FINAL
ENVIRONMENTAL STATEMENT
FOR THE
PROTOTYPE OIL SHALE LEASING PROGRAM

Volume II of VI

Energy Alternatives

U.S. DEPARTMENT OF THE INTERIOR

1973

FINAL

ENVIRONMENTAL STATEMENT

FOR THE

PROTOTYPE OIL SHALE LEASING PROGRAM

Volume II of VI

Energy Alternatives

Prepared in Compliance With

Section 102 (2) (c) of the National Environmental

Policy Act of 1969

Prepared by

UNITED STATES DEPARTMENT OF THE INTERIOR

1973

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SUMMARY

Final Environmental Statement
Department of the Interior, Office of the Secretary

1. Administrative type of action:

2. Brief description of action:

This action would make available for private development up to six leases of public oil shale lands of not more than 5,120 acres each. Two tracts are located in each of the States of Colorado, Utah, and Wyoming.

Such leases would be sold by competitive bonus bidding and would require the payment to the United States of royalty on production. Additional oil shale leasing would not be considered until development under the proposed program had been satisfactorily evaluated and any additional requirements under the National Environmental Policy Act of 1969 had been fulfilled.

3. Summary of environmental impact and adverse environmental effects:

Oil shale development would produce both direct and indirect changes in the environment of the oil shale region in each of the three States where commercial quantities of oil shale resources exist. Many of the environmental changes would be of local significance, and others would be of an expanding nature and have cumulative impact. These major regional changes will conflict with uses of the other physical resources of the areas involved. Impacts would include those on the land itself, on water resources and air quality, on fish and wildlife habitat, on grazing and agricultural activities, on recreation and aesthetic values, and on the existing social and economic patterns as well as others. The environmental impacts from both prototype development at a level of 250,000 barrels per day of shale oil and an industry producing a possible 1 million barrels per day by 1985 are assessed for their anticipated direct, indirect and cumulative effects.

4. Alternatives considered:

A. Government development of public oil shale lands.
B. Change in number and location of tracts to be leased.
C. Delay in development of public oil shale lands.
D. No development of public oil shale lands.
E. Unlimited leasing of public oil shale lands.
F. Obtaining energy from other sources.

5. Comments have been requested from the following:

Federal agencies, State agencies, and private organizations listed in Volume IV, Section F.

6. Date made available to the Council on Environmental Quality and the Public:

Draft Statement: September 7, 1972

Final Statement: August 1973

INTRODUCTORY NOTE

THIS FINAL ENVIRONMENTAL STATEMENT HAS BEEN PREPARED PURSUANT TO SECTION 102 (2) (C) OF THE NATIONAL ENVIRONMENTAL POLICY ACT OF 1969 (42 U.S.C. SECS. 4321-4347). ITS GENERAL PURPOSE IS A STUDY OF THE ENVIRONMENTAL IMPACTS OF OIL SHALE DEVELOPMENT.

THE SECRETARY OF THE INTERIOR ANNOUNCED PLANS ON JUNE 29, 1971, FOR THIS PROPOSED PROGRAM AND RELEASED A PRELIMINARY ENVIRONMENTAL STATEMENT, A PROGRAM STATEMENT, AND REPORTS PREPARED BY THE STATES OF COLORADO, UTAH, AND WYOMING ON THE ENVIRONMENTAL COSTS AND PROBLEMS OF OIL SHALE DEVELOPMENT.

THE PROPOSED PROGRAM IS IN CONCERT WITH THE PRESIDENT'S ENERGY MESSAGE OF JUNE 4, 1971, IN WHICH HE REQUESTED THE SECRETARY OF THE INTERIOR TO INITIATE "A LEASING PROGRAM TO DEVELOP OUR VAST OIL SHALE RESOURCES, PROVIDED THAT ENVIRONMENTAL QUESTIONS CAN BE SATISFACTORILY RESOLVED."

AS PART OF THE PROGRAM, THE DEPARTMENT AUTHORIZED INFORMATIONAL CORE DRILLING AT VARIOUS SITES IN COLORADO, WYOMING, AND UTAH AND 16 CORE HOLES WERE COMPLETED. THE DEPARTMENT REQUESTED NOMINATIONS OF PROPOSED LEASING TRACTS ON NOVEMBER 2, 1971, AND A TOTAL OF 20 INDIVIDUAL TRACTS OF OIL SHALE LAND WERE NOMINATED. WITH THE CONCURRENCE OF THE CONCERNED STATES, THE DEPARTMENT OF THE INTERIOR ANNOUNCED ON APRIL 25, 1972, THE SELECTION OF SIX OF THESE TRACTS, TWO EACH IN COLORADO, UTAH, AND WYOMING.

THE PROGRAM IS ESSENTIALLY UNCHANGED FROM THAT ANNOUNCED ON JUNE 29, 1971, BUT THE PRELIMINARY STATEMENT ISSUED AT THAT TIME

WAS EXPANDED TO CONSIDER THE IMPACT OF MATURE OIL SHALE DEVELOPMENT, THE IMPACT OF DEVELOPMENT OF THE SIX SPECIFIC TRACTS, AND A COMPREHENSIVE ANALYSIS OF OTHER ENERGY ALTERNATIVES.

THE DRAFT OF THIS FINAL ENVIRONMENTAL STATEMENT WAS RELEASED TO THE PUBLIC ON SEPTEMBER 7, 1972. A PUBLIC REVIEW PERIOD WAS HELD THAT ENDED ON NOVEMBER 7, 1972. THIS REVIEW PROVIDED IMPORTANT INFORMATION UPON WHICH TO EXPAND AND CORRECT, WHERE APPROPRIATE, THE DRAFT MATERIAL.

VOLUME I OF THIS FINAL SET OF SIX VOLUMES PROVIDES AN ASSESSMENT OF THE CURRENT STATE OF OIL SHALE TECHNOLOGY AND DESCRIBES THE REGIONAL ENVIRONMENTAL IMPACT OF OIL SHALE DEVELOPMENT AT A RATE OF ONE MILLION BARRELS PER DAY BY 1985. VOLUME II EXTENDS THIS STUDY WITH AN EXAMINATION OF ALTERNATIVES TO THE ONE MILLION BARREL PER DAY LEVEL OF SHALE OIL PRODUCTION. VOLUMES I AND II THUS CONSIDER THE REGIONAL AND CUMULATIVE ASPECTS OF A MATURE OIL SHALE INDUSTRY.

VOLUME III EXAMINES THE SPECIFIC ACTION UNDER CONSIDERATION, WHICH IS THE ISSUANCE OF NOT MORE THAN TWO PROTOTYPE OIL SHALE LEASES IN EACH OF THE THREE STATES OF COLORADO, UTAH, AND WYOMING. ITS FOCUS IS ON THE SPECIFIC ENVIRONMENTAL IMPACTS OF PROTOTYPE DEVELOPMENT ON PUBLIC LANDS WHICH, WHEN COMBINED, COULD SUPPORT A PRODUCTION POTENTIAL OF ABOUT 250,000 BARRELS PER DAY.

VOLUME IV DESCRIBES THE CONSULTATION AND COORDINATION WITH OTHERS IN THE PREPARATION OF THE FINAL STATEMENT, INCLUDING COMMENTS RECEIVED AND THE DEPARTMENT'S RESPONSES. LETTERS RECEIVED DURING THE REVIEW PROCESS ARE REPRODUCED IN VOLUME V, AND ORAL TESTIMONY IS CONTAINED IN VOLUME VI.

THIS DOCUMENT IS BASED ON MANY SOURCES OF INFORMATION, INCLUDING RESEARCH DATA AND PILOT PROGRAMS DEVELOPED BY BOTH THE GOVERNMENT AND PRIVATE INDUSTRY OVER THE PAST 30 YEARS. MANY FACTORS, SUCH AS CHANGING TECHNOLOGY, EVENTUAL OIL PRODUCTION LEVELS, AND ATTENDANT REGIONAL POPULATION INCREASES ARE NOT PRECISELY PREDICTABLE. THE IMPACT ANALYSIS INCLUDED HEREIN IS CONSIDERED TO CONSTITUTE A REASONABLE TREATMENT OF THE POTENTIAL REGIONAL AND SPECIFIC ENVIRONMENTAL EFFECTS THAT WOULD BE ASSOCIATED WITH OIL SHALE DEVELOPMENT.

IT SHOULD BE NOTED THAT SUBSTANTIAL AMOUNTS OF PUBLIC LANDS IN ADDITION TO THE PROTOTYPE TRACTS WOULD BE REQUIRED FOR AN INDUSTRIAL DEVELOPMENT TO THE ONE MILLION BARREL PER DAY LEVEL CONSIDERED IN VOLUMES I AND II. IF EXPANSION OF THE FEDERAL OIL SHALE LEASING PROGRAM IS CONSIDERED AT SOME FUTURE TIME, THE SECRETARY OF THE INTERIOR WILL CAREFULLY EXAMINE THE ENVIRONMENTAL IMPACT WHICH HAS RESULTED FROM THE PROTOTYPE PROGRAM AND THE PROBABLE IMPACT OF AN EXPANDED PROGRAM. BEFORE ANY FUTURE LEASES ON PUBLIC LANDS ARE ISSUED, AN ENVIRONMENTAL STATEMENT, AS REQUIRED BY THE NATIONAL ENVIRONMENTAL POLICY ACT, WILL BE PREPARED.

AVAILABILITY OF FINAL ENVIRONMENTAL STATEMENT

The six-volume set may be purchased as a complete set or as individual volumes from the Superintendent of Documents, U. S. Government Printing Office, Washington, D. C. 20402; the Map Information Office, Geological Survey, U.S. Department of the Interior, Washington, D. C. 20240; and the Bureau of Land Management State Offices at the following addresses: Colorado State Bank Building, 1600 Broadway, Denver, Colorado, 80202; Federal Building, 124 South State, Salt Lake City, Utah, 84111; and Joseph C. O'Mahoney Federal Center, 2120 Capital Avenue, Cheyenne, Wyoming, 82001.

Inspection copies are available in the Library and the Office of the Oil Shale Coordinator, U.S. Department of the Interior, Washington, D. C., and at depository libraries located throughout the Nation. The Superintendent of Documents may be consulted for information regarding the location of such libraries. Inspection copies are also available in Denver, Colorado, in the Office of the Deputy Oil Shale Coordinator, Room 237E, Building 56, Denver Federal Center, Denver, Colorado 80225, in all the Bureau of Land Management State Offices listed above, and in the following Bureau of Land Management district offices: <u>Colorado</u>: Canon City, Craig, Glenwood Springs, Grand Junction, Montrose; <u>Utah</u>: Vernal, Price, Monticello, Kanab, Richfield; <u>Wyoming</u>: Rock Springs, Rawlins, Casper, Lander, Pinedale, Worland.

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I. INTRODUCTION

In his Clean Energy Message to the Nation, President Nixon, on June 4, 1971, emphasized that the United States is now entering a period of increasing demand for energy and growing problems of supply. As an element of the President's comprehensive energy program to help assure future energy supplies, Interior Secretary Morton outlined a concept for a Proposed Prototype Oil Shale Leasing Program (1).[1/] The goal of the Department of the Interior's proposed prototype leasing program is "to provide a new source of energy for the Nation by stimulating the timely development of commercial oil shale technology by private enterprise, and to do so in a manner that will assure the minimum possible impact on the present environment while providing for the future restoration of the immediate and surrounding area" (2).

As discussed in Chapter IV of this volume, a maximum of 1 million barrels of shale oil per day may be produced by the year 1985. This level of production would require public lands in addition to those considered for development under the proposed prototype leasing program. It would also require parallel development on private lands. The present volume considers alternatives to the 1 million daily rate of production and is organized in the following way:

The initial sections consider the energy situation, the role of energy in economic growth, and the energy requirements of the U.S. to meet projected future needs. To relate shale oil to the total energy

1/ Underlined numbers in parentheses refer to items in the list of references at the end of this section.

picture, the subject of substitutability of energy in its solid, liquid, or gaseous forms is discussed, followed by a consideration of factors that affect fuels development. A background of the petroleum situation, both present and future, is presented followed by a consideration of oil shale development possibilities. Alternatives to oil shale production exist in two broad general categories: (1) those that arise from Federal policy actions regarding petroleum and natural gas; and (2) those that arise from substituting other energy forms for the shale oil that would be produced. Alternatives within each of the above general categories are considered as are the associated environmental impacts. Combinations of these various alternatives are considered in the last section of this volume.

A. References Cited

1. Secretary Morton's Departmental Energy Statement to the Senate Committee on Interior and Insular Affairs, dated June 15, 1971.

2. Program Statement for the Proposed Prototype Oil Shale Leasing Program. U.S. Department of the Interior, June 1971.

II. THE ENERGY SITUATION

A. The Role of Energy in Economic Growth

Abundant supplies of low-cost energy supported economic growth throughout the history of the United States. Water power was important for early industries in New England; coal was important for railroads and industries through the early part of this century; and petroleum has supplied much of the energy during the automobile and jet age.

The close correlation between energy consumption and gross national product is shown in Figure II-1. The 1972 report of the Council of Economic Advisers discusses relationships between the GNP and energy consumption as follows:

> "The growth in consumption of fuels by automobiles, electric generating plants, homes, and factories is closely associated with increases in our material levels of living. Historically, however, energy use has not grown as rapidly as GNP. While real GNP (in 1958 dollars) rose from $183.5 billion in 1930 to $617.8 billion in 1965, for a compound annual growth of 3.5 percent, energy consumption rose from 22.3 quadrillion btu's to 54.0 quadrillion btu's during the same period, an annual growth rate of only 2.5 percent. The use of energy per dollar of GNP (Figure II-2), therefore, fell from 121,500 btu's in 1930 to 87,400 in 1965.
>
> "During this same period, energy was becoming cheaper relative to other goods and services. While the price index of all goods and services (the GNP deflator) rose 125 percent during this period, the wholesale price index of fuels and electric power rose only 70 percent. Thus, although energy consumption was growing it was not growing as rapidly as GNP, and although energy prices were rising they were not rising as fast as the prices of other goods and services.

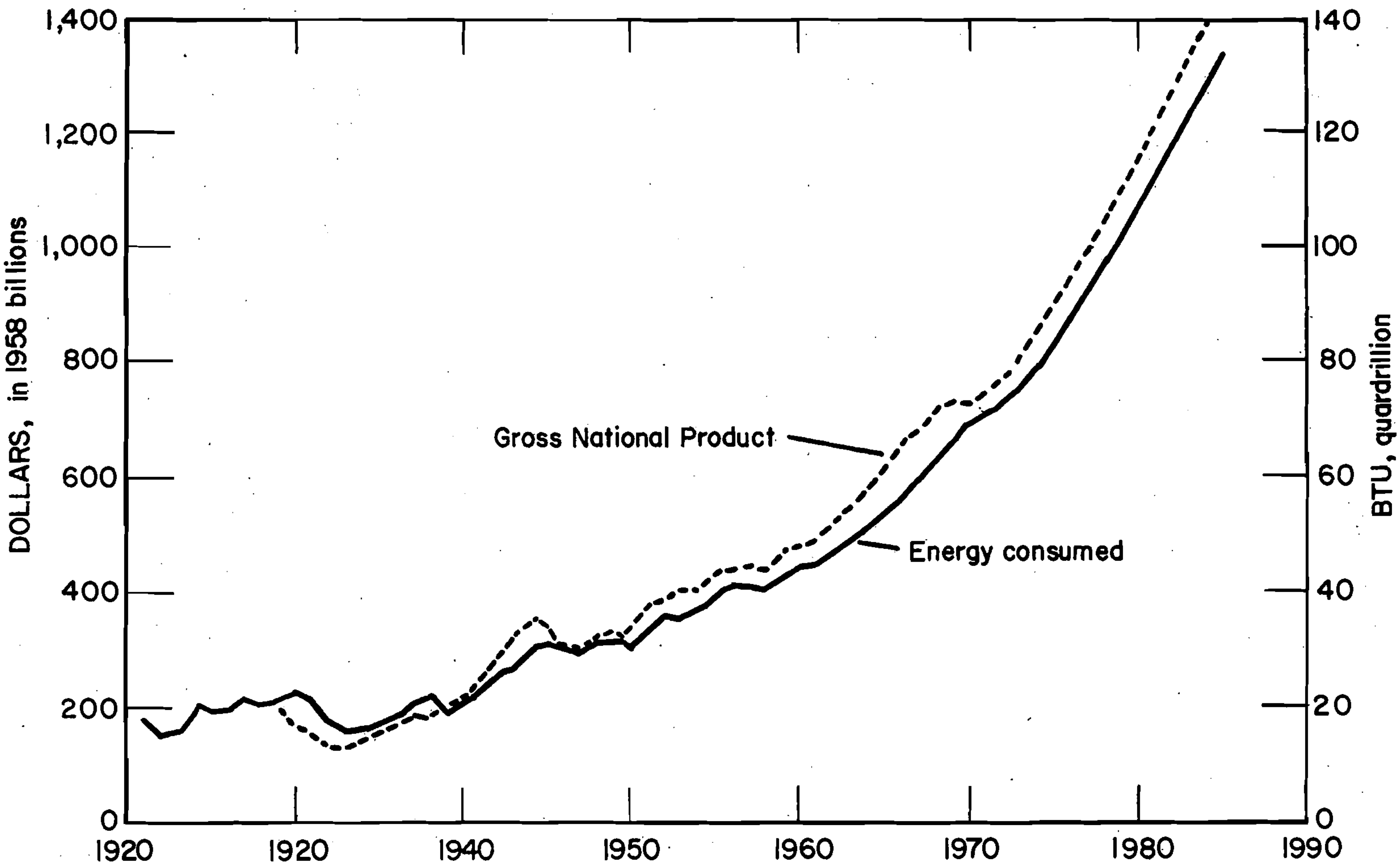

Figure II-1 – Energy Consumption and Gross National Product, 1920–1970, with Projections to 1990.

Source: Office of Oil and Gas, Department of the Interior, May 1971.

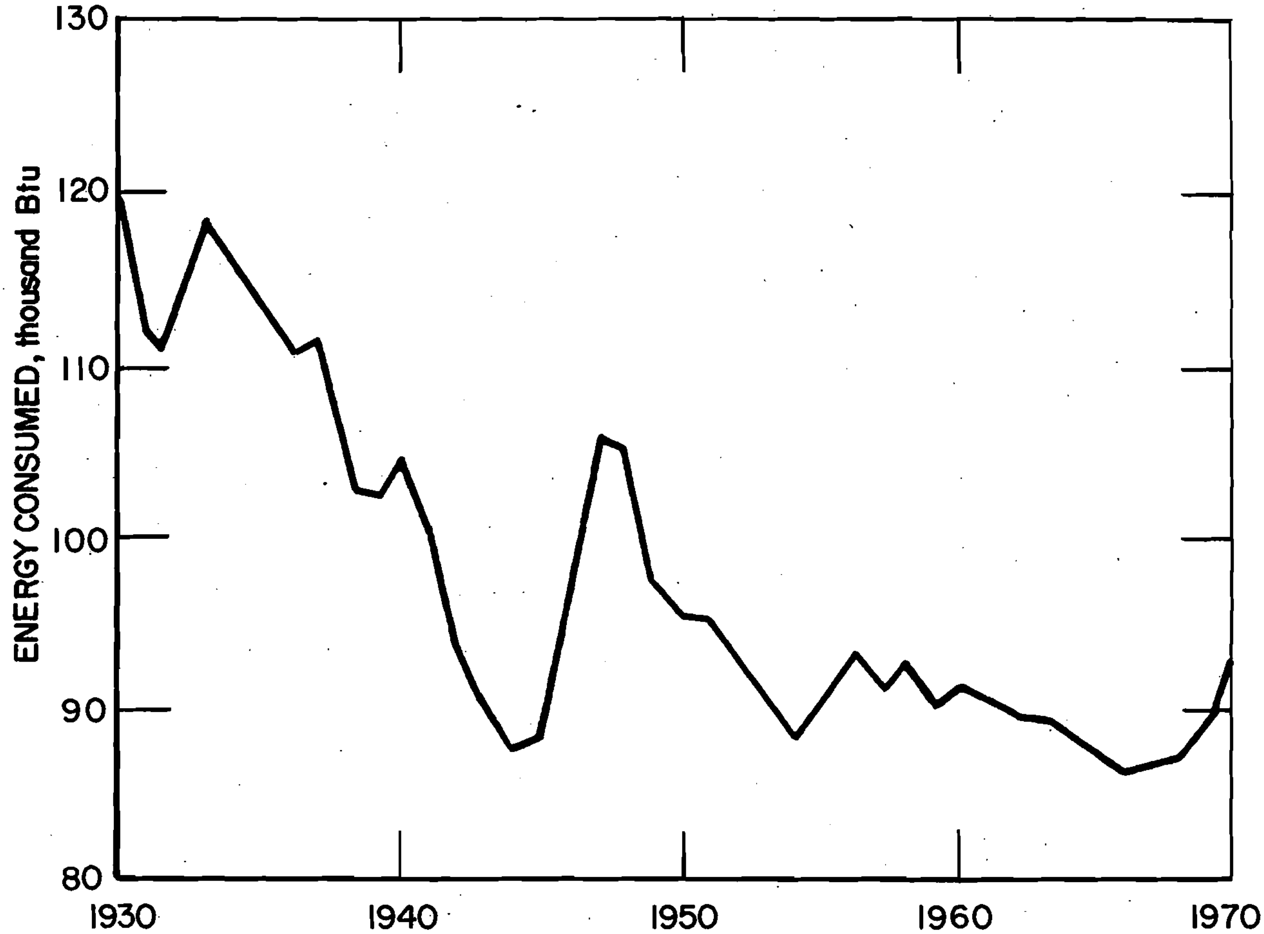

Figure II-2 — Energy Consumed in the United States per Dollar of GNP*, 1930–1970 in 1958 Dollars. Source: Statistical Abstract of U.S. (GNP), Bureau of Mines (Energy)

Source: Statistical Abstract of U.S. (GNP)
Bureau of Mines (Energy)

Source: Reference (6, pg. 2)

"Since 1965, however, a sharp upturn in the energy-GNP ratio has occurred. From 87,400 btu's per dollar of real GNP in 1965, the number rose to 95,600 in 1970. While output for the economy as a whole was growing at 3.1 percent per year, energy consumption grew at 5.0 percent. This sharp upturn in energy was associated with a more rapid increase in prices. Prices of fuel oil and bituminous coal, in particular, rose sharply in 1970.

"These developments gave evidence of at least a short-run shift in energy demand and prices. At the same time more fundamental changes were occurring in the domestic supply picture... discussed in detail below ...

"The accelerated growth in energy demand relative to GNP in recent years is not expected to continue. Most observers forecast an annual average growth in energy consumption of just over 4 percent, paralleling the expected growth in GNP. A comparison of earlier forecasts and current realities, however, suggests that any assumptions about future demand and supply must be regarded as tentative, to be modified as new evidence becomes available" (1).

An analysis (2) of the possible reasons for the reversal of the trend in the energy consumption-gross national product relationship found no single cause, but suggested that the trend reversal was due principally to a combination of three causes: "(a) the increasing relative importance of nonenergy uses of fuels, (b) tapering-off in the year-to-year improvement in thermal efficiency at central power stations, and (c) the increasing relative importance of air conditioning and electric heating." That study also found that the reversal was probably not due to the increasing importance of the service sector in the computation of gross national product. Another source (3) attributes most of the change to the substitution of "electricity, with a thermal efficiency of perhaps 32 percent, for many direct fuel uses with efficiencies ranging from 60 to 90 percent." From these relationships, it is clear that, unless our energy-based society changes quite markedly, maintenance and improvement of the material standard of living will continue to demand increased amounts of energy.

Interior Department predictions (10) estimate that gross energy consumption per 1958 dollar of Gross National Product is expected to decline from 93.0 thousand Btu/dollar of GNP in 1971 to 78.7 thousand Btu/dollar in 2000. This represents a reversal of the sharp rise in 1970 to a gradual downtrend through 2000.

The United States, which has 6 percent of the world's population, uses 35 percent of the energy consumed each year (4). Because energy consumption in other countries is similarly correlated with both economic growth and population (Figure II-3), world energy consumption may be expected to rise much faster than domestic consumption, as world population is growing rapidly and the economic growth of the less developed countries is rising rapidly. For the world as a whole, per capita energy consumption is rising about a third faster than per capita consumption in the U.S. (5) (Figure II-4). As a result, the U.S. share of world consumption is expected to fall to 25 percent by the year 2000, but total requirements for energy will increase.

B. Energy Requirements

Demand for energy resources to the year 2000 has been projected by the Department of the Interior (10) from forecasts that correlated resource inputs and demands for final market products with economic indicators such as GNP, population projections, and industrial production. As a result of these studies, a conventional or base forecast was made having the following conditional assumptions: Beyond 1980 GNP was assumed to grow at an annual rate of 4 percent (4.3 percent prior to 1980);

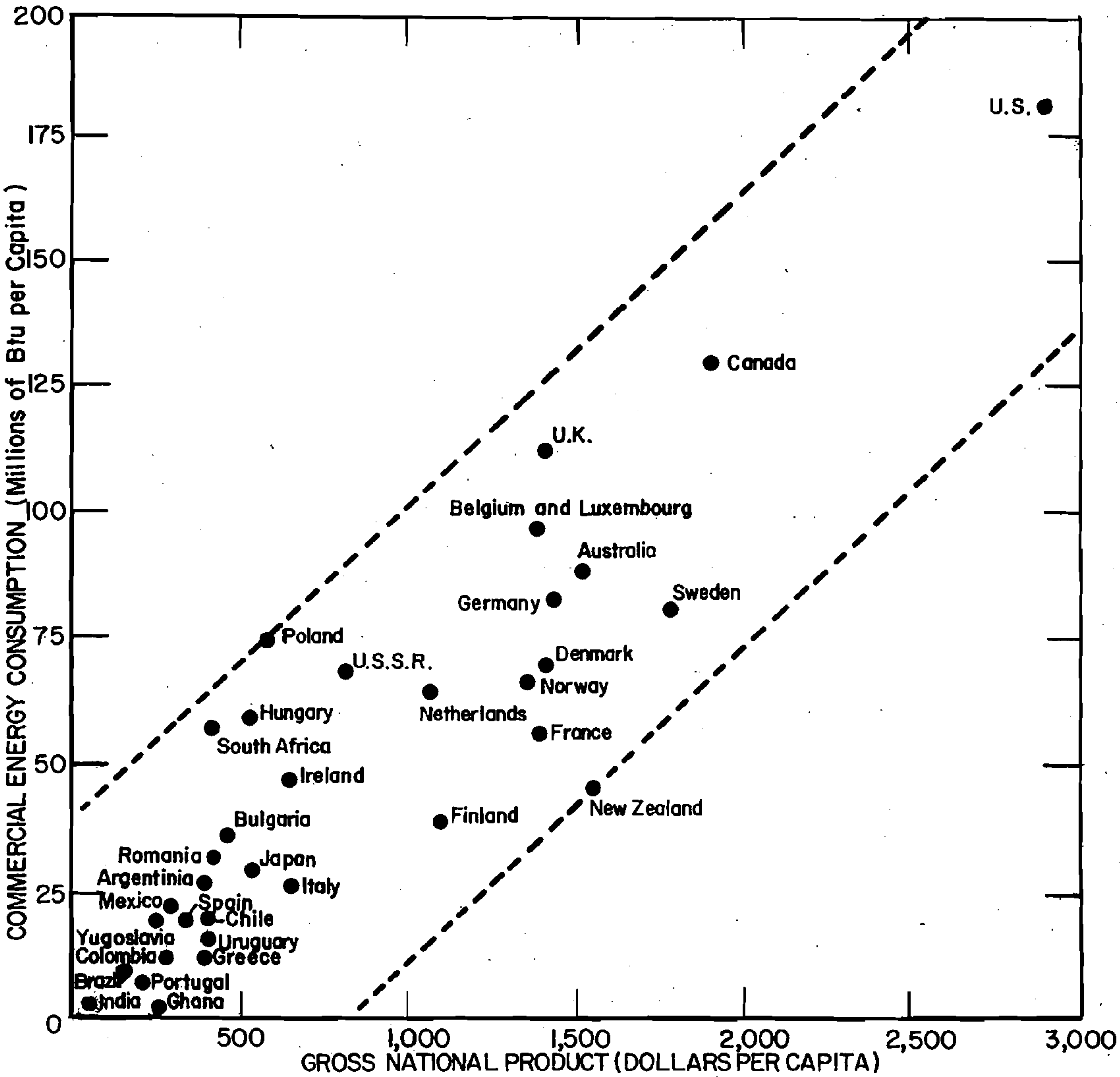

Figure II-3 —Relation of Per-Capita Energy Consumption and Gross National Product, Worldwide

Dotted lines, drawn parallel to U.S. rate and enclosing all data points. added for this figure.
Source: Reference (3, pg. 142)

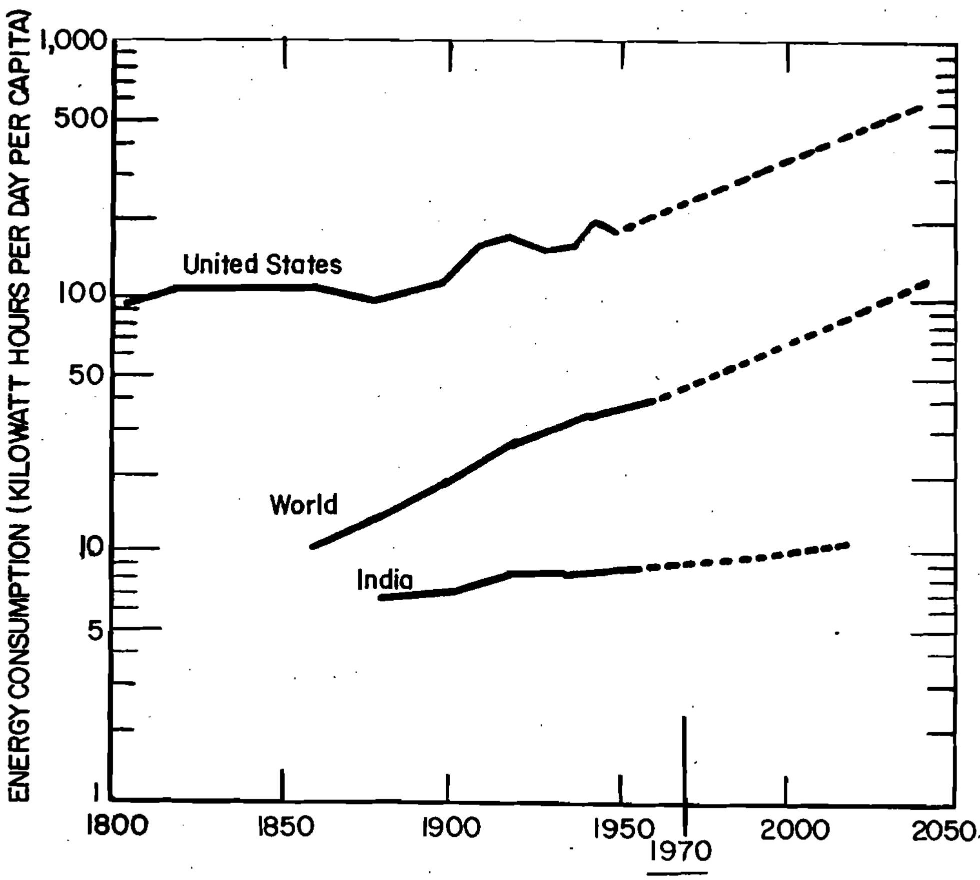

Figure II-4 – Trends in Per-Capita Energy Consumption. (Note logarithmic scale)

Source: Reference (4, pg. 40)

industrial production was based on a composite growth rate of 4.4 percent; foreign trade in energy was assumed to remain at the same relative proportions as in the past; and evolutionary changes in technologies and efficiencies were presumed. In addition, it was assumed that inflationary trends will raise the nominal prices of all fuels but that fuel prices, in general, will rise faster than other commodity prices. Additionally, intercommodity price relationships are expected to shift gradually, restructuring the relative price standings of the various fuels. The rate of increase in gaseous fuel prices is expected to be about 1.5 times the rate to be experienced in petroleum, and about 2.0 times the rate expected for coal.

Table II-1, United States consumption for energy resources by major sources, 1971 actual with projections to 2000 is a summary of energy sources. As shown, petroleum consumption will increase from 15.1 million barrels per day in 1971 to approximately 35.6 million barrels per day in 2000. Its share of the total energy input will decline from 44.1 percent to 37.2 percent. Natural gas usage will increase from 22,050 billion cubic feet to 32,959 billion cubic feet. Its share of the market will decline from 33.0 percent to 17.7 percent. The compound annual growth rate of total gross energy input is 3.6 percent for the 29-year period from 1971 to 2000.

Some better understanding of what this energy consumption means can be gained from the following tabulation of selected United States economic and energy indicators, actual for 1971 and projected to the year 2000. The energy/GNP ratio is expected to decline from the 93.0 thousand

Table II-1 -United States consumption for energy resources by major sources, 1971, actual, with projections to the year 2000

	1971	1975	1980	1985	2000
Petroleum (includes natural gas liquids)					
Million barrels	5,523	6,340	7,615	9,140	12,985
Million barrels per day	15.1	17.4	20.9	25.0	35.6
Trillion Btu	30,492	35,090	42,190	50,700	71,380
Percent of gross energy inputs	44.1	43.8	43.9	43.5	37.2
Natural Gas					
Billion cubic feet	22,050	24,462	26,169	27,537	32,959
Trillion Btu	22,734	25,220	26,980	28,390	33,980
Percent of gross energy inputs	33.0	31.4	28.1	24.3	17.7
Coal (bituminous, anthracite, lignite)					
Thousand short tons	510,800	565,000	665,000	893,000	1,310,000
Trillion Btu	12,560	13,825	16,140	21,470	31,360
Percent of gross energy inputs	18.2	17.2	16.8	18.4	16.3
Hydropower					
Billion kilowatt-hours	266.3	350	420	470	700
Trillion Btu	2,798	3,570	3,990	4,320	5,950
Percent of gross energy inputs	4.1	4.4	4.2	3.7	3.1
Nuclear power					
Billion kilowatt-hours	37.9	240	630	1,130	5,470
Trillion Btu	405	2,560	6,720	11,750	49,230
Percent of gross energy inputs	.6	3.2	7.0	10.1	25.7
Total Gross Energy Inputs					
Trillion Btu	68,989	80,265	96,020	116,630	191,900

Source: Reference (10, pg. 17)

Btu per 1958 dollar to approximately 78.7 thousand Btu in 2000. At the same time the gross energy consumption per capita is expected to increase from 333.3 million Btu per person to 686.1 million Btu in 2000 for an average annual growth rate of 2.5 percent. Net energy consumption per capita is expected to increase from 275.4 million Btu in 1971 to 500.9 million in 2000 for an average annual growth rate of 2.1 percent.

	1971	1975	1980	1985	2000
Gross Energy Inputs (Quadrillion Btu) 1/	69.0	80.3	96.0	116.6	191.9
Net Energy Inputs (Quadrillion Btu) 2/	57.0	65.1	75.9	90.0	140.1
Population (million)	207.0	216.2	229.4	243.3	279.7
Gross National Product (Millions of 1958 dollars)	739.5	891	1,102	1,343	2,438
Energy/GNP Ratio (Thousands of Btu per 1958 dollars)	93.3	90.1	87.1	86.8	78.7
Gross Energy/Capita Ratio (Millions of Btu)	333.3	371.4	418.5	479.2	686.1
Net Energy/Capita (Millions of Btu)	275.4	301.2	330.8	369.9	500.9
Efficiency Factor (Percent) 3/	82.7	81.1	79.0	77.2	73.0

1/ Gross energy inputs refers to the total energy inputs to all sectors.

2/ Net energy inputs refers to the direct energy going to the Industrial, Transportation, and Household and Commercial sectors plus electrical energy converted on the basis of 3,412 Btu/kwhr.

3/ Refers to the overall efficiency of conversion of gross energy to the form used by the final consuming sectors. Equal to net energy/gross energy.

As stated earlier, the future energy requirements are based upon a variety of forecasting techniques and the personal judgment of experts, especially with respect to the timing of possible technological developments. Gross national product, population, manufacturing indices, and other basic economic data were correlated with energy consumption and any important and consistent trends were extrapolated [(6)]. However, science and technology can and probably will produce some revolutionary as well as evolutionary technological, environmental, and economic changes that could significantly alter energy supply and demand patterns. Such developments cannot be forecast with reasonable assurance; therefore, only evolutionary developments considered as logical outgrowths of present trends and efforts were used. Accordingly, the energy demands forecast should be considered as order of magnitude levels to provide planning targets and not as absolute commodity demand predictions.

In coming years some energy commodities, notably natural gas, will encounter supply limitations; others will be disqualified from some markets by environmental restrictions. To the extent that these limiting factors materialize, requirements will have to be filled by other energy commodities. Petroleum demand is especially difficult to project. For example, the forecast presented in Table II-1 and used as the basis for subsequent analyses in this report anticipates a petroleum demand of 25.0 million barrels per day by 1985, whereas other current projections (7) show that oil demands in excess of 29 million barrels per day are possible.

C. Substitutability of Energy Forms

The use of energy materials can generally be considered in terms of the physical state of the energy source, i.e., solid, liquid, or gas. Thus, though some substitutability is possible, the most likely substitute for a liquid energy source material will be another liquid energy source material within a 10- to 15-year time frame. The reason is obvious. For example, liquid petroleum fuels are the most widely used materials for the automobile and these vehicles have a life of about 12 years. Unless technological advancement gives energy converters that will use other forms of fuel, transportation needs will be dependent upon liquid energy sources from petroleum or some other substitute that can be converted to a liquid form, i.e., coal liquefaction or oil shale.

"Mineral Facts and Problems" presents the following discussion of the potential for alternatives to petroleum (8):

> "...Petroleum currently has a virtual monopoly in the fields of transportation, organic chemicals, lubes, and waxes. The substitution of other materials for petroleum would not be economically feasible in most uses because of the higher cost of raw materials and the cost of equipment conversion.
>
> "Gasoline has no successful competitor as a passenger car fuel; however, steam and electric prime movers, which were utilized but discarded many years ago, are again undergoing experimentation. The use of natural gas (compressed or liquefied) also is being investigated. [But the supply situation in gas appears to be more severe than that in oil.] The use of electricity as motive power in utility vehicles such as golf carts is increasing.
>
> "For some commercial vehicles, trucks and tractors there is competition between gasoline, diesel oil, and LPG. Diesel engines are used to a limited extent in automobiles. Diesel locomotives have performed so well for U.S. railroads that the majority of the roads have converted to diesels from coal. In aviation, jet

fuel is replacing gasoline. Liquified natural gas and other fuels are possible substitutes for petroleum jet fuels in supersonic aircraft. (However, such substitution does not alleviate the liquid fuel problem.)

"In household, commercial, and industrial heating, and in the generation of steam and (electrical) power, distillate and residual fuels compete with coal and natural gas. A competitor with growing strength in the household heating market is electricity, which is generated from several fuel sources including fuel oil. In industrial and large commercial applications, price frequently is more decisive than it is in domestic or small commercial uses where convenience and related factors outweigh the price advantages of other fuels.

"Air quality regulations is a factor of increasing importance in fuel substitution. Alternative energy sources are being discussed as possible substitutes for air-polluting petroleum fuels in some uses. Such sources include electricity, natural gas, and nuclear energy." (The conversion of liquid or gaseous fuel to electrical energy is a consumer of energy because of the inefficiency of the current conversion techniques. Therefore, any increase in electrical generation has the potential for increasing the demand for liquid fuels.)

