
Pyrolysis and oil recovery					
Raw shale preheat	107	1,160	Treated fuels*	28	295
Steam superheater--ball stacks	39	33	None	39	33
Product upgrading					
Hydrogen unit	37	135	None	37	135
Naphtha hydrogenation	37	2.3	None	37	2.3
Gas oil hydrogenation					
Feed heater	39	11	None	39	11
Fired reboiler	39	9.2	None	39	9.2
Delayed coker	37	19	None	37	19
Utility boiler	210	114	Treated fuels*	13	6.9

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*Treated fuels include fuel oil meeting federal new source performance standards for power plants instead of fuel oil planned by Colony.

from individual subsystems in the plant. The only other substantial emission is 76 g/s of hydrocarbons from the raw shale preheat system. An incinerator controls hydrocarbon emissions to this level.

The final column for each table lists the estimate of emissions remaining after application of "best control." The assumptions leading to establishment of standards for best control are:

- Dust loading controlled to a level not exceeding 46 mg/m^3, equivalent to 0.02 gr/ACF.*
- Use of treated fuels, including use of a fuel oil meeting the federal new source performance standards for oil fired boilers, to control levels of SO_2 and NO_X.
- Sulfur plant emission of SO_2 controlled to a level of 250 ppm by volume.
- Electric power plant emission of particulates controlled 99.5 percent and emission of SO_2 controlled 90 percent.

A principal uncertainty in the estimates is the oil originally intended to fuel the plant. Other captive fuels planned for use have relatively lower emissions than the fuel oil in all categories.[2] Colony has indicated that this fuel oil will be subjected to further hydrotreatment, reducing both sulfur and nitrogen content, when it is necessary to insure that the plant meets relevant emission or ambient standards.[5] This procedure is said to be expensive, although relatively less costly than flue gas desulfurization. Until experience is gained with the

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*Grains per actual cubic foot; at the elevated temperatures involved, an actual cubic foot is considerably less dense than a cubic foot at normal temperatures and pressures.

process in its given environment, the present estimates serve best for comparison with other synthetic fuel processes.

A recent discovery[5] at Colony, not yet fully confirmed, adds another element of uncertainty. It appears that SO_2 emissions in the raw shale preheat subsystem (Table 16-4) may be effectively lowered by contact with materials present in the raw shale. The effect on emission levels would be significant since most of SO_2 is emitted from this unit. The tentative finding is that as much as two-thirds of the expected SO_2 may be removed from the raw shale preheat exhaust.

b. Options for Further Control

Later sections of this chapter indicate that further control of particulates and SO_2 may be required.

It is likely that improved control of particulates can be obtained. Principal sources are shale dust from the ore-preparation system and the raw shale preheat subsystem. Where shale dust is controlled, estimates of efficiency were derived using the quantities of sludge disposed to estimate loadings before control. This procedure overestimates efficiency since coarse particles are trapped by gravity to some extent before final collection. Since no measure of the proportion of fine particulates was available, the estimated emissions must be considered an upper limit. In addition to this consideration, the "best control" level used here may be conservative, depending on the proportion of fine particulates present.

Flue gas desulfurization remains an option for further control of the SO_2 levels. The economics of this process compared with hydrotreatment of the fuel oil, at the time of plant construction and later, would determine the selection.

c. Other Processes

In general, the estimates of emissions for ore-preparation systems and product upgrading systems associated with other surface retorting processes would be similar to TOSCO II. The emissions from a different retorting module could vary significantly, especially in dust emissions. The TOSCO II estimates would probably be highest of all processes under consideration with regard to dust from this module. Other emissions would depend primarily on similarity of fuels. Further discussion of these considerations may be found in Reference 2.

2. Syncrude from Coal

In estimating the emissions to the atmosphere from the operation of an H-Coal plant* producing 16,000 m^3/day (100,000 B/D) of syncrude two cases are considered: (1) processing Wyoming Powder River subbituminous coal, and (2) processing Illinois No. 6 bituminous coal. The characteristics of these coals are given in Table 16-6.

a. Control of Emissions

Tables 16-7 and 16-8 contain a summary of the emissions for an H-Coal plant processing each type of coal. In contrast to TOSCO II, a detailed breakdown of the fuel consumed in each major unit of the process is not available. Only two fuels are consumed--a captive fuel gas and coal. Emission factors for natural gas[7] were used for the fuel gas.

For Illinois coal, adequate quantities of fuel gas are expected to provide all fuel needed for the process. Coal is combusted

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*H-Coal process is described in Chapter 4 and Reference 6.

Table 16-6

CHARACTERISTICS OF REPRESENTATIVE WESTERN AND EASTERN COALS

	Ultimate Analysis (% by wt)	
	Wyoming Powder River Subbituminous Coal	Illinois No. 6 Bituminous Coal
Moisture	33	10
Ash	5.8	9
Carbon	45.7	62.7
Hydrogen	3.2	4.8
Oxygen	11.1	8.9
Sulfur	0.5	3.5
Nitrogen	0.7	1.1
Total	100.0	100.0
Higher heating value		
MJ/kg (Btu/lb)	18(7800)	26(11,000)

only to provide the electricity required. For Powder River coal, the fuel gas evolved in the process is not adequate to supply fuel needs, and coal is used to make up the difference as well as to produce electricity.

The emission factor for coal dust from the dryers is a pessimistic choice from the range of factors[7] that are likely. Removal of essentially all moisture is specified for the process.

Control of emissions from coal combustion,[8] using an electrostatic precipitator and flue gas desulfurization, is estimated at 99.5 percent for particulates and at 90 percent for SO_2. While the estimate for SO_2 removal may be controversial, the best independent judgment at present is that it can be met.[8] A high performance Venturi

Table 16-7

EMISSIONS FOR H-COAL LIQUEFACTION OF POWDER RIVER COAL
(16,000 m^3/day)

	Emissions Without Control Devices			Control Methods		Emissions Remaining With Best Control	
	Type	Factor	Rate (g/s)	Device	Efficiency (%)	Loading	Rate (g/s)
Coal drying							
Dryer exhaust	Particulates	12.5 kg/10^3 kg[*]	4200	Multiple cyclones and Venturi scrubber	99.0	36.7 mg/m^3[†]	44
Fuel combustion (coal)	Particulates	46.4 kg/10^3 kg	1325	Electrostatic precipitator	99.5	12.8 g/GJ	6.6
	SO_2	9.5	271	Flue gas desulfurization	90	52.4	27.1
	NO_x	9	257	None		496.	257
	HC	0.15	4.3	None		8.3	4.3
Steam reformer							
Fuel combustion (gas)	Particulates	290 kg/10^6 m^3	5.8	None		6.2	5.8
	SO_2	9.2	0.19	None		0.2	0.19
	NO_x	3700	74	None		81.	74
	HC	48	1.0	None		1.	1.0
Plant							
Fuel combustion (coal)	Particulates	46.4 kg/10^3 kg	2340	Electrostatic precipitator	99.5	12.8	11.7
	SO_2	9.5	479	Flue gas desulfurization	90	52.4	47.9
	NO_x	9.	454	None		496.	454
	HC	0.15	7.6	None		8.3	7.6
Fuel combustion (gas)	Particulates	290 kg/10^6 m^3	1.3	None		6.2	1.3
	SO_2	9.2	0.04	None		0.2	0.04
	NO_x	3700	17	None		81.	17
	HC	48	0.2	None		1.	0.2
Sulfur plant	SO_2	5000 ppm (vol)	320	Tail-gas scrubber	95	250 ppm (vol)	16.
Electricity							
Fuel combustion (coal)	Particulates	46.4 kg/10^3 kg	1079	Electric precipitator	99.5	12.8 g/GJ	5.4
	SO_2	9.5	221	Flue gas desulfurization	90	52.4	22.1
	NO_x	9.	209	None		496.	209
	HC	0.15	3.5	None		8.3	3.5

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[*] 2.87 gr/dSCF (grains per dry standard cubic foot).

[†] 0.03 gr/dSCF.

Table 16-8

EMISSIONS FOR H-COAL LIQUEFACTION OF ILLINOIS COAL ($16{,}000\ m^3$/day)

	Emissions Without Control Devices			Control Methods		Emissions Remaining With Best Control	
Source Unit	Type	Factor	Rate (g/s)	Device	Efficiency (%)	Loading	Rate (g/s)
Coal drying							
Dryer exhaust	Particulates	12.5 kg/10^3 kg*	4520	Multiple cyclones with Venturi scrubber	99.8	43.3 mg/m^3†	10.7
Fuel combustion (gas)	Particulates	290 kg/10^6 m^3	0.69	None		6.0 g/GJ	0.69
	SO_2	9.2	0.02	None		0.2	0.02
	NO_x	3700	8.8	None		76.4	8.8
	HC	48	0.11	None		1.0	0.11
Steam reformer							
Fuel combustion (gas)	Particulates	290 kg/10^6 m^3	2.19	None		6.0	2.19
	SO_2	9.2	0.07	None		0.2	0.07
	NO_x	3700	28.0	None		76.4	28.0
	HC	48	0.36	None		1.0	0.36
Plant							
Fuel combustion (gas)	Particulates	290 kg/10^6 m^3	9.47	None		6.0	9.47
	SO_2	9.2	0.30	None		0.2	0.30
	NO_x	3700	121	None		76.4	121
	HC	48	1.57	None		1.0	1.57
Sulfur plant	SO_2	5000 ppm (vol)	1370	Tail-gas scrubber	95	250 ppm (vol)	68.7
Electricity							
Fuel combustion (coal)	Particulates	72 kg/10^3 kg	1080	Electrostatic precipitator	99.5	14.1 g/GJ	5.4
	SO_2	66.5	998	Flue gas desulfurization	90	260	99.8
	NO_x	9	135	None		351.7	135
	HC	0.15	2.25	None		5.9	2.25

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*12.68 gr/dSCF (grains per dry standard cubic foot).

†0.03 gr/dSCF.

scrubber following multiple cyclones is likely to be necessary[8,9] to meet the proposed federal standard[9] for coal drying--70 mg per dry normal cubic meter (0.03 gr/dSCF).* The efficiencies shown necessary to meet this standard are judged to be reasonable.[8,9]

Sulfur plant emissions were calculated from the sulfur input and output rates. The efficiency of the scrubber applied to the tail-gas from the sulfur plant was estimated at 95 percent, a commonly achieved figure.

Combustion calculations were performed for all fuels (the fuel gas has a different composition for the different coals) to determine the flow rates and the set of stack parameters used in Section C to calculate the ambient air quality in the plant vicinity. Coal dryer flow rates were determined from coal moisture and typical exhaust temperatures.

The plant processing Illinois coal was assumed to be at sea level, while the Powder River elevation, 1230 m (4000 ft), corresponds to a pressure of 87.4 kPa (25.84 in. Hg).

b. Options for Further Control

The level of control indicated above is estimated in later sections to be adequate. Should further control become necessary, particulate emission from the coal dryers would be closely examined. Some improvement, especially for Powder River coal, seems possible with the same type of equipment. Improvement in flue gas desulfurization would bring about the best improvement in SO_2 levels. An alternative would be to replace at least part of the coal with a cleaner fuel.

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*Grains per dry standard cubic foot.

c. Other Processes

Emissions associated with other coal conversion processes have been estimated by others.[10] Total emissions from SRC and CSF plants* are given in Table 16-9 for comparison with other synthetic fuel processes. Emissions are shown for central coal (25 MJ/kg, 11.3 percent ash, 3.7 percent sulfur) and northwest coal (20 MJ/kg, 6 percent ash, 0.5 percent sulfur). These are very similar to Illinois No. 6 and Powder River coals, respectively (Table 16-6).

Table 16-9

CONTROLLED EMISSIONS† FOR SRC AND CSF COAL LIQUEFACTION PLANTS ($16,000\ m^3$/day)

Process and Operation	Pollutant	Emission Rate by Coal Type (g/s) Central	Northwest
SRC			
Combustion and drying	Particulates	34	35
Combustion	SO_2	97	16
	NO_x	900	900
	HC	2.9	2.9
Sulfur recovery	SO_2	203	32
CSF			
Combustion and drying	Particulates	24	21
Combustion	SO_2	257	44
	NO_x	550	540
	HC	2.7	2.5
Sulfur recovery	SO_2	64	14

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*SRC and CSF processes are described in Chapter 4.

†Includes emissions from electricity generation.

The level of control of emissions assumed for Table 16-9 was similar to that used for H-Coal. Coal dryer dust was controlled to the 99.85-percent level with a Venturi or Baghouse following the multiple cyclones, and sulfur plant tail-gas scrubbing was 95 percent effective. The SRC plant derives 92 percent of fuel demand from a captive fuel gas and the remainder from a product fuel oil. Since the sulfur content of the fuel gas is negligible, and the fuel oil contains only 0.28 percent of the sulfur level of the feed coal, no further control is imposed on the SRC plant. The CSF plant fuel needs are met 84 percent with fuel gas containing 0.4 percent of the sulfur level of the feed coal; the remaining 16 percent fuel needs are satisfied with coal. As above, an electrostatic precipitator plus flue gas desulfurization control emissions from the burning of coal--particulates are reduced 99.5 percent and SO_2 is reduced 90 percent (95 percent was assumed in Reference 10--this was adjusted to give the data shown in Table 16-9). Emissions associated with generation of the required electricity are included in Table 16-9.

3. Methanol from Coal

A general description of the process for producing methanol from coal is given in Chapter 4 with the SASOL process described in more detail in Reference 11. In estimating emissions to the atmosphere resulting from the operation of a SASOL plant producing 16,000 m^3/day (100,000 B/D) of methanol, two cases are considered: (1) operation of the plant as designed[11] using a fuel gas manufactured from the coal, and (2) operation of the plant burning the coal directly to obtain necessary process steam and electric power. A western coal yielding 20 MJ/kg (8700 Btu/lb) and containing 19 percent ash and 0.69 percent sulfur is assumed for both cases. This coal is of somewhat lower quality, in terms of ash and sulfur content, than the Powder River coal (Table 16-6).

a. Control of Emissions

Tables 16-10 and 16-11 present emissions for a SASOL plant processing coal to methanol for each fuel scheme. In both cases all fuel is consumed in a steam and power generation plant, and all purge gases (those evolved as a byproduct) are consumed. For the case considered in Table 16-10, part of the coal input is gasified to produce a fuel gas that is cleaner burning than the coal. The efficiency of this conversion is about 67 percent, leading to a total coal input rate of 35.4×10^6 kg (39,000 tons) per day. When the coal is burned directly (Table 16-11), the total coal input rate is 31.6×10^6 kg (34,800 tons) per day for the same methanol output.

Emission factors for natural gas[7] were used for both the purge gas and the manufactured fuel gas with one exception. The known sulfur content[11] of the manufactured fuel gas, in the form of H_2S, was assumed to be entirely converted to SO_2 during combustion. Sulfur content of the purge gas was specified[11] to be negligible, so that the factor for natural gas[7] was used. Emission factors for the coal[7] were calculated from the properties specified above. Since coal drying is not specified for this process, no special dust emissions are listed for this potential source. The uncontrolled emission rate for the sulfur plant was calculated from the specified[11] H_2S in the tail-gas stream. This flow was adjusted in Table 16-11 to account for deletion of manufactured fuel gas.

No controls are added for the relatively clean-burning gas. Controls for the coal burning are analogous to those imposed for the liquefaction processes (see Section B-2). A reduction in

Table 16-10

EMISSIONS FOR SASOL METHANOL PLANT USING MANUFACTURED FUEL GAS
(16,000 m^3/day)

	Emissions Without Control Devices			Control Methods		Emissions Remaining With Best Control	
Source	Type	Factor	Rate (g/s)	Device or Other Method	Device Efficiency (%)	Loading	Rate (g/s)
Combustion							
Purge gas	Particulates	290 kg/10^6 m^3	4.6	None		7.3 g/GJ	4.6
	SO_2	9.2	0.1	None		0.16	0.1
	NO_x	3700	60	None		95	60
	HC	48	0.8	None		1.3	0.8
Manufactured fuel gas	Particulates	290	16	None		7.3	16
	SO_2	9000	151	Treated fuel		71	151
	NO_x	3700	202	None		95	202
	HC	48	2.7	None		1.3	2.7
Sulfur plant	SO_2	1960 ppm (vol)	194	Tail-gas scrubber	95	250 ppm (vol)	9.7

Table 16-11

EMISSIONS FOR SASOL METHANOL PLANT USING COAL FOR FUEL
(16,000 m^3/day)

	Emissions Without Control Devices			Control Methods		Emissions Remaining With Best Control	
Source	Type	Factor	Rate (g/s)	Device	Device Efficiency (%)	Loading	Rate (g/s)
Combustion							
Purge gas	Particulates	290 kg/10^6 m^3	4.6	None		7.3 g/GJ	4.6
	SO_2	9.2	0.1	None		0.16	0.1
	NO_x	3700	60	None		95	60
	HC	48	0.8	None		1.3	0.8
Coal	Particulates	154 kg/10^3 kg	13960	Electrostatic precipitator	99.5	39	70
	SO_2	13.1	1190	Flue gas desulfurization	90	66	119
	NO_x	9	816	None		450	816
	HC	0.15	14	None		7.7	14
Sulfur plant	SO_2	1960 ppm (vol)	134	Tail-gas scrubber	95	250 ppm (vol)	6.7

particulates[8] of 99.5 percent is expected for an electrostatic precipitator followed by flue gas desulfurization, and a reduction of SO_2 level[8] is expected to be about 90 percent. The tail-gas scrubber should be 95 percent effective in removing sulfur from the tail-gas stream of the sulfur plant.

b. Options for Further Control

The clearest option for better control is to select the process using the manufactured fuel gas. The SO_2 levels are similar but the other emissions are considerably lower. The cost in coal feed is about 12 percent of the total feed rate. Another option would be to treat the fuel gas for further sulfur removal. The SO_2 loading from the fuel gas combustion is already comparable to the scrubbed flue gas from the coal.

4. Summary

Table 16-12 summarizes the total emissions from each processing plant and feedstock combination considered. These values include the emissions attributed to generation of electricity needed for each plant. However, the values given in parentheses in Table 16-12 exclude the generation of electricity, and are used in Section C to model the ambient concentrations for those processes. Electricity is assumed to be generated off-site for the processes modeled.

C. Atmospheric Dispersion Modeling

Requirements for additional control, beyond the levels taken to represent best available control in the preceding section, are derived by comparing ambient concentrations of air pollutants that result from synthetic fuel plant emissions to ambient air quality standards that could apply in the vicinities of the plants. This section describes the atmospheric dispersion modeling used to calculate ambient concentrations from emission levels and presents the results of those calculations. These results are displayed later in this section as possible control requirements. A subset of these results forms the basis for estimates of the applicable control requirements (Section D).

Table 16-12

SUMMARY OF EMISSIONS FROM ALTERNATIVE SYNTHETIC FUEL PLANTS EMPLOYING BEST AVAILABLE CONTROL*

	Total Emissions Including Electricity† (g/s)			
	Particulates	SO_2	NO_x	HC
TOSCO II	109(103)	420(394)	761(514)	80(76)
H-Coal--Powder River	75(69)	113(91)	1011(802)	17(13)
H-Coal--Illinois No. 6	28	169	293	4
SRC--Northwest	35	48	900	3
SRC--Central	34	300	900	3
CSF--Northwest	21	58	540	3
CSF--Central	24	321	550	3
SASOL--Fuel gas	21	161	262	4
SASOL--Coal	75	126	876	15

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*Plant size taken to be 16,000 m^3/day (100,000 B/D).

†Numbers in parentheses exclude emissions attributed to generation of electricity.

1. General Principles

Atmospheric dispersion modeling requires suitable specification of input data describing both the sources of emission of air pollutants and the region into which the pollutants are emitted. The model employed here requires a standard set of data to characterize sources: the heights, diameters, temperatures, gas flow rates, pollutant emission rates, and positions of the stacks comprising the source of emissions. It also requires readily available meteorological data. (Appropriate data for source characterization are shown in Tables 16-13 and 16-16 and Figures 16-1 and 16-6 later in this section.) Information on the emission source is combined with information on the site in question to form an estimate of the ambient air quality. The required data are available for sites near but not precisely at western oil shale and coal regions.

The model used here for calculation of air pollutant concentrations is the Climatological Dispersion Model (CDM),[12,13] which is a computerized model that permits calculation of seasonal or annual average pollutant concentration patterns resulting from stationary point sources and area sources. The fundamental physical assumption of the model is that the steady-state spatial distribution of pollutant concentration from a continuously emitting point source is given by the Gaussian plume formula. It is assumed that meteorological conditions over short periods of time (of the order of one hour) can be regarded as steady-state and that these conditions can be approximated with a constant and spatially uniform wind vector for the entire area.

Gaussian plume assumption is used when there are no restrictions on vertical diffusion. When vertical diffusion is restricted to a finite mixing depth, a uniform vertical concentration distribution is assumed at distances a few kilometers downwind.

Equations for the long-term average concentrations due to point and area sources are weighted according to a frequency function to account for the variability of meteorological conditions. These empirical functions express the observed joint frequency of occurrence of various classes of wind direction, wind speed, and a stability.

Integration of the formulae over the area and point sources describes the simulated concentration at selected location for a certain set of meteorological conditions. These concentrations, taken together with the frequency of occurrence of each combination of conditions, produce the climatologically averaged spatial distribution of concentration.

The CDM program used in this study assumes that the pollutant be properly simulated by a single wind vector; thus topographic influences of complex terrain are not currently incorporated into the dispersion model. Topographical features of the regions modeled for oil shale production in Colorado (Section C-2) and coal liquefaction in Wyoming (Section C-3) are discussed below.

For comparisons with ambient air quality standards the concentration of air pollutants are calculated here using averaging times that fit the various standards. Four air pollutants are included: particulates, sulfur dioxide (SO_2), oxides of nitrogen (NO_x) and hydrocarbons (HC). The time periods involved are: annual averages for particulates, SO_2, and NO_x; 24-hour averages for particulates and SO_2; and a 3-hour average for HC. Since photochemical interactions with NO_x and HC are not considered, no decay with time of NO_x and HC concentrations is assumed. Decay of SO_2 is accounted for in model calculations by an exponential decay term having a 3-hour half life.

The results of the dispersion modeling are compared with federal and state ambient air quality standards. Emissions and ambient concentrations of NO_x (combining both NO and NO_2) are expressed as NO_2 equivalent and compared to the NO_2 standard. This amounts to a worst-case assumption for NO_2 in that NO_x emissions are assumed to consist entirely of NO_2. However, as mentioned above, no photochemical atmospheric dispersion model has been used, and therefore we have not addressed the possibility that photochemical oxidant formation could be the most significant limit on emissions of NO_x and HC.

2. Modeling a TOSCO II Oil Shale Plant

a. Characterization of Emission Source

Table 16-13 and Figure 16-1 present the emission source characteristics required as part of the inputs to the CDM. The emission rates given in Table 16-13 are those derived and explained in Section B. Figure 16-1 shows a possible configuration of stacks comprising the specific emission sources within the 16,000-^{3}/day (100,000-B/D) oil shale plant, based on the description of a 8,000-m^3/day (50,000-B/D) TOSCO II oil shale complex given by Colony Development Operation.[4] Radical changes in the assumed configuration could result in concentrations somewhat different from those calculated here.

b. Characterization of Oil Shale Region

Meteorology and topography will affect the ambient air quality from a given emission source. The oil shale regions considered here are the Piceance Basin in western Colorado and the Uinta Basin in eastern Utah. Because the oil shale deposits developed first are most likely to be in or near the Piceance Basin, that region is emphasized.

(1) Topography.* The major oil shale area of the Piceance Basin lies on the Roan Plateau, bounded by steep escarpments in all directions. The land surface of the region has been shaped by erosion into valleys and ridges oriented in the north and northeasterly directions. The difference in elevation from ridge to valley floor ranges from 62 to 185 m (200 to 600 ft), and most of the valleys are

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*The information contained in this section was extracted from Reference 14.

Table 16-13

STACK PARAMETERS AND EMISSION RATES FOR A 16,000-m^3/D (100,000-B/D) TOSCO II PLANT WITH EMISSIONS CONTROLLED[*]

								Emissions (all stacks) (g/s)			
Location[†]	Description of Unit	Flow Rate[‡] (all stacks) (m^3/s)	Temp. (°C)	No. of Stacks	Stack Height (m)	Stack Diameter (m)	Gas Exit Velocity (m/s)	Particulates	SO_2	HC	NO_x
1	Hydrogen unit	317	260	2	30.5	3.0	21.7	2.7	81.0	--	135.4
2	Naphtha hydrogenation	7	427	1	24.4	0.9	10.8	0.05	1.3	--	2.3
3	Gas oil hydrogenation: feed heater	36	427	2	24.4	1.8	6.8	0.23	1.8	--	10.8
4	Gas oil hydrogenation: fired reboiler	31	427	1	24.4	2.1	8.6	0.20	1.5	--	9.1
5	Sulfur plant	30	38	1	76.2	1.5	16.6	--	16.1	--	--
6	Delayed coker	45	260	1	24.4	1.8	17.2	0.39	11.3	--	18.9
7	Steam superheater--ball stack	244	54	12	76.2	1.8	7.8	11.1	5.3	--	33.6
8	Raw shale preheat	1160	54	12	76.2	4.0	7.8	52.8	257.0	75.6	297.0
9	Processed shale moisturizer	119	91	12	12.2	1.2	8.4	5.6	--	--	--
10	Primary crusher	236	16	2	15.2	2.4	25.2	10.8	--	--	--
11	Final crusher	283	16	20	15.2	1.2	12.1	13.1	--	--	--
12	Fine ore storage	76	16	2	15.2	1.5	20.6	3.3	--	--	--
13	Utility boilers	49	260	4	15.2	1.2	10.8	1.5	18.6	--	6.9

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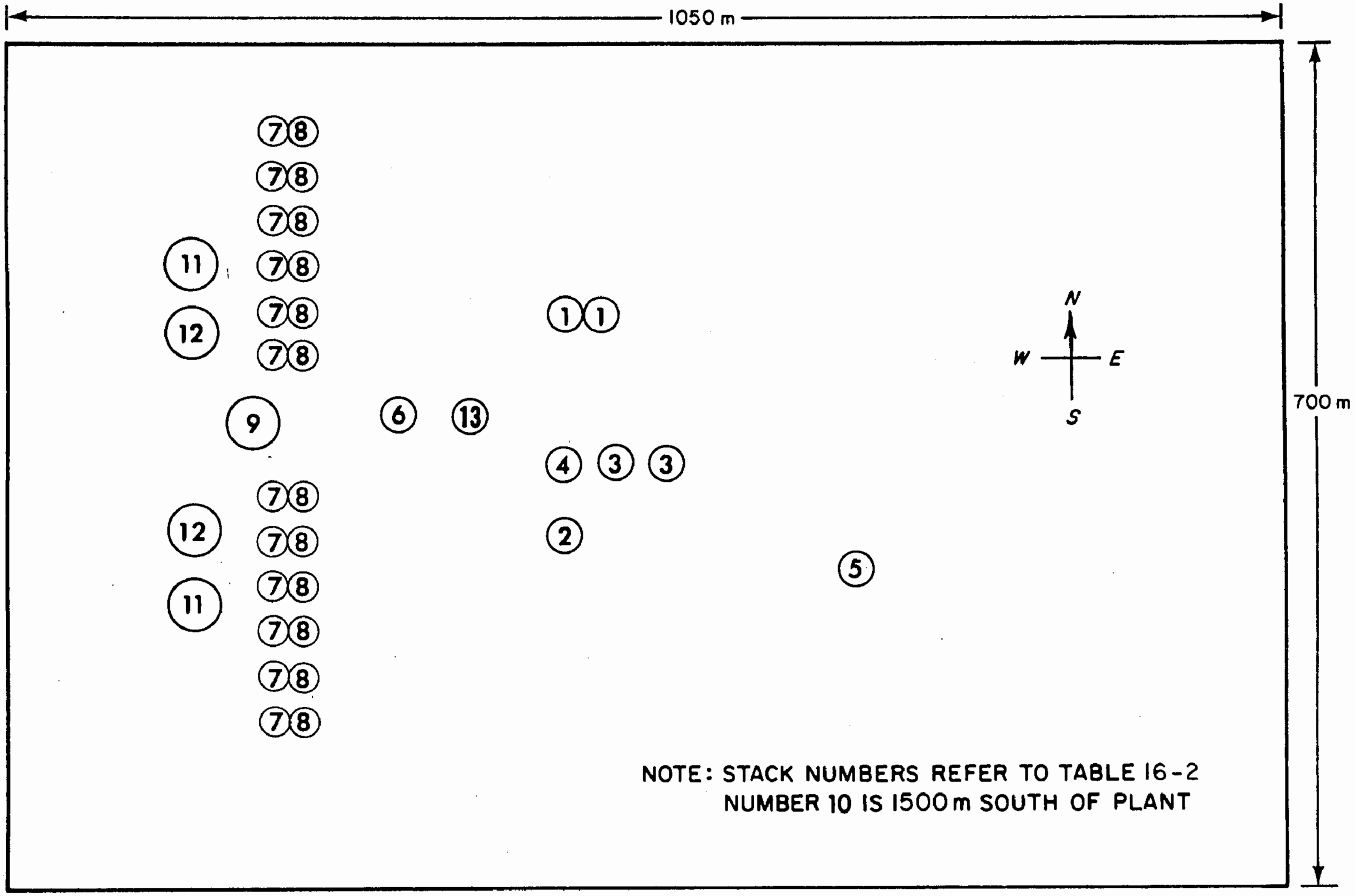
[*] Assumed best available control as specified in Section B of this chapter.

[†] Location refers to Figure 16-1.

[‡] To convert to ACFM (actual cubic feet per minute), multiply by 2120.



NOTE: STACK NUMBERS REFER TO TABLE 16-2
NUMBER 10 IS 1500 m SOUTH OF PLANT

FIGURE 16-1. TOSCO II PLANT CONFIGURATION narrow and steep sided. Land elevations above mean sea level (MSL) range from about 1600 m (5250 ft) near the White River to about 2800 m (9000 ft) on southern ridge crests.

The Uinta Basin of Utah is a depression bounded by the Uinta and Wasatch Mountains, the Roan Cliffs, and the cliffs west of the Douglas Creek Arch. Land features include rough mountains and flat valleys, with deep gulleys and rock-capped ridges. Elevations range from 1400 m (4600 ft) to more than 2500 m (8000 ft) MSL.

In general, these steep-sided valleys are unsuitable locations for plant sites. Moreover, from the point of view of minimizing pollution potential, oil shale processing facilities should be located on plateau, rather than valley sites.[15] The evidence for the necessity of such location is sufficiently compelling that the dispersion modeling reported here is based on the assumption that the oil shale plants will be located on plateau sites. If an oil shale plant should be located in a narrow valley, the actual concentrations of pollutants will be higher than those calculated by the CDM. However, if the facility is located on a plateau or in a broad valley, as Colony plans for its first plant, the dispersion model will adequately predict concentration patterns.

(2) Meteorology. The meteorological data required for application of the CDM are not available within the oil shale region. Therefore, annual averages were calculated from frequency distributions of meteorological conditions observed at Grand Junction, Colorado, and Salt Lake City, Utah because these were the closest weather stations recording sufficient data. These distributions are the output of the National Climatic Center's* STAR computer program. However, the wind

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*U.S. Department of Commerce, National Oceanic and Atmospheric Administration, Environmental Data Service, National Climatic Center, Federal Building, Asheville, N.C. 28801.

data for three stations in the oil shale region show that the differences in the wind direction frequency distributions between any two of these stations are at least as great as the differences between Grand Junction and any of these stations.[2] Therefore we have used Grand Junction meteorology for calculations of air pollutant concentrations expected in the Piceance Basin. All of the annual average calculations presented here are based on Grand Junction meteorology. Some other results based on Salt Lake City meteorology are presented in an earlier SRI report.[2] Sensitivity to meteorology is discussed below in Section C-5.

Twenty-four hour averages and 3-hour averages were calculated using the assumption that worst-case meteorological conditions prevailed. Statistical weather records indicate that neutral atmospheric stability and a light wind of 1.5-m/s occur for 24 hours or longer in the oil shale region an average of 15 days per year. These conditions have been shown to be representative of worst-case conditions in the oil shale region and do not involve use of Grand Junction or Salt Lake City meteorological data. The CDM was used to compute the 24-hour and 3-hour averages for various wind directions, assuming 100 percent frequency of occurrence of neutral stability and 1.5-m/s winds.

c. Results of Dispersion and Site Modeling

Pollutant dispersion patterns for a 16,000-m^3/day (100,000 B/D) TOSCO II plant were calculated using the emission source characteristics given in Table 16-13 and Figure 16-1 and the characteristics of possible oil shale sites. Isopleths of concentrations for some of the pollutants and averaging times are shown in Figure 16-2 through 16-5. Tables 16-14 and 16-15 summarize model results for the TOSCO II process and give background concentrations, air quality standards, and the level of control required to meet each standard. Background concentrations

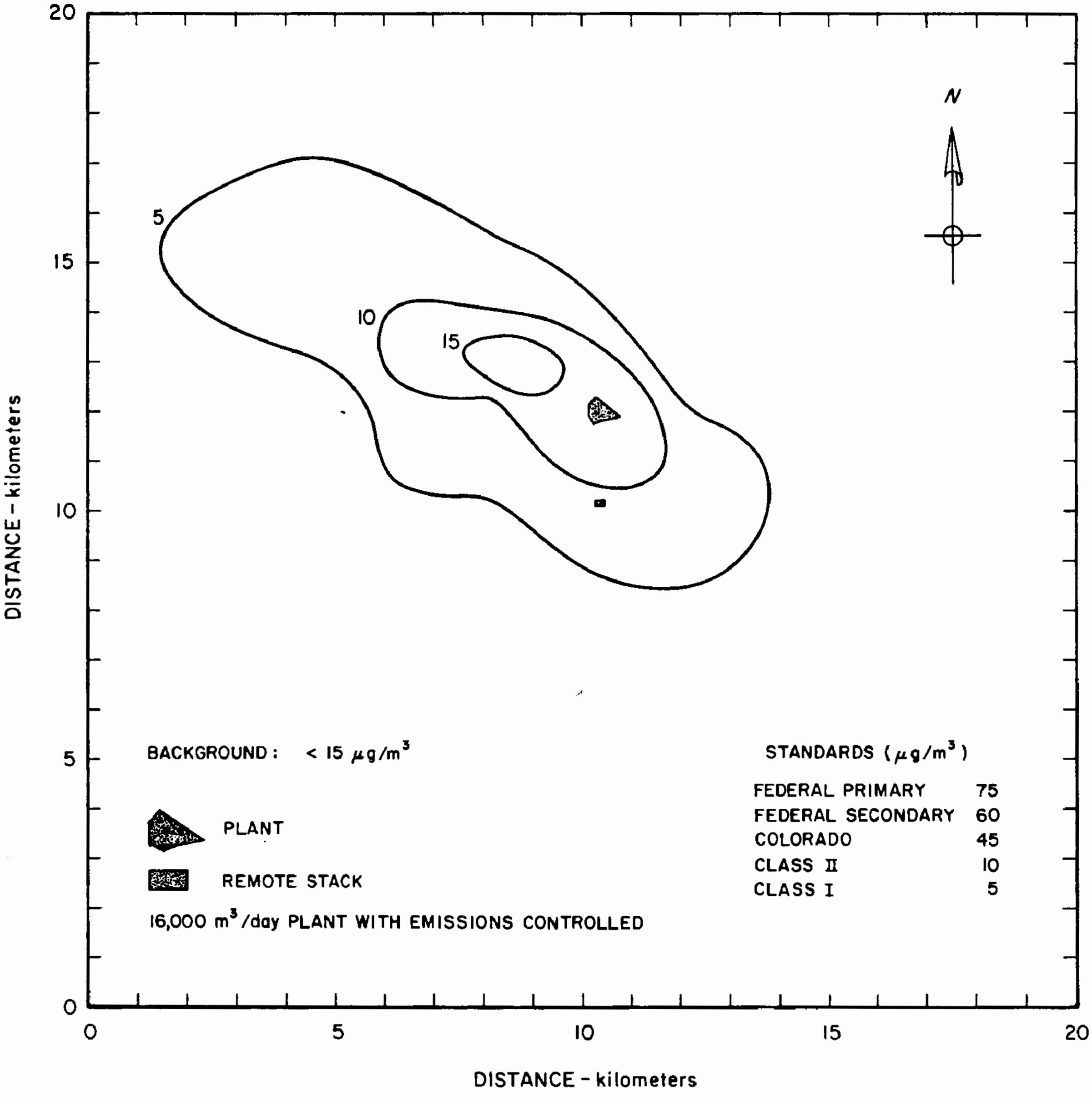

FIGURE 16-2. ANNUAL AVERAGE PARTICULATE CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT USING GRAND JUNCTION, COLORADO METEOROLOGY

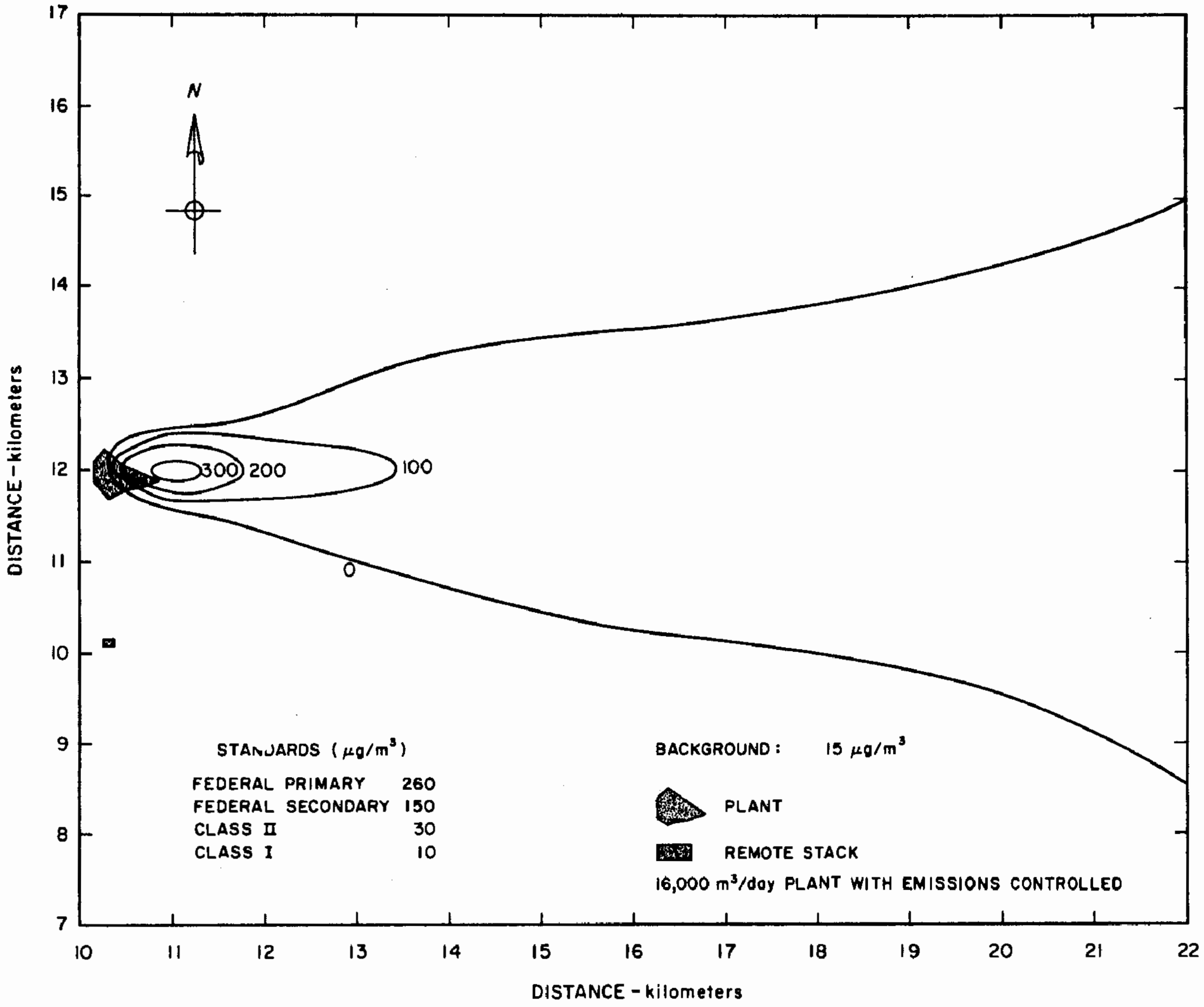

FIGURE 16-3. 24-HOUR WORST CASE AVERAGE PARTICULATE CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT UNDER CONDITIONS OF NEUTRAL STABILITY AND A WEST WIND OF 1.5 $msec^{-1}$

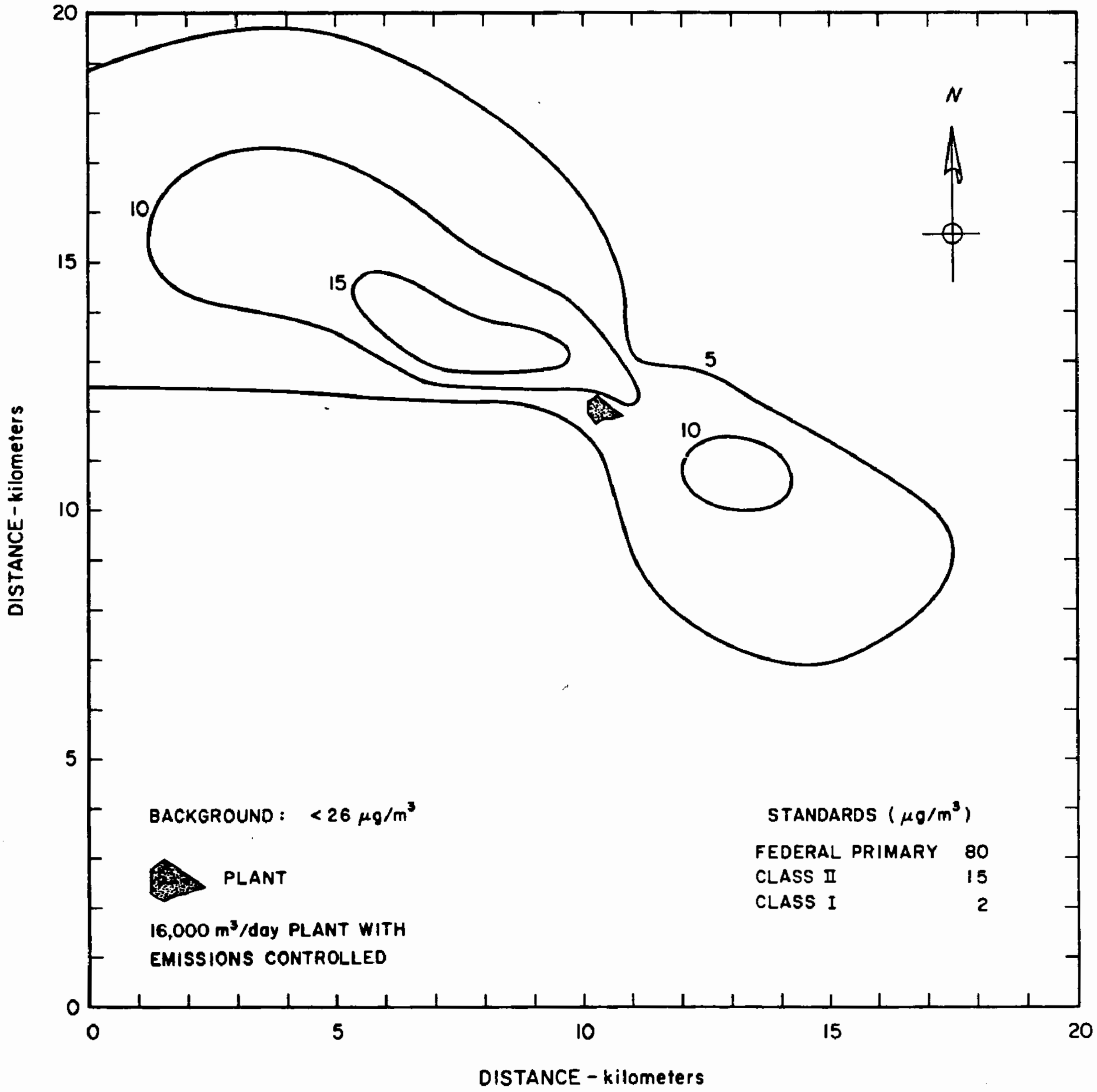

FIGURE 16-4. ANNUAL AVERAGE SO_2 CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT USING GRAND JUNCTION, COLORADO METEOROLOGY

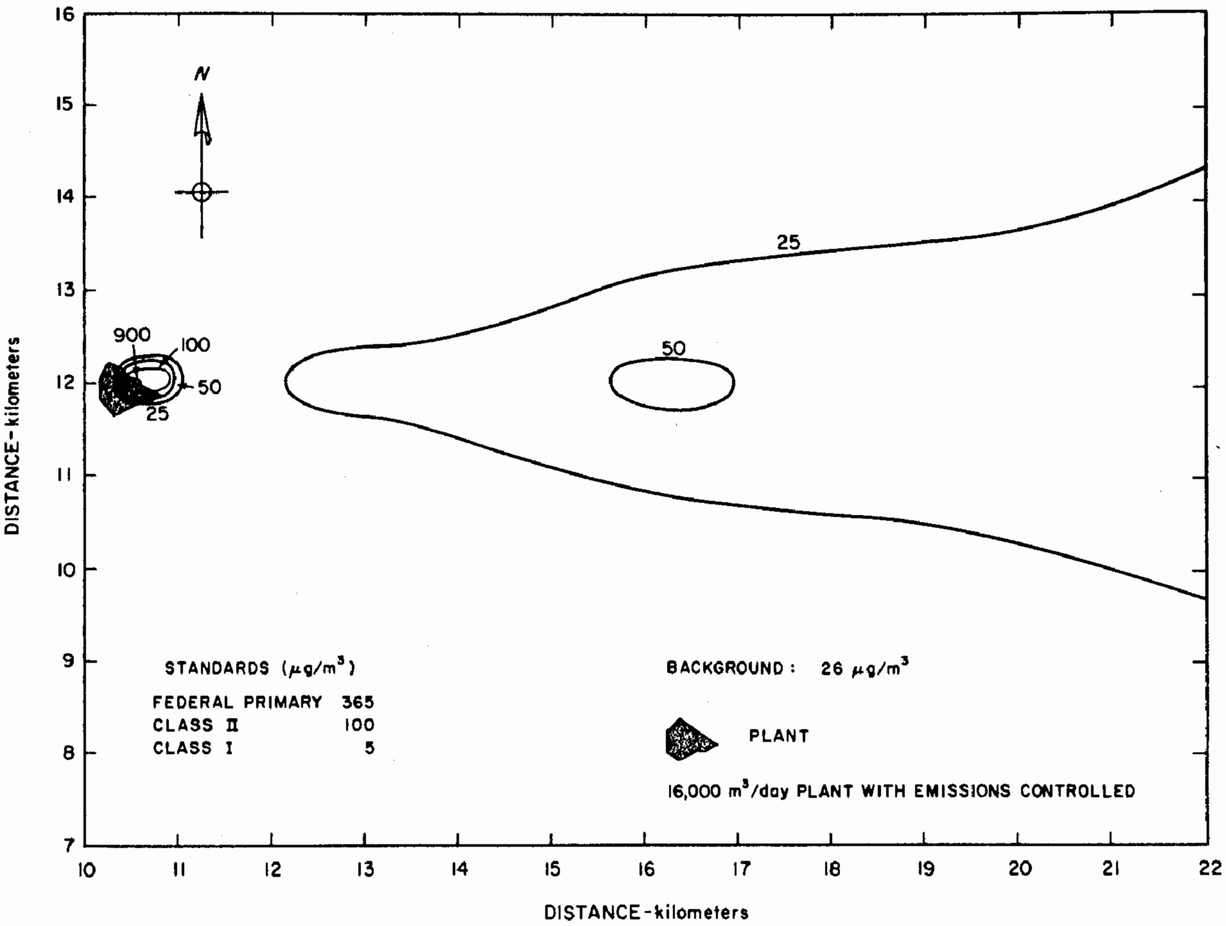

FIGURE 16-5. 24-HOUR WORST CASE AVERAGE SO_2 CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT UNDER CONDITIONS OF NEUTRAL STABILITY AND A WEST WIND OF 1.5 $msec^{-1}$

Table 16-14

CONTROL REQUIREMENTS BASED ON FEDERAL PRIMARY AND COLORADO AIR QUALITY STANDARDS AND EMISSIONS FROM A 16,000-m^3/day (100,000 B/D) TOSCO II PLANT, CONTROLLED

Pollutant	Averaging Period	Maximum Calculated ($\mu g/m^3$)	Background* ($\mu g/m^3$)	Standard ($\mu g/m^3$) Federal Primary	Standard ($\mu g/m^3$) Colorado‡	Control Required† (percent) Federal Primary	Control Required† (percent) Colorado
Particulates	1 yr	15	< 15	75	45	None	None
	24 hr	200	15	260	150	None	25
SO_2	1 yr	18	< 26	80	--	None	--
	24 hr	51	26	365	15	None	99+§
HC	3 hr (6-9 AM)	11	--	160	--	None	--
NO_x	1 yr	23	--	100	--	None	--

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*Based on preliminary Colony Development Operation data. Current measurements suggest that the 26-$\mu g/m^3$ value is too high.

†Control required in addition to the best available as specified in Section B.

‡Standards for nondesignated areas of Colorado. The 24-hr standard is not to be exceeded more than one day per year.

§Background concentrations alone may exceed standard.

Table 16-15

CONTROL REQUIREMENTS BASED ON FEDERAL SECONDARY, CLASS I AND CLASS II AIR QUALITY STANDARDS AND EMISSIONS FROM A 16,000-m^3/day (100,000-B/D) TOSCO II PLANT, CONTROLLED

				Standard (μg/m^3)			Control Required† (percent)		
Pollutant	Averaging Period	Maximum Calculated (μg/m^3)	Background* (μg/m^3)	Federal Class I	Federal Class II	Federal Secondary	Federal Class I	Federal Class II	Federal Secondary
Particulates	1 yr	15	< 15	5	10	60	67	33	None
	24 hr	200	15	10	30	150	95	85	32
SO_2	1 yr	18	< 26	2	15	--	89	17	--
	24 hr	51	26	5	100	--	90	None	--

---

*Based on preliminary Colony Development Operation data. Current measurements suggest that the 26-μg/m^3 value is too high.

†Control required in addition to the best available as specified in Section B.

were taken from the results of monitoring conducted in the Colorado oil shale region for Colony Development Operation.[16]

In calculating the control requirements shown in Tables 16-14 and 16-15, background concentrations and concentrations resulting from oil shale operations have been considered together for the federal primary and secondary standards and for the Colorado standards. This has been done by subtracting the background concentration from the standard and computing the level of control needed so that the concentrations resulting from oil shale facilities do not exceed the remaining portion of the standard. When background concentrations equal or exceed a standard, the level of control has been specified as 99+ percent. Federal Class I and Class II standards are the so-called "nondegradation" standards; they refer to increases in concentrations and do not involve background concentrations.

The maximum calculated concentrations and the percent control requirements given in Tables 16-14 and 16-15 are not always the same as those that would be derived from a straightforward application of the calculated dispersion patterns such as Figures 16-2 through 16-5. Instead, the maximum concentrations used in Tables 16-14 and 16-15 reflect our judgment that only concentrations that occur over an appreciable area at some distance beyond the plant boundary should be taken as the basis for a requirement for additional emission control technology. A control requirement should not be based on a calculated concentration that occurs in the immediate vicinity of a relative low stack because in actual commercial operations any such problems would be solved by use of taller stacks.* Therefore, only concentrations that occur over areas

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*The use of taller stacks referred to here concerns replacing relatively low (about 15 m) stacks with some of moderate height (about 30 m). The same logic does not apply to avoiding excessive ground level concentrations associated with tall (about 100 m) stacks. See the discussion of the stack height issue in Section E.

of at least 1 km^2 at least 1 km away from the plant are included in the control requirement calculations shown in Tables 16-14 and 16-15.

The judgment just described is of much greater significance for oil shale case than for coal liquefaction. Stack characteristics used in modeling of the oil shale plant emissions are those published by Colony[4] as part of their plans for an actual facility. In the coal liquefaction case we have chosen reasonable but hypothetical, stack parameters for the modeling and have deliberately avoided the low (about 15 m) stacks that can cause anomalously high concentrations in the oil shale case.

Particulate emissions from the TOSCO II process described will produce concentrations that exceed all standards listed in Tables 16-14 and 16-15, escept the federal primary and secondary air quality standards. Background concentrations for particulates and SO_2 were measured in the Parachute Creek area of the Colorado oil shale region by Colony Development Operation. The analysis of these concentrations[16] revealed that the median of the 24-hour averages was about 15 $\mu g/m^3$. The average annual background concentration is expected to be less than 15 $\mu g/m^3$. The combination of background concentrations with plant-produced concentrations for those standards which are applicable leads to the conclusion that no additional control is needed to meet the federal primary 24-hour standard and the Colorado annual standard. The federal 24-hour secondary standard can be met with approximately 32 percent control of plant emissions. Approximately 95 percent control will be needed to meet the Class I 24-hour standard and 67 percent will be needed to comply with the Class I annual standard. The Class II 24-hour and annual standards require 85 percent and 33 percent controls, respectively.

Projected concentrations of SO_2 do not exceed the federal primary air quality standards nor the Class II 24-hour standards. Some preliminary measurements[4] suggested a 24-hour average background concentration of SO_2 of 26 $\mu g/m^3$. This is now known to be too high,[5] but a revised measurement has not yet been published. The annual average is expected to be considerably lower. The addition of background concentrations to the calculated concentrations resulting from the plant is not sufficient to exceed the federal primary air quality standards. However, SO_2 concentrations from the plant exceed the stringent Colorado annual air quality standard, where 99+ percent control is required, since background concentrations alone may exceed the standard. The federal Class I annual and 24-hour standards can be met with 89 percent and 90 percent control, respectively. The Class II annual standard requires only 17 percent additional control.

No additional controls are indicated for NO_2 and HC in Tables 16-14 and 16-15. The calculated concentrations of these pollutants are well below the NO_2 and HC standards shown. However, as mentioned above, no analyses of photochemical oxidant concentrations have been made.

3. Modeling an H-Coal Syncrude Plant

The Powder River Basin of Wyoming was selected for modeling the air pollution from plants producing synthetic crude oil from coal on the basis of physical, economic, and political availability of large blocks of coal, and the H-Coal process has been selected on the basis of (1) a relatively well developed technology, (2) high yield of a liquid product, and (3) availability of process descriptions in the open literature.

a. Characterization of Emission Sources

Table 16-16 and Figure 16-6 present the emission source characteristics of a 16,000-m^3/day (100,000-B/D) coal liquefaction plant employing the H-Coal process. The emission rates are taken from the process and control descriptions of Section B of this chapter. These rates are for a highly controlled plant, one employing the best available control technology (Section B). Stack characteristics (Table 16-16) were estimated on the basis of reasonable combustion conditions and other process requirements, as well as by analogy to the Colony plans for an oil shale plant. The stack configuration shown in Figure 16-6 was chosen to occupy an area of about 1 million m^2 (250 acres)* and to reflect likely capacities of various process units and their associated stacks. Radical changes in the assumed configuration could result in concentrations somewhat different from those calculated here.

b. Characterization of Powder River Coal Region

(1) Topography.† The strippable coal reserves of the Powder River Basin are concentrated along a north-south line through Gillette, Wyoming. The eastern Powder River Coal Basin lies within the Missouri Plateau in the drainage basin of the Missouri River. The landscape consists primarily of plains and tablelands and low-lying hills. Some areas feature entrenched river valleys, isolated uplands, flat-topped buttes and mesas, long narrow divides, and ridges 30 to 150 m (100 to 500 ft) high.

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*This area for the conversion process units is consistent with the land requirement scaling factor given in Chapter 4 and with a published design for an SRC coal liquefaction facility.[17]

†The information contained in this section was extracted from Reference 18.

Table 16-16

STACK PARAMETERS AND EMISSION RATES FOR A 16,000-m^3/day (100,000-B/D) H-COAL PLANT USING POWDER RIVER COAL

Stack No.*	Description of Unit	Flow Rate† (all stacks) (m^3/s)	Temp. (°C)	No. of Stacks	Stack Height (m)	Stack Diameter (m)	Gas Exit Velocity (m/s)	Emissions (all stacks) (g/s) Particulates	SO_2	NO_x	HC
1	Coal dryer--process	1200	63	10	30	4.	9.6	44	--	--	--
2	Coal dryer--combustion	277	55	2	75	3.	19.6	6.6	27.1	257	4.3
3	Steam reformer	603	260	5	30	3.	17.1	5.8	0.19	74	1.0
4	Plant (gas fuel)	135	260	1	30	3.	19.1	1.3	0.04	17	0.2
5	Plant (coal fuel)	489	55	4	75	3.	17.3	11.7	47.9	454	7.6
6	Sulfur plant	27	38	1	75	1.3	20.3	--	16.	--	--

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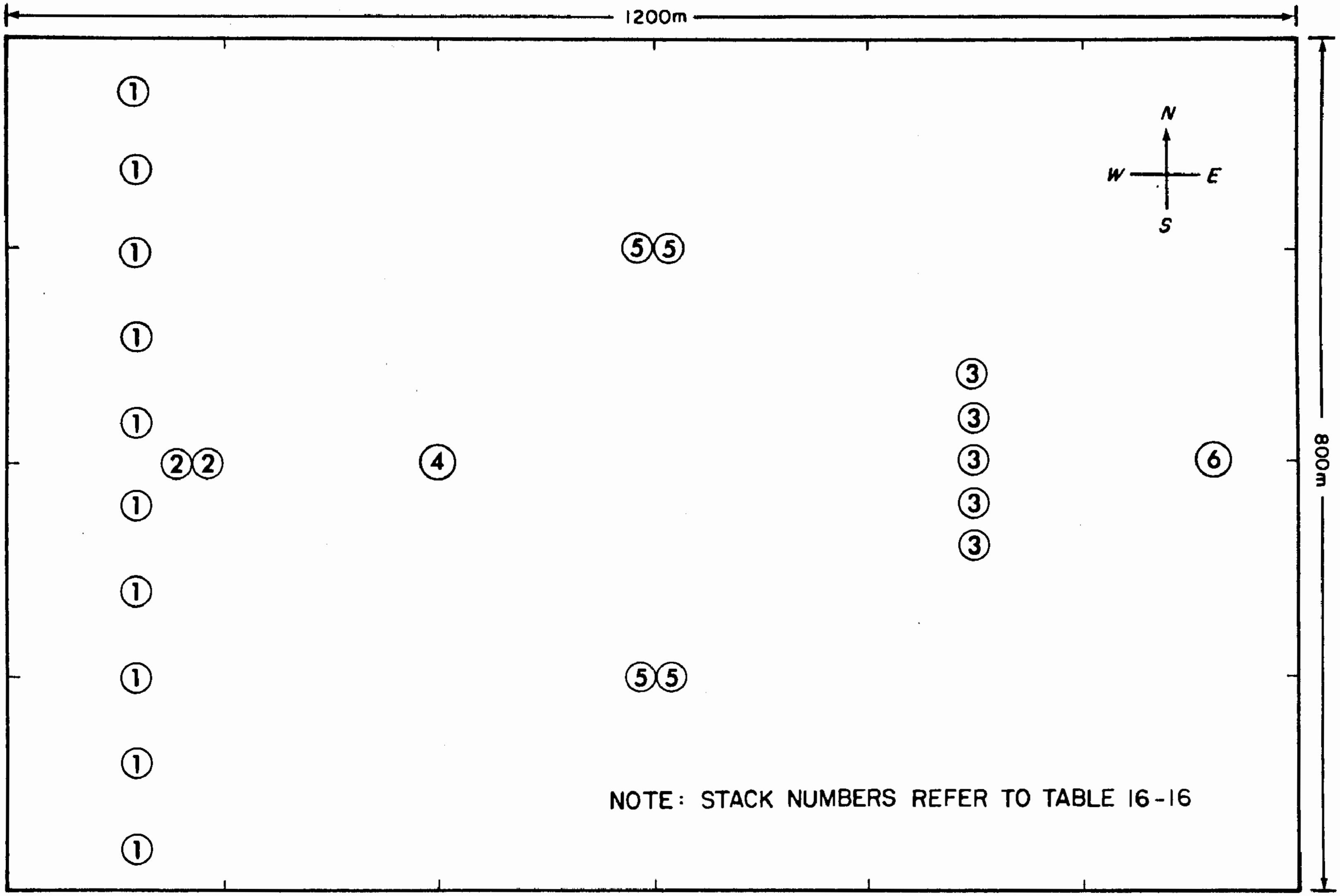
*Stack locations are shown in Figure 16-6.

†At pressure of 87.4 kPa (25.8 inches of mercury) corresponding to an elevation of 1230 m (4000 ft).



NOTE: STACK NUMBERS REFER TO TABLE 16-16

FIGURE 16-6. STACK CONFIGURATION FOR COAL LIQUEFACTION PLANT

The coal basin is part of a topographic depression that lies between the Black Hills and the Bighorn Mountains. The central part of the basin consists of a broad plateau, with the strippable coal near the eastern edge of the rolling, grass-covered upland. Irregular, rough, broken terrain borders the shallow coal deposits. To the east, erosion has reduced the terrain to knobs and ridges.

In the northern part of the topographic basin, there are high open hills north of Gillette and tablelands south of Gillette. The open hills have a local relief of 120 to 240 m (400 to 800 ft) and the gently sloping plains and tablelands have local relief of 60 to 120 m (200 to 400 ft). The southern part of the basin is characterized by rolling grass-covered prairie cut by broad steam valleys.

(2) Meteorology. Sufficient meteorological data for application of the CDM are not available for potential coal liquefaction plant sites within the boundaries of the coal reserve region. However, a complete weather station is located at Moorcroft, Wyoming, about 25 km (15 miles) east of Gillette, and from frequency distributions of meteorological conditions observed there the CDM was used to calculate annual averages. Considering the topography of the region and the proximity of Moorcroft to possible plant sites, the meteorology of Moorcroft is a good approximation of the meteorology of future coal plant sites. The same type of argument that applied to Grand Junction for the oil shale region applies here, but with the advantage that the topography of the Wyoming coal reserves is far less rugged and varied than that found in the oil shale bearing portions of Colorado.

SRI has recently developed a computer program (WRSCASE) to determine the days on which worst-case pollutant concentrations occur. The program takes as input the stack characteristics and emission rates of a simplified version of a plant and hourly meteorological data for a period considered statistically representative (e.g., 3 years). It then calculates the hourly pollutant concentrations at several locations, computes 24-hour (or 3-hour) average concentrations at each location, and for each pollutant, selects the sequence of meteorological conditions that produces the greatest concentration 1 km or farther from the plant. This program was used with Moorcroft, Wyoming, meteorological data to determine the worst-case sequence for each pollutant over the appropriate averaging time (24 hours or 3 hours). Table 16-17 lists these worst-case meteorological sequences determined by the program and used in the 24-hour and 3-hour average coal liquefaction plant calculations. When the wind is calm, the wind direction of the previous hour and a wind speed of 1 m/s are used in model calculations since the Gaussian plume formulation does not allow for calm winds.

c. Results of Dispersion Modeling

Dispersion of pollutants from a syncrude plant was calculated using the stack characteristics and emission rates listed in Table 16-16 and the plant configuration illustrated in Figure 16-6. Figures 16-7 and 16-8 show isopleths of concentrations for various pollutants and averaging times. Tables 16-18 and 16-19 summarize dispersion model results for a single coal liquefaction plant. Measured values of background concentrations of particulates in the coal region range from 13 to 21 $\mu g/m^3$ (see Reference 16-18). Background levels of SO_2, NO_x, and HC have not been measured in the basin. However, 24-hour maximum and annual average values of SO_2 background concentrations have been measured in nearby Casper,[19] and these values are included for reference in Tables 16-18 and 16-19. Since it can be expected that background levels in the basin will be less than those measured in the Casper urban area, it seems safe to assume that no additional controls will be required for SO_2 due to background levels. The method of calculating the

Table 16-17

WORST-CASE METEOROLOGICAL SEQUENCES FOR MOORCROFT, WYOMING

	SO_2 (24-hr sequence)			Particulates and NO_x (24-hr sequence)			HC (3-hr sequence)		
Hour	Wind Direction*	Wind Speed (m/s)	Atmospheric Stability†	Wind Direction*	Wind Speed (m/s)	Atmospheric Stability†	Wind Direction*	Wind Speed (m/s)	Atmospheric Stability
0100	10	11.8	4	8	10.8	4			
0200	10	8.2	4	8	13.4	4			
0300	10	3.6	5	8	11.8	4			
0400	6	2.1	6	8	15.9	4			
0500	10	1.5	6	8	14.4	4			
0600	10	6.2	4	8	15.9	4			
0700	10	6.7	4	8	18.0	4	11	1.0	6
0800	10	10.8	4	8	13.4	4	11	1.0	3
0900	10	12.3	4	8	9.8	4	calm	calm	3
1000	10	11.8	4	8	18.0	4			
1100	10	9.8	4	8	21.6	4			
1200	10	10.8	4	8	18.5	4			
1300	10	12.3	4	8	20.0	4			
1400	10	10.3	4	8	18.5	4			
1500	10	7.2	4	8	20.0	4			
1600	10	8.2	4	8	17.5	4			
1700	10	8.7	4	7	16.4	4			
1800	10	11.8	4	8	17.5	4			
1900	10	8.7	4	8	15.4	4			
2000	10	12.3	4	8	14.9	4			
2100	10	8.7	4	8	9.3	4			
2200	10	14.4	4	8	7.7	4			
2300	10	13.4	4	8	7.7	4			
2400	12	9.3	4	9	5.1	5			

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*Wind direction sector. The compass is divided into sixteen 22.5° sectors; sector 1 is from 348.75° to 11.24°; succeeding sectors are in a clockwise direction from sector 1.

†Pasquill-Gifford stability categories.

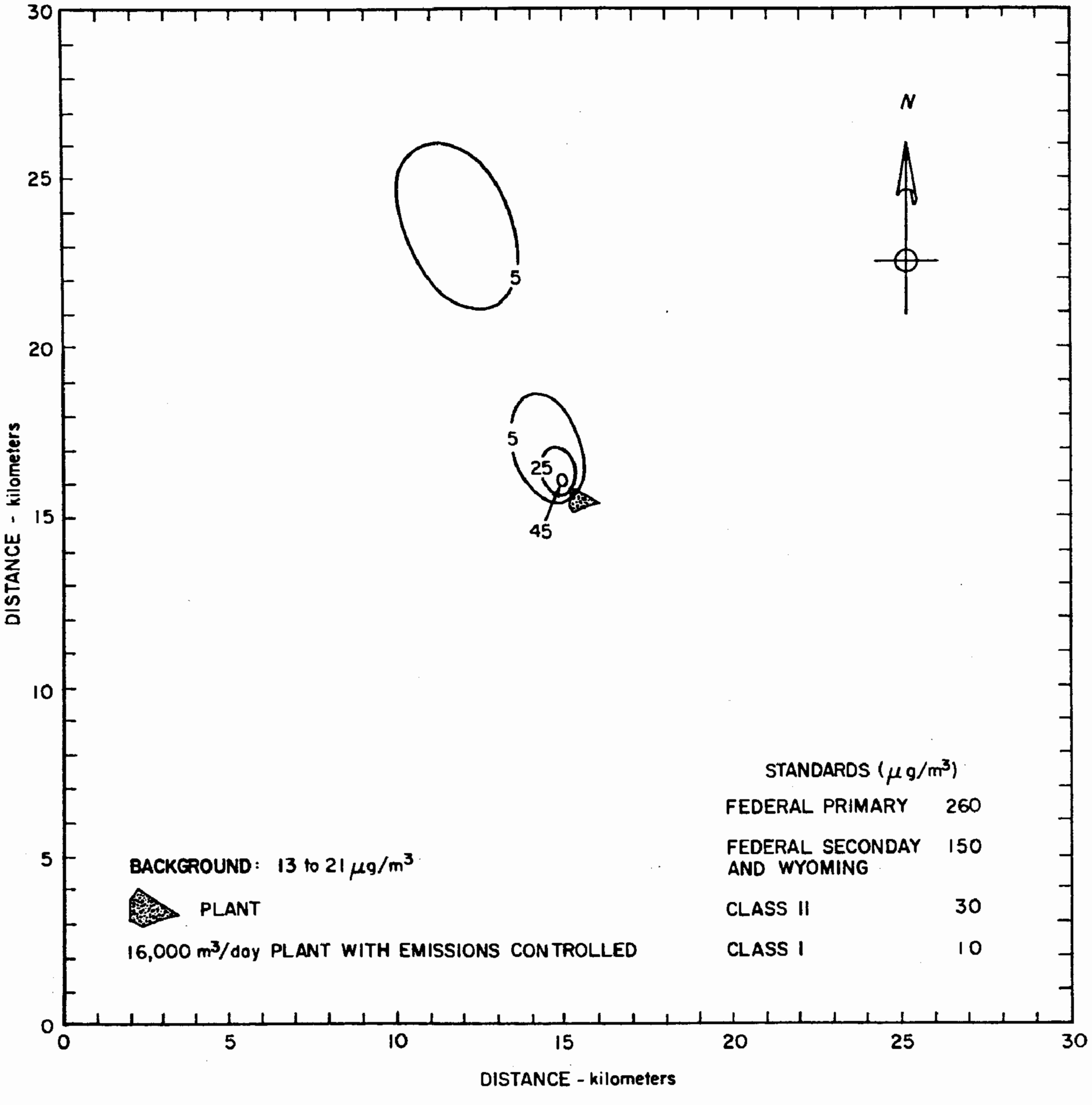

FIGURE 16-7. WORST CASE 24-HOUR AVERAGE PARTICULATE CONCENTRATIONS (μg/m^3) FOR A COAL LIQUEFACTION PLANT

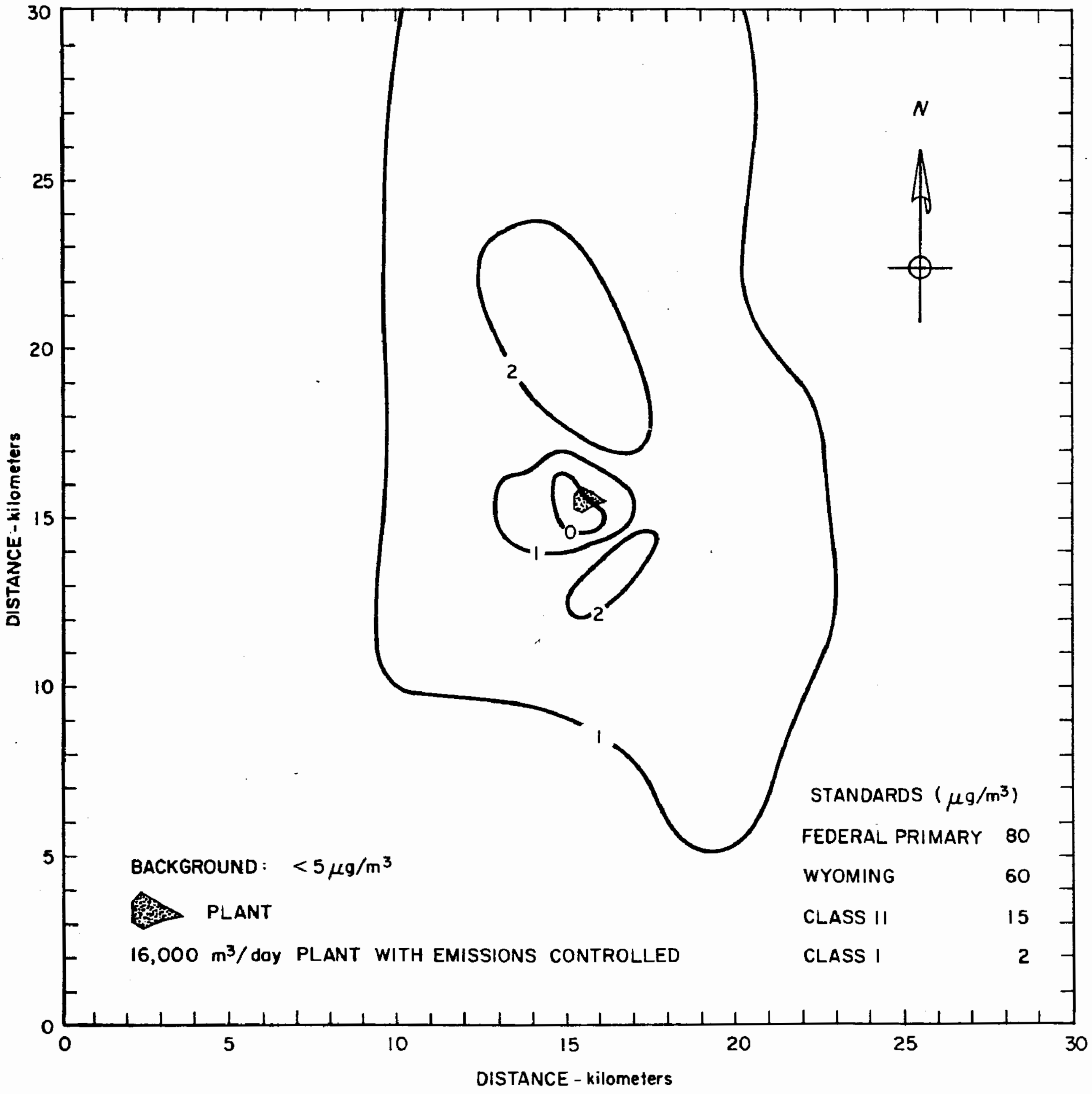

FIGURE 16-8. ANNUAL AVERAGE SO_2 CONCENTRATIONS (μg/m³) FOR A COAL LIQUEFACTION PLANT

Table 16-18

CONTROL REQUIREMENTS BASED ON FEDERAL PRIMARY AND WYOMING AIR QUALITY STANDARDS AND EMISSIONS FROM A 16,000-m^3/DAY (100,000-B/D) COAL SYNCRUDE PLANT

				Standard ($\mu g/m^3$)		Control Required[*] (%)	
Pollutant	Averaging Period	Maximum Calculated ($\mu g/m^3$)	Background ($\mu g/m^3$)	Federal Primary	Wyoming	Federal Primary	Wyoming
Particulates	1 yr	4	13 to 21[†]	75	60	None	None
	24 hr	25	13 to 21[†]	260	150[*]	None	None
SO_2	1 hr	2	5[‡]	80	60	None	None
	24 hr	7	16[‡]	365	260[§]	None	None
	3 hr	38	--	1300	1300[§]	None	None
NO_x	1 yr	15	--	160[**]	100[**]	None	None
HC	3 hr (6-9 a.m.)	4	--	100	160[*]	None	None

---

[*] Control required in addition to the best available as specified in Section B of this chapter.

[†] Measured in the Powder River Basin (Reference 18).

[‡] Measured at Casper, Wyoming (Reference 19).

[§] Not to be exceeded more than once per year.

[**] NO_2 standard.

Table 16-19

CONTROL REQUIREMENTS BASED ON FEDERAL SECONDARY, CLASS I AND CLASS II AIR QUALITY STANDARDS AND EMISSIONS FROM A 16,000-m^3/DAY (100,000-B/D) COAL SYNCRUDE PLANT

				Standard ($\mu g/m^3$)			Control Required[*] (%)		
Pollutant	Averaging Period	Maximum Calculated ($\mu g/m^3$)	Background ($\mu g/m^3$)	Federal Class I	Federal Class II	Federal Secondary	Federal Class I	Federal Class II	Federal Secondary
Particulates	1 yr	4	13 to 21[†]	5	10	60	None	None	None
	24 hr	25	13 to 21[†]	10	30	150	60	None	None
SO_2	1 yr	2	< 5[‡]	2	15	--	None	None	--
	24 hr	7	< 16[‡]	5	100	--	29	None	--

---

[*] Control required in addition to the best available as specified in Section B of this chapter.

[†] Measured in the Powder River Basin (Reference 18).

[‡] Measured at Casper, Wyoming (Reference 19).

control requirements shown in Tables 16-18 and 16-19 is the same as that described for oil shale.

The dispersion calculations (Figures 16-7 and 16-8; Tables 16-18 and 16-19) indicate that no additional controls are required to meet any of the standards except the 24-hour Class I particulate and SO_2 standards. To meet the federal "nondegradation" standard for particulates, emissions must be controlled by an additional 60 percent, and to meet the "non-degradation" standard for SO_2, emissions must be controlled by an additional 29 percent.

4. Effects of Multiple Plants in a Region

a. Assumptions for Modeling

Lack of definite meteorological data and plant site information makes it necessary to base the modeling of air pollution from a complex of plants on a possible, but hypothetical, situation. In the modeling process, a simplified worst-case situation was devised. Four plants, identical to the single coal liquefaction plant first modeled, were sited 6 km apart on a north-south line. The 6-km separation is about the minimum separation possible for plants using a 20-year supply of coal from a 9 m (30 ft) seam of Powder River coal. Annual average pollutant concentrations from the plant complex were calculated using the Moorcroft annual frequency distribution. In the actual 24-hour average worst-case, the meteorological sequence was a wind from the south-southeast for 22 hours with one hour periods with the wind blowing from adjacent sectors.* For this calculation, the sequence was rotated clockwise by one sector so that for 22 hours the wind blew from the south. Such a sequence, although hypothetical, was judged to be possible and would represent the worst-case for the complex of plants

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*There are 16 wind direction sectors.

assumed. Thus, for the most part, the wind is assumed to be blowing along the string of plants, causing superposition of plumes. This synthesized sequence of meteorological conditions is likely to occur and represent a worst-case wind direction.

b. Results for Complex of Coal Syncrude Plants

Figures 16-9 and 16-10 show the complex of four plants and illustrate results of the dispersion modeling for the two cases that lead to maximum control requirements. Similar calculations for comparison with the complete set of ambient standards have been made. The results for all of the pollutants and averaging times are summarized in Tables 16-20 and 16-21. Background concentrations are treated as they were for oil shale (Tables 16-14 and 16-15).

As shown in Tables 16-20 and 16-21, no additional control is required to meet the federal primary or secondary standards nor the Wyoming standards for any of the pollutants modeled. However, Table 16-21 indicates some additional control requirements based on Class I and II standards. For particulates, 17 percent control is required to meet the annual Class I standard; 75 percent is required to meet the 24-hour Class I standards; and 25 percent is needed to satisfy the 24-hour Class II standard. The annual Class II standard for particulates can be met with no additional controls.

Again referring to Table 16-21, no additional controls are needed to comply with the Class II SO_2 standards. For the annual Class I standard for SO_2, an additional 67 percent control is needed, and for the 24-hour Class I SO_2 standard, an additional 77 percent control is needed.

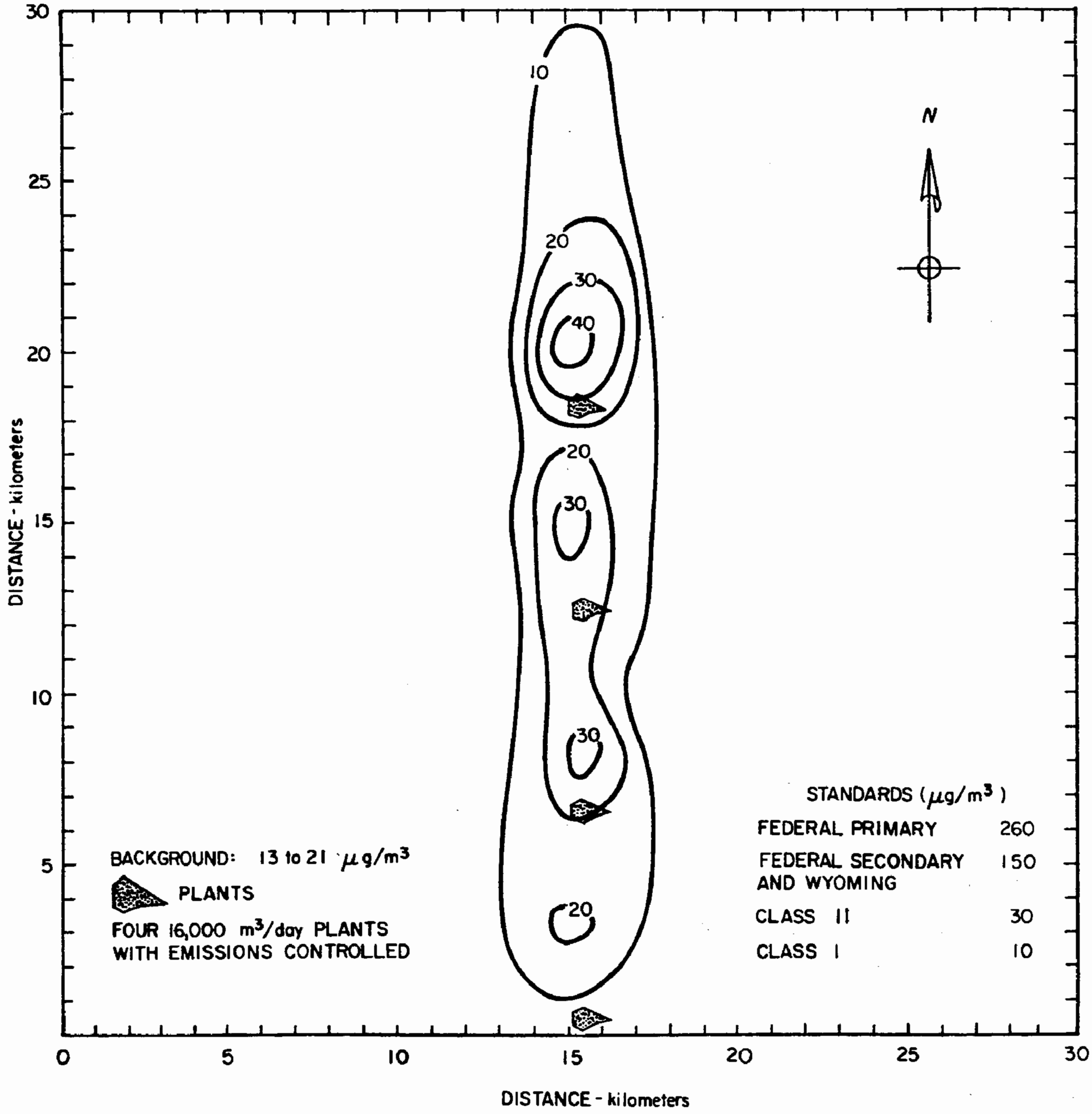

FIGURE 16-9. WORST CASE 24-HOUR AVERAGE PARTICULATE CONCENTRATIONS ($\mu g/m^3$) FOR A COMPLEX OF COAL LIQUEFACTION PLANTS

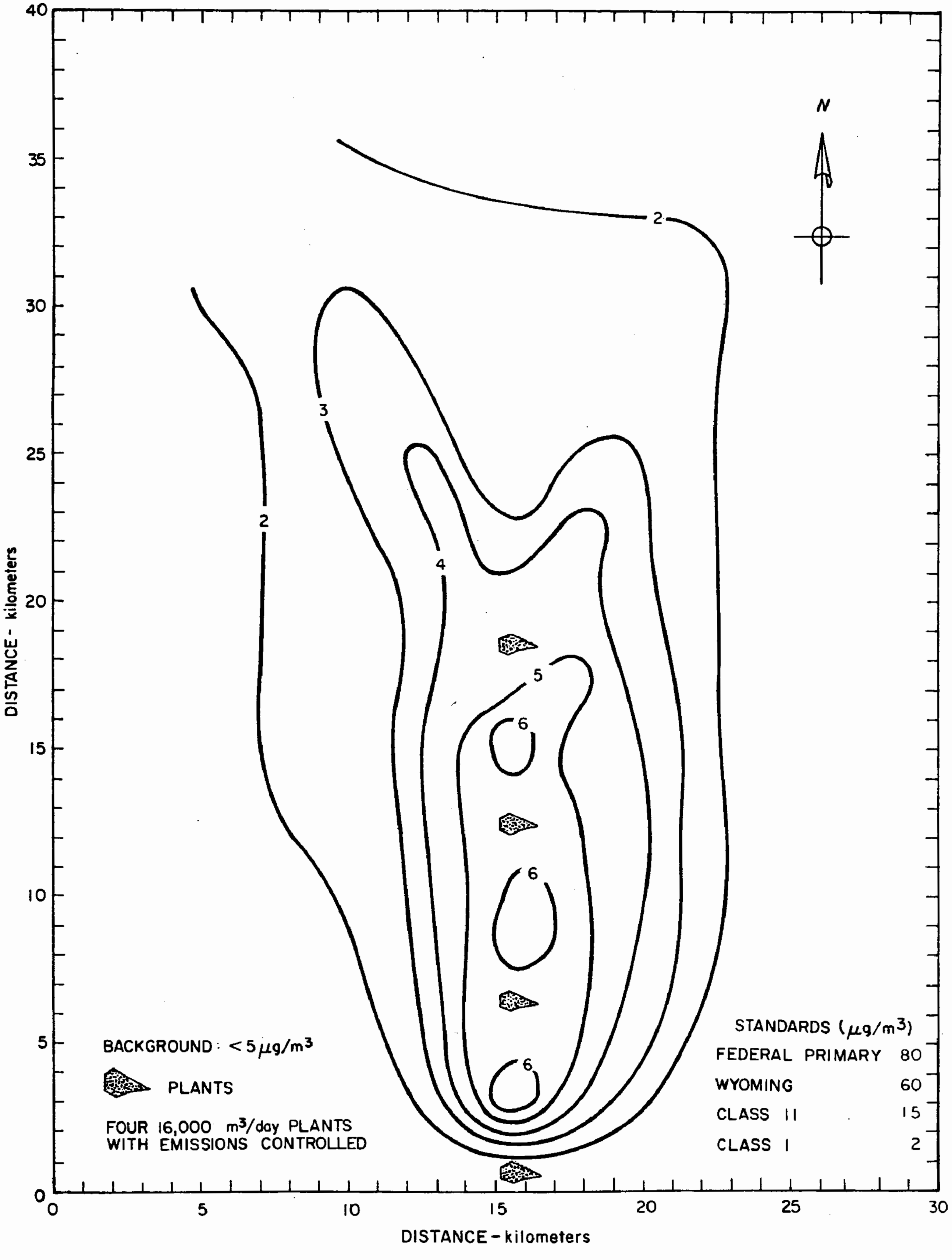

FIGURE 16-10. ANNUAL AVERAGE SO_2 CONCENTRATIONS (μg/m³) FOR A COMPLEX OF COAL LIQUEFACTION PLANTS

Table 16-20

CONTROL REQUIREMENTS BASED ON FEDERAL PRIMARY AND WYOMING AIR QUALITY STANDARDS AND EMISSIONS FROM A COMPLEX OF FOUR 16,000-m^3/DAY COAL SYNCRUDE PLANTS

Pollutant	Averaging Period	Maximum Calculated ($\mu g/m^3$)	Background ($\mu g/m^3$)	Standard ($\mu g/m^3$)		Control Required[*] (%)	
				Federal Primary	Wyoming	Federal Primary	Wyoming
Particulates	1 yr	6	13 to 21[†]	75	60	None	None
	24 hr	40	13 to 21[†]	260	150[*]	None	None
SO_2	1 yr	6	5[‡]	80	60	None	None
	24 hr	22	16[‡]	365	260[§]	None	None
	3 hr	38	--	1300	1300[§]	None	None
NO_x	1 yr	40	--	160[§]	100[**]	None	None
HC	3 hrs (6-9 a.m.)	4	--	100	160[*]	None	None

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[*] Control required in addition to the best available as specified in Section B of this chapter.

[†] Measured in the Powder River Basin (Reference 19).

[‡] Measured at Casper, Wyoming (Reference 19).

[§] Not to be exceeded more than once per year.

[**] NO_2 standard.

Table 16-21

CONTROL REQUIREMENTS BASED ON FEDERAL SECONDARY, CLASS I, AND CLASS II
AIR QUALITY STANDARDS AND EMISSIONS FROM A COMPLEX OF FOUR
16,000-m^3/DAY COAL SYNCRUDE PLANTS

				Standard ($\mu g/m^3$)			Control Required[*] (%)		
Pollutant	Averaging Period	Maximum Calculated ($\mu g/m^3$)	Background ($\mu g/m^3$)	Federal Class I	Federal Class II	Federal Secondary	Federal Class I	Federal Class II	Federal Secondary
Particulates	1 yr	6	13 to 21[†]	5	10	60	17	None	None
	24 hr	40	13 to 21[†]	10	30	150	75	25	None
SO_2	1 yr	6	5[‡]	2	15	--	67	None	--
	24 hr	22	16[‡]	5	100	--	77	None	--

---

[*] Control required in addition to the best available as specified in Section B of this chapter.

[†] Measured in the Powder River Basin (Reference 18).

[‡] Measured at Casper, Wyoming (Reference 19).

5. Sensitivity Analysis

a. Variation of Stack Parameters

The Gaussian plume formulae used in the CDM assume that air pollutants originate from a point located along the vertical axis of the physical stack. The distance of the effective source point above ground level is called the effective stack height, H. The effective height is a sum of two terms, the physical stack height, h, plus the plume rise, Δh, i.e., $H = h + \Delta h$.

The plume rise is a function of stack characteristics, wind speed, and distance from the source. Physically, the plume rise is caused by both the upward velocity of the gas emerging from the stack and the buoyancy of the hot stack gas in the cooler ambient air. The buoyancy effect generally dominates. The combined effect is described by a buoyancy flux parameter, F, whose value can be calculated from the ambient air temperature and the stack parameters, namely, gas exit velocity, gas temperature, and stack diameter. The value of F is a measure of the flow (or flux) of heat energy from the stack, with the reference or zero level of heat energy being set by the ambient temperature in accordance with the formula[21]

$$F = gVR^2 \frac{(T-T_a)}{T}$$

where g is the acceleration of gravity, V is the gas exit velocity, R is the inner radius of the stack, and T and T_a are the absolute temperatures of the gas and the ambient air, respectively. The plume rise itself, Δh, is proportional to the one-third power of F and is inversely proportional to the wind speed. The proportionality constant is different for different distances from the source and ranges of F.

By using the derived parameter F as the indicator of plume rise it is possible to reduce the number of possible stack parameters that must be considered as individual cases in determining how changes in stack parameters can affect the control requirements presented here. Quantity F was calculated for all of the stacks used in modeling the oil shale and coal liquefaction plants, and six nonzero values of F were identified that could be taken to be typical of six groups encompassing the range of reasonable stack parameters. Table 16-22 lists the six F values chosen and indicates several sets of stack parameters that would lead to each of the F values.

Table 16-23 shows how different combinations of buoyancy flux, F, and physical stack height, h, yield different values of the calculated maximum concentration of air pollutants emitted by a single stack. The maximum concentration used to normalize the values shown in the fourth column of Table 16-23 is that of Case 1, i.e., at a distance of 1 km from a low (15.2 m or 50 ft) stack with no buoyancy flux. Higher concentrations less than 1 km from the source are not included for consideration in the table for the reasons given above in Section C-2, namely, the fact that unacceptably high concentrations close to a low stack will almost certainly be reduced by using higher stacks rather than by employing more stringent emission control systems.

Some meteorological assumptions are indicated explicitly in Tables 16-22 and 16-23. In both of these, an ambient temperature of 5°C (41°F) was used for the calculations. In Table 16-23 the meteorological assumptions are those appropriate for a worst-case situation, namely, neutral stability and a wind constant in direction and speed at 1.5 m/s.

If the ambient concentration of an air pollutant can be attributed entirely to a single stack within a plant, results like those

Table 16-22

STACK CHARACTERISTICS THAT RESULT IN VARIOUS BUOYANCY FLUX VALUES (F VALUES)

$\frac{m_4}{s^3}$ F*	Exit Velocity (m/s)	Gas Temperature (°C)	Stack Diameter (m)
0	Any velocity	Ambient	Any diameter
9	20.4	38	1.3
9	9.6	38	1.9
9	3.9	38	3.0
9	22.5	100	0.8
60	17.8	55	3.0
60	9.3	60	4.0
60	11.9	300	2.0
60	17.0	500	1.5
68	8.6	751	2.1
68	14.9	751	1.6
68	10.8	500	2.0
68	6.8	100	4.0
104	7.9	145	4.0
104	7.4	500	3.0
104	20.6	300	2.0
104	19.0	50	4.0
190	18.0	260	3.0
190	10.0	100	5.5
190	7.6	500	4.0
190	17.4	700	2.5
302	21.7	481	3.0
302	14.9	700	3.4
302	10.0	300	4.9
302	14.9	500	3.6

---

*For ambient temperature equal to 5°C.

Table 16-23

SINGLE STACK SENSITIVITY ANALYSIS RESULTS*

Case	F $\frac{m^4}{s^3}$	Stack Height (m)	Normalized Value	Distance from Source (km)
1	0	15.2	1.000	1†
2	0	30.5	0.786	1†
3	0	61.0	0.164	2
4	0	121.9	0.027	5
5	9	15.2	0.252	1†
6	9	30.5	0.118	2†
7	9	45.7	0.066	3
8	9	76.2	0.031	5
9	68	15.2	0.0042	15†
10	68	24.4	0.0042	15†
11	68	45.7	0.0042	15
12	68	76.2	0.0038	15
13	104	38.1	0.0025	20
14	104	45.7	0.0025	20
15	104	76.2	0.0021	20
16	104	121.9	0.0017	20
17	302	15.2	0.0001	--
18	302	30.5	0.0002	--
19	302	61.0	0.0002	--
20	302	121.9	0.0002	--

---

*A constant wind direction and neutral stability were used in this analysis. Results will vary for other stabilities and a nonconstant wind direction. Wind speed used here is 1.5 m/s.

†A value greater than that used as the maximum occurred < 1 km from source.

displayed in Tables 16-22 and 16-23 are adequate for assessing the impact of a change in stack parameters. For instance, a stack 76-m high by 1.3 m in diameter emitting a fixed rate of some pollutant with an exit velocity of 20.3 m/s and a temperature of 38°C has an F value of 9, as given in Table 16-22, and would be Case 8 of Table 16-23. Replacement of this by a Case 3 stack, one releasing the pollutant at the same rate but at a height of 61 m and at ambient temperature, would lead to a factor of 5.3 (i.e., 0.164/0.031) increase in the maximum concentration and would result in the new maximum occurring at a distance of 2 km from the stack instead of the previous 5 km.

To better understand the sensitivity of the dispersion pattern of an entire plant, in which emissions from a single stack do not dominate, a two-stack sensitivity analysis was performed, based on two sets of stack parameters that are fairly characteristic of the many stacks listed in Table 16-16 for a coal liquefaction plant. A listing of the buoyancy flux values and stack heights for the coal liquefaction plant reveals that a stack having an F value of 9 accounts for 18 percent of the SO_2 emissions and that stacks having F values near 60 account for the other 82 percent. We used the CDM to calculate dispersion patterns resulting from the combination of two stacks having these F values on an 82/18 ratio of emission rates. The calculations were made for a variety of assumed stack heights. Results are presented as the first nine cases shown in Table 16-24. Similar listing and grouping based on the emissions of the other pollutants from the coal liquefaction plant leads to a two-stack model that has 90 percent of the emissions from stacks having an F value of about 60 and 10 percent of the emissions from stacks having an F value near 190. Cases 9 through 18 in Table 16-24 show how the calculated maximum concentration changes with various combinations of physical stack heights for the two stacks.

Table 16-24

TWO-STACK SENSITIVITY ANALYSIS RESULTS*

					Maximum Concentration	
Case	F_1 $\frac{m^4}{s^3}$	Stack $Height_1$ (m)	F_2 $\frac{m^4}{s^3}$	Stack $Height_2$ (m)	Normalized Value	Distance from Source of Maximum Concentration (km)
1	9	15	60	30	1.0	1†
2	9	15	60	75	1.0	1†
3	9	15	60	122	1.0	1†
4	9	30	60	30	0.46	2†
5	9	30	60	75	0.46	2†
6	9	30	60	122	0.46	2†
7	9	75	60	30	0.15	5
8	9	75	60	75	0.14	5
9	9	75	60	122	0.12	5

Case	F_4 $\frac{m^4}{s^3}$	Stack $Height_1$ (m)	F_4 $\frac{m^4}{s^3}$	Stack $Height_2$ (m)	Normalized Value	Distance from Source of Maximum Concentration (km)
10	60	30	190	30	1.0	10
11	60	30	190	60	1.0	10
12	60	30	190	122	1.0	10
13	60	75	190	30	0.75	10
14	60	75	190	60	0.75	10
15	60	75	190	122	0.75	10
16	60	122	190	30	0.50	14
17	60	122	190	60	0.50	14
18	60	122	190	122	0.50	14

---

*A constant wind direction and neutral stability were assumed. Results will vary for other stabilities and a nonconstant wind direction.

†Wind speed was assumed to be 1.5 m/s.

b. Roles of Other Variables

Changes in the configuration of stacks located within a plant may or may not have a significant effect on pollutant concentrations. If new stack locations do not differ appreciably from previously assumed locations, that is, stack locations are shifted within the previously defined boundaries of the plant, changes in calculated concentrations will be minimal. However, if the location of a stack is changed to a position that is removed from the confines of the plant area (or vice versa), pollutant patterns may be significantly affected, and concentrations and resulting control requirements should be recalculated. Moreover, for a stack having a small effective stack height (the sum of plume rise and physical stack height), movement of the stack from one side of the plant boundary to the other may cause an appreciable difference in concentrations at receptor locations near the plant boundary. When a significant portion of the pollutant emissions emanate from such a stack, the maximum concentration is usually close to the stack. For this study, a receptor must be located at least 1 km from the plant boundaries to qualify as the point at which the maximum concentration occurs. Therefore, if the wind direction is roughly constant (as it is for 24-hour and 3-hour averages), movement of such a stack from the downwind edge of the plant boundary to the upwind edge (or vice versa) could greatly affect the maximum concentration. In this case, concentrations and control requirements should be recomputed. However, for most stacks, maximum concentrations occur at distances sufficiently removed from the plant so that relocation of a stack within the confines of the plant will alter the shape and magnitude of pollutant concentration patterns only slightly.

Pollutant concentrations are directly proportional to emission rates. Thus, if the emission rates of all stacks within a plant are changed by the same factor, pollutant concentrations will also change by that factor. However, if the emission rates of some, but not all, stacks change, pollutant concentrations must be reassessed, unless the dispersion pattern, or at least the maximum concentration of the pattern, can be approximated as being due to a single emission source. Such an approximation will be warranted to the extent that a single stack dominates the emissions.

Finally, the meteorology assumed in a calculation obviously has a significant influence on the concentration pattern and levels calculated. While a systematic analysis of meteorological parameters similar to that just described for stack parameters was not performed, some indication of the sensitivity of the calculations to meteorological assumptions can be obtained from a comparison of two CDM results for the TOSCO II oil shale plant. Reference 2 gives annual average calculations of ambient air quality near a 16,000-m^3/day (100,000-B/D) oil shale plant based on both Salt Lake City and Grand Junction meteorology. The results presented here in Tables 16-14 and 16-15 include annual averages based on Grand Junction data. If Salt Lake City data had been used instead, the annual average maximum concentrations would change from 15 to 30 $\mu g/m^3$ for particulates, 18 to 15 $\mu g/m^3$ for SO_2, and 23 to 20 $\mu g/m^3$ for NO_2. The change for particulates leads to an estimate of additional control required that is appreciably higher than those given in Tables 16-14 and 16-15.

c. Conclusions from the Sensitivity Analysis

Because of the relatively small effort within this project that could be devoted to a sensitivity analysis of atmospheric dispersion modeling, the conclusions presented here are tentative.

The very large range of maximum concentrations associated with the various cases of stack parameters shown in Tables 16-23 and

16-24 suggests that the calculated control requirements are extremely sensitive to the choice of stack parameters. Although the range is narrowed considerably by selection of stack parameters most likely to be employed in practice (i.e., notice the reduced range of maximum concentrations in Table 16-24, compared with that in Table 16-23), the uncertainty in maximum concentrations remains substantial. A range of a factor of 3 or 4 can be found in Table 16-24, even after the low (15 m) stacks are ruled out. The interpretation of the limited sensitivity analysis performed here is derived from the summary presented in Table 16-24 and the results, described above for oil shale, that indicate the unsuitability of 15 m stacks. On this basis a range of a factor of 3 or 4 (suggested by the 0.12 to 0.46 range in Table 16-24) is probably a reasonable estimate for maximum concentrations that would be associated with likely stack parameters. Therefore, a maximum concentration calculated to be 100 units could be as low as 40 or 50 units or as high as 150 or 160 units, depending on the parameters of the stacks employed in the plants.

The suggestion that 15 m stacks are unacceptably low as sources of substantial emissions is one of several implications that emerge from this sensitivity analysis. Another implication, emphasized by the F = 0 cases of Tables 16-22 and 16-23, concerns the high potential for air pollution associated with stacks emitting pollutants at ambient temperature. The need for very substantial application of particulate emission control to the ore preparation (i.e., crushing) stages of the TOSCO II oil shale plant arises from the emission of large quantities of dust at ambient temperature. A third implication is the significant improvement in ambient air quality in the vicinity of a plant that can be achieved through use of tall stacks. This is most pronounced for the low F values shown in Table 16-23, where increasing a moderate (30 m) stack to a tall (120 m) stack cuts the maximum concentration by a factor of more than 20. A fourth implication, shown by the increase in distance of the maximum concentration point as stack height is increased, is that the lowered maximum concentration is necessarily accompanied by an increased area and distance affected by the air pollution. This fact is one of those that has led EPA to restrict the stack height that can be used to meet ambient air quality standards. (See Section E.) Finally, an implication that is directly related to the one just named, is that the overlap of plumes from two or more plants is greater when tall stacks lead to dispersion over a larger area surrounding the plant. Comparison of Cases 2 and 4 in Table 16-23 suggests that the area affected in the tall (120 m) stack case is 25 times that affected by the moderate (30 m) stack case, a factor comparable to the reduction in level of the maximum concentration in the two cases. Thus, the need for a multiple-plant, regional, air pollution analysis is greater for the tall stack cases.

D. Control Requirements

To provide a unique estimate of the control required in addition to the estimates given in Section C (Tables 16-14, 16-15, 16-18, 16-19, 16-20, and 16-21), a particular comparison ambient air quality standard must be selected. The actual setting of these standards for regions in which synthetic fuel plants may eventually be located will be one critical factor that could affect deployment of the plants. In deriving control requirements, the Class II standards proposed by EPA were selected as one of three sets of standards that the states could choose to prevent significant deterioration of air quality in regions now enjoying relatively unpolluted air.

Of the three levels of standards proposed by EPA, Class II represents those that are strict but not so strict that they preclude industrial development. The other two levels are Class I, intended for application in regions that are to remain underdeveloped, and Class III, equivalent to the existing federal secondary standards (or primary when no secondary standards exist). We have chosen Class II as the comparison standard because (1) concern over air pollution in the Colorado and Wyoming areas considered in Section C makes it unlikely that air quality there will be allowed to be degraded to the most lenient standard, and (2) the most strict standards will not be applied if a significant synthetic fuels industry is to be brought into existence.

Control requirements for an oil shale plant, based on application of Class II standards to the dispersion modeling results of the preceding section, are shown in Table 16-25. The validity of the control requirements given in Table 16-25 depend not only on the comparison standard chosen but on the particular inputs of emission and meteorological data used in the dispersion modeling. Sensitivity to these inputs was discussed in Section C-5. To compensate for local effects of unnecessarily low (about 15 m in height) stacks, only concentrations that are calculated to apply over areas more than 1 km^2 in size and more than 1 km in distance from the plant are used to derive the control requirements given in Table 16-25. Hence, the calculated maximum concentration of particulates for the 24-hour worst case is taken as 200 $\mu g/m^3$ rather than the peak concentration greater than 300 $\mu g/m^3$ shown in Figure 16-3. Figures 16-4 and 16-5 show other cases summarized in Table 16-25.

Table 16-26 presents the control requirements derived for the H-Coal plant modeled in Section C. Again, Class II standards are used for comparison. In this case, no violation of the Class II standards indicated by the calculations based on emissions from a single 16,000-m^3/day (100,000-B/D) coal liquefaction plant. Only the particulate emissions come close to exceeding the comparison ambient air quality standard. Figures 16-7 and 16-8 show the dispersion pattern of the particulate and SO_2 emissions leading to the control requirements summarized in Table 16-26.

Table 16-25

CONTROL REQUIREMENTS BASED ON A SINGLE 16,000-m^3/DAY (100,000-B/D) OIL SHALE PLANT*

Pollutant	Calculated Concentration ($\mu g/m^3$)	Averaging Time	Class II Standard ($\mu g/m^3$)	Control Requirement* (%)
Particulates	200	24 hr	30	85
SO_2	18	1 hr	15	17
NO_x	23	1 yr	100†	None
HC	11	3 hr	160‡	None

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*Plant is controlled to "best available control" level as defined in Section B. Control requirement is in addition to that level.

†Federal primary standard for NO_2; no Class II standard exists.

‡Federal primary standard for hydrocarbons, 6-9 a.m.; no Class II standard exists.

Table 16-26

CONTROL REQUIREMENTS BASED ON A SINGLE 16,000-m^3/DAY (100,000-B/D) COAL LIQUEFACTION PLANT*

Pollutant	Calculated Concentration ($\mu g/m^3$)	Averaging Time	Class II Standard ($\mu g/m^3$)	Control Requirement (%)
Particulates	25	24 hr	30	None
SO_2	2	1 yr	15	None
NO_x	15	1 yr	100†	None
HC	1	3 hr (6-9 a.m.)	160‡	None

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*Plant is controlled to "best available control" level as defined in Section B. Control requirement is in addition to that level.

†Federal primary standard for NO_2; no Class II standard exists.

‡Federal primary standard for hydrocarbons, 3 hr, 6-9 a.m.; no Class II standard exists.

Table 16-27 presents values for control requirements for coal liquefaction plants based on dispersion modeling of the complex of four plants shown in Figures 16-9 and 16-10. The combination of plant locations and meteorology used for the modeling of emissions from a complex of plants represents a worst-case situation. Comparison of Tables 16-26 and 16-27 shows that for multiple plants the maximum concentrations of pollutants are increased by a factor of approximately 3.

Table 16-27

CONTROL REQUIREMENTS BASED ON A COMPLEX OF FOUR 16,000-m^3/DAY (100,000-B/D) COAL LIQUEFACTION PLANTS*

Pollutant	Calculated Concentration ($\mu g/m^3$)	Averaging Time	Class II Standard ($\mu g/m^3$)	Control Requirement* (%)
Particulates	40	24 hr	30	25
SO_2	6	1 yr	15	None
NO_x	40	1 yr	100†	None
HC	3	3 hr (6-9 a.m.)	160‡	None

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*Each plant is controlled to "best available control" level as defined in Section B. Control requirement is in addition to that level.

†Federal primary standard for NO_2; no Class II standard exists.

‡Federal primary standard for hydrocarbons, 6-9 a.m.; no Class II standard exists.

The increase in maximum particulate concentration is not as large because the single-plant maximum in that case is closer to the plant and, therefore, the overlap between the dispersion patterns of the different plants occurs farther out from the position of the single-plant maximum. The increases over the single-plant case are sufficient to indicate some need for additional control of particulate emissions from coal liquefaction plants.

Table 16-28 summarizes emissions, ambient concentrations, standards, and control requirements for synthetic liquid fuel plants.

1. Conclusions

A general conclusion that can be drawn from the foregoing analysis is that control beyond the best available technology will be needed for particulate and SO_2 emissions from synthetic liquid fuel plants located in relatively undeveloped regions of the United States. In the absence of nondegradation standards for NO_2 and HC, there is no apparent need for improved control of these pollutants.

Specific conclusions are as follows:

- Particulate emissions from oil shale plants may have to be reduced. The TOSCO II retorting process modeled here requires an additional 85 percent control beyond that of the best available technology to meet the Class II 24-hour standard of 30 $\mu g/m^3$. Other oil shale processes are expected to have lower particulate emission control requirements.
- Sulfur dioxide (SO_2) emissions from oil shale plants may have to be reduced by an additional 17 percent beyond that of the best available technology to meet the Class II annual standard of 15 $\mu g/m^3$
- No additional control on emissions of nitrogen oxides (NO_x) and hydrocarbons (HC) from the oil shale plant are indicated by comparisons with air quality standards for nitrogen dioxide (NO_2) and hydrocarbons. No Class II standards exist for these pollutants. Because the scope of this work did not include photochemical reactions in the dispersion modeling, the conclusion regarding NO_x and HC emissions is not based on comparisons with ambient standards for photochemical oxidant.

Table 16-28

SUMMARY OF EMISSIONS AND CONTROL REQUIREMENTS

Type	Amount (kg/hr)	Control Device or Method	Efficiency With Best Control (%)	Emissions Remaining With Best Control (kg/hr)	Ambient Air Quality Comparisons[*]		Additional Control Requirement (%)
					Calculated from Best Control Case ($\mu g/m^3$)	Class II Standard ($\mu g/m^3$)	
Oil shale							
Particulates	107,700	Baghouse, cyclone, scrubber	99.66	370	200	30	85
SO_2	2671	Treated fuels, tail-gas	47	1417	18	15	17
NO_x	5343	--	65	1849	23	100[†]	None
HC	--	Incinerator	--	272	11	160[†]	None
Coal liquefaction							
Particulates	28,300	Multiple cyclones, Venturi scrubber, electrostatic precipitator	99.12	250	25	30	None
SO_2	2700	Scrubber	88	330	2	15	None
NO_x	2890	None		2890	15	100[‡]	None
HC	47.2	None		47.2	4	160[‡]	None

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[*] Based on Table 16-15 and accompanying text.

[†] Federal primary standard. No Class II standard exists.

[‡] Federal primary standard. No Class II standard exists.

- Emissions from a single large coal liquefaction plant employing best available control will not result in violation of ambient air quality standards for any of the four pollutants considered. However, particulates and SO_2 are within factors of 1.2 and 7.5, respectively, of violating Class II standards, while the other two pollutants, NO_2 and HC, are far from violation of the relevant comparison standards (federal primary).

- Dispersion modeling based on a worst-case configuration of a complex of four coal liquefaction plants indicates a need for 25 percent additional control of particulates. Ambient concentrations of SO_2 remain below Class II standards. Ambient concentrations of NO_2 and HC remain well below the federal primary standards for this complex of plants.

- A preliminary sensitivity analysis indicates that the calculated concentrations used in determining the above control requirements should be viewed as accurate to within 50 percent.

2. Recommendations

- Control of Particulate Emissions--Appreciable additional control is indicated for the TOSCO II oil shale plant. Some additional control is indicated for the coal liquefaction plant. The potential contribution of higher stacks and more perfectly maintained baghouses to the attainment of this additional control should be determined. Efforts to improve technology for removal of fine particulates from emission streams should be continued.

- Flue Gas Desulfurization--Control of SO_2 emissions from a complex of only four coal liquefaction plants must be at least 70 percent to meet Class II standards. Efforts to improve flue gas desulfurization (FGD) units capable of 90 percent control should be continued.

- Oil Shale SO_2 Control--Emissions of SO_2 from combustion sources within the oil shale plant must be controlled beyond the control considered best available according to new source performance standards for liquid fossil-fuel fired boilers. FGD and additional hydrotreating of liquid fuels burned in the plant are both options for fuels burned in the plant are both options for achieving additional control. Because hydrotreating of fuel oil is an integral part of oil shale processing and because additional hydrotreating may be needed for NO_x control, it would be premature to recommend FGD for oil shale plants. Only the continued improvement of FGD technology is recommended; the 90 percent control expected from FGD units would be adequate to meet the estimated requirement.

- Oil Shale NO_x Control--No requirement for additional control of NO_x has been established by comparison of dispersion modeling results with ambient air quality standards. However, because the achievement of emissions consistent with best available control is likely to require a reduction of the nitrogen content in raw shale oil, the feasibility of more extensive hydrotreating of plant fuels should be studied. This has significance beyond the oil shale plant because the product oil, with its high nitrogen content, is a candidate for sale as a fuel oil as well as a refinery feedstock.

- Air Quality Standards in Undeveloped Regions--Both the setting of nondegradation standards and the designation of regions within which the standards will apply are issues. The conclusions presented in this chapter based on Class II standards are not the only ones possible, and it is recommended that the tables in Section C be used by readers interested in control requirements based on other standards that could be applied.

- Tall Stacks--Use of tall stacks (higher than about 100 m) to disperse pollutants sufficiently to avoid violation of ambient air quality standards in the vicinity of industrial plants is a subject of current controversy, especially for electric power plants. The results presented in this chapter illustrate the sensitivity of control requirements to the height of stacks employed in a plant. Additional analysis of the physical, economic, and legal aspects of this issue, should be carried out if more definitive control requirements are desired.

- Control Requirements Specific to Unit Operations--Additional dispersion modeling would make it possible to assign control requirements to unit operations within the energy conversion facilities. If more definitive control requirements are desired, additional analysis should be performed to better resolve the location within the plant in which control requirements would be most important and productive.

- Multiple Plants and Emission Sources in a Region--The most significant air pollution issue associated with synthetic liquid fuels concerns the regional impact of large-scale development of both energy facilities and population. The preliminary analysis of a complex of four liquefaction plants in the Powder River Basin has predicted a factor of 3 increase in concentrations calculated for some pollutants and averaging times. Alternative approaches to determining control requirements based on regional, multiplant considerations should be identified, developed, and compared.

- Sensitivity Analysis--The preliminary analysis of the sensitivity of the calculations used in this chapter to variations in emission parameters confirms the importance of specifying these in estimating control requirements. This limited work, reinforced by implications of the preceding recommendations on tall stacks, unit operations, and multiple plants, leads us to a recommendation for further sensitivity analysis. Such work would be especially important if dispersion modeling calculations become the basis for determining whether a plant would meet the nondegradation standards at its proposed location.

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17--SECONDARY ENVIRONMENTAL IMPACTS FROM URBANIZATION

By Barry L. Walton and Edward M. Dickson

A. Sources of Secondary Environmental Impacts

The environmental effects of the operation and construction of synthetic liquid fuel plants can be considered to be "primary" or "direct" impacts. The environmental consequences that arise from the attendant urbanization and behavior of residents can be considered to be "secondary" or "indirect" impacts. These secondary effects can contribute significantly to the overall environmental change that is likely to occur in a predominantly rural region that undergoes substantial growth at a fairly rapid pace. Sources of secondary impacts derive from municipal services (fresh water, production of waste water and solid waste), land use (construction of dwellings, roads, and utility corridors; effect on water run-off patterns), habitation (automotive air pollution, energy utilities, animal mortality), and recreation/leisure activities (use of parklands, vandalism, alteration of habitats). This chapter is primarily concerned with these secondary effects as they apply to the coal and oil shale regions of the West. Some of these effects can be quantified using scaling factors for readily predicted changes, and others can only be projected in a general way, based on empirical evidence from past occurrences.

B. Urban Growth: Coal and Oil Shale Regions of the West

Urban areas in Wyoming, Montana, North Dakota, and Colorado occupy a very small fraction of the total land area. For example, Gillette, in Wyoming's Powder River Basin, occupies only abour 10,000 acres of the over 3 million acres of Campbell County. Towns in these states are widely dispersed (50 to 100 miles apart).

Urban growth on the open grasslands of Montana, Wyoming, and North Dakota is characterized by sprawling communities with small populations. Urban development in the oil shale country of Colorado, which is characterized by a broken landscape of cliffs, river valleys, and plateaus,[1] would be restricted to the broad-bottomed river valleys, the only land suitable for town-making.

Nearly all of the towns in the coal regions of Montana, Wyoming, and North Dakota, and in the oil shale regions of Colorado have small populations. Gillette, Wyoming (1975 population of 11,000), and Rangeley, Colorado (1970 population of 2150),[2] typify their regions. Population growth from the construction and operation of a 100,000-B/D (16,000-m^3/D) coal liquefaction plant would add an estimated 2400 primary jobs to employment (see Chapter 6) in coal mining, while a 100,000-B/D oil shale complex would add 1700 jobholders in oil shale country. The 2400 jobholders, their families, and the associated service personnel and their families would likely locate in the one or two towns close to the liquefaction facility and the coal mines.

C. Quantifiable Impacts

1. Scaling Factors

Tables 17-1 and 17-2 provide some of the important scaling factors for urban living applied to predicted urban growth in the coal and oil shale regions of the West. The data in Table 17-3 are a compilation of automotive emissions scaling factors for various levels of control anticipated for the future. However, recent postponements in the

Table 17-1

SCALING FACTORS FOR URBAN LIVING

Item	Unit*	Quantity
Fresh water consumption		
National average	Gal/capita day	150
Domestic 40%		
Commercial 18%		
Industrial 24%		
Public uses 18%		
Colorado		170
Wyoming		200
Montana		190
Waste water production		
National average	Gal/capita day	120
Colorado		140
Wyoming		160
Montana		150
Solid waste production		
National average	Lbs/capita day	1400
Residential and commercial electric power consumption	1000 kWh/capita	5.2
Private automobiles		
National average	Cars/capita	0.48
Colorado		0.55
Wyoming		0.51
Montana		0.49
Distance traveled per passenger automobile	Miles/car-year	10,000
Land requirements for dwelling units	Acres/person	0 .065
Streets and roads (municipal and rural)		
National average	Mileage/capita	1.8×10^{-2}
Colorado		3.6×10^{-2}
Wyoming		1.2×10^{-1}
Montana		1.1×10^{-1}
Acreage or municipal and rural roads	Acres/mile	12

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*Conversion factors: 1 gal = $3.79 \times 10^{-3} m^3$; 1 mi = 1.61 km; 1 acre = $4.05 \times 10^3 m^2$.

Table 17-2

WATER RUNOFF COEFFICIENT "C" AND RAINFALL IN WYOMING AND COLORADO

(Fraction of Rainfall Flowing into Rivers and Streams)

Undisturbed land		
Eastern Wyoming[*]	0.07-0.09	
Piceance Basin[†]	0.04-0.08	
Disturbed land		
Suburban land[‡]	0.25-0.40	
Light industrial[‡]	0.50-0.80	
Gravel roadways[§]	0.15-0.30	
Rainfall		
Gillette/eastern Wyoming		
Average annual[*]	11-15 (27-38)	in./yr (cm/yr)
Peak daily[**]	2.8 (7.1)	in./yr (cm/yr)
Piceance Basin Colorado		
Average annual[†]	12-24 (30-61)	in./yr (cm/yr)
Peak daily[**]	2.8 (7.1)	in./yr (cm/yr)

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[*] Average annual runoff of 1 in./yr (Reference 3) with annual rainfall of 11 to 15 in. (Reference 4).

[†] Average annual runoff of 1 in./yr (Reference 3) with annual rainfall of 12 to 24 in. (References 1, 5).

[‡] Reference 6.

[§] Reference 7.

[**] Reference 8, assuming the same peak daily rainfall for Piceance Basin.

Table 17-3

AVERAGE EMISSION FACTORS FOR HIGHWAY VEHICLES BASED ON NATIONWIDE STATISTICS

			Hydrocarbons											
	Carbon[*] Monoxide		Exhaust[†]		Crankcase and Evaporation		Nitrogen[‡] Oxides (NO_x as NO_2)		Particulates				Sulfur Oxides (SO_2)	
									Exhaust		Tire Wear			
Year	g/mi	g/km	g/mi	g/km	g/mi	g/km	g/mi	g/km	g/mi	g/km	g/mi	g/km	g/mi	g/km
1970	78	48	7.8	4.8	3.9	2.4	5.3	3.3	0.38	0.24	0.20	0.12	0.20	0.12
1975	50	31	5.0	3.1	1.5	0.93	5.0	3.1	0.38	0.24	0.20	0.12	0.20	0.12
1980	23	14	2.4	1.5	0.53	0.33	3.1	1.9	0.38	0.24	0.20	0.12	0.20	0.12
1990	12	7.5	1.3	0.81	0.38	0.24	1.8	1.1	0.38	0.24	0.20	0.12	0.20	0.12
2000[§]	3.4	2.1	0.41	0.25	0.38	0.24	0.4	0.25	0.38	0.24	0.20	0.12	0.20	0.12

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[*] 1975 standards - 3.4 g/mi.
1976 standards - 3.4 g/mi.

[†] 1975 standards - 0.41 g/mi.
1976 standards - 0.41 g/mi.

[‡] 1975 standards - 3.9 g/mi.
1976 standards - 0.4 g/mi.

[§] We assume 1976 standards are met for all vehicles in 2000.

Source: "Compilation of Air Pollutant Emission Factors," 2nd Edition, Supplement 2, U.S. Environmental Protection Agency (April 1973).

imposition of increasingly stringent emissions standards, suggest that the relevant factors applied in any given time frame of this study are uncertain.

The scaling factors given in Tables 17-1 through 17-3 have been used to derive the results shown in Tables 17-4 through 17-7 for the Powder River Basin in Wyoming and the Piceance Basin in Colorado for the maximum credible implementation scenario. The significance of the results given in the tables is amplified from the standpoint of environmental concerns in the following sections of this chapter.