From the foregoing discussion, it is concluded that energy from one form to another (for example, natural gas for gasoline in automobiles) is not likely in the time frame of the projected development of oil shale under the prototype oil shale leasing program. This document, therefore, is organized to consider shale oil in its most likely energy use form as a supplement for the use of petroleum liquids.

Other energy forms can be substituted only partially for crude oil. Over half the demand for such oil is for transportation use, for which satisfactory large-scale alternatives to liquid fuels are unlikely during the 1980-1985 period. The most commonly suggested alternative is to replace residual oil as a fuel for electric utility boilers by some other fossil fuel or some other form of electricity generation. Several of the alternatives considered would require such substitution. However, use of petroleum for electricity generation in 1970 was less than 1 million barrels per day, and projected use for this purposed in 1980 is some two million barrels per day. Thus, substitution of this nature essentially would require removing an entire sector of petroleum usage, and at a time when low sulfur residual oil is being substituted for coal to generate electricity.

It must be kept in mind, however, that all forms of energy supplement one another in the total energy picture. Thus, if the use of one kind of energy source material is freed from use in electrical power generation, for example, the material freed is available for use elsewhere in the total energy picture, but other forces are set in motion that require adjustment of materials usage throughout the entire energy picture (See Figure V-3 in Section V, Part C of this Volume). The possibility of reduction of demand is consistant with the analysis in Section V.

D. Fuels Development and the Environment

The environmental impact caused by fuels development will vary significantly, depending on the energy form to be utilized. A review of the present situation has been prepared by Mills, Perry, and Johnson (9). Their review is outlined in Table II-2; pertinent sections of the text of that review are quoted below:

Table II-2 - Significant Environmental Impacts: Fuels Development

	Impacts on Land Resource			Impacts on Water Resource			Impacts on Air Resource		
Energy Source	Production	Processing	Utilization	Production	Processing	Utilization	Production	Processing	Utilization
Coal	Disturbed Land	Solid Wastes	Ash, slag disposal	Acid Mine Drainage		Increased Water Temp.'s			Sulfur oxides Nitrogen oxides Particulate Matter
Uranium	Disturbed Land		Disposal of radioactive material		Disposal of radio-active material	Increased Water Temp.'s			
Oil				Oil Spills, Transfer, Brines		Increased Water Temp.'s			Carbon monoxide Nitrogen oxides Hydrocarbons
Natural Gas						Increased Water Temp.'s			
Hydro									

Source: Reference (9, pg. 31)

"Land use

"About 3.6 billion tons of solid wastes are generated each year in the U.S. Agricultural wastes constitute nearly two-thirds of the total, and mineral wastes account for most of the rest....fuels account for only 125 million tons, or about 3% of all solid wastes generated.

"The last complete survey of mining operations in the U.S. indicated that, in 1965, about 3.2 million acres of land had been disturbed by surface mining. Of this total, about 41% resulted from activities associated with coal production.

"As yet, only a few tenths of 1% of the total land area of the U.S. has been disturbed by surface mining. Effects of such mining upon the environment, however, vary widely and depend upon such factors as the type of mining, characteristics of overburden, steepness of the terrain, amount of precipitation, and temperature. Where land reclamation is not practiced, water pollution from acid mine drainage and silt damage occur...In the principal coal mining areas, the average costs of completely reclaiming coal lands range from $169 to $362 per acre, an average cost of 4 to 8 cents per ton.

"Underground coal mining can cause subsidence unless the mining systems are designed to prevent deterioration and failure of abandoned mine pillars. Underground fires may weaken or destroy coal pillars that support the surface, causing subsidence with consequent damage to surface structures. An additional threat is the possible collapse of buildings and openings of surface fissures and potholes.

"Fuel processing also contributes large quantities of wastes during the washing of coal to improve its quality. Over 62% of all coal mined is washed, producing 90 million tons of waste annually. If not returned to the mine, the water accumulates in these piles near the plant and mine. At times, these piles ignite and burn for long periods, thus creating air pollution. Rainwater leaches salts and acid from the piles to contaminate nearby streams.

"Utilization of coal also produces solid waste in the form of ash and slag. About 30 million tons of these materials are collected each year; an estimated 8 million tons are discharged into the atmosphere.

"Uranium mined by either open pit or underground methods creates similar land problems. However, since uranium mining in quantity is a relatively new industry, the volumes and tonnages involved are only 1% of those for coal, and the adverse effects are much smaller....

"Solid wastes resulting from nuclear generation of electricity involve only small tonnages of materials, but have a very great potential for environmental damage for long periods because of their radioactivity....

"Water problems

"Two distinct water problems are of growing concern in fuels management--water quality and water temperature. Questions of quality relate to individual energy sources; thermal problems, however, are common to use of all fuel commodities.

"Poor water quality, whether it be through chemical pollution or sedimentation, is a major damage resulting from both surface and underground mining. Available data make no distribution between the two, but it has been estimated that approximately 48% of mine water pollution, primarily sediment, results from surface mining. In the U.S., some 5800 miles of streams and 29,000 surface acres of impoundments and reservoirs are seriously affected by such operations. Acid drainage from underground mines is more difficult to control than that from surface mines, but preventing water from entering the mine and the rapid removal of water which does get into the mine are effective methods for reducing pollution...Erosion and sedimentation from surface mining are serious problems in many areas, but they can be prevented by controlling the surface runoff that follows rainstorms.

"In processing uranium ores, some of the potentially hazardous radioactive elements or isotopes, particularly Ra-226 and Th-230, are partly dissolved during the leaching operation used to recover uranium oxide. While most processing plants are located in very isolated areas, steps are taken to avoid pollution of water supplies by radioactive constituents of liquid effluents.

"Disposal of the effluent is accomplished principally by impoundment and evaporation, controlled seepage into the ground, and injection through deep wells into saline or nonpotable aquifers. Where ore processing plants are adjacent to rivers or streams, the effluents may be released directly to the streams at controlled rates if, after dilution, the concentration is within predetermined limits. During periods of low stream flow, effluents are impounded or may be chemically treated before release.

"Onshore oil production, except for accidental occurrences, does not present any difficult pollution problem. Nevertheless, nearly three barrels of brine must be disposed of for every barrel of oil produced. Accidental pollution may occur from blowouts of wells, dumping of oil-based drilling muds, or losses of oil in production, storage, or transportation. Methods must be found for their prevention and control. Spills and discharges from tankers are also important. However, the greatest, if less dramatic, problem is the contamination of inland waterways and harbors resulting from transfer of oil between or from vessels.

"Thermal Pollution

"By far the most important water problem resulting from fuel use is thermal pollution. Over 80% of all thermal pollution arises from the generation of electricity. The amount of heat rejected to cooling water represents 45% of the heating value of the fuel used in the most efficient fossil fuel plants, and 55% in nuclear plants. If projected use of electricity is accurate and if nuclear energy, as expected, supplies nearly 50% of the electricity demand, more than 10 times as much heat will be rejected to turbine cooling water in 2000 as is being rejected now. Even with greatly increased use of brines or seawater for cooling, the demands for fresh cooling water will be larger than its supply.

"Air pollution

"Nearly 80% of all air pollution in the U.S. is caused by fuel combustion. About 95% of all sulfur oxides, 85% of all nitrogen oxides, and over half of the carbon monoxide, hydrocarbons, and particulate matter are produced by fuel use. Management of fuels, therefore, is critical for the minimization of the nation's air pollution problems.

"The most competitive market for fuels is the generation of electricity. Not only do the fossil fuels compete with each other, but they also compete with hydropower and, more recently, with nuclear energy. Obviously, from an air pollution standpoint, hydropower is the perfect method of electricity generation. During the generation of electricity from fossil fuels, production of oxides of nitrogen or carbon monoxide is not greatly different for any of the fossil fuels used. The production of electricity using natural gas produces no sulfur oxide emissions, but the use of coal and residual oil in electric generating plants is the source of 74% of all the oxides of sulfur emitted into the air.

"About seven times as much coal as oil is used in electricity generating plants. For this reason, and because of its relatively high sulfur content, coal accounts for nearly two-thirds of the sulfur oxides emitted to the atmosphere. In addition, nearly one-third of the particulate matter emitted into the atmosphere is from burning coal for generation of electricity.

"About one-half of the coal consumed by industry is used to make coke....

"Local air pollution problems in the vicinity of plants that make coke are severe. Alternatives to the use of coke for the production of pig iron are available, and these processes might reduce the amount of air pollutants released to the air. Uncontrolled surface and underground coal fires emit smoke, fumes, and noxious gases.

"About 17% of all the oil consumed in this country is used by industry. Much of it is residual oil, which in most cases is high in sulfur. Moreover, residual oil is difficult to burn efficiently and is ususally burned in large equipment at high temperatures. Because of these two factors, industrial use of oil tends to contribute larger amounts of carbon monoxide, hydrocarbons, and oxides of nitrogen than the household and commercial sector, which consume about 25% of the fuel oil.

"The largest use of oil is for gasoline to power the nation's 100 million vehicles. About 42% of each barrel of oil is used in this manner. If we include diesel and jet fuels, about 54% of each barrel of oil is used for transportation.

"The use of fuels in transportation causes approximately one-half of all the air pollution in the U.S. There are alternatives to the use of gasoline for automobiles and trucks, such as natural gas and liquefied petroleum gases. But it is doubtful that the massive changeover that would be required by two of the country's largest industries would occur if other solutions could be found to reduce air pollution generated by the transportation sector."

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III. PETROLEUM

In 1970 the United States consumed petroleum products at an average rate of 14.7 million barrels per day. Petroleum comprised 44 percent of our national energy supply, including almost all of our transportation fuel, 45 percent of energy used in households and commercial establishments, almost a quarter of our industrial energy, and 13 percent of the energy input of electric power stations.

Precise estimates of future petroleum requirements are difficult. Recent projections of the demand growth rate of 1975 vary from 3.2 percent to 5.0 percent. The Department of the Interior's projections of demand approximate 18.0 million barrels per day in 1975 and anticipate an annual growth rate between 4.0 and 4.7 percent. Beyond 1975 projection becomes increasingly difficult.

Variables which complicate near term projections include rates of economic growth, an apparent shift toward increased energy consumption relative to real gross national product, and potentials for sizable shifts to petroleum from other fuels as energy users seek to meet new environmental standards and as they encounter limitations in supplies of natural gas. In the longer term, other important unknowns must be considered such as technological advances in nuclear energy, and the use of coal in the production of synthetic oil and gas; Federal regulatory policies as they relate to oil and natural gas; and changes in cost relationships and life styles which may appreciably affect energy requirements. The latter include possible major shifts in transportation patterns, such as greater dependence on mass transit and a possible trend toward smaller and more efficient cars, and potentially a shift from internal combustion engines in motor vehicles in the interest of environmental quality improvement.

Within the probable range of future U.S. oil requirements, one conclusion seems obvious. Even with a major increase in domestic petroleum finding and producing efforts, the United States will become increasingly dependent on other nations for oil supplies. Ultimately, production of synthetic oil from shale, coal, or tar sands may contribute to domestic self-sufficiency; but before these sources can begin to make significant contributions, we may become dependent on foreign sources for as much as half of our petroleum supplies. This estimate of dependence assumes that we will be able to maintain domestic petroleum production near its present level. Some industry analysts have questioned our ability to sustain these rates. The less optimistic anticipate a decline of about 30 percent in production from 1970 to 1985.

An estimated 2.8 trillion barrels of crude petroleum and more than 200 billion barrels of natural gas liquids occured originally in place in the earth within the United States and its offshore areas. About one-half of these resources are offshore, and of this portion, about half are in water depths greater than 200 meters. However, only 171 billion barrels of petroleum offshore and 246 billion onshore are estimated to be recoverable under current technological and economic conditions--once they have been found. (See Figure III-1.) Proved reserves of crude petroleum and

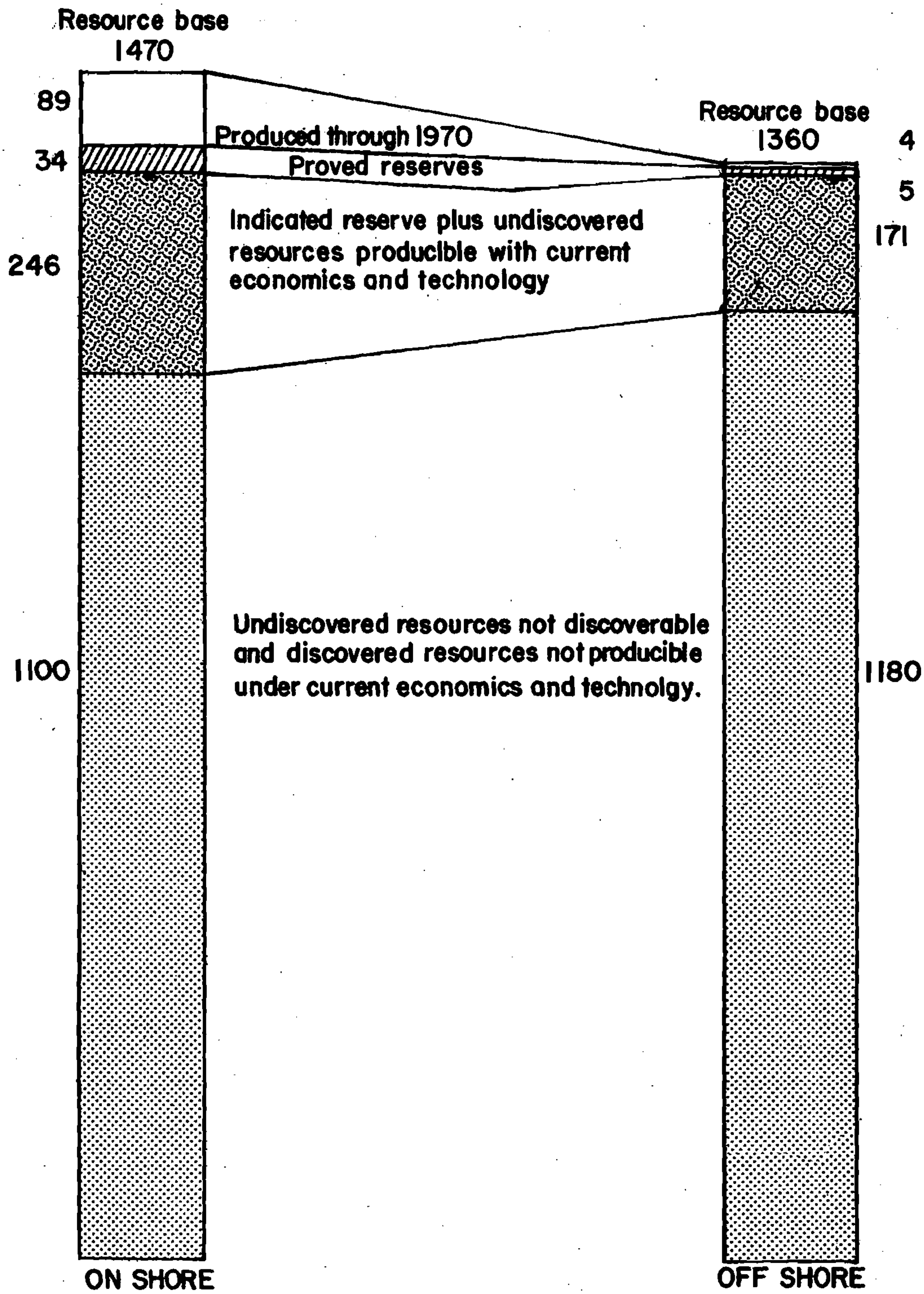

Figure III-1 — U.S. Crude Oil Resources (Billion barrels)

Source: Reference (10, pg. 16)

of natural gas liquids, both on and offshore, amount to 39 billion and 7.7 billion barrels, respectively. Included are 9.6 billion barrels of crude petroleum reserves on Alaska's North Slope. Reserves in the lower 48 States declined in recent years. About 4 billion barrels of petroleum liquids were produced in the United States in 1971. The ratio of reserves to production in the lower 48 States has fallen to about 8.8 for crude oil.

A. Components of Demand for Petroleum

Table III-1 shows petroleum consumption by major products and by major consuming sectors in 1968. The following discussion of current consumption patterns in that year is taken from Bureau of Mines 1970 Mineral Facts and Problems (1):

> "About 90 percent of the petroleum products consumed in the United States in 1968 were used to produce energy in the form of heat and power. Such products included motor and aviation gasolines, distillate fuels, residual fuels, liquefied petroleum gases, jet fuels, kerosene, and petroleum coke. The remaining 10 percent consisted of products used for nonenergy purposes and included petrochemical feedstocks, asphalt, road oil, solvents, coke, lubricants, waxes, and miscellaneous products.
>
> "The 1968 demand for petroleum products by major consuming sectors is shown in... Table III-1...A breakdown of product demand on a percentage basis by energy and nonenergy uses is shown in Table III-2.
>
> "Approximately 66 percent of the nonenergy products was consumed in the industrial sector for making petrochemicals, in aluminum manufacturing, as lubricants and waxes, and for other purposes; 29 percent was used in the commercial sector in the form of asphalt and road oil; and 5 percent was consumed as lubricants in the transportation sector.

Table III-1

Petroleum consumption by major products and by major consuming sectors [1] in 1968 [p]

	Household and commercial		Industrial		Transportation [2]		Electricity generation, utilities		Miscellaneous and unaccounted for		Total domestic products demand	
	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu
Fuel and power:												
Liquefied gases	171.1	686.3	20.8	83.4	30.0	120.3	...	...	3.4	13.7	225.3	903.7
Jet fuel (kerosine and naphtha types)	...	...	...	...	348.3	1,938.0	...	...	...	...	348.3	1,938.0
Gasoline	...	...	...	...	1,955.8	10,264.8	...	...	...	...	1,955.8	10,264.8
Kerosine	78.7	446.2	23.5	133.2	...	...	...	...	.9	5.1	103.1	584.5
Distillate fuel	555.0	3,232.8	61.3	357.1	212.9	1,240.1	3.0	17.5	30.5	177.7	862.7	5,025.2
Residual fuel	196.0	1,232.3	171.0	1,075.0	127.9	804.1	185.0	1,163.1	...	...	679.9	4,274.5
Still gas	...	...	149.8	898.8	...	...	...	...	...	...	149.8	898.8
Petroleum coke	...	...	54.2	326.5	...	...	...	...	...	...	54.2	326.5
Total	1,000.8	5,597.6	480.6	2,874.0	2,674.9	14,367.3	188.0	1,180.6	34.8	196.5	4,379.1	24,216.0
Raw material: [3]												
Special naphthas	...	...	27.0	141.7	...	...	...	...	...	...	27.0	141.7
Lubes [4] and waxes	...	...	28.5	170.5	24.1	146.2	...	...	...	...	52.6	316.7
Petroleum coke	...	...	22.1	133.2	...	...	...	...	...	...	22.1	133.2
Asphalt and road oil	148.2	983.5	...	...	...	...	...	...	...	...	148.2	983.5
Petrochemical feedstock offtake:												
Liquefied refinery gas	...	...	46.5	186.5	...	...	...	...	...	...	46.5	186.5
Liquefied petroleum gas [5]	...	...	113.9	456.9	...	...	...	...	...	...	113.9	456.9
Naphtha (−400°)	...	...	55.6	291.8	...	...	...	...	...	...	55.6	291.8
Still gas	...	...	9.8	58.8	...	...	...	...	...	...	9.8	58.8
Miscellaneous (+400°)	...	...	27.5	160.2	...	...	...	...	...	...	27.5	160.2
Total	148.2	983.5	330.9	1,599.6	24.1	146.2	...	...	...	...	503.2	2,729.3
Miscellaneous and unaccounted for	...	...	...	...	...	...	...	...	17.9	98.8	17.9	98.8
Total domestic product demand	1,149.0	6,581.1	811.5	4,473.6	2,699.0	14,513.5	188.0	1,180.6	52.7	295.3	4,900.2	27,044.1

[p] Preliminary.
[1] Includes liquefied refinery gas and natural gas liquids.
[2] Includes bunkers and military transportation.
[3] Includes some fuel and power use by raw material industries.
[4] Lubricants are distributed equally between the Industrial and Transportation sectors.
[5] Includes LP gas for synthetic rubber.

Source: Reference (1, pg. 158)

Table III-2

Sector	Percent 1967	Percent 1968
Energy uses (fuel):		
Household and commercial	20.5	20.4
Industrial	10.8	9.8
Transportation	54.5	54.6
Electricity generation utilities	3.5	3.8
Not specified	.7	.7
Nonenergy uses:		
Petrochemical feedstocks	5.1	5.2
Other	4.6	5.1
Miscellaneous and unaccounted for	.3	.4
Total	100.0	100.0

Table III-3

Product	Growth rate, 1964 to 1968, inclusive (percent)
Liquefied gases (fuel use)	6.5
Jet fuel	12.7
Gasoline	3.9
Motor	4.3
Aviation	−9.5
Kerosine	1.9
Distillate fuel	2.9
Residual fuel	4.8
Still gas (fuel use)	3.0
Petroleum coke	1.9
Special naphthas	3.6
Lubricants and waxes	2.1
Asphalt and road oil	3.6
Petrochemical feedstocks	10.2
Miscellaneous and unaccounted for	1.8
Total product demand	4.5

Source: Reference (1, Pg. 160)

"To facilitate discussion of uses, the trends in product consumption are indicated in Table III-3,...which includes annual compound growth rates for the major products used during the 5-year period ending with 1968.

"Gasoline and diesel oil (distillate) are consumed primarily as fuel in mobile and stationary engines. By far the largest use is for transportation purposes, including automobiles, trucks, buses, trains, aircraft, ships, and tractors. Gasoline makes up almost three-fourths of the fuels used in the transportation sector. The overall growth rate of gasoline has been curtailed as a result of the declining use of aviation gasoline.

"Jet fuel has had the highest growth rate of all the petroleum fuels in recent years. Nearly all jet fuel used in domestic commercial aircraft is the kerosene type. The military uses predominantly the naphtha type, which may be various blends of gasoline, kerosene, naphtha, and distillate fuels.

"Distillate fuel oil for home and commercial heating has been losing its share of the heating market to natural gas and electricity. The demand for residual fuel oil, used for heating large buildings and electricity generation, has been increasing at a fairly rapid rate since 1964, mostly as a result of use by electricity generation utilities. Utility use of residual fuel oil, instead of coal, increased substantially in the East after import controls were relaxed and air pollution restrictions were effected in some areas. The sale of fuel oil for heating and steam generation depends to a great extent on low-cost transportation from the refinery or port of entry to the marketing areas. Thus, the markets for these fuels are near coasts, the Great Lakes, and the major waterways, such as the Mississippi, Ohio, Illinois and Hudson, and near refining centers.

"The liquefied petroleum gas (LPG) fuels are used for cooking and heating in mobile homes and travel trailers, and in areas where natural gas or oil are not readily available. They are used for many types of transportation including passenger cars, buses, and trucks. In addition, LPG is used extensively on farms for brooders, for flame cutting and weeding, barn heating, crop drying, irrigation pumping, tractor and truck power, and poultry scalding and waxing. The growth rate of LPG in recent years has been second (among energy uses) only to that of jet fuel.

"The principal raw material use of petroleum is as a base input or feedstock for the production of petrochemicals...

"Raw materials used in the synthesis of organic chemicals include ethylene, acetylene, propylene, and butylene (all derived from liquefied gases), and naphtha, benzene, toluene, and xylene.

"Major petrochemical products are ammonia, carbon black, synthetic rubber, plastics and resins, and synthetic fibers.

"Asphalt and road oil constitute the second largest use of petroleum as raw material. Asphalt is used extensively for paving roads, making shingles and other building materials, waterproofing, and miscellaneous purposes. Its growth rate is governed to a great extent by both highway construction programs and general building activity.

"An important but slow-growing use of petroleum is for lubricants. The growth rate has diminished in recent years with improvements in lubricant quality, increasing use of turbine-type engines, and improved bearings.

"The principal uses of petroleum coke are for refinery fuel (71 percent) and making electrodes. Almost 12 percent of the 1968 coke demand was consumed as electrodes in alumina reduction plants. Another important use is for electrodes in electric motor brushes. Approximately 25 percent of coke production was exported, mostly to Japan, Canada, and Europe. The high sulfur content of some petroleum coke renders it unfit for many uses.

"Miscellaneous uses of petroleum include solvents, chemicals (oil base), wax products, pharmaceuticals, injection of LPG into oil reservoirs for secondary recovery purposes, protein synthesis and a wide variety of specialty uses. Wax consumption is now turning upward after several years of slump, and is regaining some markets in carton and paper coating it had lost to the plastics industry." (1)

Table III-4 shows petroleum consumption by sector in 1970 with National Petroleum Council (NPC) projections for 1975, 1980, and 1985. Comparison of Table III-4 with Table III-1 is difficult because Table III-4 shows an "other" category which does not appear in Table III-1. Nevertheless, some marked differences in recent growth rates are apparent. From 1968 to 1970, while petroleum consumption grew slightly less than 10 percent, consumption in the utility sector rose 76 percent due to the rapid shift from coal to low-sulfur residual fuel oil.

Table III-4

U.S. PETROLEUM DEMAND BY SECTOR
(MB/D)

	1970	1975	1980	1985	AAI % 1970-85
Transportation	7,838	9,647	11,774	13,801	3.8
Residential/Commercial	2,607	2,898	3,104	3,299	1.6
Industrial	1,500	1,839	2,256	2,683	4.0
Utilities	910	1,697	2,345	2,665	7.4
Petrochem Feedstocks	818	1,163	1,586	2,089	6.5
Other	1,049	1,102	1,264	1,440	2.1
TOTAL	14,722	18,346	22,329	25,977	3.8%

Source: Reference (8, pg. 17)

NPC projects that the demand by utilities and the demand for oil as petrochemical feedstocks will increase at a faster rate than other uses, but that transportation will continue to claim approximately 53 percent of petroleum demand.

Table III-5 shows Bureau of Mines contingency forecasts of components of consumption in the year 2000. Note that in each case, transportation use is expected to become increasingly dominant, rising from 55 percent of all petroleum uses in 1968 (Table III-1) to 74 percent in the low demand case or 69 percent in the forecast base case (Table III-5). Only in the high demand case (45.0 million barrels per day) would the transportation sector consume a smaller fraction (48 percent) of petroleum than it did in 1968.

B. Petroleum Supply

U.S. demand for oil is growing much faster than the available domestic supply. Exploratory activity has been declining since 1957, which has led to a similar decline in discoveries. Additions to proved reserves have been less than withdrawals in 6 out of the past 10 years, and our ability to produce oil declined in 1968, 1969, 1970, and 1971. The United States could have supplied, without imports, all of its requirements for petroleum from domestic fields until 1967. We are now some 1.5 million barrels per day short of being able to do so, and dependence upon foreign sources is increasing so that an additional 750,000 barrels per day must be imported with each passing year.

Table III-5

Petroleum consumption by major products and by major consuming sectors[1] year 2000, forecast base

	Household and commercial		Industrial		Transportation[2]		Electricity generation, utilities		Total domestic product demand	
	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu
Fuel and power:										
Liquefied gases	30	121	40	160	75	300	...	...	145	581
Jet fuel (kerosine and naphtha types)	...	...	...	...	1,127	6,284	...	...	1,127	6,284
Gasoline	...	...	...	...	4,665	24,482	...	...	4,665	24,482
Kerosine	6	34	12	68	...	...	...	...	18	102
Distillate fuel	38	225	130	757	500	2,913	4	24	672	3,919
Residual fuel	18	114	271	1,704	200	1,257	133	837	622	3,912
Still gas	...	...	291	1,748	...	...	...	...	291	1,748
Petroleum coke	...	...	103	617	...	...	...	...	103	617
Total	92	494	847	5,054	6,567	35,236	137	861	7,643	41,645
Raw material:[3]										
Special naphthas	...	...	84	439	...	...	...	...	84	439
Lubes and waxes	...	...	50	299	60	364	...	...	110	663
Petroleum coke	...	...	120	722	...	...	...	...	120	722
Asphalt and road oil	226	1,506	...	...	...	...	...	...	226	1,506
Petrochemical feedstock offtake:										
Liquefied refinery gas	...	...								
Liquefied petroleum gas[4]	...	...			...	...	...	...		
Naphtha (−400°)	...	...	} 1,444	6,576	...	...	...	...	1,444	6,576
Still gas	...	...			...	...	...	...		
Miscellaneous (+400°)	...	...			...	...	...	...		
					...	...	...	...		
Total	226	1,506	1,698	8,036	60	364	...	...	1,984	9,906
Total domestic product demand	318	2,000	2,545	13,090	6,627	35,600	137	861	9,627	51,551

[1] Includes liquefied refinery gas and natural gas liquids.
[2] Includes bunkers and military transportation.
[3] Includes some fuel and power use by raw material industries.
[4] Includes LP gas for synthetic rubber.

–Petroleum consumption by major products and by major consuming sectors

	Household and Commercial		Industrial		Transportation		Electricity generation, utilities		Total domestic product demand	
	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu	Million barrels	Trillion Btu
					YEAR 2000 (LOW)					
Fuel and power:										
Liquefied gases	31	124	4	16	50	201	...	...	85	341
Jet fuels (kerosine and naphtha types)	...	...	...	...	960	5,353	...	...	960	5,353
Gasoline	...	...	...	...	3,883	21,652	...	...	3,883	21,652
Kerosine	6	34	1	6	...	...	...	...	7	40
Distillate fuel	38	222	13	76	420	2,449	...	...	471	2,747
Residual fuel	18	113	102	641	90	566	137	861	347	2,181
Still gas	...	...	223	1,339	...	...	...	...	223	1,339
Petroleum coke	...	...	81	487	...	...	...	...	81	487
Total	93	493	424	2,565	5,403	30,221	137	861	6,057	34,140
Raw material:										
Special naphthas	...	...	51	267	...	...	...	...	51	267
Lubes and waxes	...	...	39	235	40	243	...	...	79	478
Petroleum coke	...	...	41	247	...	...	...	...	41	247
Asphalt and road oil	225	1,499	...	...	...	...	...	...	225	1,499
Petrochemical feedstock offtake	...	...	890	4,053	...	...	...	...	890	4,053
Other	...	...	...	...	...	...	...	...	...	...
Total	225	1,499	1,021	4,802	40	243	...	...	1,286	6,544
Total domestic product demand	318	1,992	1,445	7,367	5,443	30,464	137	861	7,343	40,684
					YEAR 2000 (HIGH)					
Fuel and power:										
Liquefied gases	500	2,004	66	264	90	361	...	...	656	2,629
Jet fuels (kerosine and naphtha types)	...	...	...	...	1,660	9,256	...	...	1,660	9,256
Gasoline	...	...	...	...	5,000	27,880	...	...	5,000	27,880
Kerosine	20	113	19	108	220	1,246	...	...	259	1,467
Distillate fuel	1,000	5,832	260	1,516	640	3,732	...	...	1,900	11,080
Residual fuel	370	2,327	387	2,434	215	1,352	1,200	7,544	2,172	13,657
Still gas	...	...	490	2,943	...	...	...	...	490	2,943
Petroleum coke	...	...	172	1,034	...	...	...	...	172	1,034
Total	1,890	10,276	1,394	8,299	7,825	43,827	1,200	7,544	12,309	69,946
Raw material:										
Special naphthas	...	...	95	496	...	...	...	...	95	496
Lubes and waxes	...	...	63	380	65	394	...	...	128	774
Petroleum coke	...	...	200	1,203	...	...	...	...	200	1,203
Asphalt and road oil	550	3,664	...	...	...	...	...	...	550	3,664
Petrochemical feedstock offtake	...	...	2,970	13,525	...	...	...	...	2,970	13,525
Other[1]	...	...	160	880	...	...	...	...	160	880
Total	550	3,664	3,488	16,484	65	394	...	...	4,103	20,542
Total domestic product demand	2,440	13,940	4,882	24,783	7,890	44,221	1,200	7,544	16,412	90,488

[1] Miscellaneous uses including natural gas liquids used in secondary recovery operations and oil used in protein synthesis.

Source: Reference (1, pg. 173)

Increasing dependence on foreign oils has been brought about by two converging trends: (1) The increasing use of oil to help offset the supply lag by the other energy commodities, and (2) decreasing ability to meet the increased oil requirements from domestic sources. The convergence between demand and supply has important political and economic implications that are analyzed in the discussion which follows.

The present oil situation is the result of events that began 25 years ago, when demand for all goods and services exploded following the relaxation of World War II controls. Responding to sharply higher demands for oil, the petroleum industry increased exploration and applied newly developed production technology. At the same time, rising foreign oil imports began to dampen the growth in demand for domestic oil and demand was further slowed following the 1956-58 recession. Supplies of oil, therefore, increased much faster than demand, and large amounts of spare producing capacity developed (Figure III-2). The over-supply conditions peaked in 1964, when the Nation could have increased production by nearly 40 percent. Over most of this period, the wholesale price of oil remained virtually unchanged.

With an ever-increasing amount of supply and a relatively stable wholesale price, the petroleum industry had neither the need nor the economic incentive to spend money to develop new oil supplies (Figure III-3). However, large sums of money have been expended in recent years to acquire leases, which strongly suggests that the industry has been preparing a base for renewed exploration and development (2).

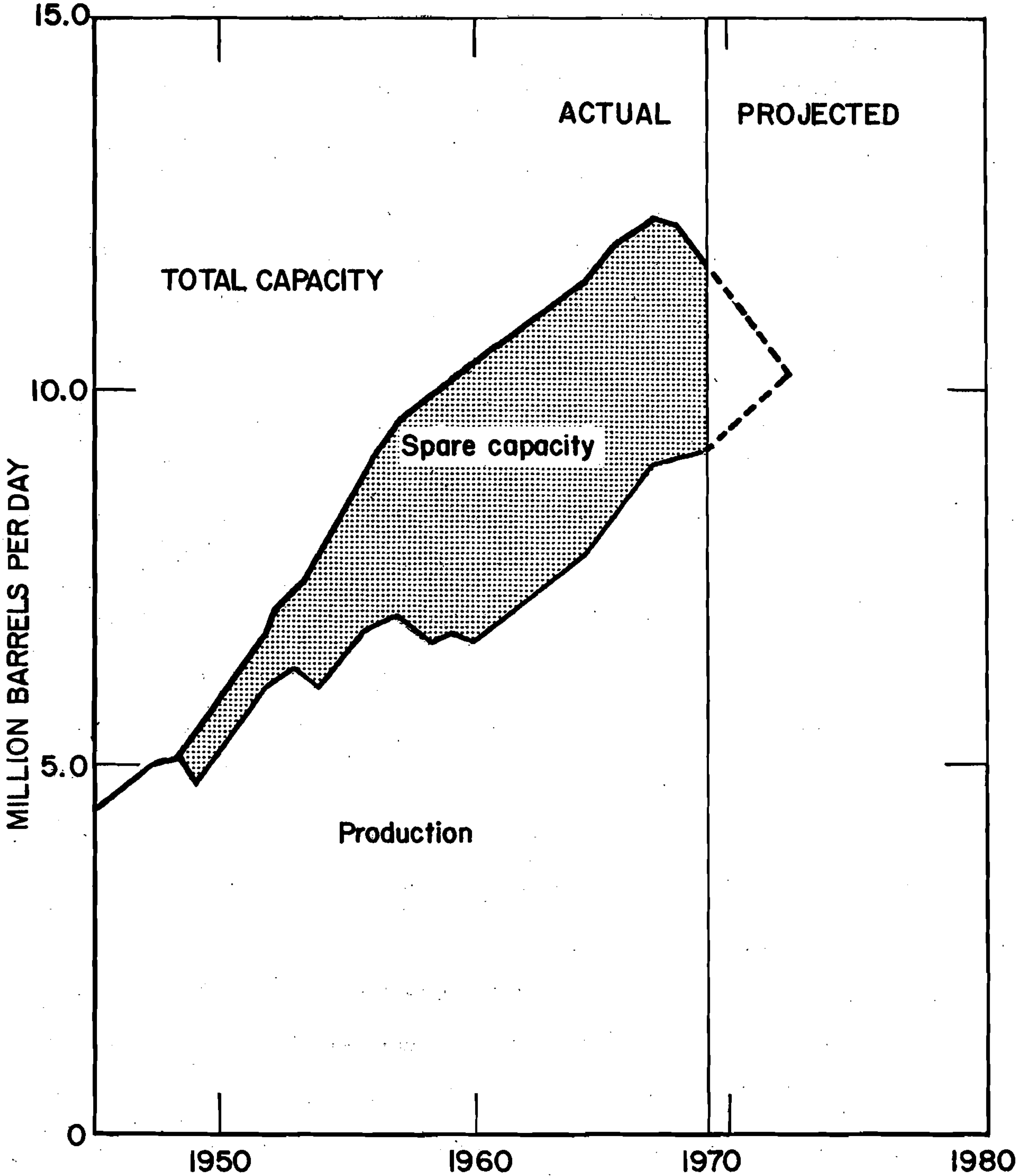

Figure III-2 - U.S. Crude oil producing capacity.

Office of Oil and Gas
Department of the Interior
(Excludes Alaskan North Slope)

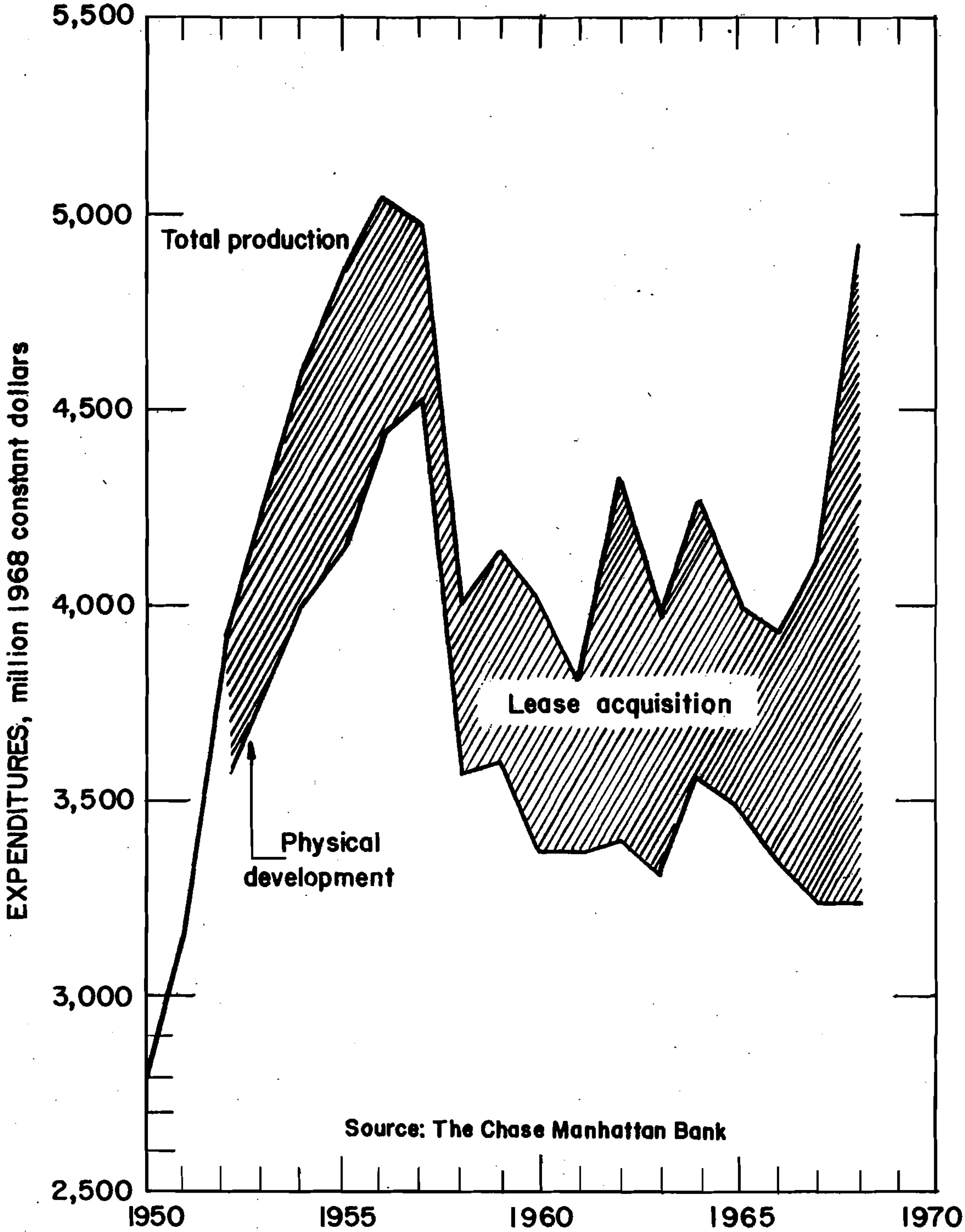

Figure III-3 – **Expenditure for total production, lease acquistion, and physical development.**

Source: Reference (2, pg. 5)

New additions to productive capacity must be developed if this Nation is to continue to have some spare capacity for emergency conditions, since all of the spare capacity is now essentially gone. Over the short term, these trends can be altered by technology, prices, and foreign oil imports. Over the longer term, the development of the Nation's vast supplemental energy sources can provide the flexible supply options that will be needed to stabilize the energy situation.