2. Water-Related Impacts

a. Runoff

The paving of streets and the roofing of structures alter the runoff of precipitation because there is less open ground to absorb it. This results in the alteration of stream flows manifested both by an increase in quantity and by a compression in time of the flow*

The runoff Q can be expressed by the simple equation

$$Q = CIA$$

where C is a constant, I is the precipitation rate, and A is the area affected.†

Table 17-2 gives the fractional runoff coefficient for various activities that cover the land surface with water-diverting

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*Less time elapses between the falling of the precipitation and the onset of runoff flow, and the runoff flow ceases quicker after the precipitation ends.

†Q is usually given in ft^3/s, I in in./hr, and A in acres.

Table 17-4

IMPACTS FOR CAMPBELL COUNTY, WYOMING, COAL LIQUEFACTION AND METHANOL PRODUCTION--MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO

Impact	Impact Scaling Factor		Quantities Derived from MCI and Figure 22-2					Scenario for Year				
	Quantity	Units	1975	1980	1990	2000	Units§	1975	1980	1990	2000	Units§
Fresh water consumption	200	Gal/day person	17	22	60	110	1000 people	3.4	4.4	12	22	10^6 gal/day
Waste water production	160	Gal/day person	17	22	60	110	1000 people	2.7	3.5	9.6	18	10^6 gal/day
Solid waste production	1400	Lbs/person yr	17	22	60	110	1000 people	24	31	84	150	10^6 lbs/yr
Residential and commercial electric power consumption	5.2	1000 kWh/person-yr	17	22	60	110	1000 people	88	110	310	570	10^6 Wh/yr
Land area directly affected by urbanization (cumulative)	0.065	Acres/person	17	22	60	110	1000 people	1100	1400	3900	7200	Acres
Municipal and rural road distance (cumulative)	1.2×10^{-1}	Miles/person	17	22	60	110	1000 people	2000	2600	7200	13,000	Miles
Acres affected by municipal and rural roads (cumulative)	12	Acres/mile	2000	2600	7200	13,000	miles	2.4	3.1	8.6	16	10^4 acres
Increased runoff from urbanization during peak annual periods	C = 0.16 to 0.33 I = 0.7* A	Dimensionless In./hr† Area	1100	1400	3900	7200	acres	120 to 250	160 to 320	440 to 900	810 to 1700	ft^3/s water‡
Increased runoff from municipal and rural roads during peak annual periods	C = 0.08 to 0.23*		2.4	3.1	8.6	16	10^4 acres	1300 to 3900	1700 to 5000	4800 to 14,000	9000 to 26,000	ft^3/s water

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*Runoff, Q = CIA (C = a constant, I = precipitation rate, A = area affected).

†Assumes peak daily rainfall of 2.8 inches occurs in a 4-hr period due to thunderstorm activity.

‡1 $ft^3/s = 0.646 \times 10^6$ gal/day.

§Conversion factors: 1 gal = $3.79 \times 10^{-3} m^3$; 1 acre = $4.05 \times 10^3 m^2$; 1 mi = 1.61 km; 1 in. = 2.54 cm; 1 $ft^3 = 2.83 \times 10^{-2} m^3$.

Table 17-5

IMPACTS FOR GARFIELD AND RIO BLANCO COUNTIES, COLORADO, OIL SHALE DEVELOPMENT--MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO

Impact	Impact Scaling Factor		Quantities Derived from MCI and Figure 22-13					Scenario for Year				
	Quantity	Units	1975	1980	1990	2000	Units‡	1975	1980	1990	2000	Units‡
Fresh water consumption	170	Gal/day person	23	50	220	245	1000 people	3.9	8.5	37	42	10^6 gal/day
Waste water production	140	Gal/day person	23	50	220	245	1000 people	3.2	7.0	31	34	10^6 gal/day
Solid waste production	1400	Lbs/person yr	23	50	220	245	1000 people	32	70	310	340	10^6 lbs/yr
Residential and commercial electric power consumption	5.2	1000 kWh/yr person	23	50	220	245	1000 people	120	260	1100	1300	10^6 Wh/yr
Land area directly affected by urbanization (cumulative)	0065	Acres/person	23	50	220	245	1000 people	1500	3300	14,000	16,000	Acres
Municipal and rural road mileage (cumulative)	3.6×10^{-2}	Miles/person	23	50	220	245	1000 people	830	1800	7900	8800	Miles
Acres affected by municipal and rural roads (cumulative)	12	Acres/mile	830	1800	7900	8800	miles	1	2.2	9.5	11	10^4 acres
Increased runoff from urbanization during peak annual periods	C = 0.17-0.36 I = 0.7* A	Dimensionless In./hr† Area	1500	1300	14,000	16,000	acres	180 to 380	390 to 830	1700 to 3500	1900 to 4000	ft^3/s water
Increased runoff from municipal and rural roads during peak annual periods	C = 0.07 to 0.26*		1	2.2	9.5	11	10^4 acres	490 to 1800	1100 to 4000	4700 to 17,000	5400 to 20,000	ft^3/s water

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*Runoff, Q = CIA (C = a constant, I = precipitation rate, A = area affected).

†Assumes peak daily rainfall of 2.8 in. occurs in a 4-hr period due to thunderstorm activity.

‡Conversion factors: 1 gal = $3.79 \times 10^{-3} m^3$; 1 acre = $4.05 \times 10^3 m^2$; 1 mi = 1.61 km; 1 in. = 2.54 cm; 1 ft^3 = $2.83 \times 10^{-2} m^3$.

Table 17-6

AUTOMOTIVE POLLUTION IMPACTS FOR CAMPBELL COUNTY, WYOMING, COAL LIQUEFACTION AND METHANOL PRODUCTION--
MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO

	Impact Scaling Factor		Quantities Derived from MCI and Figure 22-2					Scenario for Year				
Impact	Quantity	Units	1975	1980	1990	2000	Units*	1975	1980	1990	2000	Units*
Private automobiles	0.51	Cars/person	17	22	60	110	1000 people	8.7	11	31	56	10^3 cars
Automobile travel	10	1000 miles/car-yr	8.7	11	31	56	10^3 cars	87	110	310	560	10^6 miles/yr
Air pollution from automobiles												
Particulates	Mileage	Use data for the appropriate year from Table 17-3	0.58	0.58	0.58	0.58	g/mi	0.05	0.06	0.18	0.32	10^6 kg/yr
SO_2			0.2	0.2	0.2	0.2	g/mi	0.02	0.02	0.06	0.11	10^6 kg/yr
Hydrocarbons			6.5	2.9	1.7	0.8	g/mi	0.57	0.32	0.53	0.45	10^6 kg/yr
NO_x			5.0	3.1	1.8	0.4	g/mi	0.44	0.34	0.56	0.22	10^6 kg/yr
CO			50	23	12	3.4	g/mi	4.4	2.5	3.7	1.9	10^6 kg/yr

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*Conversion factors: g/mi = 0.62 g/km; 1 mi = 1.61 km.

Table 17-7

AUTOMOTIVE POLLUTION IMPACTS FOR GARFIELD AND RIO BLANCO COUNTIES, COLORADO, OIL SHALE DEVELOPMENT--MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO

	Impact Scaling Factor		Quantities Derived from MCI and Figure 22-13					Scenario for Year				
								1975	1980	1990	2000	Units*
Impact	Quantity	Units	1975	1980	1990	2000	Units*	0	1	15	20	100,000 B/D
Private automobiles	0.55	Cars/person	23	50	220	245	1000 people	13	28	121	135	10^3 cars
Automobile travel	10	1000 miles/car-yr	13	28	121	135	10^3 cars	130	280	1210	1350	10^6 miles/yr
Air pollution from automobiles												
Particulates	Mileage	Use mileage data for the appropriate year from Table 17-3	0.58	0.58	0.58	0.58	g/mi	0.08	0.16	0.70	0.78	10^6 kg/yr
SO_2			0.2	0.2	0.2	0.2	g/mi	0.03	0.06	0.24	0.27	10^6 kg/yr
Hydrocarbons			6.5	2.9	1.7	0.8	g/mi	0.85	0.81	2.1	1.1	10^6 kg/yr
NO_x			5.0	3.1	1.8	0.4	g/mi	0.65	0.87	2.2	0.54	10^6 kg/yr
CO			50	23	12	3.4	g/mi	6.50	6.4	14	4.6	10^6 kg/yr

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*Conversion factors: 1 mi = 1.61 km; 1 g/mi = 0.62 g/km.

materials and undisturbed areas. Urbanization of undisturbed lands could be expected to increase runoff 3 to 5 times that of the undisturbed landscape. Much of this extra water goes into storm drains and sewers. In rural areas, new roads will increase runoff into streams.

Table 17-2 also shows the range of annual rainfall for the two regions. Much of the nonsnow precipitation occurs during thunderstorms, with thunderstorms occurring about 30 days per year in eastern Wyoming and about 40 days per year in western Colorado.[3] We assume a peak daily rainfall of 2.8 in./day (7.1 cm/D) for both regions. Thunderstorms will induce the most damaging runoff.

b. Increased Salinity

It is predicted that the withdrawal of river water for municipal use will increase the concentrations of dissolved salts in the Upper Colorado Basin, which experiences problems with increasing salinity.[9] Each milligram per liter increase in dissolved solids per unit volume (salinity) increases the economic detriment in the lower Colorado Basin at the rate of $230,000 per mg/$\ell$ increase. For an oil shale industry of 1.5 to 2.0 million B/D, the increase in dissolved solids (mg/ℓ) from the increase in residential water consumption is estimated at 0.6 to 1.0 mg/ℓ, which gives a total annual detriment of $1.2 to 2.3 million per year.

c. Waste Water

Analysis has shown that the cost of a shale- or coal-derived synthetic crude oil is insensitive to the cost of water, consequently, a plant could easily afford to treat urban waste water for use. However, it can be readily calculated that the population induced by an oil shale plant would generate waste water at a rate that would satisfy only about 10 percent of the water requirements of a single plant. Thus, a population of almost 100,000 people would produce only enough waste water per year to satisfy a single 100,000-B/D (16,000 m^3/D) oil shale plant. Clearly, reuse of residential waste water could at best make only a small contribution to meeting the water needs of an oil shale industry.

3. Air Quality Impact

Table 17-8 compares the automotive air pollution with that from an oil shale plant. As can be readily seen, the automotive air pollution is 1/40 to 1/900 that of the air pollution from the oil shale industry. Thus, the impact on regional air quality derived from the atmospheric dispersion modeling of Chapter 16 will be a good representation of the total effect on air quality in the Piceance Basin.

D. Nonquantifiable Impacts

1. Impact of Increased Land Use

Three major urban land uses will develop around the towns in the coal and oil shale regions: Land use of permanent housing and recreation areas for the operating force of the plant and mines, and for the service personnel and their families. Land use for temporary housing for the construction force for the plant (often temporary housing in trailers evolves into permanent housing in the same trailers). Land use for commercial development, roads, and utility corridors.

All of these land uses disturb rangeland, open space, and watershed adjacent to a town. Unpaved roads and graded lands, highly subject to wind and water erosion, create dust and contribute to topsoil degradation. The sparse groundcover and low rainfall contribute to soil instability in areas of disturbed vegetation.

Table 17-8

AIR POLLUTION FROM AUTOMOBILES AND OIL SHALE PLANTS

	Impact Scaling Factor		Quantities Derived from MCI					Scenario for Year				
Impact	Quantity	Units	1975	1980	1990	2000	Units	1975	1980	1990	2000	Units
Air pollutants from oil shale complex*												
Particulates	103	g/s-100,000 B/D	0	1	15	20	100,000 B/D	0	103	1545	2060	g/s
SO_2	394	g/s-100,000 B/D	0	1	15	20	100,000 B/D	0	394	5910	7880	g/s
Hydrocarbons	76	g/s-100,000 B/D	0	1	15	20	100,000 B/D	0	76	1140	1520	g/s
NO_2	514	g/s-100,000 B/D	0	1	15	20	100,000 B/D	0	514	7710	10,280	g/s
Air pollution from automobiles†												
Particulates								2.5	5.1	22	25	g/s
SO_2								1.0	1.9	7.6	8.6	g/s
Hydrocarbons								27	26	67	35	g/s
NO_x								21	28	70	17	g/s
CO								210	200	440	150	g/s

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*Chapter 16.

†From Table 17-7.

2. Water Quality Degradation

The relatively arid areas of the Powder River and the Piceance Basin afford considerable opportunity for water quality degradation. Sparse groundcover in the Powder River Basin, when disturbed by construction activity, leads to erosion and stream siltation following rains. In these areas, which are already short of water for urban use, an increase in water consumption will lead to stream degradation through flow reduction. Urban construction on important underground water recharge can lead to the lowering of water tables. Diversion of rainwater runoff through construction activity or the rechannelling of streamflow can lead to water quality degradation. Road construction on the steep unstable hillsides of the Piceance Basin often leads to landslides, which fill or block streambeds.

Much of the water in the areas under consideration flows in underground aquifers. In the Powder River Basin, these aquifers are unlikely to be affected by construction activities or urban growth except through increased usage for residential or industrial use. In Colorado, many of the recharge areas for aquifers lie at the base of cliffs and in the flat areas along rivers. Some disturbance of underground aquifers in this area is possible.[2]

3. Impact on Recreation Areas

Scaling factors cannot be used to generalize environmental impacts that stem from increased recreational or leisure time activities in an area because the effects of these activities are related to the nature of a given locale and the socioeconomic status of the inhabitants of the settlements involved. Particular to this category of impact are the activities of increased use of public parkland, hunting and fishing, and off- and on-the-road travel.

Growth of population brings heavier use of public parklands. Unless the quantity of park-like land with public access increases along with the population, the existing areas receive more intense use--sometimes exceeding their capacity to recover from wear and tear.

People frequently seek outdoor recreational activity on private lands--sometimes by trespass. As the nation becomes increasingly motorized, leisure activity has more and more involved off-the-road driving with such vehicles as motorcycles, dune buggies, four-wheel-drive jeeps and trucks. Much of this off-the-road operation is destructive to vegetation, disruptive to wildlife, and it creates dust and noise problems. Often, access by these vehicles leads to vandalism of historic sites, archeological resources, and unique features of the environment, not to mention litter, which is a common product of off-the-road travel.

State and federal agencies own nearly 35 percent of the land in the Northern Great Plains Resources Program study area, with these lands forming a virtual patchwork quilt on the land. Many different federal and state agencies control land. The recreational value of the land is most likely to be seriously affected by growth. The biological responsiveness of the land and the biological carrying capacity of the land are most likely to be impacted last. Population growth already impacts several areas; for example Flaming Gorge near Rock Springs, Wyoming; Keyhole State Park in northeastern Wyoming near Gillette and Sheridan, Wyoming; and Custer National Forest near Colstrip. Coal development in Wyoming would likely make Keyhole State Park Wyoming's most heavily used park.[10] The Northern Great Plains area and the Rocky Mountains to the west now contain uncrowded recreation areas. Population growth will impact the quality of recreation by introducing crowding and heavy use of the most accessible recreation areas. Rivers and reservoirs, for example, are prime recreation use areas. With a growing demand for water by energy companies, surface area reductions in many reservoirs are to be expected. More people will share less water for recreation.

The recreation habits of residents in the Northern Great Plains area differ from those of out-of-state tourists. Tourists tend to frequent the better known national parks and monuments. Those residents who hunt and fish generally use state lands, national forests, and Bureau of Sport Fisheries and Wildlife areas. An increase in the resident population from coal mining and conversion will impact local recreation opportunities most heavily, with city and county parks, state parks close to mining towns, and federal lands close to mining activities the most seriously affected. In Wyoming, the annual influx of visitors to Yellowstone National Park, which totals over 2 million people, dwarfs the 300,000 Wyoming residents. In another part of the state, however, in Natrona, Converse, and Niobrara counties (along the Platte River) over 90 percent of the fishing in 1970 was by residents.[10] The impacts from new residents will overshadow the impacts from tourists in most recreation areas other than national parks and monuments.

4. Impact on Animal Populations

Increased population brings with it increased road mileage and road travel in rural areas. This travel endangers the lives of large and small animals that frequently cross the roads: antelope, squirrels, skunks, deer, rabbits, turtles, snakes and raccoons. Nocturnal animals are especially susceptible. Studies have confirmed that a large cause of death among wild animals is their being struck by vehicles on highways.

Increased numbers of people increase the legal and illegal hunting and fishing pressure on game animals and sport fish. In addition, there is an increase in destruction for destruction's sake--especially of predatory animals, birds of prey, and snakes.

The layout of roads, habitation, and recreational areas can affect animals and plants, in a region differentially. Some species adapt well to human activity and even increase in numbers as domestic vegetation substitutes for native forage, or as the number of predators is lessened. Human habitation harms other animals or birds when home range territories are diminished or transected, or when a unique feature essential to part of their life cycle (e.g., trout spawning beds in streams) is destroyed.

Other subtle factors can also be important to the viability of wildlife habitat. For example, the sage grouse and sharptailed grouse prefer certain sagebrush areas as strutting ground for their mating ritual. In the Powder River Basin development will lead to more power utility lines which in the past have given birds of prey an unnatural but strategic vantage point from which to attack grouse; several grouse colonies have been decimated in the past by this means.[11]

In the Piceance Basin, development will withdraw critical winter range in the river valleys for deer, antelope, and elk in the White River and Colorado River Basins. The availability of winter range determines the size of the herd that can be supported by the available habitat. Destruction of winter range has a far more severe effect on herd size than similar destruction of the more abundant summer range.

E. Summary

There are many indirect environmental consequences of the urbanization that would be induced by coal and oil shale conversion facilities developments. Among those that can be estimated quantitatively are effects on precipitation runoff, waste water production, and air quality impacts from automobiles. We have shown that there is little chance of using urban waste water to satisfy all the needs of an oil shale plant because a single plant needs about 10 times as much water as the population induced by the plant will produce. We have also shown that the automobile contribution to air pollution will be small compared to the pollution caused by the plants themselves.

Important, but nonquantifiable, impacts include effects on land use patterns, over use and abuse of recreational and rural landscapes, and increased animal mortality from being struck by automobiles.

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18--HEALTH ISSUES IN SYNTHETIC LIQUID FUELS DEVELOPMENT

By Robert V. Steele

A. Introduction

There is little question that synthetic liquid fuels development will produce adverse effects on human health due both to the further emission of pollutants already regulated and the release of yet to be identified toxic, carcinogenic, or other health-impairing agents. However, owing to the lack of concrete data on which to base an analysis, the extent of such effects cannot be predicted quantitatively until some development takes place and the appropriate clinical and epidemiological studies are carried out. All that can be done at this stage is to discuss the health issues that are likely to arise as a synthetic fuels industry develops and to point out the critical areas in which research, planning, and testing will be necessary to forestall or minimize deleterious effects on human health.

B. Effects of Industrial Development in New Areas

To the extent that synthetic fuels development is carried out in areas that currently enjoy low levels of environmental pollution, increased levels of health effects are likely to occur in these areas. The impacted population will consist not only of the current residents of these areas, whose numbers are small in many cases, but also of plant and mine workers and their families who will have migrated to the development sites. Even with moderate levels of growth, the new population associated with development could swamp the current population in many areas after 10 or 15 years, as shown in Chapter 22.

Since the number of cases of impaired health should be proportional to both the ambient concentration of pollutants and the number of people exposed, a "square law" might be proposed to express the health impacts of additional development. The "square law" says that health effects increase roughly as the square of the level of production, since both ambient pollutant concentrations and population exposed are roughly proportional to this quantity. Although it would be difficult to make any quantitative formulation of this "square law," the notion indicates that the level of effects may be higher than would be initially expected due to the remote siting of much of the development.

The most obvious health effects would be those related to increased levels of pollutants for which EPA has set standards, especially air pollutants such as NO_x, SO_2, particulates, oxidants, and so forth. The EPA primary standards for these pollutants are designed to protect human health. EPA secondary standards are designed to protect human welfare by minimizing the effects on plant life, materials, etc. If these ambient air quality standards are rigorously enforced, then few health effects would arise from these sources of pollution. As discussed in Chapter 16, there are many variables, however, that determine ambient concentrations of pollutants, including the relative location of plant sites, weather conditions, secondary pollutant releases due to increased population, and so forth. Control measures may not necessarily be applied until some level of pollution is reached at which health effects begin to appear. Even then, it may take several years before appropriate control measures can be implemented.

Another area where time lags may occur between the onset of health effects and the implementation of control regulations is the emission of compounds specific to the new synthetic fuel processes that have not previously been regulated. Careful advance planning and testing will be required to ensure that the releases of all substances that affect health are accounted for and quantified so that appropriate regulations can be formulated, if necessary.

C. End Use Impacts

Due to the potential for the widespread use of synthetic liquid fuels in automotive transportation, there is a great potential for impacting the health of large numbers of people. The effects of interest are those that arise from differences in the combustion of synthetic fuels compared with those that arise from the combustion of conventional fuels.

The most pronounced differences in automotive pollutant emissions are in the combustion of methanol or methanol-gasoline blends compared with the combustion of gasoline. Reductions in the emissions of automotive pollutants (NO_x, CO, hydrocarbons, and aldehydes) have been reported for straight methanol fuel[1,2] and methanol/gasoline blends,[3] with the exception that aldehyde emissions are higher than for gasoline. Formaldehyde is a partial oxidation product of methanol and it accounts for most of the aldehyde emissions from methanol combustion. It can act as a respiratory irritant and an allergenic agent. The use of advanced catalytic converters can reduce CO, hydrocarbon, and aldehyde emissions by an order of magnitude for both gasoline and gasoline/methanol combustion.[3] Although differences remain in emissions between the two cases, the levels are so low that the differences are no longer as significant.

A problem in the use of methanol is that it displays acute toxic effects both through vapor inhalation (the maximum allowable exposure is 200 ppm compared with 400 ppm for octane) and through absorption by the skin.[4] It is also acutely toxic when ingested orally.[4] However, this is not likely to be a problem in fuel use, especially if blends are employed. Rather, the routine contact with both vapor (methanol has a vapor pressure of 100 mm of Hg at 20°C compared to 10 mm of Hg for octane) and spilled liquid poses a significant health hazard to service station attendants and others who frequently handle or are exposed to automotive fuels.

Differences in the emissions from the combustion of fuels refined from shale or coal syncrude and those from combustion of conventional fuel have not been identified. It is likely that the only significant differences would be in the trace elements or unburned hydrocarbon emissions. For example, it is known that upgraded shale oil and coal syncrude contain higher fractions of aromatics than do natural crudes.[5] This aromatic fraction is largely converted to gasoline, and the aromatic content of exhaust gas is apparently proportional to the aromatic content of the gasoline. Therefore, higher emissions of aromatics may occur from the use of synthetic gasoline. It is not known whether or not any of these aromatic compounds will be among those identified as carcinogens. However, it has been reported that carcinogens in raw shale oil are destroyed in the process of hydrotreating (upgrading) to produce synthetic crude oil.[6]

Both coal and oil shale contain toxic trace elements. (See Tables 4-13 and 4-14.) It is likely that many of these will be removed during coal liquefaction and shale oil upgrading. However, analyses of the syncrude products have not been carried out, and there is no indication as yet of the extent to which trace elements will find their way into refined products.

D. Localized and Occupational Health Problems

An important concern in coal and oil shale conversion activities is the possibility of adverse health effects on workers and on local communities. This concern is centered more around the possible release of carcinogens, toxic trace elements, or more exotic pollutants than it is around pollutants whose release is currently regulated and that can be readily controlled. It is well known that substances derived from coal, such as coal tar, contain carcinogenic compounds. Raw shale oil is also known to contain carcinogens. The toxic trace elements in coal and oil shale are discussed in Chapter 4.

The main questions concerning these and other toxic materials are whether will they be released to the environment, and if so, what will be the quantities involved. It has been reported that a coal liquefaction pilot plant operated by Union Carbide had to be shut down in 1960 because the plant workers developed cancerous lesions on their skins.[7] Some mechanisms of airborne release of cancer-inducing material can be inferred from this report. However, since such reports have not been received from other operations, more would have to be known about the actual operating conditions of the plant to draw any conclusions generally applicable to coal liquefaction.

At one point it was feared that the disposal of large quantities of spent shale would create a cancer hazard due to the presence of carcinogenic compounds such as benzo[a]pyrene in the carbonaceous residue on the spent shale. However, tests carried out for The Oil Shale Company (TOSCO) indicate that the carcinogenic potential of spent shale is low, due to the very small concentrations of benzo[a]pyrene and other polycyclic aromatic hydrocarbons.[8] Raw shale oil has a mild carcinogenic potential, comparable to some intermediate refinery products and fuel oils.[8] Upgraded shale oil has a carcinogenic potential about an order of magnitude less than that of raw shale oil, consistent with the belief that polycyclic aromatics are broken down by hydrogenation. Thus, oil shale and its products do not appear to present a serious cancer hazard. However, safe plant operating procedures should be enforced to prevent the workers from contact with intermediate retorting products, which display a "mild" carcinogenic potential.

The release of other toxic substances should be carefully studied to insure that these materials are not released to work areas or the general environment. The pathways and ultimate fates of many substances, including toxic trace elements, in the conversion process are not well understood. Thus, basic chemical and analytical studies should be carried out to determine the contents of all waste streams from synthetic liquid fuel processes to determine if health hazards might be created by these streams and if abatement procedures may be needed.

Another area of concern is the potential for contamination of local water supplies through runoff from solid waste disposal piles--primarily spent shale and coal ash. Although current plans for coal and oil shale conversion incorporate measures to prevent such contamination, some monitoring of waste disposal practices will help to insure that contamination does not occur accidentally--during flash floods, for example. In addition, there are subtle effects that might go easily unnoticed. Examples are percolation of highly saline water through spent shale piles to underlying aquifers and the disposal of coal ash in mined out areas where aquifers have already been disturbed, which would cause further contamination.

E. Research Needs

A great deal remains to be learned about the health effects of synthetic liquid fuel production and use. The need for research in this area is large, but just as important is the timing with which the research is carried out. To have the greatest effect in moderating human health impacts, the research should be carried out simultaneously with the development of the synthetic fuel technologies.

The following important data are needed:

- Identification of all toxic substances, including carcinogenic, teratogenic, and mutagenic agents, in waste streams.
- The transport of these substances through the environment.
- The fate of these substances in the environment, including mechanisms of degradation and transformation.
- The potential for human health impairment at the concentration levels expected from releases from full-scale plants.

The strong need for the type of data indicated above has prompted a number of government agencies to institute research programs to acquire data on health effects of energy technologies. In particular, EPA has begun a study, to be performed by SRI, concerned with radioactive contaminants associated with new energy technologies including coal liquefaction and oil shale conversion. In addition, the EPA Office of Energy, Minerals, and Industry has established several programs in this area. Other organizations, such as the National Institute of Environmental Health Sciences and the National Institute for Occupational Safety and Health, have held workshops in health aspects of energy conversion. Furthermore, the Biomedical and Environmental Division of the Energy Research and Development Administration (ERDA) will be responsible for carrying out health effects research on ERDA-supported technology programs.

There is, therefore, a reasonable expectation that important health effects data will be obtained on synthetic fuel technologies as they are developed and reach the stages of final commercialization. If thorough research and appropriate measures for control and regulation are carried out, it is possible that health effects of synthetic fuels development may be minimal. To insure this, careful coordination of the research efforts of government agencies and private industry is required, along with thoughtful and timely application of research results.

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19--WATER AVAILABILITY IN THE WESTERN UNITED STATES

By R. Allen Zink

A. Introduction

The production of synthetic liquid fuels from coal and oil shale involves water intensive processes.* For projected synthetic fuel plants in the eastern states, it appears that--on a major watershed basis--the water impact will be small even in the dry months of dry years (see Chapter 20). However, for the oil shale region in Colorado and the coal region of the Northern Great Plains, the situation is more complex. The water problem in the semiarid, energy-rich West is not simply one of getting enough water to satisfy demands, it is also the problem of establishing a decision making mechanism to select the priorities that will dictate future allocations of a limited amount of water. The western region has reached the point at which the order of those priorities will soon have to be set.

The demands on the West's limited budget of water come from many directions:

- Irrigation of crops
- Livestock watering
- Domestic use (status quo)
- Urban development (growth)

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*Advances in the technologies such as processing oil shale while still underground hold promise of reducing the water required by one-half or more; also, dry cooling towers in coal conversion processes, although considerably more expensive than the contemplated wet cooling, could reduce water use.

- Industrial production
- Aesthetic values
- Recreational use
- Energy development

West of the 100th meridian, there is an imminent water budget dilemma that will pit the many needs in direct competition. The primary contributing factors to this competition are:

- Generally arid conditions (precipitation of approximately 14 inches per year)
- Population growth
- Increasing use of irrigation in agriculture
- Federal subsidies of water that result in cheap irrigation water for agricultural projects
- Stated national goal of reducing dependence on foreign sources of energy, with consequent interest in new domestic sources.
- Extensive coal and oil shale resources in this arid region.
- Rising interest in protection of the fragile environment.

In view of this competition, some hard decisions will have to be made affecting different people with different needs. How does the energy-poor New Englander feel about the Montana rancher whose land is being stripped of its character? How does that rancher feel about gasoline shortages in Los Angeles? These decisions will have both regional and national implications, and presently existing laws and institutions may not be up to the task of making the necessary choices. This chapter sets out the nature and sources of the complex problems implicit in western water for energy development.

B. Water Rights and the Federal Government

A major factor in the issue of water for energy in the West is the role of the federal government--both as a claimant to certain amounts of water, and as an institutional disburser of water. From the perspective of the western states, a more accurate statement would be the federal government as claimant to uncertain amounts of water. The situation is so unsettled that neither private investors nor state governments can act with confidence in planning projects where water will be needed.

This section explores the source and dimensions of the federal claims, the conflicts created by them, and the implications of the situation for energy development.

1. Scope of Federal Water Rights

When the United States government obtained the territories that are now the western states, it assumed sovereign dominion and power over all the land, mineral resources, and water. The government encouraged development of the new territory through homesteading and stock grazing land grants, and new states were carved out of the territories. Of the original federal domain, much of the land continues to be property of the United States. Table 19-1 shows the percentages of federally owned land in the mineral rich states of Colorado, Wyoming, and Montana:[1] Of greater significance is the contribution that federally owned lands make to natural water runoff in the major river basins of the West--66 percent of the Missouri River Basin and 96 percent of the Upper Colorado River Basin.[1] From a strictly proprietary standpoint, the federal government has a powerful equitable argument for ownership and control over waters arising on "its" property. The U.S. Constitution, in fact, gives Congress the power

> to dispose of and make all needful Rules and Regulations respecting the territory or the Property belonging to the United States; and nothing in this Constitution shall be so construed as to prejudice any claims of the United States....[2]

Table 19-1

PERCENTAGE OF FEDERALLY-OWNED LAND IN COLORADO, MONTANA, AND WYOMING

State	Federally-Owned Land (%)
Colorado	36.3
Montana	29.6
Wyoming	48.2

Other sources of federal power over water are also found in the Constitution. Indeed, the war power has been relied upon to justify the Tennessee Valley Authority project.[3,4] Under the supremacy clause, treaties are superordinate to state law; thus, federal power exists to construct improvements on international watercourses pursuant to a treaty obligation, irrespective of state law.[5] The general welfare clause of the Constitution has been cited as authority for federal action vis-á-vis a privately held water right.[4,6] Federal power over waters capable of use as interstate "highways" (waterways) arises from the commerce clause of the Constitution.[5] An early Supreme Court case held that this power to regulate commerce necessarily includes control over navigation.[7] Thus, Congress may control the navigable waters of the United States and keep them open and free.

Of the above impressive federal powers over water, all but two would--if exercised to the detriment of a privately held right--result in compensation being paid by the federal government for that private loss. Exercise of federal power over navigable waters would not result in compensation being paid to one whose loss occurs with the exercise of the power:

> Ownership of a private stream wholly upon the lands of an individual is conceivable; but that running water in a great navigable stream is capable of private ownership is inconceivable.[8]

That is, no power resides in an individual to acquire a property right in a navigable stream; therefore there can be no taking away of said right and no compensation would be paid. Similarly, exercise of federal power over a federally-owned proprietary water right could not result in an individual loss for which compensation would be forthcoming.

These last two federal powers are most feared by the states because of the extent of the powers and because when they are exercised no compensation is paid to those whose water rights are displaced. Each of these powers will be discussed in turn.

2. Federal Power Over Navigable Streams

Federal power over large navigable streams such as the Mississippi or Delaware Rivers seems reasonable since such waterways have served as highways for interstate commerce throughout our country's history. However, application of the doctrine has been so extensive that true navigability is no longer the test. Thus, a stream is navigable if it can be made so by reasonable improvements.[9] A stream is navigable if it affects the navigable capacity of the mainstream.[10] The definition of a "navigable stream" reaches so far that one must explore in order to find a nonnavigable stream. The impact on state action is clear, for the state's power to authorize appropriation of water "...is limited by the superior power of the [federal government] to secure the uninterrupted navigability of all navigable streams within the limits of the United States."[10] The extended definition of navigable streams has potentially provided Congress with the necessary tool to establish sweeping national water legislation with, e.g., a "Federal Water Board" reviewing <u>every</u> application for water, superseding all prior state allocations--and no compensation would have to be paid.[11]

3. <u>Federal Properietary Water Rights</u>

For the few nonnavigable streams that escape the definition extension discussed above, or for all western streams arising on federal lands--in the event Congress does not establish plenary power over the nation's waters--the power of the Congress under the property clause to deal with its "water" property is impressive.

As previously described, federal land holdings in the West are substantial. The underlying force of the proprietary federal claim to western water is based on the argument that unless and until the United States gives up control or ownership of such lands and waters, they remain under the control of the federal government.

It is argued that, relative to these lands, federal legislation of 1866,[12] 1870,[13] and 1877 (the Desert Land Act)[14] served to sever federal water from the federal land, making the water available for disposition through the laws of the respective states. Support for the argument came from the U.S. Supreme Court in <u>California-Oregon Power Company v. Beaver Portland Cement Co.</u>:[15]

> The fair construction of the provision now under review is that Congress intended to establish the rule that for the future the land shall be patented separately...with the result that the grantee will take the legal title to the land conveyed, and such title, and only such title, to the flowing waters thereon as shall be fixed or acknowledged by the customs, laws and judicial decisions

> of the state of their location.... What we now hold is that following the Act of 1877, if not before, all non-navigable waters then a part of the public domain became publici juris, subject to the plenary control of the designated states....

The language seems clear. However, subsequent cases have had the result of severely weakening the message. The first warning to the states came in Federal Power Commission v. Oregon,[16] known as the Pelton case. In Pelton the Supreme Court acknowledged that the Desert Land Act severed the water from the land, but the Court made a critical distinction between "public lands" and "reserved lands," holding that the Act applied only to public lands. Public lands, the Court said, are those lands owned by the federal government that are subject to disposal under federal public land laws, e.g., land available for homesteading or mining. Reserved lands are not so subject, but are those lands being held by the federal government for a particular purpose--e.g., national recreation areas, national forests, national wildlife preservation areas, and petroleum reserves for national defense.

Federal power to reserve water for these public land reservations was first recognized in Winters v. United States.[17] The Supreme Court held that, in the case of the Indian reservation before it, even though the subject of water rights was not mentioned in the documents used to create the land reservation, there existed an implied intent on the part of the federal government to reserve sufficient water arising on traversing or bordering the Indian land to make the land usable. The Court said:

> The power of the government to reserve the waters and exempt them from appropriation under the state laws is not denied and could not be....,[10] That the government did reserve them we have decided....

In a federal district court case involving a federal land reservation in Nevada for the United States Navy,[20] Nevada attempted to force the United States to seek a state water permit before taking water from the land. Again, the court held that there was no requirement for compliance with state law--the act of reserving the land for military purposes removed the land and water from the Desert Land Act and indicated an intent to reserve sufficient water for the purposes of the land reservation.

The Supreme Court addressed the issue again in Arizona v. California,[21] in which several kinds of federal reservations were before the Court. After affirming the validity of the Winter's doctrine in the Indian water question before it, the Court upheld the Special Master's finding that

> The principle underlying the reservation of water rights for Indian Reservations [is] equally applicable to other federal establishments such as National Recreation Areas and National Forests. We agree...that the United States intended to reserve water sufficient for the future water requirements of the Lake Mead National Recreation Area, the Havasu National Wildlife Refuge, the Imperial National Wildlife Refuge and the Gila National Forest.[22]

The Court proceeded to describe a quantified standard for Indian reservation water related to the number of irrigable acres, but left unmeasured the water allocation for the other federal reservations, saying only that they shall have an amount of water "reasonably needed to fulfill the purpose" of the reservation.

The Court also reiterated the Winter's holding that the effective date for determining the priority of these water rights is the date the land was withdrawn from public land status, i.e., the date the reservation was created. As a result, water appropriations made prior to such date are vested in the appropriator, but appropriations made subsequent to that date are not vested and could be subject to taking without compensation through exercise by the federal government of its water rights.

4. Summary of Federal Water Power

The federal government has the constitutional power to develop, regulate, and allocate--including making allocations to itself--all western water resources, and it can do so irrespective of state laws. When acting under the commerce clause's navigation power, the government need pay no compensation for disrupted private investments.

Furthermore, the federal government can withdraw large tracts of its western land from public sale or lease. These reservations have a water right in an amount necessary to accomplish the purposes of the reservation, and the priority of the water right is the date of the land withdrawal. Any private water rights acquired subsequent to that date are junior to the federal right and can be usurped without payment of compensation.

5. Federal Reserved Lands in the Oil Shale Region

The operation and impact of federal power is seen in the oil shale region of the Upper Colorado Basin. Seventy-two percent of the land in the region is owned by the federal government, and that federal land contains 79 percent of the region's oil shale.[23] Of the total federal land in the region, reservations have been carved out (1) for future Navy fuel needs[24] and (2) for purposes of "investigation, examination and classification."[25] The Naval Oil Shale Reserves were clearly made for the contemplated development of the hydrocarbon resource. If the Arizona v. California[21] "purpose of the reservation" test is applied to determine the amount of water implicitly reserved by the action of the

Executive Orders, the result is an amount of water needed to support the mining and retorting operation. This figure has been estimated at not less than 200,000 acre-ft per year.[26] The priority of the federal water right in this amount dates from the issuance of the Executive Orders establishing the reservations. Again, private rights acquired after those dates are junior to the federal right.

The reservation made in this region by the 1930 Executive Order "...for the purposes of investigation, examination, and classification" is less easily handled under the Arizona v. California test. It is argued that "investigation, examination, and classification" are bare administrative geological functions requiring very little water, and that there was no purpose stated encompassing government development of oil shale in commercial quantities.[27] If this argument is accepted, then a new statement by the federal government would be necessary to the effect that commercial development of the oil shale resource on the reservation tract is the federal purpose. The federal government could then have the necessary water, but the priority date of the water right would be the date of the new statement rather than the 1930 date of the original Executive Order. Private water rights derogated by the "newly contemplated" oil shale development would be senior to the federal rights and therefore would have to be compensated in the taking by the federal government.

6. Implications of the Federal Power

The amount of water for all the various "purposes" of federal reserved land in the West is a matter of speculation. For example, it may be argued that a purpose of the extensive national forests reservations is the production and control of water, thereby creating a federal water right in the total amount of the water arising on that forest land.

One study[28] has pointed out that

> The federal theories underlying reservations and navigation servitude assume that the United States can leave its ownership or authority in suspended animation and can call it in piecemeal or in toto whenever it feels that the time has come for a project....

The uncertainty of that "suspended animation" has angered and frustrated state authorities in their efforts to deal with both state interests in water and the interests of their private citizens.

7. Attempts at Resolution

Colorado has recently tried to remove federal water rights and interests from suspended animation in particular cases. A little used federal law states the following:[29]

> Consent is given to join the United States as a defendent in any suit (1) for the adjudication of rights to the use of water of a river system or other source, or (2) for the administration of such rights, where it appears that the United States is the owner of or is in the process of acquiring water rights by appropriation under state law, by purchase, by exchange, or otherwise, and the United States is a necessary party to such suit. The United States, when a party to any such suit, shall (1) be deemed to have waived any right to plead that the state laws are inapplicable or that the United States is not amenable thereto by reason of its sovereignty, and (2) shall be subject to the judgments, orders and decrees of the court having jurisdiction....

Colorado did include the United States as a party in a state court water rights adjudication and the United States refused to participate. The matter ultimately was carried to the U.S. Supreme Court where Colorado prevailed.[30] [31] The victory is a limited one, however, for the decision does not give the states power to quantify federal water rights generally.* The result is a mechanism for a slow, painstaking, expensive, ad hoc measuring of federal water claims, with the federal government unrelenting in its point of view. Now that the case is back at the state court level (to where the U.S. Supreme Court sent it saying, "Proceed") the federal government is listing its claims in vague and expansive terms. Typical is the federal claim for its water rights in the Arapaho National Forest in Colorado:

> The United States of America hereby claims certain quantities of the surface, ground and underground waters, both tributary and nontributary, which were unappropriated as of the reservation dates.... The United States claims direct water rights, storage water rights, transportation rights and well rights for purposes which include, but are not limited to, the following: growth, management and production of a continuous supply of timber; recreation; domestic uses; municipal and administrative-site uses; agriculture and irrigation; stock grazing and watering; the development, conservation and management of resident and migratory wildlife resources including birds, fishes, mammals, and all other classes of wild animals and all types of aquatic and land vegetation upon which wildlife is dependent; fire fighting and prevention; forest improvement and protection; commercial, drinking and sanitary uses; road watering; watershed protection and management and the securing of favorable conditions of water flows; wilderness preservation; flood, soil and erosion control; preservation of scenic, aesthetic and other public values; and fish culture; conservation, habitat protection, and management. With respect to the category of fish culture, conservation, habitat protection, and management, the United States claims the right to the maintenance of such continuous, uninterrupted flows of water and such minimum stream and lake levels as are sufficient in quantity and quality to:

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*Left unanswered is the effect of the statute on permit-type states, such as Wyoming and Montana, where water rights are determined administratively, not judicially.

> (1) Insure the continued nutrition, growth, conservation, and reproduction of those species of fish which inhabited such waters on the applicable reservation dates, or those species of fish which are thereafter introduced.
>
> (2) Attain and preserve the recreational, scenic, and aesthetic conditions existing on the applicable reservation dates, or to preserve those conditions which are thereafter caused to exist.[32]*

It is important, after catching a breath, to emphasize the government's early-stated caveat that the federal claim is "...not limited to...." the purposes stated in this exhaustive list. Stunned by the vigor of the federal government's activities in the aftermath of the Eagle County decision, the Colorado Water Conservation Board passed the following resolution:†

> Whereas the federal government has now filed numerous claims for water rights in the State of Colorado...to establish federal claims to much of the water originating in Colorado...; and
>
> Whereas the federal government is claiming an unspecified and unknown amount of water...; and
>
> Whereas the granting of the claims sought by the United States could seriously jeopardize the existing system of water rights within the State of Colorado, could create a dual system of administration and decrees, could require water users needlessly to re-adjudicate rights already acquired and decreed under state law, could adversely affect Colorado's rights under the Colorado River Compact and the Upper Colorado River Basin Compact, and will cast an almost impossible burden

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*Taken directly from the U.S. filing papers in the Colorado Court. The lengthy quote is felt necessary to make the point.

†Colorado Water Conservation Board; Resolution passed at the meeting of January 18, 1973. (Emphasis added.)

> upon the citizens of this state in attempting to protect their individual water rights;
>
> Now therefore, be it resolved...that the Board does hereby recommend to the Governor...[etc.]...that all steps necessary and proper, including appropriate funding, be taken and authorized to adjudicate them and thereafter administer them in accordance with state law....

The Board is calling for the fiscal resources to oppose the federal water lawyers. The gauntlet was thrown when the open-ended federal claims were filed.

There have been numerous attempts in the U.S. Congress to legislate a solution to the problem of seemingly open-ended federal water claims, but none of the measures was passed.[33] For the most part, they were introduced by western congressmen seeking to subject virtually all federal water claims to state law.

Nevertheless, most people agree that something must be done to remove the federal water cloud. Two national studies have called for congressional action to require federal cooperation in pursuit of a solution. The Public Land Law Review Commission recommended a complete quantification of all federal water claims, including public notice of all prospective water uses under federal reserved rights; this group also recommended that provision be made for payment of compensation where the exercise of a federal right would interfere with water rights vested under state law prior to the 1963 decision in Arizona v. California.* In its 1973 report,[34] the National Water Commission called for a quantification only of existing federal water uses,† with future reserved rights

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*Reference 1, pp. 147-149.

†See Sect. 10 for discussion of National Water Commission treatment of the intricate Indian water rights issue.

to be exercised through compliance by the federal government with the law of the state in which the federal project is located; the priority of the federal water right so acquired would be the date of the application for state permit or otherwise as determined by state law.

Legislation has been drafted by the Land and Natural Resources Division of the U.S. Department of Justice at the request of the Secretary of the Interior, acting in his capacity as Chairman of the U.S. Water Resources Council. The proposed act seeks "...to provide for the inventorying and quantification of the reserved, appropriative, and other rights to the use of water by the United States...,"[35] including an inventory of Indian water rights. The act provides for judicial review in federal court of the administrative determinations made in pursuit of the comprehensive inventory. No provision is made for the payment of compensation and there is no intent to subject federal rights to state law:

> ...more than ever before, in this day of awareness of ecological necessities and environmental and other values which may be antithetical to the economic objectives of many local water developments, it would seem clear that the public interest does not necessarily require that all future development under the United States reserved rights yield to immediate development under state law.[35]

A noted commentator, Dean Frank J. Trelease, has pointed out that such a proposed inventory could cause great problems in that the federal agencies concerned

> ...may prepare inventories which are grandiose claims of a pie-in-the-sky order, which may confirm the worst fears of state planners [and energy developers] who will see little left for them, and which may unnecessarily becloud titles to unused waters, perhaps deterring development even more than the present uncertainties.[36]

The response of the Department of Justice to this criticism is that the provision for adjudication of claims made by the administrative agencies will keep the inventory accurate. The rebuttal is, of course, that everything is still in favor of the federal government.

Despite such criticism, some action to reduce the uncertainty of the dimension of federal (and Indian) water rights would be welcomed by all concerned. The status quo is simply unacceptable. As a first step, then, this proposed legislation could serve to get the quantification process underway, and other lingering points of controversy--such as the issue of compensation--could be addressed at a later time in the process. Investors in energy development would have some sense of stability in their decision making for the first time since the Arizona v. California decision of 1963.

8. The Mexican Treaty of 1944

Unquantified federal (and Indian) water rights act as a destabilizing influence on the western water-for-energy picture. The major destabilizing factor is the uncertainty of the amounts which might suddenly--or someday--be demanded. There is one instance in which the amount is quantified--the obligation to provide water 1.5 million acre-ft per year* to Mexico under the treaty of 1944.[37] As an international treaty obligation, the pledge occupies a special place in both international and U.S. domestic law.

Treaties are made by the President, with the "advice and consent" of the Senate,[36] and, together with the Constitution and the laws

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*In addition, "...in any year in which there shall exist in the river water in excess of that necessary to satisfy the requirements of the United States and the guaranteed quantity of 1,500,000 acre-feet...the United States...[will attempt] to supply additional quantities of water... up to a maximum of 1,700,000 acre-feet...." (Reference 37, Article 15).

of the United States, they stand as "the Supreme Law of the Land."[39] Treaties, therefore, are superordinate to actions taken by the states individually or collectively:

> It is the necessary result of the explicit declarations of the Federal Constitution...that where there is a conflict between a treaty and the provisions of a state constitution or of a state statute...the treaty will control. Its provisions supersede and render nugatory all conflicting provisions in the laws or constitutions of any state.[48]

This means that before a state can allocate "its" waters, or before a compact between two or more states can allocate the water of shared watercourses, provision must be made for deducting water amounts promised by treaty by the federal government. This is acknowledged in the Upper Colorado River Basin Compact:

> Nothing in this Compact shall be construed as...affecting the obligations of the United States of America under the Treaty with the United Mexican States....[41]

Thus, the 1.5 million acre-ft promised to Mexico is to be deducted from the Colorado River flow for any given year before allocating the remainder via the pertinent compacts.

It has not been decided how the obligation is to be borne between the Upper Basin states and the Lower Basin states--in particular, whether or not the Lower Basin tributaries should be taken into account in computing the amount of surplus which, under the Colorado River Compact, is to be used for meeting the treaty commitment. If the Lower Basin tributaries share the burden, it would lessen the Upper Basin's share of the treaty obligation, thereby making available more Upper Basin water for oil shale development (or other) purposes.

In the drawn-out treaty negotiations, the original offer of the United States in 1929 was for one-half of the 1.5 million acre-ft, which was the amount used for irrigation and domestic purposes by Mexico from the Colorado River in 1928.[42] However, the treaty covers three rivers: the Colorado River, the Rio Grande, and the Tijuana River. It is said that powerful political forces in Texas, desirous of getting a maximum amount of Rio Grande water for Texas agriculture, effectively bartered away "extra" Colorado River water to get additional Rio Grande water under the treaty.* The result is that the United States, contributing approximately 30 percent of the flow of the Rio Grande, under the treaty takes about 50 percent, while Mexico, contributing virtually nothing to the flow of the Colorado, takes roughly 10 percent of the average annual flow of the Colorado River. From a quantity standpoint, considering these two major rivers, the figures are shown in Table 19-2.

Table 19-2

FLOWS AND ALLOCATIONS IN THE COLORADO RIVER
AND THE RIO GRANDE
(million acre-ft)

River	Approx. Yearly Flow	U.S. Contribution	Mexican Contribution	U.S. Allocation	Mexican Allocation
Colorado	15	15	0	13.5	1.5
Rio Grande	2	0.67	1.33	1.0	1.0

Thus, the United States contributes a total of 15.67 million acre-ft per year and receives 14.5 million acre-ft in allocations, while Mexico

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*As a matter of interest, from Ft. Quitman, Texas, to the Gulf of Mexico, 70 percent of the Rio Grande's water originates in Mexico (Reference 42, p. 375).

contributes 1.33 million acre-ft per year and receives 2.5 million acre-ft per year.

Although the Colorado River will soon be overallocated from the U.S. standpoint alone, it is practically impossible that any diplomatic adjustments will be made to the amounts of those obligations. In the first place, the parties have come to rely on the provisions of the treaty; for example, Mexico uses its Colorado River water to irrigate 450,000 acres in the Mexicali Valley, a field cultivation valued at $200 million.[42] Second, now that Mexico has discovered significant quantities of oil, there will be a desire in Washington to preserve access to this oil as a hedge against future Arab (and other) embargoes.

Recent action in Washington reinforces this good faith commitment. In the Colorado River Basin Project Act,[43] Congress addressed the issue of projected water shortages, specifically mentioning the augmentation possibilities of desalination, weather modification (mountain snowpack augmentation) and interbasin transfers. With respect to such augmentation, Congress declared that

> The satisfaction of the requirement of the Mexican Water Treaty from the Colorado River constitutes a national obligation which shall be the first obligation of any water augmentation project...authorized by Congress.*

Still further evidence of the national commitment followed Mexican complaints about the poor quality of the water it was receiving. After discussions were held at the head-of-state level and lower diplomatic levels, Congress passed a law[44] aimed at decreasing the salinity

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*The figure used in the Act is 2.5 million acre-ft which represents the 1.5 million acre-ft Treaty obligation plus 1.0 million acre-ft for calculated Basin losses in supplying the Treaty amount at the border (Reference 42, Section 202).

of the Colorado River so that the quality of the water received by Mexico will be equal to (or better than) that found in the lower main stem of the river.*

Both of these treaty-related actions have implications for the water-for-energy picture. With respect to augmentation, whatever water quantities are provided will be a dividend; the extra water will be a "bonanza" addition to the river's total flow while the amount dedicated to meeting the Mexican Treaty obligation will remain constant. The net increase represents additional water for energy development (or other) purposes. With respect to the water quality issue, until the desalination plant provided for in the legislation is built and comes on-line, low-salinity water is to be released upstream at federal water storage locations to dilute the high-salinity water heading for the border. Water for dilution will come "off the top" of the available water supply of the Colorado system as a federal obligation--reducing the net amount available for allocation under the compact and state law formulas.

9. The Federal Government as a Disburser of Water

The Reclamation Act of 1902[45] provided authority and funding for the construction of storage and diversion facilities to provide water for irrigating semiarid lands, thereby "reclaiming" the lands from their near-desert condition. Later amendments broadened the uses to which the water could be put, such as municipal and industrial uses, and provided for production and sale of electrical energy in conjunction with reclamation projects.[46]

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*This diplomatic and political action made moot the legal question of whether or not the 1944 treaty addressed the issue of water quality.

In 1967, the Bureau of Reclamation of the Department of the Interior initiated a program under which it planned to sell water from the Boysen* and Yellowtail† Reservoirs to industrial users for industrial purposes. Table 19-3 shows the status of these industrial water sales.

On October 16, 1973, the Environmental Defense Fund and others filed suit in U.S. District Court in Billings, Montana, to declare the water contracts null and void and to put a halt to the industrial water marketing program. Defendants in the original lawsuit included the Secretary of the Interior, the Army Corps of Engineers, the Commissioner of the Bureau of Reclamation, and others. The suit has been amended and parties to the suit have been added, but basically the stage is set for a probable trial in late 1975.

The plaintiffs maintain, inter alia, that[47]

- Both Boysen and Yellowtail Reservoirs were authorized by Congress for the exclusive purposes of providing water for agricultural irrigation, hydroelectric power, flood control, silt control, and supplementation of stream flows.
- Defendants have failed to provide water for agricultural irrigation purposes from these reservoirs.
- Defendants plan to sell to industry 697,000 acre-ft of water annually from Yellowtail which exceeds its usable storage capacity.

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*The Boysen Reservoir is in Wyoming on the Wind River, a tributary to the Bighorn and Yellowstone Rivers. Completed in 1952 by the Bureau of Reclamation, it has a total capacity of 952,400 acre-ft of water, of which 549,900 is usable.

†The Yellowtail Reservoir lies on the border between Wyoming and Montana on the Bighorn River. This Bureau of Reclamation project was completed in 1967, and has a capacity of 1,375,000 acre-ft of water of which 613,700 is usable.

Table 19-3

INDUSTRIAL WATER CONTRACTS
BOUSEN AND YELLOWTAIL RESERVOIRS

Purchaser	Contract Date	Water To Be Used In	Acre-ft Per Year Sold
Yellowtail Reservoir			
Kerr-McGee Corp.	11/09/67	Unspecified	50,000
Shell Oil Co.	11/22/67	Unspecified	28,000
Humble Oil and Refining Co. (now Exxon Corp.)	12/14/67	Unspecified	50,000
Peabody Coal Co.	5/24/68	Montana	40,000
Reynolds Mining Corp.	6/19/69	Wyoming	50,000
International Geomarine Corp.	6/20/69		
-assigned to Coal Conversion Corp.	7/13/70		
-assigned to John S. Wold, Casper, Wyoming	8/25/71	Wyoming	50,000
Gulf Mineral Resources Co. (now Gulf Oil Corp.)	3/02/70	Montana	50,000
Peabody Coal Co.	5/22/70	Montana	40,000
Colorado Interstate Gas Co.	9/04/70	Wyoming	30,000
American Metal Climax, Inc. (Ayrshire Coal Co. Division)	1/20/71	Wyoming	30,000
Panhandle Eastern Pipe Line Co.	1/11/71	Wyoming	30,000
Shell Oil Co.	2/10/71	Montana	20,000
Norsworthy & Reger, Inc.	3/01/71		
-assigned to Westmoreland Resources	7/22/71	Montana	30,000
Norsworthy & Reger, Inc.	4/21/71	Wyoming	50,000
Cardinal Petroleum Co.	5/07/71	Wyoming	50,000
Yellowtail Reservoir Subtotal			623,000
Boysen Reservoir			
Sun Oil Co.	8/15/69	Wyoming	35,000
Total Yellowtail, Boysen Sales			658,000

Source: Reference 47.

- Defendants have also received applications from industrial firms and other nonagricultural entities for water option contracts covering an additional 1,281,000 acre-ft of water per year as follows:

Acre-ft	To Be Diverted From
431,000	Yellowtail and Boysen Reservoirs
630,000	Unspecified locations on Wind-Bighorn-Yellowstone River System
220,000	Powder River
1,281,000	Total Additional Applications

- Other major appropriations of water from the Yellowstone River and tributaries have been made by industry, without recourse to the U.S. Government, totalling in excess of 1,000,000 acre-ft of water per year.
- In violation of federal law, defendants have not determined rights of existing water users; determined future agricultural water needs in the region; determined availability of alternative water supplies; required industrial water users to employ best available water conservation techniques; analyzed alternative sources of energy supply; or adequately analyzed any alternative course of action other than maximum U.S. Government promotion and subsidy of maximum private industrial and energy development.

The averments continue, but the point is very clear: is this action on the part of executive agencies of the U.S. Government ultra vires, i.e., is it in fact not authorized by, or even in derogation of, laws passed by Congress? The question in the Yellowstone Basin will be answered by the District Court (and the Appeals Courts), but a look at congressional intent in the Colorado River Basin is enlightening.

The Colorado River Basin Project Act of 1968, which authorized the Central Arizona Project, states that:

> ...long-term contracts relating to irrigation water supply shall provide that water made available thereunder may be made available by the Secretary [of the Interior] for municipal or industrial purposes....[48]

The legislative history of the Act elaborates on this section:

> The provision for conversion of irrigation water supply to municipal and industrial uses was included so that it would be possible to progressively increase the amount of water available for municipal and industrial supply as the needs for these uses increase.[49]

It is particularly interesting that this inclination on the part of the Congress toward municipal and industrial uses took place five years before there was an "energy crisis." It is very likely that Congress will observe the above-described litigation in the Yellowstone River Basin. If the ultimate outcome of the suit supports the principal argument of the plaintiffs--that the scope of the original authorizing legislation, dating back to 1902, does not provide for industrial use of reclamation water--Congress may move quickly to amend that legislation so that water for energy development is available from the Boysen and Yellowtail storage projects. However, at that juncture Congress will have to deal with the other value-laden issues in the suit. This will require an open discussion, at the national level, of the tradeoffs between agriculture and energy development for this pristine but increasingly visible region.

Another reclamation-related issue is the degree to which the federal reclamation scheme operates in respect of the laws of the state in which the project is located. Section 8 of the Reclamation Act of 1902[50] provides:

> That nothing in this act shall be construed as affecting or intended to affect or to in any way interfere with the laws of any State or Territory relating to the control, appropriation, use, or distribution of water used in

> irrigation, or in any vested right acquired thereunder, and the Secretary of the Interior, in carrying out the provisions of this act, shall proceed in conformity with such laws....

As clear as this language may appear, the courts have interpreted it in recent years in a way that gives great flexibility to federal action. Thus, in Ivanhoe Irrigation District v. McCracken[51] the U.S. Supreme Court said, in regard to Section 8 of the Act:

> It merely requires the United States to comply with state law when, in the construction and operation of a reclamation project, it becomes necessary for it to acquire water rights or vested interests therein.*

In addition, in City of Fresno v. California[52] the Court said:

> The effect of Section 8...is to leave to state law the definition of the property interests, if any, for which compensation must be made [under the federal government's constitutional obligation to compensate for the taking of property.]†

The sum of these two cases would indicate that Section 8 applies only to the acquisition of waters for a reclamation project in a given state and not to the distribution of those waters. In the landmark case of Arizona v. California, the Court again considered the effect of Section 8 and affirmed the concept that state law can have no control over the issue of reclamation water distribution:

> [Where Congress has] undertaken a comprehensive project for the improvement of a great river and for the orderly and beneficial distribution of water, there is no room for inconsistent state laws....

---

*Reference 51, p. 291.

†Reference 52, p. 630.

The Court went on to say that no water could be had under the Boulder Canyon Project other than through contract with the federal government's designated agent, the Secretary of the Interior.

If Section 8 of the Reclamation Act leaves only the acquisition of water for reclamation projects to state law, it is an open question as to the interplay of federal water rights under the navigation servitude and the reservation doctrine vis-á-vis the Section 8 provisions. In an analysis of the broad federal power over water, developed earlier in this paper, it was concluded that the federal power to acquire water was virtually unlimited. If that is the case, the combined powers of acquisition and distribution would appear completely vested in the Congress. A major problem is that this result has been reached in piecemeal fashion through judicial decisions culminating in Arizona v. California.[21] Juxtaposing the Boysen/Yellowtail and Boulder Canyon situations, it may evolve that the Supreme Court will be constrained to find different national purposes for different major river basins--the encouragement of energy development in the Colorado River Basin but not in the Yellowstone Basin. All of this calls for clarification and positive statements by the Congress on the "details" of our unstated national energy policy.

10. Indian Claims to Western Water

a. The Problem

A factor in the quest of water for energy development in the West is the ultimate water demand likely to be made by the many Indian reservations through or near to which flow watercourses feeding the Yellowstone and Colorado Rivers (Figure 19-1). A serious problem does exist as shown by the following situation.

In February 1973, John Love Enterprises received a permit from the state of Wyoming to construct a $4.3 million water reservoir

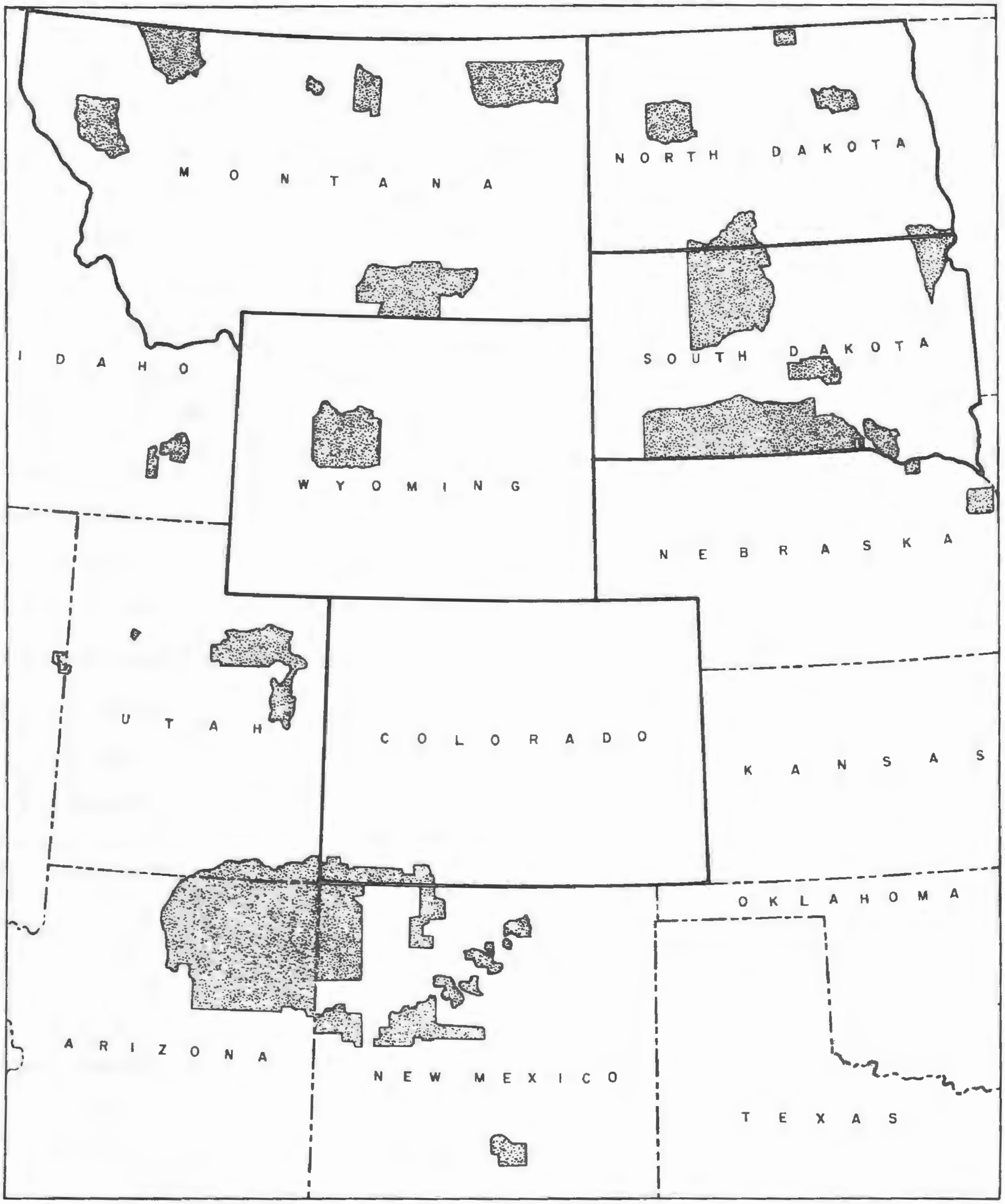


FIGURE 19-1. INDIAN RESERVATIONS IN THE COAL- AND OIL-SHALE-RICH REGIONS OF THE WEST

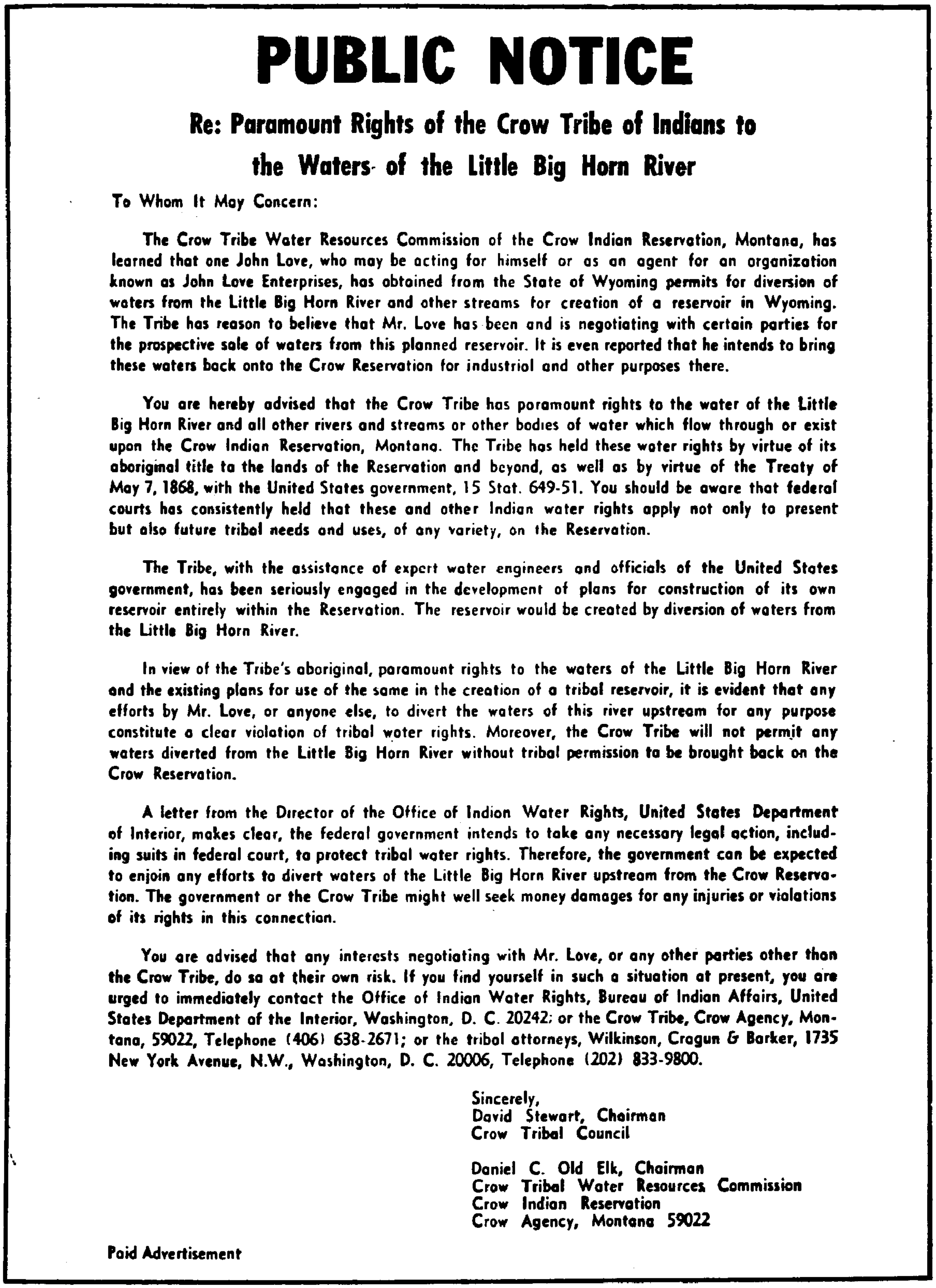
and pipeline facility for industrial and commercial purposes in the Powder River Basin. The amount of water was 42,500 acre-ft to be drawn from the Little Big Horn River, which feeds the Bighorn River and thence the Yellowstone. The Crow Indians of Montana, through whose reservation the Little Big Horn flows, have protested the proposed appropriation through an announcement published in several newspapers (Figure 19-2). The Indians warned that "...the Crow Tribe has paramount rights to the water of the Little Big Horn River and all other rivers and streams or other bodies of water which flow through or exist upon the Crow Indian Reservation, Montana,"[53] The announcement went on to say that anyone negotiating for water from the proposed project would do so "at their own risk" (Figure 19-2). In other words, mere compliance with state law might not be enough for John Love Enterprises to be assured of the water right it sought.

There is ample authority for the position taken by the Indians, as will be demonstrated. The basic questions in an analysis of Indian water rights are threefold:

- What is the theory on which the rights are based?
- What is the measure of the right? (i.e., the quantity of water).
- What is the relationship of the Indian rights to water rights administered under state law?

b. Theory of Indian Water Rights

The key to Indian water rights is a 1908 U.S. Supreme Court case, which produced what is widely known as the "Winters Doctrine."[17] The facts of the case reveal a dispute between Indians of the Fort Belknap Reservation and non-Indian appropriators of waters of the Milk River, a nonnavigable Montana waterway. The Fort Belknap Reservation was created in 1888 by a treaty between the Indians and the United



PUBLIC NOTICE

Re: Paramount Rights of the Crow Tribe of Indians to the Waters of the Little Big Horn River

To Whom It May Concern:

The Crow Tribe Water Resources Commission of the Crow Indian Reservation, Montana, has learned that one John Love, who may be acting for himself or as an agent for an organization known as John Love Enterprises, has obtained from the State of Wyoming permits for diversion of waters from the Little Big Horn River and other streams for creation of a reservoir in Wyoming. The Tribe has reason to believe that Mr. Love has been and is negotiating with certain parties for the prospective sale of waters from this planned reservoir. It is even reported that he intends to bring these waters back onto the Crow Reservation for industrial and other purposes there.

You are hereby advised that the Crow Tribe has paramount rights to the water of the Little Big Horn River and all other rivers and streams or other bodies of water which flow through or exist upon the Crow Indian Reservation, Montana. The Tribe has held these water rights by virtue of its aboriginal title to the lands of the Reservation and beyond, as well as by virtue of the Treaty of May 7, 1868, with the United States government, 15 Stat. 649-51. You should be aware that federal courts has consistently held that these and other Indian water rights apply not only to present but also future tribal needs and uses, of any variety, on the Reservation.

The Tribe, with the assistance of expert water engineers and officials of the United States government, has been seriously engaged in the development of plans for construction of its own reservoir entirely within the Reservation. The reservoir would be created by diversion of waters from the Little Big Horn River.

In view of the Tribe's aboriginal, paramount rights to the waters of the Little Big Horn River and the existing plans for use of the same in the creation of a tribal reservoir, it is evident that any efforts by Mr. Love, or anyone else, to divert the waters of this river upstream for any purpose constitute a clear violation of tribal water rights. Moreover, the Crow Tribe will not permit any waters diverted from the Little Big Horn River without tribal permission to be brought back on the Crow Reservation.

A letter from the Director of the Office of Indian Water Rights, United States Department of Interior, makes clear, the federal government intends to take any necessary legal action, including suits in federal court, to protect tribal water rights. Therefore, the government can be expected to enjoin any efforts to divert waters of the Little Big Horn River upstream from the Crow Reservation. The government or the Crow Tribe might well seek money damages for any injuries or violations of its rights in this connection.

You are advised that any interests negotiating with Mr. Love, or any other parties other than the Crow Tribe, do so at their own risk. If you find yourself in such a situation at present, you are urged to immediately contact the Office of Indian Water Rights, Bureau of Indian Affairs, United States Department of the Interior, Washington, D. C. 20242; or the Crow Tribe, Crow Agency, Montana, 59022, Telephone (406) 638-2671; or the tribal attorneys, Wilkinson, Cragun & Barker, 1735 New York Avenue, N.W., Washington, D. C. 20006, Telephone (202) 833-9800.

Sincerely,
David Stewart, Chairman
Crow Tribal Council

Daniel C. Old Elk, Chairman
Crow Tribal Water Resources Commission
Crow Indian Reservation
Crow Agency, Montana 59022

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FIGURE 19-2. CROW INDIAN NEWSPAPER ANNOUNCEMENT

States. Subsequent to the treaty, and before the Indians put the water to use, Winters and other non-Indians, at a point upstream from the reservation, diverted the waters of the Milk River for their own use. The United States, as trustee and on behalf of the aggrieved Indians, filed suit to enjoin the upstream appropriations.

The Court held that, although not explicitly mentioned in the documents creating the Fort Belknap Reservation, there existed an implied reservation of rights to the use of waters that rise on, traverse, or border on the Indian land, with a priority dating from the time of creation of the reservation by treaty. The language of the Court has led to two interpretations of the source of the right. One line of reasoning argues that with regard to Indian reservations created by treaty,* water rights were retained by the Indians at the time the treaty was made. Furthermore, so the reasoning goes, the documents were silent on the question because there was no intent on the part of the Indians to transfer the water rights.† The alternative view (and apparently the view of most legal writers) holds that the water rights were in fact transferred, but that the federal government, under its own powers, "reserved" an amount of water from proximate streams to support an agricultural existence for the Indians. In the case of <u>Arizona v. California</u>,[17] in which the Court approved water allocations to various Colorado River Basin Indian reservations, the Court alluded to "...the broad powers of the United States

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*Some Indian reservations were created by Executive Order and Act of Congress. For example, the Northern Cheyenne Reservation was created by Executive Order on November 26, 1884. The Fort Peck Reservation was created by Act of Congress on May 1, 1888.

†"...(T)he treaty (in <u>Winters</u>) was not a grant of rights to the Indians, but a grant of rights from them--a reservation of those not granted." (Reference 55)

to regulate navigable waters under the Commerce Clause and to regulate government lands under Act 4, Section 3 of the Constitution."[54] The Court stated that Winters was good law, and that as the United States government did in that case it did here--reserve water rights for the Indians effective as of the time the Indian reservations were created. The court did not directly answer the question of the source of the water right itself (i.e., aboriginal rights, reserved by the Indians and therefore reserved by the federal government versus rights reserved by the federal government as a government gesture to enable the purposes of the Indian enclaves to be fulfilled). To this date the issue has not been directly litigated.

Nevertheless, whatever the source of the right, case law and legal scholars are in agreement that there is an Indian water right associated with each reservation, and the priority of that right is at least as old as the reservation itself.

c. Measurement of Indian Water Rights

The measurement of the right is related to which of the above sources the courts eventually recognize. In Arizona v. California,[21] the U.S. Supreme Court was dealing with Indian reservations located on the "hot, scorching sands" of the lower Colorado River Basin. The Court held that the amount of water reserved is to be measured by the irrigable acreage of the Indian reservations. The National Water Commission points out that this may be acceptable for reservations on which farming and ranching are expected to take place, but that other reservations better suited for other types of occupations (e.g., hunting, fishing) may have water rights measured by different formulas.[8] In Winters,[17] the Court asked the following rhetorical question: "The Indians had command of the lands and the waters--command of all their beneficial use, whether kept for hunting, and grazing roving herds of stock, or turned to agriculture and the arts of civilization. Did they give up all this?" Even under the restrictive view of the measurement of Indian water rights, the phrase "command of the...waters...(which might be) turned to...the arts of civilization..." indicates that one possible measurement for reservations located in the coal and oil shale areas is an amount of water necessary for development of these industries. The view that Indian water rights are aboriginal and are to be used as the Indians desire, would certainly allow for the use of the water rights for energy development.[57] Remaining untested is the freedom with which these water rights could be sold for use at a greater distance from the reservation and whether such marketing constitutes an acceptable use of the water rights.

d. Relation of Indian Water Rights to Water Rights Administered Under State Law

Unfortunately for the states, no matter which "source" theory is propounded, Indian water rights are not subject to control under state allocation systems. If the rights are seen as flowing from Indian treaties with the United States, the treaties take precedence over state law under the supremacy clause of the U.S. Constitution.[58] The supremacy clause applies with equal force to remove the water rights from state jurisdiction where the rights stem from congressional and executive authoritative action. Thus, state laws regarding acquisition, vesting, priority, preference, and transfer of water rights have no applicability to Indian water rights.

Indian rights are similarly a thing apart from interstate compacts governing distribution of the water in interstate watercourses. The Yellowstone River Compact provides that "Nothing contained in this Compact shall be so construed or interpreted as to affect adversely any rights to the use of the waters of the Yellowstone River and its Tributaries owned by or for Indians, Indian Tribes, and their Reservations."[59]

Both the Colorado River Compact[60] and the Upper Colorado River Basin Compact[41] exclude Indian water rights from their consideration; that is, they are dividing up water left after Indian (and other federally protected) water rights are deducted from the respective river's total flow.

e. Scope of the Problem

Returning to the original problem of John Love Enterprises, it perhaps is clear just how open-ended the rights of the Crow Indians are. The Crow Reservation was formed by the Treaty of May 7, 1868. At best, only holders of vested rights prior to that date can be sanguine about the sanctity of their rights. State-approved water rights with a later date are subject to being denied by the higher priority of the Indian rights--and no compensation would be paid.

The oil shale region is just as vulnerable. The rights adjudicated in the case of Arizona v. California[21] amounted to 1 million acre-ft of water. A look at the number of Indian reservations on the Colorado River or on tributaries of the Colorado is instructive. With the exceptions of those noted, water quantities demanded and ultimately adjudicated for these reservations remain to be determined. Whatever the amounts, the water will come off the top of the available water in the Colorado River Basin, cutting down on the amounts remaining to the states for allocation for agricultural, energy development, municipal, recreational, and other uses.

Tributary	Indian Reservation
Green River	Uintah Ouray
Kanab River	Kaibab
San Juan River	Ute Mountain Southern Ute Jicarilla Navajo
Little Colorado River	Hopi Zuni (via Zuni River)
Gila River	San Carlos Fort Apache (via Salt River) Salt River (via Salt River) Ft. McDowell (via Salt River) Gila River Papago
Colorado River	Hualapai Fort Mojave* Chemehuevi* Colorado River* Ft. Yuma* Cocopah*

f. Conclusions

The open-ended nature of Indian water rights is unacceptable to all concerned. As one observer has noted:

> This uncertainty is not good for Indians; it is not good for non-Indians. It gives neither Indians nor non-Indians a clear title, and leaves as the source of Indian water rights a conglomerate mass of unconstrued treaties, agreements and executive

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*The total of these entries were adjudicated at 1,000,000 acre-ft in Arizona v. California.[21]

> orders. Indians occupy thousands of square miles in the Western states...The time for an orderly procedure which will end the Indian water right chaos has long passed.[61]

The National Water Commission believes that an across-the-board adjudication is not necessary. Instead, the Commission calls for the following:[62]

- Inventory of existing Indian water uses (to be placed in state records for informational purposes).
- Quantification of water necessary to accomplish a sound economic development plan for each reservation (responsibility to rest with the Secretary of the Interior).
- Quantification of rights wherever a non-Indian project is planned for a basin in which there is an Indian reservation (e.g., the John Love-Crow Indian situation).

When Indian rights are exercised in a basin whose water is completely appropriated, the Commission recommends that the Indians get the water, and that the persons who lose the water be compensated by the federal government as follows:[63]

- No compensation for projects developed after June 3, 1963, the date of the Arizona v. California. (Presumably, this case put the water developer on notice regarding Indian water rights.)
- Where possible, the federal government will provide substitute water from its own water rights.
- No compensation when developer had actual notice of a conflicting Indian claim at the time of development.
- No compensation for values created by federal subsidy.

Because the Yellowstone and Colorado Basins are virtually closed to further appropriations (especially the Colorado), it would seem that complete adjudication of Indian water rights in these regions would be desirable to create some certainty for future decisions.

C. Interstate Allocation of Water

1. Allocation by the Court

When a river flows across the boundaries of two states, or forms the boundary between two states, disputes can arise over the proper use of the waters by each of those states. When a case or controversy exists between two states, the U.S. Constitution provides that the U.S. Supreme Court shall have original jurisdiction.* This means that in such disputes the Supreme Court acts as a trial court, determining not only the law but resolving questions of fact as well.

A good example is the U.S. Supreme Court case of Wyoming v. Colorado.[64,65] Wyoming sued Colorado, and two Colorado corporations, to prevent a proposed diversion from their natural basins of the waters of the Laramie River, a nonnavigable interstate stream rising in Colorado and flowing into Wyoming. Colorado maintained that it could dispose of all the waters within its borders. The Court held otherwise:[66]

> The contention of Colorado that she as a state rightfully may divert and use, as she may choose, the waters flowing within her boundaries in this interstate stream, regardless of any prejudice that this may work to others having rights in the stream below her boundary, cannot be maintained. The river throughout its course in both states is but a single stream, wherein each state has an interest which should be respected by the other.

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*U.S. Constitution; Article III, Section 2. Federal law adds that the jurisdiction shall be exclusively in the Supreme Court in disputes between two states: United States Code; Volume 28, Section 1251(a). Note that because the trial is held in the highest court in the land, there is no opportunity for appeal.

The Court went on to say that the doctrine of prior appropriation would apply and the Court enjoined Colorado from diverting water from the Laramie River in a manner that would deny water rights held by prior appropriators in Wyoming. The Court determined the dependable flow of the river and then proceeded to make firm allocations to Colorado and Wyoming. The rule of law applied by the Court is known as the doctrine of "equitable apportionment."

The Supreme Court does not see itself as an expert in water allocations, and encourages what amounts to "out of court settlements" by the states. In this regard, the U.S. Constitution states that "No state shall, without the consent of Congress...enter into any agreement or compact with another state...."[67] However, Congress had made it clear that it also encourages the resolution of interstate water disputes by the concerned states themselves, and that approval of such agreements or compacts would be readily given.

2. The Colorado River Basin

The implications of Wyoming v. Colorado were not lost on the states of the Upper Colorado River Basin; they knew that there was much water development activity going on in the Lower Basin states, and they feared that an interstate application of the doctrine of prior appropriation to those developments in the Lower Basin could eventually deny any use of the Colorado River to the more slowly developing Upper Basin states. Accordingly, they sought an agreement with the Lower Basin states, which would preserve to them some water rights in the Colorado River Basin.[68] The result of those negotiations was the Colorado River Compact of 1922.[69,70]

The Colorado River Compact has the following features:

- Designates two basins--Upper and Lower with dividing point at Lee Ferry, Arizona (near Utah/Arizona border).
- Each basin to receive in perpetuity 7.5 million acre-ft of water per year.
- Lower Basin may increase its annual consumptive use by 1 million acre-ft in addition to the initial allocation of 7.5 million.
- Upper Basin is obligated not to deplete the flow at Lee Ferry below an aggregate of 75 million acre-ft for any period of 10 consecutive years.
- Within each basin, no specific allocation is made to individual states.
- The Compact does not apply to Indian water rights.

In the Boulder Canyon Project Act of 1928,[70] Congressional consent was given to the River Basin states

> to negotiate and enter into compacts or agreements, supplemental to and in conformity with the Colorado River Compact...for a comprehensive plan for the development of the Colorado River and providing for the storage, diversion and use of the waters of the River.

Representatives of the Upper Basin states of Wyoming, Utah, Colorado, Arizona, and New Mexico, in 1946, joined with President Truman's appointee in forming a Commission to develop what was to be the Upper Colorado River Basin Compact. The Commission worked for two years to produce the document. One of the major stumbling blocks was how to deal with water rights of the federal government and Indian tribes in the Basin. The Commission's difficulties in this regard are illustrated by the following response of the U.S. Department of the Interior to a Commission inquiry:[71]

> The Compact should not attempt, in our judgment, to define, limit, or in any manner to determine the powers of the United States in, over, or to the waters of the

> Colorado River System. The extent to which those powers should be exercised is a matter for determination by the Congress.

Recognizing that the federal landholdings are extensive in the Upper Basin, this significant water factor's absence weakened the impact of the final product. The applicable section of the resulting Compact contains the following critical language:[41]

> Nothing in this Compact shall be construed as
>
> (a) Affecting the obligations of the United States of America to Indian tribes;
>
> (b) Affecting the obligations of the United States of America under Treaty with the United Mexican States;
>
> (c) Affecting any rights or powers of the United States of America...in or to the waters of the Upper Colorado River System...;
>
> (d) ...;
>
> (e) Subjecting any property of the United States of America...to the laws of any state....

Other provisions of the Compact are

- Detailed apportionment
  - -- 50,000 acre-ft per year of consumptive use to Arizona.
  - -- Balance of consumptive use to Colorado (51.75%); New Mexico (11.25%); Utah (23%); Wyoming (14%).
- Existing rights must be satisfied out of apportionments.
- Apportionments only for beneficial use.
- Procedures for equitable curtailment in time of water shortage.
- Procedures for dealing with evaporation and seepage losses.
- Consumptive use of water by United States (and Indians) to be charged as a use by the state where made.

- Each state and the United States can acquire water rights or construct project works in a signatory state (subject to certain conditions).
- Power generation is "subservient" to agricultural and domestic uses.
- Failure of a state to use apportionment shall not constitute a relinquishment of such right.
- No prohibition on trans-basin (interbasin) transfers of water.

In addition to the aforementioned problem of unquantified federal and Indian water rights, there are energy development water problems between the lines of the two Colorado River Compacts. The initial problem lies in the use by the draftsmen of the Compact of the figure of 15 million acre-ft of virgin flow* at Lee Ferry, Arizona, as the average flow of the river for making allocations between the Upper Basin and the Lower Basin. From 1922 to 1967, the average virgin flow was only 13.7 million acre-ft.[72] Because the Lower Basin is guaranteed an average annual flow of 7.5 million acre-ft with the Upper Basin receiving the balance, the corresponding average annual flow available to the Upper Basin for these years was only 6.2 million acre-ft. When the Upper Colorado River Basin Compact percentage allocations are applied, the following figures result:

	Acre-ft
Arizona	50,000
Colorado (51.75%)	3,183,000
Utah (23.00%)	1,414,000
Wyoming (14.00%)	861,000
New Mexico (11.25%)	692,000

---

*"Virgin flow" is the water which, e.g., would flow by Lee Ferry if there were no man-made diversions of the River Basin.

The resulting allocation to Colorado is far less than that state's contribution to the flow of the River, estimated at 11.46 million acre-ft per year.[73] Of its total contribution, then, Colorado is allocated only 28 percent.

When these compacts were drawn up, it was not foreseen that large scale energy development in the national interest would take place in western Colorado. From the following statement of a Conservation District official, it is clear that the water squeeze on the state is not appreciated by Colorado:[74]

> It appears that Colorado is going to be asked to produce large amounts of both liquid and electrical energy with the largest percentage of both of them to be exported. But right now we are not really sure what our answer to that result will be....If Colorado is to be asked (and right now it is more like a demand) to furnish energy for the rest of the U.S., then it may be necessary to re-examine the allocations of the already limited Colorado River supplies....Colorado may be forced to prevent or limit the building of energy-exporting facilities in the future unless other states are willing to make some kind of agreement with Colorado to help us solve this problem.

But the other states in the Colorado River Basin have their own energy development, irrigation, and municipal growth water requirements. It is difficult to get more water out of a river by describing it differently--no new compact could perform that miracle. It would seem that allocations of values will be of equal importance with allocations of quantities; i.e., a reassessment of how a given amount of water should best be used. In this regard, the Colorado water official stated:[69]

> Colorado is pressing forward with planned irrigation projects; we are not willing to totally trade off our western Colorado agricultural base for the production of energy.

The answer, of course, is not to deal in "total trade offs," but to negotiate in a new and open manner national, regional, and state concerns and values.

3. The Northern Great Plains

There are two interstate rivers near the coal development region of the Northern Great Plains. These are the Belle Fourche River, rising in Wyoming and flowing into South Dakota, and--more significantly--the Yellowstone River, beginning in Wyoming, running through Montana and on into North Dakota. There are interstate compacts covering each of these rivers.

The Belle Fourche Compact of 1943 makes a division of the unappropriated waters of the Belle Fourche River Basin as follows:

South Dakota	90 percent,
Wyoming	10 percent.

The amount of water available to Wyoming is approximately 20,000 acre-ft per year,[75] not a major factor in the water for energy picture. What is of interest, however, it a comment made by the President of the United States in signing the legislation under which Congress approved the Compact.[76] Article XIV(c) contains the following language:

> The United States...will recognize any established use, for domestic and irrigation purposes, of the apportioned waters which may be impaired by the exercise of Federal jurisdiction in, over, and to such waters; provided that such use is being exercised benefically, is valid under the laws of the appropriate state and in conformity with this compact at the time of the impairment thereof, and was validly initiated under state law prior to the initiation or authorization of the Federal program or project which causes such impairment.

The Congressional act contained the same language through which the federal government was bowing toward existing state water rights vis-a-vis future federal projects. This clearly upset the Chief Executive:[77]

> In signing the Belle Fourche River Basin Compact Bill, I find it necessary to call attention...to the restrictions imposed upon the use of water by the United States. The procedure prescribed by the bill for the exercise of the powers of the Federal Government would not be entirely satisfactory in all circumstances, but the prospects in fact for the exercise of such powers in the Belle Fourche basin are not great. For streams where conditions are otherwise and there appears to be a possible need for Federal comprehensive multiple-purpose development or where opportunities for important electric power projects are present, I believe...(this)...Compact should not serve as a precedent. In such cases the compact and the legislation should more adequately reflect a recognition of the responsibilities and prerogatives of the Federal Government.

This statement strongly illustrates the latent federal water interest and power waiting in the wings. This tension and its ramifications were discussed in another section, but it is clear that these interstate compacts exercise little real constraint on federal water rights. Simply stated, the President is saying that interstate compacts should merely divide up--as between the signatory states--that water remaining after federal and Indian water interests are satisfied. Furthermore, the division will be subject to future federal and Indian water needs.

Interestingly enough, the Yellowstone River Compact of 1950 is stripped of the language which troubled the President. Significantly, U.S. "sovereignty" and "jurisdiction" over the subject waters are interjected into the Compact. Thus:[78]

> Nothing in this Compact shall be deemed to impair or affect the sovereignty or jurisdiction of the United States of America in or over the area of waters affected by such Compact...,(or) any rights or powers

> of the United States of America...in and to the use of the waters of the Yellowstone River Basin....

By way of emphasis, in the legislation approving the Compact, Congress reserved the right to amend the Compact, presumably unilaterally, or to repeal it entirely.[79] In this regard, the U.S. Supreme Court has acknowledged that the Congress is not bound by its approval of an interstate compact.*

Notwithstanding this profound weakness of the instrument, the features of the Yellowstone River Compact are as follows:

- Existing rights are confirmed as of January 1, 1950.
- Unappropriated waters of interstate Yellowstone tributaries are apportioned†

Tributary	Wyoming (%)	Montana (%)
Clarks Fork	60	40
Bighorn	80	20
Tongue	40	60
Powder	42	58

- Each of the Compact states (Wyoming, Montana, North Dakota) may divert and impound water in another state for its own use.
- Tributaries arising entirely in one state are wholly allocable by that state.
- Diversion of water out of the Yellowstone subbasin is prohibited unless approved by all three signatory states.

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*That is, Congress can legislate in a manner inconsistent with its prior approval of a compact (Reference 80).

†There are no interstate tributaries running into North Dakota; hence, no tributary water allocation is made to North Dakota.

Energy development in the arid Powder River Basin coal fields, lying north and south of Gillette, Wyoming, will require large amounts of water. Much thought and planning have gone into interbasin transfers of water to the Powder River Basin. As noted above, for the Yellowstone subbasin, this is prohibited unless all three states approve of the transfer.[81]

If consent should not be forthcoming, there is another alternative. Because neither the Colorado River Compact, nor the Upper Colorado River Basin Compact restrict interbasin transfers, Wyoming can divert water from its Upper Colorado River Basin share.* This interbasin transfer would bring water from the Green River Basin, a headwater tributary of the Colorado River eastward across the state to the Powder River Basin.

D. State Systems for Water Allocation in the West

1. General Systems

Because of the generally arid conditions in the West, a special legal doctrine evolved, which allowed water to be physically moved away from the source of the water (river, lake) to a place where it could be put to use. This represented a departure from the riparian law of the water-rich eastern United States inherited from water-rich England--the riparian doctrine gives equal rights to the waters of a river or stream to all whose lands border on the river or stream. Each user is entitled to a "reasonable" amount, but under no circumstance may the water be used

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*The Wyoming share is 14 percent. Typically, then 14 percent of 6.2 million acre-ft gives Wyoming 861,000 acre-ft for allocating within the state. Of this amount "...the feasibility of exporting 100,000 to 200,000 acre-ft is now under consideration." Note: As used here, "Export" refers to the interbasin transfer of this amount of water from the Upper Colorado Basin to the Powder River Basin (Reference 7.3, p. 40).

outside of the basin of the waterway. The riparian doctrine provides that the water right exists whether or not it is exercised, and the right is not forfeited by nonuse.

The appropriation doctrine of the West appears in the early California case of Irwin v. Phillips,[82] in which two gold miners were squabbling over the right to use the waters of a stream. The court's decision "announcing" the doctrine was based on the need to protect the rights of those...

> ...who by prior appropriation have taken the waters from their natural beds, and by costly artificial works have conducted them for miles over mountains and ravines, to supply the most important interests of the mineral region...(Where, as here)...two rights stand upon an equal footing, when they conflict they must be decided by the fact of priority....

The doctrine's major features are as follows:

- A right to the use of water is created by a diversion of the water from a stream for a beneficial use.
- The first to so acquire the right shall have a priority in law: "first in time is first in right." (In the event of a shortage, the last to divert and make use of the stream is the first to have his water supply shut off.)
- Water can be used at any location without regard to the distance of the use from the stream.

With some embellishments over time, such as the feature of relating back,* this approach stood as the water law of the West. No government

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*The priority of a right is established by commencing work on an appropriation. If the work is continued with due diligence, then upon completion, the priority of the completed right relates back to the time the work was commenced.

approval was required to establish the water right. Subsequent statutes merely confirmed the court developed doctrine.*

2. The Need for Certainty of Water Rights

Although it fully embraced the doctrine of prior appropriation, Wyoming legislatively instituted a permit system to improve the record keeping of water rights, thereby injecting more certainty into the status of the water rights of the individual. Thus, anyone desiring to appropriate water in Wyoming must first make application to the state engineer--diversion of water without a permit from the state engineer is a punishable offense.[83] The engineer must approve the application if he finds that the proposed use is a beneficial use, that the proposed use will not impair the value of existing rights, and that the proposed use is not otherwise detrimental to the public welfare.[84]

Wyoming went to the permit system in 1890--Montana in 1974. Montana was responding to increasing demand for a system that would provide conclusive determination of existing rights.[85] A 1972 Montana constitutional amendment[86] prodded the legislature into action. The new law's declaration of policy and purpose is instructive:[87]

> The legislature declares that this system of centralized records recognizing and establishing all water rights is essential for the documentation, protection, and preservation and future beneficial use and development of Montana's water....

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*For example, the Colorado constitution provides that..."(t)he right to divert the unappropriated waters of any natural stream to beneficial uses shall never be denied. Priority of appropriation shall give the better right..." (Article XVI, Section 6. See also Wyoming Laws 1869, Chapter 8 and Chapter 22).

The law requires "...each person claiming an existing right...to file a declaration...."[88] The court then adjudicates the status of existing decrees. Based on its final decree, individual certificates of water rights are issued, with copies filed at the county clerk's office.[89]

Because Colorado continues not to be a permit-system state, record-keeping shortcomings have created problems. A random search of court decrees was less than a satisfactory way for would-be appropriators to discover existing senior rights to a given stream. To remedy this, the Colorado legislature in 1969 called for

> ...a tabulation in order of seniority of all decreed water rights and conditional water rights...Such tabulation shall describe each water right and conditional water right by some appropriate means and shall set forth the priority and amount thereof as established by court decrees.[90]

The tabulation was to be published, corrected, and published in final form by October 1971; however, special legislative action moved this deadline to October 1972. The legislation said that in November 1974 (and every two years thereafter) the latest tabulation must be presented by the state engineer to the water judge for public hearings:

> A copy of (the court's) judgment and decree shall be filed with the state engineer (for placement in his records to show) the determinations therein made as to priority, location, and use of...water rights and conditional water rights....[91]

It should be emphasized that the above procedure does not alter one's right under the Colorado constitution to appropriate water. This is accomplished by diverting the water and putting it to beneficial use.[92] However, the tabulation and adjudication procedure does affect the priority of one's appropriative rights. Thus, failure to come forward at the time of the tabulation and adjudication could result in a senior right (relatively speaking) slipping to the most junior right of all. The right still exists, but in time of water shortage it will be the first one cut off.

These mechanisms provide a degree of certainty and they go a long way toward reducing the number of "stale" or "paper" rights going unused. Included in the efforts of the states to eliminate such rights are abandonment provisions in the law. Thus, e.g., Montana law provides that

> If an appropriator ceases to use all or part of his appropriation right, or ceases using his appropriation right according to its terms and conditions, for a period of ten (10) successive years...there shall be a prima facie presumption that the appropriator has abandoned his right in whole or for the part not used.[93]

Wyoming uses a figure of five years after which time the water right is forfeited.[94] In Colorado, failure to use the water right for a period of ten years creates a rebuttable presumption of abandonment.[95]

Although designed to make available water that is going unused, the forfeiture statutes have the unintended effect of encouraging waste, in that a holder of a "dusty" water right might be encouraged to use the water profligately to avoid forfeiture of the right.[96]

The certainty of rights, discussed above, has a positive economic effect. Knowing what water is available and what the order of priority is, a potential investor (whether in irrigation or energy production) is in a much better position to make an investment decision.

3. Transfer of Water Rights

Where all the water available to the state is spoken for, either by absolute decreed rights or by conditional rights* as it is in Colorado, it becomes necessary to consider a transfer of the right from one type of use to another, e.g., from irrigation to the production of synthetic fuels. Such a transfer very likely would require a change in the place of use and a change in the point of diversion of the water.

The law in most western states allows such transfers, subject to the administrative procedures of the particular state involved. The delay and red-tape caused by some of those administrative procedures were points of criticism made by the National Water Commission in its 1973 Report.[97] The Commission stated that "...any person or organization having the right to use water should be entitled to transfer such right, and all statutes, judicial decisions, and administrative regulations to the contrary should be repealed."[98] An example of how transfer of water rights was thwarted may be seen in a Wyoming law, which made a water right appurtenant to the land benefiting from the right--"Water rights for the direct use of the natural unstored flow of any stream cannot be detached from the lands, place or purpose for which they are acquired...."[99]

This situation was changed, perhaps as a result of the National Water Commission's recommendation, by a 1974 Wyoming law which allows the change

> provided that the quantity of water transferred--shall not exceed the amount of water historically diverted under the existing use, nor exceed the historic rate of diversion..., nor increase the historic amount consumptively used..., nor decrease the historic amount

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*See footnote on page 19-46

> of return flow, nor in any manner injure other existing lawful appropriators.[100]

Notwithstanding the intentions of the new law, administrative convolutions continue. An example of the red-tape involved in a transfer of rights is provided by the Panhandle Eastern Pipe Line Company. Panhandle proposed to purchase water rights with an 1884 priority date from a ranch on the North Platte River and to convert the use from irrigation to industrial (coal gasification). The proposal also included a one-hundred-mile change in the point of diversion. The Wyoming administrative authority, the Board of Control, denied the requests on several grounds:[101]

- Failure to show that holders of other rights would be protected from injury.
- Unresolved discrepancies in the accounting of all the water rights involved.
- The distance involved and the time lag between the proposed point of diversion and the present point of diversion made it impossible to assess general compliance with the Supreme Court decree requirements in Nebraska v. Wyoming (1945) regarding administration of the North Platte River.

Panhandle had to resort to the Laramie County District Court, which reversed the Board's findings and sent the proposal back for reconsideration. Panhandle finally prevailed, with the Board granting a permit to divert 26,500 acre-ft of water with a stipulation that diversions were not to deprive any Wyoming water right holder of previously entitled North Platte River water. This exhausting, costly, and time-consuming process clearly has a chilling effect on the free transfer of water rights.

Montana law on transfer of water rights allows a change if it is determined "...that the proposed change will not adversely affect the rights of other persons."[102] In Colorado, unrestricted transfer is allowed where no other right is injured.[103] The kind of injury contemplated is seen in the situation where an upstream irrigation appropriator "A" sells his water right to a synthetic fuel producer "B" who contemplates a total consumptive use of that water. Such use would in fact reduce the flow of water as seen by a downstream appropriator "C" because some of the water contained in the water right of "A" historically returned to the stream after performing the irrigation function. Thus, the best "B" can hope for is "A's" water right scaled down by the amount of return flow customarily seen by "C."

To allow time to check for injury to other appropriators, Colorado law allows for a trial period after the change. Thus, the change is allowed·

> subject to reconsideration by the water judge on the question of injury to the vested rights of others during any hearing...in the (subsequent) two calendar years...[104]

4. Interbasin Transfers

The transfer of a water right to a different place of use can logically be extended to rather great distances. The institutional resistance to such moves on an interstate basis is discussed in another section, but even within a given state the issue of interbasin transfers creates strains on the system. Generally, under the principles of the appropriation doctrine, the basin of origin has no right to receive the natural flow of the basin's streams.[105] Thus water in one basin may be appropriated and put to beneficial use in another basin. A prime example of this is the use by the "front range" metropolitan areas of Denver and Fort Collins, Colorado, of water flowing on the "other" side of the Rocky Mountains, on what is called the "western slope." About one-half of Denver's water comes from such transmountain diversions.[106] The water demand of cities is typically given a statutory preference over other uses, which means that although the priority may be later in time, the allocation system will supply these needs first.[92,99] In Colorado, preferred users are given the power of condemnation over other users, thus--with payment of just compensation--a growing Denver could condemn an energy company's absolutely vested water right on the western slope and transfer the water over the mountains for its municipal uses.[107]

5. Conditional Decrees

Since many energy companies are holders of Colorado conditional decrees some discussion is necessary. As previously mentioned, the priority of a right is established by commencing work on an appropriation. The decree is conditioned upon (1) completion of the work accomplishing the diversion, and (2) application of the water to a beneficial use. When that is done, the decree becomes absolute and the priority of the completed right relates back to the time the work was commenced. To eliminate speculation in water rights, the law requires that the would-be appropriator exercise "due diligence" in his work to complete the diversion. Every second calendar year he must obtain a finding by the water referee that reasonable diligence has in fact been exercised. Otherwise the conditional decree (and its precious priority date) lapses.[108] This law means that those energy companies holding on to conditional decrees while their energy development plans crystalize must make some effort at actually constructing their water project. A similar squeeze is presented in the permit states of Montana and Wyoming. Montana law allows the administrative authority to establish a time limit

> for commencement of the appropriation works, completion of construction and actual application of the water to the proposed beneficial use. [The authority] shall consider the cost and magnitude of the project, the engineering and physical features to be encountered, and, on

> projects designed for gradual development and gradually increased use of water, the time reasonably necessary for that gradual development and increased use....[109]

For good cause, the time limit may be extended, but, in absence of such an extension, the permit and its priority date will be revoked if the work is not "commenced, prosecuted or completed" in the time allowed or if the water is not being applied to the contemplated beneficial use.[110]

Under Wyoming law, the state engineer must specify a time limit on the permit, not to exceed five years.[111] For good cause the time limit may be extended. Again, failure to comply may lead to revocation of the permit. This presents a dilemma for the energy company contemplating construction of a synthetic fuels plant; if the water project is completed, satisfying this statute, the permit may nevertheless be revoked if the water right thus perfected goes unused for a five-year period while construction is completed on the fuel plant. This is because of the abandonment provisions of the Wyoming water law previously discussed.[94]

6. Public Interest in Water

In its comprehensive study of water issues, the National Water Commission dedicated part of its effort to noneconomic or social values in water. The study concluded that the appropriation doctrine does not provide for protection and preservation of scenic, aesthetic, recreational, and environmental values. The Commission called upon the states for legislative action:[112]

- Reserving portions of streams from development and setting them aside as "wild rivers."
- Authorizing a public agency to file for and acquire rights in unappropriated water.

- Setting minimum stream flows and lake levels.
- Establishing environmental criteria for the granting of permits to use water.
- Forbidding the alteration of watercourses without state consent.

State action has been remarkably responsive. Colorado quickly passed legislation aimed at the in-stream values issue. One of the new laws eliminates the requirement of actual diversion to effectuate a valid appropriation, so that now the only requirement is "...the application of a certain portion of the waters of the state to a beneficial use."[113] Companion legislation gives to the state the opportunity to take advantage of the lack of a diversion requirement. The new law broadens the definition of the term "beneficial use"* to include appropriations by the state of minimum flows between specific points on natural streams and lakes "as are required to preserve the natural environment to a reasonable degree."[114,115] Elation by environmentalists may be premature, however, for the state is not given a preferential right of appropriation. Thus, if the state wishes to appropriate water to maintainin minimum flows, it must do so in the same manner as the nongovernmental water user. Recalling that Colorado's waterways are already overappropriated, it would seem that the only practical possibility of accomplishing the purposes of the legislation would be for the state to purchase the water rights of others. Whether accomplished by appropriation or by purchase, it is clear that this new water demand will cut further into any supply available for the synthetic fuels industry.

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*"Beneficial use" has not been specifically defined until these recent statutes. Whether a use was "beneficial" was typically handled on a case by case basis, with the main thread of the decision being seen in the question, "is it reasonable and economical, all things considered?"

A 1974 Wyoming law states that

> All water being the property of the state and part of the natural resources of the state shall be controlled and managed by the state for the purpose of protecting and assuring the maximum permanent beneficial use of waters within the state.[116,117]*

A caveat for energy companies is provided in a later paragraph:

> None of the water of the state either surface or underground may be appropriated, stored or diverted for use outside of the state or for use as a medium of transportation of mineral, chemical or other products to another state without the specific prior approval of the legislature on the advice of the state engineer.†[118]

The state of Montana has also responded to the recommendation of the National Water Commission that in-stream values are to be protected through state legal mechanisms. Montana law declares its purpose is

> to provide for the wise utilization, development and conservation of the waters of the state for the maximum benefit of its people with the least possible degradation of the natural aquatic ecosystems...[87]

To implement the state program, power is given to the state "...to reserve waters for existing or future beneficial uses or to maintain

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*"Beneficial use" includes, but it not limited to the following: municipal, domestic, agricultural, industrial, hydroelectric power and recreational purposes, conservation of land resources and protection of the health, safety and general welfare of the state of Wyoming.

†The Act goes on to give approval (subject to the decision of the state engineer) for up to 20,000 acre-ft per year of Madison formation well water for use in a coal slurry pipeline to carry coal from Wyoming to Arkansas (Reference 118, Section 1-10.5(c)).

minimum flow, level, or quality of water...."[119] After defining "beneficial use" in the Wyoming manner (domestic, municipal, agricultural, etc.) the law goes on to state that "...use of water for slurry to export coal from Montana is <u>not</u> a beneficial use" (emphasis added). This compares interestingly with the Wyoming provision on the subject. Wyoming says yes, if legislative approval is obtained, whereas Montana says no, period.

The legislative tools with which the mineral-rich states have equipped themselves will apparently make it harder for energy companies to get the amounts of water they need for mining and synthetic fuels production, and once obtained the use of the water will likely be constrained by the water quality goals explicitly contained in the language of the new laws.

7. <u>Pricing of Water</u>

It is said that cheap energy encouraged wastefulness, which led to energy shortages. A similar comment can be made about water. The National Water Commission has called for an abandonment of water subsidies which artificially make water appear to be cheap, and the Commission encourages a less inhibited system of water rights transfer.[120] Their position is that a free market for water will result in the evolution of true value reflecting the most productive economic use for the water.

Professor Charles J. Meyers, in a legal study done for the National Water Commission, made the following observation:[121]

> ...(W)hen criteria of allocation other than willingness to pay are used, it is very difficult to decide which uses (or users) of a resource will be most productive... The price system produces an unambiguous and usually quite satisfactory answer. The party in whose hands

> the property will be most productive is the party who values it most highly and is willing to pay the most for it.

Others are fearful of what can happen if water goes to the highest bidder. They point to the need for increased planning to avoid the tragedy of what free market land development did to Los Angeles.[122] The bidding is real. At the time that farmers were paying $20 per acre-ft for water, one energy company was prepared to pay up to $1200 per acre-ft to secure the use of the water for energy development.[123] "To an energy company, even a high price of water is a minor expense, both in terms of the other costs of energy production, and in terms of the profitability of the operation."[124] The price elasticity of water is illustrated in a study which revealed that doubling the price of water caused an 11.4 percent increase in the price of agricultural products, while the doubling raised the cost of electric power by only 1 percent.[125]

Thus, a totally free market could conceivably result in a "going rate" for water affordable only by energy companies--thereby eliminating other uses, such as agricultural, recreational, and environmental.

Under the protections built into the "beneficial use" provisions previously discussed under the section entitled Public Interests in Water, the necessary first-step tools exist to determine the equivalent economic values of these other water uses, and to create a politically, if not economically, well-balanced water allocation scheme. The result is analogous to the concept of comprehensive land use planning where zoning predetermines the land use balance--parks, industrial, residential, etc. The water supply would be "zoned" to create a politically acceptable distribution, but within those constraints, free and unfettered transfer of rights would be encouraged, with the highest bidder prevailing.

The shortcomings of the present system lie in the failure of the various legislatures to supply the "equivalent economic values" which the state engineer can use in judging appropriation applications.

8. Groundwater

While groundwater has been heralded by some as a great source of water for energy development, others have warned of the havoc that could result from an unstructured, haphazard use of this resource.

In his well-respected 1942 water law treatise, Wells Hutchins, pointed out that "...complete coordination of surface and ground waters... remains a most difficult (problem) owing to the invisibility of subterranean waters and the mass of data required to prove satisfactorily their origin, quantity, and movements."[126]

Groundwater hydrology, replete with misinformation, misunderstandings, and mysticism, "...has always been a favorite refuge for quacks and pseudoscientists...(and) practitioners of the willow branch or the brass welding rod."[127] Nevertheless, strict attention to the quantity and quality of underground water, especially in its interrelationship with surface water flows, is called for by two national study commissions.[128,129]

As long as there were sufficient supplies of surface water, the groundwater issue was not an important one. Accordingly, Western water law developed for the allocation of surface streams almost to the exclusion of consideration of groundwater disputes. The occasional groundwater controversy was handled with a separate set of rules taken from the common law. The general common law rule, inherited from England, provided that waters beneath the land are property of the landowner who may withdraw them irrespective of the effect on others. Because this produced a harsh result on neighboring property, two modified doctrines arose; the "reasonable use rule" stated that any use is subject to the similar rights of others who would be negatively affected by an unreasonable withdrawal; an extension of this rule became the "Correlative rights doctrine," which gave co-extensive and co-equal rights to adjoining landowners. The Western appropriation doctrine for surface waters was, in some cases, applied to groundwater giving the first person to put the water to beneficial use the senior right.

As water became more and more scarce in certain places in the West, the inadequacy of this treatment of groundwater resources was made clear. The initial corrective step was to draw distinctions between underground waters tributary to natural streams and those enclosed in impervious basins. The former were the first to be reexamined because wells that removed water from tributary groundwater, by definition, affected surface rights in the stream toward which the groundwater was moving. Hydrologically speaking, such tributary groundwater is a part of the stream it feeds.[130] Wyoming's groundwater law recognizes this, as follows:

> ...where underground waters and the waters of surface streams are so interconnected as to constitute in fact one source of supply, priorities of rights to the use of all such interconnected waters shall be correlated and such single schedule of priorities shall relate to the whole common water supply....[131]

Colorado law makes the important distinction between tributary and nontributary groundwater and applies the surface water appropriation rules to tributary water. Nontributary water is catalogued in designated groundwater basins for administration by a special commission.[132] A permit from this commission is necessary before a well may be drilled in a designated groundwater basin. The commission must deny the permit if there are no unappropriated waters in the basin, or if the proposed appropriation would unreasonably impair existing water rights from the source or would create unreasonable water waste.[133]

Wyoming law designates certain groundwater areas as "control areas" where any of the following circumstances exist:[134]

- The use of underground water is approaching a use equal to the current recharge rate.
- Groundwater levels are declining or have declined excessively.
- Conflicts between users are occurring or are foreseeable.
- The waste of water is occurring or may occur.
- Other conditions exist or may arise that require regulation for the protection of the public interest.

If there is an inadequacy of water in the designated control area, the state engineer may close the area to further appropriation, apportion a measured amount among the appropriators, shut down or reduce withdrawals by junior appropriators, specify a system of rotation of use, and for future permits--if any are granted--he may institute well spacing requirements.[135]

Montana simply includes groundwater in the statutes that allocate surface streams.[136] However, there is administrative power provided for regulating the construction, use, and sealing of wells to prevent the waste, contamination, or pollution of groundwater.[137]

A critical factor in the husbandry of groundwater resources is the "recharge rate"--the rate at which an underground basin replenishes itself after a given amount of water is withdrawn. In a truly impervious basin, the recharge rate may be zero. When one withdraws water in this situation, one is said to be "mining" the water resource. Like minerals, once it's gone, it's gone. The term "mining" is also applied to rechargeable basins where the rate of withdrawal is greater than the recharge rate. In this case, the water table lowers, allowing adjoining waters--which may be contaminated--to flow into the underground basin.

Demand placed on groundwater resources by energy companies has created political tensions in mineral rich areas. In a move still drawing hostile fire, Wyoming passed legislation providing up to 20,000 acre-ft of groundwater for use by Energy Transportation Systems, Inc., (ETSI).*[138] ETSI proposes to use the water for a coal slurry pipeline to carry Wyoming coal over 1,000 miles to power generating stations in Arkansas. The water is to come from the Madison limestone formation underlying northeastern Wyoming (and western South Dakota), brought up by wells drilled to a depth of 3,500 to 4,500 ft. According to the U.S. Geological Survey, the formation contains from 500 million to 1 billion acre-ft of water with an annual recharge rate of 100,000 acre-ft. Those legislators who voted for the measure approving the use of the water were apparently swayed by the cited recharge rate and by the claim that the water was highly saline and therefore of little use for other purposes. Both of these factors are now coming under attack. The recharge rate is under continuing study by the state,† and some Madison formation water brought up near Gillette, Wyoming, has proved to be of higher quality than that under present use for municipal purposes.[139] The matter at this point is unresolved, but the situation is illustrative of the problems faced by all the parties concerned. As a final note, because the Madison water table (which also underlies South Dakota) may be detrimentally lowered, South Dakota is contemplating a suit against Wyoming in the United States Supreme Court to halt the proposed action.[140]

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*The legislation makes this particular use subject to the approval of the state engineer.

†See, for example, "Underground Water Supply in the Madison Limestone," Wyoming State Engineer's Office, Cheyenne, Wyoming, December (1974).

9. State Action Generally

The power of the states to control the waters flowing through or underlying their lands, vis-a-vis federal power, is discussed at length in another section. However, it is worth observing at this point that the states want as much control as they can get (preferably complete control), and, also, that they will use it. In 1974, the Montana legislature passed a sweeping three-year moratorium on further water development in the Yellowstone River Basin. The legislature's statement of policy behind the action is as follows:* [141]

> The legislature, noting that appropriations have been claimed, that applications have been filed for, and that there is further widespread interest in making substantial appropriations of water in the Yellowstone River Basin, finds that these appropriations threaten the depletion of Montana's water resources to the significant detriment of existing and protected agricultural, municipal, recreational, and other uses, and of wildlife and aquatic habitat. The legislature further finds that these appropriations foreclose the options to the people...to utilize water for other beneficial purposes, including municipal water supplies, irrigation systems, and minimum flows for the protection of existing rights and aquatic life. The legislature...declares that it is the policy of this state that before these proposed appropriations are acted upon, existing rights to water in the Yellowstone Basin must be accurately determined for their protection, and that reservations of water within the basin must be established as rapidly as possible for the preservation and protection of existing and future beneficial uses.

Accordingly, no applications will be processed for new appropriations or transfers of use until the three years are up, or until a final

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*The moratorium expires in March of 1977.

determination of existing rights has been made.*[142] An example of the moratorium's effect is provided by the experience of the Intake Water Company. In an effort to provide 245,000 acre-ft of water for energy development, Intake proposes to construct a dam on the Powder River in Montana at a point four miles north of the Wyoming-Montana border. Twenty-one miles of the 24-mile-long reservoir will lie in Wyoming, but the proposal must await the passing of the three-year moratorium.

E. Water Requirements for Coal and Oil Shale Development

The water requirements for the production of syncrude and methanol from coal and syncrude from oil shale are different, but the amount for both types of production are large. As we have seen, the allocation of water in the West is a complex subject. Basic to the problem of allocation is the question of the amount of water that is available. This section sets projections of water demand for coal and oil shale development against available water supplies and their possible augmentation.

1. Syncrude and Methanol from Coal

Just how much water is available for coal development in the semiarid Northern Great Plains states of North Dakota, Montana, and Wyoming is an important question because of large water requirements of some of the processes contemplated for the coal once it is out of the ground. The alternative processes for coal development are given in Figure 19-3, along with the location of the processing, whether in-state or out-of-state. The alternative that requires virtually no water, of course, is the shipment of mined coal out of the region by train to

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*The moratorium does not apply to projects of less than 14,000 acre-ft capacity.

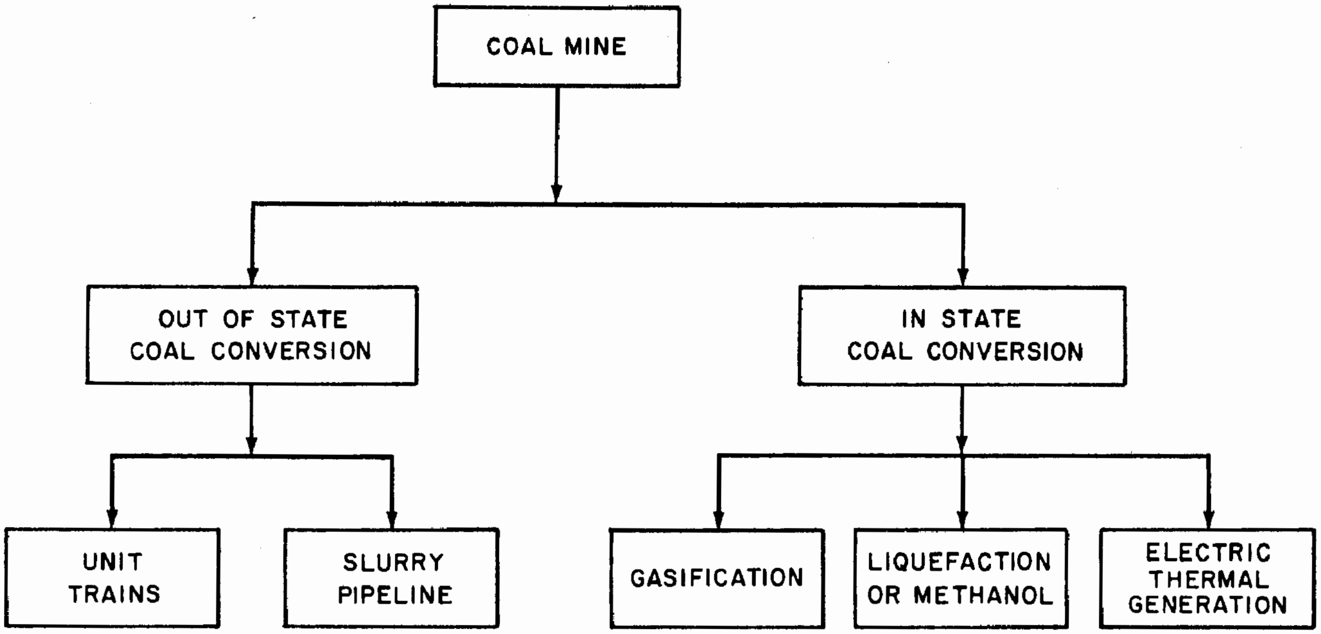

FIGURE 19-3. COAL DEVELOPMENT ALTERNATIVES, IN-STATE AND OUT-OF-STATE

water-rich areas for processing. At the other extreme is the alternative of burning the coal in a power plant located at the mine to generate electrical power, which would consume large amounts of water for cooling. The various alternative uses of coal and their associated water requirements are shown in Table 19-4.

The likelihood is that the future will see a mix of the various alternatives, and the availability or nonavailability of water at a given geographic location at a given price will be a major determinant in what particular coal utilization alternative is selected. Other factors will also go into the decision, including population impacts, jobs created, and tax assessing opportunities for state and local governments.

The major rivers that flow through the Northern Great Plains all come together to swell the Missouri River. Looking upstream from Sioux City, Iowa, one sees a net flow (the virgin flow less present day depletions) of 21,821,000 acre-ft/year. Table 19-5 reveals that, even in low water years, a net of 5,970,000 acre-ft/year of this water is available for all future uses--energy development of all forms as well as agricultural, municipal, industrial uses, and fishing habitat and wildlife improvement programs.