1. Crude Petroleum Recovery

The recovery of petroleum from known oil fields has followed a gradual evolutionary process, responding to both improving technology and the changing character of the discovered fields. The earliest period of the petroleum industry was characterized by a lack of understanding about how best to produce oil, and many fields were abandoned following the cessation of primary flush production. Substantial improvements in oil recovery were made during the 1920-40 period, with the discovery of many of the Nation's major natural water-drive fields (East Texas, for example). After 1940 the overall trend was the discovery of oil fields which were not capable of yielding as high a recovery efficiency as those discovered in the 1920-40 period. The decline in reservoir quality, however, was gradually offset by the introduction of formation fracturing and the large-scale application of secondary recovery.

A constantly improving production technology has permitted the average recovery from a field to increase at an estimated annual rate of about 0.5 percent over the past 20 years; the current total recovery is about 31 percent of the oil that has been discovered to date. This trend is due mainly to the injection of water into oil fields to supplement or replace the natural energy of the field. Improvements are being made, but the types of oil fields now being found are not as susceptible to this technique as those that were found in the past.

The interrelationship between price, technology, and supply has been described (3) and is illustrated in Figure III-4.[1/] As shown, the amount of "proved reserves" plus those estimated as "economically producible" at current prices totaled about 49 billion barrels in 1965. An additional 22 billion barrels was estimated as physically recoverable using conventional fluid injections, but this oil is contained in marginal fields and the application of the technology is more costly. The last category in Figure III-4, "Recoverable using new technology," refers to the application of miscible fluid drive and in situ combustion to recover oil, but widespread application of these techniques could be justified economically only if the price

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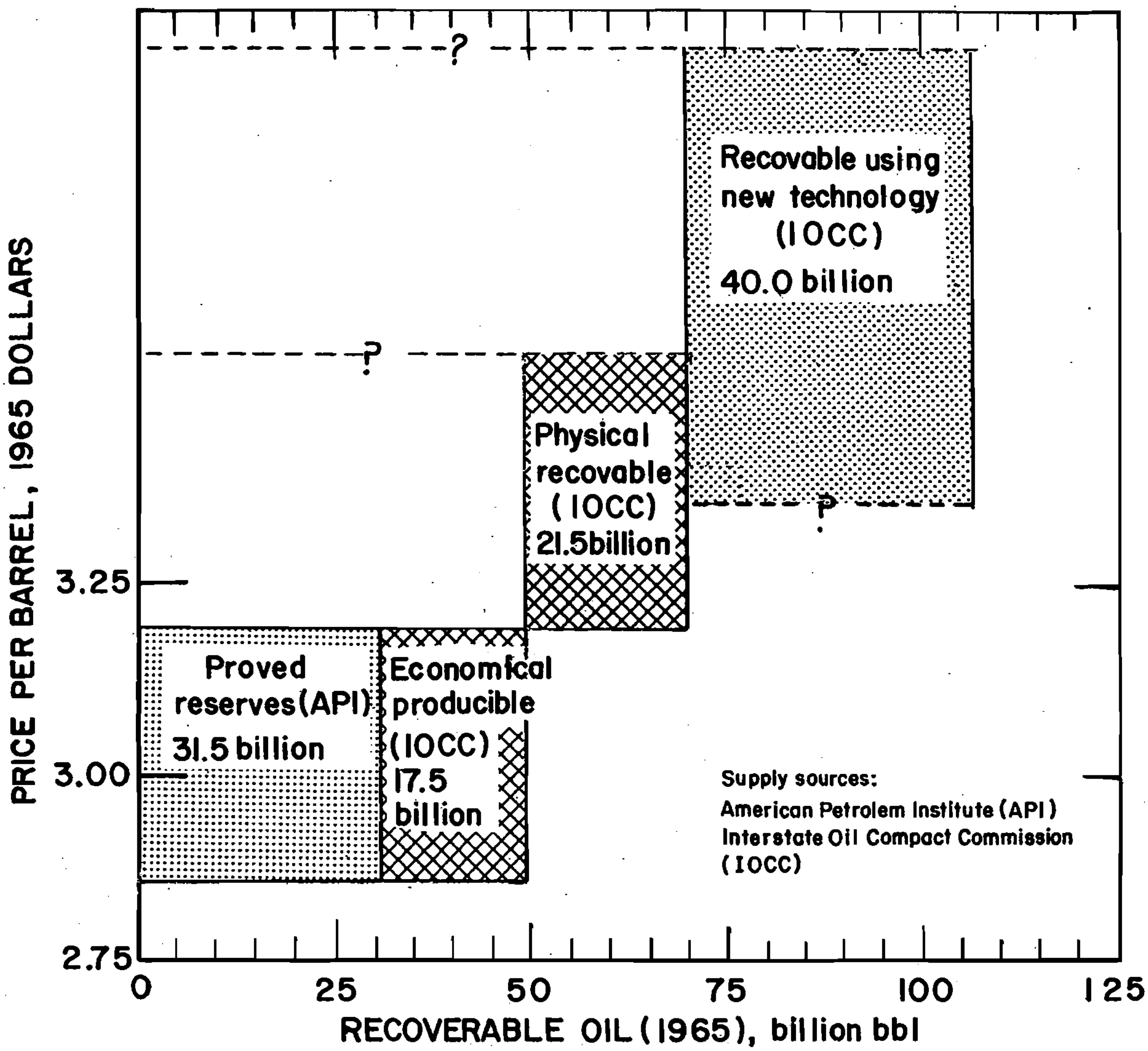
1/ The Interstate Oil Compact Commission last made estimates in 1965 of the amount of oil that could be produced by secondary recovery if such techniques were actually applied to known oil fields. Although the data was dated, the supply-price concept discussed above is valid.

Figure III-4 - Petroleum recovery depends on Technology.



Source: Reference (3, pg. 125)

of oil were to advance significantly. Complete adoption of all recovery methods where applicable to existing oil fields could physically recover nearly 100 billion barrels of oil from these fields.

Production of crude oil from known reservoirs, therefore, depends on both technology and oil prices. Higher prices and/or improved technology would make it profitable to extract substantial amounts of additional oil from fields which are now economically marginal. Our ability to continue to advance technology and the economic availability of energy supplies from oil shale, coal, and tar sands will determine future price relationships for energy sources.

2. Increased Discovery

No matter how efficient and sophisticated recovery techniques become, they necessarily must follow and depend upon initial discoveries made by exploratory drilling. Since the act of discovery is the genesis of proved reserves, discovery trends and related technology have been intensely studied (4-6). The voluminous data developed in these efforts show that:

1. Exploratory drilling has consistently declined for the past 15 years, the longest decline in the history of the industry.
2. New oil discoveries have also followed the downward trend.
3. Except for Northern Alaska, the oil deposits found are getting smaller since the most favorable prospects have been discovered and developed first.

4. The cost of exploration and development is increasing sharply as deeper formations are probed both on land and in more costly offshore and Arctic environments.
5. Discovery technology is in a mature state of development and only evolutionary improvements can be expected.

The 1968 discoveries of oil on the North Slope of Alaska and in some offshore areas are exceptions to the record of the U.S. petroleum industry, which can otherwise be characterized as a mature extractive industry well into the decline stage of its discovery cycle. Although many billions of barrels of oil have been discovered in the Arctic, oil from this region could be limited by the availability of adequate transportation to markets. If the Trans-Alaska pipeline is constructed as proposed, about 2 million barrels per day of oil from Alaska will be available by 1980. While this involves a significant amount of oil, it will only supply a fraction of the increase in demand between 1970 and 1980. The United States must continue to look to the Lower 48 States and the Outer Continental Shelf for a major portion of future domestic supplies. Production increases in those areas can occur only if the tempo of exploration is significantly and successfully expanded.

Extensions of old fields and discoveries of new fields at conventional or greater depths are forecast for all regions covered by the extensive study completed by the National Petroleum Council in

1970 (7). Indeed, the total volume of undiscovered oil and gas in this Nation is expected to equal or surpass the volume that has been discovered from 1859 to the present. However, there is little likelihood of a technical breakthrough that will significantly alter discovery rates.

It is not possible to accurately predict the amount of oil that will be discovered and recovered in the future. Advances in exploration and recovery technology, the randomness of discovery, economic incentives, and Government policies related to leasing, foreign oil imports, taxation, price controls and supplemental source development all bear directly on future oil supplies from domestic sources. But even if a significantly increased exploratory effort were started immediately and were highly successful, from 5 to 10 years would be required before the new discoveries could be developed into producing oil fields with significant output.

3. Projected Supplies of Domestic Crude Petroleum

Many variables influence the supplies of domestic oil that can be developed. Two of the most significant are the rate of discovery (finding rate) and the rate of development (drilling rate). The NPC Summary Report, December 1972 (11), considers four cases which are combinations of two finding rates and three drilling rates. The low finding rate is based on past trends and the other is approximately 50 percent higher. The low drilling rate is based on the current 4 to 5 percent per year downtrend. The high drilling rate corresponds to the nearly 6 percent per year growth attained following World War II. The following tabulation summarizes the four cases considered.

Variable	Cases Analyzed Highest Supply I	II	III	Lowest Supply IV
Drilling Rate	High Growth	Medium Growth	Medium Growth	Current Downtrend
Finding Rate	High	High	Low	Low
	North Slope Production Starts			
Oil	1976	1976	1976	1981
Gas	1978	1978	1978	1983

Table III-6 shows the projected total petroleum liquids production rates for 1975, 1980 and 1985 (10).

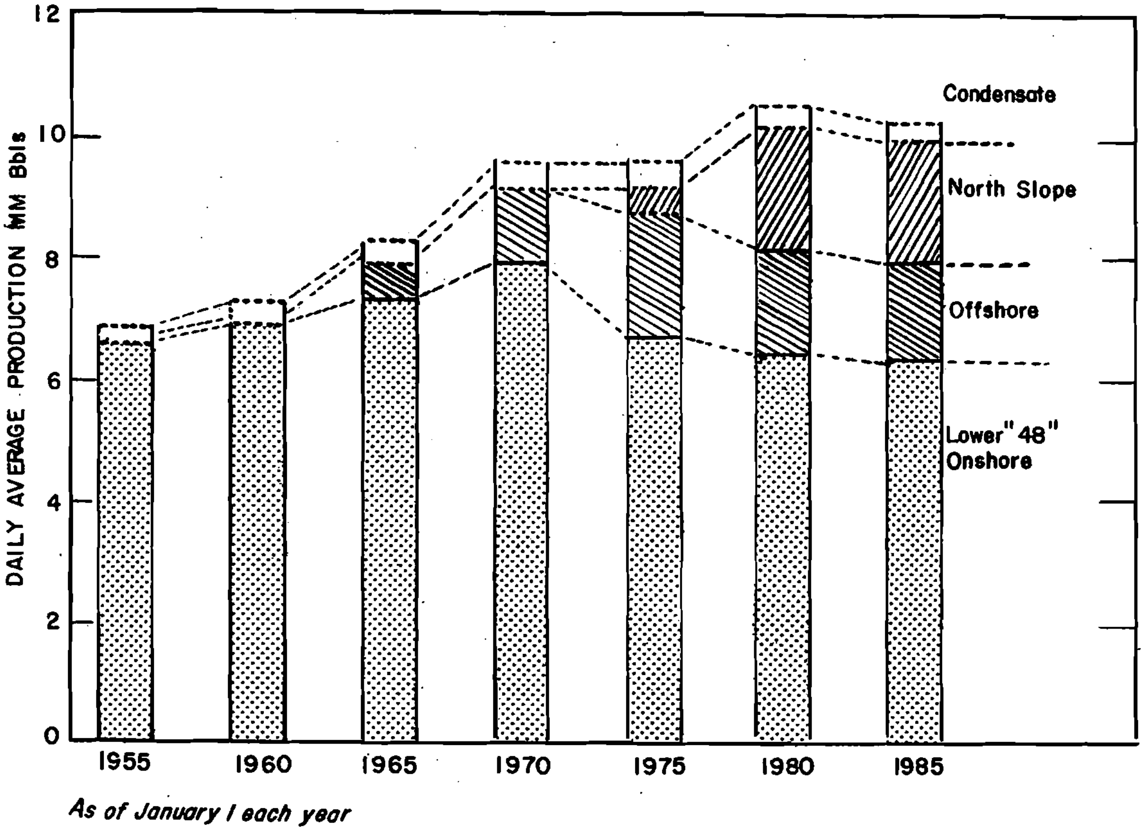
Table III-6

TOTAL U.S. CONVENTIONAL LIQUID
PETROLEUM PRODUCTION

	MMB/D 1970	1975	1980	1985
Case I	11.3	10.2	13.6	15.5
Case II	11.3	10.2	12.9	13.9
Case III	11.3	9.8	11.6	11.8
Case IV	11.3	9.6	8.9	10.4

Figure III-5 shows a breakdown by sector of past and projected oil supply corresponding roughly to Case IV. As indicated earlier in Table II-1 25.0 MM b/d are projected as the need for liquid fuels in 1985. The difference between the 10.4 to 15.5 MM b/d potential production and the need represents the shortfall that must come from some other source--imports or substitute fuels.

Figure III-5 - U.S.A. Oil Supply



Source: Reference (8, pg. 29)

4. Oil Imports

The United States is critically dependent upon liquid and gaseous fuels that presently can only be obtained, in the quantities needed, from conventional petroleum sources, both foreign and domestic. This will remain true for the next 10 or more years regardless of the progress made in the extraction of liquids and gases from coal and oil shale, because long lead times are necessary to develop these supplemental sources. The adequacy, security, and cost of petroleum supplies have a direct influence on the Nation's national product, trade position, diplomatic posture, and military capability.

Under these circumstances, Government has the responsibility to encourage a favorable administrative and economic climate under which the Nation's petroleum industry can provide oil and gas supplies that are both secure and adequate, at the lowest practicable cost, and with minimal environmental impacts. In addressing itself to this responsibility, the Federal Government in 1959 made the fundamental determination that unless the domestic market was shielded from foreign supplies, too large a share of it would eventually come to be dependent upon foreign sources, subject to denial by either political or military action. With security of supply as the primary criterion to be satisfied, a policy and program restricting foreign oil imports to a moderate fraction of domestic production was enacted.

The potential insecurity of Middle East oil supplies is evidenced by the history of the past 20 years. In 1951 the seizure and shutdown of oil facilities in Iran virtually stopped all oil exports from that country for over 2 years. The Suez Canal, closed by Egypt for a period of 5 months in 1956, was again closed in 1967 and remains closed at the time of this writing. The 1967 outbreak of hostilities between Israel and the Arab Nations interrupted, for a brief interval, over two-thirds of the oil supply to Western Europe. Moreover, a 2-month embargo was imposed on oil shipments to the United States, the United Kingdom, and the Federal Republic of Germany by certain oil-exporting nations. The Trans-Arabian pipeline was ruptured in May 1970. Its repair was delayed by the Syrian Government throughout the balance of the year. Concurrently, the Libyan Government sharply curtailed production from oil fields located in that country. These actions placed tremendous pressure on the world's tanker fleets, forcing upward the costs of chartering tankers to transport this crude.

These interruptions in oil supplies occurred at a time when substantial switches from coal to imported residual oil were being made to meet environmental standards. Sharply increased residual oil demand and limited availability of transport caused the price of residual oil to increase by nearly 65 percent over the first 10 months of 1970. This development largely was the result of dependence on foreign sources and lack of adequate transportation. Today, nearly 94 percent of the East Coast demand for residual oil is supplied by foreign imports. Of even greater concern, the supply source is shifting from the relatively secure South American oil fields to those of the more unstable North African area, as suppliers seek the low sulfur oil needed to meet environmental standards.

In the case of crude oil, spare domestic supplies were drawn down. Production from wells located principally in Texas and Louisiana was increased, and by November 1970, total production exceeded 10 million barrels per day for the first time in the Nation's history. This daily production rate, 500,000 barrels (or about 5 percent) greater than the average rate during the first 6 months of 1970, served to replace the deficit in overseas supplies. This action was possible during 1970, but by 1973 spare productive capacity will be eliminated and it will no longer be possible to increase the oil output from Texas and Louisiana wells.

The 1970 broken pipeline in Syria and production cutback in Libya affected less than 3 percent of the free world's oil supply, but this 3 percent is all it took to force a major readjustment in world movements of oil. Today, about 40 percent of the total oil needs of the world are supplied by output from fields located in the Middle East and Northern Africa. These areas, moreover, have about 70 percent of the free world proven oil reserves. Thus, the rapid increases in world demand that are now taking place must force increasing reliance on these highly unstable supply sources. A new dimension to international oil movements must also now be considered--the demonstrated ability of the oil-exporting nations to act both separately and in unison to attain specific economic objectives at the expense of both the oil companies and consuming nations. Increasingly, the exporting nations have won price concessions from producing companies which ultimately must be paid for by consumers. The balance has now been tipped in favor of the oil-exporting nations.

Oil is being used increasingly as a tool for obtaining political and economic objectives. In its supplemental energy fuels, however, this Nation has within its own borders the oil equivalent of several Middle East oil fields. Technology for economic production of this oil from our oil shale, coal, and tar sand resources must be developed if oil supplies from these sources are to be available to meet future fuel needs.

5. Supplemental Sources

Each of the supplemental sources (coal, oil shale, tar sands) contain vast quantities of recoverable solid organic materials that are convertible to liquid and gaseous products. The oil represented by all of these deposits in place is not measured in billions of barrels, as is petroleum, but in trillions of barrels.

Recent studies based on known but as yet commercially unproven processes indicate that of these three potential sources of supplemental oil, coal is the least promising economically, requiring an estimated selling price of upwards of \$6.00 per barrel. The economic picture in the case of domestic tar sands is quite nebulous; however, based on gradual advances over a period of years by the operators at Athabaska, it appears that tar sand operations probably are approaching a profitable position. Oil shale is thought to have the most favorable current economic position of the three potential supplements; most recent estimates indicating large scale oil shale operations would be nearly, if not actually, competitive with natural petroleum.

Processes for each of the potential supplements mentioned above involve large scale material handling which lends itself to technological breakthroughs that may lead to substantial cost reductions. Scaling up from the current prototype development state to multibillion-dollar industries will require years to plan and construct both the industry and supporting communities. In addition, the commitments of capital required for construction of operating plants alone will range from \$3,000 to \$5,000 per daily barrel of production; or from \$3 billion to \$5 billion for a 1-million-barrel-per-day output.

Oil shale economics have significantly improved relative to crude oil since this Department completed its last comprehensive analysis (9). Between 1966 and 1970, for example, costs have increased about 45 cents per barrel for the system identified in the referenced study as the "improved first generation" retorting option. This cost increase, however, has been balanced by crude oil prices which have risen by about $0.45/bbl. In addition, the Tax Reform Act of 1969 changed the point of application for calculating depletion from the oil shale before entering the retort to the shale oil as it leaves the retort, a change which increased the tax allowance by about $0.15 per barrel. Since shale oil economics have remained about unchanged or have been slightly improved, while those of crude petroleum have declined, the economic viability of shale oil production has been enhanced when compared to crude petroleum. The alternative that proves to be most economical will depend on the positions of individual firms as they evaluate their resource situations and future needs. Many firms may meet their needs only through exploration and development of conventional sources; others will move toward the development of alternative sources.

The state of technology, the size of the investments required to develop supplemental sources as compared to alternative investment opportunities, i.e., Alaskan and offshore oil, and the planning and associated long lead time indicate that oil production from any of the supplemental sources cannot be a significant part of total supplies until after 1980. The potential for the more distant future, however, is great.

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3. Johnson, Harry R., "Petroleum in Perspective," Nat. Res. J., v. 11, No. 1, January 1971, pp. 120-147.

4. National Petroleum Council, "Factors Affecting U.S. Exploration Development and Production, 1946-65," Washington, D.C., 1967, 163 pp.

5. National Petroleum Council, "Impact of New Technology on U.S. Exploration and Production, 1946-65," Washington, D.C., 1967, 341 pp.

6. U.S. Department of the Interior, "U.S. Petroleum Through 1980" Washington, D.C., 1968, 92 pp.

7. National Petroleum Council, "Future Petroleum Provinces of the United States - A Summary," Washington, D.C., 1970, 138 pp.

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9. U.S. Department of the Interior, "Prospects for Oil Shale Development, Colorado, Utah, and Wyoming," Washington, D.C., 1968, p. 65.

10. U.S. Dept. of the Interior, "United States Energy: A Summary Review," January 1972.

11. National Petroleum Council, "U.S. Energy Outlook, A Summary Report of the National Petroleum Council," December 1972.

IV. OIL SHALE: RESOURCES AND POTENTIAL

Large areas of the United States are known to contain oil-shale deposits, but those areas in Colorado, Utah, and Wyoming that contain the shale-rich sedimentary rocks of the Green River Formation are of greatest promise for shale oil production in the immediate future (Fig. IV-1). These oil shales occur beneath 25,000 square miles (16 million acres), and of this area, 17,000 square miles (11 million acres) are believed to contain oil shale of potential value for commercial development in the foreseeable future.

The known Green River Formation deposits include high-grade shales, in beds at least 10 feet thick and yielding 25 or more gallons of oil per ton containing about 600 billion barrels of oil.1/ Recovery of even a small fraction of this resource would represent a significant energy source adequate to supplement the Nation's oil supply for many decades, providing economic and environmentally safe methods of shale oil production are developed.

It has long been known that petroleum liquids and gases can be obtained by heating oil shale in a closed vessel called a retort. Commercial production of shale oil abroad actually preceded by several decades the drilling of the first oil well in the United States. Shale oil industries have been established in many foreign countries in the past and exist today in mainland China and the U.S.S.R. Although the Ute Indians used

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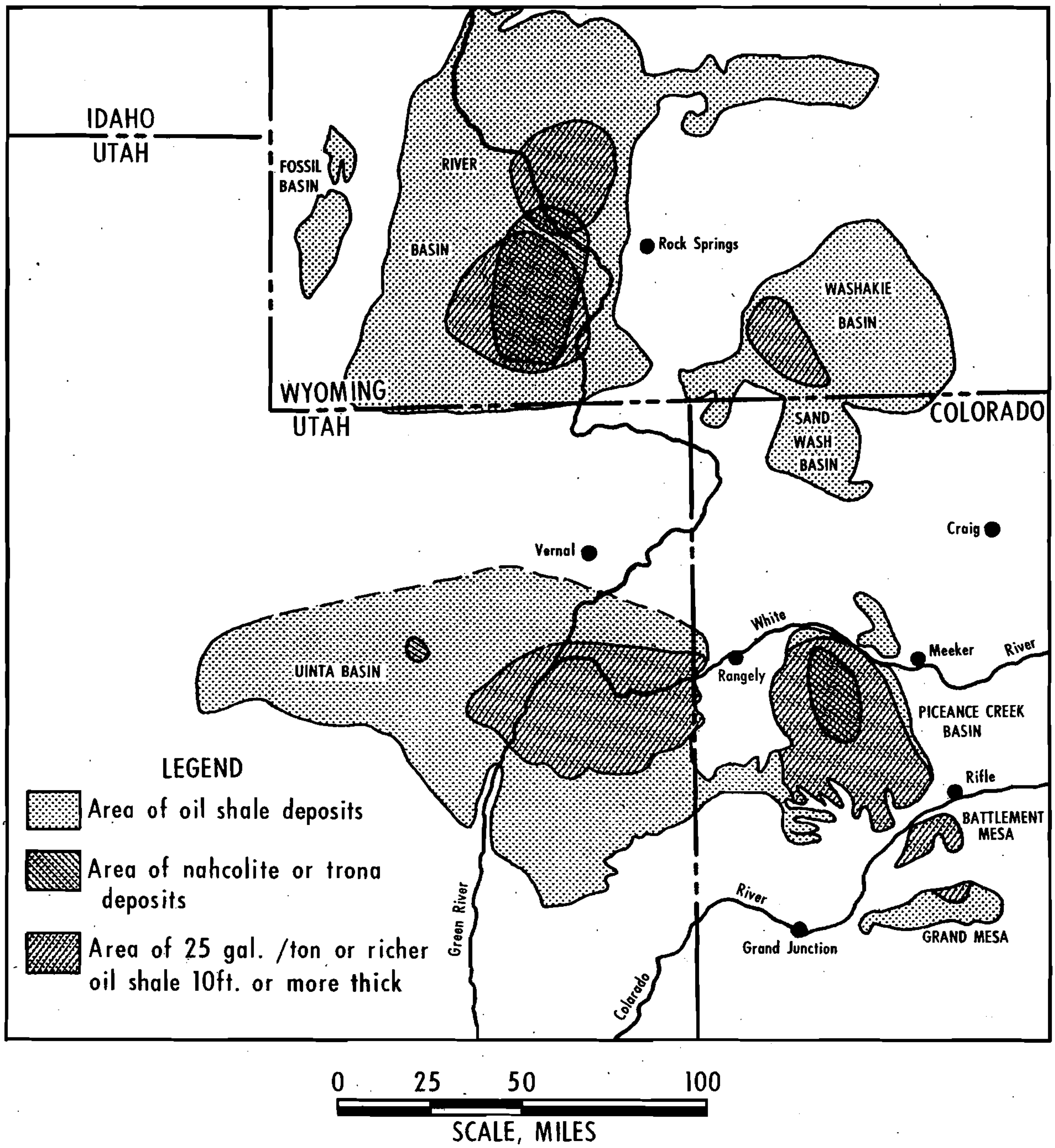
1/ An additional 1,200 billion barrels are present in place in lower grade shales, in sequences more than 10 feet thick that have an average yield of 15 to 20 gallons per ton.

Figure IV-1 -Oil Shale areas in Colorado, Utah and Wyoming



oil shale for campfires long before the first settlers arrived in Colorado, Utah, and Wyoming, interest in the commercial development of this extensive potential source of energy has fluctuated widely. Some oil from shale was produced prior to the 1859 discovery of natural petroleum, but industrial attention did not focus on oil shale until immediately prior to 1920, when there was some concern that domestic petroleum resources might become inadequate. Interest declined at that time as ample supplies of liquid petroleum were discovered and developed. Oil shale deposits were withdrawn from leasing pursuant to Executive Order No. 5327 of April 15, 1930, subject to certain later modifications (1) which authorized leasing of oil and gas and sodium in accordance with the terms of the modifications.

The Synthetic Liquid Fuels Act of April 5, 1944, as amended (30 USC § § 321-325), made possible a large-scale oil shale research and demonstration effort by the Department of the Interior's Bureau of Mines during the period 1944-56. This effort was aimed at the creation of a new and more economic mining, retorting, and refining technology, and also sought to provide reliable information on the costs of commercial shale oil production. Industry has also conducted extensive research on oil shale processing; several methods have advanced through the demonstration phase as discussed in Volume I, Chapter I, of this study.

The Department's accumulated knowledge of this resource and its expected potential were summarized in a comprehensive 1968 Interior study (2). Contemporary and future technologies, and the public policy factors that could influence the rate of development of this resource were clearly delineated. Included also were estimates of the resource size and land ownership status. Efforts, since the study's publication have concentrated on: (1) an analysis of the probable environmental impact of oil-shale development, (2) the formulation of a prototype leasing program within the framework of existing law, and (3) a program to determine ownership of the oil shale where title conflicts exist.

Commercial shale oil production, under the most optimistic estimate, could begin about 1975 at a rate of about 18 million barrels per year (50,000 barrels per day), on the basis of anticipated technologic progress. The first generation technology needed for this rate of production would be improved from 1976 to 1980. This development stage will be reflected by only small increases in annual production of about 18 million barrels per year as the new technology is applied. By 1980 a productive capacity of more than 100 million barrels per year (300,000 barrels per day) could be established. More importantly, the technology probably will have been advanced to the point where large incremental increases in production could be achieved. Also, the nucleus of people, supporting services, facilities, and experience needed for this expanded effort will have been established.

After 1980 the second generation extraction-retorting systems would be expected to permit annual additions to shale-oil productive capacity of about 37 to 73 million barrels per year (100,000 to 200,000 barrels per day). The rate at which oil shale may be developed provides the framework within which subsequent calculations may be made, considering both the stage of technology and the size of the capital investments that will probably be required. The cumulative six-plant capacity of 300,000 barrels per day by 1979 reflects the necessary construction and evaluation phase of this new technologic development. Second generation technology could be expected to be available by 1980, enabling the large increases in capacity from surface processing systems shown in Table IV-1. It is assumed that seven installations with a cumulative capacity of 400,000 barrels per day will be constructed on both private and public lands in the period 1973 to 1981 (Table IV-1). In situ retorting may also be advanced to the point where the first commercial operation could be initiated. By 1985 cumulative capacity is estimated at 1 million barrels per day from both private and public lands.

Table IV-1 - Projected Shale Oil Capacity - Cumulative

(Thousands of Barrels per day)

	Colorado		Utah	Wyoming	Total
	Federal land	Private land	Federal land	Federal land	
1973	--	--	--	--	--
1974	--	--	--	--	--
1975	--	--	--	--	--
1976	--	50	--	--	50
1977	--	50	--	--	50
1978	50	100	--	--	150
1979	150	100	--	--	250
1980	150	100	50	--	300
1981	150	150	50	50	400
1982	--	--	--	--	550
1983	--	--	--	--	700
1984	--	--	--	--	850
1985	--	--	--	--	1,000

A. References Cited

1. See Executive Orders No. 6016 of February 6, 1933 and No. 7038 of May 13, 1935; Public Land Order No. 4522 of September 23, 1968.

2. U.S. Department of the Interior, "Prospects for Oil Shale Development, Colorado, Utah, and Wyoming," 1968, 134 pp.

V. ALTERNATIVES TO OIL SHALE DEVELOPMENT

The principal alternatives to the proposed prototype oil shale leasing program are of two types: those that can be implemented through public policies and those that can be implemented by substituting one energy form for another. The alternatives are not mutually exclusive and, therefore, interact. Moreover, considering supply/demand projections, all sources of energy may have to be considered supplementary rather than alternative with reduced consumption being the only viable alternative (148). They are separated in this document only to facilitate the discussion.

A. Alternative Energy Policies

1. Reduction in Demand for Energy

One alternative to the production of 1 million barrels per day of shale oil by 1985 is to reduce, in some manner, the need for liquid energy products by that quantity by the year 1985.

Before proceeding with a discussion of this alternative, the motivation for the proposed oil shale leasing program should be recalled. The emphasis of the program is one of information gathering to expand the range of options available for an energy consuming society presently committed to increased energy consumption. Furthermore, energy conservation will also be evaluated as an alternative in this section. Most significant measures for energy conservation require intensive social and legal changes which must be begun now in order to achieve results in the near future.

In Section II-A of this report it was noted that energy demand correlates closely with gross national product (GNP), which, in turn, correlates closely with both population and per capita income.

The increasing use of energy has therefore been correlated with increasing affluence and a rising material standard of living. This is the nature of the past and present culture. In part, perhaps because the economic cost of energy has not taken full account of environmental costs and because supplies of resources have been ample, growth in energy demand has been little constrained by its cost. Now, however, in the face of increasing concern over the quality of the environment, declining energy resources, and a high material standard of living, it is appropriate to consider whether historic energy consumption patterns should be allowed to continue unabated. A number of writers have argued that it should not. Among the more recent works are those of Professor Meadows and a group at MIT working in collaboration with the Club of Rome's project on the Predicament of Mankind (1), the "Blueprint for Survival" statement published in the Ecologist (2), and an article by Michael McCloskey, executive director of the Sierra Club (3). Professor Commoner (4) has warned of the consequences of continuation of current technological trends.

Not all scholars agree with such arguments. Drs. Kneese and Ridker of Resources for the Future (5) and Dr. Abelson, president of the Carnegie Institution and editor of Science (6), take issue with results of the MIT project, principally on grounds that technological improvements have kept pace with demand in the past and are likely to do so in the future. Indicated in these contrasting opinions is the difficulty of social changes coming about that would obviate energy shortages through the desirable alternative of demand reduction.

There are essentially two ways of reducing the growth in energy demand: (1) reduction in population growth and (2) reduction in per capita energy consumption. Both measures could be encouraged by government policy. The following analysis describes policies which government can exercise to control population growth, but points out the limited extent to which population control affects the rate of growth of energy demand. The role of government policy in influencing the per capita energy consumption is discussed in the subsections a and b below.

Government policy has, or can have, a limited impact on rate of population growth. Strict immigration laws can control the influx of aliens. Tax, welfare and military compensation, and even draft structures, often encourage larger families. Reform of these policies, along with effective public education programs on birth control, could reduce the number of large families. Free clinics for birth control, abortion and voluntary sterilization all have direct impact on rate of births, and thus, on population growth.

In the absence of such policies, the current base forecast of the Bureau of Census, Series D (7), shows population growth comparison with Bureau of Mines energy forecast (8):

Year	Population (million)	Percent change	Total energy consumption (trillion Btu)	Per capita consumption (million Btu)	Percent change
1970	204	-	68,810	337	-
1975	216.2	+6%	80,300	372	+10%
1985	243.3	+11%	116,800	479	+29%
2000	279.7	+20%	191,900	688	+44%

Clearly, the increase in per capita consumption is far more important to growth in energy demand than the growth in U. S. population. At the extreme of replacement fertility and no new immigration (103) growth trends would be:

Year	Population (million)	Percent change	Total energy consumption (trillion Btu)	Per capita consumption (million Btu)	Percent change
1970	204	-	68,810	337	-
1975	214	+5%	79,500	372	+10%
1985	233	+9%	111,600	479	+29%
2000	256	+10%	176,100	688	+44%

The continued increase in population to the year 2000, despite a zero population growth rate, is due to the age distribution and consequent fertility expectations of the existing population.

Population growth is in a transitional phase; United States population growth rates appear to be declining without government intervention. The most likely rate of growth of population is the Bureau of Census's Series D and E, which shows population increases only 1.0 to 1.2 percent per year through 1985 (104). Thus, only about 1 percent of the growth in energy demand of about 4 percent per year can be attributed to increased population. Increased per capita consumption with increased per capita income and income growth contribute the balance. Thus, it appears that only limited effect on energy demand can be made by altered population trends.

a. More Efficient Energy Use

A reduction in the rate of growth of per capita energy demand could be accomplished by (1) reducing the rate of growth of demand for the goods and services produced by the energy demanded, (2) producing the demanded goods and services more efficiently, or (3) converting energy sources to useful work more efficiently.

A report prepared in October, 1972 by the Office of Emergency Preparedness (OEP), "The Potential for Energy Conservation," (105) offers many helpful suggestions on a variety of means to save energy. These range in scope from what the individual can do immediately, i.e., thermostat control, shutting off lights, etc., to longer term measures such as public transportation. The United States has developed the largest and most sophisticated system of energy consumption in the world. Such a system is slow to change, but past patterns can be altered in the future if the national effort is directed toward the transportation, residential-commercial, industrial, and electric utility sectors of our economy. Each of these major energy users is discussed in turn below.1/

(1) Transportation.- The transportation sector currently accounts for approximately 25 percent of the total energy consumed in the United States. Since petroleum provides 96 percent of this requirement, about one-half of all oil used is consumed in transportation. Shifts among transportation modes in recent years have been based on factors such as convenienience and speed rather than on

1/ This discussion of the four sectors is based on the OEP report (105).

the efficient use of energy. Intercity movements of passengers and freight have been increasingly provided by airplanes and trucks instead of by railroads and buses. Within the city, the private automobile has become the preferred means of transportation.

More than 50 percent of total transportation energy consumed can be attributed to automobiles, and more than one-half of this amount is used in urban areas. This suggests that urban transportation has considerable potential for energy demand reduction.

Short-term measures to save transportation energy include educational programs to use automobiles more efficiently or to substitute communication for personal contacts. More powerful incentives to accomplish this end include taxes and direct regulations. Over the longer term, high-quality public transportation offers a promising way to reduce energy consumption. The possibilities can be extended by systematic planning that incorporates the concept of transportation systems into urban development. Energy savings through these measures are discussed in the following section.

(2) Residential and Commercial. - The residential-commercial sector accounts for about 21 percent of total energy consumption. The major requirements are for space heating and cooling, water heating, refrigeration, and cooking.

The OEP report suggests a number of useful measures that can be used by the public to reduce energy use. These include turning off lights when not in use, utilizing appliances such as washing machines more efficiently, and keeping energy using equipment in good operating condition. Over the longer term, further reduction in energy demand could be achieved through manufacture of more efficient energy using items, i.e., improved stoves, refrigerators, water heaters, and lighting devices. A key target in this sector is increasing the energy efficiency of air conditioners, many of which are highly inefficient. Another target is to improve the insulation of homes. This, however, will take time because it is more efficient to insulate new homes than to add additional insulation to existing structures.

Commercial energy use, over a long term, could be reduced by designing buildings with energy saving in mind. Window areas could be reduced, building direction and location could be varied, and better insulation could be installed. There will be a time lag, however, because many of these changes would be practical only for new buildings.

(3) Industry.- Energy consumption in the industrial sector accounts for approximately 29 percent of total energy consumption in the United States. The major consumers in this sector are the primary metals, chemicals and allied products, and petroleum refining and related industries. These industries are responsible for over 50 percent of total industrial energy consumption.

There has been a tendency towards more efficient energy use in most industries and a notable efficiency increase in the steel industry. It is suggested by the OEP report that many industries "could easily cut energy demand by 10 to 15 percent (and probably much more) over a period of time by accelerated retirement of old equipment, more energy-conscious process design, and upgrading and increasing maintenance of existing equipment." Long-run measures include reliance on technological advances and the "reuse and recycling of materials."

(4) Electric Utilities.- The electric utilities sector presently uses 25 percent of total primary energy consumption in the generation of electricity. Much of the discussion in the OEP report is in terms of more efficient sources of power generation. Improved efficiency of conversion is considered in chapter V, **Section** C-10, of this volume.

Potential long-run measures for reducing energy inputs to electricity generation include the construction of new and efficient facilities and improved utilization of waste heat. A possible short-term measure is to level the variation in demand, thereby reducing the use of the inefficient equipment needed to meet peak power demands.