Projections of the Northern Great Plains Resources Program for the year 2000 show 41 gasification plants and 19,400 MW of electrical generating capacity.[143] Assuming a consumptive use (no discharge) of 9,500 acre-ft/year of water for each gasification plant and 12,000 acre-ft/year for each 1000 MW of electricity, the water required for gasification and electrical power generation in the year 2000 would total about 620,000 acre-ft/year. Water used consumptively to revegetate areas stripped to provide coal for these uses is estimated at about 31,000 acre-ft/year.[146] Projected additional agricultural consumptive use, based on 1.6 acre-ft per acre, is conservatively estimated at about

Table 19-4

ANNUAL WATER CONSUMPTION FOR VARIOUS COAL USES

Use	Facility Size	Water Required (10^3 acre-ft)	Coal Required (million tons)	Relative Water Requirement (acre-ft/million tons of coal)
Thermal electric power generation	1000 MW	12	4.5	2670
Methanol from coal	100,000 B/D	15	13	1150
Gasification	250 million SCF/D	9.5	9.5	1000
Liquefaction	100,000 B/D	29[*]	35	830
Slurry pipeline	25 million tons/year	18.8	25	750
Unit trains	61 million tons/year	Negligible	61[†]	--

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[*] Assumes wet cooling; with dry cooling this figure could be reduced to about 12,000 acre-ft.

[†] The exact capacity of a system of unit trains has not been determined. The analysis assumes 61 million tons of coal could be exported by unit trains in the tenth year.

Source: References 143 and 144, and Table 4-5, Chapter 4.

Table 19-5

UPPER MISSOURI RIVER BASIN WATER AVAILABILITY AND DEPLETIONS

	Average Year (10^3 acre-ft)	Critical Year (10^3 acre-ft)
Historic flow[1]	28,321	--
Depletions for past use[2]	6,500	--
Water supply available after 1970	21,821[3]	14,200[9]
Indian requirements in Montana and Wyoming[4]	2,637	2,637
Committed to authorized Bureau of Reclamation projects[5]	1,293	1,293
Remaining water subject to Indian claims[6]	17,891	10,270
Suggested water quality control required on main stem[7]	4,300	4,300
Available for additional development by Indians and non-Indians[8]	13,591	5,970

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[1] 28,321,000 is an estimated value of long-time (1898-1972) average annual flow at Sioux City, Iowa, prior to any water development in the basin above Sioux City. It was derived from streamflow records adjusted for known and reported developments throughout the upper basin and the measured and estimated depletions associated with those developments.

[2] Above Sioux City 6,500,000 is a composite of water depletions for all projects in operation in 1970. Estimates include irrigation, imports, exports, land treatment measures, stockponds, rural domestic uses, evaporation from major impoundments, minerals, and mining, industrial, and municipal uses. It represents water currently consumed and no longer available to meet additional future needs.

[3] A measure of the expected average annual water production between 1898-1972 repeated, but with current uses accounted for. It is equal to the historic flow less all depletions for 1970 level of development.

[4] Compiled from inventories of land and water by consulting engineering firms under contract. Refinement in these preliminary numbers will evolve as studies continue. (Indian water requirements do not necessarily define Indian water rights.)

[5] Congress has authorized six units to be constructed by Bureau of Reclamation in the basin under the Pick-Sloan Missouri Basin Program. They are in the construction or preconstruction stage. The expected depletions above Sioux City for authorized projects total 1,293,000 acre-ft from Garrison, Oahe, and O'Neill Units.

[6] These figures are the residual flows after subtracting projected Indian claims in Montana-Wyoming and committed waters of authorized Bureau of Reclamation units from the water supply available as of 1970 level of development. These totals represent water available for further development in the Dakotas and is subject to the undetermined paramount rights of Indians in the Dakotas, for which land and water inventories have not begun.

[7] 4,300,000 acre-ft is the annual equivalent of 6000 cubic ft/s currently thought to be the flow between and from main stem reservoirs required for recreation, flow maintenance, public health, and water quality control.

[8] These figures represent average and critical year water quantities available for future development in the Dakotas if water quality control flow requirements are maintained, and the demands listed in 4 and 5 are met.

[9] This value is an estimate derived from a recent operations study of the main stem reservoirs at 1970 development level. That study determined that water quality control could be maintained and also allow 9,900,000 acre-ft annually as the additional tolerable depletions which the system storage could accommodate. 14,200,000 is the sum of 9,900,000 and 4,300,000.

Source: Reference 14.

1,900,000 acre-ft/year for the year 2000.[147] Fishery habitat and wildlife improvement programs could consume about 320,000 acre-ft/year.[148] These consumptive uses are totaled in Table 19-6.

Table 19-6

PROJECTED ANNUAL CONSUMPTIVE USE OF WATER
FOR THE YEAR 2000--NORTHERN GREAT PLAINS STATES

Use	Water (10^3 acre-ft/year)
Gasification and electric power generation	620
Revegetation	31
Municipal	14
Agricultural	1900
Fishery habitat and wildlife improvement	320
Total*	2890

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*Total does not add due to rounding.

In addition to these projected uses are the syncrude and methanol water demands projected by the maximum credible scenario for the year 2000, shown in Table 19-7. The sum of these state demands is the total competing water figure for syncrude and methanol production (last column, Table 19-7).

Table 19-7

SYNCRUDE AND METHANOL CONSUMPTIVE WATER DEMANDS FOR THE YEAR 2000

State	Number of Liquefaction Plants	Water for Liquefaction Plants* (10^3 acre-ft/yr)	Number of Methanol Plants*	Water for Methanol Plants* (10^3 acre-ft/yr)	Number of Coal Mines to Support Those Plants*	Water for Coal Mines* (10^3 acre-ft/yr)	Total Water Needs (10^3 acre-ft/yr)
Wyoming	13	377	13	195	81	12	584
Montana	11	319	10	150	66	9.9	479
North Dakota	0	0	21	315	76	11.4	326
Total†							1390

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*Plant size and resource requirements from Tables 6-3, 6-6 (Chapter 6).

†Total does not sum due to rounding.

The sum of all these competing uses must then be compared to the earlier available water figure of 5.97 million/year.

	10^3 acre-ft/year
Demands other than syncrude and methanol	2890
Syncrude and methanol	1390
Total	4280

The conclusion is that there is enough water available in the upper Missouri River system to support the maximum credible scenario for syncrude and methanol production in that region while still meeting projections for all other demands.

This conclusion is not entirely valid, however, because the geographical distribution of the water is not coincident with the distribution of the coal resource. Typical of this situation is the Powder River Basin of northeastern Wyoming and southeastern Montana where the maximum credible scenario has sited the major coal effort for these states. This area is extremely coal-rich and markedly water-poor. One of the water facts of life of the entire region becomes very clear very quickly; the flows in the rivers are seasonal, ranging from a maximum in the late spring to a minimum (in some cases zero) flow in the late summer and fall, as illustrated by the historic Yellowstone River Basin flows shown in Figure 19-4. To control flooding at times of high flow and to provide water for release in dry seasons, the storage reservoirs listed in Table 19-8 have been constructed on many of the region's rivers. The prime impetus for their construction was to provide a reliable source of water for irrigation of agricultural land in the dry season. Some of these existing storage areas could, perhaps, be tapped to provide water

Table 19-8

MAJOR RESERVOIRS THAT AFFECT STREAM FLOWS IN THE NORTHERN GREAT PLAINS

		Storage (thousand/acre-ft)				
Stream	Reservoir	Inactive and Dead	Active	Flood Space	Total	Uses*
Missouri	Fort Peck	4300	10,900	3700	18,900	R, FC, Irr., N, P, M, I
	Lake Sakakawea	5000	13,400	5800	24,200	R, FC, Irr., N, P, M, I
	Oahe	5500	13,700	4300	23,500	R, FC, Irr., N, P, M, I
Milk	Nelson	18.7	66.8	--	85.5	R, Irr.
Clarks Fork	Cooney	0	24.4	--	24.4	R, Irr.
Wind-Bighorn	Bull Lake	0.7	151.8	--	152.5	R, Irr.
	Pilot Butte	5.4	31.5	--	36.9	P, Irr.
	Boysen	252.1	549.9	150.4	952.4	R, FC, Irr., P, M, I
	Buffalo Bill	48.2	373.1	--	421.3	R, Irr., P
	Bighorn	502.3	613.7	259.0	1,375.0	R, FC, Irr., P, M, I
	Upper Sunshine	1.0	52.0	--	53.0	Irr., S, D, I
	Lower Suhsine	1.9	54.9	--	56.8	Irr., D, S, P, I
Powder	Lake DeSmet	0	239.0	--	239.0	R, Future Industry
Tongue	Tongue	5.9	68.0	--	73.9	R, Irr., M, I
Heart	Dickinson	1.2	5.5	--	6.7	R, Irr., M, I
	Heart Butte	6.8	69.0	150.5	226.3	R, FC, Irr., M, I
Grand	Bowman-Haley	4.3	15.8	72.9	93.0	R, FC, M, I
	Shadehill	58.2	30.0	269.6	357.8	R, FC, Irr.

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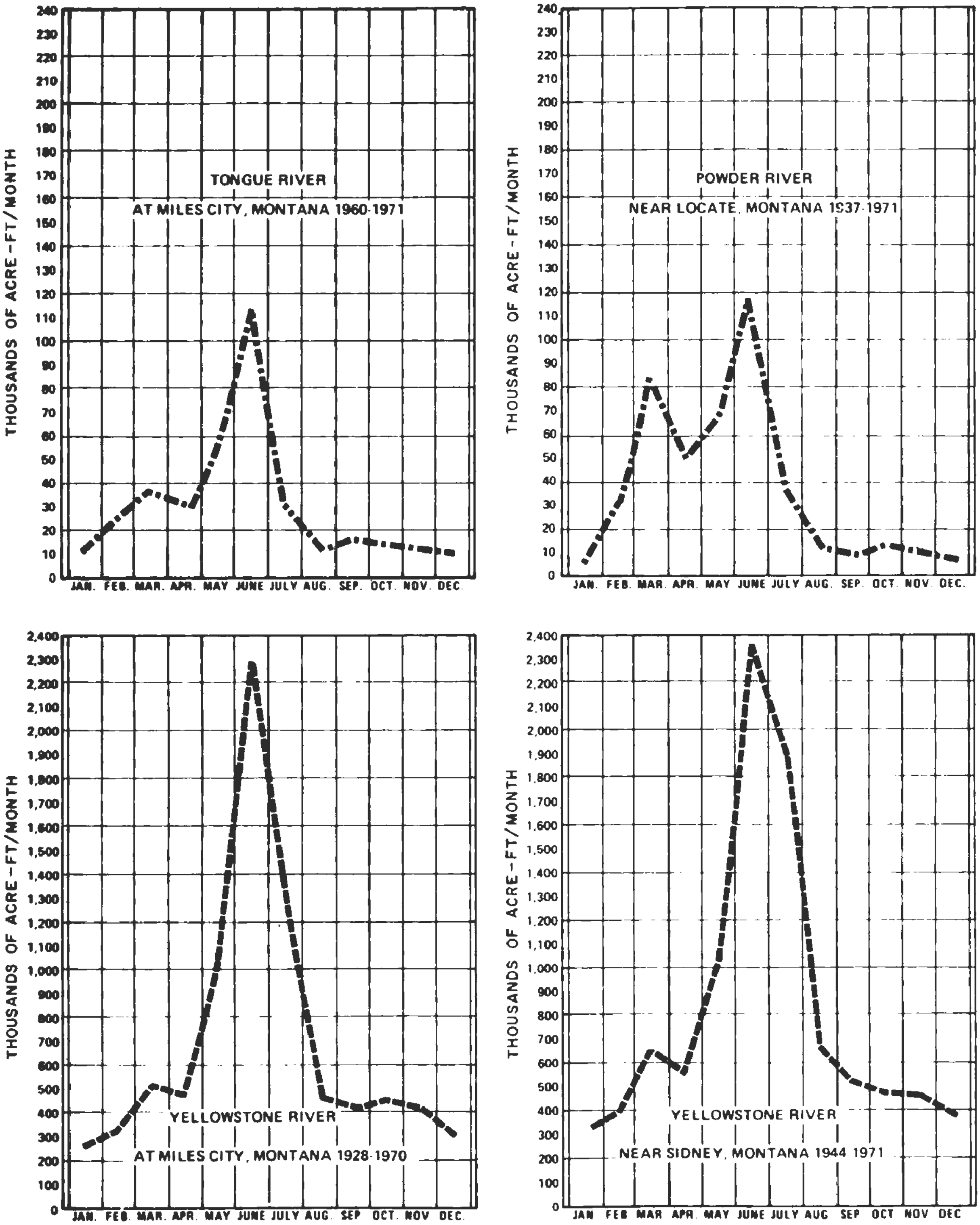
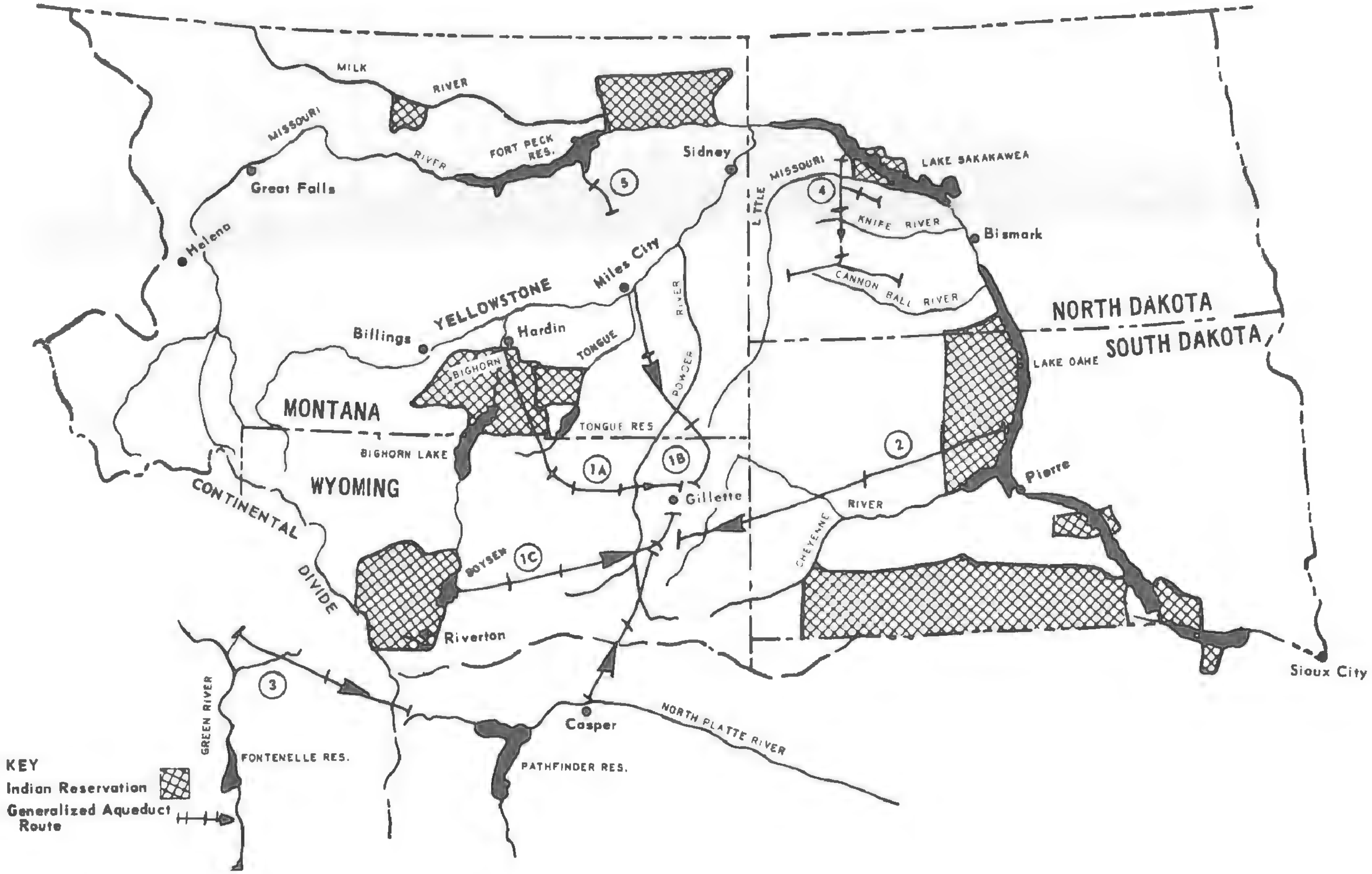
*R = recreation (includes fish & wildlife), FC = flood control, Irr. = irrigation, N = navigation, P = power, M = municipal, I = industrial, S = stockwater, D = domestic.

Source: Reference 149.



Source: Reference 144

FIGURE 19-4. HISTORIC YELLOWSTONE RIVER BASIN FLOWS for energy development as described below. Consideration may also be given to building additional impoundment facilities--with the impetus for construction this time being the storage of a water supply for the year around operation of various coal processing plants. The storage development potential for rivers close to the Gillette, Wyoming, coal resource focal point is not impressive vis-a-vis the projected amounts of water needed. Table 19-9, which is a summary of surface water resources available or subject to development, shows that the Powder River and Tongue River reservoirs could only provide a total of 131,000 acre-ft/year, far short of Wyoming's projected need of 584,000 acre-ft/year for syncrude and methanol. For this reason, major aqueduct pipelines would be necessary to bring in water from the reservoirs listed in Table 19-8. Construction of these water conveyance lines could make it unnecessary to construct several small capacity (but close-in) reservoirs. Figure 19-5 shows several ways of bringing water from where it is to where it will be needed. Route 1C could bring up to 135,000 acre-ft/year to the coal region. Route 1A could transport up to 435,000 acre-ft/year. However, under the latter alternative, there would not be enough water remaining for other demands, including the full 6000 cubic ft per second flow necessary to preserve instream values. (See Table 19-5, Note 7.) For this reason, route 1B may be more acceptable in that the diversion is at a point farther downstream where an equivalent amount of withdrawal would have a lesser impact because the 6000 cubic ft per second standard would be met. Another alternative is route 2, which could provide water from Lake Oahe in South Dakota, although the distance involved would represent significant pipeline construction costs. This alternative has been challenged by the state of South Dakota, which insists that Lake Oahe water should be reserved for future irrigation needs in the state. The South Dakota Attorney General, William Janklow, has said on this issue, "Let them try and take that water away from us--they'll need a federal marshal along every mile if they want to build that pipeline."[151]



Source: Reference 75

FIGURE 19-5. MAJOR POTENTIAL DELIVERY SYSTEMS, NORTHERN GREAT PLAINS COAL RESOURCE REGION

Table 19-9

SUMMARY OF INDUSTRIAL WATER RESOURCES FOR THE UPPER MISSOURI RIVER BASIN

	Water (acre-ft/year)			
	Available		Potential	
	Montana	Wyoming	Montana	Wyoming
Bighorn and Wind Rivers				
Boysen Reservoir		85,000		50,000
Bighorn Lake	262,000	435,000		254,000
Little Bighorn Reservoir			40,000	
Powder River				
Moorhead Reservoir			57,000	51,000
Hole-in-the-Wall Reservoir				20,000
Tongue River				
Tongue River Reservoir			60,000	
Other development with major storage				60,000
Yellowstone River				
Main stem (with regulation by offstream reservoirs, or Allenspur)			1,356,000*	344,000†
Shoshone River				
Modification of Buffalo Bill Reservoir				50,000
Green River				
Importation and diversion				108,000
Total	262,000	520,000	1,513,000	937,000

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*About 1.7 million acre-ft would remain in the Yellowstone River for other future development and for minimum flows.

†Wyoming's share of Clarks Fork Yellowstone River.

Source: Reference 150.

A final alternative would be to take water from the Fontanelle Reservoir on the Green River over the Continental Divide to the North Platte River, and then remove it from the North Platte at the place where the river passes closest to the coal resource. Routes 1A, 1B, and 1C raise the institutional restriction of the Yellowstone River Compact, which forbids any signatory state (Wyoming, Montana, and North Dakota are signatory states) from moving water out of one basin into another (e.g., out of the Bighorn River Basin into the Powder River Basin) without the consent of the other states. Route 2 avoids this problem, but, as previously mentioned, it is expensive and it invites a hostile response from South Dakota. Route 3 avoids the institutional problem inasmuch as the Upper Colorado River Basin Compact (the Green River is a tributary of the Colorado River) does not constrain interbasin transfers. Removal of this high quality water, however, would exacerbate the salinity problem of the lower Colorado River states.

Referring to Figure 19-5, Route 4 would provide water from Lake Sakakawea for the processing of North Dakota coal, and Route 5 would bring main stem Missouri River water to coal development sites in northeastern Montana. These routes appear to have fewer political or institutional problems associated with them.

South Dakota is also a major factor in one of the options depicted in Figure 19-3, the transportation of coal from the Powder River Basin to distant processing points via coal slurry pipeline. Present proposals call for obtaining the water for the slurry from deep wells, which tap into the geologic Madison limestone formation underlying the Powder River Basin. However, the Madison aquifer, reported as having as much as 1 billion acre-ft of water, also underlies western South Dakota. Extensive pumping in Wyoming may lower the water table or cause a drop in the quality of the water presently being pumped out of the Madison formation by South Dakota citizens. South Dakota has pledged to go to court to challenge the large-scale pumping envisioned for the coal slurry pipeline option.[151]

A number of organizations have begun to plan for the future of this region in general, and in the utilization of the region's coal in particular, but there has been no integration of the planning process. Energy companies are filing plans for construction of small storage reservoirs that will satisfy their particular water-for-energy needs, but that, it may be argued, runs counter to the interests of local citizens with other needs for that water, interests of the state concerned, interests of the region as a whole, and national interests.

2. Syncrude from Oil Shale

The maximum credible scenario projects 20 large (100,000 B/D) oil shale plants by the year 2000. At a water scaling factor of 16,000 acre-ft/year for each such plant, the total water required for the 20 plants would be 320,000 acre-ft/year. Because the oil shale resource lies in the Upper Colorado River Basin, this water requirement must be met from supplies in that basin.

The total water available to the Upper Colorado River Basin states for all uses is conservatively estimated to be 5.8 million acre-ft annually.*[152] Present uses (including reservoir evaporation) require 3.71 million acre-ft per year.[153] Projected increases in annual demand for the year 2000 are shown in Table 19-10. If the increase in water demand of 2.75 million acre-ft/year is added to the 3.71 million acre-ft/year of present use, the total demand for the year 2000 would be 6.46 million acre-ft/year.

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*Some figures are as high as 6.3 million acre-ft/year; see Reference 155.

Table 19-10

PROJECTED INCREASE IN WATER DEMAND FOR THE UPPER COLORADO RIVER BASIN

Category of Use	Increase in Water Demand (10^3 acre-ft/yr)
Municipal	750
Environmental (fish, wildlife, recreation, water quality)	150
Agricultural (primarily irrigation)	800
Mineral production	115
Coal fired electric generation	475
Coal gasification	140
Syncrude from oil shale	320
Total	2750

Source: Reference 154.

Clearly if there is but 5.8 million acre-ft/year of water available to the Upper Basin, there would not be enough water under the projected demand to accommodate all users. A Department of the Interior study, which projected an oil shale development amounting to only three-fourths that of the maximum credible scenario, indicates that the water shortfall will occur in the early 1990s.[156]

There is little hope of increasing Upper Basin supplies at the expense of the Lower Basin. The Lower Basin of the Colorado has committed its full share of water available to it under the 1922 Colorado River Compact, considering its present demands and projected plans for energy (and other) development.

Although water supplies can be increased through snowpack augmentation (i.e., winter cloud seeding resulting in greater water runoff in the spring), the estimates of the increase range only from 6 to 9 percent.[157] A proportionate increase in the Upper Basin supply would thus be from 350,000 to 520,000 acre-ft/year--not enough to meet the projected deficit of 660,000 acre-ft/year.

The allocative formula of the Upper Colorado River Basin Compact of 1948 further demonstrates the foreseeable shortages on an individual state basis within the Upper Basin. Under the maximum credible scenario Colorado's Rio Blanco and Garfield counties experience the bulk of oil shale development. The 1948 Compact, after allocating 50,000 acre-ft/year to Arizona, gives Colorado 51.75 percent of Upper Basin water, or 3.00 million acre-ft/year. The Compact operates to require the water for Colorado's oil shale development to come from its allocated Upper Basin share. The result is that Colorado will experience a projected water resource shortfall by the early 1990s when the 3.00 million acre-ft/year figure of available water will be surpassed by in-state demand.[158]

The MCI projects a maximum oil shale development effort in the Piceance Basin of northwestern Colorado. In the southern part of the Basin, surface water will have to be transported to the oil shale site. In the northern part of the basin, close to the White River drainage system, a different situation exists. There, groundwater will have to be pumped at the outset of mining operations to keep the mine itself dewatered; indications are that this water will be initially of sufficient quantity and quality for retorting and refining needs, in addition to meeting water requirements of crushing, mining, and processed shale disposal.[159] Depending on the salinity, the water may also meet drinking water and sanitation needs.[160] However, as the water table lowers, the quality of the pumped water will deteriorate and fewer and fewer productive uses can be made of the water. Thus a twofold problem appears; excess "unsatisfactory" water will have to be disposed of in a way that avoids contaminating surface waters and water of a satisfactory quality will have to be obtained from a surface source to meet the needs of the operation.

The White River produces about 610,000 acre-ft of water per year. However, claims on the parts of Utah, other downstream states, the federal government, and Indians through whose reservations the river flows--in addition to prior appropriation claims of agricultural interests--leave little, if any, of this water available for oil shale development.[161]

Even in areas where surface water rights are granted, some means will have to be provided to transport the water from the source to the mining operation. Because ice formation in winter would hinder transport via canals, buried pipelines appear to be necessary.[162] Atlantic Richfield, e.g., has filed for 50,000 acre-ft/year of White River water, proposing to transport the water 36 miles through a 48-inch diameter pipeline.[163]

Oil shale developers have also filed water claims for Colorado River water, seeking to pump the water over the Book Cliffs to the Piceance Creek drainage area. It has been pointed out that this would be a very expensive lift system.[164]

To illustrate the degree of the allocation problem, the total claims made on Colorado River water flowing near the oil shale resource area exceed the entire flow of the river during some seasons.[165]

If the allocative dilemma is resolved, the magnitude of the demand forecast makes it clear that for White River and Colorado River water to be available for year around oil shale operations, additional water development projects will be necessary to store the disproportionate spring flow; in the spring, 60 percent of the White River's annual flow occurs in 120 days.[166]

There is a continuing investigation into the method of syncrude production from oil shale by in situ processes in which the shale is mined and crushed underground through blasting and is then retorted in place. The raw shale oil product is pumped out for further processing. From a water standpoint this process is particularly attractive because total water needs are thought to be about one-fourth those of "conventional" processing.[167] (Water savings result because shale does not have to be wet down or slurried in the mining, crushing, or retorting phases of the operation; moreover, because the process takes place underground, there is no need for dust control, or for compacting spent shale in the disposal phase, which is the most water intensive aspect of all.[168]) However, the in situ process is considered to be in an experimental phase and it is not clear that it will ever be a viable alternative to present water intensive processes.[169]

Assuming that the forecasts are accurate and that the predicted shortfall does occur, the answer will be to increase the water supply and/or to reconsider from an institutional point of view where the available water supplies should go. It has been pointed out that snowpack enhancement to augment spring runoff water will ease the problem but will not solve it. Interbasin transfers, e.g., from the Columbia River, are costly and politically unpalatable. More efficient agricultural methods will save some water, but state laws which operate to encourage the profligate use of a water right will have to be changed. The market transfer of water rights from agricultural use to energy development use is possible if laws unfettering such transfers are implemented (see Section D). It will be important to do this in a knowing way so that the desired amount of agriculture production is preserved. If freely spent "energy" dollars buy up all of agriculture's water rights, land reclaimed through Bureau of Reclamation projects and irrigation over the years will revert to its original condition. This will, of course, have a profound effect on the local society, which developed as an "agricultural culture." Because such decisions have both a regional and national character to them, as well as a profound local impact, some kind of mechanism will be necessary to make intelligent choices for all concerned.

F. Coal Transport: Pipeline versus Rail

There are going to be hard choices in the coal-rich states on the Northern Great Plains concerning the best use of their precious water resources. Because coal-burning electric power plants and coal conversion technologies such as gasification and liquefaction are water intensive processes, serious consideration is being given to transporting the coal out of the region for use or processing in locations with sufficient water resources.

There is great demand for coal at long distances from western coal fields. For example, utilities in Texas and Arkansas, hard-pressed by oil and gas shortages, and eastern utilities, faced with clean-air constraints on the use of high-sulfur eastern coal, are interested in having western coal carried to their boilers for electric power generation.

The question is how best to transport the huge quantities of coal. The two practical alternatives are transport (1) by railroad, and (2) by coal slurry pipeline.

The policy of the United States is to move away from dependence on foreign oil. To that end, the U.S. Senate in 1974, passed a bill calling for all oil-burning electric power generating plants to convert to coal. An amendment to that law, sponsored by Senator Henry Jackson (D. Wash.), precipitated the present debate over railroads versus coal slurry pipelines. The amendment proposed to give to slurry pipeline companies the federal power of eminent domain, whereby the pipeline companies could acquire the necessary rights-of-way to lay the pipe from coal producing areas to the consumer. The measure died in the House of Representatives of the 93rd Congress for want of time. Reintroduced in the 94th Congress, it was referred to the Committee on Interior and Insular Affairs, where it remains with little likelihood of being brought to the floor.*

1. Coal Slurry Pipelines

In a coal slurry system, coal at the mine mouth is pulverized into particles as fine as or finer than ground coffee. The resultant powder is then mixed with water in a one-to-one ratio with water producing a slurry with the consistency of cream. This coal slurry is pumped through a pipeline, which is laid underground and which surfaces at pumping stations located at about one-hundred-mile intervals. At its destination, the slurry is "dewatered" (usually by centrifuge). The transport water can be used as "make-up" or cooling water in a liquefaction, gasification, or power generating plant operation.† In an electric power plant, the moist powdered coal is readily usable by the boilers.

Coal slurry pipelines are not a new idea. In London in 1914, a short pipeline of 1950 ft served to transport coal from Thames River barges to a nearby boiler plant. In 1958, a 108-mile coal slurry pipeline was built to move coal from the Ohio coalfields northward to Cleveland. In full operation, that line carried over one million tons of coal per year. There is a 273-mile pipeline currently carrying five

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*Private communication.

†Slurry water must be treated before plant use at the delivery end. However, the cost of the energy product is relatively insensitive to this added expense.

million tons per year from a Peabody Coal Company mine in northeastern Arizona to a steam plant in southern Nevada. This line, known as the Black Mesa pipeline, is owned by the Southern Pacific Transportation Company.

There are many attributes of a coal slurry pipeline transport system that have gained it attention:

- The pipeline is underground, and is therefore
  - Environmentally unobtrusive
  - Relatively invulnerable to damage
  - Not affected by severe weather or low ambient temperatures.
- The pipeline is extremely reliable.
- The pipeline can follow a straight path through steep and rugged terrain.
- Pumping stations are run on electricity, which can be generated by domestic coal.
- Operation is not labor intensive (a factor that means both limited vulnerability to labor disputes and limited exposure to inflation escalation).
- The coal slurry mixture is nonflammable (an obvious safety feature).
- The coal can be washed of unwanted impurities during slurry preparation.

A coal slurry pipeline gains still more attention when it is compared with coal carriage by rail:

- For an equal amount of coal, a pipeline consumes 20 percent less energy than rail transport.[170]
- Rail transport requires increasingly precious petroleum to power the diesel locomotives.
- Land dedicated to rail lines is not usable for other purposes (compared with the restored land over a buried pipeline).
- There is a lower product loss with the pipeline.

- There is a higher industrial injury/death rate per ton-mile for movement by rail.
- A rail line typically must traverse a 10 percent or more greater distance in reaching the consumer (because of accommodations made for terrain).
- Subject to economies of scale, it is significantly cheaper to move coal by pipeline.

For the proposed 1000-mile coal slurry pipeline from the Powder River Basin in Wyoming to Pine Bluff, Arkansas, the savings over rail are estimated at one-third to one-half, or $14 billion over a 30-year period.*

2. Railroad Transport of Coal

The response by the railroads to the challenge of the coal slurry pipeline has been both defensive and competitive.

The defensive arguments are fundamentally ones of survival: "Whatever benefits may be found in the slurry pipeline are greatly outweighed by the price to be paid through the weakening of our railroad system."[172] There is concern that "...the cream will be skimmed from the railroads' business leaving the remaining customers with the very real prospect of wholesale abandonment of lines no longer economically viable."[173] There is fear that loss of coal traffic of nearly-bankrupt eastern railroads to slurry pipelines will be the final blow to the survival of the railroads.

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*"...or fourteen billion dollars our customers need not and would not pay through their monthly electric bills."[171] (These are apparently dollars current to the year the expense is incurred; and this figure is also apparently not discounted to a present value.)

On the competitive side, the railroads claim they are ready now to handle greater coal traffic; that long-term coal carrying contracts spurred by energy demands will enable the railroads to attract the investment capital needed to build new hopper cars and new, heavy-duty locomotives, and to repair trackage and roadbeds showing wear. The railroads boast of the "pipeline-like" unit trains, which may consist of more than 100 high-capacity coal cars with an individual weight of as much as 110 tons, made of lightweight aluminum to maximize the payload. The unit train is indeed a major cost-saving advance from traditional single-car shipments in mixed trains. High-horsepower locomotives provide the power for the mile-long string of hopper cars, loading at one point of origin and unloading at a single destination. To make the unit train cost-effective, long-term contracts of 10 years or more, large-volume shipments per train and per year, and a single destination are all necessary.[174,175]

Outside railroad circles, there is concern that (1) the railroads cannot, in fact, handle the prospective increased coal-carriage even with extensive roadbed rebuilding and great investment in new equipment and (2) that an all-out carriage effort would be at the expense of impaired movement of other freight and passengers.[176]

3. Critical Factors

The proposed large-volume transfers of coal from western producing areas to major consumers would appear to represent a shining opportunity for the operation of unit trains. In fact, Montana went from near zero unit-train shipments in 1968 to 7.7 million tons in 1972. The 1972 figure represents 94 percent of the coal shipped out of the state. But the vast coal movements contemplated raise questions even for the acclaimed unit train. The proposed Wyoming-Arkansas slurry pipeline is designed to move 25 million tons per year to a single destination. Taking into account the empty return trip for the railroad alternative, this corresponds to 20-unit train trips per day. On the delivery route, the constant flow of high-payload trains could cause serious roadbed maintenance problems. Any down-time for maintenance would cut into the system's reliability.* In the words of one utilities executive, "...this is what concerns (the utilities): the capability to deliver continuous, reliable service..."[178] By way of contrast, the reliability of the Consolidated (Ohio) slurry pipeline was 98 percent, and that of the Black Mesa pipeline, 99 percent.[179]

The railroads make the point that slurry pipelines use scarce western water to carry the coal through the pipe. The Wyoming to Arkansas line will use 15,000 to 20,000 acre-ft per year. The pipeline people respond with the observation that the water used will be saline water from deep-water wells (3500 ft to 4500 ft) drilled into the Madison geologic formation which, according to the U.S. Geological Survey, contains from 500 million to 1 billion acre-ft of water with an annual recharge rate of 100,000 acre-ft.† The salinity, and the cost of the water as a result of drilling, make it unattractive for competing purposes. By way of rejoinder, the pipeline supporters point out that if trains were to carry the coal foreseen in the projected doubling of coal output by

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*Under a combination of restrictions including maintenance, classification, and scheduling, "...the average freight car moves both loaded and empty, only 56 miles a day."

†There is dispute as to the salinity issue and as to the recharge ratio on this Madison formation water. One drilling near Gillette, Wyoming, brought up water with a saline concentration of only 500 parts per million (ppm), better quality water than that presently being used for municipal purposes in Gillette. The recharge rate is under continuing investigation. (Telephone interview with Mr. Paul Rechard, Department of Water Resources, University of Wyoming, Laramie, Wyoming, March 12, 1975.)[179]

1985, the locomotives would burn an additional 2.5 billion gallons of diesel fuel per year.*[176]

Another resource issue is the competing demand for steel represented by these two modes of energy transport. The buildup of each mode would require large amounts of steel.† The proposed Wyoming-Arkansas slurry line, for example, calls for 460,000 tons of steel. Whatever comparative railroad figure is used, it must include the cost of replacing cars, locomotives, and track worn out during an equivalent 30-year operating period. An electric utility spokesman has put that figure at 795,000 tons of steel.[180] The Project Independence Blueprint study made the point that the overall projected railroad need of 16 million tons of steel compared closely with the figure needed for all-out pipeline construction and therefore, it concluded, "...for the critical investment and construction items there is in general little basis to choose between the modes."[176] However, this does not take into account the multiple-use character of railroads. Not that coal cars can be used for other purposes, but rather that (1) an increased trackage network with well maintained roadbeds could support increased freight car and passenger car traffic, and (2) the business boom experienced by the railroads through coal-related growth might allow the fiscal flexibility to respond to other freight and passenger demands.

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*The coal liquefaction scenario (Chapter 6) scale factors show that if the locomotives were powered by synthetic fuel derived from coal, this would require 33 million tons of coal per year.

†However, the percentages are not overwhelming vis-a-vis other U.S. competing steel demands. Of the 111 million tons of steel produced in the U.S. in 1973, 3.2 million tons went to rail transportation and 0.85 million tons went into the manufacture of pipe for pipelines.

The "all of one or all of the other" approach taken so far for the sake of comparing the two modes has served to highlight their attributes, shortcomings, and important differences. As will be argued later, the more likely approach involves a well reasoned mix of the two modes to meet the nation's needs.

4. Eminent Domain for Pipeline Right-of-Way

Before reasoning the mix, one is faced with the essence of the Jackson amendment: providing the slurry pipeline companies with the federal power of eminent domain. Acquisition of a right-of-way is a matter of settled law. If one wishes to traverse another's private property, one must negotiate with the owner and strike a bargain. If accord is reached, a document is drafted, executed, and in many states, recorded as a kind of property right: right-of-way across another's land by virtue of and for the purposes stated in the agreement. Of course, the seeker of the right-of-way can make an outright purchase of the property if that is desirable, or if that is the only alternative.* Right-of-way across public lands may be a matter of negotiated fee or of legislative grant, where a public purpose described in law is accommodated. In dealing with an owner of private property, that owner can thwart the progress of right-of-way attainment by refusing to bargain. Thus, for example, wherever the proposed route crosses the private property of a railroad, the railroad might well refuse to negotiate.† The likelihood of impasse becomes clear in the proposed Wyoming-Arkansas slurry pipeline, which would cross railroads at 44 points.

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*A right-of-way across private grounds may also be acquired by prescriptive easement; i.e., through long-term, undisturbed use. In the large-scale operation contemplated, however, such an accomplishment is unlikely.

†Since the pipeline company represents head-on economic competition to the railroads, this is to be expected.

Consistent with the Fifth Amendment to the U.S. Constitution, individual states and the federal government have the power to grant the right of eminent domain to pipeline companies when just compensation is paid, and where the taking is in the public interest. There are statutes in many states giving to oil and gas pipeline companies the power of eminent domain for the purpose of securing rights-of-way within that particular state for the building, maintenance, and operation of their pipelines. These statutes also proffer the right to construct the lines along or across public highways, railroads and streams, and across public land.* Federal legislation permits the Secretary of the Interior to grant easements of way for oil and gas pipelines over public lands of the United States, and over Indian lands.[182,183] The federal power of eminent domain is given to natural gas companies,[184] and during the Second World War (and through 1947), it was given for the construction of oil pipelines.[185]

Organized, vehement opposition by the railroads would very likely thwart a state-by-state effort by the coal slurry pipeline proponents to secure reasonably consistent eminent domain authority. Each state would have different strings attached to its grant of the power, even if the power were granted. Railroad opposition to petroleum pipelines starting back in the 19th century is enlightening on this point.

5. Railroad Opposition to Pipelines

In 1846, the first successful oil pipeline was built of two-inch wrought iron pipe. It covered a distance of five miles from Pit Hole, Pennsylvania, to the Miller Farm railroad station.[186] The

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* See, e.g., Reference 181.

railroads favored these lines, which fed oil from drilling areas to railroad loading racks for rail transshipment. As the pipelines extended to greater distances, cutting into railroad oil-carrying business, the railroads refused to allow them permission to cross their tracks. To remedy the situation, the Pennsylvania and Ohio legislatures, in 1872, passed laws granting pipelines the power of eminent domain in their acquisition of rights-of-way. Thus, the pipelines could, by law, cross under the railroad tracks. The success of the oil pipelines was clear and convincing: the railroads were forced to reduce their rates.

In 1958, the Consolidated Coal Company's coal slurry pipeline was put into operation, carrying over one million tons per year from the Ohio coal fields to utilities in Cleveland. When this pipeline was opened, railroad coal-carrying rates were $2.63 per ton, rising later to $3.47 per ton. The successful operation of the pipeline resulted in a reduction in railroad rates to $1.88 per ton.*[187]

The success of this pipeline led to a proposal in 1959 to build a coal slurry pipeline from West Virginia to eastern seaboard generating plants. The proposal was never implemented because of railroad opposition to efforts at obtaining rights-of-way from the state legislatures concerned.

The next efforts were made in Congress where, on March 21, 1962, bills were introduced simultaneously into the House and Senate to confer the federal power of eminent domain on coal slurry pipeline companies.[189] The bills died, as a result of intense, organized railroad opposition.

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*It has been asserted that this pipeline success created the impetus for the railroad introduction of the unit train concept.[188]

6. Pipeline Regulation

Coal slurry pipelines, as do the railroads, come under the control of the Interstate Commerce Commission (ICC) by virtue of Section 1 of the Interstate Commerce Act.[190] As such, the pipeline companies, once operating, must maintain reasonable rates, avoid discrimination, file tariffs of rates and charges, submit to regulations of rates, "...and otherwise conduct their business in the manner of a federally regulated common carrier."[191] The Black Mesa Pipeline Company files its reports with the ICC and is regulated by the ICC. However, pipelines operating strictly intrastate engaged solely in transporting wholely owned coal to wholely owned storage or processing facilities would not come under ICC regulation.[192]

7. Pipeline Impact on Railroads

To better understand the relative impact of slurry pipeline competition on the railroads, a look at some statistics may be helpful. In 1974 western railroads carried 15.5 percent of the nation's total coal carried, while eastern and southern railroads carried 84.5 percent.[193] Burlington Northern, by far the largest coal-carrying western railroad, carried 4.7 percent of the nation's total-coal-carried, while owning 5.3 percent of the nation's hopper cars. The second ranking western railroad, Union Pacific, carried 1.9 percent of the nation's coal, while owning 2.4 percent of the nation's hopper cars. By regional comparison, the eastern leader, Penn Central, carried 14 percent of the nation's total, while owning 16.5 percent of the nation's hopper cars. In the category of coal-carrying, Burlington Northern and Union Pacific (the West's largest coal carrying railroads) rank sixth and thirteenth, respectively. In ownership of hopper cars owned, they rank sixth and tenth, respectively.

Figure 19-6(d) illustrates that the overwhelming concentration of major coal-carrying rail lines and linkages lies in the eastern half of the United States.

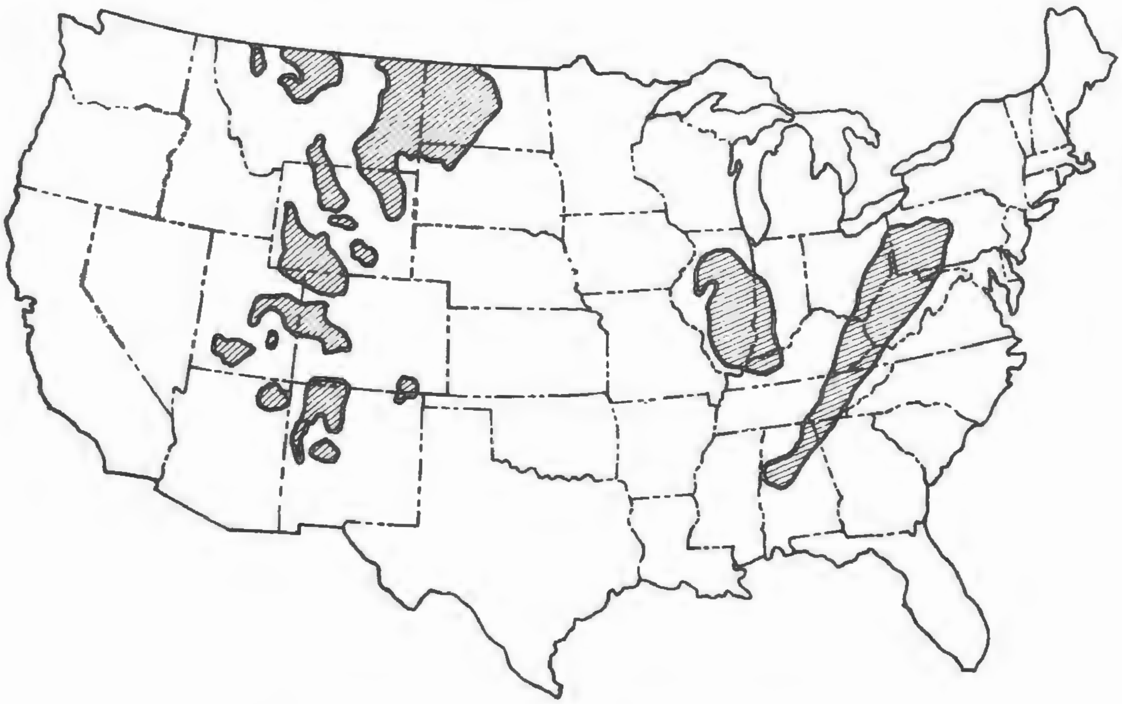
Coal has not been the major factor in development of western railroads, whereas for some eastern railroads, coal accounts for as much as 50 percent of their business. Thus, for the most part, western railroads would be losing potential coal-carrying business to a competing coal slurry pipeline, whereas eastern railroads could lose both potential and existing coal-carrying business. Loss of that existing coal traffic could mean bankruptcy for the marginal eastern railroads. It happens that the proposed major coal slurry pipelines (e.g., Wyoming to Arkansas; Colorado to Texas) lie predominantly in the western half of the United States. And the paths of the proposed lines appear not to strike a redundant path with existing rail lines.

Because, as Figures 19-7(a) and (b) show, moderate-volume, short slurry pipelines are less economically competitive, there is proportionately less economic demand in the eastern sector to construct pipelines. In addition, eastern pipelines would most likely strike a redundant path with existing rail lines of the fiscally strained eastern railroads. This is because of the high density of eastern coal-carrying rail lines, as illustrated in Figure 19-6(d).

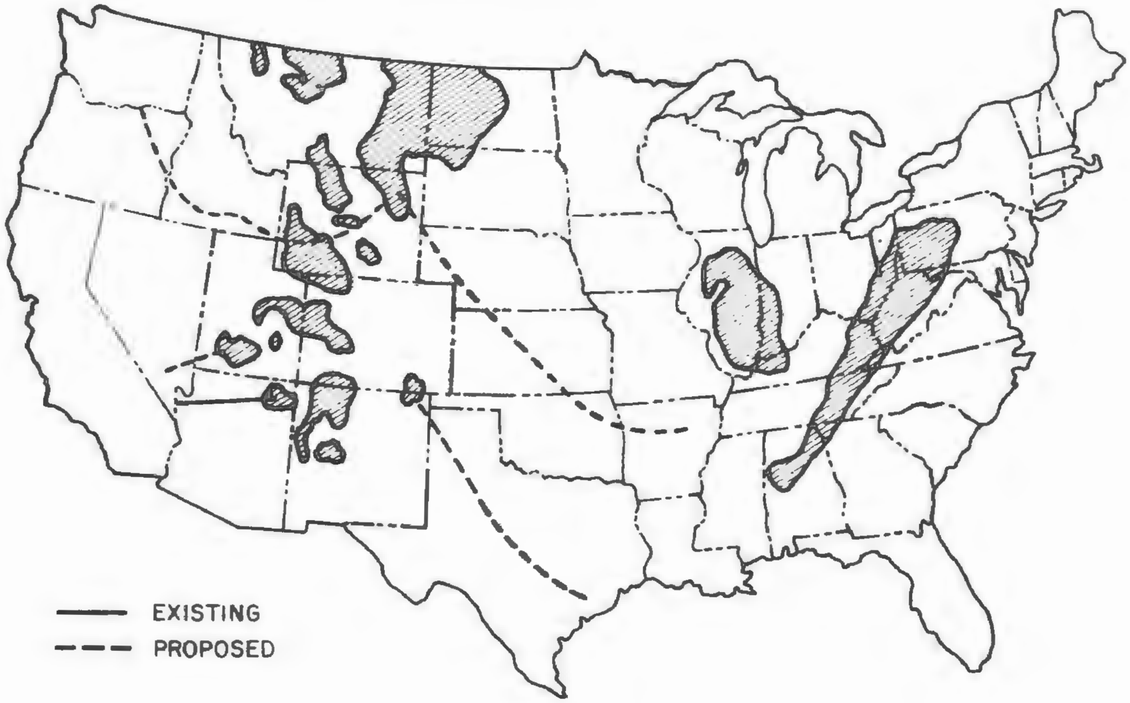
8. Proposed Resolution

The slurry pipeline/railroad tension may be viewed from two public policy standpoints. On the one hand, slurry pipeline technology should be immediately utilized:

> "Growing efficiency in transportation requires that new technological opportunities be seized promptly. With a constantly changing technology, the lag between average practice and the best possible practice is critical....

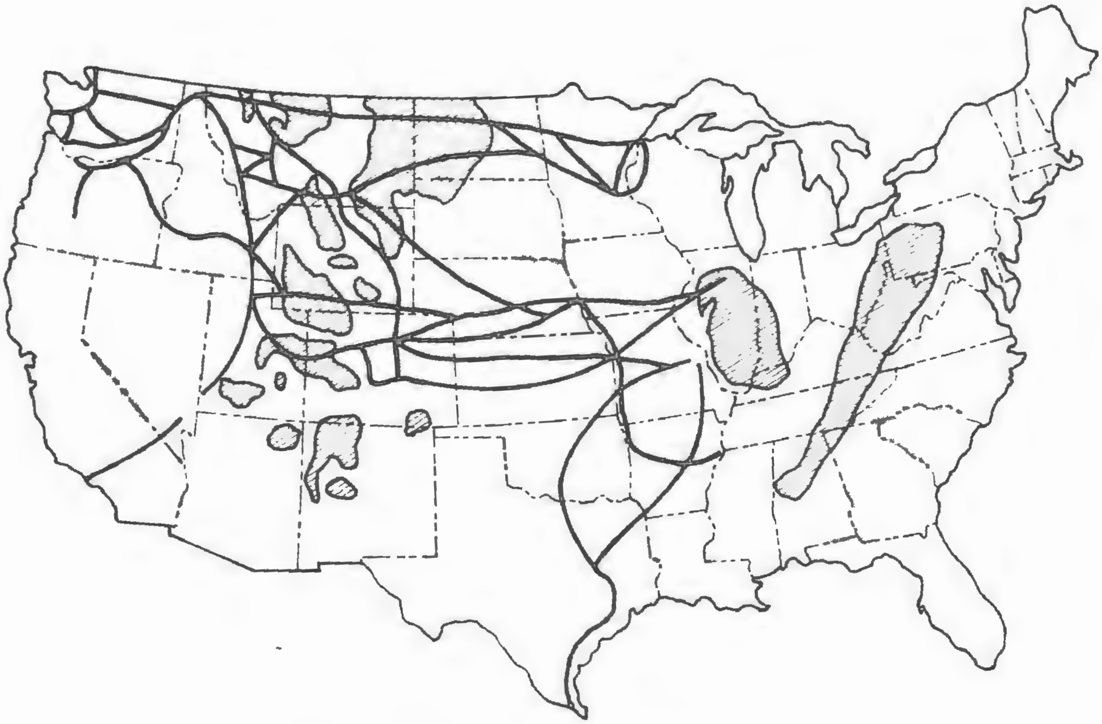


a. Location of Major Coal Deposits

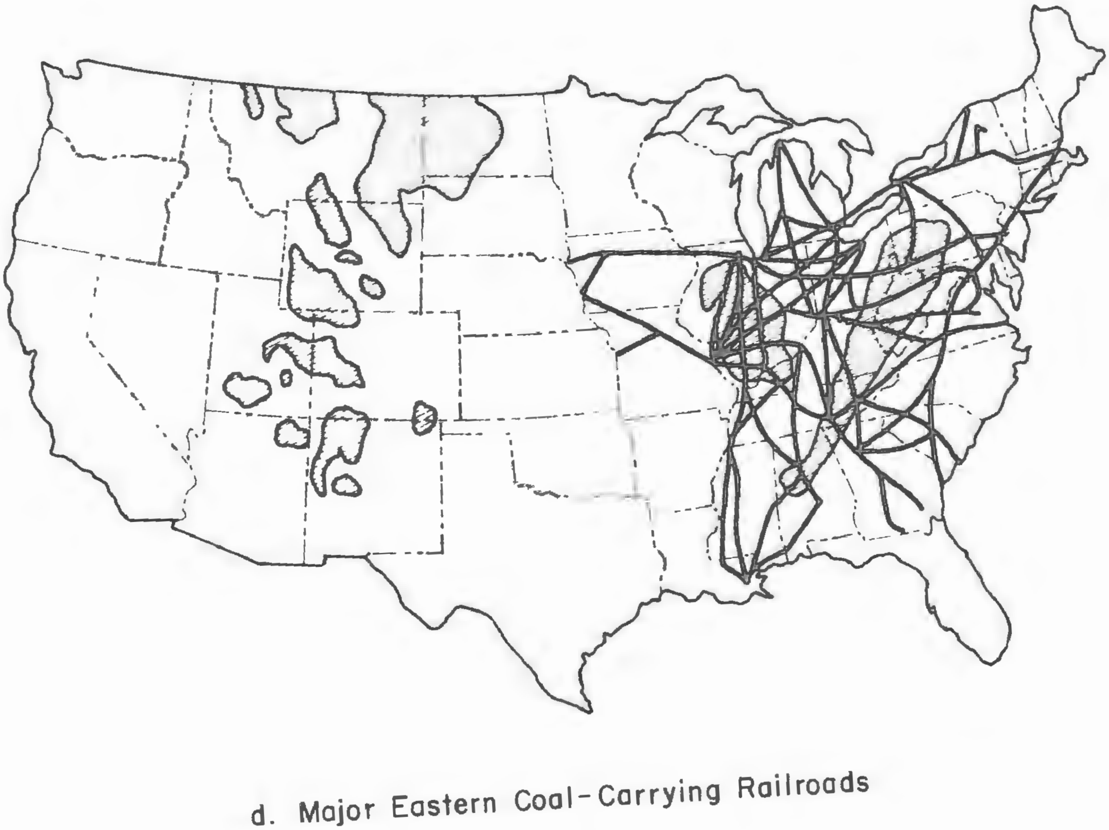


b. Existing and Proposed Coal-Slurry-Pipelines

FIGURE 19-6. COAL DEPOSITS IN RELATION TO TRANSPORTATION FACILITIES

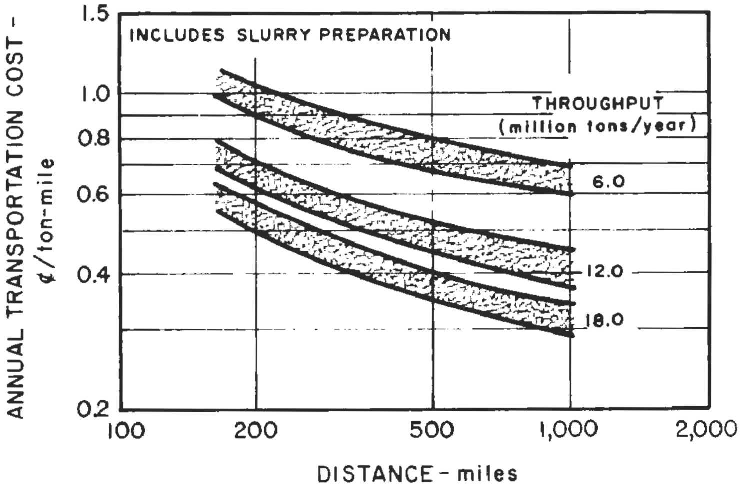


c. Major Western Coal-Carrying Railroads

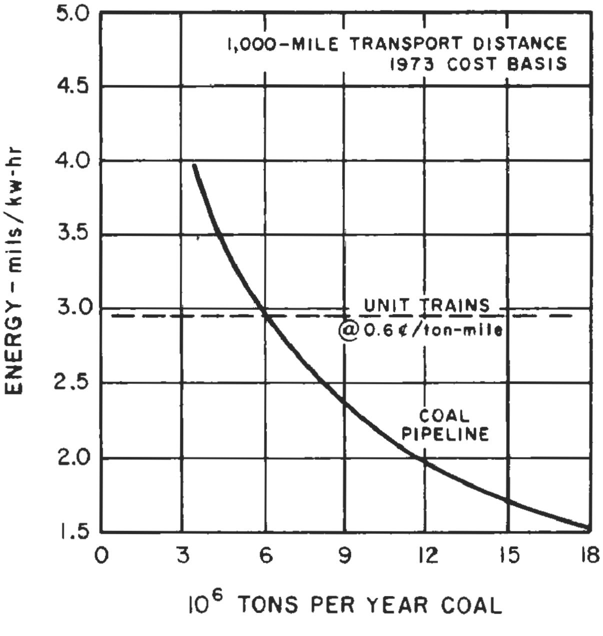


d. Major Eastern Coal-Carrying Railroads

FIGURE 19-6. Continued



a. Coal-Slurry-Pipeline Transportation Costs



b. Coal Energy Transmission

Source: Reference 195

FIGURE 19-7. ECONOMICS OF COAL SLURRY TRANSPORTATION

> Prompt adoption of new technological opportunities enhances the returns to the public...from private initiative in innovation."[*][194]

On the other hand, this kind of efficiency must be contrasted with the broader purposes served by governmentally preserving and supporting a multiuse rail service (passenger movement, freight movement, defense network) that might otherwise die in a pure, free market setting. Thus, in light of the need to consider these dimensions, while at the same time seeking to meet the nation's energy needs, eminent domain power might be granted only in cases where (1) the economics of a pipeline are attractive compared with other transportation alternatives, (2) construction would not strike a redundant path with existing rail lines, and (3) operation of the slurry pipeline would not result in an economic death blow to a neighboring railroad coal hauler. In the same spirit and form of the proposed Jackson Amendment, this additional formula would be applied by the Secretary of the Interior prior to his authorizing the exercise of eminent domain power by a particular project.[†]

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[*] Ironically, these remarks were directed at encouraging expanded use of the unit train concept.

[†] "The power of eminent domain granted pursuant to this title shall be subject to regulations promulgated by the Secretary of the Interior to insure that the exercise of such power by a carrier is compatible with the public interest. Said regulations shall require that, prior to the exercise of any carrier of the power of eminent domain, the Secretary shall find...that the project--

(1) would help meet national needs for coal utilization;
(2) is superior to available alternate means of transportation of coal;
(3) may be impeded or delayed unless granted the power of eminent domain; and
(4) involves no significantly greater disruption to the environment than other modes of transportation or utilization of the coal resources involved."[196]

It may well be that the projected doubling of coal production by 1985 will create considerable coal-carrying and other business for all railroads even as slurry pipelines are built. For example, railroads will handle short hauls to liquefaction, gasification, and power plant facilities; unit trains will be used to haul western coal to intermodal transfer points on waterways, such as Duluth, Minneapolis-St. Paul, and St. Louis;* general growth in the Rocky Mountain and Northern Great Plains states will be reflected in increased general freight revenues; and finally, increased coal-carrying business by eastern railroads may take them far enough along economically that consideration can be given to increasing slurry pipeline construction through an easing of eminent domain restraint.

G. Summary

The Western water problem is centered around the oil shale region located principally in the Piceance Basin, in the Upper Colorado River Basin, and coal-rich Powder River Basin of northeastern Wyoming and southeastern Montana. The following are major issues in both regions:

- Available water supply and augmentation potential
- Competing demands and their alternatives
- Projected energy development
- Energy development alternatives
- Federal control or influence
- Indian water rights
- State laws and interests
- Interstate river basin compacts

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*Burlington-Northern studied slurry pipelines for possible use from the Great Plains coal area to Duluth and St. Louis for intermodal transfer to barge transportation. Their study rejected the idea in favor of movement of the coal by rail.[197]

1. Water Availability

Irrespective of institutional factors which may inhibit a given water-seeker from securing the water he needs, nature provides a limit in terms of the annual precipitation. In the coal-rich Northern Great Plains region, from a total quantity standpoint, there is probably enough water to support a major coal development effort--including coal liquefaction and methanol production. However, the coal and the water locations are not congruent. As a result, the coal will have to be transported to the water, or water will have to be brought to the coal by aqueducts combined with water storage facilities.