(5) Potential, Logistics, and Costs.- General suggestions on how conservation of energy might be attained through improved efficiencies of energy use and through reduction in demand do not necessarily imply easy solutions. The interrelationships between various forms of energy use patterns, together with associated pollution control measures presently being advocated, are extremely complex. Recommendations of what, at first, seem to be simple solutions, must be analyzed in depth to examine all possible effects not immediately apparent. For example, one suggestion to reduce the quantities of electricity consumed is to reduce excessive urban lighting when the trend is currently towards increasing it. However, proponents

quote crime statistics to show that significant reductions in street crime have resulted in areas where lighting is increased. The trade-off, here, is a social benefit at the cost of increased use of energy. Other suggestions, however, can be implemented without serious social overtones, for example, by replacing the 3 million outdoor lights now being fueled by natural gas with electric bulbs would release enough energy to heat about 600,000 homes.

The design of buildings to decrease window area, therefore leading to less heat loss from the building, illustrates the technical complexities that must be considered. A decrease in window area, for example, results in need for internal lighting brought about by loss of outside light. But the possible gain in heating the building may require an offsetting increase in air-conditioning capacity to remove the heat created by the added light. Complete energy balances are required to assess these complex interrelationships to determine what system would yield the most efficient energy usage.

Time is a key characteristic of major changes in energy use. Even after the studies are complete, implementation plans would have to be formulated and recommendations made. Many years would normally pass before implementation, and long periods are required before any significant impact on net energy consumption patterns of the United States is seen, even assuming that general acceptability by the public can be obtained.

For example, to reduce energy demand by 250,000 barrels per day of oil in 1980 by switching from private automobiles to buses in urban transportation would require an initial investment in buses of nearly $10 billion.[2] This measure would require the construction and operation of 240,000 buses, five times more buses than the 50,000 currently operating in local transportation.[2] This number of buses could transport 27 million people to and from work each day, nearly one-third the total present civilian work force of 84 million persons.

Rapid transit systems require extensive planning and significant amount of money for construction. To reduce energy consumption in urban areas by 250,000 barrels per day by substituting subways for cars would require an expenditure of $264 billion; about $1 billion for each 1,000 barrels of oil saved.[3] Savings in excess of 250,000 daily barrels would not be possible for urban application, since the $264 billion expenditure would be sufficient to build 189 subway systems similar to that in San Francisco, or enough to supply nearly every major American metropolitan area with such a system.

2/ The substitution of buses for private automobiles in urban transit reduces the consumption of energy by 3,820 Btu per passenger mile (106). A transit bus operates, on the average, 575,000 passenger miles per year (107) and has an initial cost of about $40,000. The capital cost for buses is thus $18.20 per million Btu saved per year.

3/ Rapid transit systems such as subways reduce energy consumption by 3,930 Btu per passenger mile compared to private automobiles (108). The San Francisco subway system is expected to operate 715 million passenger miles per year and the capital cost of the system was $1.4 billion (109). Thus, the capital cost of subways is $500 per million Btu saved per year.

The growth of urban transportation systems would decrease the number of individual vehicles in urban use. Additionally, the number of vehicles needed would also be reduced, but it is likely that the automobile would be used for access to bus or rapid transit terminals. One recent analysis (110) for example, has concluded that doubling the availability of public transit in the next 15 years would reduce total automobile usage by only 4 percent.

Insulation of new single-family homes offers good potential for energy reduction, as previously discussed. Assuming that every new single-family dwelling was optimally insulated[4/] and that annual starts remain at the current level of 1 million per year, the maximum energy savings by 1980 due to insulation would be about 250,000 barrels of oil per day. The cost of achieving these savings would total some $5 billion. In the absence of legislation, however, an individual homeowner would need to be convinced that the initial capital investment would be offset by lower annual costs. The estimated overall net monetary savings for each homeowner would total about $38 per year (111).

4/ It has been estimated (111) that the net additional cost of optimally insulating an 1,800 square foot house in the New York City area is $632. This is the cost of insulation above minimum FHA standards (pre-June 1971 standards) less the reduction in the cost of the furnace and air conditioner equipment required. "Optimally" insulated is defined as that providing the maximum net monetary saving to the owner.

The annual heat saving per house would be 66 million Btu. The capital cost of saving energy via house insulation is thus $9.58 per million Btu per year. To save the equivalent of 250,000 barrels per day of oil would cost $5,078 million and require the optimal insulation of 8 million houses.

Although there is a potential for energy saving in industry, much of the industrial sector is already utilizing energy in a fairly efficient manner. Additional saving will come about in time as less energy efficient equipment is replaced. This trend would be greatly accelerated if fuel prices were to increase significantly. The Paper and Allied Products sector was mentioned as one susceptible to such a reduction by OEP. This industry consumed 1,121 trillion Btu (112) in 1968 and had depreciable assets in that year valued at $14.4 billion (113). If process improvement to realize a 10-percent fuel saving required replacement of 10 percent of the industry's depreciable assets, the capital cost of energy reduction would be $12.85 per million Btu reduction per year. At this rate, the paper industry would be able to save the equivalent of 53,000 barrels of oil per day by the expenditure of $1.44 billion.

Another aspect of the Nation's total energy balance is programmed inefficiencies resulting from attempts to achieve other national objectives that are in direct conflict with a major national need to increase efficiencies. The dramatic increase in gasoline demand is a case in point. The effect of vehicular emission standards is already being seen in the Nation's demand for gasoline. In recent years, passenger car registrations have been increasing at a rate of 3 to 3.5 percent per year.

However, during the first half of 1972, gasoline consumption has jumped to 6.5 percent over the previous year. The difference of 3 percent is equivalent to a consumption of about 180,000 barrels of oil per day. Nothing in terms of vehicle population or miles travelled per vehicle could alone account for such a sharp increase. The post-1968 emission controlled vehicles are obviously producing an upward pull on gasoline demand which will become increasingly greater with each passing year as controlled vehicles become a greater part of car populations. By 1980, the increase in oil requirements due to emission controls is estimated to range from 800,000 to 1,200,000 barrels each day (105).

Current proposals to reduce the lead content of gasoline will also have a dramatic impact on petroleum consumption. If enacted, these proposals are estimated to increase 1980 oil requirements 1.2 million barrels per day (114).

The full ramifications of what appears to be a simple solution to a problem are often overlooked. For example, reducing the lead content in gasoline is relatively easy to achieve, but this measure would require additional crude oil for refinery runs to produce gasoline of acceptable specifications plus additional oil owing to decreased efficiencies in the use of gasoline in motor vehicles. Domestic production cannot be increased to offset this incremental demand, and dependence upon Eastern Hemisphere oil supplies would increase about 20 percent over what is currently projected, with attendant increase in problems of security, foreign policy, and balance of trade. To ship and process 1.2 million additional barrels of oil daily will require 76 additional arrivals each month of the 70,000-dead-weight-ton vessels now serving U.S. ports and 10 additional new refineries of the average size now being constructed.

The cost of lead restrictions is estimated at $48 billion in this decade, and the incremental balance of trade deficit would total $1.6 billion each year.

The discussion above is not meant to imply that changes are not needed in the Nation's energy consumption patterns. The Nation has been using low-cost energy in many wasteful ways. The point is that physical limitations do exist and that simple solutions to a particular problem may have far reaching effects. These changes are not free, but, indeed, may be very costly. The illustrations above indicate the complexity of the problem and suggest the need to have a wide range of options available for energy related decisions with sufficient time allowed for implementation.

Perhaps even more important and less predictable are the changing habits and preferences of society's members.

b. Limit Economic Growth

The basic premise of this alternative is that industrial and economic growth and clean environment are mutually incompatible. In this regard, a recent review (110) concluded that:

> In the 15 years between 1950 and 1965, the U.S. labor force increased by 12 million. It took an average annual increase in Real Gross National Product of 3.75 percent to provide jobs for these new workers. By comparison, 23 million people will enter the labor market between 1970 and 1985; and assuming that there is the same rise in productivity as we experienced between 1950 and 1965, it will take an annual increase in Real Gross National Product of 4.25 percent just to keep unemployment at the current level.

With these figures in mind, the impact of zero economic growth on the job market and national economy is clear.

What the advocates of the zero economic growth philosophy seem to minimize is that society is going to need the jobs and goods and services that industry provides. Advocating zero growth also means telling the disadvantaged members of our society, who strive for a better way of life, that their goals are unattainable.

To reduce energy demand by the equivalent of the projected 1985 shale oil production would entail reduction of energy consumption from petroleum by an estimated 4.2 percent. The mechanisms by which demand would be reduced are not yet clear. Most entail some method of regulation or taxation to alter consumption patterns. The OEP study contends that there are basically three ways to implement their suggested energy conserving measures. These are standards and regulations, tax incentives, and education. Many of the demand reducing measures depend on education and persuasion and will involve a change in public habits and tastes. Even apart from this, all three of the suggested devices require public acceptance in a free society. The imposition of standards and regulations or additional taxes will reduce individual freedom in consumption. Education probably tends to enhance the individual's capacity to make rational decisions and to expand his range of choices. The OEP potential energy savings are based on the assumption that all the measures would be implemented. On the other hand, they caution that no "in-depth analysis of feasibility or consumer acceptance has been undertaken." It seems reasonable to expect that some measures will be rejected on the basis of cost or preferences. Of course, there are suggestions by others.

Mr. McCloskey suggests:

> A short-run strategy would involve the following changes in public policy: ending or reducing the many biases in public policies which provide incentives to energy growth; maintaining and strengthening environmental constraints on energy growth; reducing energy demands by educating the public to understand the importance of conservative use of energy; encouraging intensified research and development in order to achieve greater efficiencies in energy utilization and in order to find new, more environmentally acceptable, energy sources; and discouraging growth in industries that are the most profligate consumers of energy. Coordination of these efforts would be facilitated through the establishment of new government agencies, specifically geared to respond to the energy problem. Each of these changes would involve efforts that would go well beyond the traditional bounds of energy policy, and all could have profound economic and social impacts. Yet changes are already beginning to occur in all these fields, and environmentalists are determined to promote them (115).

The Blueprint for Survival provides the following "strategy for change":

> The principle conditions of a stable society, one that to all intents and purposes can be sustained indefinitely while giving optimum satisfaction to its members, are: (1) minimum disruption of ecological processes; (2) maximum conservation of materials and energy or an economy of stock rather than flow; (3) a population in which recruitment equals loss; and (4) a social system in which the individual can enjoy rather than feel restricted by, the first three conditions.
>
> The achievement of these four conditions will require controlled and well-orchestrated change on numerous fronts and this change will probably occur through seven operations: (1) a control operation whereby environmental disruption is reduced as much as possible by technical means; (2) a freeze operation, in which present trends are halted; (3) a systemic substitution, by which the most dangerous components of these trends are replaced by technological substitutes, whose effect is less deleterious in the short term, but over the long-term will be increasingly ineffective; (4) systemic substitution, by which these technological substitutes are replaced by "natural" or self-regulating ones, i.e., those which either replicate or employ without undue disturbance the normal processes of the ecosphere, and are therefore likely to be sustainable over very long periods of time; (5) the invention, promotion and application of alternative technologies which are energy and materials conservative, and which because they

are designed for relatively "closed" economic communities are likely to disrupt ecological processes only minimally (e.g., intermediate technology); (6) decentralization of policy and economy at all levels, and the formation of communities small enough to be reasonably self-regulating and self supporting; and (7) education for such (116) communities.

c. Environmental Impacts

To the extent that the costs of pollution associated with production and consumption of energy are not adequately reflected in the prices paid for such energy, utilization of energy resources has been economically inefficient. Inclusion of costs of pollution mitigation as a result of institution and enforcement of pollution standards will tend to cause energy to be used more efficiently in the future. Such higher prices will reduce the demand for energy below the levels that would be reached if pollution costs were not reflected in the energy prices, providing the demand for energy is significantly elastic.

(1) Mobile Sources.- If the demand for petroleum were reduced by 1 million barrels per day in 1985, environmental damages to the air associated with the consumption of this much oil would be avoided. For example, the following tabulation provides estimated quantities of air polluting emissions from mobile equipment for 1985 (117).

Table V-1 -Estimated Emissions from Mobile Equipment
(Millions of tons per year)

	Autos	Trucks & Buses	Aircraft	Off-Highway	Total
Hydrocarbon	0.9	1.4	0.1	0.5	2.9
Carbon monoxide	12.7	14.2	.8	3.4	31.1
Nitrogen oxide	1.3	1.7	.09	1.1	4.2
Particulate	.1	.2	.05	.1	.5

With crude oil demand estimated to reach a minimum of 26 million barrels per day by 1985 and a transportation use of 13 to 14 million barrels per day (118) a 1-million-barrel-per-day reduction would represent a 7.7- to 7.1-percent reduction in use in mobile equipment. This reduction in demand presumably would result in an equivalent reduction from the air polluting emissions from the mobile equipment as estimated above.

(2) Stationary Sources. - Another major air pollutant, sulfur dioxide (SO_2), is emitted from stationary plants. The following tabulation shows estimated quantities of SO_2 emissions which are projected to occur in 1985 from plants burning petroleum and coal and from plants smelting copper, lead, and zinc. These estimates are based on the assumption that the same air pollution standards will be in effect in 1985 as were in effect in 1965. Thus, the quantities of SO_2 emission are likely to be considerably overestimated if the technology necessary to meet more recent standards is developed.

Projected SO_2 Emissions from Stationary Plants, 1985-1/

(Million tons per year)

Coal	106
Petroleum	81
Smelting Copper	28
Lead	4.3
Zinc	3.5
Total	222.8

1/ Interpolated from the figures in the source table for 1985 and 1990. Source: Reference 23, p. 326.

From the above, a reduction of 1-million-barrels-per-day would be equivalent to a 20-percent reduction in petroleum used for stationary plants and would reduce SO_2 emissions by 12.5 million tons in 1985. However, the 1-million-barrel-per-day reduction in demand could only reduce either auto emissions <u>or</u> stationary plant emission, or some combination, depending on where the reduction occurs.

(3) Costs. - Another major consideration when evaluating the environmental impact resulting from reducing demand for energy is that of the costs involved in the related reduction in environmental damage. Parts 1 and 2 above show that certain atmospheric contamination would be prevented by not producing, transporting and consuming the energy resources derived from 1-million-barrels-per-day of shale oil. Where pollution standards are introduced and enforced, causing the amount of environmental damage per unit of energy consumed to

decrease with time, the incremental environmental benefit of the regulation declines; the associated costs of the regulation do not necessarily decline. Achieving these environmental benefits, by means of reduction of energy demand, would be less costly than achieving the same benefits through introduction of regulatory standards after having produced and consumed the extra energy.

Assuming that energy demand is reduced by the energy equivalent of 1 million barrels of crude oil per day, and that this reduction is to be accomplished through a reduction in petroleum use in mobile equipment, Table V-2 shows the trend in quantities of air pollutants estimated to be emitted from mobile equipment using petroleum products (23). The impact of the stricter air pollution standards is quite apparent from the tabulated data. Interpretation of these data is more complex.

Table V-2 - Estimated Emissions from Mobile Equipment
(millions of tons per year)

	1970	1975	1980	1985
Hydrocarbons				
Autos	11.0	5.9	2.4	0.9
Trucks & buses	1.9	1.7	1.4	1.4
Aircraft	.3	.2	.1	.1
Off-highway	.6	.6	.6	.5
Total	13.8	8.4	4.5	2.9
Carbon Monoxide				
Autos	54.3	40.6	24.3	12.7
Trucks & buses	17.4	16.2	14.0	14.2
Aircraft	.4	.5	.7	.8
Off-highway	5.3	5.5	4.4	3.4
Total	77.4	62.8	43.4	31.1
Nitrogen Oxide				
Autos	5.7	5.0	2.8	1.3
Trucks & buses	1.4	1.6	1.5	1.7
Aircraft	.05	.06	.08	.09
Off-highway	.9	.9	1.1	1.1
Total	8.1	7.6	5.5	4.2
Particulates				
Autos	.3	.3	.2	.1
Trucks & buses	.2	.2	.2	.2
Aircraft	.04	.04	.04	.05
Off-highway	.2	.2	.2	.1
Total	.7	.7	.6	.5

Ideally, the attainment of these standards would be achieved through a combination of methods that will attain the standards and minimize costs. Alternative methods include both hardware development for vehicle emission control and nontechnical solutions that would decrease demand.

Since the cost per unit of pollution that is removed increases exponentially by the application of control hardware, the cost to remove the last unit of pollution to attain the 1985 standards will be significantly higher than the cost required to remove the first pollution unit in 1970. In addition, hardware pollution controls increase energy consumption (less miles per gallon).

From the foregoing, it may be concluded that an equal reduction in energy demand in 1970 and in 1985 would be <u>more</u> costly in 1985 per unit of pollution avoided. However, it may be cheaper to remove the last pollution units through a decrease in demand rather than through the application of control hardware. Such a demand reduction over the short-term would also conserve supplies of depletable energy resources. The benefits and costs of reduced energy use is complex and will depend upon where the reduction is to occur and the level and method of meeting pollution standards. All of these will be reflected in the relative prices of alternative energy fuels.

There is little evidence concerning the price elasticity of energy demand. In some applications, notably in automobiles, demand may be quite inelastic, i.e., higher prices would have little effect on demand. Gasoline and lubricating oils represent only 25 percent of the total per mile cost of automobiles (119); thus, a 4-percent rise in oil prices would raise total automobile costs only one percent. Given the substantial capital investments in automobiles and other energy-consuming facilities, there may be considerable reluctance to incur costs of replacement with lower-consumption equivalents.

As indicated above, the minimum petroleum and energy demand estimates include increased efficiency in use to the extent it is expected to occur through the operation of current policies and economic adjustments.

Such trends could be increased by Government regulations and education efforts. Increasingly, the private sector and the Government are seeking ways to conserve energy.

(4) Summary - When demand is reduced the impacts associated with finding, producing, and processing the energy "raw materials" (whatever they might be) will be reduced. Furthermore, those impacts associated with consuming the extra energy-producing products will be avoided. The specific impacts, i.e., commitments of and disturbances to land, water, air, people and mineral resources, will depend on which of the several alternative sources the energy would be drawn upon as detailed in Chapter V, Section B of this volume.

A reduction in demand would result in reduced levels of air contaminates emitted by stationary and/or mobile sources. The benefits to be derived from successful implementation of this alternative would be most likely directed toward the larger metropolitan areas.

2. Increased Oil Imports

An alternative to oil shale development might be increased oil imports. The projected production of shale oil by 1985 with the oil shale development program would be about 1 million barrels per day, thus an alternative source of energy might be increased imports of 1 million barrels per day by 1985. The quantities of crude oil imported are controlled by policy set by the President. The present license fee program can be adjusted from time to time with a conceivable adjustment in the amounts of oil being imported. The details of the oil imports program and the license fee system are described in the following sections a and b.

a. Oil Import Controls

Imports of crude oil, unfinished oil, and petroleum products have been controlled since 1959 by Presidential Proclamation 3279. The statutory foundation for Presidential action originates with Section 232 of the Trade Expansion Act of 1962.

On January 26, 1973, the President announced a reorganization of the executive offices which, among other things, delegated the responsibilities of OEP pertaining to oil imports to the Treasury Department. The pertinent parts of the reorganization are as follows:

> Investigation of imports which might threaten the national security--assigned to OEP by Section 232 of the Trade Expansion Act of 1962--would be reassigned to the Treasury Department, whose other trade studies give it a ready-made capability in this field; the National Security Council would maintain its supervisory role over strategic imports.

> The Oil Policy Committee will continue to function as in the past, unaffected by this reorganization, except that I will designate the Deputy Secretary of Treasury as chairman in place of the Director of OEP. The Committee will operate under the general supervision of the Assistant to the President in charge of economic affairs.

The Committee is composed of the Secretaries of State, Treasury, Defense, Interior, and Commerce, the Attorney General and the Chairman of the Council of Economic Advisors. The Chairman (Deputy Secretary of Treasury) of the Oil Policy Committee makes his oil import recommendations to the President.

On April 18, 1973, the President issued Proclamation 4210, modifying Proclamation 3279.

> By suspending tariffs on imports of petroleum and petroleum products and by shifting to a system whereby fees for licenses covering such imports shall be changed and whereby such fees may be adjusted from time to time, as required in order to discourage the importation into the United States of petroleum and petroleum products in such quantities or under such circumstances as to threaten to impair the national security; to create conditions favorable, in the long range, to domestic production needed for projected national security requirements; to increase the capacity of domestic refineries and petrochemical plants to meet such requirements; and to encourage investment, exploration, and development necessary to assure such growth.

b. <u>License Fee Program</u>

1. Effective May 1, 1973, any person or company wishing to import crude oil and petroleum products may do so simply by applying for an import license to the Department of the Interior, Office of Oil and Gas and by paying the appropriate license fee.

2. Also effective May 1, 1973, existing tariffs on crude oil and refinery products will be suspended. In their place, license fees will be imposed on imports equal,

in the long run, to 1/2¢ per gallon of crude and 1 1/2¢ per gallon for unfinished oils and all refinery products. Fees will be paid to the Office of Oil and Gas at the time of application for an import license.

3. These long-term fees will take effect at the end of 1975. In the meantime, license fees will be stepped-up over time. The following schedule of fees will apply to all but exempt imports.

Schedule of License Fees
(cents per barrel)

Product	May 1 1973	Nov 1 1973	May 1 1974	Nov 1 1974	May 1 1975	Nov 1 1975
Crude Oil	10½	13	15½	18	21	21
Residual fuel oil, unfinished oils, distillates and refinery products other than gasoline	15	20	30	42	52	63
Gasoline	52	54½	57	59½	63	63

4. All import licenses outstanding as of May 1, 1973, will be honored by the United States Government license fee-exempt.

5. Certain crude oil and product imports will also be exempt from license fees for a limited period of time after May 1, 1973. Current program participants will be granted yearly allocations, exempt from license fees, equal to import levels in effect as of April 1, 1973, for residual fuel oil and quota levels in effect as of January 1, 1973, for crude oil and petroleum products other than residual fuel oil. The exempt allocations will be granted through April 30, 1974, after which the level upon which allocations are based will be reduced by a fraction of the original level each year for the next seven years. No allocations will be granted license fee-exempt beyond April 30, 1980. The schedule by which exemptions will be phased out is:

Percentage of Initial Allocation
Exempt from License Fees

After April 30	Percentage
1973	100
1974	90
1975	80
1976	65
1977	50
1978	35
1979	20
1980	0

6. Crude oil import license not subject to license fees will continue to be convertible to unfinished oils and finished products at existing rates (15 and 1 percent, respectively) until January 1, 1974. Crude oil licenses subject to license fees will not be convertible.

7. Imported crude oil may be exchanged for domestically-produced crude oil at a rate negotiated by the parties involved in the exchange.

8. Imports of ethane, propane and butane will be exempt from license fees. License fees will also be refunded on quantities of imported crude used to produce asphalt.

9. Companies building new refineries or petrochemical plants or expanding existing refineries or petrochemical plants coming on-stream after April 30, 1973 will be granted license fee-exempt allocations equal to 75 percent of their additional inputs for their first five years of operation. Throughput earning exempt allocations under these provisions will not be counted as certified refinery inputs in estimating exempt allocations.

10. Deepwater terminal operators in District I currently under the program will be allowed to import 50,000 barrels per day of No. 2 fuel oil exempt from license fee. After May 1, 1973, these imports of No. 2 fuel oil must be produced from Western Himisphere crude oil unless otherwise exempted.

    The Western Hemisphere preference requirement will apply only if the Chairman of the Oil Policy Committee determines that imports from the Western Hemisphere are available. If they are not available, license fee-exempt imports will be permitted from other sources.

The Chairman of the Oil Policy Committee shall determine whether, because of supply, price, and other considerations, the Western Hemisphere restriction is unduly restrictive and may suspend or reimpose this restriction as needed.

11. Import licenses for crude oil and products produced in all Western Hemisphere countries will be subject to license fees unless otherwise exempted. The fee exempt volume of imports for all Canadian and Mexican crude oil and products will be established at the average daily volume of imports into the United States under the existing quotas or during the first quarter of 1973, whichever is higher. The State Department will advise the OPC from time to time of any changes in the license fees on these imports which it deems to be in the security interests of the United States. Product imports for which no quota now exists will be allowed into the country under the license fee schedule presented in Section 4.

12. Imports of crude oil and finished products to Puerto Rico will be subject to the same license fees after May 1, 1973 as the Mainland and will be allowed from anywhere in the world.

    a. All finished products refined in Puerto Rico will be shipped to the Mainland license fee-exempt.

    b. All license fees on Puerto Rican imports of oil will revert to the Commonwealth of Puerto Rico.

    c. Imports of crude oil and unfinished oils now governed by contractual agreements between Puerto Rico and the U.S. Government will be exempt from license fees for the remainder of the terms of these contracts. Upon expiration of these contracts, the exemption will be phased out according to the schedule in paragraph 7.

    d. Imports of crude oil and unfinished oils used to manufacture finished products shipped to the Mainland under the historical classification based on shipments prior to 1965 will be exempt from license fees and that exemption will be phased out over the same schedule provided for exempt refinery allocations.

    e. Finally, the Commonwealth will be allowed to impose restrictions on shipments to the Mainland of petrochemical and intermediates and products necessary to assure continued growth of the downstream petrochemical industry in Puerto Rico. However, ultimate responsibility for determining import policy will reside with the Chairman of the Oil Policy Committee.

13. Imports of crude oil and finished products into the Virgin Islands and free trade zones would be exempt from license fees after May 1, 1973. Exports from the Virgin Islands and entries from free trade zones into the United States will be subject to fees. However, the existing refinery in the Virgin Islands may continue to export to the United States license fee-exempt those products governed by contract with the United States Government for the term of that contract.

14. All imports from possessions outside the United States customs territory will be subject to license charges.

15. Imports under existing allocations to the Department of Defense will be allowed license fee-exempt. These allocations will be phased-out over the same period allowed for exempt allocations.

c. Balance of Payments

The United States is currently experiencing large deficits in its balance of payments and more specifically in its balance of trade. Such continued deficits have a deterimental effect on the stability and value of the dollar. The reduction of petroleum imports by one million barrels per day could have a positive effect on balance of payments of as much as $1 billion per year.

d. International Uncertainties

Future increases in imports can be expected to come from those countries which have the largest petroleum reserves. This indicates a greater reliance will be placed on the Persian Gulf which has 67 percent of the free world's reserves, and North Africa with 13 percent. Thus, the United States will become increasingly dependent on the Eastern Hemisphere for about three-fourths of petroleum imports in 1985.

In considering increased imports as an alternative to 1 million barrels per day of shale oil, a particular concern is the security of Middle East supply sources which have been characterized by instability and international tension. The supplies of oil from that area may be subject to interruption for political or economic reasons with little or no advance warning. In their comments relative to the Department of the Interior's Analysis of the Economic and Security Aspects of the Trans-Alaska Pipeline (15), the Secretaries of State and Defense and the Director of the Office of Emergency Preparedness indicated their concern that "failure to obtain desired additional oil supplies (from the North Slope) will necessitate increasing imports from insecure sources to such high levels that a long-term foreign supply distribution could slow down industry and imperil our national security." Failure to bring shale oil into production would raise dependence on imported oil from a range of from 33 to 41 percent to a range of from 37 to 45 percent in 1985.

A systematic treatment of the oil import subject is contained in the report of the Cabinet Task Force on Oil Import Control (18). The majority of the task force concurred that no more than 10 percent of U.S. requirements should be met by imports from the Eastern Hemisphere. Such a limitation would require some type of continuing import controls.[1/]

Eight major difficulties that might attend dependence on foreign supplies were identified by the Cabinet Task Force (18):

"(1) War might possibly increase our petroleum requirements beyond the ability or willingness of foreign sources to supply us.

(2) In a prolonged conventional war, the enemy might sink the tankers needed to import oil or to carry it to market from domestic production sources such as Alaska.

(3) Local or regional revolution, hostilities, or guerilla activities might physically interrupt foreign production or transportation.

(4) Exporting countries might be taken over by radical governments unwilling to do business with us or our allies.

(5) Communist countries might induce exporting countries to deny their oil to the West.

(6) A group of exporting countries might act in concert to deny their oil to us, as occurred briefly in the wake of the 1967 Arab-Israeli war.

1/ A subcommittee of the House Committee on Interior and Insular Affairs held extensive hearings on the Task Force report. See U.S., Congress, House, Committee on Interior and Insular Affairs, Oil Import Controls Hearings, before the subcommittee on Mines and Mining, March and April 1970.

(7) Exporting countries might take over the assets of American or European companies.

(8) Exporting countries might form an effective cartel raising oil prices substantially."

A subsequent study made by the Petroleum Industry Research Foundation reexamined the principal assumptions and conclusions of the Task Force regarding U.S. dependency on oil imports in 1980 under various price assumptions (124). This study raised further questions as to the extent to which the United States should depend on Middle Eastern and North American petroleum sources.

A Joint Economic Committee Background Study relative to the April 15, 1971, OEP Report on price increases in crude oil and gasoline raised numerous questions relative to the need for, and effectiveness of, the Mandatory Oil Import Program (125).

The security problem has two principal parts: (1) a question of military security, and (2) a question of economic security. Both advocates and critics of the Oil Import Program have tended to focus principally on the economic security issue.

The crux of the argument against importing a substantial fraction of the nation's oil is that the sources of additional foreign oil, in general, the Middle East and North Africa, are "insecure" and might be tempted to withhold oil exports to the United States for political and/or economic gain (generally in an environment short of war, though local conflicts in volatile areas are not inconceivable).

A study by Drs. Schurr and Homan for Resources for the Future (19) notes that the question of supply interruptions

> "...needs to be dealt with in the interests of both the importing and exporting countries because supply interruptions are economically damaging to both. Not only do they have sharp short-run effects which are economically painful, but their long-run consequences can also be damaging if channels of commerce are diverted into

> alternatives which impose a permanent economic penalty upon both those countries that sell oil and those that buy."

However, this interdependence does not guarantee that interruptions will not occur. The study points to interruptions from the shutdown of Iranian production beginning in 1951, the closure of the Suez Canal and attendant lengthening of transportation routes in 1956-57 and again from 1967 to the present, and quotes Walter Levy, a leading international oil authority and consultant, as saying:

> Nor can the West rely on the importance of uninterrupted oil operations and oil revenues to Middle East governments as a deterrent to hostile actions. Economic considerations, important as they are to the relatively impoverished countries of the area, become insignificant when confronted with political necessities or political pretentions.

Eleven major oil-producing countries have joined the Organization of Petroleum Exporting Countries (OPEC) in an attempt to obtain greater bargaining power in their dealings with the international oil companies. A 5-year agreement reached in 1971 with the Persian Gulf countries provides for substantial increases in the payments to the host governments. The other members followed with equal or larger increases. In the second year of the agreement, the OPEC countries have been given further increases to compensate for the devaluation of the dollar. They also seek participation as part owners in the oil companies exploiting their resources. If OPEC can maintain cohesiveness in the face of diverse national demands and historical relationships, continuing pressure for economic and political concessions by the oil-importing countries may be anticipated.

d. <u>Potential Environmental Impact of the Alternative</u>

Increasing imports in lieu of shale oil production would affect the environment through: (1) Provisions needed to protect the national security from interruption of oil supplies, and (2) the additional oil handling associated with the vessels and related facilities required to transport and handle additional imports.

Security measures which do not require precrisis investment (drawdown, rationing, etc.) would have little environmental impact. Storage in steel tanks or in cavities created in salt domes would require importing oil for the inventory in addition to that for current demand, with associated tanker risks discussed below. Storage of 1 million barrels of oil in steel tanks would require approximately 25 acres (assuming a 16-foot high dike is used to protect against accidental spills) and the danger of leakage would increase as tanks age. Storage in cavities in salt domes would remove the requirement for aboveground tanks; however, pipelines, injection, and extraction facilities would still be required. Also, it might be anticipated that due to the attraction of the oil to the mineral matrix, less than 100 percent of the oil injected into cavities in salt domes can be extracted. Quantities in excess of the desired emergency supply would have to be imported and a portion of this would be unrecoverable. Salt removed from the salt cavities during oil extraction, if not handled properly, could be a source of pollution through leaching of the salt by water.

Development of spare shut-in capacity in the Naval Petroleum Reserves, on other lands purchased by the Federal Government, or through a Federal prorationing system would entail environmental impacts similar to those associated with exploration and development both on- and off-shore (described in the subsequent Section B-1 of this analysis). Potential production at Elk Hills is not equal to those from the proposed oil-shale development, so that development of shut-in capacity at Elk Hills alone would not suffice.

The environmental impacts of increased imports arise from three sources: (1) Increased ship traffic to the subject ports, (2) the construction and operation of increased capacity of terminals for the receipt of the oil, and (3) the transportation of the oil from offshore terminals to coastal refineries.

The worldwide tanker casualty analysis indicates that 0.0192 percent of the oil transported is spilled, exclusive of transfer operations. Applied to the 1,000,000-barrel-per-day throughput, this amounts to approximately 192 barrels per day discharged from casualties. However, it must be recognized that an average calculation such as this has little meaning from an environmental impact standpoint. Such impacts could be nominal where small spills are involved or where the spill occurs in such a manner as to have little impact on coastal or restricted water areas. By contrast, a single catastrophic incident can have disastrous results. In March 1967, for example, the tanker Torrey Canyon ran aground at Seven Stones Reef, about 15 miles offshore Cornwall, England. It was carrying 821,000 barrels of Kuwait crude oil. The oil lost remained at sea from one to three weeks before coming ashore at various locations. A recent study (20) showed that 75 percent of past major spills were associated with vessels (Figure V-1). Further, the source of spills of more than 2,000 bbl was likely to be a tanker, and the spill would occur within a few miles of shore and be noticable for

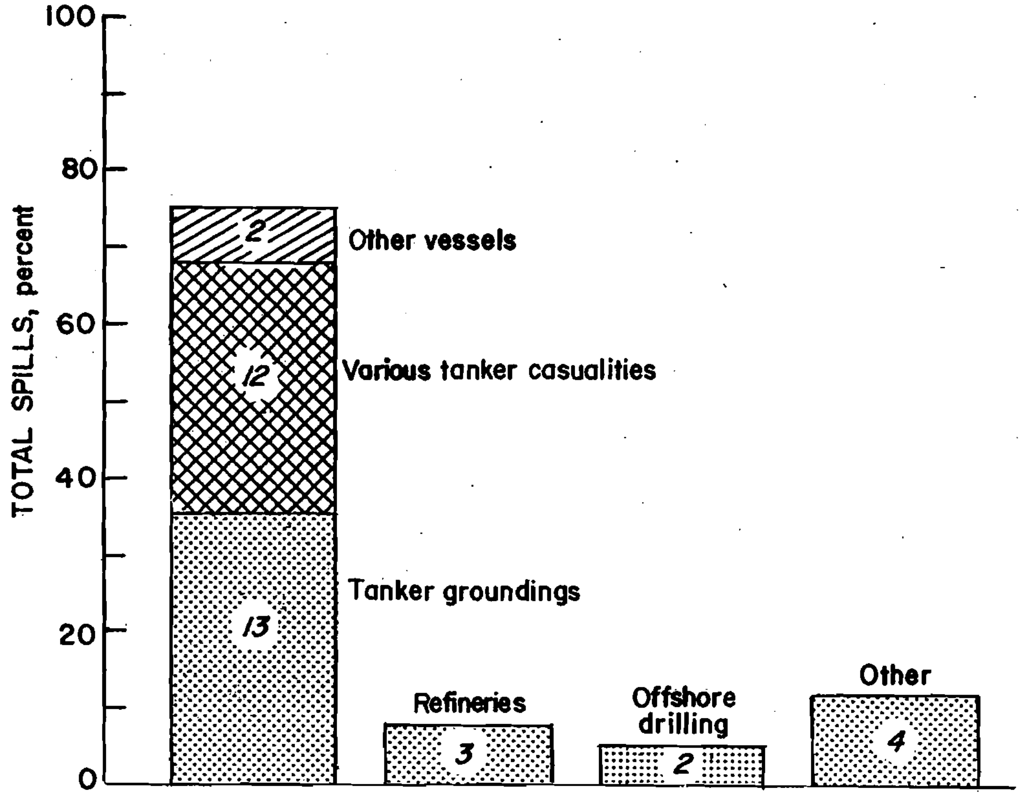


Figure V-1 —**Source of spill (Data from 36 incidents).**

Source: National Petroleum Council, Environmental Conservation, v. 2, February 1972, p. 242.

more than five days. Shorelines threatened would be at least partially recreational with a reasonable chance that only light coastal contamination would occur (21).

The impact on the estuaries and wetlands from oil spills is a function of size, time, weather, and water currents as well as seasons. In an estuary, the movement of an oil slick is complicated by the oscillatory nature of tidal currents. During ebb tide, the slick or plume will extend down the estuary; during flood tide, the plume will extend up the estuary. In general, it appears that single exposures to heavy concentrations of oil on marsh areas will temporarily destroy vegetation but does not appear to cause any significant long-range damage. Chronic exposures would impose greater environmental damage in estuaries and marshes because of the continual rekill of new vegetation and complexing with pollution from other sources. Thus, chronic oil spills will likely degrade water quality and have long-term toxic and subtoxic effects on the marine environment.

Regardless of the source and size of the oil spill, several biological responses are important: (1) immediate lethal toxicity; (2) lethal or sublethal effects of direct coating of marine life by oil substances; (3) altered behavioral activities; (4) incorporation of aromatic hydrocarbons into the food chain; and (5) changes in habitat. In general, because of high dilution factors and widespread biotic populations, offshore areas have greater assimilative capacities and are relatively less vulnerable than shoreline or estuarine areas to critical environmental damage from chronic low-level spills.

Finfish and other mobile pelagic organisms which can detect low concentrations of oil in seawater presumably avoid higher concentrations. The eggs, larvae, and juvenile stages of these fish are generally more susceptible to the effects of oil than are the adults.

The benthic fauna may be divided into four categories: gastropods (snails, limpets), bivalves (shellfish), crustaceans (shrimp, lobsters), and all others (worms, anemones). Apparently gastropods are the most resistant to the effects of oil; crustaceans are the most sensitive.

Apparently marine mammals fail to recognize an oil slick until coating is inevitable. Mammals must periodically surface for air and in doing so are in danger of being coated with or inhaling oil. At present, however, marine mammal mortalities can only be indirectly related to such coating.

There is almost unanimous agreement that birds have probably suffered more from oil spills that any other group of organisms. Bird casualties from oil pollution number many thousand each year. Tainting of marine organisms also results from incorporation of hydrocarbons, causing the development of an objectionable taste.

The oil spill problem is a subject involving considerable study effort. The first report of the President's Panel on Oil Spills presents considerable detail relative to this subject (22).

3. Modification of Market-Demand Prorationing Systems

The objective of this alternative would be to obtain increased production from developed reserves that are being produced at less than maximum efficient rates. The alternative would require those states operating prorationing systems to revise their laws and regulations to permit such full production. This cannot be considered as an alternative to projected supplies from shale oil because declining crude oil productive capacity and increasing demand for crude oil will require production at maximum efficient rates (MER) in any event (23-25).

Elimination of state market-demand prorationing would result in very little additional crude oil and natural gas production. Important exceptions to MER production currently remain only in Elk Hills Navel Petroleum Reserve (which is not subject to state market-demand prorationing and which will be discussed in section B-1-b of this volume) and a small number of fields in Louisiana and Texas. In 1972 Louisiana officials were reviewing producing potentials on a field by field basis. By early fall of 1972, the state was essentially producing at MER.

Only three Texas fields, East Texas, Kelly-Snyder, and Tom O'Connor, were restricted below 100 percent of their respective market-demand at the time of this writing. Conservation problems encountered at higher operating rates have compelled reduced production in these fields while unresolved issues of correlative rights to the crude oil also preclude higher production from East Texas. A very few Texas fields have MER's in excess of 100 percent of their market-demand and of these the largest, Yates, also has unresolved problems of correlative rights. Projections of United States petroleum production and requirements indicate that remaining potentials and newly developed capacity will be put into production as consideration of conservation, environmental protection and equity permit and the issue of market-demand prorationing will remain moot.

4. Modification of FPC Natural Gas Pricing

This alternative postulates increases in prices for natural gas to provide additional incentives to natural gas producers to increase natural gas exploration and development. Some additional crude oil would probably be discovered as a result of increased exploration for gas. Also, some crude oil demand would be displaced by incremental natural gas supplies. Since natural gas is a clean fuel as compared to oil, this displacement would result in a net environmental benefit. However, it is not considered to be substitution that could be utilized to totally offset a major portion of shale oil supplies.

In 1954, the Supreme Court ruled that producers of natural gas for sale in interstate commerce are subject to regulation under the Natural Gas Act. Since then sales, including pricing, of gas destined for interstate markets has been subject to Federal regulations as administered by the Federal Power Commission (FPC).

The FPC changed its method of price regulations in 1960 from an individual company "cost-of-service" method to an "area rate" concept which was upheld by the Supreme Court. Under the area rate method, average unit costs associated with all aspects of natural gas production are determined for a producing area instead of examining the costs of each producing company.

Concern has been voiced that interstate gas prices resulting from FPC actions have been so low as to retard development of new gas supplies while at the same time, inducing associated consumer preferences for gas over alternative fuels. (26)

Recognizing the need for new policy initiatives, the FPC has, within the past 2 years, taken a number of measures designed to increase gas supplies, including increased price ceilings (27). FPC raised rate ceilings by about 35 percent during 1968-70 and on July 16, 1971, in its Opinion No. 598, set new, higher ceiling rates for the South Louisiana area and provided for a system of incentives to promote dedication of gas reserves to the interstate market.

To provide additional incentives, the Federal Power Commission issued Order No. 455 on August 3, 1972, which provides an optional procedure for certificating new producer sales of natural gas. This new order does not replace geographical area pricing, but rather will provide, if upheld by the courts, an alternative procedure for certification of sales for new gas at rates above established area ceilings.

Alternative sources of gas, such as liquefied natural gas imports and the production of synthetic natural gas, still involve higher costs, however, than current regulated interstate prices of natural gas. It may be likely, therefore, that recent actions to permit higher wellhead gas prices will be followed by still other steps in this direction.

The most recent action in this direction was the announcement by the President in his second energy message (April 18, 1973) that he will submit legislation to amend the Natural Gas Act so that prices paid by interstate pipelines to producers for new supplies of domestic natural gas will be determined by the competitive forces of the market system rather than by the Federal Power Commission. This proposal would stimulate new exploration and development of domestic gas resources while maintaining current prices on present interstate supplies and eliminating any possibility of unfair gains at the expense of the consumer. The legislation includes provisions for the Secretary of the Interior to monitor the price of new supplies of natural gas, and impose a ceiling if circumstances should demand such action.

Estimated United States resources of oil and gas as yet undiscovered are sufficiently large to support an expanding rate of domestic production through 1985 and beyond. Recent levels of domestic exploration and development, however, have not been sufficient to prevent a decline in the Nation's proved reserves of both gas and oil.

Improved economic incentives, whether in the form of higher prices or otherwise, would most probably increase investment in stimulated recovery of known but not now recoverable gas and oil resources and would induce a higher rate of exploration for new gas and oil. However, the relationship between economic incentives and the level of expenditures for exploration cannot now be uniquely identified; even greater speculation must be attached to the degree of success in finding commercially viable oil and gas fields at any level of exploratory activity.

Potential Environmental Impact of the Alternative.

The principal impact of the alternative would be economic rather than environmental. Prices are almost certain to rise somewhat--probably substantially. Direct consumers of natural gas will have higher fuel bills; all consumers will feel the effects of increased fuel prices on the prices of goods or services which depend on gas used by industries and utilities. Consumers are far less likely, however, to be confronted by unavailability of gas under deregulation than under continued regulation. The environmental impact would result primarily from the additional exploration, development and production stimulated by the higher gas prices. Development of domestic natural gas would reduce the need for alternative energy supplies, for example, oil imports. The increased use of natural gas would therefore lead to lower amounts of air contaminants and could potentially reduce the nation's outflow of funds to help develop foreign supplies. However, higher prices could also stimulate alternative energy development such as nuclear explosive stimulation, LNG imports, and synthetic natural gas production. Discussion of specific environmental impacts, therefore, is not included because the environmental effects of the alternatives considered in this section would be reflected by increased production, the effects of which are considered in section B-1 of this volume.

B. Alternative Energy Sources

1. Increased Domestic Production of Petroleum

Discussion of additional domestic production of crude petroleum (and natural gas) must consider production from onshore and also from the continental shelf. A separate discussion of each follows.

a. Outer Continental Shelf (OCS) Production

This alternative would require increased exploration, development and production of crude oil from offshore areas. Supplies equal to all, or a significant part, of the projected 300,000 barrels in 1980 and 1 million barrels in 1985 daily from the shale oil would have to be developed and produced in addition to those supplies that are projected to be produced from OCS resources under the present leasing schedule during the same time frame.

In his April 18, 1973, Energy message, the President announced that he had directed the Secretary of the Interior to take steps to triple the acreage leased on the OCS for drilling for oil and gas by 1979. In response to the President's Energy Message the Department of the Interior on July 11, 1973, issued a proposed schedule of provisional OCS leasing calling for three sales per year of up to one million acres each.

He also announced that leasing would begin in new frontier areas including beyond the 200 meter isobath, and beyond the Channel Islands in the Pacific if the environmental impact statements indicate it can be done safely. He directed the Council on Environmental Quality, in cooperation with the National Academy of Sciences and other government agencies, to complete studies within one year on the environmental suitability of drilling on the

Atlantic OCS and the Gulf of Alaska. By 1985, this accelerated OCS leasing schedule could increase annual production by approximately 1.5 billion barrels of oil (approximately 16% of our projected requirements) above what would be expected if the current lease schedule were maintained.

The offshore areas of the United States are estimated to contain 186 billion barrels of crude oil and over 844 trillion cubic feet of natural gas resources, which are recoverable with existing technology. These amounts represent approximately 40% of the nation's total undiscovered oil and gas reserves and offer promising opportunities since most onshore areas have already been explored and developed.

The Federal Government has leased OCS lands since 1954. Currently, leases in the OCS are producing over 400 million barrels of oil and about 3 trillion cubic feet of natural gas annually.

In 1969 regulations of the Department of the Interior governing leasing and operations by lessees on the OCS were extensively revised and strengthened after the problem in the Santa Barbara Channel. Since then, improvement of these standards for safety and pollution control has been a continuing effort covering a wide range of operations including drilling procedures, well abandonments, well completion procedures, pollution and waste disposal, and procedures for the installation and operations of platforms and pipelines. Inspection procedures have been standardized and a statistical basis for inspection strategy has been developed. The OCS field inspection staff has been tripled since 1969. Six full-time helicopters are in use and a radio communication system has been installed. The revisions and strengthening of OCS operating standards and the increase in surveillance personnel have resulted in a marked improvement in OCS operations with regard to oil spills. There were no major oil spills in 1972. Minor oil spills in 1972 were reduced by 45 percent from 1971.

Changes that could be beneficial to stimulation of additional development include price increases, subsidies, tax benefits, and changes in leasing procedures. The cost and effectiveness of such changes are unknown. The timeliness and the volumes of increased supplies that would result from increased incentives are also unknown. It is estimated that up to 12 years lag time will exist between leasing and production in the frontier areas. To provide the additional production equivalent to the projected shale oil supplies, drilling efforts would have to be increased from forty to sixty-six percent on the OCS. Drilling rig availability might be a major problem. Less than 100 mobile drilling rigs were operating in domestic offshore waters in 1971. Furthermore, no leasing in new OCS areas will be initiated until further environmental, natural resource, economic and geophysical studies have been completed and all requirements of NEPA have been met. With these uncertainties there is a real possibility that production resulting from further increased leasing schedules would not be able to completely offset the projected shale oil development, after meeting the supply expected from the current leasing schedule.

(1) Potential Environmental Impacts. - The environmental impact discussed below is based on past leasing and production experience in the Gulf of Mexico. Environmental information has not been developed to a similar degree for frontier areas. However, that data is currently being accumulated, and even though it is realized that environmental conditions in these areas differ from currently producing OCS areas, it is believed that the same categories of impacts will be encountered.

The potential environmental impacts that are encountered from OCS leasing and production include impacts on air and water quality, commercial and sport fishing, shipping, recreation and tourism, beach, and marsh, estuarine, and seaward biota. These impacts result from exploratory surveying, platform (structure) placement, normal drilling activities, initiation of production, and storage and transportation of produced oil including pipeline construction. Related activities which can cause impacts are debris and waste water disposal. Unpredictable activities such as accidental spilling of oil as a result of blowouts or transportation to refineries contribute to the impacts.

Possible environmental impacts from OCS oil and gas development are covered in detail in a final environmental statement issued by the Bureau of Land Management, U.S. Department of the Interior (28) (hereinafter referred to as the OCS statement).

(a) Exploratory Surveying. - The initial effort in OCS exploration involves geophysical or seismic exploration. Exploratory seismology surveys leave little, if any, lasting impact on the environment. The use of explosives as an energy source has been largely discontinued in marine survey operations and less environmentally hazardous methods of generating sound energy, such as compressed air charges or vibrating acoustical systems, have been adopted. Therefore, the only adverse impact resulting from exploratory surveys would be minor noise and exhaust emissions normally associated with diesel powered vessels.

(b) Structures. - As of April 30, 1973, there were 1,939 platforms in OCS Gulf of Mexico waters and 5 in California. Turbidity resulting from the placement of drilling and production platforms involves a small area and is of short duration. Destruction of the benthos is also confined, and only involves a few square feet for each piling.

Since the advent of offshore oil and gas activities many species of fin fish have become concentrated around the drilling structures, which provides an artificial habitat. Among these are: red snappers, groupers, trigger fish, spade fish, giant sea bass, pompano, and many smaller species. There is evidence that these species and other larger seasonal game fish, such as sail and bill fish, have appeared since the offshore oil industry became active. The platforms create unique offshore artificial environments which attract and concentrate many predatory species, providing favorable fishing sites for sportsmen and commercial snapper fishermen. The long-term effects of this intense species concentration, in lieu of the more random distribution patterns, are not known; but natural predator-prey relationships could be affected.

Platforms and drilling rigs in view of land may disturb the scenic views and vistas of coastal inhabitants and tourists and the open space qualities of the seascape. The distance from shore at which a structure can be seen is mainly a function of the height of the structure and visibility. For example, a 100-foot high platform drops below the horizon at 16 miles while a 169-foot high platform disappears at 20 miles. Visibility conditions may also reduce the distance at which a platform may be seen.

Despite the installation of navigational aids the erection of additional platforms on the OCS, particularly those adjacent to fairways, is a potential hazard to shipping. Safety fairways have been established to permit safe passage of vessel traffic into and out of ports. Anchorage areas are similarly designated for safety purposes. While exploratory drilling in shipping lanes is permitted with approval by the Corps of Engineers, installation of fixed structures is prohibited under 33 U.S.C. 403 and 43 U.S.C. 1333(f). Production can be initiated by directional drilling from a portion of the tract outside the lane or from adjacent leaseholds outside of fairways. In some cases platforms act as aids to navigation by providing a reference point from which a ship may find its position. They have also been used as refuges by sport fishermen in rough weather.

Platforms may be obstacles to commercial fishing when fish trawling equipment is used. The noise of drilling rigs, acoustical warning devices, and support vessel traffic operating in rivers, canals, and on the open sea could also be expected to have an effect on the coastal area environment.

(c) Debris. - Debris means those substances which are discharged or thrown into the sea (excluding waste water) as the result of a platform or support operation.

The improper disposal of this debris (trash, drilling muds, bilge wastes, and spills of crank case oil and engine fuel) characterizes other possible kinds of vessel or platform-related sources of pollution. Toxic debris, such as paints and thinners, can poison and cause the death of some organisms. Floating non-biodegradable debris is unsightly to tourism and recreational use and poses a hazard to small crafts. Sinking debris can foul and damage commercial fishing nets. It may act as an artificial reef because some biodegradable material may be eaten by some marine organisms. The amount of debris discharged into the environment as a result of OCS operations has been found to be small due to enforcement of pertinent regulations. For an extensive discussion of all types of debris including regulations and methods of enforcement concerning their discharge see the aforementioned OCS Statement.

(d) Oil Spills. - During the period 1964 through 1972, 39 significant recorded oil spills involving 50 barrels or more of oil and condensate occurred on Federal OCS lands[1/]. The estimated total volume of oil spilled as a result of these incidents is slightly less than 300,000 bbl. During this same period, more than 2 billion bbl. of oil and condensate were produced in the Gulf of Mexico, offshore Texas and Louisiana, and on the Pacific Coast OCS. The amount of recorded spills represents approximately 0.014% of the oil and condensate produced in the OCS during the same period.

Blowouts during exploratory drilling pose the greatest potential for serious pollution of offshore waters by hydrocarbons and of air quality by fire. Normally, drilling muds and blowout prevention devices (all drilling rigs are equipped with blowout preventers) control the natural pressure in a well, nonetheless, blowouts do occur. From June 9, 1956, to December 1972, 41 blowouts occurred on Federal OCS oil and gas operations[2/]. Ten of the 41 blowouts resulted in a total oil or condensate spillage of approximately 80,000 bbl. Fire occurred in 10 of the 41 blowouts; 8 of the fires burned gas only. During the 16-year period, 10 blowouts resulted in oil or condensate spills into the water and 2 of the 10 blowouts had oil fires which impacted on air quality.

Through December 1972, a total of 1,553 oil and gas tracts have been leased in Federal areas of the Gulf of Mexico and

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1/ All data is taken from tables prepared by the Conservation Division, U.S. Geological Survey, "Accidents Connected with Federal Oil and Gas Operations in the Outer Continental Shelf Through 1972."

2/ Work cited in footnote 1.

Santa Barbara clean-up attempts. Similarly, bird species are vulnerable if beaches and marshes become contaminated by oil, especially if vegetation and food sources are destroyed. In the Northern Hemisphere, hundreds of thousands of swimming and diving birds have perished from oil pollution during and since World War II, and a marked reduction of some nesting populations of sea birds from such mortality has been documented (31). However, no such problem has been documented in the Gulf of Mexico as a result of oil spills on the OCS.

Equipment and procedures for recovering oil spilled in protected waters are well developed, but similar capability in the open sea is severely limited. There are no recovery devices capable of picking up oil in rough seas with wave levels over five feet. The use of sorbents which have an affinity for oil poses specific problems: distributing sorbent over the area affected by the oil spill is difficult particularly in high winds; there is no effective procedure for collecting the sorbent after contact with spills; and treating or disposal of such oil-saturated materials is difficult. The chemical and physical process and potential impacts of sinking oil to the ocean bottom is particularly undesirable in shellfish-producing intertidal areas. The use of dispersants on spills introduces the problem of toxicity of such materials if they are poorly handled or are not properly diluted in the water column (29). An extensive discussion of present oil spill recovery techniques can be found on pages 237 and 249-255 of the OCS statement.

Marine life may also be affected by efforts to remove the surface oil. Emulsifiers, as well as natural storm action, remove oil from the surface by redistributing it as minute droplets throughout the water column. In this condition, oil is more susceptible to biological and chemical degradation, although in combination with such chemicals, it is usually more toxic. Furthermore, the oil treating chemicals themselves has been found to be more toxic than crude oil in many instances (30).

> Shellfish appear to be quite vulnerable to the majority of chemical dispersants, and in past oil-spill incidents where heavy dispersant spraying has been conducted in the tidal zone or in shallow areas with restricted circulations, large shellfish kills resulted. Fortunately, the effects of oil spillage on shellfish appear to be fairly temporary, and even in those situations where high mortalities were observed at the time of the incident, complete recovery of the shellfish population appears to have taken place within a period of 6 months to 2 years. (29, p. 14.)

Nearshore, estuarine, and coastal environments are adversely affected as a result of oil spills if current and wind conditions are such that the spilled oil is transported shoreward in large amounts. Beaches, water recreation areas and historic sites could be rendered temporarily unusable resulting in a loss of recreational enjoyment and economic benefit to the local populace.

Water sports, such as swimming, diving, spearfishing, underwater photography, fishing for finfish and shellfish, boating, and water skiing would be most directly affected. Other marine-related activities such as beachcombing, shelling, seascape painting, shoreline nature study, camping, and sunbathing would be made much less attractive for an indeterminate period depending upon the promptness and efficiency of the clean-up effort.

Much more critical in terms of total value is the degradation of estuarine and marsh areas which are vital to the ecology as nursery grounds. A complete discussion of the effects of oil pollution in these areas has been documented.[1/]

There has been one case where mortality of organisms in the immediate area of a No. 2 fuel oil spill was relatively high (95 percent), and within one year after the spill repopulation was occurring at most of the stations of the study. Larvae of the commercially important species such as oysters, crabs, and shrimp which use marshes and estuaries to feed and grow are also affected by spilled hydrocarbons. Continued research on the impact of oil spills on inshore organisms will provide more definitive answers to the questions of mortality and repopulation by indigenous organisms.

(e) Waste Water. - A production element which can contribute to offshore pollution is the disposal of waste water associated with oil production. Although the volume of such waste discharge is relatively small, an increase in offshore oil activity and the advancing state of depletion of water drive fields will cause waste of this kind to be an important consideration. The oil content of waste water discharged as a result of OCS operations is limited to an average of not more than 50 ppm under OCS Order No. 8.

1/ For a thorough treatment of this subject see pp. 91-143 of the OCS Statement.

In Federal areas offshore Louisiana 1,935 structures produce a total of nearly 1 million barrels of oil per day; waste water is discharged from approximately 214 of the structures. Total waste water production is about 420,000 barrels per day; 240,000 barrels are transported to shore and 180,000 barrels are discharged into the sea. The largest volume of waste water discharged at a single location is approximately 20,000 barrels per day. The decision to separate, treat, and discharge waste water on the platform or pipe it to shore depends primarily on whether or not space exists on the platform for separating facilities and if pipeline capacity is available. The oil content of waste water discharged in OCS operations in the Gulf of Mexico, which averaged 40.8 ppm in March 1972 can contribute as much as 7.3 barrels of oil per day to the Gulf of Mexico waters.

During 1971, approximately 16 barrels of oil may have been introduced into the ocean daily, either from minor spills or waste water discharge. Based on these figures, increased production of 300,000 barrels per day, the projected amount recoverable from oil shale by 1980 could contribute an additional 4 to 9 barrels of oil per day from continuous pollution sources on the OCS in addition to spills from unidentified sources.

There is little research on the effects of waste water discharge on the environment. The only two studies to date have produced diametrically opposite results. One study shows that due to the extreme salinity (between 6.1 and 27.0 percent dissolved salts), and the difference in proportion of salts in waste water and sea water, that where quantities were dumped into a stream the biota was destroyed. When the brine was diluted measurably by rainfall, the fauna moved back into the area suffering pollution. The other study states that results of brine effluent in a stream had no observable effect at a distance of a few feet from the discharge pipe. The study goes on to state that there may even be a "fertilizing" effect due to the introduction of the brine. These studies are, at best, minimal evidence on which to base a sound judgment of the effect of waste water on the environment.

(f) Pipeline Construction. - Pipelines laid offshore are buried (required by BLM administrative procedures for water depth of 200 feet or less) to avoid the danger of being struck or dragged by ship anchors as well as to avoid movement in the event of strong water currents in times of intense storms, such as hurricanes. Approximately 98 percent of the oil and all the natural gas produced offshore is transported to shore by pipeline and the remaining 2 percent is transported by barge. Although well blowouts attract the most attention, spillage of oil due to the rupture of pipelines which transport offshore production to shore terminals can be serious. During the last decade ruptured pipelines caused more pollution than drilling and production operations. From 1967 through 1972, there were 12 pipeline breaks or leaks of 50 barrels or more connected with OCS oil and gas operations, totaling approximately 176,000 barrels. The largest, a spill of 160,639 barrels of oil caused by a pipeline leak due to anchor dragging occurred on October 15, 1967.

Pipeline construction in marsh areas resulting from OCS operations will cause temporary damage, and disturbance of benthic organisms. Depending upon existing environmental conditions, some of this damage may be permanent. When pipelines are buried in coastal marshes, it has been a common practice to dredge canals in which to place them. Such pipeline canals increase the ratio of water to wetlands by physically removing the coastal marshes, by facilitating drainage of fresh-water necessary to maintain diluted conditions in the estuaries, and by increasing the rate of salt water intrusion from the more highly saline coastal waters. The dredging and redepositing of the displaced sediment also disturbes the local habitat of acquatic plants and animals. Recent studies (32) indicate that 16.5 square miles of marsh have been destroyed each year in coastal Louisiana by erosion, subsidence, and construction. Most of this destruction is attributable to natural causes, including hurricanes, but some annual marsh destruction can be attributed directly to canal dredging operations associated with the oil industry, and to construction of pipeline canals. Some of these pipeline canals serve onshore production and others serve offshore production.

Adverse effects of pipeline construction may be either short-term or permanent, and may be minor or serious, depending on the methods employed in laying pipelines and their location. These effects can be substantially reduced with adequate planning and by using the most appropriate construction techniques. Usually bulkheads are placed in canals to prevent saltwater intrusion and to maintain existing drainage and water-exchange routes. To protect oysters, pipelines are usually routed around major oyster reefs, and where shallow estuaries are to be crossed, the canal is usually backfilled, as is often the case with canals through marshlands.

A ditching or jetting operation associated with construction in offshore areas generally causes temporary turbidity of the water in the immediate vicinity and may temporarily disturb fish and other aquatic life during that time. It is possible that the operation may also temporarily damage a portion of any shell fisheries existing in the immediate area.

(g) Summary. - Even with the best systems and controls, some oil pollution from OCS leasing will occur. The recently strengthened regulations and operating orders 1/ are as stringent as technology allows at this time. Although increased Federal inspections and the large costs involved in controlling, containing, and cleaning up spilled oil have combined to generate an awareness of the necessity to improve the OCS safety record, no regulation or enforcement can guarantee that there will be no pollution from oil producing operations on the OCS. Natural disasters, equipment failure or human error could occur despite regulations and enforcement procedures. Federal enforcement and regulation procedures, and better equipment and engineering standards, although they cannot guarantee there will be no spillage, have served to reduce the risk of oil spill accidents and pollution incidents resulting from OCS development.

Cumulative effects on the environment from OCS leasing will result as more areas are made available for offshore mineral development. An increased level of conflict and navigational

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1/ Including the National Oil and Hazardous Substances Pollution Contingency Plan, 36 FR 16215, August 20, 1971.

hazard will result from additional offshore structures associated with OCS development. The greatest effect will be on commercial shipping and fishing activities. Increasing the numbers and lengths of pipelines to shore will have its greatest impact in nearshore and onshore areas, i.e., estuaries, marsh and wetlands environments. The biota in the path of a pipeline will undergo disruption, loss of habitat, and will suffer physiological stress, injury, or death. In addition to pipelines, additional increments of transportation, storage, refinery, treatment, and other facilities and activities associated with oil and gas production on the OCS will have an overall, cumulative effect on the coastal environment and local and regional economies. The initial effect on biota will be one of disruption and destruction in the construction areas. A cumulative effect will result from solid, liquid, and gaseous waste disposal associated with OCS development and any oil polluting events should they occur. The quality of air over a developing area could be degraded by exhaust emissions of stationary power units and service vessels and by the accidental release of oil and gas from wild wells. The effect will be physiological stress and death for oiled plants and animals and possible contamination of marine food sources for man. The scope, duration, location, and overall significant effects of an oil spill on a cumulative basis are unknown. However, the area of greatest potential for receiving lethal and sub-lethal adverse effects on a cumulative basis are embayments and semi-enclosed waters where many species undergo early development and are more vulnerable to toxic compounds. Oil on a beach would be aesthetically unpleasant and would disrupt recreational events and usually render affected beach areas unsuitable for human enjoyment.

b. Onshore Production

This alternative would require increased exploration, development and production of crude oil (and natural gas) from onshore sources. To be a real alternative, supplies equal to all or a significant part of projected supplies from shale oil would have to be developed in addition to those supplies that are projected to be produced from onshore sources, during the same time frame. Experience indicates that it would be extremely difficult, if not impossible, to expand drilling efforts to provide additional needed supplies, especially when consideration is given to the drilling effort required to offset continuing declines in onshore production. Past discovery rates indicate that the drilling of over 50,000 additional wells might be required to provide equivalent supplies to what could be delivered from oil shale within the proposed time frame. In 1970, less than 30,000 wells were drilled in onshore areas.

Onshore drilling in recent years has continually declined; a major contributor to the decline has been a lack of economic incentive. Additional incentives such as subsidies, price increases and tax benefits could result in increased drilling and development of onshore domestic supplies, but little information is available to evaluate the cost effectiveness of such a program. With increased incentives, additonal exploration, development, and production of supplies could be expected but increases in crude oil supplies from new discoveries could not be expected to be forthcoming in significant enough quantities to offset a 1-million-barrel-per-day rate of shale oil production in 1985.

Two hundred forty-six billion barrels of crude oil are estimated to be recoverable from domestic onshore areas, including Alaska North Slope, under current technological and economic conditions. Potential onshore reserves would be adequate to meet projected requirements, but past and current drilling efforts have not resulted in discoveries that would have provided adequate increased production. The most favorable geologic provinces already have been developed so exploration success possibilities are reduced. In the late 1940's only 30 wildcat wells were needed to locate a significant new field; the number of wells required had nearly doubled by 1960, and this trend has not reversed.

The importance of finding large fields becomes apparent when it is noted that last year 63 percent of U.S. production was from only 264 giant fields; there are over 35,000 oil fields in the United States.

Development of spare shut-in capacity in the Naval Petroleum Reserve at Elk Hills in Kern County, California, could be a partial alternative. Production has been limited to about 2,000 barrels of oil per day. In 1970 shut-in capacity was estimated to be about 160,000 BPD. At that time, the expenditure of approximately $100 million for drilling, plants and compressors, and $50 million for additional transportation facilities could result in increased production to about 350,000 barrels of crude oil per day of production (33). Congressional approval would be required for any appreciable increase over the current producing rate.

Technological advances permit improved recovery of oil from existing reservoirs, and, in effect, increase the "recoverable reserves" in a producing formation by a process called "secondary recovery". Injecting water into the reservoir to mechanically displace some of the trapped oil is an example. Improved recovery techniques have added about 0.5 percent per year to the expected ultimate recovery.

Ultimate recovery of oil is currently estimated at 31.1 percent of original oil in place. The applicability of recovery techniques depends strongly on the nature of the oil reservoir; the estimated recovery ranges from 13.5 percent in Ohio to 65 percent in District 6 of Texas. With estimated original oil-in-place of 425 billion barrels, an increase of only 1 percent in the average recovery of oil-in-place would yield 4.25 billion barrels, or 2 million barrels per day for 12 years. The historic 0.5 percent per year derived primarily through improved water-flooding techniques, however, appears to be decreasing (35).

> The rate of improvement in recovery efficiency appears to be diminishing rapidly, however. The fact that an average of only one-third of the discovered oil in the ground is being recovered currently, and that significant oil deposits are becoming more difficult to find, emphasizes the need for a continuing research effort in these areas.

It is also important to note that supply-demand forecasts usually include provision for some improvements in recovery, often explicitly. For example, the National Petroleum Council projects reserve additions of 28.5 billion barrels, or 71 percent of its 1971-1985 totals, from application of secondary and tertiary recovery processes (34). Much of the production capacity added in recent years has been obtained through such improvements, and further dramatic increases are generally not anticipated at current costs and price levels. Technologic breakthroughs which could contribute an additional one million barrels per day will probably come from secondary or tertiary recovery methods other than waterflooding. Miscible and thermal techniques have been proven in the laboratory. Some have shown limited technical but not economical success when applied to the actual reservoir.

Incremental gas production, while possibly substantial, is measured with respect to a base of excess production which is declining under present regulation. Natural gas reservoirs are not amenable to the secondary recovery technology breakthroughs that petroleum reservoirs are.

(1) Description of Field Activities.

(a) Exploration.- A variety of surveys are carried out by aircraft and surface methods. Small single- and twin-engine aircraft and helicopters conduct visual reconnaissance at altitudes of 100 to 500 feet. Flights above 3,000 feet conduct photographic, geophysical magnetometer, and geologic visual reconnaissance surveys.

Surface exploration includes: (1) casual use of existing roads and trails to conduct geochemical and reconnaissance surveys, make stratigraphic, lithologic, and structural maps, and take air samples, and (2) intensive use requiring extended physical presence on the land and resulting in significant disturbance to the environment.

Geophysical surveys include use of explosives, thumpers, or vibrators to transmit shock to the ground. Explosive methods involve drilling holes in the ground and detonating explosives in the hole.

Thumper and vibrator methods use truck-mounted equipment to pound or vibrate the earth. Access trails may be cleared of soft vegetative cover and loose mineral material so that detectors spaced along the trails can receive as much energy as possible. During preliminary reconnaissance, a few such trails would be cut; more intensive investigation of a promising area could require a network of trails on a 1- to 2-mile grid or closer.

The seismic explosive method can damage water wells and irrigation facilities in close proximity to the test area.

Other types of geophysical surveys (to measure temperature and other characteristics) use light-weight equipment which is usually hand-carried with very little if any disturbance due to the survey itself.

Subsurface exploration begins with stratigraphic tests, which are usually shallow (100 to 500 feet), uncased holes designed to determine subsurface structural features and correct seismic data. They are usually drilled with truck-mounted equipment and disturb a relatively small area. Temporary roads and trails constructed for access to the test sites are minimal.

Wildcat wells are drilled to verify the existence of hydrocarbon deposits. To support the drilling rig and other equipment, a heavy-duty but temporary road is built. In deciduous forest biome, this could require cutting of some trees.

The wildcat well site is cleared of all vegetation and graded to a flat surface. The area of the site depends on the type and depth of well drilled, equipment used, and the topography, and may cover an acre, more or less. At the well site, a drilling rig, mud pumps and pit, generators, pipe rack, and tool house are located on the drill pad. Other facilities, such as water and fuel storage tanks, will be nearby. In remote areas, the drilling company may construct additional support facilities, such as a drilling camp and an aircraft landing strip or heliport.

During drilling, a special fluid called "mud" (a mixture of water, clay, and mineral additives) is pumped down the drill pipe under controlled pressure. When the mud reaches the bottom of the hole, it is forced out through the drilling bit and returns to the surface between the drill pipe and walls of the hole. This mud is sometimes mixed and stored in pits dug in the ground. If abandoned, it may form a surface crust but may not harden for years.

"Casing" consists of lengths of steel pipe set in the drill hole. It helps maintain good circulation of the mud, prevent erosion of the walls of the hole, protect fresh water strata, and shut off high-pressure zones. Once casing is set in the hole, it is sealed in place by a cement slurry.

"Blowout preventers" are installed as safety devices, whose function, if unexpected high pressures are met, is to close off the sp ce between the drill pipe and the casing in a matter of seconds and to contain these pressures until normal drilling can be resumed. When the well is ready for production, a system of high-pressure surface valves, called a Christmas tree, is installed on top to control the well flow.

A well requires water for mud, cleaning equipment, and cooling engines; a water well may be drilled if no other source is available. A pipeline may be laid several miles and a pump installed at a stream to furnish water.

Discovery of oil or gas leads to testing which requires additional equipment such as separators and storage tanks.

In some areas, an operator may be allowed to flare gas for a short period for testing; in others, gas may be released unburned to the atmosphere.

If the wildcat does not discover oil or gas in commercial quantities, the hole will be plugged and the location abandoned. The drilling pad and surrounding area should be cleaned up and restored (required in most circumstances).

(b) Development. - Development differs from the later stages of exploration primarily in the extent and intensity of activities. More detailed seismic work may be required to determine the best location for the first offset or development well sites of a more permanent nature; they are generally more stable in their location and construction methods better planned than those in the exploratory phase.

As the field develops, the wells are interconnected with a road and pipeline system.

Many fields go through several development phases; new development wells may be drilled past the known producing horizon in an attempt to find additional productive zones. If a deeper zone is developed within the field area, additional wells may be drilled adjacent to existing producing wells--reducing effective well spacing--or the existing wells and any new development wells may be drilled deeper and completed as "multiple completions."

(c) Production. - The production phase involves periodic inspection and repair of operating equipment and facilities. In cases of smaller production capacity, oil will be stored temporarily in tanks and picked up periodically by tank truck. When brines are a principal byproduct of the production operation, corrosion is a particularly important problem. Late stages of production usually involve secondary recovery operations requiring additional pumping or injection equipment.

(d) Abandonment. - As production declines, some wells in the field may begin to produce too much water. In some oil fields gas produced becomes excessive and wells are eventually shut in and abandoned. Abandonment of gas wells usually comes when reservoir pressure and rate of gas production become too low. Deregulation and higher prices would tend to delay abandonment of existing gas fields and prolong production in new fields. Some of the gathering system, flow lines, and other buried pipe may be left in place if the cost of removal exceeds salvage value and regulations do not so require.

(2) Potential Environmental Impacts. - This section discusses environmental impacts involved in current domestic crude petroleum and natural gas production onshore. Developing petroleum production needed to meet an incremental increase of one million barrels per day would increase these environmental impacts on the average by about 5 percent. These impacts can

be associated with areas where petroleum exploration production is already a common practice and to areas where petroleum extraction is virtually unknown. If the incremental production derives from existing producing wells and if storage and distribution systems are adequate to handle the additional produced fluids, the resulting impact will be minimal. If the extra production comes from extending the limits of producing reservoirs, recompleting wells in the producing reservoir or in other reservoirs which they penetrate at greater or lesser depths, or secondary recovery operations, additional impacts will result (discussed in detail in the following section). These impacts are associated with drilling and reworking production or injection wells, erecting gathering, storage and distribution systems as well as any other required operating equipment. Higher unit prices for crude oil or natural gas should stimulate exploration and, since fossil fuels such as petroleum and natural gas can theoretically be discovered in essentially any area where the earth's subsurface crust is composed, at least in part, of sedimentary rocks, the additional production could result from successful exploration of areas where oil and gas extraction is not common. For this case the resulting environmental impacts will be maximum.

The following impacts relate generally to any area where crude petroleum or natural gas extraction could occur.

(a) Air Quality. - The impact of additional petroleum production on air quality stems principally from the emission of particulates into the atmosphere; however, some disturbance results from noise and vibrations.

Engine exhausts from vehicles and stationary engines result in emission of the products of combustion. The impact of such pollution dependent upon the size of the operation, climatic conditions, topography, and localized factors. Noise and vibrations from stationary engines used in drilling and production operations and transporting systems can disturb the natural environment. Air quality in immediate areas could undergo some temporary reduction because of removal of ground cover, dust from vehicle traffic, and from occasional equipment failure or blowouts.

Vapor venting from storage tanks and vessels, the friendly or accidental burning of petroleum and other chemical products, especially those containing sulfur compounds, could release particulates, volatile and noxious oxides of combustion into the atmosphere, as well as objectionable odors. These emissions can generally be classed as intermittent, infrequent and present in small amounts.

Since production operations result in relatively small amounts of air contaminants, it is highly unlikely that air quality reductions from such operations associated with increased petroleum or natural gas production would significantly alter biological conditions affecting the growth of flora. However, the feeding and nesting habits of birds and animals, wilderness qualities and hunting could be altered as a result of noise and vibrations associated with increased operations. After termination of operations, a reversion back to original conditions would be expected.

(b) Water Quality. - The construction of roads for access into prospective petroleum producing areas could affect water quality where drainage patterns are disturbed or when erosion is possible. Canal dredging can result in temporarily increased turbidity and sediment suspension.

Entry of foreign substances such as oil, chemicals, brine, and waste materials into the water cycle can be a major environmental risk associated with petroleum production operations. Spills or leaks allowing such substances to enter the surface or ground water systems can result from human error and neglect; corrosion of pipelines and container vessels; pipeline breaks from vibrations, earthquakes, landslides, ruptures, or mechanical failures; burning pits and open ditches and blowouts. During production, large amounts of salt water are usually produced as oil fields age. Such water can create disposal and pollution problems. A study by the Interstate Oil Compact Commission (IOCC) indicates that up to 25 million barrels of salt water are produced daily from the Nation's oil wells. Proper disposal of produced brines has been and continues to be of major concern to producing operators. Subsurface disposal is strictly regulated by state water resources agencies and disposal of salt water is not permitted in fresh-water streams (29, p. 147).

The principal causes of water pollution from barges transporting petroleum inland and on coastal waterways are loading and unloading operations; collisions; ship operations, such as bilge disposal; and human error. Data compiled from the Pollution Incident Reporting System (PIRS) of the U.S. Coast Guard show that there were 295 spills attributed to barges in 1970. Average size of the spills was estimated to be approximately 66 barrels per spill. Even though spill control methods are being improved, increased movement of petroleum has increased this pollution problem.

(c) Surface and Subsurface Land Quality. - A potential source of land pollution is a blowout during drilling, but the frequency of blowouts is small. A well blowout, while not common, may occur at any time during exploratory or development drilling. If blowout preventers fail, a well may flow out of control for days or months until the pressure declines, rocks and debris lodge in the well hole and restrict the flow to a controllable rate, or a relief hole or other control operations are successful.

During a blowout oil, gas, drilling mud, and brines may be sprayed into the air (36). Wind-blown pollutants can damage surrounding vegetation and other resources. A blowout can also charge subsurface formations with gas, oil, or brine, endangering ground and surface water quality. Fire is a possibility and seriously complicates control operations.

The likelihood of a blowout is usually reduced by use of a blowout preventer--a large control valve that can be closed to stop or reduce the well flow. Although usually standard equipment, blowout preventers, like any mechanical device, may malfunction when needed. One hundred and six blowouts occurred in drilling 273,000 wells in 8 major oil-producing states from 1960 through 1970. Most blowouts are from high pressure gas rather than oil.

The injury experience of the oil industry has been far less than that of mining. For example, injuries are about one-fourth of those attributed to coal mining. Moreover, historical injury rates of the oil industry are relatively constant; which indicates that increased production would not significantly increase the rate of additional fatalities (For additional details see Volume I, Chapter III, section G.1.f.).

In exploration and pipeline operations, spills are generally small. Major spills could occur in drilling, production, and in transportation of petroleum liquids by marine transportation. The Environmental Protection Agency (EPA) estimated that 10,000 oil spills occur per year of which 2,500 are ground spills (29, p. 146). Most ground spills cause little ground damage. According to the 1970 report of the Office of Pipeline Safety (Department of Transportation) on spills incidents, there were a total of 347 liquid pipeline accidents. Crude oil was being transported in 216 of the accidents. In those accidents, spills averaged approximately 1,780 barrels of crude oil. Principal cause of over 50 percent of the accidents was corrosion. Many pipelines are old, dating back to the 1920's before techniques for protection against corrosion became widely used. With the development and expanded use of cathodic protection of pipelines, fewer accidents in new lines would be expected, but accidents from old lines will continue to be of concern.

2. Arctic Oil and Gas

a. Arctic Oil Potential

The Prudhoe Bay field currently is estimated to contain 24 billion barrels of oil-in-place. At an estimated recovery rate of 40 percent, the current proved recoverable reserves of the field are 9.6 billion barrels of crude oil (37). These reserves alone make the Prudhoe Bay field the largest ever discovered on the North American continent (38). Nevertheless, the 9.6 billion barrel estimate may be a conservative indication of the crude oil potential of the field, the Arctic Slope province, and the adjacent regions of the Canadian Arctic.