In the oil shale region of Colorado, projected real* water uses will consume all the available annual precipitation. Thus, for maximum oil shale development, water would have to be shifted from other demands to oil shale development.

2. The Federal Interest

The federal government has a complex role in the water area. Because it has claims to water to support the land which it owns (50 percent of the land of the western states), it is a disburser of water from reclamation projects, and it has broad constitutional power to control (if it sought to exercise it) the allocation of virtually <u>all</u> the nation's water. These latent powers overshadow state and private water-use decisions. The federal government is also the promise-keeper for the Mexican Treaty of 1944, which promises 10 percent of the Colorado River's annual flow to Mexico in perpetuity.

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*As distinguished from "paper" water rights, which are claimed but not used.

3. Indian Water Rights

Indian claims to western water also present a serious issue. Indian water rights extend at least as far back as the time of the various treaties forming the existing reservations. Unfortunately, the amounts of water under these Indian rights are generally in dispute, and it appears that separate court proceedings will be necessary to determine the amounts in each case. Finally, Indian claims are clearly not subject to the law of the states in which the reservations lie.

4. State Water Laws

Neither the federal power over water, nor Indian water rights is subject to state control. If the federal power were fully exercised, the states would be preempted and left with no allocative powers except those given them by the federal government.

In the absence of federal exercise of that sweeping power, the states have developed varying systems to apportion their water. The humid eastern states rely on the riparian doctrine of water law, inherited from England, by which lands bordering streams have the right to use the flowing water subject to the considerations of downstream users. The water-poor western states developed the appropriation doctrine, which awards water to the individual who diverts the water from the stream for a beneficial use, and in the event of water shortage, the water right secured earliest in time prevails.

Wyoming has a permit system to help keep records of water rights. Colorado has recently introduced a recordation mechanism, but not before more water rights were established than there is water in the rivers of the state. Montana's concern over who would get what amounts of water, and for what purposes, caused it to establish a three-year moratorium, to expire in 1977, on the issue of new water rights.

A significant problem in the state law area in terms of water for energy development is the transferability of a water right. The degree to which a water right can be bought and sold, the degree to which the purpose of the water right can be changed (e.g., from agricultural use to energy development use), time restrictions on when the water can be taken (e.g., agricultural needs are typically summer needs while energy development needs would be year around), restrictions on the point of diversion and the point of application of the water (including the interbasin transfer problem), and the advisability, from the state's standpoint, of having all agricultural water rights bought up by energy development companies, all bear on the subject of transferability.

States are now recognizing the need to reserve certain amounts of water for in-stream values such as recreation, fish life, and water quality. Whatever water is used for this purpose will have to come from the available supply and this will worsen the problem of shortfall.

The large projected water demands have placed a strain on state laws relating to groundwater use. Only very recently has there been a move to protect the water table from haphazard exploitation and contamination. The groundwater issue is so new that recharge rates of these underground reservoirs are generally unstudied and unknown.

5. Interstate Allocation of Water

The U. S. Supreme Court is the potential arbiter of the respective water rights of two states with a river that forms their common border and of the rights to water from a river that flows through two or more states. The Supreme Court and the U. S. Congress have encouraged the states concerned to develop formulas for sharing the water--subject to Congressional approval of the agreements.

In the areas considered in this study, there are four such interstate compacts: the Colorado River Compact of 1922; the Upper Colorado River Basin Compact of 1948; the Belle Fourche River Compact of 1943; and the Yellowstone River Compact of 1950. These compacts in no way delimit federal or Indian water rights. Accordingly, they could be rendered moot if full federal power were exercised over the nation's water. In the absence of the exercise of that power, the allocative formulas have been operable.

Particular problems with the compacts relate to the fairness of the formulas themselves and the numbers used, especially because the compacts were made long before the region became a focal point for energy development. For example, Colorado's annual contribution to the Colorado River is over 11 million acre-ft per year, but the state is allocated only about 3 million acre-ft per year. Because Colorado is the primary oil shale development area, the state is angry that it is being forced, essentially, to shift agricultural water to energy development use as a result of its meager allotment under the compacts.

Another institutional barrier may be seen in the Yellowstone River Compact, which prohibits interbasin transfers without the consent of all signatory states. This could prevent transfer of water into the Powder River Basin--rich with coal but short of water--even from nearby river basins such as the Bighorn or Yellowstone.

6. Transport of Coal: The Slurry Pipeline Issue

Planners looking at the total impact of a major coal conversion program in the Northern Great Plains are attracted by the possibility of transporting the coal out of the region for processing elsewhere. An intense political battle is being waged over the granting of eminent domain power to pipeline companies so that they can construct the pipelines to these distant processing points. The chief opponent to pipelines is the railroad lobby because railroads want to reserve coal transportation to themselves. Impressive arguments can be presented in favor of each of the means of transport. It is a water-related matter because the pipelines would use large amounts of western water to form the slurry, although the amount of water is far less than if the coal were converted in the region. Economics appear to favor the pipeline, while the railroads argue that they face bankruptcy without the coal-carrying business and that the country needs its railroads to cary people and other commodities.

To sum up, there is at present no comprehensive effort on the part of the Congress to deal with the difficult political value questions implicit in the question of water for energy development in the West. There is no hint of action going beyond the joint study of the Northern Great Plains Resource Program and the Environmental Impact studies for the Colorado oil shale region. The water sought for energy development is vital to the way of life of the western states. The economic base, and the very culture of Colorado, Wyoming, Montana, and North Dakota could be greatly altered if the region's energy-rich resources are developed without a comprehensive water plan.

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20--WATER AVAILABILITY IN THE EASTERN UNITED STATES

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A. Introduction

This chapter treats the question of water for synthetic fuel plants in the eastern United States under the maximum credible implementation (MCI) scenario for 1980-2000. Water requirements are set against water supply, and the availability of water from a legal standpoint is discussed.

The Water Resources Council (WRC), which is the agency charged with developing, coordinating, and assessing water resources planning information for the entire nation, is the source of the data on water supply and nonsynthetic fuel requirements used in this chapter* For the analysis, synthetic fuel plants are located according to the planning areas established by WRC in its study '75 Water Assessment.[1]

The '75 Water Assessment provides greater detail concerning water demands, uses, and resources than the previous assessment of 1968. New concerns for increasing energy production within the United States have

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*Arden O. Weiss, Chairman of WRC's National Programs and Assessment Committee for the '75 Water Assessment has kindly made data available to this study--data that are, however, preliminary and subject to revision. WRC is not, of course, responsible for any errors in use or interpretation of this data.

changed projected water resource demands dramatically in some regions. WRC is currently working with the Bureau of Mines to determine future water resource requirements for planned and anticipated coal conversion processes of various types. In addition, WRC is reevaluating estimates for future withdrawal and consumptive uses for electric power generation.

Figure 20-1 shows the major river basins of the United States; these correspond to the WRC's water resource regions. Figure 20-2 shows the subareas established by the WRC that are affected by the MCI. The aggregated subareas (ASA) within each region follow major river watersheds and are composed of one or more subareas. For purposes of defining river watershed areas the WRC has normally maintained county lines as subarea boundaries.

B. Water Requirements

Data developed by WRC on "Current and Future Annual Water Requirements" for each ASA for the _'75 Water Assessment_ are used here to provide a regional estimate of the quantities of water required for synthetic fuel plants located in the East. Water requirements for plants hypothetically sited by the MCI in Illinois, Kentucky, Ohio, and West Virginia, are given in Table 6-3 (Chapter 6). Table 20-1 summarizes these requirements for the year 2000; the requirements for plants in Kentucky are divided into eastern and western components; WRC ASA designations are also given.

Table 20-2 lists the consumptive water uses for the plants (Table 20-1), the additional water consumption projected by the WRC, and determines the percentage water consumption as a function of both the total water supply and the indigenously produced water supply for each ASA in which the relevant subareas reside. Data in the upper half of Table 20-2 indicate that, on a gross regional basis, the impact on the water resources of each ASA would appear to be small.

FIGURE 20-1. WATER RESOURCE REGIONS OF THE UNITED STATES

FIGURE 20-2. SUBAREAS FOR THE 1975 WATER ASSESSMENT
(Water Resources Council)

Table 20-1

EASTERN UNITED STATES MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO WATER REQUIREMENTS IN THE YEAR 2000

State	Requirement (10^3 acre-ft/yr)*	WRC ASA No.	WRC Subarea No.
Illinois	415	705	714
Kentucky	266		
East	(133)	502	507†
West	(133)	505	515
Ohio	133	502	507†
West Virginia	134	504	505

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*10^3 acre-ft/year is about $1.2 \times 10^6 m^3$/year.
†Note that the Eastern Kentucky and Ohio water requirements are in the same WRC subarea.

However, such conclusions are on an annual basis. The lower part of Table 20-2 shows the relationship of the high and low flow months to the average monthly flow. The "worst case" is the driest month of a dry year in Eastern Kentucky and Ohio (ASA 502). Then average daily flows are only 26 percent of the average monthly flow, and during that month only 95,000 acre-ft would be available compared to the 22,000 acre-ft required by the synthetic liquid fuel plants. Thus, in the driest month of a dry year, the synfuel plants would require about 23 percent of all indigenous water in this region.

Table 20-3 compares the consumptive use requirements for synthetic liquid fuel plants with the consumptive use requirements projected by

Table 20-2

FUTURE WATER DEMAND COMPARED TO WATER SUPPLY IN THE YEAR 2000

	Illinois (ASA 705; subarea 714)	Eastern Kentucky and Ohio (ASA 502; subareas 503, 507, 509)‡	Western Kentucky (ASA 505; subareas 510, 511, 515)‡	West Virginia (ASA 504; subarea 505)
Supply				
Total				
Median Year* (10^3 acre-ft/y)	132,000	71,400	106,000	12,100
Dry year† (10^3 acre-ft/y)	69,300	46,100	58,700	8,310
Indigenous (Surface)				
Median year* (10^3 acre-ft/y)	14,400	24,650	41,600	11,800
Dry year† (10^3 acre-ft/y)	14,400	15,000	14,300	8,250
Demand				
Projected total of nonsynthetic fuel uses (10^3 acre-ft/y)	406	1,638	691	392
Synthetic liquid fuel (10^3 acres-ft/y) uses (from Table 20-1)	415	266	133	134
• Fraction of dry year total supply (%)	0.6	0.6	0.2	2
• Fraction of dry year indigenous supply (%)	3	2	0.9	2
Fluctuations in total supply				
• Highest flow month compared to mean monthly flow in a dry year (%)	156	151	167	162
• Lowest flow month compared to mean monthly flow in a dry year (%)	43	7.6	26	14

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*50% chance of being drier

† 5% chance of being drier

‡ relevant subarea underlined

WRC for electric plants in the same ASA; the requirements are generally comparable in magnitude.

Table 20-3

PROJECTED WATER CONSUMPTION BY ELECTRICITY GENERATING AND SYNTHETIC LIQUID FUEL PLANTS IN THE YEAR 2000
(10^3 acre-ft/year)

Area	Electricity Generation Plants	Synthetic Liquid Fuel Plants	Total
Illinois (ASA 705)	70	415	485
Eastern Kentucky and Ohio (ASA 502)	477	266	743
Western Kentucky (ASA 505)	254	133	387
West Virginia (ASA 504)	88	134	222

C. Water Supply

1. Illinois

This area (ASA 705) consists entirely of Subarea 714. This area straddles the Mississippi River and includes portions of Southern Illinois and East-Central Missouri. The Wabash River in Illinois, directly to the east of this subarea is in Subarea 515 (see Western Kentucky section 2-a, below). The plants in this subarea are sited on the Illinois side of the Mississippi River to remain as close to the coal fields as possible. The river basins included are as follows:

- Kaskaskia
- Big Muddy
- Cache.

Existing water storage capacity totals 1,640,000 acre-ft. This storage is in two major lakes on the Kaskaskia River. There is additional potential storage capacity of 1,240,000 acre-ft.

Flows in the Big Muddy River range from a low of 10,000 acre-ft/year in dry years to 268,000 acre-ft/year in median years. Existing water storage capacities total 119,000 acre-ft. This storage is primarily on Rend Lake, which is on the river. There is additional potential storage capacity of 758,000 acre-ft. Current and projected withdrawals for thermal cooling from the Basin are negligible. In view of the low flows in dry years and the relatively small flow from existing storage, the Big Muddy would not appear to be a primary candidate for the location of even a small syncrude plant unless the plant either drew water from the mainstem of the Mississippi River or located a source for transbasin diversion.

2. Kentucky

a. Western Kentucky

The WRC has divided this area (ASA 505) into three subareas: 510, 511, and 515 (Figure 20-2). We have sited the western Kentucky synthetic fuel plants in subarea 515.

Although Subarea 515 spans both sides of the Ohio River mainstem, the main river basin in the subarea is the Green River Basin with a total area of 9273 mi^2 in 31 counties. Except for a relatively small area in northern Tennessee, the Basin's natural drainage area is entirely within Kentucky. The drainage basin is roughly 60 to 80 miles wide and 160 miles long.[2] The Green River and its tributaries flow through the heart of Kentucky's western coal region. The average annual runoff in the Basin is 15-20 inches.[2] Three major federal reservoirs are in the area--Nolin, Rough, and Barren. Moreover, the identified additional storage potentials in the Basin amount to approximately 1 million acre-ft.[2]

The general precipitation runoff-storage situation in the Ohio River Basin is as follows: Of the total precipitation, over 60 percent is lost to the atmosphere by evaporation and transpiration. The remainder, averaging annually 17.3 inches equivalent depth over the drainage area, flows to the Mississippi River.[2] Generally, sufficient runoff for summer and fall use could be stored during each high water season without holding stored waters from year to year except in very high water use areas and during periods of extreme or extended drought. Even in lower tributaries, streams may run dry during periods of low precipitation, especially where ground water seepage is deficient.

Existing storage capacities have been developed generally for flood control and for control of low stream flow because the maintenance of stream flow is important to the preservation of water quality in the region.

While total flows in the region appear adequate to sustain the needs of the synthetic liquid fuel plants, attempts to establish the long-term water supply for necessary plants may require the development of considerable storage capacity or use of existing storage. In addition, general factors relating to the uncertainties of future developments would affect the amount of water that is available.

b. Eastern Kentucky and Ohio

The WRC has divided this area (ASA 502) into three subareas: 503, 507, 509. The synthetic liquid fuel plants, however, have all been sited in subarea 507 which contains 37 counties in Kentucky, Ohio, and West Virginia.

The major rivers in the ASA are the

- Pittsburgh
- Cincinnati
- Little Miami

As this is an area of rugged terrain in the Appalachian mountains, industrial sites are at a premium.

3. West Virginia

This area (ASA 504) consists entirely of subarea 505. The Kanawha River basin includes six major subbasins:[3]

Subbasin	Drainage Area (mi^2)
New River	6918
Greenbrier River	1656
Elk River	1532
Gauley River	1420
Coal River	899
Pocatalico River	359

Average annual precipitation in the Basin as a whole is approxmately 43.5 inches. If annual precipitation less than 85 percent of the mean is considered to be a drought condition, 16 of the 76 years for which weather records have been kept for Charleston, West Virginia, would be classified as drought years; 1904, 1930, and 1953 were particularly severe.[3]

The Kanawha Basin has the highest sustained flow of the tributaries of the upper Ohio River. There are no major natural lakes in the basin. Streamflows are subject to wide seasonal variations and to relatively wide variations between extremely wet and dry years,[3] and thus access to storage capacities would appear essential to satisfy the water demands of the synthetic fuel plants.

The terrain of the area features steeply rising hills and narrow valleys, which lie along the watercourses of the streams and rivers. All of the important existing industrial, residential, and transportation facilities and networks in the basins are located in these valleys. Because of the topography, industrial sites in the basin are at a premium.

D. Legal Aspects of Water Availability

1. Riparian Law

Unlike water rights in the western states, which are governed by an "appropriation" system, water rights in the eastern states are governed by riparian law.* Under riparian law, the right to use water attaches to the land over which the water flows. Thus, historically, a riparian right has been a property right.

Early in American history the rules of English riparian law were incorporated into the law of the respective states:

- "*Prima facie* the proprietor of each bank of a stream is the proprietor of half of the land covered by the stream; but there is no property in the water."[4]
- "Every proprietor has an equal right to use the water which flows in the stream; and, consequently, no proprietor can have the right to use the water to the prejudice of any other proprietor."[4]

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*Riparian relates to that which is located on the banks of a natural watercourse.

- "Without the consent of the other proprietors who may be affected by his operations, no proprietor can... diminish the quantity of water which would otherwise descend to the proprietor below."[4]
- "Every proprietor, who claims a right...to diminish the quantity of water which is to descend below, must, in order to maintain his claim, either prove an actual grant or license from the proprietors affected by his operations, or must prove an uninterrupted enjoyment of twenty years."[4]
- "Though the proprietor may use the water while it runs over his land as an incident to the land, he cannot unreasonably detain it or give it another direction, and he must return it to its ordinary channel when it leaves his estate."[4]

There is also a rule that water may be used only on riparian land by its proprietor. Thus, if a riparian parcel of land is divided and sold in such a manner that what was one large, riparian parcel becomes one riparian and one nonriparian parcel, there are no water rights associated with the newly created nonriparian land. In other words, water rights are incidental to lands bordering on streams and cannot be created or transferred independently. Thus, use of water is strictly limited to uses on riparian lands.

Some states have modified this practice by establishing a test of reasonableness of the nonriparian use. If lower riparians claim injury because of a nonriparian's use of the waters of a stream, the courts will look to the nonriparian's application of the water to determine whether it is reasonable. Generally, the cases indicate that any productive use except waste* is considered reasonable by the courts. Consequently,

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*As used here, "waste," is a legal term meaning, roughly: an abuse or destructive use of property by one in rightful possession.

the party seeking to enjoin a diversion by a nonriparian must prove, in addition to injury, that the use to which the diversion is put is unreasonable.

When the stream flow is insufficient to satisfy all users because of low flow, then the rule of "correlative rights" comes into play: All riparians must suffer diminution of use equally.

The general law of riparian water law is in effect in the states in which the eastern syncrude and methanol plants would be sited but the modified rule of reasonable use of diversions is in effect in Kentucky and Illinois.

The National Water Commission made attempts to determine how riparian water law actually works in practice in those states in which it is in effect.[5] The Commission found the general situation to be as follows: As a consequence of the riparian rules and the absence of records, the public planner and private investor are confronted with the following uncertainties in water resource development:

- What is the existing demand on supply?
- What is potential demand on supply?
- What supply security will present development have in the future?
- What kind of private consensual arrangements can be made to safeguard supply?[6]

Thus our general knowledge of how the riparian system works in actual practice in the states of the East and of how present water rights actually relate to supply is limited. This also applies to the transfer of water rights under riparian law. One type of transfer is common; a sale of riparian land automatically transfers the seller's water rights to the purchaser. This is not the interesting case in terms of the development of a law of water transfers. The interesting case is where the water is sought to be sold apart from the land. It is here that we have almost no information about the operation of the riparian system. Evidently such transfers are rare in that system, due probably to the plentifulness of water in most of the areas where the riparian system is in effect, but it may also be due to the legal difficulties of attempting to transfer riparian rights except as an incident to a sale of riparian land.[7]

The actual fact is, of course, that power plants using once-through cooling water have been built in the three states under consideration in this study; large chemical processing plants have been developed in West Virginia along the Kanawha; other industrial operations, which require an assured supply of water, have flourished in the states under consideration here. Most such plants are located along the main stems of the major rivers, ones whose flow throughout the year is assured (often with the assistance of major storage projects) and, where the consumptive uses of the plants either diminish the total flow so little that no downstream riparian is injured, or that no downstream riparian is in a position to complain. Shortage of water also plays an important part in the ability to maintain an assured flow for a number of uses. Where this is the case, the common law doctrines of riparian water law may be inapplicable. What often happens is that state and/or federal statutes authorizing the projects became the legal means by which the storage and allocation of water is established (see Section E, below). In the "humid East" these storage projects generally are aimed at capturing and controlling flood waters, waters which could not be of use to any riparian anyway and in most cases constitute a positive threat. The storage of flood waters for later use in the maintenance of stream flows and related or dependent uses appears to present little or no controversy. In fact, the National Water Commission did not consider this aspect of the problem in its strictly legal studies in the area.[5]

In summary, a description of the riparian law which obtains in the eastern states under consideration in this study, while perhaps necessary for background, is of little assistance in determining whether or not water would actually be available.

In contrast with the appropriation law system, the effect of riparian law is more in the nature of a negative influence over new developments rather than a positive system for the identification and determination of quantitative rights in water uses. This is especially true when the contrasted appropriation system has been strengthened through application of a state permit system. Water rights under riparian water law doctrines tend to be uncertain, thereby compounding the difficulty of any attempt to ascertain whether water would be available for the projected development of synthetic fuel plants. Moreover, riparian water law, and the traditions on which it is founded, does not readily lend itself to the development of positive water use permit systems. Proposals that riparian states should enact permit systems like those in effect in some western states have been firmly rejected by the eastern states.

2. Position of the States

The National Water Commission asserted that "no crisis in water use exists generally in the humid East" and that the uncertainties over the state of knowledge of water rights, supply, and demand "have not yet caused serious problems in the East, for water supplies have been abundant."[6] This situation may have changed in the short time since 1973 when the Commission issued its final report. Water supplies in the East may become generally "critical" at a more rapid rate than was anticipated.

For Project Independence, the Water Resources Council polled the states concerning water related problems in connection with energy developments.[8] Those states that attended the WRC regional conferences as a follow-up to the WRC questions "expressed a belief that the Federal government must first propose a definitive policy on energy self-sufficiency including time frames and needs before states can do adequate long range planning."[9] In the area of "water rights" and legal impediments, the states expressed views indicative of problems that would be encountered by an attempt to establish the plants in the East as a matter of federal policy without that policy also having been adopted by each involved state for itself. In the matter of <u>water rights</u> the states held strong opinions regarding federal jurisdiction over water rights. They felt that energy self-sufficiency would be impeded due to litigation if the federal government were to move strongly into the water rights area. In fact, a suggestion was made that Congress should enact legislation assuring that water rights granted under state law be protected. It was felt that under most present systems, water rights can be acquired by negotiated purchase or by condemnation and most state water laws are well adapted to provide water for self-sufficiency.[8] In the matter of <u>legal impediments</u> almost all states indicated that compliance with water rights acts and water quality control acts would impede energy developments. However, it was pointed out that regulatory laws may help and not hinder the best use of water and that energy developments should proceed only under strict and rigidly enforced controls. In fact, concern over the adverse impacts of rapid development of energy sources has prompted states to consider or enact stringent regulatory measures for mining, facilities-siting, and related activities.[8]

In view of the foregoing, and because "Federal water projects are seldom initiated without strong State support and almost never undertaken in opposition to State desires,"[8] it appears that not only state law--in the sense of the riparian law governing water rights--but state policies and administration directed toward water resources development will heavily influence the question of water availability for projected synthetic fuel plants.

The following is a brief summary of the situation as it pertains to three of the states considered in this chapter.

a. Illinois[10]

- The Illinois state constitution contains no water policy statement for the state.
- Water use in Illinois is governed primarily by its state court fashioned rules of law. Generally, in this regard, the courts follow the common law of England, modified as the courts find rules that are in harmony with the state's legal system.
- Periodically, attempts have been made to implement the common law through legislation. These attempts have failed, but there is some disconnected legislation that deals with certain phases of water use.
- There have been relatively few court cases reported regarding water use in Illinois.
- Under the riparian doctrine, the courts have distinguished between artificial and natural uses. The latter use, which includes those needs that are absolutely necessary for the existence of civilization (i.e., drinking water, water for household purposes and for watering livestock) has a clear priority over all other uses in times of drought. Each proprietor may, when necessary, use all of the water in a stream for these purposes without liability to a lower proprietor on the stream.
- The rule of reasonable use appears to apply in Illinois, but its effect in practice is uncertain.
- The state's courts have taken a strict view of what constitutes a navigable stream. It must be in the nature of a highway that bears commerce. A stream that is not naturally navigable cannot be made so by deepening, widening, etc. (Legally, if this state view conflicts with the federal view, the latter prevails.)

- The attorney general has expressed the opinion that the Department of Public Works and Buildings may permit the withdrawal of water from a public body of water through a pipeline for industrial and manufacturing purposes if it determines that to do so will be in the public interest and if the riparian rights of lower riparian owners are not adversely affected by diversion of the water.

- Diversion between basins has been considered by the state's courts mainly as a problem of burdening the riparian owners of the water course from which the diversion was made. That is, a riparian proprietor has the right to natural flow, unaugmented by diversions from other basins.

- The state has broad eminent domain powers for the acquisition of property for water management and development. The Departments of Public Works and Buildings and of Conservation are the primary agencies with the power to exercise eminent domain. The state has also delegated this power to a number of its subunits of government: cities and villages, counties; townships; soil and water conservation districts; subdistricts of same; port, sanitary, river conservancy, surface water protection, and public water districts; and water authorities.

- Under the state's regulatory authorities, permits or approvals are required for the drilling of wells, impoundments, and channel encroachments. Some of these permits require the applicant to obtain the consent or approval of downstream riparian proprietors.

- Approximately seven state-level departments, including 42 divisions and seven boards or commissions are involved in one aspect or another of development, maintenance, operation, and regulation of the state's water resources. In addition, the state has numerous subunits of government, including special purpose districts, which have powers and duties relating to water resources development and utilization.

- As a matter of policy, water management functions in Illinois are centralized. The Department of Business and Economic Development, Division of Water and

Natural Resources, is the state's "lead agency" in the coordination of water resources management and development policies.

- In general, the power of home rule has not been granted to local governmental units by the state. It has granted powers to local governments to develop water resources on a categorical basis: sewage, water supplies, etc. In general, this has led to creation of special purpose districts to solve local problems. These districts have home-rule-like powers for special purposes in some cases.

- Coordination between the state and the federal government, including the Corps of Engineers and the Soil Conservation Service, on matters of water resource management and development is the responsibility of the state's Department of Business and Economic Development.

- The state follows the policy of seeking the greatest degree of overall development of each reservoir project in the state. The Rend Lake project on the Big Muddy is a recent example; the project provides water resources for multipurpose operations: municipal, industrial, and agricultural water supply; recreational facilities; flood protection; minimum downstream low-flows; pollution abatement; and other purposes. The project was carried out by the state's Division of Waterways.

- The Rend Lake project is also an example of the state's policies towards multigovernmental cooperation. The Rend Lake Conservancy District, the state, and the federal government participated directly in the project, with the latter two coordinating with the many other agencies and districts involved.

b. Kentucky[2]

- Riparian rights under Kentucky law have been narrowed by legislative action. A riparian proprietor has the right to withdraw waters for agricultural and domestic purposes without a permit.

- With the above exception, and the one cited in the following, all other public water users in Kentucky must obtain a permit from the state's Division of Water. The statutory permit system requires the permittee to maintain certain records of withdrawal.
- No permit is required for industrial or manufacturing operations provided that the water withdrawn "is returned in substantially the same quantity and condition as it is withdrawn...."
- Kentucky's permit system does not operate to allocate the state's waters, although the Division of Water has the power to apportion shortages. (This power has apparently never been exercised.) The permit system in effect appears to be a step towards improved record keeping and a potential basis for the exercise of increased state control of water uses should future demands so require.
- The state requires permits for the construction of impoundment dams and other forms of water containment, and for obstructions.
- The state requires permits or exercises authority over water resource related activities concerning drilling or abandoning wells, developments in flood plains, construction of public water supply, and flow regulation.
- By statutory declaration, "it is declared the policy of the Commonwealth to actively encourage and to provide financial, technical and other support for the projects that will control and store our water resources in order that the continued growth and development of the Commonwealth might be assured."
- Approximately nine departments, including eight divisions, and five Boards or commissions are involved in the state's water resources.
- The Division of Water within the Department of Natural Resources is the state function assigned the primary responsibility for developing the state's water resources, preventing floods, and

controlling water usage within the state. The Division also holds the power of eminent domain.

- The state has enabled a number of water resource related special purpose districts: conservancy, flood control (subdivided into city flood control districts, flood control districts, and levee districts), sanitation, soil conservation, and water districts.
- Responsibility for development of the state's water resources is "ultimately" centralized at the various state agencies. The extent and practical nature of home rule in the state is unclear. However, it is thought to be extensive for a number of purposes.

c. West Virginia

- The riparian law of water rights obtains as the common law of West Virginia in practically unmodified form with respect to its origins in the English common law.
- Most of the water rights cases in the state deal with the protection of property against water damage due to excesses of water on lands of others.
- There has been little or no litigation concerning diversion between basins. Strict adherence to riparian doctrines would appear to preclude such diversions, but apparently there has been no significant diversion in the state.
- Impoundments are permitted by the state (for example the Buffalo Creek impoundment was under state permit): the state regulates little else with respect to the use of water resources.
- There are approximately six state departments, including six divisions, and six boards or commissions, which are responsible for state's water resources in one way or another.
- The Division of Water Resources within the Department of Natural Resources is the "lead agency," to the extent that the state does

exercise responsibility, for water resources development and management.

- Three special purpose districts have been created by the state: soil conservation, watershed improvement, and public service districts.
- Home rule obtains in West Virginia by a 1936 amendment to its constitution.

The foregoing overview summary of the laws, policies, and administrative scope of the three states may be deceptive for its apparent simplicity. If the states and their local units of government are involved at all in the siting of projected synthetic fuel plants--and it is difficult to see how they would not be under existing federal-state law unless the Congress were to enact legislation which simply preempts all state law in water related questions--then the plants will be sited within the context of complex, perhaps exceedingly complex, legal, policy and administrative frameworks which, for the most part, are unique to each state. This also means that a particular solution to a problem, or a cluster of problems, related to water availability in one state or locale will not necessarily assist in solutions to similar problems in the other states. From a practical point of view, the issue of water availability in the eastern states may depend more on factors other than apparent quantitative flows. Many of those factors result because of the fact that the states under consideration have no experience with water shortages and therefore have no policy or legal traditions behind them from which to deal with the problem.

It is evident from the material reviewed for this study that the states under consideration in this chapter are strong opponents of trends leading to a centralized planning, implementation, and regulatory approach toward water resources: "Resistance (by the riparian states) to the granting of firmer rights has already been demonstrated by the general refusal to adopt appropriation style permit systems giving users in the East rights similar to western appropriation rights."[5] The main argument by the states for retention of the present methods of water resources development and the allocation of water rights on a project-by-project basis appears to be that the rule of "reasonable use" provides a greater flexibility in meeting shifting water demands than would a rigidly applied appropriative system coupled with a "permit" authority. Under riparian law, the basic conflict appears to be between certainty and flexibility: "Courts have responded (to this conflict) generally by expressing the notion that riparian rights must be flexible, and yet practical priorities are recognized. It does seem fair to conclude that reasonableness represents a rule of accommodation, and subject to legitimate claims for accommodation, priority in time is likely to give priority in right over new users competing for an insufficient supply."[6]

Maintaining the riparian system--with all its uncertainties--on a notion of flexibility is all very well when water quantities and qualities are sufficient to allow plenty of room for maneuvering to take advantage of that flexibility. In the event--which now seems to be in the offing--that there is no more room to maneuver between existing demands on the water resource, low-flows in drought years, and increasingly poor water quality in the available supply, the riparian system would probably come under considerable stress if faced with substantial demands for new water resources related to economic growth. Of course, it is impossible to predict how the states may respond to such a situation, and mapping alternative possibilities would be gross speculation at this time.

E. Federal Programs That Relate to Water Resource Development in the East

The following summary identifies the major federal agencies and their programs that relate to water resources development in the eastern states. The discussion does not treat the federal power to conduct such programs in the states because that power applies to both the eastern and the western states. The information is drawn primarily from two staff studies for the National Water Commission,[11,12] plus additional more recent material.

From the federal government point of view there are two underlying factual differences between the eastern and the western states:

- The federal government is not a substantial landholder in the eastern states.
- Traditionally, the eastern states have not been beholden as have the western states to the federal government's application of massive resources in the development of water resources projects for new irrigation and other land development.

These two historical facts account for the substantially different bases for relationships between the states and the federal government in the East and in the West.

If the primary concern of the states in the "arid West" has been the application of federal resources and funding to the development of water resources to bring water to those lands, then by contrast the primary concern of the states in the East with respect to the federal government has been to seek assistance in keeping excess waters--flood waters--off the lands of the state.

To continue this contrast, while the Bureau of Reclamation has been the federal agency most involved in the development of major public works devoted to the development and conservation of water resources for application to arid lands, the Corps of Engineers has had a much longer tradition (since 1824) of flood-control works in the eastern and midwestern states. (Navigation is also the responsibility of the Corps.)

The most recent programs of the Corps for reservoirs are directed to multipurpose developments, meaning that a major reservoir project must serve multiple water resources purposes. Primarily it has been the Corps which has undertaken, on behalf of the federal government, the large reservoir projects that relate to improved water resource management and use. It is the Corps that would be involved in any future major works for water storage, although where pumped storage and hydroelectric power are involved the Federal Power Commission and the utility itself undertake the primary responsibilities.

It is not necessary to review the Corps' responsibilities, programs, policies, and practices here because they have been well documented through recent studies and public controversies. However, from a planning point of view, it is important to note that the Corps is running into increasing difficulty in obtaining approval for its water resources development, management, and control projects. The very recent events surrounding the Corps-proposed project to build a $30 million dam on the Red River Gorge in eastern Kentucky is an example that is geographically and politically pertinent to this study. The Council on Environmental Quality (CEQ), in a rare action, has publicly opposed the Corps' project. In its general nature, the project is a typical multipurpose reservoir project of the type undertaken in the eastern states. Local landowners have succeeded in obtaining a temporary restraining order from a federal court in Louisville to halt the project. They have been joined by a number of conservation groups.* The controversy has split

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*Under present doctrine, conservation groups must join with plaintiffs who would actually be injured by the proposed developments in order to achieve standing.

the former and present members of the congressional delegation. Opposition has been going on since at least 1968 when the former Justice and Mrs. Douglas took a walking tour through the area to underscore their personal protests. It is an issue in local elections. The Corps remains adamant on the issue that it need not provide further quantitative information concerning certain aspects of the project, nor does it think it has overlooked the major social and cultural changes that would be wrought through consequential developments. This could force each plant either to go to the main stem of major rivers in the area, such as the Ohio and the Mississippi, or to storage projects for each plant's water needs. The latter could well meet with local opposition as intense as that directed at the Red River project if the project were developed under the eminent domain powers of public authority, which might prove to be a necessity.

In addition to the Corps, the Soil Conservation Service (SCS) has had long standing water resource development and control authority and programs. The responsibilities, powers, programs, and general methods of operation of the SCS are the same in the eastern states as they are in the western states, except that the agency relates to the Corps of Engineers as the developer of large project works instead of the Bureau of Reclamation.

The Federal Power Commission is the federal agency with exclusive powers to license hydroelectric projects. Unlike the statutorily established policies of the other two agencies mentioned above, the court interpretation of the powers of the FPC is that it may exercise its licensing authority in direct derogation of state laws and policies. This, too, has been the basis for intense controversy--both political and legal--in the eastern states over specific projects that have been proposed but not yet approved.

Until recently, the programs of the federal government could be expected to provide stability and certainty of water supplies for major industrial and municipal needs in the face of uncertain and "flexible" (or shifting) water rights under riparian law. Intense opposition to the projects of these development oriented agencies has introduced a strong element of uncertainty into the question of assured and available water supplies for the proposed plants. From a planning point of view, there are no "mechanisms" or "devices" that could be introduced at this time to provide a greater degree of certainty in these areas. Resolution may well depend on political resolution of the underlying factors, such as the relationship of economic growth to environmental protection.

As a final point, the effect of water pollution controls on water availability should be mentioned. It may be that enforcement of water pollution control laws and regulations by each state will reduce the importance of the riparian doctrine as the major allocator of water uses. The stream standards set for each major river and stream are based, in part, on calculated minimum flows during dry years and dry periods during each year; that is, on the average minimum capacities of the flows to abate pollution. Any substantial impact on these stream standards of withdrawals for consumptive uses would tend to increase the burden of additional pollution control of all other dischargers.* In this way, the states may be forced to allocate the quantity and quality of major stream flows among users, which would have the effect of achieving a limited appropriation system-by-permit, although in a relatively indirect manner. With the ability of the states and the federal government to develop water storage and control projects almost at will under serious challenge and with the increasing competition among water users

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*The Miami Conservancy District in Ohio has taken this approach, for example, with the municipal dischargers along the river. The interdependency of stream users and dischargers is increased with drinking water standards are included in the balancing.

for what amounts to the assimilative capacity of water courses, and with the newly created drinking water standards responsibilities of the EPA, the question of water rights in the eastern states may become a matter of administrative determination of the departments of environmental protection of the states rather than the divisions of water, as is the present structure.

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21--THE IMPACT OF INDUSTRIAL GROWTH ON RURAL SOCIETY

By Peter D. Miller

A. Introduction

The people of the Northern Great Plains and the Rocky Mountains have witnessed the beginning of an industrial revolution in their region. Because of an international conflict half a world away, domestic resources of coal and oil shale have suddenly increased in value. An entire domestic energy industry, based on the mining and retorting of oil shale and the mining and processing of coal into synthetic fuels, has become more viable almost overnight owing to the new scarcity of once-cheap energy. This scarcity has stimulated intense interest in the abundant deposits of coal and oil shale in the West that have never before been mined on a large scale.

Concomitant with this interest, the Western regions rich in oil shale and coal are experiencing the initial stage-setting for industrialization and urbanization. In one of the most remote places in the continental United States, Colorado's Piceance Basin on the western slope of the Rockies, Rifle, Colorado, now regularly hails visitors from government, banking, industry, academia, and other walks of life rarely seen before in that vicinity. A similar scene can be observed in Gillette, Wyoming, located at the center of about one-fifth of the U.S. continental deposits of coal. At an early hour on a typical day, the motel coffee shop serves hard-hatted construction workers and miners, Stetson-hatted cowhands and tourists, bankers, real estate agents, trailer salesmen, government officials, and researchers. Processions of businessmen, lawyers, branch managers, salesmen, investment analysts, government bureaucrats, and social scientists stream through the town. Older residents watch the parade with a mixture of awe, excitement, and irritation. Many of them have become interview-hardened from being asked the same questions repeatedly, having developed from extensive practice a smooth, routine answer to every question. For some, opinions about the coal mining industry have hardened, too; it is either "raping the landscape" or "the best thing that ever happened to Wyoming." Retail sales are booming, land prices are bid up, wages are high; merchants, landowners willing to sell, and construction workers therefore derive some immediate benefits from the new industry. They are likely to feel strongly that the industry benefits everyone.

A common topic of conversation in Gillette concerns rumors of new coal mines, electrical generating facilities, or a uranium mine and processing complex. Announcements are made, modified, retracted, and made again. People talk hopefully or apprehensively, depending on their point of view, about possibilities for employment and prosperity or possibilities for a disastrous cycle of boom and bust.

Development of these coal and oil shale resources to the extent necessary to free the United States from dependence on foreign sources of energy would require industrialization of regions in the West that heretofore have known only a rural way of life. Wherever industrialization has occurred in the past, it has profoundly changed the values, lifestyles, and organization of society. The purpose of this chapter is to outline the social changes likely to result from mining for synthetic fuels development. Since qualitative and quantitative data on social impacts are to be found in the impacts that have occurred in similar settings in the past, past and present mining and industrial communities were studied for evidence applicable to social impacts of synthetic fuels development.

The consequences of energy development decisions necessarily spread out in many directions. Which ones are applicable in social impact assessment depend largely on the interests of those affected by these decisions. Some groups are interested in site-specific impacts, while others are concerned with national and international consequences. Some set their sights on the twenty-first century, while others are most concerned about the here and now. Some view social impacts exclusively in terms of planned consequences, while others focus their attention on effects that may have been ignored. These divergent interests can be considered in terms of space, time, and purpose.

Some impacts are clearly meaningful only at the site-specific level. Examples are disturbances of ground surface, reduction of vegetation, unsightly disposal of mine wastes, and other problems of reclamation. Other impacts are concentrated in the locality or county where mining takes place. Effects on the fiscal and institutional capacity of local governments to absorb growth are examples. At the regional (multistate) level, social impacts may involve political relationships between energy-producing states and energy-consuming states. National social impacts concern the attainability and desirability of energy independence and the appropriate balance among domestic production, imports, and conservation. Finally, energy development decisions can have worldwide repercussions, affecting trading relationships, currencies, and international stabilization.

Because of the different size of the units involved in space, it is difficult to compare social impacts at one level with those at another level. The balancing of favorable consequences at one level with unfavorable consequences at another level is a task for the political process.

Social impacts can vary in time as well as in space. Although the term "impact" suggests a definite time, in practice it is difficult to identify exactly when that time occurs. Neither the causes (energy development decisions) nor the effects (social impacts) are momentary occurrences. Energy development decisions may begin to cause social consequences at any time along the way to implementation--corporate planning, congressional debate, passage of legislation, lawsuits, project planning, environmental impact reporting, project modification, mine and plant construction, mine and plant operation. Similarly, some impacts may be felt immediately, while others may be delayed, or extended. Some may be reversible, others irreversible. Here again, it is important to make comparisons in terms of similar units. Impacts that take place during a construction period, for example, may not be indicative of impacts that take place during an operating period.

A crucial distinction in the assessment of social impacts is the one between intended and unintended consequences.[1] The intended consequences of energy development decisions have to do with increasing domestic energy production to reduce dependence on imports. Decisions of such magnitude often lead to unintended consequences that prove to be at least as important as the intended ones. The National Environmental Policy Act and the growing emphasis on technology assessment attest to the significance of unintended consequences. Environmental impact reporting and technology assessment are two means of attempting to assure consideration of issues that otherwise would have been neglected. Knowing these impacts in advance enables decision-makers to take better account of them in their planning, or to reevaluate their plans.

In assessment of the potential social impacts of a synthetic fuel industry, the discussion is organized as follows:

- The interests of various parties involved in or affected by energy development decisions.
- Local impacts of energy development and analysis of the dynamics and economics of growth that would result from very rapid energy development, compatible with a "maximum credible" level of development.

- Controlled growth consistent with considerations of the interests of the various concerned parties.

Chapter 23 analyses the effects on the urban growth process of varying plant sizes, construction schedules, and rates of population growth, and considers the implications of this analysis for increased energy development in Appalachia and southern Illinois.

B. Interest Groups

All groups to be affected by decisions regarding energy development should be included in a discussion of social impacts. At a minimum, the following groups would be affected by energy development: local government; state government; federal government; ranchers and farmers; workers and other residents; businessmen; new employees and other newcomers; energy industrialists; environmentalists; and energy consumers.* This is a diverse assortment of interest groups. Some of them are better-organized and better-financed than others and thus better able to communicate their position to the general public. Some of them claim to speak for others, and within each group, there may be sharp differences of opinion. Nevertheless by examining the interests of each group separately and assessing the impact of energy development on each it is possible to indicate the problems that would be created for a region subjected to the dynamics of growth discussed in Section C, following.

1. Local Government

Local officials in the coal-producing regions of the Rocky Mountain and Northern Great Plains states are generally oriented to the needs and interests of a local constituency, with strongly-held beliefs

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*Impacts on railroads and some impacts on Indians are discussed in Chapter 19.

about what is good and bad for their own. They tend to be conservative in the sense of approaching change cautiously and wishing to preserve the status quo. As a general rule, they believe that government and planning should be minimized. At the same time, they are concerned about the decline of the economic base and population that has afflicted many rural towns and counties. While some of them view energy development as a means to revitalize the local economy and promote growth, others view energy development as a threat to traditional ways of life and regard the costs of very rapid growth as greater than the benefits.

The mining of energy minerals and their conversion to synthetic fuels would bring large numbers of people to regions of the Rocky Mountain and Northern Great Plains states that now have a typical population density of two people per square mile. This influx of people would quickly overwhelm the present institutional capacity of local governments: housing, schools, roads, utilities would have to be provided in relatively short order.

The building of new cities or the expansion of existing ones does not require only money. It also requires an "infrastructure capacity," a network of local service industries, public services, and skilled work force and management, which is formed by the gradual accumulation of the requisite social and economic structure. In almost all areas where energy minerals are plentiful, this capacity would have to be imported, that is, attracted to the region.

Building or expanding a city in the midst of a sparsely populated region requires a sizable public investment. The quicker the pace of development, the more urgent the need for revenues to provide services. At the same time, localities faced with energy development are operating in a high-risk situation. Unable to collect the bulk of tax revenues until after development impacts have occurred, they must nevertheless invest, in effect, in a market whose future is uncertain. Changes in world oil prices, trade balances, geopolitical arrangements, and so on, could easily remove the need for these energy projects and turn the entire urban apparatus into a ghost town. If intensive western energy development proved unprofitable, the depopulated remains of these localities would be saddled with indebtedness.

Local governments, however, have little to say about the scope, intensity, or location of energy development. In many areas of potential mineral development, land ownership is fragmented among different jurisdictions such that the mineral estate is almost exclusively under federal control, while local governments retain control over surface improvements. At the same time; local governments have little control over the emerging economic base associated with energy development. Without the capacity to raise funds to meet development costs, these localities could find themselves in the position of bearing a large part of the social and economic burden for supplying national energy demands.

Rock Springs, Wyoming, for example, which had lapsed from a railroad boom town in the 1880s to a declining rural town, has become a small industrial center in the last five years. Industrial activity in trona mining and soda-ash refining, oil drilling, as well as coal mining and electrical generating facilities more than doubled the town's 1970 population of 12,000 to 26,000 in 1975. Rock Springs Mayor Paul Wataha referred to the high risks inherent in very rapid development when he stated, "I don't see how we could have adequately prepared for this. Even if in 1970 we could have persuaded the voters to pass bond issues, how were they to know the companies wouldn't change their minds?... If we could have had the same growth over a ten-year period instead of two years, things would have been a lot better."[2] The implication is that to avert problems of industrialization/urbanization, one would have had to slow the rate of local growth. Similarly, Gillette, Wyoming, doubled its population between 1960 and 1970 (3600 to 7200), and, at the present rate of growth, will see its population double again by 1977. Once the scene of early coal mining activity, and of an oil boom in the 1950s, Gillette reverted to relative quiescence in the 1960s until the current coal boom. Like Rock Springs, it could well develop into a major western industrial center.

2. State Government

State governments, like local governments, have an interest in maximizing tax revenues while minimizing expenditures for which they are responsible. They share with the regional public an interest in gaining the maximum value for their natural resources. In energy development, the interests of state officials appear to converge with those of local officials. They both wish to ensure the economic stabilization of local jurisdictions by regulating the pace of development so that it does not interfere with orderly growth. State officials have wider responsibility for coordination and planning, of course, and may have to reconcile diverse interests within their states. State officials must also respond to federal pressures for increased coal leasing and mining.

The governors of the Rocky Mountain and Northern Great Plains states have reached some consensus (if not total agreement) on the conditions they believe should govern coal mining, with local autonomy as a major theme. Montana Governor Thomas Judge stated, for example, "If we are going to produce [coal], it's doing to be on our terms--not on terms somebody else dictates."[3] In a letter to the Senate Interior and Insular Affairs Committee, North Dakota Governor Arthur Link stated the position of North Dakota: "The State of North Dakota desires to assist in the effort to meet the 'energy needs' (to be distinguished from mere 'energy demands') of the nation. But, concurrent with the offer of assistance, this state will demand necessary environmental, social, and economic safeguards to protect the state. North Dakota will not 'subsidize' the energy needs of the rest of the nation by bearing a disproportionate share of the social and environmental costs of massive energy production."[4] The recently-formed Western Governors' Regional Energy Policy Office adopted 19 substantive and eight procedural policies for energy production. Regarding social and environmental impacts of energy production, the governors resolved "to obtain timely assistance for local political entities which are affected by energy development impacts from such appropriate sources as an energy industry or state or federal government," and "to weigh the critical need for food production in the assessment of possible adverse impacts of energy production on top soil, water supply, water quality and air purity."[5] The position of the governors of the Western coal-producing states is to cooperate with federal and industry efforts to develop the coal resource to the extent such development is compatible with enhancement of living standards and maintenance of environmental values.

3. Federal Government

The federal government includes diverse interests related to the social impact of energy development. Debates within the federal government over such issues as the role of energy conservation, the rights of surface landowners, definition of a fair return to the Treasury from use of the public lands, the scope, pace, and location of coal leases, the feasibility of reclamation, the nation's position in international trade, and the allocation of western water have so far not led to a coherent energy policy. In general, however, federal officials have an interest in reducing American dependence on energy imports.

The ability to cut oil imports as a result of increased domestic energy production would promote other international interests of the United States. The United States currently imports about one-fourth of the total oil in the world market. Former Interior Secretary Morton has argued that the energy needs of developing countries depend on the United States foregoing some of these oil imports.[6] This would help preserve existing trade relationships and earn the goodwill of other energy consuming nations.

Federal officials with responsibility for managing the economy have an interest in keeping energy prices down. Although the era of "cheap energy" is undoubtedly over, it is still desirable to minimize the shock of adjustment to higher energy prices. Moreover, circulation of the dollars domestically would be a more desirable alternative than exporting them.

The federal government also has a clearly recognized responsibility to foster orderly community development, and to maintain equitable and efficient administration of all its natural resources. Energy development is a high-risk venture for the public sector as well as for the private sector. If citizens, producers, and consumers are to benefit equitably from energy production, some sharing of the costs and risks of such development will probably be necessary. Although states and localities can provide some assistance, only the federal government has the resources to manage this sharing.

Over a long period, federal policy has been directed toward preventing the burden of community development from falling solely on local residents. Federal compensation for local development costs may be traced back to the federal ordinance of May 20, 1795, in which one-sixteenth of every township was deeded to the township for support of schools. Land grants to the states for specific national purposes, such as higher education, continued throughout the nineteenth century. Concern about the federal government's sovereign immunity from tax liability led to the establishment by Congress in 1907 of a revenue-sharing formula whereby the counties in which federal timber was harvested would receive one-fourth of all sales revenues for roads and schools. The formula for federal forest lands in Oregon and California was even more generous: 50 percent of income from valuable Pacific Northwest timber was allocated to the counties under the Oregon and California Act of 1937. Similarly, under the Knutson-Vandenberg Act of 1964, timber harvesters can be required to pay for reforestation and other improvements to the public lands. Congress also recognized the adverse impact of military bases on local fiscal capacity to the extent of providing special compensation for schools and other costs.[7]

As a proprietor, the federal government has an interest similar to that of other landowners--to obtain the maximum revenues from use of the land, to prevent environmental degradation, to manage its resources wisely, and to exercise effective control over the use of its land. Thus the federal government has an interest in guaranteeing a fair return to the Treasury for the extraction of valuable resources. The Department of the Interior has procedures for leasing its mineral holdings (see Chapter 7 for a detailed discussion). In addition, it has recommended a new, more participatory leasing program consisting of three phases:[8]

Nominations. In contrast to the past practice in which nominations for leased land were received exclusively from the mining industry, the proposed regulations allow for nominations also to be received by the Bureau of Land Management (BLM) from citizens and from local and state officials. In addition, nominations against the leasing of federal lands for coal mining purposes would be accepted.

Planning. The BLM would undertake an integrated program of land use planning and resource management in relation to multiple-use goals.[9] Coal leasing decisions would be based on multiple-use principles of the BLM rather than solely on considerations pertaining to the mining industry. The BLM would seek to resolve conflicting land uses, prepare a land use plan, select lease tracts from nominations, and prepare a leasing schedule.

Leasing. Leasing would take place within the context of overall land use planning objectives and field office objectives. The BLM field office would handle the lease sales.

As managers, federal officials have an interest in resolving the many controversies that divide the country over energy policy and environmental protection. They need to have at least a minimal consensus on the amount of domestic energy production necessary to reduce dependence on imports while at the same time protecting the people and the environment of the coal-producing regions. Without some such minimal consensus, disputes will probably reach the courts in increasing numbers and although legal scholars disagree over whether the courts have a legitimate role in this area,[10,11] the courts may become involved.

4. Ranchers and Farmers

Ranching and farming are traditional modes of land use in the rural western coal-producing states. Generally, the rancher's interest consists in keeping things as they have been, improving the productivity of the range, preserving a sufficient water supply, and keeping a dependable source of labor. Since it takes 30 to 40 acres to graze a cow on the western range, very large tracts of land are necessary for profitable ranching. Ranchers also have a particular interest in keeping the price of land low if they intend to continue ranching. If the price of land rises, taxes also rise, and ranch profits are reduced.

Intensive coal mining and industrial activity would threaten ranchers' and farmers' traditional ways of life. Major decisions regarding land use, water use, and other matters of importance to ranchers and farmers would probably be made in increasing numbers by people far removed from the local community. The process of industrialization tends to elevate the importance of economic rationality and to reduce the importance of values that cannot be measured in dollars and cents. Intangibles such as aesthetic appeal, environmental amenities, or open space tend to lose out to easily quantifiable values such as product sales. It is often argued, that because traditional land uses such as ranching and farming are less profitable in the short run than strip mining, mining constitutes the land's "highest and best use." Resource management and environmental management can be integrated with coal mining when renewable resources are dealt with but involves consumptive (nonrenewable) use of a resource and therefore cannot be managed on the basis of securing a sustained yield. Customary mining practice is to recover the most easily accessible and valuable reserves first, and to mine less accessible and valuable resources later. The interests of the mine operator are thus not tied to resource conservation in the same way that the interests of livestock grazers and farmers are tied to the continuing productivity of the land.

Some ranchers have been offered high prices for the right to mine coal under their land, but some have refused to strike a bargain. They may feel that continued occupancy means more to them than the substantial profits they would realize from sale or lease, or they may have concluded that reclamation after surface mining is not possible. Those who have chosen to sell or lease have reaped substantial financial benefits. They were free to retire or buy land elsewhere and relocate their ranches and farms. Incentives to sell or lease may include the desire to move out of an area surrounded by mining operations, future lack of an adequate water supply, higher taxes resulting from high land values and assessments, or difficulties in recruiting a work force. The high wages offered by the new mining industry in areas like Campbell County, Wyoming, have made it difficult for ranchers to rely on a steady supply of labor. Where high school students can drop out and make twice what their teachers make, part-time jobs at the ranch no longer seem attractive. Ranch hands and virtually anyone else employed at lower wages are candidates for higher-paying industrial employment. Other employers must then pay higher wages to match the competition.

5. Workers and Other Residents

The opportunity to earn higher wages would benefit residents who were prepared to adapt to the industrial environment. Young people with limited opportunities elsewhere would especially benefit. Many of them would receive on-the-job training in the specialized skills necessary to operate a modern surface mine, synthetic fuels facility, or power plant. This would enhance their employability in the energy industry and in other industries. They would enjoy higher income and greater mobility than otherwise possible. Those residents who either chose to remain outside the new industrial environment or who were unable to occupy a place within it would be left behind by energy development. In general, the aged, the poor, and the hard core unemployed would be put at a disadvantage by the higher cost of housing and retail goods resulting from local development-induced inflation.

6. Businessmen

Merchants would benefit from energy development. In Rock Springs, Wyoming, for example, retail sales jumped from $31,000,000 in 1970 to $59,000,000 in 1973.[2] Virtually anyone who owned a business supplying goods and services to the new industry and its employees would gain, but businessmen engaged in the sale of farm and ranch machinery would probably not gain. Increased demand for housing and land would also benefit builers and land developers. Professional incomes would probably rise. These business opportunities would attract new people to the growing community and would make a larger variety of goods and services available to residents.

7. New Employees and Other Newcomers

People are attracted to mining towns by the prospect of employment at relatively high wages. For the unemployed, productive work is obviously a benefit. Many are attracted by the excitement of starting up a new industry, or by the stimulation of a booming industrial town. One indication of the extent of opportunity open to coal mining employees is the fact that little formal education is required as a qualification for relatively high-paying jobs.[12] A study of North Dakota's coal mining and utility plant work force revealed that 42 percent of the coal employees they questioned* terminated their education after 12 years. Forty percent of the total number of mechanics, welders, carpenters, dozer operators, and truck drivers they questioned† had less than 8 years of formal education,[12] but most had had some vocational training. Despite their lack of formal education, which would have disqualified them for many lesser-skilled jobs with other employers, they were able to find employment and on-the-job training. Moreover, if the study data are generally indicative, the coal companies tend to promote from within. For example, more than 63 percent of the dragline operators (the most highly skilled position) had held four or more positions with their current employer.[12] Thus opportunities for advancement as well as for entry are very good.

On the other hand, newcomers to less stable communities can experience some hardships. For example, Gillette, Wyoming, which has experienced a very high rate of population growth due to energy

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*Sample size: (n = 241).
†Sample size: (n = 64).

development, found that its ability to accommodate the newcomers was limited. Housing costs rose rapidly until home ownership was beyond the means of the new residents, despite their increased incomes. By 1970, the median rent of $140 a month in Campbell County (where Gillette is located) was the highest in Wyoming.[13] Even trailers were being rented at higher prices than fixed housing would have brought in ordinary times. Many latecomers could find housing only in tents.

Trailer camps typically offered a cramped dwelling space with no yard, little privacy, and sometimes no sewage hookup. Gillette's rapid growth also led to overcrowded schools, strains on public safety manpower, and a sudden need for medical and public health services.[14] Signs of social malaise such as alcoholism, crime, divorce, suicide, and similar problems began to increase, according to local clinical psychologists.[15] The need for such specialized social services as family therapy, mental health counseling, and alcohol detoxification soon became apparent, but the clinic and the jail were forced to function as all-purpose caretakers in the absence of these services. High rates of turnover and absenteeism are thus added to the costs of production. These problems have caused needless suffering.

8. The Energy Industrialists

The economics of the extractive industries favor rapid development of resources to minimize the time and money invested before sales of the resource. Particularly in the current period of high prices for energy minerals, the incentives for rapid exploitation of western coal reserves are very strong. It is reasonable to expect that mining activity will be greatest when energy prices are at their highest. Coal mining activity would probably decline if coal prices declined. Thus, energy industrialists are interested in assuring production as soon as possible.

Energy industrialists also have an interest in minimizing the risk in undertaking new large-scale development. Availability of key equipment such as draglines (now back-ordered several years at many mines), the availability of skilled labor, expected future demand for energy, costs of transporting coal, and commercial feasibility of synthetic fuels conversion technologies are the kinds of uncertainties likely to be faced by any industry contemplating large-scale innovation.

Uncoordinated and contradictory policies among the federal agencies involved with energy development are another source of uncertainty to the energy industry. Policies and regulations of the following federal agencies have to be taken into account in corporate planning: Energy Research and Development Agency, Federal Energy Administration, Environmental Protection Agency, Mine Enforcement and Safety Administration, Bureau of Mines, Bureau of Reclamation, and Bureau of Land Management. Changes in mining practices mandated by Congress, the courts, and the states complete the picture of uncertainty. Industry spokesmen state that they would like to have clearly articulated laws and regulations regarding energy development. To the extent that decisions to undertake extensive energy development would remove regulatory and legal uncertainties, these decisions would benefit the energy industry.

9. Environmentalists

Although environmentalists have no direct economic stake in energy development decisions, they have an interest in preserving wilderness values, natural resources , and rural, land-based ways of life. Environmentalists are a varied interest-group, consisting of fishermen, hunters, hikers, wilderness seekers, and others who wish to preserve opportunities for outdoor recreation, scientific study, or simple enjoyment. Although economists have attempted to quantify such values[17] environmental values also have a symbolic dimension for environmentalists.

Unique features of land in the United States have become symbols of national identity and have thus acquired a protected status. One of the most popular patriotic songs extolls the nation's "shining seas, purple mountain's majesties, and amber waves of grain." The National Parks, and to a lesser extent all public lands are a cultural resource of symbolic value even for those who rarely visit them. Reverence toward land, traditional in most agrarian and nomadic cultures, including that of the Indians and early white settlers, is being revived by environmentalists as a philosophy of resource use. This philosophy means that environmentalists will (and do) exert their influence to control growth, prevent pollution, and conserve and preserve wilderness areas.

Controlling growth. The goal of controlling growth is based on the observation that growth may not always be compatible with human welfare. Environmentalists question the "conventional wisdom" that economic growth and population growth always work to everyone's benefit. Some unintended consequences of growth may be depletion of resources, inequitable distribution of wealth, and externalties such as pollution of air and water.

Conservation. The goal of conservation is an attempt to come to terms with the unpleasant fact of limited resources. It suggests preserving resources (such as energy reserves) for future use rather than using them up at an excessive rate. Environmentalists believe that conservation efforts will soften the effects of reaching resource limits.

Preventing pollution. The goal of preventing pollution stems from the desire to minimize adverse health effects of polluted air and water, and to have the freedom to enjoy pure air and water. Recognizing that industrial growth is a primary cause of air and water pollution, environmentalists seek ways of regulating industry in order to minimize or prevent pollution. In the environmentalists' view, the Rocky Mountain and Northern Great Plains states are the most endangered by energy development, because these regions have the largest quantities of clean air and pure water to lose.