Initial estimates of the reserves of newly discovered fields seldom indicate their full potential. As further drilling occurs, the proved area of pools is extended. Further developmental drilling and production provide additional information upon which more accurate estimates of reserves can be based. The application of secondary recovery techniques in the field also increases the amount of proved reserves (39).

The current reserve estimate for the Prudhoe Bay field is for unextended pools and assumes primary recovery only. Since the Prudhoe Bay discovery is quite recent and since relatively few wells were drilled at the time this estimate was made, it is highly probable that reserve estimates will increase as the field is developed. ARCO officials have recently indicated that they hope to recover ultimately 65 percent to 70 percent of the oil-in-place (40). This increase in the recoverable percentage would increase present reserve estimates to 15.6 to 16.8 billion barrels of recoverable reserves from present estimates of oil-in-place. With the addition of possible extensions, it is likely that at lease 20 billion barrels of crude oil will eventually be recovered from the Prudhoe Bay field. This would make it the fifth largest oil field ever discovered (41).

The estimated reserves of the Prudhoe Bay field do not exhaust the petroleum potential of the Arctic Slope province in Alaska. The Prudhoe Bay field is located in the Colville Basin. Geologically, this basin is classified as an intermediate crustal type, i.e., its underlying crust is intermediate to that beneath continents and that beneath oceans, the basin itself being extracontinental (located on the margin of a continent) and sloping downward into a small ocean basin. Extracontinental, downward warping basins are among the richest sources of oil and gas in the world. Examples of such basins include the Arabian platform and Iranian basin (Persian Gulf), the East Texas basin, and the Tampico embayment (Mexico). Over one-half of the 119 known oil fields with at least 1 billion barrels of recoverable reserves are found in the 10 known basins of this type (42).

The ultimate potential of the onshore area in the Arctic Slope province (excluding the Arctic Wildlife Refuge but including Naval Petroleum Reserve No. 4) is uncertain. The platform along the Arctic coast gives considerable geologic indications of being very favorable for both oil and gas (43). Comparison with the history of similar basins indicates a high probability of further discoveries of varying size. One estimate made prior to the release of detailed information on the Prudhoe Bay field suggested an ultimate recovery of up to 30 billion barrels for the province, including speculative reserves (44). Other professional estimates made before and since that time (which incorporate higher recovery rates as well as greater optimism about additional discoveries) are somewhat higher, ranging up to 40 to 50 billion barrels (45). Considerably higher estimates than these have been made (46), but the geologic evidence for them is lacking.

The Beaufort Basin, east of the Richardson Mountains and encompassing the Mackenzie Delta, also has considerable geologic potential for petroleum. Two discoveries of oil have been made already in this area by Imperial Oil, Ltd. They are considered to be significant, but official reserve estimates for them have not yet been published. Imperial has only indicated that it is optimistic about finding at least 2 billion barrels of recoverable crude on its Beaufort Basin leases (47).

The Chukchi and Beaufort Seas off the northern Alaskan and northern Canadian coasts are also believed to be potential oil and gas areas (48). These must be considered more speculative possibilities than the onshore areas. Imperial Oil, Ltd. currently plans to build artificial islands by dredging in shallow parts of the Beaufort Sea off the Mackenzie Delta later this year. Exploratory drilling will begin from these in late 1973 (49). Other shallow sections may be open to similar techniques. Drilling in deeper areas (50 feet or more) may, however, prove to be prohibitively expensive, even if geologic prospects are good. Hence, recoverable oil from deeper offshore areas may be limited.

There are large sedimentary areas in Canada that are favorable for the discovery of oil and gas. Recent years have seen increasing exploration activity in the Arctic Islands. Results to date have indicated large discoveries of natural gas; however, discoveries of oil have not been extremely promising. Exploration has also been conducted in Canada's offshore areas in Eastern Canada. The only find so far has been oil near Sable Island which is in the southern part of Canada's offshore area and near the U.S. offshore area.

During the period from 1950 to 1969 Canada's proved crude oil reserves increased steadily from 1.2 billion barrels to 10.5 billion barrels. Since 1969 Canada's proved reserves have been slowly declining. A future increase in reserves will depend on results in the frontier areas in the Artic and offshore. Assuming a finding rate between 1970 and 1985 comparable to that which occurred in the prior 15 year period in Canada and assuming a reserve to production ratio of about 10 to 1, Canadian production in 1985 could be about 3,300,000 barrels per day. If 50 percent of the production is exported to the U.S. this would amount to 1,650,000 barrels per day. Canada also has high reserves of tar sands; however, with the large capital investments required the production from this source will probably be in the range of a few hundred thousand barrels per day by 1985.

Canadian oil production is approximately in balance with Canadian oil consumption. Thus, Canadian imports of oil from the Caribbean and Middle East areas of about 50% of her consumption allows

Canada to export about 50% of her production to the U.S.

Canadian oil has received preferential treatment under the oil import program, and thus, imports from Canada have increased rapidly. At the same time Canada's oil imports from overseas areas have continued to increase so that Canada remains over 50% dependent on overseas imports for her internal consumption of petroleum.

In 1959 the U.S. recognized its growing dependence on imported oil and its security position and instituted the Oil Import Program. Overland imports from Canada were ostensibly exempt. Actually, Canadian imports have always been subject to some degree of informal or formal control recognizing that a Canadian policy of accepting more Middle East imports to sell more oil to the U.S. at a higher price would not represent either security or economics. While Canadian crude oil has been made subject to quota restrictions, the quota has been increased each year and often during a year. Recent comments in the Canadian trade press suggest that Canadian producers may not be able to produce the oil required to use all the quota tickets already issued.

B. Arctic Gas Potential

The Prudhoe Bay field has large reserves of natural gas dissolved in or associated with its crude oil reserves. Recoverable gas reserves in the field were estimated to be 26 trillion cubic feet as of the end of 1970 (50). An average of 750 cubic feet of dissolved gas per barrel (51) for the current oil reserves of 9.6 billion barrels would indicate reserves of approximately 7 trillion cubic feet of dissolved gas and 19 trillion cubic feet of associated gas. These reserves, which, like the crude oil reserves of the Prudehoe Bay field, are subject to extension and revision, constituted 8.9 percent of recoverable U.S. natural gas reserves at the end of 1970 (52). They also make the Prudhoe Bay field the 13th largest gas field ever discovered in the world (53).

The natural gas prospects of the North Slope are not limited to the Prudhoe Bay field. Several gas fields were discovered in the 1940's and 1950's on NPR-4, the largest of which was the Gubik field with 300 billion cubic feet of reserves. Geologic investigations of other parts of the North Slope have indicated a favorable potential for future gas discoveries within them as well (54).

Large reserves of natural gas in separate fields have recently been found in the Mackenzie Delta region. Imperial Oil has drilled two successful gas wells on Richards Island at the mouth of the Mackenzie River. Although no official reserve estimates have been released for this new field, its reserves are believed to constitute a substantial proportion of the estimated 15 trillion cubic feet of gas reserves found in the Canadian Arctic so far (55). This would be a significant addition to current Canadian gas reserves (56) and would rank the Richards Island field among the 30 largest gas fields discovered in the world (57). The potential of this region is also believed to be much greater. Current exploration activity is very intense. One additional gas discovery was made in February 1972, 45 miles north of Inuvik and additional ones in the near future would not be surprising (58).

Given the large size of the Arctic gas reserves and the projected shortages in other sources of domestic supply, there is high probability that this gas will be developed and transported to U.S. and Canadian markets. Three different consortia have made proposals for gas pipelines down the Mackenzie Valley to these potential markets. However, many major uncertainties remain; for example, at this time industry experts differ in their opinions about how soon the gas caps in the Prudhoe Bay field can be tapped. Assuming 750 cubic feet of dissolved gas per barrel of oil produced, only 1.5 billion cubic feet per day of dissolved gas would be produced when oil production reaches a level of 2.0 million barrels per day. The additional gas required to meet the full planned pipeline capacity would have to come from the gas caps. The issue may not be fully resolved until several years after oil production begins, at which time empirical data on the effects of production of associated gas on the production of oil will be available. It is likely that a gas pipeline to the Midwest and lower Canada would transport gas from both the North Slope and the Mackenzie Delta region.

c. Transportation

The proposed trans-Alaska pipeline is scheduled to have a capacity of 2 million barrels of oil per day for delivery to the West Coast. If built as planned, its full capacity will be required for meeting those needs. However, with the prospect of the increase in North Slope proved reserves through extensions and with further high potential of discovery of significant additional Arctic reserves, such additional reserves could be transported via a trans-Canada pipeline to the PAD II area (Chicago) for meeting growing Midwest needs. Such potential could be considered as a future alternative to shale oil production if and when the additional reserves materialize. However, even this significant potential could meet only a portion of growing U.S. oil and gas requirements.

Once construction of the trans-Alaska pipeline is underway, exploratory and developmental drilling should begin again with increased intensity. Several years following, enough should be known to provide better indications of total recoverable reserves, particularly for the area between Naval Petroleum Reserve Number 4 (NPR-4) and the Arctic Wildlife Refuge. Knowledge of the full potential of other parts of the North Slope, such as NPR-4 and Canadian resources, is not likely to be obtained for several years after that. Leasing and drilling for NPR-4 would require new legislation permitting commercial development. Accordingly, it is not possible at this time to project the timing and magnitude of the development of those potentials.

d. Environmental Impacts

The potential environmental impacts associated with the development and transportation of Arctic oil and gas resources are set forth and evaluated in great detail in the Department of the Interior's Final Environmental Impact Statement--Proposed Trans-Alaska Pipeline, of March 1972 (15). In addition to the various environmental considerations associated with other onshore petroleum operations, environmental considerations are far more complex as a result of the severe climate and the fragile nature of the Arctic lands and surface resources. Detailed studies such as those made for the trans-Alaska pipeline would be required to assure that all design, engineering, development, construction, and operations were so conducted as to assure adequate protection of other land, resource, and environmental values. Examples of potential unique aspects include:

(1) Thawing of permafrost from oil pipeline heat loss and from construction activities. The materials then could become unstable and flow or slide, especially on slopes.

(2) Disruption of normal surface drainage and stream flows.

(3) Surface or ground water contamination from construction, operations, and possible oil spills.

(4) Destruction of fragile vegetation, particularly along pipeline right-of-way.

(5) Fresh water fishery resources.

(6) Wildlife resources in a wilderness type environment.

3. Nuclear Stimulation of Natural Gas Reservoirs

Since all projections of energy demand for the middle 1980's indicate that domestic sources of natural gas are not sufficient to meet the Nation's needs, all potential sources of gas should be considered as supplementary rather than an alternative to oil shale.

To the extent that excess natural-gas supplies could satisfy certain oil markets, however, the development of substantial new gas reserves could be considered as an energy alternative to oil from oil shale. The Rocky Mountain belt has numerous basins with proved reserves of oil and gas. Certain deep, thick reservoirs in these basins are known to contain substantial quantities of natural gas that cannot be recovered economically because of their very low natural permeability. Exploding nuclear devices in these massive formations offers the potential of stimulating gas production, draining the reservoirs at much higher rates than obtained by conventional production methods. Government and industry are cooperating in the Atomic Energy Commission's Plowshare program to develop technology relative to nuclear stimulation of deep natural-gas reservoirs. To date, three nuclear-explosive experiments have been successfully executed. Project Gasbuggy and Rulison provided valuable data (94, 95) needed to evaluate the concept. Rio Blanco "Phase I" as yet has not been evaluated. Rio Blanco and Wagon Wheel (yet to be executed) each employ several explosives in a single emplacement well (96, 98). Prior to further testing or commercial development of nuclear gas-stimulation technology a detailed evaluation of results and impact statement of proposed experiments will be required. In addition to evaluating the economics of gas stimulation, effects on ground-water quality and quantity, seismic damage to man-made and natural structures, radioactive-material disposal, land use restrictions and product acceptability to the public will be determined. Only then can consideration be given to any industry proposal for full field development on a commercial basis.

a. Reserve Potential from Nuclear Stimulation

The resource potential of the tight gas sands in the Rocky Mountain region is nearly 600 trillion cubic feet (Tcf) of natural gas; the corresponding technically recoverable potential reserves have been estimated (99) to be 300 Tcf. Most of the resources amenable to nuclear stimulation are in the Green River, Piceance, and Uinta Basins. The potential reserves from these three basins correspond to about 300 x 10^{15} Btu or, on an energy equivalent basis, to about 50 billion barrels of oil. The rate of recovery is important when considering the reserve potential. One possible schedule being considered by AEC estimates that the annual production from full commercial development will be at just less than 100 Bcf the first year and level out at about 3.4 Tcf (100). This would cause the basins to be drained in about 80 years.

b. Possible Schedule for Commercial Development

Current emphasis in the Plowshare program is to develop technology. A research and development period of approximately

5 years is required, which includes the design and testing of explosives and execution and evaluation of pilot tests in each basin. The Rio Blanco Gas Stimulation Project impact statement (101) discusses a three-phase demonstration program for the Rio Blanco Unit.

Assuming success during pilot testing, commercial development could begin by the late 1970's. A hypothetical plan developed by the Lawrence Livermore Laboratory (LLL) (100) presumes technical capability and public acceptance of drilling, necessary field construction, and explosive firing of 80 wells (290 explosives) per year by 1980. This could result in the production of about 600 Bcf of natural gas per year by that time. Favorable conditions might allow a development program of 100 wells (370 explosives) per year beginning in 1981. Such a schedule could yield 1.50 Tcf per year (4.35 billion cf/day) by 1985. This corresponds to an energy production of 4.35 trillion Btu's/day.

c. State-of-the-Art

Nuclear stimulation of natural gas sands is still in the R&D stage and the projected reserve potential resulting from nuclear stimulation is predicted on the basis of technology that has not been fully proven.

To date the Plowshare program has resulted in the successful execution of three stimulation tests. The Gasbuggy test in the San Juan Basin (Rio Arriba County, New Mexico) provided information on evaluation of the effectiveness of stimulation and the seismic and radiological effects of exploding a nominal 29-kiloton device in a gas reservoir (94). An important result of this experiment was that the reservoir was not sufficiently thick to determine the economic potential. A nominal 43-kiloton device was used in the Rulison project (Garfield County, Colorado). The cumulative thickness of the gas-bearing sandstone layers was twice that of the Gasbuggy test; the total interval, including the nongas-bearing strata, was nearly 10 times as thick. The cavity created by the explosive and the subsequent roof-fall (chimney) was not sufficient to stimulate the entire potentially productive interval. The most recent was the Rio Blanco "Phase I" experiment.

Project Rio Blanco Phase I and Wagon Wheel each proposed the use of multiple explosives spaced at vertical intervals in a single well. Rio Blanco, executed May 17, 1973, consisted of the simultaneous detonation of three 30-kiloton explosives in a single emplacement well. These two tests should prove the technical effectiveness and economics of multiple-explosive stimulation of very thick geologic sections. Prior to Rio Blanco, only meager experimental data were available on the depth of tensile fractures in near surface rocks (spall) from nuclear tests and its effects on minability of adjacent strata is uncertain. Considering the other valuable mineral deposits associated with these basins, particularly the Piceance Basin, it is also critically important for any future tests to be sufficiently instrumented and documented to further define the effects, if any, of spall, ground motion, and aftershock on other mineral resources. Such programs were implemented on Rio Blanco to fully evaluate any potential effects on these resources.

d. Potential Environmental Effects

The geographic areas which have reservoirs amenable to nuclear stimulation have been or are involved with exploration for and development of petroleum and natural gas. In terms of environmental effects, field development using nuclear-explosive stimulation involves only two considerations which are not common to conventional field development. These considerations concern residual radioactivity and seismic effects resulting from the nuclear explosion.

Most of the radioactivity produced by the explosions will remain underground trapped in the resolidified rock near the bottom of the chimney or attached to the rock surfaces in the chimney. Project design must assure that the chimney remains isolated from mobile water. The formations of interest for nuclear-explosive stimulation lie generally at depths of 5,000 to 10,000 feet or deeper, have very low permeability, and would not be expected to contain mobile water. Significant vertical communication with shallow water-bearing formations through existing or created faults or fractures after nuclear stimulation would present an environmental hazard. As discussed on page V-94, this is extremely unlikely.

Water produced with the gas from nuclear-explosive stimulated wells will contain tritium. Control methods to dispose of the tritiated water will have to be developed.

The question of small amounts of radioactivity in the gas itself is under careful study to evaluate radiological implications. Contamination effects are controllable to within acceptable limits; expected levels and means of control are discussed in detail in reference (100).

The potential environmental impacts resulting from nuclear stimulation of a single well or in a small geographic area have been stated and evaluated in the environmental impact statements prepared for the proposed Phase I Rio Blanco (101) and Wagon Wheel (102) projects. Extrapolation of the impacts to a full commercial development relates primarily to the frequency and size of explosives and to changes in local environment as the areas of development expand.

The schedule described by LLL (100) calls for the drilling and firing of 100 wells per year (for maybe 50 to 60 years). On the average, this would involve approximately 370 explosive devices per year; usually 3 or 4 explosives in each well. The AEC estimates that four detonation days per year should suffice for the 30 to 40 wells to be completed for each field area.

Full scale development will require significant quantities of fissionable material. The yield required to stimulate the very thick geologic sections and the actual seismic effect of such devices are not completely known. Prior to full field development, this impact must be assessed and evaluated. Public inconvenience and repairable damage must be compensated. Unrepairable impacts would deter development.

In extrapolating the projected or observed impact of test projects, consideration must be given to the total environment of the basin, which has been detailed in Volumes I and III. There are thought to be no current surface or subsurface structures or operations in the zone where damage may be substantial. The fact that this will not invariably be true, e.g., underground oil shale mines, is an important environmental factor when considering commercial development. The following paragraphs explain why the depth of the shale from the ground surface must be considered.

By its nature, nuclear stimulation has a dramatically destructive effect on the natural-gas host rock. The fracture zone should extend 300 to 400 feet from the center of the explosion. Also the compression wave moving out from the explosion can cause spall near a free surface (ground level) or other faulting or fracturing in areas where there are relatively large directional stress concentrations. This leads to concern where there are other valuable mineral resources in the vicinity. Oil shale and associated sodium and aluminum-bearing minerals represent the major mineral resources in the basins whose geographic location coincides with the gas sands which underlay the oil shales, which complicates the problems of the potential effect of this alternative on the development of other mineral resources. This interrelation is particularly obvious in that the C-b lease site lies wholly in the Rio Blanco Unit Area.

Within the present state of technology, the effect of widespread nuclear-explosive activity in deep natural-gas sands on the shallower oil shale deposits remains uncertain. Fractures will emanate from the cavity and under certain extreme conditions it is possible that they could extend beyond the 300 to 400 feet range. Because of the difference in depth between the gas sands and the oil shale in the Rio Blanco unit, direct fractures from the chimney would not reach the oil shale strata from below. Spalling caused by strong tensional seismic waves reflected from the earth's surface will probably extend to depths of 150 to 200 feet, may extend to depths as great as 500 feet in some parts of the Rio Blanco Unit, and could (but almost certainly would not) extend to a maximum credible depth of 850 feet. The overburden above the Mahogany oil shale zone in the Rio Blanco unit ranges from 0 to about 1,400 feet. This implies that in full-field development spall could fracture or otherwise weaken a part of the oil shale. Although a detailed analysis is still underway by the Atomic Energy Commission, the spalled zone for the Rio Blanco experiment can be described as a relatively shallow dish with a depth of less than 350 feet from the surface and a radius of less than 24,000 feet. Since the overburden above the top of the oil shale at the detonation site was approximately 750 feet, AEC has concluded that no spall occured in the oil shale deposit as the result of the Rio Blanco experiments.

As the lead agency for the Rio Blanco Gas Stimulation Project, the AEC has made a detailed study of the Rio Blanco Phase I test and concluded that this single set of explosives will have no severe impact on the associated minerals. In a report prepared for AEC by Lawrence Livermore Laboratory the authors explain that, under an expanded program, there are local (proximity of emplacement well) considerations for each well and that reevaluation will need to be made in each location for which nuclear stimulation is proposed (100). The Department of the Interior has reviewed the technical issues involved and concluded that underground mining of oil shale may be incompatible with full-field nuclear stimulation of gas-bearing formations in the Rio Blanco unit of the Piceance Basin. Each development would be subject to a number of constraints and additional responsibilities. For example, gas-producing wells which penetrate active or inactive mining areas allow the possibility of gas entering the mine. By law, this potential for an underground gassy condition requires "permissible" mining equipment, more monitoring devices and, in some cases, greater ventilating capacity. For additional safety, by law, a 300 feet x 300 feet mine-pillar must be left surrounding the well bore. In order to do this, the position of the bore is determined by rather expensive precise directional surveys on each level of the mine it penetrates. Pillars around 145 wells would equal an area of about 300 acres on each level of the mine. It should be noted, however, that the field development proposed calls for either 320- or 640-acre spacing. Thus, there would be only one or two large pillars required per section. It is also significant that the type of mining being considered necessitates leaving pillars for roof support in any case.

If oil shale development is started after gas stimulation is completed, sinking shafts through near-surface spall zones and mining in the leached zone may encounter fractured rock due to spall. Free-faces along walls of cavities in that part of the leached zone not filled with water may be affected by seismic waves, as well as the floor, roof, and wall areas of an underground mine.

If gas stimulation is started after oil shale development is completed, drill penetration and sealing of the mined zones may be a critical problem. For oil shale areas mined by the open-pit method, the problem of drilling may be restricted to directional holes from outside the disturbed area or drilling costs may increase because of having to penetrate refilled pit areas.

Costs of design, construction, well completion, mining and monitoring would be greater than costs for these same functions under normal conditions. Simultaneous development remains to be proven as a practical method for producing both the gas and shale oil of the Piceance Creek Basin.

4. Increased LNG Imports

This alternative would require increased liquified natural gas (LNG) inputs to replace the energy expected to be available from 1 million barrels per day shale oil rate of production. Unlike oil, the importation of LNG, at present, is not subject to import quotas. The only legal constraint upon increasing importation is the necessity of obtaining FPC approval of any project. Before approving a project the FPC solicits the advice of the Departments of State and Defense.

Liquefied natural gas1/ (LNG) has been in commercial use since 1940. Because of the more than 600: 1 volume reduction caused by the liquefaction process, large volumes of natural gas in a liquefied form are easy to transport and to store. Until recently LNG has been used by gas utility companies primarily for peak-shaving purposes and has been imported only in limited quantities. However, in March 1972 the FPC approved a 20 year project to import LNG from Algeria at the rate of 42 million cubic feet per day. Pending applications could increase LNG imports according to the schedule shown below :

LNG IMPORTS2/

Year	Quantity MMCF/Day
1975	800
1980	5,500
1985	8,200

If oil shale is not developed, and the expected production replaced by LNG, imports would have to increase in quantities approximating 6 billion cubic feet/day by 1985; an increase of about 70 percent over that shown above for 1985. An increase in imports of this amount would

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1/ Natural gas becomes liquid at 258°F at atmospheric pressure.

2/ Federal Power Commission, National Gas Supply and Demand, 1971-1990, Staff Report No. 2, p.70

require between 2 to 4 additional LNG tanker shipments per day and an equivalent increase in the size or number of the highly specilized liquifaction and gasification plants now being proposed. While it may be physically possible to increase LNG imports by 70 percent over that projected, it is not know at this time if the economics of this alternative relative to other competing energy sources is attractive enough to stimulate the investments required to make LNG imports a viable alternatives to oil shale development.

a. Environmental Impacts

The alternative of increasing LNG imports could have an effect on the environment in serveral different ways. These potential impacts are analyzed below:

(1) Air Quality. - The use of LNG imports as a substitute for the oil production expected from oil shale development through the replacement of liquid fuel products by natural gas could lead to a cleaner environment. Natural gas is by far the least polluting of all fossil fuels. The increased imports, however, would require additional ship traffic to certain ports, contributing to the airborne particulate and combustion gas contamination in the port area. Transfer of the LNG from the tanker to the transportation system will result in substantial venting of hydrocarbons (primarily methane) to the air. This vented natural gas would contribute to the total atmospheric hydrocarbon load, although, it does not represent the same potential threat to air quality that certain higher molecular weight hydrocarbons do. Construction and operation of receiving terminals and regasification plants and associated transmission systems would cause at least temporary

degrading of air quality at the construction sites and along pipeline rights-of-way.

(2) Construction and Operation of Regasification Plants. - The construction of regasification plants will cause a disruption of the land and water resources resulting from the effects of additional dredging on the marine environment and from the preemption of coastal lands necessary to provide a site for the facilities. The extent and duration of this impact will depend on the size and location of the plants. For example, a plant now being proposed at Cove Point, Md., would regasify 650 million cubic feet per day and require 1,022 acres of land. Another plant proposed at Savannah, Ga., would produce 335 million cubic feet per day and require 860 acres. LNG as an alternative to shale oil could require the construction of at least six large plants with the consequent commitment of about 12,000 acres. During construction, there will be some disruption of the land surrounding the plant.

A regasification plant also requires terminal facilities to permit the transfer of LNG from tankers to storage areas. In the Cove Point case, this could be accomplished by the construction of a 1-mile-long pier into the Chesapeake Bay. The proposed Savannah River location would allow the tankers close to the plant. Both of these proposals would require dredging, causing increased turbidity of the water and disruption of bottom sediments. This disruption should be temporary.

The construction of regasification plants would also have an impact on both land and marine animals. During the construction period, there will be some damage to the natural habitat of the land animals. However, this damage will be permanent only in the area occupied by the plant. Any surrounding areas that are damaged should return to a near-normal condition after construction is completed. The dredging operation could also disrupt the marine habitat, especially in the case of bottom-dwelling organisms. In most cases, this disruption would be temporary.

The choice of the plant site is an important factor in minimizing the impact of scenic qualities and recreational activities. An esthetically pleasing plant would reduce the disruption of scenic views. The increase in ship traffic will inevitably have an effect on water-oriented recreational activities, depending on its location.

The actual regasification process involves little environmental risk. The Cove Point plant plans to use natural gas in the regasification process and will avoid potential water and air pollutants. The Savannah plant plans to use water drawn from the river to regasify the LNG. After going through the vaporizers, the temperature of the water will be lowered about 5°F and then be returned to the river. Lower water temperature could actually be beneficial by allowing the water to hold more oxygen, which might counteract some upstream-caused pollution.

(3) Transportation. - After the LNG has been regasified, it can be transported through any existing gas pipeline. Thus, existing pipelines will be used if they are available. New pipelines, however, will be required in some areas. The potential

environmental impact of the new lines has been examined in Section V-B-1 of this Volume.

The chance of a major spill is a potential hazard associated with increased LNG imports. A study conducted by the Bureau of Mines has indicated that under certain conditions, there exists the possibility of small-scale explosion resulting from a LNG spill (120). They were not able, however, to predict the result of a large-scale spill on open-water. Another study by Shell Pipeline Corporation (121) concluded that there was no danger of normal LNG exploding when spilled on water since an explosion would result only if the methane content of the LNG is 40 percent or less. Normal methane content is 80-90 percent and the boiling rate is 0.2 percent - 0.3 percent per day. With present day shippping practices, a reduction to 40 percent would not be possible. Further discussions with the Bureau of Mines researchers indicated that an explosion resulting from a LNG spill in open water is unlikely. The chief hazard from a spill would be fire.

b. Summary

LNG as an alternative to the production of 1-million barrels per day of shale oil would require about a 6 billion cubic feet per day increase over the 8.2 billion cubic feet per day LNG imports currently forecast for 1985. The replacement of natural gas for liquid products could lead to a positive benefit in air quality should this gas be used in metropolitan areas, but this benefit would be partially offset by reduced air quality in the port areas as the consequence of increased traffic and venting of hydrocarbons during gas transfers. Some 2 to 4 additional LNG shipments per day would be required, increasing the congestion of the ports and the probability of accidents. Explosives down an LNG spill in open water is unlikely, but fires could result. Additional regasification plants (6 or more) will be required to process the increased LNG imports, causing construction related impacts on land and marine animals. Some 12,000 acres would need to be committed to these facilities. The increase in shipping and facilities will adversely affect water-oriented recreational activities, the extent being dependent on the actual location.

5. Coal

The premise of this report is that as an alternative to shale oil production, other energy resources would substitute or supplement for one other on the basis of their physical state - liquid, solid, or gas. Coal could be an alternative to liquid shale oil principally for electric power generation. However, because of its potential for conversion to clean liquid and gaseous fuels, full consideration must be given to coal for other uses also as an alternative to shale oil.

The energy supplied by 1 million BPD (i.e., 365 million barrels/yr; projected for 1985 production) of shale oil would be equivalent to 95 million short tons/yr. of 11,000 Btu per pound of coal. To replace the energy supplied by the projected oil shale development schedule in the period 1974-1985 would require a total of 482 million short tons of 11,000 Btu/lb coal. However, coal production could be increased on a graduated scale; that is, in 1976, approximately 1 million short tons of coal would be required to provide the energy projected to be obtained from oil shale; whereas by 1985, 95 million short tons of coal would be needed.

At present, a large surface coal mine may produce 5 million short tons of coal per year; a large underground mine may produce 2 million short tons per year. In order for the Rocky Mountain coal industry to produce the 95 million short tons of coal needed by 1985, approximately 50 large underground mines or 20 large surface mines, or a combination of large and small underground and surface mines would be necessary. Such mines could only become operational after considerable study which includes the adequacy of clean coal reserves and water supplies, the determination of market requirements, and capital availabilities for the construction of mines, utility plants and transportation facilities.

a. Coal Resources and Reserves

The Nation's coal reserves are more than adequate to support an accelerated schedule of development. Coal is the Nation's most abundant fossil fuel, representing 94 percent of "identified" recoverable primary energy resources, as compared to 3 percent each for natural gas (dry) and oil (including natural gas liquids) (59).

Coal underlies 458,600 square miles in 37 States. Of the remaining coal resources, estimated as of January 1, 1967, to total more than 3,200 billion short tons, over 2,800 billion tons are at depths of less than 3,000 feet, of which over 1,500 billion tons have been identified by mapping and exploration (59), with 1,600 billion tons estimated to be at less than 1,000 feet below the surface (60). About 390 billion short tons are commercially recoverable under present economic conditions and mining technology (61).

There is an abundant supply of low-sulfur bituminous coal and sub-bituminous coal and lignite in the Rocky Mountain States that could be used in power generation, coal gasification, and coal liquefaction plants; the remaining resources in the region were estimated to be 874 billion short tons as of January 1, 1967 (59, p.33), with 188 billion tons in beds usually 10 feet or more thick and less than 1,000 feet below the surface. The recoverable resources are about 94 billion tons to a depth of 1,000 feet and 440 billion short tons to a depth of 3,000 feet.

Approximately 47 billion tons of recoverable resources in the Rocky Mountain and Northern Great Plains provinces can be extracted by surface mining, 26 billion short tons of which are so well known as to character, thickness, and tonnage that they are considered as reserves (62). Of 45 million tons of coal produced west of the Mississippi River in 1970, 33 million tons were low-sulfur coal, 78 percent of which was mined by surface operations.

b. Coal Utilization

Currently, coal provides about 20 percent of the total U.S. energy consumption, down very markedly from earlier years when it provided most (78 percent in 1920) of the Nation's energy. Its largest market is power generation which accounts for 61 percent of the total U.S. coal production of about 610 million short tons in 1970. Coal for coke production consumes about 18 percent and the balance, exceeding 100 million tons, is used for manufacturing, general commercial purposes, and space heating - markets that have been declining steadily in recent years.

Many important technologic, economic, and social factors will influence coal's future capabilities. Among these are the adequacy of mining capacity, new additions to which have been discouraged by uncertainties as to the timing and extent of increased nuclear power generation and of utility commitments thereto; oil imports;

and environmental problems, including air and water pollution, land reclamation, and uncertainties as to legislative curtailments of strip mining. Other important considerations include more stringent health and safety regulations that have resulted in a reduction in the number of underground mines, a loss in mine productivity, increased costs at underground mines in order to provide an acceptable working environment; and increases in the number and production of surface mines. In addition, mechanization in mining already has reached such high levels (97 percent of underground production mechanically loaded in 1970, 40.5 percent of total production mined by stripping, and 3.3 percent by auger mining) that further major advances in mechanization are unlikely.

All of these factors point to the challenges for research on, and the development of, new and improved technologies in both underground and surface mining. New technologies, and their timing, will both affect and be affected by the extent to which long-term contracts are made for coal for electric power generation and other uses; by the effect of environmental restrictions on the development of additional productive capacity for deep-mined low sulfur and other coals, and in the development, or the extent of participation, of surface-mined coals in meeting increasing energy requirements; and by the need for improved efficiencies in sulfur removal by stack emission processes to permit the use of high sulfur coals, and for coals to be used in conversion to gas and liquid fuels.

The large coal resources of the Nation, if interchangeable for other energy source forms, are adequate to provide the energy needed if the oil shale lease program is not undertaken. Many very thick and closely spaced beds of lignite and sub-bituminous coal, containing about one-half of the remaining coal resources in the West, underlie the northern part of the Great Plains. About two-thirds of this coal is on public lands managed by the Federal Government. The coal generally has a low ash fusion temperature, a low sulfur content, a relatively low heating value, and high volatile matter content. These characteristics suggest that this coal would be adaptable for power generation, gasification, and liquefaction, particularly that which is strip-mined at low cost. The degree of their substitutability in solid or synthetic product form could be a controlling factor.

c. Northern Great Plains Resource Program

Recognizing the potential for coal and its obligation as the Nation's natural resources agency, the Department of the Interior announced on October 3, 1972, the Northern Great Plains Resource Program (NGPRP). The Northern Great Plains, an area which consists of large segments of Montana, Wyoming, North Dakota, South Dakota, and Nebraska, has been the focus of increasing attention because the area is a potential source for vast amounts of relatively low sulfur coal (Figure V-2). The possibility of large scale development of the coal reserves has, at the same time, heightened regional concern for effective land use and resource planning, including such issues as environmental quality, mined area reclamation, competition for scarce water resources, development of other mineral

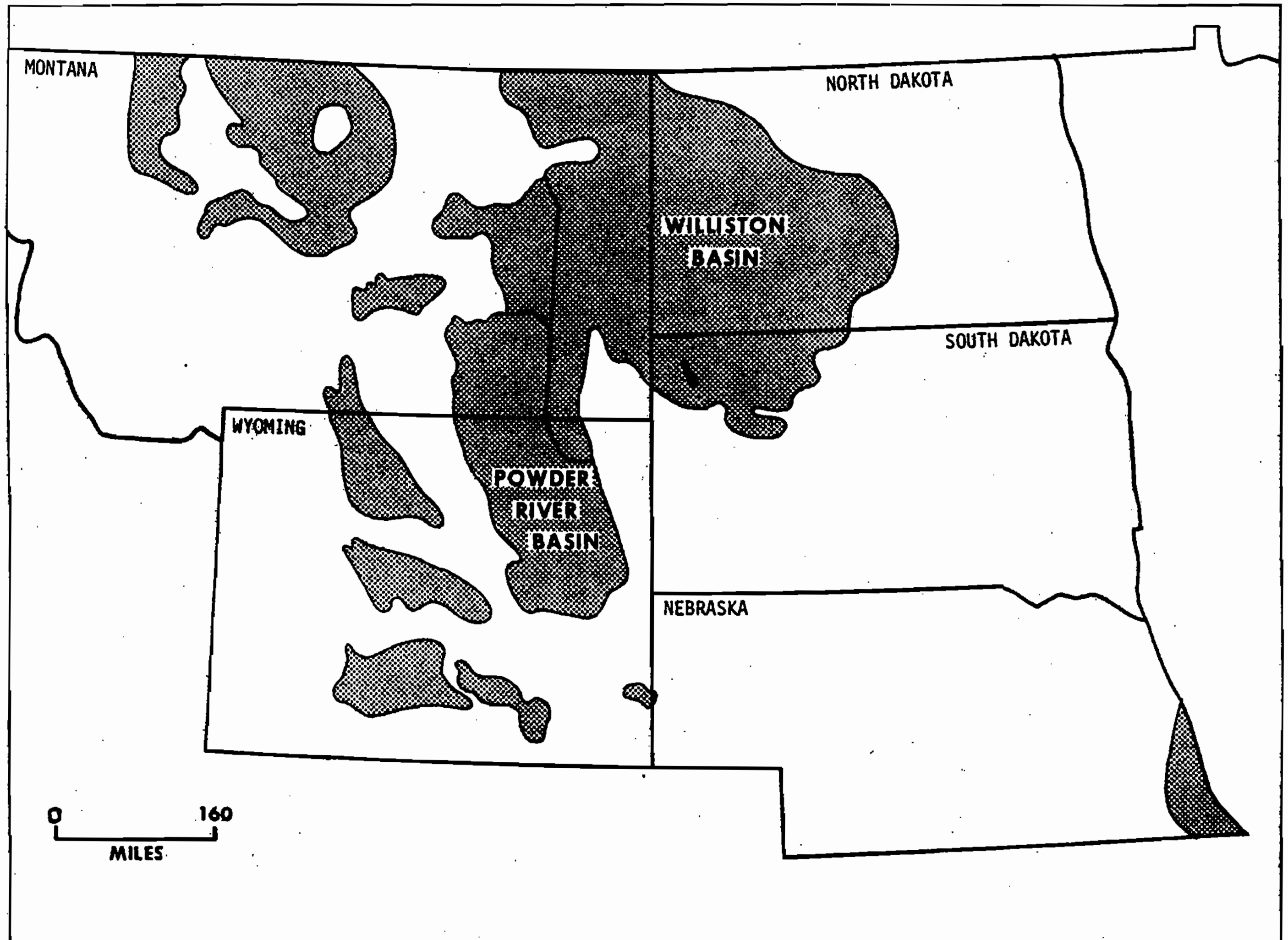

Figure V-2 - **COAL RESOURCES IN NORTHERN GREAT PLAINS**

U. S. Department of the Interior/Geological Survey resources, and potential effects on the people and economies of the Northern Great Plains States.

The NGPRP is not an alternative to oil shale development, as such, since the proposed program is solely designed to examine the possible consequences of alternative development strategies of the resources of the region, including, but not limited to, coal. The purpose of the program is not to recommend actions or make decisions but rather to display the facts and the implications of various alternative strategies upon the social, economic, and environmental future of the area. However, implementations of one or more of the alternative development strategies could be an alternative to oil shale development. If one of these developments should be coal, the environmental impacts would be those described in section d. (beginning on page V-112).

The local, State and Federal Governments which make land use and resource planning decisions affecting the Northern Great Plains area face competing economic, social, and environmental alternatives. The Federal Government continues to make decisions regarding leasing schedules for coal resources on public and Indian lands, regulations for air and water quality, and development of water projects. Congress is considering several measures related to surface mining. The States also are concerned with resource development; many have considered or taken legislative action related to surface mining and have prepared State Implementation Plans for air quality under the Clean Air Act. Local governments promulgate zoning and land use plans, and provide for essential public services. Regional Commissions for economic development and water supplies share similar concerns and responsibilities. Local, State, regional, and National interests are not well-coordinated at this time.

These factors have led the five States, the Old West Regional Commission, and several Federal agencies to cooperatively initiate the Northern Great Plains Resource Program (NGPRP). The following sets forth the objectives of the program.

The primary objective of the NGPRP is to provide an analytical and informational framework for policy and planning decisions at all levels of government. The end result is intended to be a decision-making tool for Federal, State, and local interests who together must plan and manage the area's land and natural resources.