Extensive development of western coal reserves could lead to uncontrolled urbanization and industrialization of previously rural areas, rapid depletion of domestic energy reserves, weakening of incentives to practice energy conservation, increased pollution of air and water, and loss of wilderness of semiwilderness areas, all of which would be directly contrary to the interests and concerns of environmentalists.

10. Energy Consumers

Energy consumers would benefit from extensive energy development in at least two ways: assured energy supplies, and less reliance on imports.

The Arab oil boycott reminded consumers of the vulnerability of some sources of energy supplies. Extensive domestic energy development would help assure consumers of continued supplies. This would in turn assure a continued flow of goods and services that depend on energy consumption.

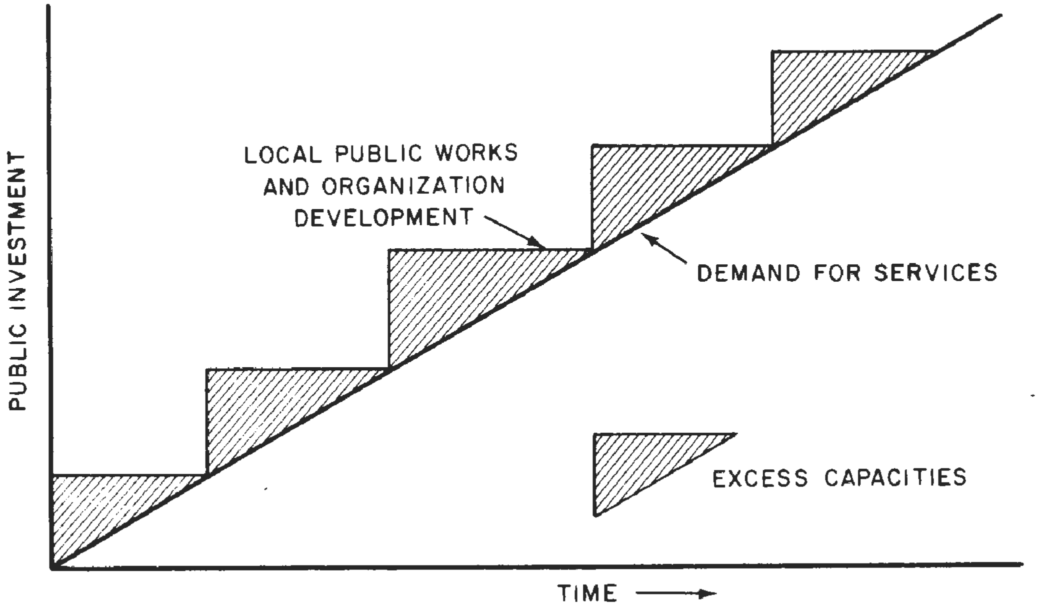
C. Dynamics of Urban Growth Related to Public Expenditure

Correlative to energy development and its consequences from the points of view of the various interest groups is the question of growth as it relates to economics. Local growth is neither the blessing that boosters have often portrayed nor the disaster that no-growth advocates have portrayed. To make informed choices about desirable rates of economic development, local and state officials need to have more precise information about the relationship between growth and public expenditures than is generally available. While a full-scale analysis of all possible alternatives cannot be made here, some aspects of the relationship between growth and public expenditures that can contribute to understanding of decision options, are presented. In general, economic development brings additional population; growing towns and cities require an investment in public services and governmental organization. Unless the locality finds a way of financing these improvements, economic development and population growth will not necessarily benefit it. From the local and state perspective, the decision calls for a judgment whether the investment in public services required for a given rate of growth will be worthwhile.

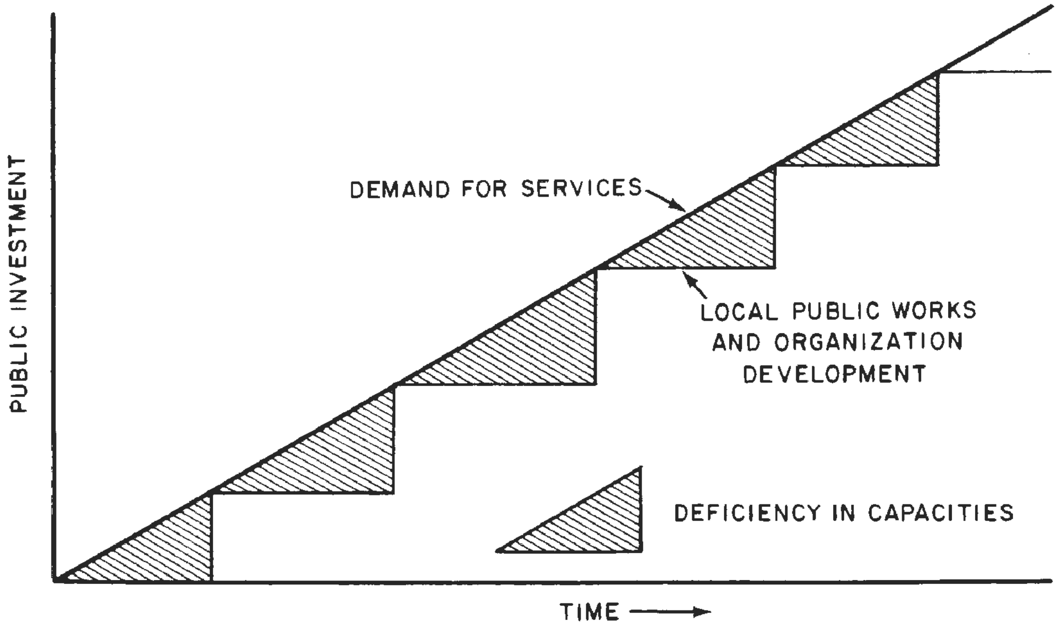
1. Stages of Urban Growth

Localities faced with rapid urbanization have two choices. They can attempt to meet demands for public services and facilities before they occur, or they can allow public works and organizational development to lag behind. In the first choice, they risk being overextended if population growth proves to be less than anticipated. For example, this could happen if mining activity were prematurely curtailed by declining energy prices or other uncertainties in the energy industry. In the second choice, existing public services are continually inadequate for the level of demand. This case tends to be more prevalent under conditions of rapid population growth because the normal life-cycles of bond issues cannot keep up with the pace of expansion. In addition, residents may be reluctant to accept higher taxes and bond issues until they become absolutely necessary. The choices are depicted graphically in Figure 21-1. A midway course between unmet demand and excess capacity would involve the least risk to the locality, but this level may be difficult to determine while expansion is still in progress.

Very rapid spurts of housing and commercial building construction often lead to an "echo effect" in later years.[18] Assuming an approximately equal useful life, buildings completed during the same



A. PUBLIC INVESTMENT LEADING DEMAND



B. PUBLIC INVESTMENT LAGGING DEMAND

FIGURE 21-1. PUBLIC INVESTMENT COMPARED TO DEMAND FOR PUBLIC SERVICES construction period will all "wear out" at roughly the same time. An initial period of boom construction necessarily creates a second construction boom because the rate of replacement tends to resemble the original rate of construction. Figure 21-2 contrasts the construction boom with the constant rate of construction and replacement. The constant rate results in a flat age-profile of buildings in which ages and conditions are varied, while boom and bust cycles of extreme severity are built into the local economy by an initial construction boom. Since rents are partially a function of a building's age and condition, there would be little basis for variation in rental values other than location, and hence little diversity of lessee choice.

Successive increments of population growth do not necessarily have identical characteristics. In changing from a crossroads to a village, then to a town, and finally into a city, different kinds of decisions are called for at each step. A town has different requirements from a set of villages with equal numbers of people. It has been suggested that this process be treated as a sequence of steps involving progressively higher expenditures.[19] As Figure 21-3 shows, the first improvements to be made are well-drilling (or reservoir construction), road-building, septic tank installation, and school-building. Later, the town may decide to invest in a sewage system, a hospital, and an addition to the school building. At this point, the town may adopt zoning ordinances and building codes. When these steps occur in rapid succession, previous investments are made obsolete before they wear out. Before the next phase arrives, development of a local bureaucracy for planning and service delivery becomes critical. Coordinating transportation, education, health services, water use, and land use for a city of 25,000-50,000 is a major job. At this population level, the stakes are much higher than before, particularly when revenue sources to pay for these commitments are uncertain. Although revenue bonds can pay for some of

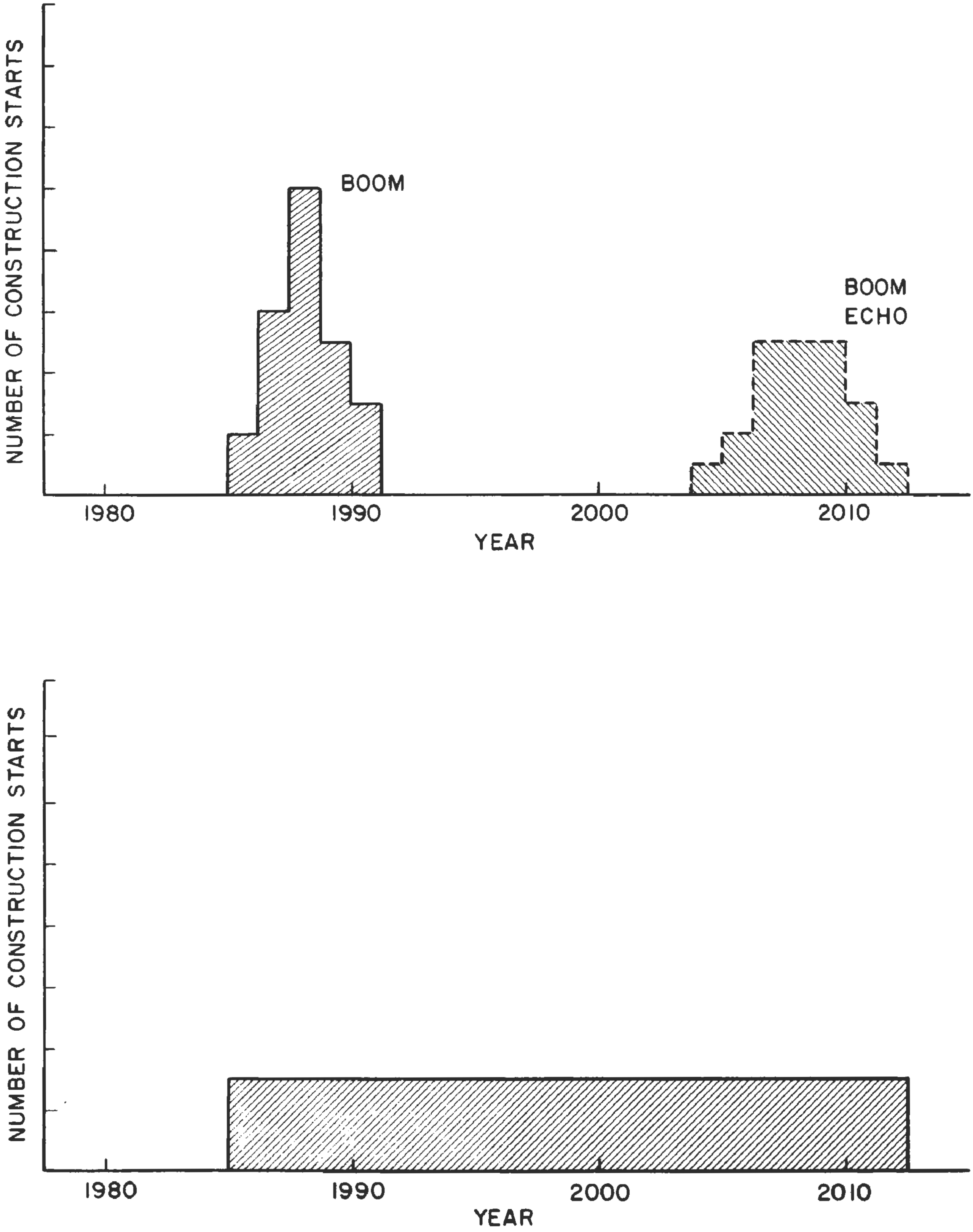


FIGURE 21-2. "BOOM" CONSTRUCTION AND ITS ECHO EFFECT CONTRASTED WITH FLAT-AGE-PROFILE CONSTRUCTION

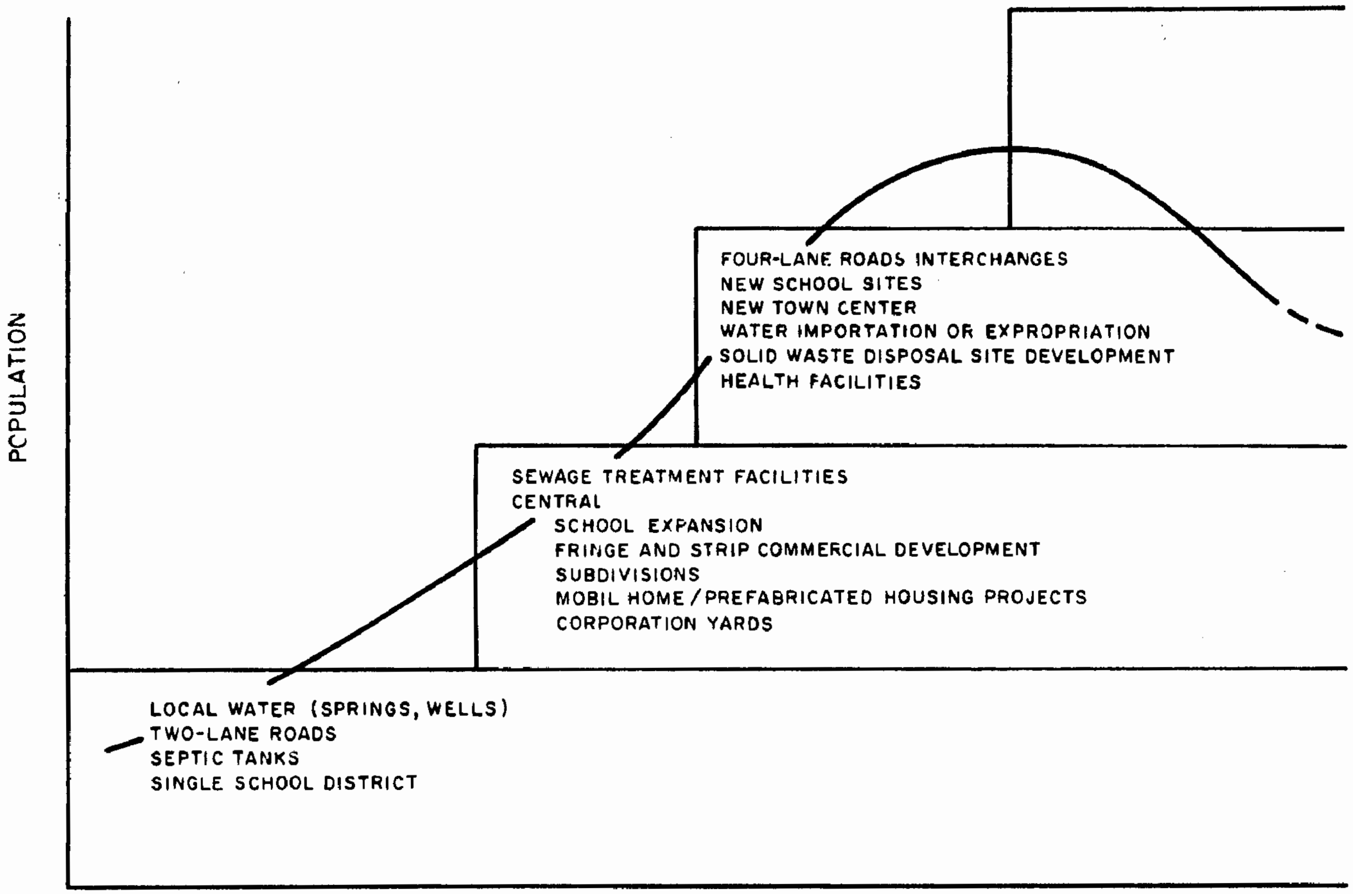


FIGURE 21-3. MAJOR INVESTMENTS AND DECISIONS VS. POPULATION GROWTH FOR AN URBANIZING SMALL TOWN

these costs, these bonds are generally repaid from user charges, not taxes.

2. Population Growth and Per Capita Costs

It might seem reasonable to expect per capita costs of public services to drop as population rises because of possible economies of scale. Once an initial capital investment has been made, the locality has a certain excess capacity that can be used to absorb new growth. Incremental additions to structures and facilities are usually easier to finance when building on an existing base than when starting anew. Many economies of scale in the delivery of local public services are related to increased population densities. Services whose costs are mainly associated with geographical dispersion include police and fire protection, garbage collection, and other field or patrol services. If (other factors being equal) population growth occurs within a relatively concentrated area, the costs of serving 30,000 people can be far less than twice the costs of serving 15,000 people. Similarly, public investments in buildings and equipment may be made with lower per capita costs where population is relatively concentrated rather than dispersed. Hospitals and schools, for example, can benefit from such economies of scale.

In practice, however, declining per capita public costs thought to result from population growth have not materialized in the western coal-producing counties during periods of rapid growth. In a detailed study undertaken for the Northern Great Plains Resources Program* by the

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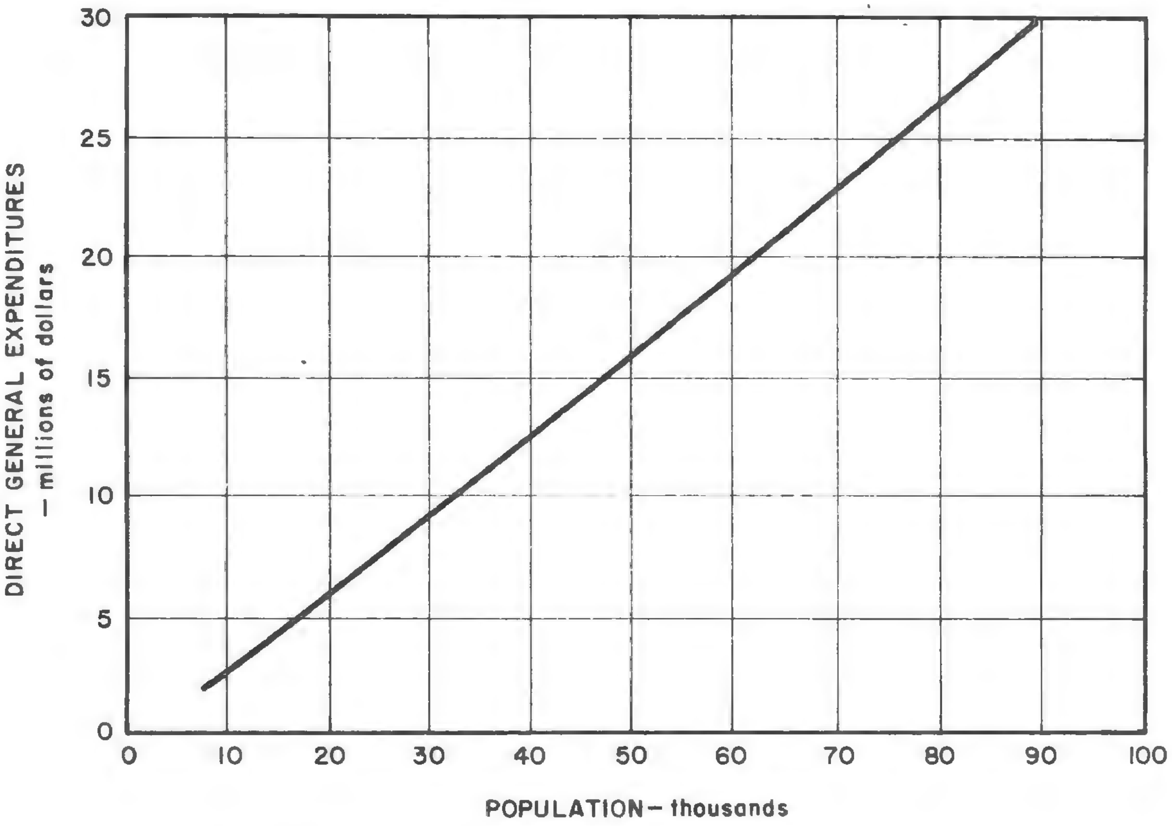
*The Northern Great Plains Resources Program is an intergovernmental agency composed of representatives of the States of Montana, Wyoming, North Dakota, South Dakota, and Nebraska, and the Department of Interior, Department of Agriculture, and the Environmental Protection Agency.

Bureau of Reclamation and the Institute of Applied Research at Montana State University, it was found that direct per capita public expenditures actually increased faster than the population in the sample.[20] The sample included Sheridan and Campbell counties in Wyoming, Big Horn and Rosebud counties in Montana, and Mercer and Oliver counties in North Dakota. The impacts experienced in these counties typify those to be expected in other counties in the same region in which energy development takes place. First, the study projected future populations for the "most probable" schedule of energy development generated by direct and secondary employment at coal mines, gasification plants, and generating facilities. Second, the study projected future public service needs in the areas of health care, social services, schools, fire protection, law enforcement, travel and transportation, municipal services, recreation facilities, and planning. Third, it estimated the costs of these governmental services and facilities and compared these costs with revenues likely to be available. The comparison showed that during the construction period revenues would be inadequate to cover costs and that after the construction period revenues would be adequate in all sampled counties except Sheridan County. Municipalities would experience greater difficult in financing services, however, because industrial complexes are not expected to be constructed within corporate limits.

Figure 21-4 illustrates the pattern of per capita public expenditures rising faster than population during periods of rapid population growth. A jurisdiction of 15,000 population, for example, spending 4 million dollars a year would be spending more than twice that sum--9 million dollars--when its population reached 30,000. At an annual rate of population growth of 5 percent, total public expenditures, corrected for inflation, would double approximately every 13 years.

Rosebud County, Montana, where coal mining has taken place but no major construction has occurred, saw its per capita expenditures jump



SOURCE: BUREAU OF RECLAMATION (1974)

FIGURE 21-4. CORRELATION OF GOVERNMENT EXPENDITURES TO POPULATION from $88 in 1969-70 to $121 (in constant 1967 dollars) in 1973-74, an increase of almost 40 percent. While taxable valuations rose during that period, they did not rise sufficiently to pay for increased expenditures. According to the Montana State Department of Natural Resource and Conservation, even these increased per capita public costs represent a minimum "make-do" budget.[21] The same pattern was revealed in Forsyth, the county seat of Rosebud County. While population rose from 2000 to 2800 as a result of coal development from 1970 to 1974, expenditures (in constant dollars) doubled. Per capita public expenditures rose from $81 to $116 (constant 1967 dollars) during that period. An increase of 18 percent in municipal taxable valuations stands in sharp contrast to the town's 100 percent increase in expenditures.

3. Growth and Revenue

The examples given above lessen assurance that services to accommodate rapid rates of population growth can always be financed from anticipated revenues. There are at least eight reasons why this might be the case.

Demographic Characteristics--The costs of urbanization are affected by demographic characteristics of the immigrants as well as by their sheer numbers. Five hundred additional young families a year, for example, would have more impact on school budgets than would equal numbers of elderly people. For example, Campbell County, which had the largest proportion of school-age population of any county in Wyoming five years ago, can be expected to increase this proportion still further in subsequent years. Since schools consume at least half of all local government expenditures, this increase alone would have a large impact. The elderly, on the other hand, would require larger expenditures for public health and hospitals. Itinerant laborers without families would have minimal impact on school budgets. However, their demand for housing would be greater than that by equal numbers of family members because of the greater incidence of one-person households. The younger the incoming population, the more need for expenditures on recreational facilities. Population requiring the more labor-intensive governmental services, such as social welfare, mental health counseling, manpower development, and vocational training, also cause greater per-capita public expenditure.

Diversity of Services--With rapid urbanization, government must assume many of the traditional "caretaker" functions since newcomers cannot depend on personal ties in the community. The newcomers exert pressure for public services not only because of their number but because of their greater dependency on government as well. This is particularly true if the newcomers come from larger urban areas in which dependence on government is heavy. Straight extrapolations of costs resulting from population growth may not indicate the full extent of future costs because "a wider variety of services is likely to be demanded because of the greater diversity of the new populations."[20]

Narrow Financial Base--Local jurisdictions are generally less able, legally and politically, to impose new or greater taxes than are higher jurisdictions. Dependent on the property tax and on grants from state and federal government, localities stand on a narrow financial base. Municipalities are particularly vulnerable because industrial complexes located outside town boundaries generate no property tax revenues for the town. Local revenue sources are generally less varied and therefore less adequate. States can impose severance taxes, license fees, royalties, income taxes, sales taxes, establish reclamation bond funds, etc., but there is no guarantee that these revenues will be distributed to the localities where the taxes were collected. It has been the practice in a number of states to put severance tax revenues, for example, into the general fund, remitting only the surplus above state general expenditures to the counties that generated the revenues.

Intercounty Disparities--Just as counties within the same state might be burdened unequally by the costs of urbanization, counties in two different states can experience the same disparity. It would be feasible, for example, for large numbers of people to live in Sheridan, Wyoming, and to commute to work in Montana. In that case, property tax revenues on the plants would be generated for Montana while Sheridan would pay the costs. Sheridan would therefore experience particular difficulty in financing its growth.

Tax Breaks--Many states grant tax breaks to new industry as an inducement to locate in the state. For example, Montana taxes new industrial property at only 7 percent of its "true and full value" for the first three years.[22] Machinery and equipment are taxed at 30 percent of their value. New industries in North Dakota may be completely exempt from property and corporate income taxes for five years. These practices remove a source of revenue during the period of fastest growth when it is most needed by urbanizing areas.

Indirect Benefits to Outsiders--Although industrial growth creates secondary employment, it does not necessarily broaden the local tax base as much as is often forecasted. Most of the local secondary employment would be in the services, sales, and government sectors. Relatively little of it would occur in a diversified industrial base on the local level. Large-scale coal mining in Wyoming would generate employment in Ohio where draglines are manufactured, in the Great Lakes states where steel is produced. Thus a substantial proportion of the benefits of secondary employment would accrue to states outside the western coal-producing regions.

Settlement Patterns--Since many economies of scale in the delivery of local public services are related to increased population densities, these economies may not materialize unless certain critical densities develop. Factors inhibiting such densities from developing include incentives toward rural land subdivision, the desire to escape municipal taxes, regulation, zoning, and building codes, and other well-documented dynamics of urban sprawl.[23] Dispersed residential settlement may also be fostered by geographical barriers such as unstable soils, steep slopes, or other rough terrain. In such cases, settlement will tend to spread out along easily buildable sites in river valleys rather than assuming a circular distribution. Unwillingness to accept land-use controls at the county-wide or state-wide levels may also facilitate settlement patterns that fail to realize economies of scale in the delivery of public services. Similarly, access to centralized facilities such as hospitals is reduced by dispersion of residential settlement, in which case effective delivery of such services can only be made with increased transportation costs.

Limited Size--The localities considered in this report are attempting to build governmental services on a relatively restricted base. Their population and their institutional capacity are limited in the beginning, and so they may not yet have reached the point where they can realize economies of scale. It has been suggested that such economies only begin to be realized at the size of 100,000 or 200,000 population.[24] None of the localities studied here is expected to reach that size as a result of projected energy development.

4. Tax Lag

A final problem faced by towns trying to finance urbanization--tax lag--deserves separate consideration. Even if there were no tax breaks for industry and no intercounty disparities, the costs of urbanization would still generally occur before the taxes to finance them arrived.

Tax structures represent the bargain struck between industry and the general public for the privilege of doing business. Since mineral extraction removes wealth from its original jurisdiction, mineral taxes are in part a form of compensation. As extractive industries dealing with foreign countries have found, taxation has become a device for tacitly sharing the wealth. A "fair" tax rate in such cases has come to mean a proportion of profits derived from sale of the raw mineral. Although the American coal and oil shale producing states do not exercise sovereign powers, they have similar interests at stake. They will want to assure themselves, at a minimum, that the costs of minerals development will not exceed their ability to finance required public expenditures. Beyond that, they may seek to regulate various aspects of industrial development by manipulating tax incentives and disincentives.

Montana, which is a leader in mineral taxation, has four major taxes that pertain to coal mining: the Net Proceeds Tax, the Resource Indemnity Trust Account Tax, the Strip Coal Mines License Tax, and the Corporation License Tax.[22] The Net Proceeds Tax, or severance tax, is based on the gross dollar value of coal extracted, less the cost of mining and marketing it, and may be averaged over five or more years. This value is then included in the assessed property of the firm and thus becomes subject to county property taxes. However, a drawback is that revenues are not collected until after public costs have occurred. Another potential drawback relates to the procedure for determining the valuation of net proceeds. One of the advantages of vertical integration is the opportunity for a firm to sell crude products to itself at below-market prices, thereby lowering taxable valuation. For in-state mining and conversion operations, this could represent a substantial loss of revenue.

Reclamation fund taxes can be based either on the value of coal extracted, the quantity of coal extracted, or on the anticipated cost of reclamation. When the reclamation bond is equivalent to the value of the coal extracted, the bond operates as a surety that reclamation work is actually performed because there would be no net benefit in forfeiting the bond. The alternative of holding a bond equivalent to the cost of reclamation has been tried in some Appalachian states, but it has been found in a significant number of cases that these were treated as "slip-out costs" by firms unwilling to perform reclamation. In one eastern state, an ingenious operator has apparently circumvented the reclamation tax entirely by stripping the overburden without touching the coal and then selling the land to another operator. Montana's reclamation fund imposes a tax of $25 plus 0.5 percent of the gross value of coal extracted. Under the vetoed federal strip mine legislation, a federal reclamation fund would collect 35 cents a ton to reclaim "orphan lands"--abandoned by untraceable strip mine operators--and sell them to responsible owners.

States have the option of remitting revenues to the general treasury or of earmarking tax revenues for specific purposes and/or counties. For example, Kentucky treats severance taxes as general-purpose revenue, sending only the surplus above the state expenditures back to the county from which the coal eas extracted. Other states earmark these taxes specifically for road maintenance and reclamation work in those counties. Montana's reclamation fund tax is earmarked for the counties where land has been disturbed. In addition, its Strip Coal Mines License Tax, levied proportionally to the heating value of the coal, collects amounts ranging from 12 to 40 cents a ton. Of this amount, the county contributing the coal receives one cent per ton. Finally, Montana's Corporation License Tax imposes a flat 6.75 percent tax on net income earned in the state, of which one-fourth is earmarked for schools.

D. Policy Options for Controlled Growth Rates

The problems attendant to growth cited in the previous section and the interests of the various stakeholders cited in Section B can be addressed through various federal, state, and local policies. Such policies should deal realistically with the choices open to the western coal-producing regions, recognizing the interdependence of rapid growth and subsequent decline. "Every region which is declining today," according to a report by the Old West Regional Commission,* "is so doing because the momentum of some earlier growth carried it to levels it could not sustain."[25] The vulnerability of these regions to the changing fortunes of extremely specialized economies suggests an approach "which is neither opportunistically promotional nor dogmatically preservationist, but which keeps local growth rates within a range to which the existing communities can adapt without hardship."[26] For these regions to avert the boom-and-bust cycle to which they have been subject in the past, the Old West Regional Commission's report concludes, "the new urban development prospects arising from coal developments should not be regarded as a means of 'saving' declining towns...."[25] Policy options to achieve desirable rates of growth can be divided into the broad categories of nonfiscal instruments and fiscal instruments.

1. Nonfiscal Options

Prospects for land use controls at the federal level appear dim since Congress has rejected federal land use legislation and has failed to override presidential veto of legislation to implement land

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*The Old West Regional Commission is an intergovernmental organization consisting of the governors of North Dakota, South Dakota, Nebraska, Wyoming, Montana, and federal representatives.

use controls on federally owned coal lease tracts. However, some land use controls are now indirectly applied by the federal government, for example, in the EPA air quality control regions. Thus, existing legislation may be sufficient to authorize some land use controls on the part of federal agencies. The Bureau of Land Management and the Forest Service, two agencies with substantial experience in multiple-use planning, have established a land use plan for management of the Decker-Birney area of southeastern Montana.[26] Their plan, produced in cooperation with Montana officials and after extensive consultation with landowners and others in the Decker-Birney area, seeks to accommodate the diverse interests of livestock grazers, timber producers, recreationists, and coal producers.

The EPA could establish land quality categories, similar to its air quality categories, to guide decision-makers on land use. Rather than approaching energy development on a mine-by-mine basis or on the basis of overall requirements, EPA could evaluate land use on the basis of relevant impact factors. Such impact factors might include:

- Vegetative and wildlife production.
- Competing land use requirements (such as farming, ranching, recreation, or residential use).
- Water consumption.
- Institutional and fiscal capacity of localities to absorb population growth.
- Net energy considerations.

A system of land quality categories would help solve two problems that are prevalent in environmental regulation--individual case-by-case treatment on the one hand, and inflexible across-the-board rules on the other hand. Instead, environmental standards could be applied to categories of conditions. For example, the need for reclamation could be treated as something not necessary in all places and at all times but only where some evident impact occurs. The needs of localities for assistance in accommodating different rates of population growth could be treated similarly.

Various tools of growth management are available at state and local levels. Montana, Wyoming, and North Dakota have enacted laws regulating the siting of synthetic fuels conversion facilities and electrical generating facilities. These laws incorporate some of the regulatory features mentioned above as impact factors in the context of possible federal regulation. Their effect will undoubtedly be to impose some state control over the scope, pace, and timing of energy development within the state. Montana and several other states in the coal-producing region have also enacted environmental protection legislation, which could regulate energy development impacts. Cities and towns can control growth by the indirect means of limiting the number of sewer or utility connections or limiting the reservoir capacity of municipal water systems. If they wish to promote concentrated settlement patterns, they can adopt an "urban service boundary" beyond which public services will not be extended. One successful policy instrument, put into practice by the town of Ramapo, New York, in 1969, required phased construction of public service facilities in parallel with land development. Ramapo's ordinance tied the rate of population growth to the rate at which public capital improvements could be financed. Other conditions besides those associated with timing can be attached to building and construction permits within local jurisdictions. For example, a specific finding on the part of a planning commission that sufficient public facilities exist may be required as a condition of granting a particular building or construction permit. In addition, local jurisdictions can adopt special-purpose zoning ordinances (such as agricultural zoning, conservation zoning, development district zoning, and down-zoning), and quotas or moratoria on building and construction permits.[27]

2. Fiscal Options

The federal government has a long tradition of aiding localities serving a national purpose which are adversely affected by their efforts. For example, military bases may occupy land that would otherwise belong to the city or county property tax base. However, federally owned land is exempt from local property tax obligations. At the same time, the presence of the military base might create a heavy burden of public expenditures for schools. Congress enacted legislation in 1950 to provide funds to school districts in areas affected by federal activity.[7] Public Law 874 was intended to aid school districts in financing current educational expenses. It now accounts for an average of 5 percent of the operating expenses of about 10 percent of the school districts in the United States, containing about 30 percent of the nation's public school enrollment. These payments continue as long as the federal activity remains in the area. Public Law 815 provides financial assistance for construction of school facilities in districts where the federal presence creates a need for such new facilities. These laws could well serve as a model for federal assistance to localities experiencing rapid population growth under pressure of energy development.

With regard to development of oil in the outer continental shelf, the Department of Commerce has recommended federal compensation of coastal states adversely impacted by energy development.[28] A similar arrangement could be formulated for coal mining. Such compensation takes three forms in the recommendation: (1) general revenue sharing, (2) adverse impact grants, and (3) front-end loans.

General Revenue Sharing--A percentage of federal bonus bid and royalty revenues could be earmarked for states affected based on impact factors.

Adverse Impact Grants--States could apply on an individual basis to the federal government for assistance based on demonstrated environmental, economic, or administrative costs associated with resource development.

Front-End Loans--States could receive low-cost federal loans to finance public facilities and services needed to accommodate resource development.

State governments can recover the costs of rapid population growth by means of valuing and taxing all productive wealth. For example, Montana enacted a 30 percent severance tax on coal, earmarking the revenues for schools, roads, recreational facilities, conservation, and reclamation. Reclamation bonds can be required as a condition of permission to mine coal. Similarly, the posting of a bond to cover the cost of expanded public facilities and services can be required.

The options discussed in this section do not offer a complete solution to the problems of energy development, environmental protection, and local growth. Many outstanding problems are not addressed, such as the issue of surface owners' rights, water rights, as discussed more fully in Chapter 19, and the allocation of resources to food and fiber production as well as energy production.

Although localities can limit population growth, the nation as a whole cannot do so, given the fact of at least some national population increase (even if at declining national birth rates). Nevertheless, while it searches for patterns of settlement that serve national needs without adversely affecting the quality of life, the nation can promote equitable and orderly local growth.

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22--POPULATION GROWTH CONSTRAINED SYNTHETIC LIQUID FUEL IMPLEMENTATION SCENARIOS

By Barry L. Walton

One approach to limiting the impacts of synthetic fuels production in a region is to constrain the population growth rate of the community. This chapter describes the preparation of scenarios on this theme and presents several alternative scenarios.

Each synthetic fuels plant of building block size has a defined labor force associated with its construction and operation phases. The primary jobholders during these phases induce additional population in the area through secondary support employment and families. The effect of this induced population can be treated analytically by applying an appropriate population multiplier to the labor force of the primary industry. This process can be used to construct a population profile for each type of synthetic fuels building block plant. On the basis of these profiles, detailed scenarios projecting the population increases under given conditions of industrial development can be plotted for a given region. The method can be used to construct scenarios that are applicable to nearly any technology and relevant region.

To illustrate the procedure, the following pages contain a description of the steps involved in constructing a fuel production schedule for a region that is limited by a planned population growth rate. Sample scenarios are given that depict the effect of introducing, on a planned schedule, coal mining and coal liquefaction or methanol production in Campbell County, Wyoming, and oil shale development operations in

Garfield and Rio Blanco counties, Colorado. A multiplier of 6.5 was chosen for reasons explained in Chapters 12 and 23.

It is important to note that the profile for a 100,000 B/D (16,000 m^3/D) coal liquefaction plant is essentially identical to a 250 million cubic foot per day (23 million m^3/D) coal gasification plant. Thus, the method immediately possesses useful generality.

Step One: A population profile for each type of facility is prepared. Figure 22-1 shows the resulting population profiles for coal mines, coal syncrude, methanol, and oil shale building blocks. Sources of the data for the building block facilities are Chapters 4 and 6. The profiles in Figure 22-1 already include the effect of the population multiplier of 6.5 (assuming a constant population during each yearly interval). Aggregation of the work force and the associated population into the profile facilitates construction of the scenarios and yields reasonably realistic population profiles.

Step Two: The current population for the county or region is established from census data or by using population estimates from local government officials. For this study, the estimated 1975 populations for Campbell county, Wyoming (17,000), and for Garfield and Rio Blanco counties combined (23,500) were obtained from local planning officials.

Step Three: Annual growth rates of 2 percent, 5 percent and 10 percent compounded continuously were applied to the current population to determine a set of theoretical population growth trajectories for the appropriate region. Figures 22-2 through 22-10 show growth curves of 2 percent, 5 percent, and 10 percent annual growth for the two selected areas.

Step Four: Paper cut-outs of the building blocks from Figure 22-1 laid on the population graph made during Step Three enable rapid construction of the final aggregate population projection. Rearranging the cut-outs on the population growth graph allows any growth rate to be easily approximated. (Use of separate cut-outs of the construction and operating phases greatly aids in experimentation and in the drawing of the final profile.) Figures 22-2 through 22-7 show a number of alternatives for Campbell county, Wyoming, derived by this method; Figures 22-8 through 22-10 show a number of alternatives for Garfield and Rio Blanco counties in Colorado. Once the start-up date for each plant is determined for each scenario, the net fuel production schedule is fixed and can be calculated. The insets to each figure show the fuel production schedule and water consumption needs for each scenario that were obtained by using the fuel output and water requirement scaling factors from tables in Chapter 6.

The implications of these population growth constrained scenarios are reported in Chapter 23.

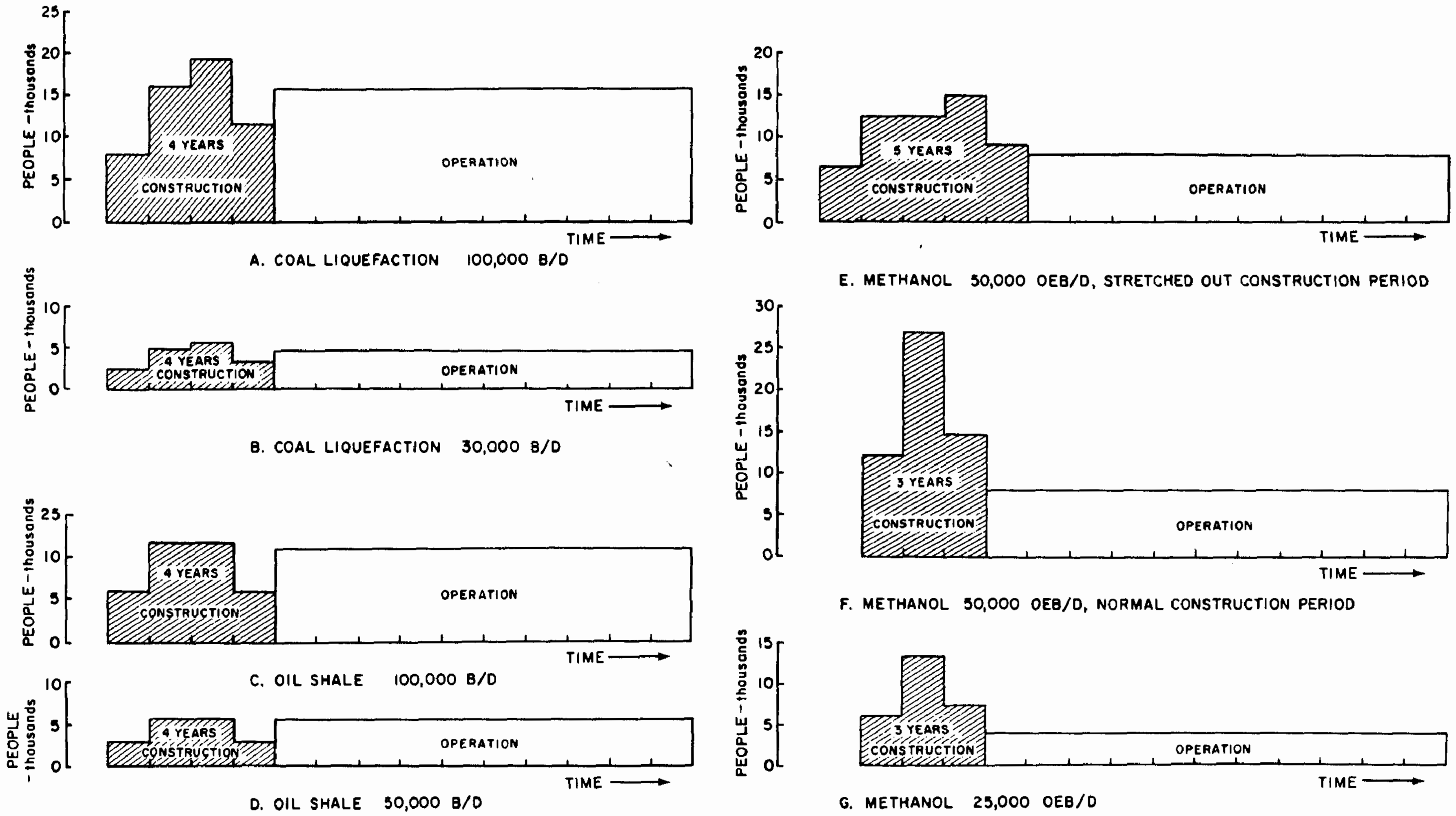

FIGURE 22-1. TOTAL POPULATION ASSOCIATED WITH INDIVIDUAL PLANT CONSTRUCTION AND OPERATION BUILDING BLOCKS. All building blocks include the mines that supply the plants. The actual labor force is multiplied by 6.5 to account for induced secondary employment and families. The data for these building blocks come from the scaling factors derived for the Maximum Credible Implementation Scenario.

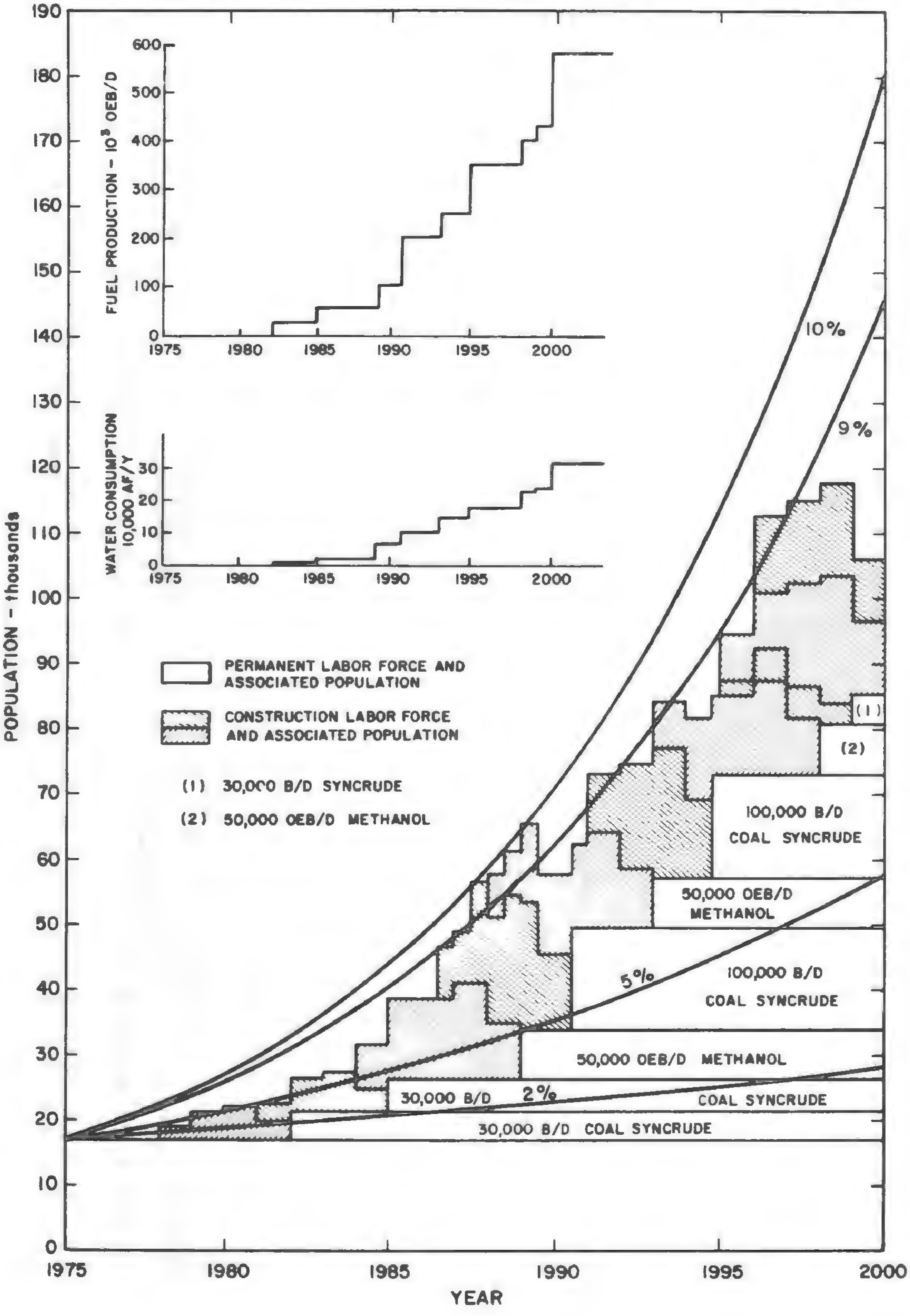

FIGURE 22-2. EFFECTS OF THE MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO UPON POPULATION IN CAMPBELL COUNTY, WYOMING. Assumes that one quarter of all the Scenario's development in Wyoming occurs in Campbell County. This assumption is expected to be on the low side.

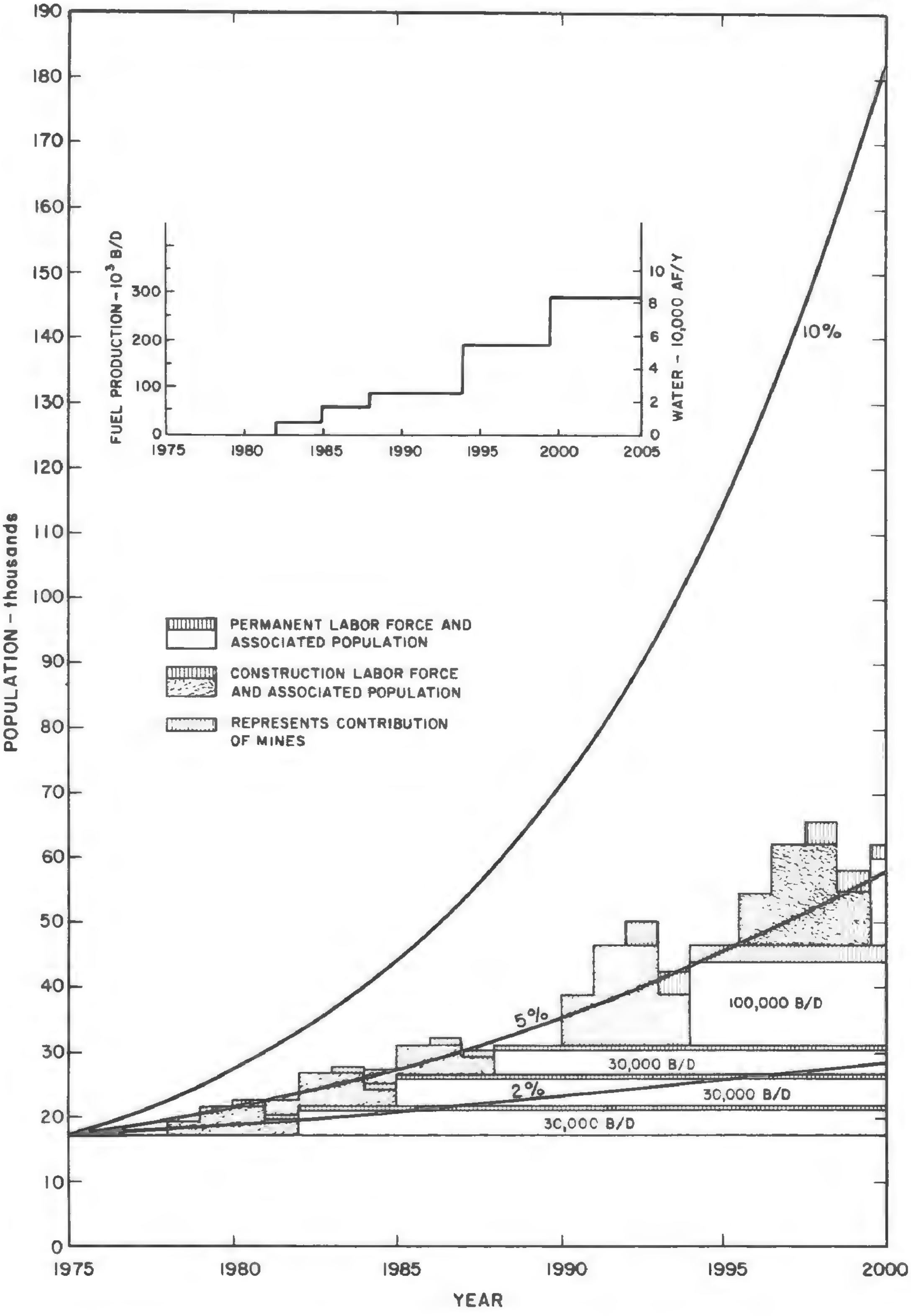

FIGURE 22-3. FIVE PERCENT CONSTRAINED POPULATION GROWTH RATE SCENARIO FOR CAMPBELL COUNTY, WYOMING ILLUSTRATED WITH COAL LIQUEFACTION PLANTS AND ASSOCIATED MINES. The larger sized plants cause rapid changes in population.

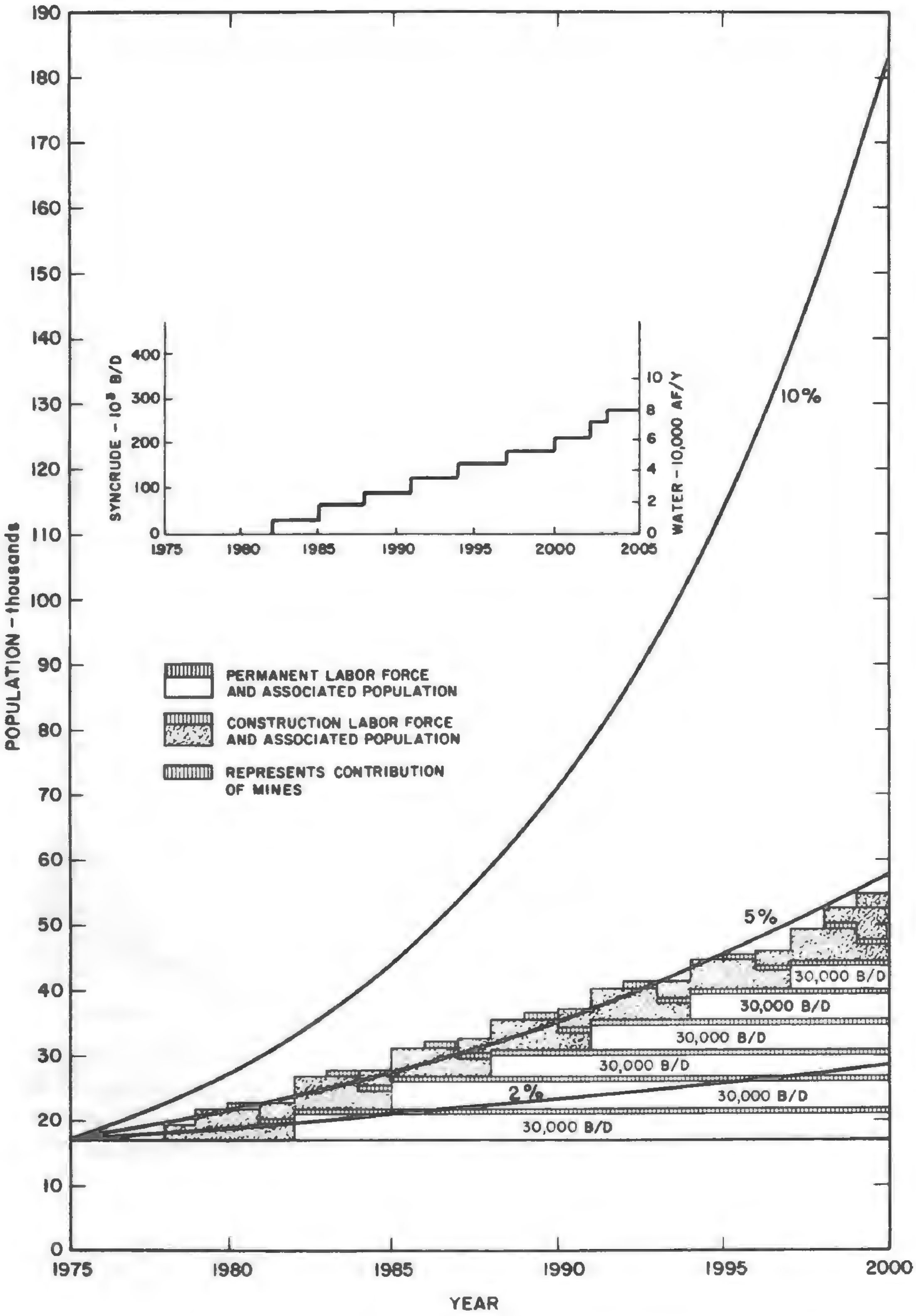

FIGURE 22-4. MODIFIED FIVE PERCENT CONSTRAINED POPULATION GROWTH SCENARIO FOR CAMPBELL COUNTY, WYOMING ILLUSTRATED WITH COAL LIQUEFACTION PLANTS AND ASSOCIATED MINES. By building only the smaller sized coal liquefaction plants, large fluctuations in population can be avoided

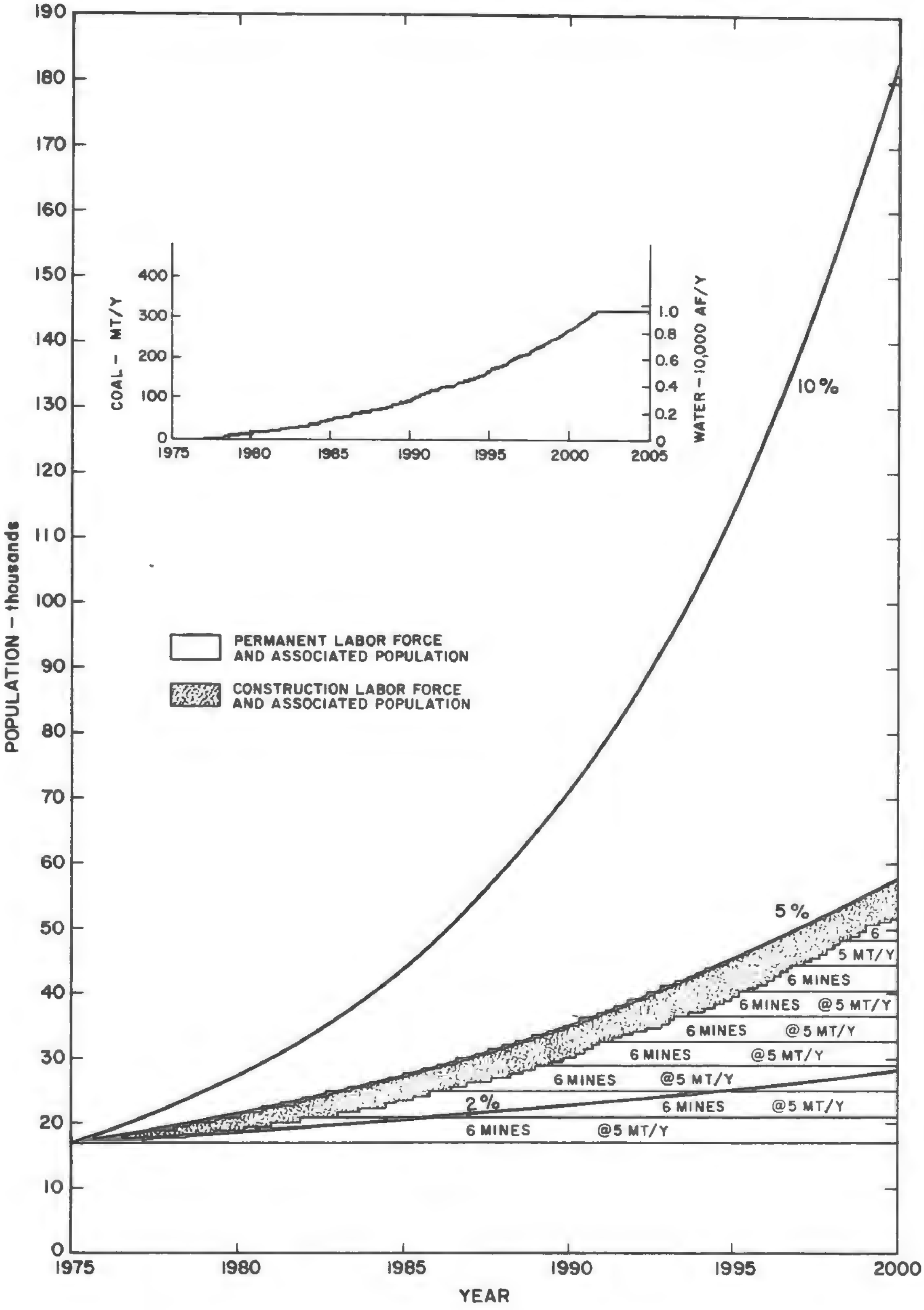

FIGURE 22-5. FIVE PERCENT CONSTRAINED POPULATION GROWTH SCENARIO FOR CAMPBELL COUNTY, WYOMING IN WHICH ONLY COAL MINES ARE DEVELOPED. Under these conditions growth in population can be made very smooth. By 2000, 54 mines, each producing 5 million tons/year, would be exporting 270 million tons of coal per year.

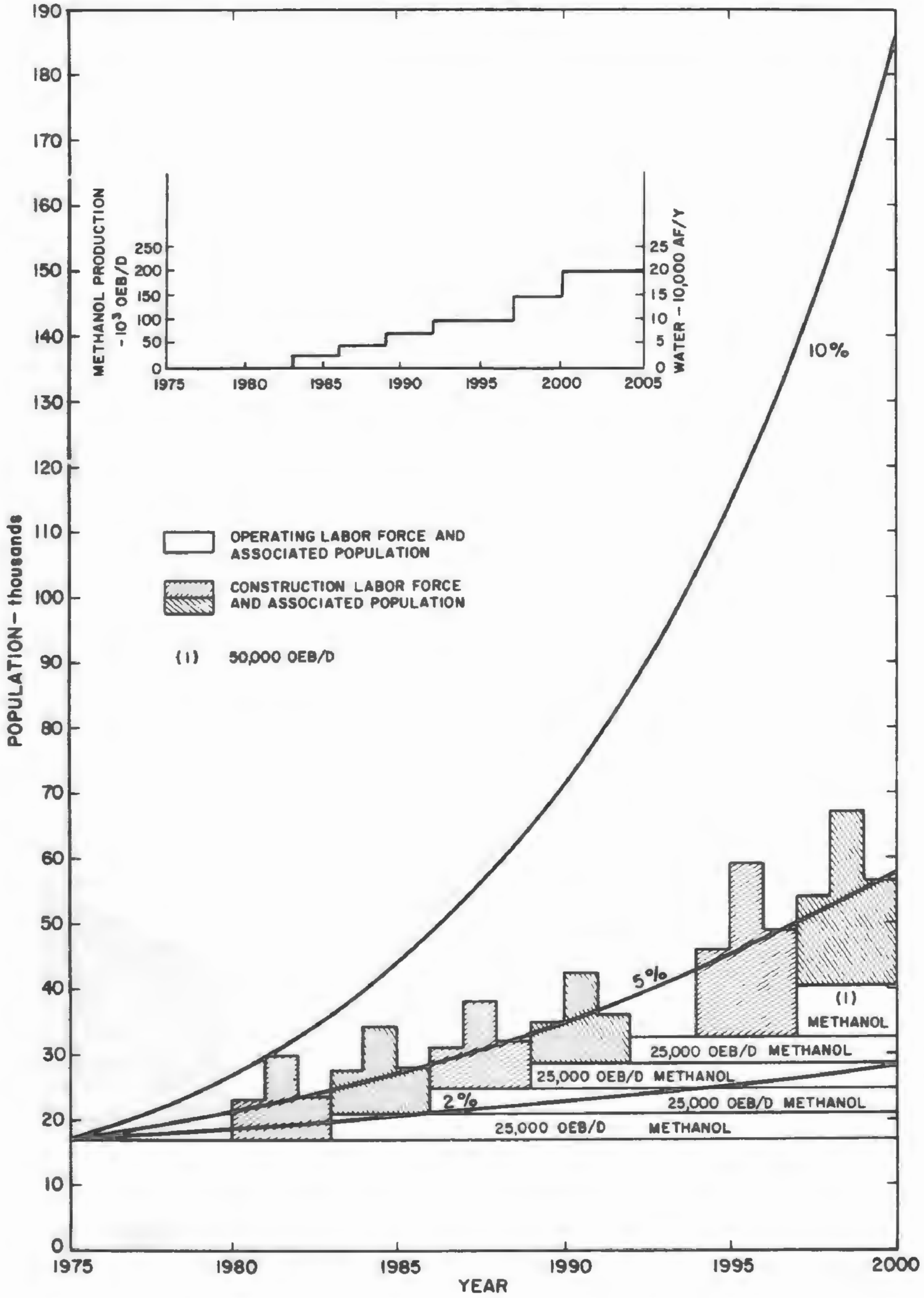

FIGURE 22-6. FIVE PERCENT CONSTRAINED POPULATION GROWTH SCENARIO FOR CAMPBELL COUNTY, WYOMING ILLUSTRATED WITH COAL TO METHANOL CONVERSION PLANTS. Severe fluctuations in population are apparent.

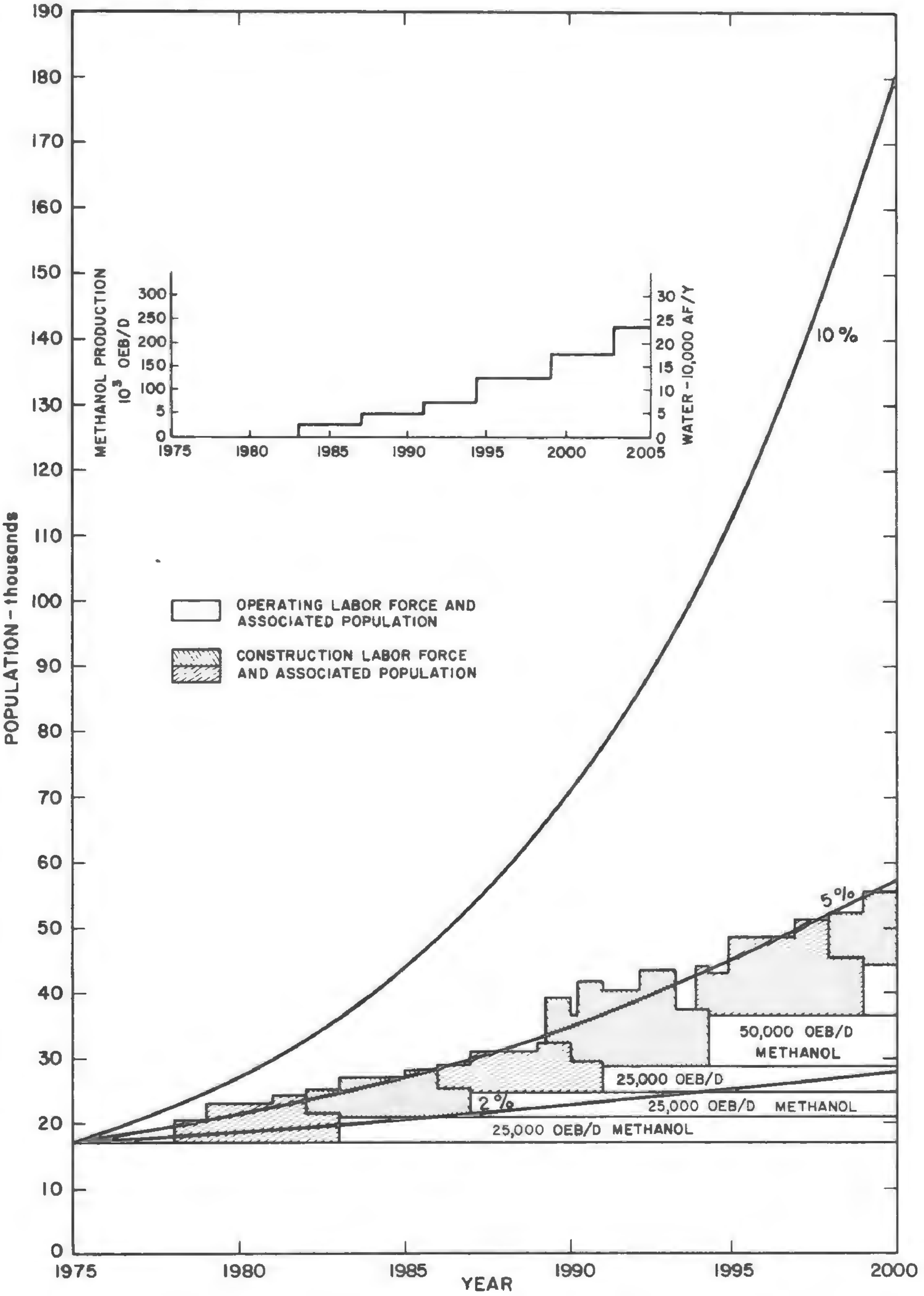

FIGURE 22-7. FIVE PERCENT CONSTRAINED POPULATION GROWTH SCENARIO FOR CAMPBELL COUNTY, WYOMING ILLUSTRATED WITH COAL TO METHANOL CONVERSION PLANTS WITH EXTENDED (5 YEAR) CONSTRUCTION PERIODS. By extending the construction time, the fluctuations in growth can be avoided.

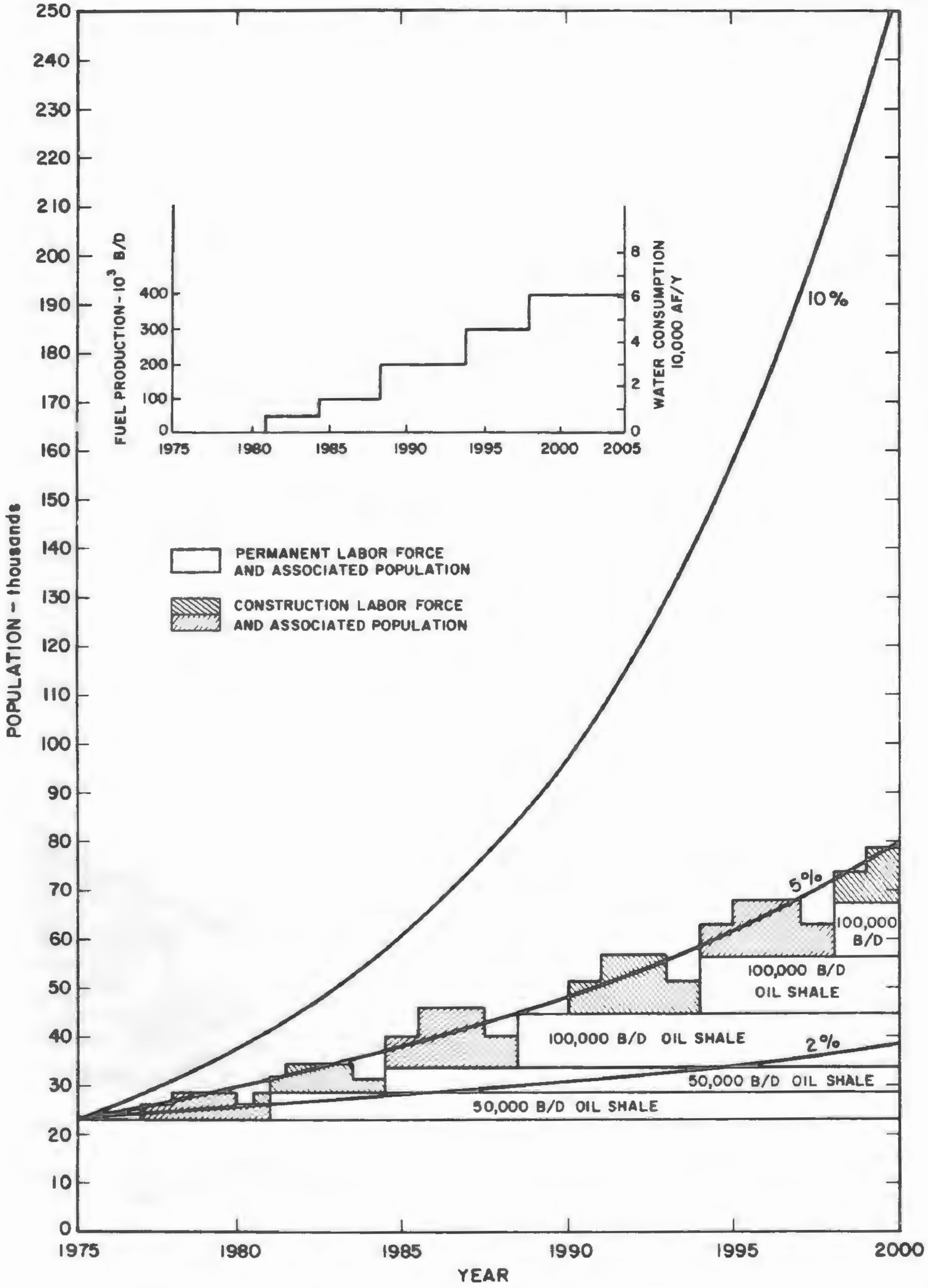

FIGURE 22-8. FIVE PERCENT CONSTRAINED POPULATION GROWTH SCENARIO FOR OIL SHALE DEVELOPMENT IN GARFIELD AND RIO BLANCO COUNTIES, COLORADO

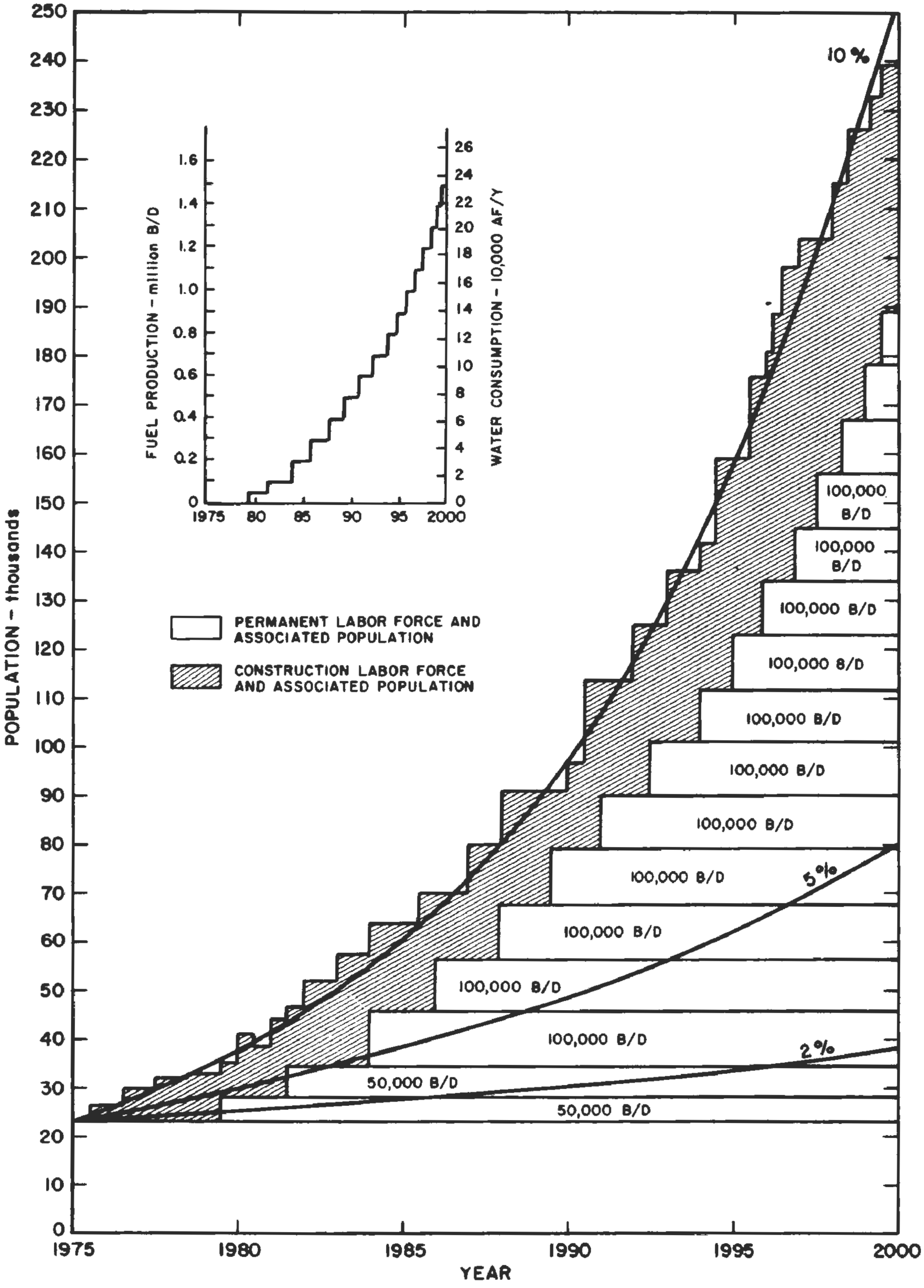

FIGURE 22-9. TEN PERCENT CONSTRAINED POPULATION GROWTH SCENARIO FOR OIL SHALE DEVELOPMENT IN GARFIELD AND RIO BLANCO COUNTIES, COLORADO

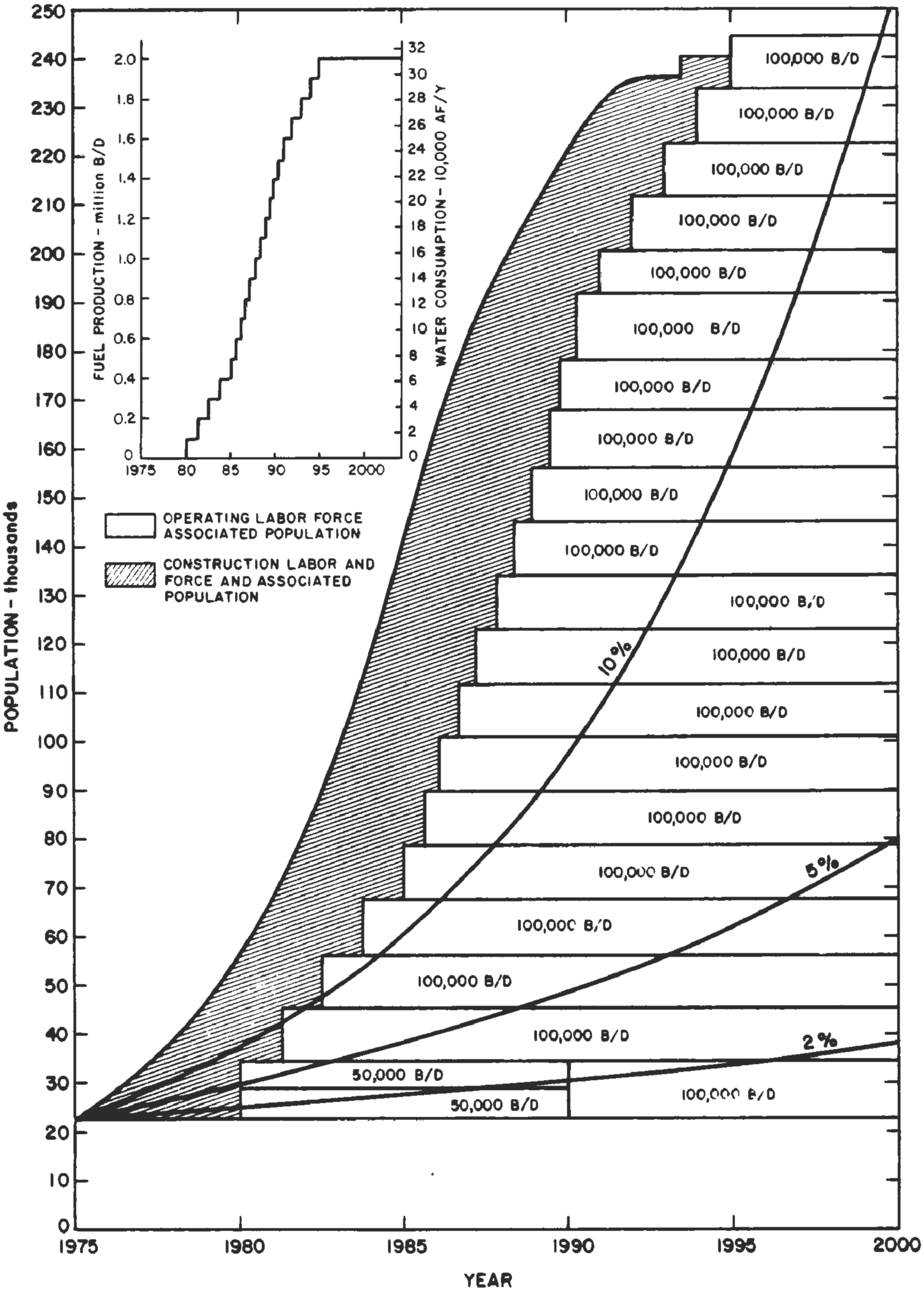

FIGURE 22-10. MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO FOR OIL SHALE DEVELOPMENT IN GARFIELD AND RIO BLANCO COUNTIES, COLORADO. The resulting annual population growth rate is about 17 percent.

23--COMPARATIVE IMPACTS OF CONTROLLED AND UNCONTROLLED URBANIZATION

By Peter D. Miller

A. Introduction

Growth and prosperity have traditionally been linked. As human groups move beyond bare subsistence and begin to produce more than they consume the surplus creates a form of wealth. Specialization of labor, industrial organization, and technological efficiency increase productivity and thus support larger populations. The capacity to generate new wealth, built into the process of growth, soon becomes dependent on growth. New products and new ways of generating demand are harnessed to the engine of growth. Jobs, firms, and entire industries become bound up with more and more growth. Annual increases in gross national products and national incomes are registered in the confident belief that they mean a better standard of living for all. Yet many observers now doubt whether the traditional alliance of growth and prosperity is still viable.

Critics of growth have made three kinds of arguments that merit the attention of anyone contemplating the prospect of more growth. The first is that "spaceship earth" has certain natural limits--of resources, of carrying capacity, of the necessities of life--that are rapidly being approached at present rates of depletion. While the capacity to generate wealth has indeed been increased by growth, so the second argument goes, control of the means of production has concentrated this wealth in a few hands, leaving many in poverty. The third argument is that social costs, negative externalities, spillover effects, and other unanticipated consequences of growth have polluted air, water, and land to such an extent as to make life unlivable.[1] None of these ideas is particularly new. Malthus, the first prophet of overpopulation, was preoccupied with natural limits. Inequitable distributions of wealth resulting from control of the means of production were, of course, a major concern of Marx and his followers. Externalities were first identified by the economist Alfred Marshall. If these ideas have acquired more cogency in recent years, it is because the effects they point to are visible on a local as well as the global level.

The following analysis focuses on the comparative impacts of two levels of growth on two specific areas, the Powder River Basin of Wyoming and the Piceance Basin of Colorado. The dynamics of growth are described in such a way, however, that they can be generalized to other areas. With appropriate modifications for technological variables, the analysis is applicable to large-scale energy production, mining, and industrial development in general.

B. Impact of the Maximum Credible Level of Synthetic Fuel Production

The "maximum credible" (described in Chapter 6) case describes the situation in which real-world constraints other than technical and physical limits are absent. It is the level of synthetic fuels production that would be achieved if labor could be attracted in sufficient numbers, if there are no obvious bottlenecks in the supply of steel, pipe, and other materials, if there were no obvious shortage of capital, if deliveries of "walking draglines," to scoop up strippable coal were assured as soon as they were needed, if residents of the coal mining regions and their elected representatives had no objections to the industrialization plan, if there were no lawsuits by environmenalists, ranchers, Indians, or anyone else who could be adversely affected in fact by the Federal Coal Leasing Program, and if world energy prices remained stable for the foreseeable future. The maximum credible case is thus by no means to be construed as a prediction, but rather as a theoretical upper limit to the level of production. Other factors, as we shall see below, begin to constrain development of synthetic fuels long before the theoretical upper limit is reached.

1. Population

Figure 22-2 in the previous chapter shows the population that would be generated in Campbell County, Wyoming, from coal liquefaction plants, methanol plants, and coal mines just sufficient to fuel them (captive mines only), according to the maximum credible level of production. In Figure 22-1, it is assumed that Campbell County would produce one fourth of the synthetic crude oil produced in Wyoming, probably a low figure. The present population of 17,000 would double by 1985, triple by 1988, and increase by a factor of 7 before the end of the century. Population density in the county, now 3.5 people per square mile (0.74 people per km^2), would be 20 to 25 (7.7 to 9.7 people per km^2). Compared to that, the current annual rate of 5.5 percent in the county and Gillette's 7 percent seems leisurely. Since the county is experiencing great difficulty in keeping up with the growth that has already occurred, it would undoubtedly experience even greater difficulty in the maximum credible case. It is evident that the major increments of growth come from the construction of coal liquefaction and methanol plants. The operating labor force and associated population for a 100,000-B/D (16,000 m^3/D) coal liquefaction plant are also substantial.

Figure 22-2 shows steep peaks and valleys for coal-related employment. This in part results because data are presented on a year-by-year basis, while in fact employment would be added and would taper off more gradually. However, even if the data were presented on a daily basis, peaks and valleys would still exist, only with rounded corners. In short, there would be severe discontinuities in the local economy and the fortunes of the county would swing up and down in response to the fortunes of the coal mining industry. With extremely large units of production, it is almost impossible to avoid such instability.

2. Housing

According to the 1970 census, Campbell County ranked second highest in Wyoming in the proportion of its housing containing one or more persons per room--14 percent. This proportion has probably gone up in the intervening five years. Nevertheless, if the same ratio of dwelling units to population (3.4) were maintained for future years, the maximum credible case would require the construction of 5000 additional housing units by 1985, 10,000 by 1988, and 30,000 by the end of the century. Failure to meet these requirements would result in additional real estate speculation and extremely high rents, probably on a scale that would drive out those who did not own property and whose wages did not compensate for these increases. Campbell County's 1970 median rent of $140 a month was already the highest in the state. Rents have gone up by a factor of 2 or 3 with a 5-mile (8 km) radius of Gillette during the last 5 years, according to the Campbell County Planning Department. The actual limits of local growth would probably be reached well before synthetic fuels production attained a small fraction of its maximum technically-credible level.

3. Age Distribution and Schools

If present trends continued, the age distribution of the incoming population would be younger than average. In 1970, Campbell County had the highest proportion of under-18 population in Wyoming, 42 percent. Its school-age population (5 to 18 years of age) was about 30 percent of the total in 1970, and has risen since then to about one-third the total population. If that proportion remained no more than one-third, the number of school children in 1988 would be equivalent to the county's present total population, in the maximum credible case. The school population alone would be a medium-sized town of 40,000 by the end of the century. Classroom expenditures and school personnel salary expenditures would be quite large.

4. Public Expenditures

Total county governmental expenditures, using the correlation developed by the Bureau of Reclamation,[2] would be over $10 million a year in 1985, $16 million a year by 1988, and $38 million a year (constant 1970 dollars) by tne end of the century. Per capita expenditures, currently $260, would rise to about $290 in 1985, $310 in 1988, and $320 by the end of the century (constant 1970 dollars). If 1970 proportions were maintained, about half would go to schools, an eighth for highways, one-twelfth for public welfare and public health, and the rest for other expenses. These expenditures would be a bare minimum, inasmuch as the raw data from which the correlation between population and expenditures was developed came from counties that had delayed necessary expenditures as long as possible. Unless tax structures were overhauled, the bulk of these public expenditures would be financed by old and new individual residents and/or by future generations through long-term debt obligations. The maximum credible case of synthetic fuels production, then, would impose substantial, perhaps insurmountable burdens on local government.

C. Development Constrained by a 5 Percent Annual Growth Rate

Relationships between the global trends mentioned above and local impacts have been brought home to the American people in recent years. Natural limits are readily understandable to anyone who has waited in a gasoline line, paid high prices for groceries, or had a well run dry. When local taxes go up as the natural resources of a region are extracted, inequitable income distribution becomes a topic of concern. Moreover, the crowding, tension, and other conditions of boomtown growth provide ample evidence of the unfortunate by-products of rapid urbanization. These considerations suggest that the largest possible scale of development may not always be equivalent to the best scale of development for all concerned.

To meet these concerns, we have treated local rates of population growth as a factor that might constrain industrial development. Just as there are limits to what can be done with available materials and technology, there are limits to how fast a region can grow without impairing a decent quality of life. In many cases, these limits are imposed by the courts or the political process, and so they vary according to the tolerance of affected interest-groups. In other cases, these limits are breached at a cost that often appears in hindsight to have been too great to pay. At that point, costly remedial measures may have to be taken. Although planners disagree on what an optimum growth rate might be in theory, they sense that it is not large.* A planner in one rural western county said he considered growth rates between 1 and 2 percent a year to be ideal. Some planners have referred to a 5 percent annual growth rate as "hyper-urbanization." There is no magic number that can guide all development planners in all circumstances; however, an approximate indication can be drawn from the experience of cities, towns, and counties that viewed their growth rates as excessive.

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*The annual growth rate, r, is derived from the formula $P_2 = P_1(1 + r)^n$ where P_1 is the population at the beginning of the time period, P_2 is the population at tne end of the time period, and n is the number of years in the time period.

Santa Clara County, California (San Jose), which is generally conceded to be an example of the unfortunate consequences of uncontrolled development, grew at an annual rate of 5 percent between 1960 and 1970. Santa Barbara and Riverside Counties, two other fast-growth areas of California, added population at the rate of more than 4 percent a year. Boulder, Colorado, another example of what many consider "runaway growth," increased its population every year at a rate approaching 6 percent. In Phoenix, Arizona, and Albuquerque, New Mexico, two cities of the Southwest where local growth has become a major public concern, the rates were under 3 percent. Thus it seems reasonable to select 5 percent additional growth per year as an upper limit of the rate communities can tolerate. Few would consider such a figure ideal, as many adverse impacts appear well below that rate, but almost all would agree that annual growth rates exceeding 5 percent impose severe burdens on community institutions, services, and resources. By using such a figure hypothetically as a constraint on development, we do not mean to suggest that population can be limited by law or regulation. Instead, our intention is to show the consequences of controlling growth on the basis of population (by whatever means society deems acceptable), contrasted with the impact of development constrained only by technical and physical factors.

Although economic growth is usually defined as increased per capita output, such a measure is not useful in small towns and surrounding regions because of the difficulties of disaggregation and because these are not self-sufficient economic entities. Growth is conceptualized here as urbanization and is measured by increases in population. Economic growth and urban growth are of course highly correlated, but the definition used here does not assume growth is tied to increased per capita output or to net welfare.[3]

1. Smooth Growth Rates as a Mathematical Approximation

Rates of population growth are not always uniform from year to year. In reality they may vary a great deal, and a compound annual average taken between two points in time smooths out these differences. For example, a town could grow rapidly at 10 percent a year for 5 years, then slow down to 0.25 percent for the next 5 years, and still finish out the 10-year period with a 5 percent annual growth rate overall. If continuity and stability were of any value to the townspeople, this would hardly be a desirable state of affairs. If they sought to maximize these values, they would try to add no more than a fixed percentage to their number every year, apportioning new residents over time as evenly as possible. In practice, of course, they could not always attain this ideal. However, a smooth rate of growth represents a reasonable objective, given the available alternatives. Hence the use of a constant growth rate as a possible constraint on development is realistic.

2. Selection of Base Year

The projection of growth rates into the future is sensitive to the base year chosen. It makes a great deal of difference whether a given constraint might start in 1960, 1965, 1970, or 1975. The smaller the population base, the smaller the number of people added by fixed percentage increases. For any period when population is increasing, earlier base years will tend to depress future values, while later base years will elevate future values. Gillette, Wyoming, for example, numbered 3600 people in 1960, 7200 in 1970, and was estimated by the county planner to contain 11,000 people in 1975. If the base year of 1960 were selected, and 5 percent a year were added to its population then, it would gain fewer than 2300 people in 10 years. The same growth rate and the same time period applied to the 1975 population adds nearly 7000 people. Therefore we have selected the current year's population as the starting point for all projections, even though growth rates may have exceeded 5 percent in previous years.

3. Selection of Geographical Base

Future values are also sensitive to the geographical base chosen. Larger geographical units, with more people in them to start with, can accommodate larger numbers of additional people than can smaller geographical units with fewer people, assuming equal growth rates. Five thousand new people added to Detroit would hardly be noticed, but the same number added to Gillette create substantial problems. Three principles governed selection of the geographical base:

- Since social impacts are often obscured when the nation as a whole or even the Northern Great Plains as a whole is examined, it was necessary to narrow the focus to where visible impacts actually take place--where people live, work, shop, play, or pass the time of day.
- A commuting distance between home and work of more than 35 miles (56 km) was considered impractical for the vast majority. In a similar problem involving selection of the boundaries of a regional housing market, Sternlieb *et al.*, found that 86 percent of the commuters sampled lived within 35 miles (56 km) of their place of work.[4] The quality and layout of roads were examined in deciding how far people might live from where they work. Existing towns within 35 miles (56 km) from the place of work were considered the most likely areas of new settlement.
- A geographical base could have been selected by including all the area within a 35 mile (56 km) radius of adjacent places of work. Populations for the parts of counties included in such a circle could then have been estimated from known population densities. For the sake of administrative simplicity, however, counties were used as the geographical base. The county is the planning unit that would have to react to impacts that occur, and counties have been selected so as to be broadly inclusive of the vast majority of immigrants. Growth rates would not be identical in every part of a county (unless immigrants happened to settle proportionally in exactly the same

places as older residents). Instead, existing towns could be expected to capture a greater proportion of new residents than their present proportion of older residents. Gillette, Wyoming, for example, had slightly more than half of Campbell County's population in 1970. Its "capture rate" of new residents will, however, probably be at least 80 percent. At that rate, if the county grows at 5 percent a year, Gillette will grow at about 7 percent a year. This pattern would pertain to all counties in which the "capture rate" of towns will exceed their present population share, as is generally the case in the West. Figure 23-1 illustrates this pattern. The use of a county-wide average growth rate thus tends to underestimate impacts on towns.

4. Employment-to-Total-Population Multipliers

Labor requirements for the coal mines, oil shale mines, and synthetic fuels production facilities have been derived from industry sources and are explained in Chapter 4. The ratio of total population

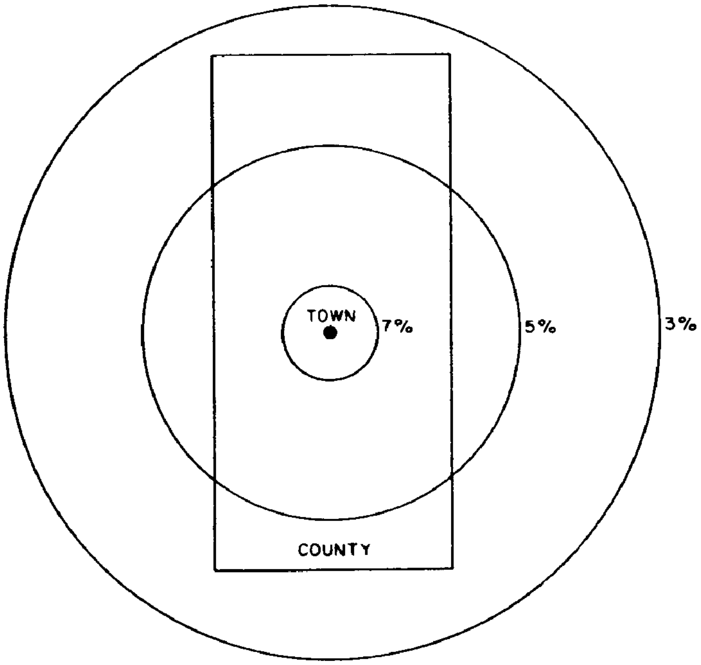

FIGURE 23-1. GROWTH RATES ARE HIGHEST NEAR THE CENTER OF ACTIVITY AND FALL OFF WITH DISTANCE. The radii shown are for purposes of illustration only; actual radii depend strongly upon the actual location.

to size of the labor force, known as the population multiplier, is usually derived from an "export base model" in which various assumptions are made about the dynamics of the local economy and demographic characteristics of immigrants. The export base model assumes that basic industrial employment generates additional services and related secondary employment. Urban growth rates are assumed to be more or less thoroughly determined by expansion of the industrial (export) base. It is not always clear, however, that the cause-and-effect relationship proceeds only one way. The efficiency of the local service industries and of local public management in fact often determines the rate of "basic" industrial growth.[5] The model also assumes that sufficient labor is available and can be attracted to the town at whatever wages it may be necessary to pay. If the export base model is relied on for precise population predictions, its assumptions about the direction of causality and the likelihood of attracting labor are likely to yield inaccuracies. If it is used only to compare two hypothetical growth rates, as it is here, the oversimplifications are relatively harmless. The multiplier is the product of two numbers: locally generated secondary employment, and average family size. If 2.6 indirect local jobs are necessary for every industrial job, and if average family size is 2.5, the multiplier will be 6.5. Figure 23-2 shows schematically the basis for population multipliers. Total population added can then be estimated by multiplying the industrial labor force by this number.

For precise predictions of future population, several refinements are possible. An input-output model of the regional economy could be constructed, and direct employment, secondary employment, and multipliers could be calculated for each industry. Multipliers vary according to the size of the community because larger towns and cities already have some existing capacity to provide needed public and private services. Smaller towns, on the other hand, have less capacity to start

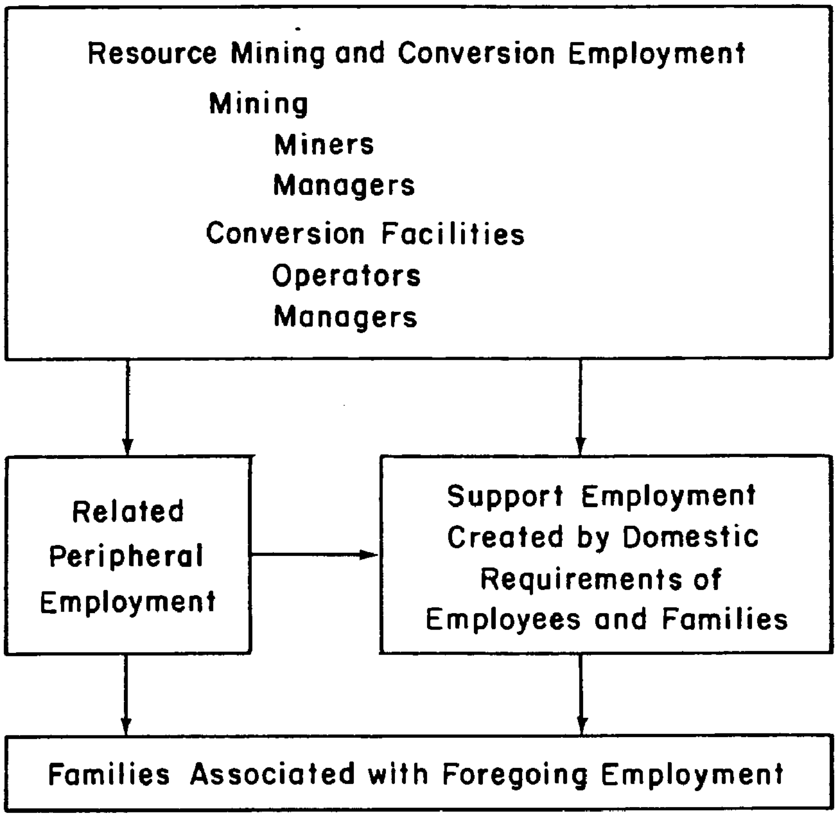

FIGURE 23-2. BASIS OF POPULATION MULTIPLIER CONCEPT

with and therefore require greater additional secondary employment. Since the propensity to shop locally affects the size of the multiplier, distance from major trade centers could be taken into account in selecting an accurate predictive value. A lower multiplier could be used for the construction labor force than for the operating labor force, on the assumption that fewer construction workers will bring their families. Finally, labor force participation rates may be broken down by age and sex to allow for varying demographic characteristics of immigrants. A model incorporating these and other elements has been constructed for the U.S. Department of Agriculture.[6]

Our purpose here, however, is not to predict total population resulting from all industries but to compare the impacts of two hypothetical levels of development in mining and synthetic liquid fuels production only. These two hypothetical levels of development are constrained in one case by technical and physical factors only, and in the other case by a 5 percent annual growth in population. Neither of these constraints will be the operative limits in real life. A multiplier of 6.5 has been selected for the Powder River Basin of Wyoming and the Piceance Basin of Colorado. Because towns in those regions are presently small, and because mining and manufacturing usually have large multipliers, there is good reason to believe that a multiplier of 6.5 underestimates actual added population. The likeliest sort of error in such an analysis, then, would be to understate the severity of local impacts that could be expected to occur.

D. A 5 Percent Annual Growth Rate in Campbell County

If Campbell County added 5 percent a year to its population in the future, its growth rate would approximately duplicate what it has experienced in the past 5 years (1970-1975). Figure 22-3 depicts an attempt to fit a combination of small and large coal liquefaction plants, along with associated coal mines, under a 5 percent growth curve. Phased to minimize discontinuities, the population profile still exhibits minor jumps during years of peak labor force in the construction of the small liquefaction plants. Major peaks and valleys appear after 1990, when construction of the large liquefaction plants would begin. Even limiting production capacity to 300,000 B/D (48,000 m^3/D) by the end of the century, the necessary facilities still could not be accommodated within a 5 percent growth rate, as the figure shows. Further study of Figure 22-3 reveals that a 5 percent growth rate is practically incompatible with construction of the extremely large, 100,000 B/D (16,000 m^3/D) liquefaction plants. One would have to wait until 1990 to begin construction of such a facility (doing nothing until then) to keep additional population within the 5 percent growth constraint.

1. The Alternative of Building Smaller Plants

Figure 22-4 (Chapter 22) depicts an alternative that smoothes out the rate of development considerably--building relatively small (30,000-B/D or 4800 m^3/D capacity) liquefaction plants only. This would create a 210,000-B/D (34,000 m^3/D) capacity by the year 2000, compared with a 290,000-B/D (46,000 m^3/D) capacity in the case of both large and small plants, and compared with a 400,000-B/D (64,000 m^3/D) capacity in the maximum credible case. Although the growth rate depicted by Figure 22-4 would actually be closer to 6 than to 5 percent until after 1990, employment would not be subject to massive increases and declines. Instead, it would rise more or less steadily if start-up construction of succeeding plants were phased to coincide with final year construction of preceding plants.

Assuming that housing in Campbell County would become neither more nor less crowded than it is at present (i.e., that the ratio of dwelling units to people would be constant), necessary additions to the housing stock would be substantial although not nearly as large as those required by the maximum credible case. As population rose in a 5 percent growth rate from its present 17,000 to about 57,000 by the end of the century, additional (cumulative) housing requirements would be as follows: 1700 by 1980, 4300 by 1985, 6400 by 1990, and 12,000 by 2000. While these requirements are certainly modest compared to those of the maximum credible case, they would still mean adding between 400 and 500 new dwelling units a year, a substantial effort for a small or medium-sized town. In practice, a large proportion of these would be mobile homes, and some additional crowding would result from any shortfall in the provision of housing.

Assuming the school-age population remained one-third of the total, the county school system would have to absorb nearly the equivalent of its 1970 pupil population by 1980, under the 5 percent a year growth constraint. There would be 7500 pupils in 1980, more than 10,000 in 1985, 12,500 in 1990, and more than 19,000 by the end of the century. Demands for classroom space, teachers, and administrative capacity would rise accordingly. In contrast with the maximum credible case, increased requirements would be steadier, more predictable, and approximately half the size. However, the increase would still be substantial in the near-term when financing would be the most difficult to obtain, and some crowding, double sessions, increased pupil-teacher ratios, etc., could be expected if construction and organizational development fell behind schedule. Although impacts would not be of the same order as those in the maximum credible case, they could still be characterized as moderately severe.

Using information from Reference 2, public expenditures in Campbell County in constant 1970 dollars would total $6.7 million a year in 1980, $9.4 million a year in 1985, $11 million in 1990, and $18 million in the year 2000. Major spending differences between the growth-constrained case and the maximum credible case would only begin to show up after 1985. Prior to 1985 (in the hypothetical cases depicted in Figures 22-2 and 22-4, population growth would advance fairly steadily in both cases. The discontinuous growth exhibited by the maximum credible case would yield no benefits in reduced expenditures because the county would only have to gear up again for resumed growth after momentary declines. Thus its expenditures in all likelihood would not decline along with temporary losses of population, but would continue to climb for several years after any leveling-off in growth rate. After 1985, annual expenditures in the growth-constrained case would be about half the annual expenditures in the maximum credible case. On a per capita basis, county expenditures would rise from $262 currently to $290 in 1980, $295 in 1985, $300 in 1990, and $310 in 2000 (constant 1970 dollars). Differences between these values and comparable values associated with the maximum credible case are of the order of only a few dollars. Individual tax burdens in the maximum credible case would be only slightly higher than those in the growth-constrained case. Because much greater numbers of people would be paying the slightly higher taxes, the differences between the two tax rates would tend to be minimized. As far as local governmental capacity is concerned, the chief advantage of the growth-constrained case would be to allow the county to defer necessary expenditures for a longer time. Slower growth would provide more flexibility and would help prevent the formation of crises such as have occurred in the recent past.

2. The Alternative of Exporting Coal from the Region

Some local and state officials have occasionally expressed a preference for a policy of having coal extracted and transported elsewhere to be processed. The advantage of the "strip it and ship it" philosophy, for these officials, is that mining activities in themselves would not disrupt the region as much as would be combination of mining and conversion to synthetic fuels at the site. The most disturbing impacts, as noted above, come from construction of extremely large industrial facilities in a relatively short span of time. Moreover, the permanent labor forces associated with liquefaction and methanol plants are only slightly less than the peak-year construction labor forces. Thus large numbers of people would be required both to build and to operate these facilities. Compared with these numbers, the labor force and associated population brought about by coal mining alone would be small. Figure 22-5 shows that a growth rate of only 2 percent a year would be compatible with extraction of about 90 million tons (8.1 billion kg) of coal a year by the year 2000. Constrained only by a 5 percent a year growth in population, Campbell County could mine

270 million tons (240 billion kg) of coal a year by the year 2000. The labor force and associated population in coal mining alone is so small that it would allow local and state officials much greater regulatory flexibility in choosing appropriate growth rates. While conversion facilities are not practical below a certain size and level of employment, coal mines are practical to operate in a variety of sizes. A more than adequate amount of coal extraction is compatible with growth rates generally regarded as manageable.

3. The Alternative of a Longer Construction Period

One characteristic of coal liquefaction and methanol plants that makes them difficult to adapt to a small town is their short construction period. With a short, say, three-year construction period, the distribution of work throughout time is typically uneven: moderate levels of effort during the first and third years, intensive level of effort during the second year. This unevenness is probably unavoidable during a short construction period because some allowances must always be made for start-up time, recruiting a large work force, and proper sequencing of the installations of parts of the plant. Figure 22-6 depicts a possible construction and operation schedule for four small (25,000 OE B/D or 4000 OE m^3/D) and two large (50,000 OE B/D or 8000 OE m^3/D) methanol plants. This schedule can almost be accommodated within a 5 percent annual growth constraint, except for the peak year of construction effort. This feature clearly creates sharp jumps and drops in the demand for labor and hence in associated population. A region subject to this instability would require either a highly mobile labor force or some other source of local employment to take up the slack during periods of lesser coal-related employment.

The incentives for a firm to minimize the construction period are clear. A plant under construction is tying up capital nonproductively, and meanwhile there is interest to pay on borrowings to finance construction (unless sufficient equity financing is available). The incentives for the public to have the construction period lengthened are equally clear. As Figure 22-7 shows, it is possible to smooth out the rate of population growth considerably by substituting a 5-year for a 3-year construction period. Periods of unemployment are reduced almost to zero, and the only period of very sharply rising demand for labor occurs at the onset of construction of the first large methanol plant. This stability brings obvious advantages to public officials, who can plan for the expansion of services, housing, etc., more readily when growth is steady than when there are violent upswings and downswings.

E. The Maximum Credible Level of Oil-Shale Mining and Retorting--Piceance Basin

Fewer alternatives are available in oil-shale development than in coal development because it is not practical to retort oil shale (extract crude oil from shale rock) far from the site where it is mined. Transportation of oil shale over long distances could not possibly compete economically with transportation of the crude oil product (after upgrading) through pipelines. Oil shale must be mined and retorted at the site or not at all. Thus the option of developing a relatively simple mining operation without an associated industrial complex does not exist.

Abundant deposits of oil shale are found in the Piceance Basin, a remote area of the Rocky Mountains' Western Slope, located in Rio Blanco and Garfield Counties, Colorado. The two counties currently have a combined population of 23,500 (1975 local planners' estimates). About half this number live in four towns: Meeker and Rangely in Rio Blanco County, and Rifle and Glenwood Springs in Garfield County. Grand Junction, to the south, is presently a major population center and could be expected to experience some impacts associated with oil-shale development in later years after highway access from the resource development sites was improved. It has been excluded from the unit of analysis considered here, however, on the basis of principles described above: (1) Rio Blanco and Garfield Counties are small enough in population and in land area to form a coherent planning unit that would show the effects of proposed development. Yet they are not so small that those effects would be distorted. Their land area is 6300 square miles (16,000 km^2) compared with 4800 in Campbell County, Wyoming. Adding Mesa County (Grand Junction) would create a land area too large to behave as a unit; (2) The only heavy-duty route between Grand Junction and places of oil-shale employment follows a zig-zag course northeast for 60 miles, then 20 miles to the northwest. A daily 160-mile (260 km) round trip would be intolerable for almost everyone. A slightly more direct route exists, but it is now only a dirt road in parts and would only cut about 10 miles from the one-way commuting distance even if it were improved; (3) In accordance with the objective of analyzing the implications of growth for administrative units, Rio Blanco and Garfield Counties have been selected as the geographical base. Piceance Creek is about in the center of this two-county area, and the layout of roads in the region also makes this area a logical unit for the analysis of local impacts.

The maximum credible level of oil-shale mining and retorting would require an annual rate of population growth of between 16 and 19 percent between 1975 and 1990, after which growth would level off. Population would grow almost tenfold during the first 15 years. As Figure 22-10 shows, the population of the two counties would climb to 56,000 in 1980, 135,000 in 1985, 220,000 in 1990, and level off to 245,000 in 1995.

This population would not be distributed evenly over the vast land area of the two counties. The presence of the White River and Routt National Forests in the eastern portion of the two counties would preclude residential development in about 1000 square miles (2600 km^2). Steep canyon sides and higher elevations would also be unsuitable for residential development. The only land remaining would be along broad valleys and upland plateaus. Much of this would be restricted as well because of lack of access by road. Areas classed as suitable for residential settlement by a recent study made up only 7 percent of the area of Garfield County, and 17 percent of Rio Blanco County.[7] Since oil shale lands in the Piceance Basin were included in the classification, the actual proportions would be somewhat less. Existing towns would likely absorb the bulk of the increased population, with the remainder absorbed along existing transportation routes. The only other Colorado county to have undergone industrialization recently, Pueblo County, has 82 percent of its population living in urbanized areas. As an indicator of expected urban population in Rio Blanco and Garfield Counties, this proportion is probably low; nevertheless it would yield an urbanized population of 176,000 in 1990. Rifle and Meeker, closest to the oil shale sites, could well become cities of 50,000 or 60,000 people.

Such sudden increases in population would strain every social and institutional resource in the region. Mobile homes would be strung out along every canyon and river valley, the Colorado River would receive urban waste water, schools would be vastly overcrowded or nonexistent, public expenditures would soar faster than population, and services would be unable to catch up with growth. Real estate speculation would become a major industry, while tourism, which grew during the 1960s, would probably decline. Labor turnover would probably be high. Competition for scarce land in valleys and upland plateaus would pit residential development against recreation, farming, transportation, tourism and other interests seeking to use the same land. If the oil shale industry were developed to its maximum possible extent, opportunities for diversification of the local economy would decline. The maximum credible level of oil shale production would lead to the sacrifice of "option values" for land use, that is, the implementation of decisions whose consequences might be irreversible.

F. Oil Shale Development Constrained by a 5 Percent Annual Growth Rate--Piceance Basin

Figure 22-8 shows the extent of oil shale development possible within an annual growth rate of 5 percent. In contrast to the maximum credible case, population would rise gradually from its current 23,500 to 28,000 in 1980, 41,000 in 1985, 52,000 in 1990, 65,000 in 1995, and 79,000 by the end of the century. Daily capacity for crude oil production would be 400,000 barrels (64,000 m^3/D) one-fifth of the capacity hypothesized for the maximum case. Instead of boomtowns of 50,000 people by 1990, cities closest to places of oil shale employment would number only about 10,000 inhabitants. Reduced population pressures would allow for needed planning of residential development so that mobile home sites and other settlements could be located with least damage to environmental values and amenities. Due to the shortage of suitable residential land, however, some real estate speculation and competing land uses could still be expected. The strain on local governmental fiscal capacity would be substantial, particularly in the area of schools and roads, but not nearly as severe as in the maximum case. For those services whose cost rises steeply with geographical dispersion, practically no economies of scale would be realized. Even if immigrants settled predominantly in the existing towns of Rangely, Meeker, Rifle, and Glenwood Springs, those towns themselves are separated from one another by large distances. Rangely, for example, is 78 miles (130 km) away from Meeker, and Meeker is another 67 miles (110 km) from Glenwood Springs. Thus needed public expenditures for those services would continue to rise throughout the entire course of growth. These expenditures would be small compared with those required by the maximum level of development.

Unlike Campbell County, Wyoming, Rio Blanco and Garfield Counties, Colorado, have not experienced boomtown growth rates recently. Garfield County's growth rate between 1960 and 1970 was 2 percent a year, and Rio Blanco County lost population in that decade. A growth rate of even as little as 5 percent a year would be a big jump, while a growth rate of 16 to 19 percent annually would be extremely high. This lack of comparable experience would undoubtedly handicap the western Colorado counties in adapting to rapid industrial and urban growth.

G. Implications for Appalachia

The coal mining regions of Appalachia currently have a much larger population base than the resource-rich regions of the West. Eastern Kentucky, southern West Virginia, and southwestern Virginia still have substantial reserves of bituminous coal averaging 10,000 to 12,000 Btu per lb (23 MJ/kg to 28 MJ/kg) and a labor force experienced in the techniques of coal mining. The Big Sandy Area Development District, a 5-county region of eastern Kentucky, contains 143,000 people (1972 local planners' estimate). The 5 counties--Floyd, Johnson, Magoffin, Martin, and Pike--form a land area of 1979 square miles (5100 km^2), less than half the area of Campbell County, Wyoming. It would appear that a population base of that size could more easily absorb the growth induced by a synthetic fuels industry than Campbell County could. Before reaching such a conclusion, however, it should be noted that the present population is overwhelmingly rural. Only 10 percent live in towns of more than 2000, and only 15 percent live in towns of any size at all. Coal mining in Appalachia has traditionally coexisted with a predominantly rural culture. A synthetic fuels industry, on the other hand, would require large urban concentrations, and these simply do not exist near the coal fields. Thus while the present population base is numerically adequate to accommodate such an industry, it is not distributed in ways that are immediately useful to the industry.

Related to the low degree of urbanization, Appalachia has been deficient in the social institutions necessary to manage an industrial economy. County governments in the coal-producing regions undertaxed productive resources and so never received a fair share of the region's wealth. As a result they were unable to finance needed services such as education, road-building, utilities, planning, and so forth. The capacity to deliver services adaptable to an urban environment has never developed in Appalachia, partly because these were not needed by a population traditionally reliant on kinship as the source of mutual aid, and partly out of distrust of government in general. New industries have not been attracted to Appalachia because the region either chose not to or failed to develop this institutional and service capacity. As far as a new industry such as synthetic fuels is concerned, then, the region is really no better adapted to urbanization and industrialization than is the sparsely populated Powder River Basin.

In Appalachia, constraints besides the size of the population base are of the greatest significance. Bitterness on the part of many people in the region toward the coal mining industry has flared up in recent years in acts of industrial sabotage costing millions of dollars.[8] In less dramatic ways, grass-roots organizations like Miners for Democracy and Appalachian Coalition Against Strip Mining have questioned the wisdom of industry domination of their region and have begun to attract a following in Congress and in state legislatures. The United Mine Workers of America has begun to take a much tougher bargaining stance than did previous union leadership. The collective bargaining agreements of December 1974 brought coal miners nearer to wage parity with other industrial workers than previous negotiations had even attempted to do. The greater productivity of the coal mines has increased the amounts generated for the union's health and welfare fund by the tonnage royalty. Also, the greater educational attainment and lesser age of the new labor force make workers less tolerant of unnecessarily low safety standards and working conditions. These factors are probably more important considerations on the part of the mining industry as to the location of synthetic fuels facilities than are demographic factors.

H. Implications for Southern Illinois

Judging by demographic and geophysical characteristics, southern Illinois would appear to be less disrupted by the growth of a synthetic fuels industry than the other regions would. In contrast to the sparsely populated West, southern Illinois has a large enough population base to accommodate industrial growth without sustaining a large percentage impact. In contrast to Appalachia, it is not isolated by geographical and cultural factors from modern industrial society. The 6-county area of Franklin, Jefferson, Perry, St. Clair, Washington, and Williamson Counties comprise a land area of 3112 square miles (8100 km^2), somewhat smaller than Campbell County, Wyoming, in size. Their total population, however, is 437,500, large enough to absorb a new labor force and associated population without severe stress. Unlike Appalachia's population, it is concentrated in urban areas in a way that makes it accessible to industrial employers. In only 1 of the 6 counties is the population predominantly rural--Washington County, with 78 percent of residents in rural places. St. Clair County's population is overwhelmingly urban (83 percent) due to the presence of East St. Louis. The other 4 counties have a rural-urban mix of about half and half. Thus the urbanized base necessary for industrial growth is substantially already in place.

The necessity for large numbers of immigrants to the area would be lessened by the prevalence of higher-than-average unemployment rates. Rates ranged from 3.9 percent in Washington County to 6.8 percent in Franklin County in 1970. Even if renewed coal mining activity in the past 5 years has employed some of these people, a large amount of unemployment in neighboring cities has probably persisted. St. Louis, Missouri, had 16,000 unemployed persons in 1970; Evansville, Indiana, had 2700 unemployed persons.[8] Some proportion of Chicago's 64,000 unemployed might also be attracted to employment in southern Illinois.

Southern Illinois has an established coal mining industry. The 6-county region produced 37 million tons (33 billion kg) of coal from 20 operating mines in 1972, more than half of the total coal production in Illinois in that year. Two billion tons (1.8 trillion kg) of strippable reserves and 19 billion tons (17 trillion kg) of deep reserves remain in the region. The coal has a heating value of 11,000-12,000 Btu per pound (26 MJ/kg to 28 MJ/kt), about midway between that of Powder River Basin coal and Appalachian coal. Southern Illinois has a relatively diversified set of service industries, and access to a large urban center, St. Louis, for many industrial needs. Existing service industries and governmental capacity should therefore reduce requirements for additional population, relative to the other resource-rich regions.

In southern Illinois agriculture has a relatively higher value than in Appalachia, or than ranching and farming in the resource regions of the West. Agriculture would undoubtedly be disturbed by large-scale surface mining operations, to some extent. This impact, however, would be mitigated by the following factors:

(1) The reclamation potential of southern Illinois farmland is greater than that of either the arid western regions or Appalachia. (See Chapters 13 and 15.) Its superiority over the arid West is that rainfall can be expected to be adequate to stabilize and restore the land. Its

superiority over Appalachia is due to the fact that the county consists of flatlands and rolling hills rather than steeply contoured slopes.

(2) Surface mining in southern Illinois could actually improve agricultural productivity because it would break up the subsurface impervious soil layer, or hardpan, that prevents adequate drainage.

(3) Custom and practice in southern Illinois indicate that agriculture and coal mining can coexist more readily than in the other resource-rich regions. Many coal miners have traditionally worked their own farms in addition to being employed at mining. The proportion of farm operators (as defined by the 1970 Census) who worked 100 days or more per year off the farm was more than half for the region, while the statewide figure was one-third. While the discipline of a large industrial workplace might not be compatible with such dual employment, the mining activity itself clearly is.

Southern Illinois also derives some advantages from being close to eastern and midwestern energy markets, Ohio River and Mississippi River barge transportation routes, and a major rail terminus from the West. Compared to the other regions discussed, it is well located for domestic energy production.

I. Summary

In assessing the impact of development, we usually apply the concept of damage, reversible or irreversible, only to the natural environment. Certain actions can cause irreversible environmental damage; for example, radioactive wastes contamination and the extinction of rare species are examples of irreversible consequences of human action. Whether environmental consequences are long-lasting or not depends on human ability to regulate development in accordance with environmental standards. Similarly, adverse social consequences are controllable by concerted effort and proper planning.

The foregoing analysis has suggested that adverse social impacts could be mitigated by the following actions:

- Building smaller plants (conversion facilities).
- Exporting coal.
- Phasing employment buildups and layoffs so as to minimize labor shortages and unemployment.
- Pay-as-you-grow system of public finance to avert tax lag.
- Fair valuation of all taxable productive wealth.
- Governmental-industry cooperation in community-building.
- Rational land use policy for agricultural, range, industrial, residential, and recreational uses.
- Full public participation in decision-making affecting fundamental values and interests.
- Diversification of local economies.
- A system for compensating involuntary displacees.
- Adequate reclamation of land.

It has been shown that the consequences of a 5 percent annual growth rate are far less severe for communities than production at the maximum theoretical level would be. The dynamics of growth at the theoretical upper limit of synthetic fuels production would probably cause lasting damage in the form of costs payable by future generations, cycles of boom and bust, massive disturbances of land, rapid, perhaps unwanted change in living conditions, and narrowing of options. A 5 percent growth rate would allow time for needed planning and development of public services and amenities. The job of community-building, in short, would be brought within the range of possibility by such a constraint.

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16. ABSTRACT

This study assesses the impacts of the development of synthetic liquid fuels from coal and oil shale; the fuels considered are synthetic crude oils from coal and oil shale and methanol from coal. Key issues examined in detail are the technology and all of its resource requirements, net energy analyses of the technological options, a maximum credible implementation schedule, legal mechanisms for access to coal and oil shale resources, financing of a synthetic liquid fuels industry, decision making in the petroleum industry, government incentive policies, local and national economic impacts, environmental effects of strip mining, urbanization of rural areas, air pollution control, water resources and their availability, and population growth and boom town effects in previously rural areas.

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