The principal issue concerns the development, or nondevelopment, of land resources within the Powder River and Fort Union areas. Particular emphasis is placed on coal resources. The program will provide data and analytical methodology, including the development of appropriate models, to demonstrate the economic, social and environmental consequences of various courses of action. The program will present both quantifiable and nonquantifiable implications of alternative land and resource uses. The final report will not recommend a particular development plan for the region, rather, it will provide adequate information on the balancing of values and net benefits of alternative plans to guide development of a coordinated Federal-State plan.

The second objective is to encourage the organization of ad hoc institutional entities that will bring together all facets--local, State, and Federal--concerned with collection and interpretation of information which will affect the future development and quality of the region. It is anticipated that this will lead toward a coordinated planning program for the entire region. The organization would draw from existing State-Federal mechanisms for socio-economic planning in the region, such as State planning groups, Title V Commission, and appropriate River Basin Commissions. Policy and decision-making authority must be retained by established agencies, organizations, and the State and local entities. The NGPRP will contribute in every possible way to encourage this coordination.

A third objective is provision of a coordinating link between data collection, research, planning and operational resource management activities that exist within many different organizations. Such a link should assure rapid interchange of technology and methodology between individual programs associated with the NGPRP.

The study envisions that the development of coal or other minerals will be considered in relation to impact on the local economy, as well as impact on the esthetic and cultural values of the region, and relation to the National energy situation. Likewise, in considering energy development cases, analyses of air quality, for example, will include implications of electrical generation in distant urban areas as opposed to generation in the study area, as well as the relative effects of each on local air quality. These two examples are meant to illustrate the wide range of concerns within the NGPRP.

The NGPRP will consist of a series of investigations and studies dealing with a common theme, rather than a single area of concern. The over-all study will be time-phased and, although a comprehensive final summary report will be issued, study results will be reported as they are completed. The NGPRP as a resource study can lead to stimulation of the production of coal from the study region. If the coal is developed, it can possibly be an alternative to oil shale development. The environmental impacts of coal development would be those described later in this report.

d. Environmental Impacts of Coal Utilization

The expanded use of coal power generation could be a viable alternative to the use of less abundant fossil fuels (oil and gas). Major limiting considerations are those associated with the extent to which it can substitute for other energy sources, including the convertibility of equipment where displacement would be involved, and the solving of problems associated with the meeting of air quality standards. The latter would be of minor significance in the West where most coals are of low sulfur content.

The sulfur content of U.S. coals ranges from 0.5 to over 7 percent. About 65 percent contain 1.0 percent or less, most of which are found in the Western States, far removed from the area of the current major demand and use (the Midwest and the East).

Most current production is in States east of the Mississippi River, where only 20 percent of the reserves (including 100 billion tons of bituminous coal) contain 1.0 percent or less sulfur, while

43 percent contain more than 3.0 percent sulfur. Sulfur oxides are emitted to the atmosphere in direct proportion to the sulfur content of the coal feedstock. The effects of SO_2 on plants, animals, and humans are documented in Vol. I, Chapter III, Section C.

Recent environmental regulations applicable to new electric generating facilities restrict the emission of sulfur dioxide to 1.2 pounds per million Btu of fuel as fired; for bituminous coal, this is equivalent to about 0.7 percent sulfur. It is necessary, therefore, to reduce the sulfur content of the coal prior to burning or to remove sulfur oxides from stack gases following combustion in order that coal may continue to be used for power generation in most areas.

Mechanical cleaning of raw coal is only a partial solution to the problem, since only a small fraction of American coals can be cleaned sufficiently to meet sulfur standards. Mechanical cleaning affects only pyritic sulfur and leaves untouched the 40 to 60 percent of the sulfur that is bound in the organic structure of the coal. In addition, freeing the small particles in which pyrites occur requires fine grinding prior to cleaning, which in turn adversely affects the cleaning efficiency and restricts the methods of cleaning that can be applied. Tests of some 322 coals representing most of the steam coals produced in eastern United States showed that, under optimum conditions and present technology, less than 20 percent of these coals could be cleaned to 0.7 percent sulfur prior to combustion (Bureau of Mines).

The status of technology for abatement and control of sulfur oxides in combustion gas was recently reviewed by the National Academy of Engineers, National Research Council, whose report (63) concluded that in early 1970 "...commercially proven technology for control of sulfur oxides from combustion processes does not exist." A number of systems are either being installed or operated at the present time on commercial plants, however, to determine the operational and economic feasibilities of the processes (63).

Coal, especially high-sulfur coal, is available in large quantities in close proximity to consuming markets, and many existing power plants can burn only coal. New coal burning plants could be built if air quality standards can be met. Process economics for coal desulfurization presently are marginal, and optimistic assessments of economics of stack emission controls in some cases are based on a substantial credit for sale of byproduct sulfur, but the supply of sulfur has exceeded demand recently, and substantial additional production of elemental sulfur could cause further disruption of the domestic sulfur industry.

President Nixon in his June 4, 1971, message to the Congress on Clean Energy emphasized the need for a greatly expanded effort on sulfur oxide control technology. Federal funding is being directed to demonstrate various techniques during the next several years.

e. Environmental Impacts of Underground Mining

The coal in the Rocky Mountain States that is too deeply buried to be extracted by surface mining could be recovered by underground mining, but at higher production costs. If the oil shale leasing program is not initiated and if the Western States should have to produce an equivalent amount of energy from coal (490,000,000 short tons for the period 1974-1985), the preponderance of requirements could come from low-sulfur surface mines. Also, surface mining could be supplemented by underground mines with low-sulfur coal although manpower requirements and capital expenditures would be substantially larger. If all the coal were to come from underground mines, manpower would total about 25,000 employees and capital expenditures would approximate $1.2 billion (34).

Social costs in terms of health and safety of mine employees must be considered along with capital expenditures and environmental costs of underground coal mining. A total of 149 men were killed in 1971 in underground coal mining operations -- a fatal injury frequency rate of 0.84 per million manhours or 0.54 per million tons of production. Enforcement of existing mine safety laws and the introduction of new technology should reduce the fatality rate in the future. Theoretically, no more than about 260 additional fatalities could be expected during the 12-year period from 1974-1985 if only underground mines were developed to supply the same amount of energy as expected from shale oil.

Subsidence of the ground surface is common above many abandoned and some active coal mines. The amount of subsidence is related to the mining method employed, the amount of coal removed, the thickness and depth of the coal bed or beds and the composition and strength of the rock strata overlying the coal. Subsidence of large areas commonly destroys man-made structures. It also disrupts the ground-water hydrology, and surface and subsurface water recharge. It may intercept or short-circuit both surface and subsurface water moving across or through the area that has subsided. Subsidence may increase vertical permeability so that recharge from the surface is increased. Subsidence also may provide increased communication between aquifers. It also, in some localities, causes land slides and minor earthquakes.

If a room-and-pillar mining system is used, the most successful method for alleviating surface subsidence problems is to plan the mining so that more pillars are left untouched. Unfortunately, this procedure results in less coal recovery, and some subsidence is almost certain to occur. The best solution to achieve as complete a recovery of coal as possible during mining is to allow controlled subsidence to the point of natural stabilization which will permit use of land surfaces. Longwall mining systems, which can achieve from 90-95 percent recovery, are widely used in Europe where methods have been developed for controlled subsidence with little environmental damage.

Ground and surface waters entering active underground mine workings are normally pumped to the surface for disposal. Because of the low-sulfur content of most Rocky Mountain coals, it is uncertain whether acid-mine water would be a problem in areas of large-scale mining and above average precipitation. Acid-mine water may drain from abandoned mines and workings for long periods, resulting in a significant cumulative effect. Acid drainage may be prevented by locating mine entries at elevations above the prevailing drainage level, by sealing abandoned mine entries, and by emplacing dams at critical points in abandoned underground entries and haulageways.

In most coal producing areas, mining and processing wastes contribute large volumes of sediment to nearby streams and are sources of air pollution. The most commonly used technique of preventing widespread scattering of mining and processing wastes is to compact the waste in layers, followed by sealing with incombustible soil, after which vegetation is established to help prevent infiltration of surface and to minimize erosion (64).

An alternative to surface disposal of mine and coal processing waste is to return it to abandoned underground mine workings. For example, this is currently being done to control surface subsidence in mined areas in compliance with restoration provisions of the Appalachian Regional Development Act of 1965, as amended (65, p. 24).

Many operations associated with underground mining such as mine-access roads, coal handling, and processing, cause dust problems. Road dust can be minimized by hard surfacing or by oiling or chemical treatment of the road surface. Dust from coal handling and processing is abated by spray treatment at transfer points and by enclosing coal-handling and processing structures. Dusting problems in live coal-storage piles can be reduced by water sprays or oiling; dead storage piles can be sealed with asphaltic or chemical materials.

Additional environmental impacts from underground mining operations, particularly after mine closure, include creation of waste disposal areas, unsealed abandoned mine openings, and abandoned mine buildings and structures. These impacts require measures to mitigate their undesirable effects.

Other environmental impacts include those associated with drilling, blasting, alteration of ground water hydrology, product processing, liquid effluent discharges, and accidents to humans.

The following environmental effects of underground mining are generally more severe than those associated with surface mining because the underground mines are generally deeper: extensive and severe alteration of ground-water hydrology, the necessity of well drilling and fluid removal, the techniques of product processing and resultant waste, liquid effluent discharges, and most accidents.

f. Environmental Impacts of Surface Mining

Near-surface coal (0 to 200 feet) generally can be extracted by surface mining. This method involves the removal of the top soil and rock (overburden) to expose the coal bed, removal of the coal, replacement of the spoil material and, in some instances, replacement of the top soil. Usually this is accomplished by working in large parallel trenches using the overburden of the second trench, or cut, to fill the first trench.

In 1929, surface coal production amounted to 3 percent of the total United States production (66, p. 9). In 1969, however, surface mining accounted for approximately 200 million short tons or 35.2 percent of the 560 million short tons of total U. S. production (67, p.309). The amount of surface-mined coal for the year 1971 increased to 50 percent of total U.S. production.

The preceding illustrates the slow growth of surface mining from 1929 to 1969 and a spurt in production from 1969 to 1971. The principal reasons for this growth are; (1) full production can be reached quickly; (2) the coal can be mined more cheaply; and (3) surface mining is much safer than underground mining.

Social costs in terms of the health and safety of mine employees are an important component of all mining operations. A total of 25 men were killed in 1971 in surface coal mining operations. On the basis of the 1971 fatal injury frequency rate of 0.09 per million short tons of production continuing until 1985, approximately 44 additional fatalities could be expected during the period from 1974-1985 at surface mines developed to supply the same amount of energy as expected from shale oil.

The use of coal as an alternative energy source, if the oil shale leasing program is not initiated, would result in the need for additional mining of about 480 million short tons of coal over the period from 1974-1985. If the peak production of 95 million short tons of coal production should be furnished totally by surface mines, 20 mines of 5 million short tons annual capacity each would be the minimum number of operations needed. Currently, a mine of this magnitude employs 610 personnel with a capital expenditure of about $40,000,000. Therefore, for surface mines to supply the 95 million tons of coal needed annually by 1985, 12,200 employees would be supplies, and water quality, all of which would locally limit the enjoyment of hunting, fishing, and allied leisure time activities in addition to affecting scenic vistas and open spaces. Furthermore, nearby agricultural, residential, commercial and industrial activities could be impacted by environmental effects that were propagated beyond the area of mining, for example, stack emissions, dust, noise. However, reclamation of the area would restore its long-run productivity.

Production of 482 million tons of coal over the 12-year period requires the handling and placement of 25 million tons of waste material. This material can generally be placed back in the pits from which the coal was removed. Ultimately, the mine pits would be backfilled, the spoil banks topped off or leveled, the highwalls backsloped, the top soil replaced, and the area reseeded.

Other short-term problems related to surface coal mining are development of acid mine water in the open pits, in spoil piles, and in mine processing waste; erosion of silt from the pits, processing waste and spoil piles; and blowing of dust from the pits, spoil piles, truck haulage roads, railroad cars, mine processing plant, and processing waste piles. These problems adversely affect water and air quality.

In comparison with underground mining, surface mining is the source of greater volumes of noise and vibrations from blasting, drilling, heavy mining equipment, trucks, and landslides. Modification of the habitat, alteration of ground cover, alteration of drainage systems, destruction of land forms, and siltation of nearby streams are also more pronounced in surface mining. Landslides are more common, and subsidence does not occur unless the area has been underground mined. Also, there is a major conflict with timber, grazing, wildlife, and other resource use.

g. Waste Disposal

Large volumes of waste are generated during coal mining and processing. The volume of mine waste depends on the type and characteristics of top and bottom strata, the continuity of a coal bed, the existence of fault zones, and the tonnage of rock that must be mined. The type and volume of waste discarded during coal processing depends upon the specifications for which the coal is being prepared, characteristics and amounts of impurities in the coal bed being mined, and the efficiency and type of coal processing equipment.

Uncontrolled disposal of coal mining and processing wastes, especially those containing coal dust and trace amounts of sulfur, constitute a source of land, water, and air pollutants. Water flowing over waste disposal areas commonly transports silt and leached minerals to adjacent land and surface water drainage areas. The cumulative effect of this leaching can be severe. In addition, dust-size particles commonly are transported by winds to contaminate adjacent land and water resources. Both the leaching and dust problems give long-term undesirable effects. If a waste pile containing sulfides and large amounts of carbon spontaneously ignites, noxious gases enter the atmosphere which are hazardous to plants, animals, and humans (69).

Waste disposal areas require a commitment of land resources. Furthermore, if poorly constructed and uncontrolled, these waste areas present an unattractive appearance to viewers. Slides and slump failures commonly occur where waste is deposited on slopes and where an improper combination of moisture and clay minerals in the topsoil or in the waste act as lubricants. In such unstable conditions, large quantities of waste can move downslope and deposit on land and in water resources. Slides also are safety hazards to people and animals.

If fine coal cleaning is included in the preparation processes for Rocky Mountain coals, the discarded fine waste would probably be deposited in slurry impoundments where the water would either be decanted for recycling to the preparation plant or allowed to evaporate. Poorly designed impoundment dikes can permit seepage of retained water to enter downslope surface water drainage areas and degrade their water quality. Also, such impoundments are subject to failure which could lead to floods and/or landslides. In addition, construction of impoundments on underlying pervious bedrock commonly results in infiltration of mineralized water to the ground water table or in percolation of such water through the base of dikes to enter downstream surface water drainage systems where these types of leakage commonly affect aquatic plant and animal life.

h. Coal Transporation

It is assumed that the total quantity of mined coal supplied over the period 1974-1985 could not be adequately handled by today's transportation network at a reasonable cost; therefore, all new power, gasification, and liquefaction plants would be situated at, or near, the actual mine locations, thereby having nominal effect upon existing transporation systems. Therefore, the options are either to greatly expand the transportation network or to transport the energy derived from the coal by locating gasification, liquefaction, or electrical generating plants near the mine location. The end product of the above plants (synthetic gas, synthetic oil, and electricity) could be more readily transported to the market areas by transmission lines and existing, or new, underground pipelines. Surface or underground transmission lines and pipelines should cause fewer environmental impacts than increasing the mileage of highways or rail routes and building the large number of highway trucks and hopper cars necessary to move this vast quantity of low sulfur fuel.

Four systems of transporting coal per se, as distinguished from the transmission of coal-generated electric power, would be available in the Rocky Mountain States for moving coal from a mine to a point of utilization. These systems are trucks, railroads, conveyors, and coal slurry pipelines. Water transportation is not considered because of the lack of navigable waterways in the western coal region. Each system has advantages that would make it economically attractive for transporting coal to a point of utilization. Selection of a system would be strongly influenced by the distance to a utilization plant.

The major adverse environmental impacts of alternative transportation systems are air and noise pollution, safety, the amount of land required for rights-of-way, trash disposal, and aesthetics.

Air pollution sources are exhaust emissions, road dust, and coal dust. The level of adverse exhaust emissions can be reduced through efficient engine maintenance; road dust can be reduced by haul-road surface treatment such as hard surfacing, oiling, or applying water-chemical solutions; and coal dust can be reduced by truck covers and spraying. Although mufflers can reduce the level of noise pollution, truck haulage, because of the large number of noise sources and frequent trips, is commonly recognized as the noisiest system of transportation.

Collisions between trucks, other vehicles, persons, and animals can occur but do not normally constitute a serious public hazard because haulage roads generally are confined to mine property.

Secondary environmental impacts from truck transportation arise from improper disposal of tires, expended oil, and used parts. These items can be disposed of in open cuts of surface mines and then buried with reclaimed spoil and revegetated. In addition, special disposal pits can be excavated at underground mining operations where these items can be buried and the area revegetated. Depending on economics of the particular mining operation, a reasonable alternative would be to recycle these items.

Rail transportation systems using diesel locomotives are sources of air and noise pollutants from engine exhaust systems. Effective maintenance of engine combustion systems and efficient mufflers can reduce the air and noise pollution levels from these systems. Coal dust lost in transit can be reduced by using partially covered hoppers or by drilling the coal during loading. Dusting during loading and unloading can be reduced with a combination of dust suppression sprays and enclosed chutes or bins.

The right-of-way for a railroad constitutes a permanent commitment of the land surface to this use, making it unavailable for other uses. Free travel of vehicles, people, and animals across the committed area is restricted; however, the potential for collisions with trains exists.

In the open or scenic areas of the Rocky Mountain States, railroad rights-of-way may be considered as aesthetic intrusions, especially if large trestles, overpasses, or cut and fill areas are required. Cut-and-fill areas can be constructed with gentle slopes and revegetated, and areas can be reclaimed as mentioned in conjunction with truck transportation systems. The visual impact of trestles, overpasses, and other appurtenant structures can be minimized with effective combinations of eye-pleasing designs and unobtrusive colors.

Conveyor system installations likewise constitute a permanent commitment of the land surface and restrict free movement of vehicles, people, and animals. The right-of-way width is less than that required for truck or railroad transportation systems. Uncovered or partly covered conveyors allow loss of dust in transit because of exposure to winds. Uncovered transfer points also are a potential source of dust when suppression devices are not provided. Open, or partly covered conveyors, constitute a safety hazard to persons or animals when a support structure is installed close to the ground. Conveyor systems can be fenced or completely enclosed to eliminate dusting and safety hazards to humans and animals.

Conveyor support structures, either frame or suspension type, as well as the conveyors, are obvious visual intrusions, especially at points where the conveyor crosses deep drainage systems. Color treatment of support structures, enclosures, and transfer structures would lessen but not eliminate this impact.

The principal impacts of coal slurry pipeline systems are the permanent commitment of land, providing an adequate water supply, and water disposal. Large quantities of water, at the rate of 1 ton of water per ton of coal, are required to transport coal in the Black Mesa, Arizona, pipeline (70, 149). In water deficient areas this method may not be an efficient transportation alternative, particularly where the water must be supplied by deep wells which, when pumped, could have a drawdown effect on shallower wells that supply people or livestock. Additionally, water disposal problems at the terminus of a pipeline could have severe impact on water quality if not properly contained or when it is not economically feasible to recycle the water for transportation purposes. Coal slurry destined for power, gasification, or liquefaction plants could be dewatered, the "spent" water used for cooling tower makeup, ash handling, and/or evaporated in disposal ponds. The Mohave generating station in Nevada is utilizing water from the Black Mesa Pipeline in this manner, including a water monitoring program.

The disposal of solids and water removed from sections of a plugged pipeline could cause environmental impacts. Holding ponds equal in capacity to the upstream pipeline, could be provided at pumping stations and at the coal slurry preparation plant for disposal of removed plugs. The water could be evaporated and the coal could be left in the impoundment unless provisions are made for recovery. Compaction and sealing would prevent spontaneous ignition, erosion, and accompanying siltation of the coal left in impoundments. The surface of the impoundment can then be revegetated with indigenous plants to inhibit erosion.

i. Coal Conversion

Through several different processes, it is possible to convert coal to various liquid and gaseous forms as a substitute for natural petroleum and gas. One form may be as a low Btu gas suitable for power boiler utilization for production of electrical energy. Another more sophisticated gasification process could produce a high Btu gas suitable for direct distribution and use through existing pipelines (71-72).

While no coal-to-pipeline gas process has yet reached the commercial stage in the United States, several companies are studying commercial application of a variety of gasification processes, some of which have been known for several years. For example, the Lurgi fixed bed process has found commercial use in India, Australia, Germany, South Africa, Russia, and the United Kingdom for many years, and a commercial size plant is under construction in New Mexico.

The feasibility of using such processes as an alternative to shale oil depends upon the rate at which technological systems are developed, tested, and proven to be economically viable and commercial scale plants could be built. Any commercial gasification plant system would have to produce about 6 billion ft^3/day of 1,000 Btu/ft^3 gas to be equivalent in energy potential to 1 million barrels/day of shale oil. Many of the individual units for a commercial gasification process have been tested; however, synthetic gas has not yet been economically proved. Under current conditions, the National Petroleum Council (NPC) has estimated that approximately 1 trillion ft^3 per year of gas from coal will be available by 1985 (81, v. I, p.9,13). Under accelerated conditions, the NPC estimates that this could be increased to a maximum of 3 trillion ft^3 per year (81, v. I, p.9,54). The difference, 2 trillion ft^3 per year, represents about 5.5 trillion Btu's per day. Since the energy available from 1 million barrels per day of shale oil production is 5.8 trillion Btu/day, acceleration of coal gasification can be considered an alternative to oil shale development.

The production of 2 trillion ft^3 of synthetic gas per year would require approximately 22 plants that each produce 250 million ft^3 per day. The coal mining capacity (strip) that would need to be developed to support this output would approximate 150 million tons per year. The environmental impacts of coal mining have been described in the previous section; the potential impact from the plants themselves are considered separately below.

(1) Coal-to-Gas Processes.- These processes are currently at different levels of development ranging from the operation of smaller process development units to obtain basic design data,

the construction of prototype plants, the operation of prototype plants, and the further development of specific process steps to allow the two existing commercial coal gasification systems (Lurgi and Koppers-Totzek) to be adapted for synthetic natural gas production.

Table V-4 summarizes the status of these coal gasification processes. Two of the processes are currently at the stage where prototype plants are in operation (IGT's HYGAS (126) and Consol's CO_2 Acceptor (127) and two others /U.S. Bureau of Mines Synthane (128) and BCR's Bi-Gas (129)/ will be on stream by (1974).

Of the plants now in the prototype stage, all except the Consol CO_2 Acceptor involve the following basic steps:

1. The gasifier or gasifier-hydrogasifier where the coal is converted into a gaseous mixture of hydrogen, carbon monoxide, carbon dioxide, water, methane, ethene, and small quantities of sulfur compounds.

2. The shift reactor where the hydrogen to carbon monoxide ratio is shifted to 3 parts of hydrogen to 1 part of carbon monoxide.

3. The purification step where the impurities such as sulfur compounds and carbon dioxide are removed.

4. The methanation step (130) where the hydrogen and carbon monoxide is converted to methane. The Consol CO_2 Acceptor gasifies lignite using the heat generated by reacting carbon dioxide with calcined dolomite rather than heat generated by reacting coal or char with oxygen. This allows the elimination of an oxygen plant but requires an increase in plant complexity and reduces the gasification temperature so that only the most reactive coals such as lignites can be used.

Table V-4 - Coal Gasification Processes

	Process	Laboratory	Sponsor	Prototype Plant Operation
1.	HYGAS	I.G.T.	O.C.R.-AGA	1971
2.	CSG (CO Acceptor)	Consolidation Coal Company	O.C.R.-AGA	1972
3.	Synthane	BuMines	BuMines	1974
4.	BI-GAS	B.C.R.	O.C.R.-AGA	1974
5.	Hydrane	BuMines	BuMines	**
6.	Fixed Bed	BuMines	BuMines	**
7.	Fixed Bed	LURGI	El Paso Gas Co	1976
8.	Atgas	Applied Technology Corporation	AGA-O.C.R.	**
9.	Kellogg Molten Salt	Kellogg	Kellogg-O.C.R.	**

* Commercial operation.
** Date for prototype plant not yet decided.

Though in a broad sense the processing steps are similar, there is a considerable difference in gasifier designs, methods of pretreatment, and the methanation processes being used.

Other processes are at the stage where design data for prototype plants are being generated in smaller process development units. These processes are the U.S. Bureau of Mines Hydrane Process (131), the Kellogg Molten Salt Process (132), and Applied Technology's Atgas Process (133). These processes are different from the processes now at the prototype stage in the following respects:

The Atgas Process gasifies raw coal with steam and oxygen, but the gasification is carried out in a molten iron bath with the addition of a limestone flux. The process is carried out at atmospheric pressure, and the limestone flux completely removes sulfur. In addition, raw-caking coals can be used without agglomeration. Disadvantages of this process are the low production of methane directly from coal, which means most of the methane must be produced indirectly by methanation and the compression required to introduce the product gas into transmission lines.

The Kellogg Process also gasifies coal with steam and oxygen but does it in a molten salt bath at transmission line pressure. Advantages claimed for this process are that the catalytic effect of the salt can lower gasification temperatures from 1900 to 1700° F and raw caking coals can be used without agglomeration. The prime disadvantage is a corrosion problem from the molten salt. In addition, the amount of methane that can be formed directly from the coal has not been established.

The Hydrane Process is unique in that it forms almost all (95 percent) of the total methane production by the direct reaction of coal with hydrogen and thus requires minimal methanation. In addition, the design of a special reactor system allows the utilization of even the most highly caking coals without pretreatment. The elimination of coal pretreatment and the production of methane directly from the coal rather than by indirect methanation are responsible for the high thermal efficiency and low gas cost estimated (134) for the Hydrane Process.

The Lurgi gasification system (135) (Item 7 - Table V-4) is the only high pressure gasifier now available commercially. Several companies including El Paso Gas Company are planning on constructing full-scale commercial plants (250 million cubic feet per day) using the Lurgi gasifiers plus commercial shift units and purification units. Their area of research is on the methanation step as there are no commercial methanation units which can operate on coal gasification gases.

At the present rate of development, a full-scale commercial plant could be operating by 1976 based on the Lurgi gasifier and by 1978 based on the other research which is proceeding through the prototype plant stage.

There is also a low pressure gasifier - the Koppers-Totzek entrained gasifier - that is commercially available. Disadvantages of the Koppers-Totzek[1/] are that it operates at atmospheric pressure, produces no methane directly, and requires (relative to the Lurgi and fluidized bed gasifiers being developed) a rather high-oxygen

1/ U.S. Licensee is the Koppers Co., Pittsburgh, Pa.

consumption. However, unlike the Lurgi, it can handle coal fines and agglomerating coal.

In addition to the above processes which produce SNG as the primary product, there are two pyrolysis processes in which SNG is a byproduct. One, the FMC COGAS Process (136) is based on the gasification of the char produced by the COED multistage pyrolysis process (136). The other pyrolysis process is one being developed by the Garrett Corporation (137), in which pyrolysis is carried out by recirculation of hot char in an entrained reactor system. However, in the Garrett Process the main products are the coal liquids and the yield of pipeline gas is relatively small.

There is at present much interest in the development of processes to convert coal to a low-Btu gas which could be used in a combined cycle power plant. The development of such a scheme would offer the advantages of allowing the utilization of sulfur containing coals and of providing a clean gas which would allow the use of more efficient power cycles. The usual cycle will consist of a steam and air gasifier to convert the coal to a gas having a heating value of about 160 Btu/scf. In this gas, the sulfur will be in the form of H_2S for which scrubbing technology is available. The cleaned gas can then be burned in a turbine topping cycle, and after exiting, the turbine would be used to generate steam for the bottoming cycle. Technology is also being developed to allow the hot removal of H_2S from producer gas which would improve the overall thermal efficiency of such combined-cycle power plants. In general, the technology for converting coal to producer gas is more highly developed than the technology for producing SNG. However, there are still problems when caking coals are to be used because of agglomeration problems. Among the several organizations currently developing low-Btu gas from coal processes are, the U.S. Bureau of Mines (138), Westinghouse, General Electric, Babcock and Wilcox, Combustion Engineering, Battelle-Union Carbide (139), and others. Information on many of these processes is not yet available. In addition, many of the SNG gasifiers can and will be adapted for SNG production, among them the Lurgi-moving bed process, the Koppers-Totzek entrained gasifier, BCR's Bi-Gas, and the Bureau of Mines' Synthane Process. For an excellent review of the prior art in synthesis and producer gas producer see reference 140.

Experiments in the underground gasification of coal date back to the 1890's. The most recent work in this country was undertaken by the Bureau of Mines from 1946 through 1956. The object of this work was to determine the feasibility of bringing the chemical constituents or the energy of coal to the surface in a gaseous form, useable in the synthesis of liquid or gaseous fuels, organic chemicals, or the production of electric power. Other objectives were to materially reduce or eliminate underground mining operations, to obtain useful products from coal or other carbonaceous materials that lie in beds that are not profitable to mine, and to recover the chemical constituents or the energy of coal remaining in areas when mining operations have been completed. From an economic standpoint, the cost of production of synthetic liquids and gases through in situ processes suitable to meet current energy requirements was found to be excessive. A recent review (73) suggests that due to advances in related petroleum technology, underground gasification of coal should be reexamined. However, this renewed interest holds little promise for significant increases to the Nation's supply of clean energy until, possibly, after 1985.

(2) Coal-to-Oil Processes.- Coal can also be converted by various means to yield synthetic oil (48-77). Many of the processes now under development convert the coal mostly to a liquid form, others produce liquids as a byproduct of coal gasification. However, liquefaction technology is a number of years behind the gasification effort and liquids from coal are not considered an alternative to oil shale development by 1985, although a few prototype plants may be operating by that time. A commercial plant would need to produce about 1.24 million barrels of synthetic crude oil to be equivalent to 1 million barrels of shale oil.

There is a long history of coal liquefaction studies and even rather large pilot developments (141), but none have as yet been commercialized in the United States. Present developmental emphasis is on four processes as discussed below (142-145). These four were selected for an in-depth evaluation study supported by the Environmental Protection Agency and conducted by Esso R&D Co. (143). Whereas previous coal-liquid conversion developments were mostly aimed at producing synthetic gasoline, the current trend is to do a cheaper, milder conversion to produce a clean, heavy fuel oil (or meltable solid) for firing electric power plants without air pollution by sulfur.

The Solvent-Refined-Coal (141-144) Process of the Pittsburgh and Midway Coal Company, subsidiary of Gulf Oil Company, is the most heavily funded. A 50-ton-per-day pilot plant supported by the Office of Coal Research and costing about 17 million dollars, started construction near Tacoma, Washington. Another pilot plant for essentially the same process has about 6 million dollars of support from a group of southern utilities and construction is being planned for Alabama. The SRC process is based upon extraction of coal with a solvent that is a distillate fraction of the product extract using a stirred vessel. The dissolved extract is filtered to remove ash and pyritic sulfur. To also remove some of the organic sulfur, late modifications of the process call for adding hydrogen or CO at up to 1,200 psig to react with the coal, thereby releasing organic sulfur. No specific desulfurization catalyst is used and pilot plant results will show whether overall sulfur removal from the extract is adequate to satisfy air quality standards for fuels (0.7% sulfur) when high-sulfur coals are the feed. The process may be limited to liquefaction of low-sulfur Western coals to give a fuel of more concentrated energy to lower transportation costs.

The development of the H-Coal (141-145) process of Hydrocarbon Research, Inc. is supported by a consortium of petroleum companies. A 2.5 TPD pilot plant with an 8-inch internal diameter reactor is being used, containing a recycle oil-coal-catalyst medium ebullated by hydrogen (144) to liquefy the coal. High conversion and good catalyst recovery are claimed. Scale-up plans are not known.

The COED (141 -144) being developed by Food Machinery Corp. under OCR sponsorship uses fractional carbonization of coal to maximize yield of tar, the product fuel oil after hydrotreating. Naturally, liquid fuels yield is lower than for coal hydrogenation processes. Also, the product char may have sulfur contents exceeding air quality standards, depending on the sulfur in the feed coal, and char desulfurization may be required. Development has advanced to successful operations of a 36 TPD pilot plant.

The Bureau of Mines hydrodesulfurization coal-to-oil process (146 - 147) uses a unique reactor system to accomplish the desired mild hydrogenation; raw coal conveyed in a recycled portion of its own product oil is propelled by rapid, turbulent flow of hydrogen through a reactor packed with immobilized (fixed-bed) catalyst pellets. The combined effect of the hydrogen, turbulence and catalyst is to liquefy and desulfurize the coal at high yields and high throughput. Sulfur is removed as H_2S which is easily converted by known technology into inert elemental sulfur for industry or storage. The key to long-term operability with the packed catalyst bed is the turbulent flow of hydrogen; this propels the coal slurry so violently through the packed bed that plugging is prevented as the coal passes through its sticky plastic phase prior to becoming liquid. Turbulence also has two more benefits; by attrition, it keeps the catalyst surface clean for good contact and, by violent mixing, it promotes mass-transfer of the hydrogen into the slurry where needed for the hydrodesulfurization reaction with coal. In this system, the intent is to do just enough hydrogenation to remove the sulfur, taking whatever amount of liquefaction incidentally occurs, thereby using only a minimum of costly hydrogen. The hydrogenation is mild because of a very short residence time, which also leads to very high throughput for reactor economy.

In the Bureau of Mines development, a 5- to 10-lb/hr pilot plant successfully processed 5 different coals in 30-day runs to yield high conversions of oil that in every case more than satisfied air quality standards by having 0.3 percent sulfur or less. The process appears to be applicable to all coals. A Kentucky coal having 4.6 percent sulfur and 16.0 percent ash was converted into fuel oil having only 0.19 percent sulfur and 1 percent ash. By early 1973, the pilot plant will be scaled-up to 50 lb/hr operation, and plans for 1973 are to begin design and construction of a 5-TPD pilot plant. It is possible that, in 2 to 3 years, this process may be ready for consideration for commercial design and utilization.

The environmental impacts associated with coal conversion processes will largely be those which are associated with the required mining of coal. The impacts of coal mining have been discussed earlier in this section and are summarized below. Impacts on air and water quality will mostly depend upon the region where the coal development and conversion processes will be brought into production.

Site preparation and plant construction would involve clearing and grading of about 200 acres per plant. Some noise and dust would be generated by the clearing operations. Cleared brush and timber would create a nuisance unless properly disposed of. Unavoidable noise would result from structural erection, and public inconvenience might develop as a result of the additional transportation and construction activity. Except for the change in appearance and the possible loss of access to the area, these impacts would be temporary.

Plant operation, consisting of handling and transporting the coal to the process, and converting the coal to gas and/or oil will involve large quantities of water for the conversion processes and scrubbing gases, and very large quantities of devolatized coal, called char, that will be burned in boilers to generate process steam and power, or gasified to make process hydrogen. Major emissions that must be controlled are as follows:

1. Sulfur and nitrogen oxides, bottom ash, and fly-ash from the plants generating process steam and power. Fly-ash emission from boiler stacks can be controlled, and furnace bottom ash and slag are handled routinely in the generation of power using coal. However, it may become desirable to locate large coal conversion plants near large strip mines where ash and slag from the process would be returned to the open cuts, and the ground restored in accordance with environmental considerations. The technology for controlling sulfur and nitrogen oxides, however, is not yet available commercially.
2. Contaminated water discharges containing phenols, cresols, benzene, oils, tars, and ammonia; gaseous discharges from the Claus tail gas containing some hydrogen sulfide and sulfur dioxide; and solid discharges such as char and ash;

and possibly solids from gas-scrubbing systems using solid sorbents such as dolomite. Process waste waters can be partly controlled by treatment and reuse. Claus tail gas can be scrubbed free of sulfur compounds. Waste solids may present disposal problems in terms of available space and/or surface water contamination, but these are not insurmountable problems.

3. Noise will occur from mechanical equipment, injectors, and pressure-reduction devices, but is unlikely that it would be a problem beyond the plant property lines.

To illustrate the order of magnitude of the major emissions that would have to be handled from a commercial coal-to-pipeline gas plant, the Federal Power Commission gave the following estimates, in tons per day, based on a plant producing 250 million standard cubic feet per day of pipeline gas, from coal with 3.7 percent sulfur:

Sulfur (mainly as hydrogen sulfide)	300-400
Ammonia	100-150
Phenols	10- 70
Benzene	50- 30
Oils and tars	trace to 400
Ash (based on coal with 10 percent ash)	1,500

6. Increasing Nuclear Energy Development

The use of nuclear power as a commercial energy source is expected to increase considerably in the next fifteen years. Installed capacity in 1970 was 7,000 MW and is currently over 15,000 MW. This is projected by the Atomic Energy Commission (AEC) to increase to 54,000 MW by 1975; 280,000 MW by 1985; and 810,000 MW by 1995.

Most of the currently operating and planned nuclear plants utilize light water reactors. In such reactors, the heat energy created in nuclear fission is removed by the circulation of water through the fuel core to generate steam to turn turbine generators to produce electricity.

Eight high-temperature, gas-cooled reactors are also completed or on order. These utilize helium circulating through the fuel core to boil water for steam to turn the turbine generators. These reactors are all of the burner type which utilize less than 2 percent of the available energy from the uranium which they burn. Breeder types of reactors which produce more nuclear fuel than they consume, such as the liquid metal fast breeder, are not expected to be available for commercial use until the mid-1980's. Breeder reactors could utilize more than 60 percent of the total energy from uranium. Thermonuclear fusion reactors are not expected to be a commercial reality much before year 2000.

If nuclear power were to displace all projected increases in petroleum demand (as estimated earlier, Table III-4) by utilities between 1980 and 1985, it would displace demand for approximately 320,000 bpd of oil. Additional substitutions could only be made by replacing facilities in place before 1980, either before or at the end of their economic life. Some shift in remaining fossil fuel plants from base to peak loading might also be necessary. Depending on the assumptions made about the amount of residential/ commercial on-site space heating capacity displaced, the additional capacity required could be between 37,000 to 50,000 MW.[1/] The capacity which would be displaced would be located primarily in the Northeast and Great Lakes States.

If all of the oil production from oil shale would be used to provide fuel for additional oil fired power plants and on-site space heating facilities, from 37 to 50 additional nuclear plants of 1,000-MW capacity each would have to be constructed to provide a complete substitute for shale oil.

Since the planning, licensing, and construction lead time for nuclear power plants involves a minimum of 6 to 8 years,

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1/ Calculated on the basis of the following assumptions:

1 bbl shale oil = 5,800,000 Btu,
3412 Btu = 1 kwhr thermal,
thermal efficiency of fossil-fuel steam-generating plants 40%,
thermal efficiency of onsite space heating facilities 65%, and
nuclear plants replace fossil-fuel plants operated at 75% load factor

nuclear power cannot be considered as an alternative to shale oil before 1980.

It is possible that the 37 to 50 additional nuclear plants required could be constructed by 1985, and serve as a substitute for shale oil at that time. This would represent an acceleration of 13 to 18 percent over the 1985 capacity projected by the AEC of 280,000 MW. To the extent that shale oil would not go into power plant or space heating uses, nuclear power would be only a partial substitute for such oil with a comparable reduction in the number of plants involved in such a substitution.

This analysis assumes complete nuclear power substitutability for shale oil (for discussion of substitutability, see Section II-C). For less than complete substitutions, a roughly proportional reduction in the environmental impact would occur. Since specific impacts depend upon where the particular activities constituting the nuclear fuel cycle would be located, a description of specific impact by location is not possible in most cases. The impacts described are considered to be a quantitative addition to similar impacts of existing or planned nuclear facilities.

Because of the lead times involved, nuclear power plants substituting for shale oil could only utilize current technology. Hence, the plants considered as replacements will be light-water reactors, either boiling water or pressurized water reactors.

It is possible that some incremental reactors could be high-temperature, gas-cooled reactors, which have a higher thermal efficiency and subsequently less waste heat problems. However, the number of these which could be built is considered to be small enough to be disregarded in the overall analysis. Neither breeder nor fusion reactors are considered to be viable alternatives before the late 1980's.

In the subsequent text, the significant impacts of uranium mining and milling, power plant operation and construction, transportation of spent fuel and waste materials, reprocessing plants, and radioactive waste material storage are discussed.

a. Uranium Mining and Milling

The construction and operation of additional nuclear generating plants would require additional mining and milling of uranium ore to supply the fuel elements for these plants. An incremental operating capacity of 37,000 MW by 1985 would require 21,000 tons of U_3O_8 for the first core fuels and 6,500 tons of U_3O_8 for annual reloads without plutonium recycling and 4,000 tons of U_3O_8 with plutonium recycling. At an average ore grade of 0.20 percent U_3O_8, a total ore output of 11 million tons would be required to supply the uranium for the first core fuels, and an annual output of 2.25 to 3.25 million tons would be required for reloads. Since the average ore grade can be expected to decline during the life of the plants, the estimated annual ore tonnage for reloads would increase, particularly after 1990.

The total U.S. nuclear power industry is forecast by the Atomic Energy Commission to require 1,164,000 short tons of U_3O_8 between 1985 and 1995. An additional 37,000 MW of nuclear capacity as an alternative to shale oil would require 86,000 tons of U_3O_8 in the 1985-95 period. Over the 10-year period, the 37,000 MW plants would increase the consumption of U_3O_8 by 7 percent. In 1995 when total nuclear power industry consumption of U_3O_8 is forecast to be 142,600 tons the additional plants would require 6,500 tons, an increase of 5 percent on the base load. As of December 13, 1972, the Atomic Energy Commission estimated that U.S. uranium resources in both the "Reasonably Assured" and "Estimated Additional" categories recoverable at $10.00 per pound of U_2O_3 totalled 1,037,000 short tons of U_2O_3. Thus, domestic uranium supplies at $10.00 per pound will be inadequate before 1995, even without the additional 37,000 MW of capacity.

Uranium mining and milling in the United States is concentrated in New Mexico, Wyoming, the Colorado Plateau, and south Texas. As most of the known and potential reserves are concentrated in

New Mexico, Wyoming, and the Colorado Plateau, the incremental mining and milling activity would be expected to occur there. In 1970, 53 percent of production came from underground mines, with most of the remainder coming from open pit mines. The ratio of production between underground and open pit mines is expected to be basically maintained over the next several decades.

In underground mining through the 1950's, excessive exposure to radioactive radon daughter products[1/] resulted in a high incidence of lung cancer. However, the recommended annual exposure limits have been vastly reduced in the past decade. By maintaining these lower limits, the incidence of lung cancer in underground uranium miners is expected to be reduced to a level not significantly higher than that of the population as a whole.

Uranium mining is largely concentrated in relatively isolated areas distant from large population centers and urban areas. Nonetheless, it does have an adverse aesthetic impact in the areas in which it occurs, as a result of the removal of the vegetative cover. Also, air quality in the immediate area could undergo some temporary reductions because of this removal of ground cover and the associated dust from vehicle and equipment movement. Waste rock is piled on the ground, changing the surface texture and

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1/ Radon is a radioactive gas produced by spontaneous decay of uranium. The gas disintegrates spontaneously into so-called daughter products. In the process of spontaneous disintegration, highly radioactive emissions occur.

accumulating extra overburden. Open pit mines require considerable acreage, reducing (depending upon location) the suitability of that area for other land uses such as grazing, wildlife, and some outdoor types of recreation. For underground mining, the extraction of deeper ores will tend to require some accumulation of waste rock dump areas. Planning for sequential land uses, followed by the reclamation of mined land and the backfilling of mined out stopes with waste rock could, however, substantially reduce these land use problems.

Because of the low concentration of U_3O_8 in uranium ore, milling the ore produces considerable amounts of tailing. The milling operation for U_3O_8 required for 37,000 MW of capacity over a 25-year operating life is expected to generate around 75 to 100 million tons of tailing. These tailings contain radioactive products and, therefore, must be contained in well constructed tailings dams to prevent erosion and leaching, which could result in the radioactive products entering surface and ground water systems. The specific adverse effects of these on the overall health of biota are not fully known; current evidence, however, does indicate increasing concentrations through upward stages of food chains. The technology for designing and constructing safe tailings dams does exist and is being used to prevent erosion and leaching and to retain harmful mill effluents at present levels of production.

Because of their low level radioactivity, mill tailings are unsuitable for subsequent use as fill material where human exposure might result. They are also a hostile environment for nearly all biota. Aboveground storage which minimizes erosion requires that they be covered with gravel or dirt upon which a vegetative cover can be established. Aboveground storage does, however, require considerable land area, which displaces other potential uses. Subsequently, in the future, an increasing amount of tailing may be utilized to back fill mined-out stopes and open pits.

b. Powerplant Construction and Operation

Assuming an average of three 1,000 mw units per site, the construction of 37,000 mw of additional nuclear capacity by 1985 would require 13 additional plant sites (less if some units were added to existing plants). Under current siting criteria, these would be located at some distance from population centers. Assuming 500 acres per site (based upon an exclusion area of one-half mile radius around each plant), 13 new plants would require a total of 6,500 acres, an area from which most other uses would be excluded.

Depending on the capacity of the transmission lines which would be required if nuclear energy were to substitute for energy produced from oil shale development, the transmission line right-of-way would require the use of ten to 15 acres per mile of line. Certain types of development such as residences would be restricted although such land would still be largely available for other purposes such as recreation. These additional transmission lines would have an adverse aesthetic impact by disrupting some scenic vistas.

Construction of the plants would present some short-run environmental problems such as the erosion of excavated materials. Special measures could be taken to prevent erosion of excavated material with subsequent siltation.

Operations of the nuclear plants will generate considerable amounts of waste heat. For example, light water reactors have comparatively lower thermal efficiencies than new fossil-fueled plants (around 33 percent compared to 40 percent). Given this difference in efficiency and under the assumption that fossil fuel plants, on average, release around 15 percent [1/] of their waste heat directly into the atmosphere, a light water reactor would release approximately 50 percent [2/] more waste heat into its cooling water than a fossil fuel plant of similar size. The effects of this waste heat will depend upon the cooling method used and the location of the plant (See Volume I, Chapter III, section C).

The effects of thermal discharges will depend in part on the size of the body of water into which this heated water is discharged. The effects along ocean sites, the Great Lakes, and

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1/ Energy Research Needs, Oct. 1971, Section IX, Resources for the Future, p. 19.

2/ Section VI, p. 15.

very large rivers are likely to be modest as the heat is more readily dispersed and more easily avoidable by aquatic species. Along smaller lakes and rivers, or in bays with limited circulation, higher water temperatures can produce fish kills, interfere with fish reproduction, disrupt food chains, decrease dissolved oxygen content, drive out desirable aquatic species, and encourage the growth of undesirable algae which may speed up eutrophication within the limits of the affected area. However, sometimes the heat can be used for agriculture and other beneficial uses.

The use of wet cooling towers, removing the heat by evaporation into the atmosphere, would not pose the problems of adverse thermal effects. However, water vapor from the cooling operations could have substantial effects on local haze, fog, cloud, and ice formation. Chemicals released in the cooled water or evaporated plume could also have adverse effects on downstream and downwind biota.

The use of cooling ponds would produce less evaporation than wet cooling towers, but haze, fog, cloud, and ice formation would still occur during periods of sub-freezing temperatures. The ponds require additional acreage (an estimated 1,000-2,000 acres per 1,000 MW unit). These may have recreational uses, but they would also displace previous land uses.

Nuclear power plants, unlike fossil fuel plants, do not emit the usual products of combustion such as particulates, sulfur oxides, and NO_x. Hence, they do not generate the air pollution problems stemming from or require control measures for such emissions. However, they do produce radioactive emissions whose release must be strictly limited if adverse effects to the health of humans and other biota are to be avoided.

In the normal operation of the incremental nuclear generating units, there would be very small amounts of radionuclides discharged in the cooling water and gaseous plant effluents. But, assuming that present standards will be maintained and enforced (these limit the release of radioactivity to no more than would expose an individual at the plant boundary to 1 percent of the individual maximum allowed), the effects of the amounts released are likely to be negligible, as the average additional annual dose which the affected population would receive would be three to four orders of magnitude less than the average level of natural radiation exposure.

The operation of nuclear plants poses some risk of accidents. Nuclear plants are designed to minimize accidents or their adverse effects if one does occur, utilizing a "defense-in-depth" principle. This includes designing and constructing plants in such a way that accidents are prevented and to contain the effects of accidents which do occur, and siting reactors away from areas of high-population density. Plants are designed to withstand a design basis accident (DBA), defined as the worst malfunction considered to have a probability of occurrence high enough to warrant corrective action. For light water reactors, the worst DBA considered is usually a major rupture in the cooling system. The maximum radiation dose which could be received at the site boundary if such an accident occurred, is estimated for some plants to not exceed the annual dose obtained from natural radioactivty.

However, the operation of many nuclear plants over an extended period of time can be considered to pose some risk of a catastrophic accident with a very remote probability of occurrence.

c. Transportation

The nuclear fuel cycle requires the transportation of radioactive materials by truck or rail at many stages. The transportation of spent fuel elements from reactors to reprocessing plants and of high-level wastes from reprocessing plants to storage sites poses a potential hazard of considerable magnitude. Existing transportation regulations and cask designs have been developed to ensure that even if accidents in transporting these materials do occur, no radioactivity will be released into the environment. For the transport of the spent fuels and high level wastes associated with an incremental 37,000 MW capacity, a very small number of accidents can be expected to occur during a 25-year operating life.

d. Fuel Reprocessing and High Level Waste Storage

Spent fuel assemblies from reactors are first partially cooled at the plant site and then transported to fuel reprocessing plants where usable nuclear fuel materials are recovered from them and radioactive wastes are separated. If 37,000 MW of additional capacity were built, this would require either the construction of one new reprocessing plant or the expansion of existing plants. The former alternative would require a new site, entailing a complete displacement of present land uses.

While radioactive emissions during reprocessing are greater than those occurring during normal power generation, the estimated dose to the affected population is still two orders of magnitude below natural levels. Hence, the impact of these emissions is not expected to be significant, even though the chronic effects of such low level radioactivity are not yet wholly known.

The high-level radioactive wastes remaining after reprocessing are first concentrated and stored in solution for five years, then evaporated to solids, sealed in containers, and put into long-term storage. The 37,000 MW of incremental capacity would produce around 300,000 to 400,000 gallons of high-level waste per year, demanding a cumulative storage capacity of 1.5 to 2 million gallons. This liquid waste, when evaporated, would yield around 3,000 to 4,000 cubic feet/year in solid waste materials for each year of operation.

Because of their high concentrations of radioactive nuclides with very slow rates of decay, these waste materials must be totally isolated from the biosphere for hundreds or thousands of years if serious adverse effects to all living organisms are to be totally avoided. The concept of storage in salt beds has been termed satisfactory by a National Academy of Science advisory committee. Engineered facilities in selected geologic environments which would be capable of insuring permanent isolation from the biosphere are being considered as an alternative to salt bed storage. Pilot studies have been conducted for several years and are continuing to determine the acceptability of specific sites. In the meantime, wastes are being stored in below surface man-made storage tanks.

7. Tar Sands

If acceptable technology can be developed to permit economic oil recovery from tar sand deposits, the estimated bitumen in place in the five largest tar sand deposits in Utah of 17.7-27.6 billion barrels, which constitutes most of the known resource in the United States, could conceivably support an industry capable of producing up to a half million barrels per day for nearly 50 years. It appears unlikely, however, that development of the needed technology and of the required industry can be accomplished in time to permit significant production from tar sands before 1985. Moreover, if the same recovery method were used, there would be little difference in both degree and kind of environmental impacts caused by either oil shale or tar sand industry developments. Thus, oil production from tar sands is not considered to be a likely alternative source for the 1 million bpd capacity anticipated from the Proposed Prototype Leasing Program for oil shale.

a. Tar Sand Resource Potential

Tar sands, also called oil-impregnated rock, bituminous sandstone, bituminous limestone, are distinguished from more conventioanl oil and gas reservoirs by the high viscosity of the included hydrocarbons. These hydrocarbons are generally semisolid to solid and not recoverable through a well by ordinary oil production methods. To initiate or sustain production, therefore, will require the continuous addition of energy to the reservoir in some form, such as heat, fluid pressure, mechanical work by mining, etc.

Tar sand deposits in the United States are numerous and some individual deposits are extensive. The most intensive effort that has been made to evaluate the oil resource potential of tar sands in the United States (78) reports 546 known occurrences in 22 states, but because of the lack of definitive information, gives partial resource estimates for only seven states. The estimated recoverable reserves in surface and near-surface petroleum-impregnated rocks amounted to between 2.5 and 5.5 billion barrels. Later refinements to data have been made in some areas which indicate that the total oil in place in the known deposits may be between 18.7 and 28.9 billion barrels. Most of this resource occurs in five deposits, located in the State of Utah (79). Until other deposits of size comparable to the large deposits in Utah are delineated, the present estimated volume of oil in known tar sand deposits constitutes the available resource in the United States; this is less than 30 billion barrels.

The largest known tar sand deposit in the world is at Athabasca in Alberta, Canada. This deposit has been variously estimated to contain from as little as 85 billion barrels of recoverable oil by mining and surface extraction (80) to appreciably more than twice this amount by the Alberta Oil and Conservation Board. The National Petroleum Council (81) estimated that 174 billion barrels may be economically recoverable. By any estimate, the Athabasca resource in Canada is substantially larger than that in the United States.

A strip mining and surface extraction technology for the production of oil from tar sands has been developed to permit commercial exploitation of the huge Athabasca deposit in Alberta, Canada. Increasing production from this deposit can be expected over the next few years as other projects are approved and activated there. This technology will have but limited use, however, for the exploitation of tar sand deposits in the U.S. because none of these deposits can compare in areal size, in volume of resource, or in thickness of overburden which have favored the large-scale strip mining operation at Athabasca. The exploitation of U.S. tar sands will probably require in situ methods for which the technology is now lacking. The lead time that will be required to develop this technology and thereafter to develop a large tar sand industry will probably prevent any significant oil production from U.S. tar sands until after 1985. Accordingly, production of oil from tar sands is not a viable alternative to shale oil in this time frame.

b. <u>Potential Environmental Impacts</u>

If the same recovery methods were used, there would be little difference, either in degree or in kind, in the impact produced on the environment by exploitation of oil shale and tar sand deposits. The most severe environmental impact would result where strip mining is used, because of the immense tonnages of overburden and resource rock that must be moved and the large surface areas, almost total land area, that would be disturbed. At Athabasca it is indicated that about 3.3

tons of tar sand and overburden will have to be processed for each barrel of oil produced, on a unit basis, the ratio is about 2.4 tons of sand and 1.0 ton of overburden per barrel of oil produced, depending on the bitumen content of the sand processed.

By comparison, in situ recovery methods would not cause the severe disturbance of the surface as in strip mining but would have similar impact on the environment in other respects. Regardless of the process used, the production of oil from tar sand deposits could produce hydrocarbons and other pollutants which would have to be removed to protect air quality. Air quality could also be affected by dust generated from strip mining operations, from wind-blown solids from disposal areas, or from traffic on access and service roads required by the field operations. Water quality of underground supplies and surface drainage would be subject to pollution from water produced in conjunction with the operations or from surface run-off and water leaching of dump and disposal areas. Impacts on existing uses of the land would result, with the principal effect on grazing.

Land used for strip mining would be totally unavailable for other uses until the land had been restored. Even in situ methods, which require comparatively little land areas for well locations and surface production facilities, would have important effects on other possible land uses, such as human habitation, recreation, livestock grazing, agriculture, or wildlife habitat, until oil production was completed. Other impacts would be associated with noise normally found with operation of process plants and equipment and with population increases in areas of established plants due to the increase in labor demands.

8. Geothermal Energy

The earth has a vast amount of internally generated and stored heat that must be considered an energy resource. The economics of geothermal power production are not certain, but estimates indicate geothermal power would be strongly competitive with conventional sources. Proven geothermal resources susceptible of commercial development in the U.S. are limited to one area, the Geysers, California, where potential development of 1,000 MW of electrical generation is reasonably assured, and perhaps a total 2,000 Mw may be developed ultimately. Currently 298 Mw capacity is in operation at the Geysers producing about 8.9 trillion Btu each year. In comparison, the projected shale oil production of 1,000,000 barrels per day is equivalent to approximately 850 trillion Btu annually (equivalent electrical energy), or about 100 times as great as the present geothermal potential. Thus, geothermal power is not a viable alternative to this amount of shale oil production.

Geothermal energy must be used or converted to other forms of energy at the production site, because heat loss from steam or water lines becomes prohibitive at distances greater than about one mile from the well head. Present commercial-scale utilization of the resource in the U.S. is limited to steam-electric power production. Distribution by area of the resource leads to development of separate powerplants on the order of 100 MW capacity served by about 10 producing wells each with a well spacing of one well per 12 to 40 acres. This dictates small powerplants to be connected by steam lines to wells within about one mile, and a series of small powerplants on about 1- to 2-mile centers connected by high-voltage transmission lines. In the Geysers development, the power company, Pacific Gas and Electric Company, has settled on two 55 MW turbine generating units housed in a single plant as the optimum scale for this type of development (82).

In view of the technical and economic constraints, it is unlikely that geothermal energy will constitute a major supply of energy to meet the national energy demand in the period 1970 to 1985. Under favorable conditions, geothermal energy may be locally important to several areas of the Western States. However, it probably will be insignificant as a factor in national power capacity (less than 1 percent of total) through the year 2000 (83).

a. Potential Environmental Impacts

Land use in the vicinity of geothermal developments will be changed by the construction of roads, wells, pipelines, powerlines, powerplants, and byproduct facilities associated with industrial development. Land used for agriculture, forestry, grazing, fish and wildlife habitat, recreation, and water supply will be disturbed in varying degrees. The Geothermal Steam Act of 1970 excludes certain public and acquired lands from the geothermal leasing program in order to protect their special land-use values or the unique characteristics of these lands. In addition to restricting certain areas from geothermal leasing, Section 3200.0-6(b) of the leasing regulations requires that developments on adjacent lands, both public and private, must be evaluated prior to geothermal leasing, to consider the impact of geothermal development on surrounding land uses.

Field development in a large field can continue for many years as new wells and additional power-generating units are developed. Since most environmental impacts can be cumulative, for example, water and air pollution, proper care must be exercised at each step. Maintenance, production testing, noise, and the associated aboveground pipe systems which cover large areas of the geothermal fields present the most severe continuing impacts to the environment.

Pipelines connecting up to 10 wells to a single power plant may be as long as one mile. As such they can severely limit access and transition.

Most of the potential adverse environmental effects that would be present during the development phases would be magnified during full-scale operations. The potential for environmental damage increases with the addition of each new well. Some adverse environmental effects are unavoidable, such as the potential for air and water pollution as a result of accidental releases; removal of wildlife habitat; restriction on surface use of land in the vicinity of installation; and general aesthetic deterioration through industrial development.

The principal objection to geothermal power development stems from the intrusion of industrial development into new areas. Nearby residents and outdoorsmen generally find the noise, odor, and disturbance of terrain and vistas highly objectionable.

Test drilling and production testing of geothermal steam resources would affect fish and wildlife. Most impacts would occur on or adjacent to well sites, although the impact on water quality could be more than localized. The magnitude of particular impacts would be interrelated with fish and wildlife and their habitat within the area of development influences, extent and duration of the entire geothermal development activities and operations, and the effectiveness of control measures.

Blowouts, in which steam or water escapes uncontrolled, potentially pose a distinct environmental hazard in geothermal drilling. The close association of geothermal areas throughout the world with major rift systems, zones of crustal spreading or convergence, Cenozoic volcanism, and earthquakes has been discussed in a number of papers (McKnitt, 1965; Tanrazyan, 1970; Muffler and White, 1972). Although the coincidence of relatively high seismic activity and tendency for subsidence increase the potential for blowouts, to date failures have resulted from earth slides and improper designs. The principal adverse environmental effects of such accidental releases are safety of operating personnel, waste of the resource, noise nuisance and air contamination from gaseous emissions (hydrogen sulfide and others). Condensed, the gaseous emissions could enter and adversely affect ground water. Once a blowout occurs it is troublesome to control because of the difficulty in handling escaping hot fluid. However, unlike similar problems encountered in petroleum drilling, there is essentially no fire hazard in the case of a geothermal accident. To further minimize this hazard, proper casing design is required to assure that the pressurized fluid will be confined to the well bore and can be controlled through surface shut-in equipment.

If a fresh-water aquifer occurs above a geothermal reservoir which contains hot saline water, tapping the geothermal strata could result in contamination of the fresh water if one horizon were not kept isolated from the other by properly cementing the casing of either production or reinjection wells.

Experience in petroleum production indicates that marked changes in reservoir pressure, whether due to pressure reduction from the production of fluids, or to pressure increase due to injection, may in certain types of reservoirs, especially in faulted or fractured rocks, result in instability leading to earthquakes. Such instability due to production alone has been documented in the Wilmington Oil Field, California (84). Instability due to injection was documented at the Baldwin Hills Oil Field, California (85), and at the Rangely Oil Field, Colorado (86), and in connection with injection of waste waters at the Rocky Mountain Arsenal, Colorado (87). Similar increases in seismic activity have also been noted in association with filling of large surface reservoirs with attendant change in hydrostatic head, including Lake Mead on the Colorado River and Lake Kariba in Africa (88). The role of fluid-pressure changes in triggering seismic activity is now well-known, and a causative relation has been established in many areas. In general, such activity has not proven disastrous, but the potential for a major quake cannot be ruled out. In any event, seismic activity must be counted as a potential environmental impact associated with geothermal development, and provisions must be made for seismic monitoring before and during major production. If monitoring indicates a significant increase in seismicity, particularly in intensity of motion, removal steps to alleviate stress would have to be initiated promptly.

Subsidence of the ground surface over and around a geothermal reservoir can result from the withdrawal of large volumes of fluids (84, 89). Subsidence would reach a maximum rate during full-scale operations unless fluid is returned to the reservoir.

Electrical transmission lines are generally benign and some favorable environmental impacts could be attributed to improved fire protection resulting from clearing of the rights-of-way. The principal adverse impacts are aesthetic, due to the intrusion of the structures on vistas. Disturbance of the terrain is minimal except for clearing trees and brush. Abrupt changes in vegetation cover such as those caused by rights-of-way cutting through dense forests can alter the feeding and migration habits of certain wildlife species. Also, where the cleared right-of-way makes a low angle with the slope of the traversed terrain, the incidence of erosion is increased.

Geothermal waste fluids normally contain substantial quantities of dissolved and precipitated minerals. Predominant problem minerals are silica and carbonate, sulfate, chloride and fluoride salts. Discharging these mineralized fluids into streams and lakes would be generally unacceptable. Even discharge to the ocean might be unacceptable in view of the thermal load. Disposal to otherwise useable underground waters likewise would generally be unacceptable. The solution available in most situations is reinjection of waste fluids into the producing zone. This has the double advantage of providing recharge and pressure maintenance to the geothermal reservoir, as well as providing for waste disposal. It might be possible to evaporate wastes and recover minerals and salts of economic value.

Another aspect of waste disposal is that of gaseous wastes. Steam from cooling towers in some situations could bring on fogging problems. Likewise, release of noxious gases with such steam also constitutes an adverse impact, but certain gases, particularly hydrogen sulfide and ammonia, can be removed from power plant steam before release.

9. Hydroelectric Power

The potential of hydroelectric capacity is limited. Of the 100,000 MW of potential capacity yet to be developed in the Lower 48 States, approximately 30,000 MW is likely to be developed by 1990 under existing programs. To equal the energy available from shale oil would require commissioning an additional 37,000 to 50,000 MW of the remaining potential, assuming that the remaining potential capacity is based on average streamflow conditions and that shale oil is assumed to be completely utilized for electric energy production. Those assumptions can be made only for the purposes of this study. The potential sites would most likely be developed to provide area load peaking capacity requirements in conjunction with fossil or synthetic fuel or nuclear base load plants.

The generating potential of any hydroelectric site is a function of both stream discharge and the height of fall. The better hydroelectric sites are concentrated in areas with heavy precipitation and large topographic relief. The following table based on information obtained from the Federal Power Commission shows the extent of U.S. potential and developed water-power capacity as of January 1971.

Geographic Region	Potential Power (10^3 Mw)**	Percent of Total	Developed Capacity (10^3 Mw)	Percent Developed
New England	4.8	2.7	1.5	31.3
Middle Atlantic	8.7	4.8	4.2	48.3
East North Central	2.5	1.4	0.9	36.0
West North Central	7.1	3.9	2.7	38.0
South Atlantic	14.8	8.2	5.3	35.8
East South Central	9.0	5.0	5.2	57.8
West South Central	5.2	2.9	1.9	36.5
Mountain	32.9	18.3	6.2	18.8
Pacific	62.2	34.6	23.9	38.4
Alaska	32.6	18.1	0.1	0.3
Hawaii	0.1	0.1	-	-
Total	179.9	100.0	51.9	28.8

Of the potential hydroelectric capacity of 179,900 Mw in the U.S., 28.8 percent or 51,900 Mw has been developed, leaving approximately 130,000 Mw to be developed. Of this 130,000 Mw of capacity some 32,600 Mw is located in Alaska. Sparsity of population and remoteness from population centers make the economic feasibility of large hydroelectric projects in Alaska subject to considerable doubt. Of the approximately 100,000 Mw of capacity yet to be developed in the lower 48 States 65,000 Mw are concentrated in the Mountain and Pacific regions. About 35,000 Mw of capacity potential could be developed in the remainder of the United States.

The Federal Power Commission projects electric generating capacity in the U.S. as follows:

Year	Total Generating Capacity (Mw)	Total Hydro Capacity (Mw)	Hydro as Percent of Total
1970	340,058	51,641	15.2
1980	665,000	68,000	10.2
1990	1,260,000	82,000	6.5

** Mw = Megawatts

Thus, by 1990 development of approximately one-half of the Nation's total hydropower potential will comprise only 6.5 percent of total electric generating capacity.

It should be noted that few dams are built solely for hydroelectric power generation. Irrigation, navigation, municipal, and industrial uses, as well as flood control are important and frequently are the dominant uses.

a. Potential Environmental Impacts

Numerous environmental impact statements filed by the Bureau of Reclamation of the Department of the Interior and by the Corps of Engineers describe environmental impacts of specific hydroelectric projects.

Hydroelectric power produces no air pollution, radioactivity, waste, heat nor water pollution (with the exception of the loss of oxygen content in storage facilities). Impacts on land and water resources tend to be limited to the vicinity of the power generation site. Dams valuable for hydroelectric purposes may be otherwise useful for such needs as irrigation and flood control. Lakes behind dams created for hydroelectric purposes provide recreational opportunities such as swimming, fishing, and boating.

Construction of a hydroelectric dam represents an irretrievable commitment of the land resources beneath the dam and lake (agriculture, minerals, wildlife habitat, free-flowing river recreation, historical and archaeological resources, timber areas, and others).

Alteration of river flows may lead to silting behind the dam, thus progressively reducing reservoir capacity and its effective use, and finally, after many years, filling of the lake. Alteration of downstream flows from power plants' discharges can cause scouring of river banks and bottoms.

Fish and wildlife habitat may be adversely altered. The reproductive habitats of anadromous fish may be severely altered by dam construction, unless elaborate provision is made for fish ladders or other means to provide safe fish passage. Increased mixing of air with water increases the amount of nitrogen contained in the water which leads to nitrogen narcosis in fish.

b. Special Problems - Alaska Hydroelectric

A specific disadvantage of the potential Alaska hydroelectric alternative would be the necessity of constructing transmission lines to carry power from Alaska not required in that area to the lower United States. This would be a distance of 1,500 to 2,000 miles from Alaska hydroelectric sites to the Northwest-Canadian U.S. border. Such distances would preclude the use of alternating current lines because of technical economic infeasibility. The use of direct current lines assumes adequate technical research developments by the time such lines would be needed. Approximately 20 D.C. lines with a 1,000-kv rating would be required to transmit approximately 30,000 Mw from Alaska to the contiguous U.S. This further assumes that all potential hydroelectric sites in Alaska would be developed and that the power requirements of that State would not be great enough to utilize all of this hydroelectric capacity.

10. Other Energy Sources

There are other potential energy sources which need to be recognized as possible energy alternatives to oil shale development. At present, these alternatives are not considered viable due to a lack of proven technology for production scale application, nonsubstitutability, cost, and timing of development. These include improved fuel use efficiency, tidal power, solar energy, biological conversion of wastes to oil, and the use of liquid hydrogen as a motor fuel.

Potential environmental impacts of these alternatives are difficult to assess, particularly where there is a great amount of research and development that must be done before operational scale systems can be developed, tested, evaluated, and readied for production application. It is not believed that any significant energy production can be obtained from these systems within the relevant time frame. Essentially, these are all in the research and development stage, and, while some discussion of potential environmental impacts is included, it is not possible to develop a full discussion due to the lack of necessary data. The following sections briefly describe the current and short-range status of each of these potential alternatives.

a. Magnetohydrodynamics

Magnetohydrodynamics (MHD) power generation is a technique for electrical generation which passes a hot ionized gas, or liquid metal, through a magnetic field. Such a high-temperature, one-stage conversion device has the potential of high overall efficiencies. Though the concept of

MHD generation has been known for over 100 years, it is only during the past decade that significant technological advances have produced systems which offer promise for use in the electric power field. Three basic approaches to MHD generation are being explored--open-cycle, closed-cycle, and liquid metal systems.

The MHD open-cycle generation, used as a "topping unit" in conjunction with steam-turbine generation, appears to hold the most promise for MHD central-station power generation in the near future. Overall system efficiency is expected to increase to a range of 50 to 60 percent, which could provide a fuel saving of 20 to 30 percent over fossil fuel steam-electric plants. General application of coal-fired MHD topping units by the mid-1980's could effectively extend fossil fuel reserves and enhance the potential for use of coal for power generation. Since the MHD generator would require little cooling water, the combined MHD-steam units would require considerably less cooling water per megawatt of capacity than convention fossil fueled or nuclear steam-electric units.

Before MHD can be utilized for central power station generation, there are many significant technological problems which must be solved. No economically practical system has yet been demonstrated for burning coal or coal-derived fuels. Designs to date have been small scale with short lifetimes and lower efficiencies than would be required for utility operation. There are problems of developing high-temperature electrodes, super-conductivity magnets, seed-recovery systems, high-temperature metal erosion and corrosion.

The characteristically high temperature and gas passage time are conducive to fixation of nitrogen so there may be significant NO_x air quality problems.

MHD research presently is being conducted in the United Kingdom, France, Germany, Japan, Poland, the Soviet Union, and the United States. The Soviet Union appears to have made a strong commitment to the development of MHD for commercial use. Soviet engineers express confidence that an open-cycle MHD unit of appreciable power output will be operating in the 1970's, but there is yet no evidence of proven economic feasibility. A 75-MW combination MHD steam pilot plant (25 NW MHD and 50 MW steam) is being constructed near Moscow. For the present, only a 25-MW portion of the plant currently is planned for completion and operation. Japan also has made great strides in achieving the high field super-conductivity magnets necessary for MHD.

Utility companies, manufacturers, research institutions, and the U.S. Government have been actively involved in MHD investigations since the 1950's. A 1969 Office of Science and Technology report identified many problem areas in which research and development are needed before MHD power system work can proceed to full-scale prototype. This report recommended that the U.S. Government encourage work on solving the difficult problems of coal-burning open-system MHD systems, and several related research projects and studies now are in progress.

While MHD appears to offer considerable future potential for coal-fired power generation, the technologic and economic uncertainties are still so great that it cannot be considered as a viable alternative power source by 1980. (For additional detail, see Part 1, Chapter 9 of the Federal Power Commission's 1970 National Power Survey Report, December 1971).

The increased thermal efficiency would reduce the overall amount of fossil fuel requirement per unit of energy produced, thereby reducing the related fuel source production environmental impacts by a like amount. The reduced water-cooling requirement would result in less thermal pollution impacts on water quality. The wide distribution of coal resources and reduced cooling water demand would be conducive to location of generation stations near coal resource and population centers, thereby reducing long-distance electrical energy transmission requirements and dependency. Reduced fuel comsumption would result in a lower volume of noxious effluents than would be discharged into the atmosphere by a comparable capacity of conventional power plants.

There is the potential of increased NO_x problems resulting from high-temperature operations. This potential for increased emissions must be balanced against the lower total emissions resulting from the higher efficiencies mentioned in the previous paragraph. The increased coal demand would require a corresponding increase in surface or subsurface coal mining with the inherent environmental impacts of such mining. There also would be a corresponding increase in the health and safety hazards to the miners engaged in producing the additional coal volumes. While generators could be located close to coal deposits, there would be the additional environmental impacts associated with transportation from mine to generator, additional transmission lines, development and operation of power station sites, and possible noise problems.

b. Fuel Cells

Fuel cells are electrochemical devices in which the chemical energy of fuel is converted continuously and directly to low-voltage, direct current electricity. The basic process is similar to that of a battery except that the fuel cell is an open system requiring a continuous supply of reactants for the production of electricity. Their potential advantages over more conventional energy conversion systems are their quietness, low temperature of operation, minimization of pollution, reliability, and greater efficiencies (up to 70 percent). Nearly one and one-half times more electrical energy can be obtained from a ton of coal in a fuel cell system than for a comparable amount burned in a modern conventional power system.

There has been considerable research and development of fuel cells in the United States and Europe. While most of the research in the United States has been aimed toward development for specialized uses in space and military applications, a number of projects also have been directed to commercial power production applications. Examples of the most probable near-term uses of fuel cells could be storage of energy during periods of off-peak demand; on-site reserve or emergency power; base-load or peaking power supplements to existing electric power systems; individual home, apartment, industrial or commercial complexes tailored to specific customer needs; and in the transportation field where batteries are now used or where electric propulsion could substitute for internal combustion engines.

Because of the current necessity for costly metal catalysts and reforming and fuel purification processes, the near future of fuel cells, even for small power units in a mass market, is remote. General application will be feasible only when efficient units capable of using impure, low-cost fuels are developed and when long reliable life units can be constructed. Even when such technology is proven, the fuel cell is not expected to replace central power station generation.

To the extent that fuel cells could replace other forms of power generation, there would be environmental advantages such as quietness, low operating temperatures, and absence of toxic wastes. Use of fuel cells in substations could reduce the need for central station power and transmission lines. Energy resource source impacts cannot be evaluated until probable fuel sources are more adequately identified.

c. Thermoelectric

When two dissimilar metals are joined together in the form of a loop and one of the junctions is held at higher temperature, an electric current will flow. With possible efficiencies in generator technology in the order of 30 percent, it appears that overall efficiencies of thermoelectric systems could not exceed 10 to 15 percent. Short operating lifetimes, which result from the instability of thermoelectric elements at high temperatures necessary for higher power operation, and undesirable heat transfer from the hot to cold junctions, which result in low efficiencies, are major obstacles to additional progress in development of this electric energy source. Although thermoelectric generation will doubtless receive continued attention for special low power applications, it would seem to hold little potential for central power station plans in the foreseeable future. (For additional detail, see Federal Power Commission's 1970 National Power Survey, December 1971).

d. Thermionic Generation

When a metal is heated, a point is reached where its electrons acquire enough energy to overcome retarding forces at the surface of the metal and escape--boil off. When collected on another cooler metal surface, electrical energy can be generated by joining the two pieces of metal with an external circuit. Since thermionic generators are another type of heat engine, their efficiency theoretically is limited to 35-40 percent. At present, efficiencies ranging from 5 to 25 percent have been reported for test models. Commercial exploitation of the phenomenon awaits solution of difficult materials problems related to operations above 3000° F and, in isotopic-fueled devices, radiation damage. The Federal Power Commission's 1970 National Power Survey indicates that the concensus is that future efforts in thermionic development during the next decade will be concentrated in space oriented activities. The principal effort will be directed to the development of nuclear-fueled systems to be used as power sources for interplanetary expeditions. There is little likelihood of thermionics achieving commercial realization for large-scale generation within the next several decades. Accordingly, such conversion systems do not represent an alternative energy source in the near future.

The state of development is not sufficiently advanced for an evaluation of potential environmental impacts. Since it is a type of heat engine, the associated loss of heat is a potential source of thermal pollution. Heat sources of fossil or nuclear fuels also would have their related environmental impacts.

e. Tidal Energy

Tidal power is a hydroelectric energy source similar to other water power sources except that it is derived from the alternate filling and emptying of a bay or estuary that can be enclosed by a dam. There are two major tidal power sites in the United States which have significant potential for such development (90.) The Bay of Fundy with nine sites, including many on the Canadian side, has an average potential power capacity of approximately 29,000 MW, and Turnagain Bay in Cook Inlet, Alaska, has an estimated potential power capacity of 9,500 MW. The distance from population centers makes the Turnagain Bay site doubtful from an economic standpoint. If the Bay of Fundy capacity was developed with half of the production going to Canada and half to the United States, the total addition to U.S. capacity would be some 15,000 MW. This would represent approximately 1.1 percent of generating needs by 1990.

The major technological problem associated with the development to tidal energy would be the need to develop turbines able to operate economically under low hydrostatic heads (91). Depending upon base load, substitutability, and conversion efficiency factors, such production could be equivalent to from 0.2 to 0.4 million barrels of oil per day. Since the overall impact of tidal power on the U.S. energy supply would be minimal, it does not represent a significant alternative to the need to develop other energy sources.

There would be significant environmental considerations associated with the damming and alternate filling and emptying of bay and estuary areas, such as impacts on sport and commercial fisheries, wildlife, water quality, recreation uses, other land uses, and aesthetics.

f. Wind Energy

The power in the wind is the result of a mass of air moving at speed in some particular direction. To capture such power requires placing in the path of the wind a machine which transfers the wind power to the machine. There is a wide range of estimates as to what the energy potential might be--one figure is 20 billion kw at elevations low enough for extraction by aerogenerators (wind turbines). This figure reflects an ultimate potential, but it has little bearing on the degree to which this resource can be utilized. Economical power generation requires an average annual wind velocity of about 30 mph with nearly steady magnitude and direction and topography in which boundary-layer effects are minimal.

Although there are many locations that appear suitable for aerogenerators, their use would be contingent largely on the development of low-cost generators, a site amenable to low-cost installation, a favorable overall wind speed, and an electric grid capable of profitable use of interruptible power of this nature. Were it economically feasible to generate 10 billion kwh per year from wind sources, it would reduce the use of conventional fuel by an amount of four million tons of coal, or the equivalent of other energy sources.

Wind energy does not appear to be a viable alternative to traditional large-scale energy sources at this time as a considerable amount of additional research and development is required. Even with reasonable success in such effort, favorable cost-benefit is questionable because of the high equipment costs and intermittent characteristics of the power source. However, there are those who feel that substantial electrical energy production is possible now from lower velocity winds and the use of technology developed in past research projects even though there has not been major activity toward commercial development of wind energy for several years (92).

Since the use of the wind for power generation is a pollution-free source of electrical energy that would replace the need for fossil fuel or nuclear generation, there would be an environmental benefit that would be generally in direct ratio to the adverse environmental impacts of the alternative electrical energy generation source displaced.

The primary adverse environmental effect would be the aesthetic effect of a large number of towers with heights of as much as 1,000 feet topped with large generators turned by wind turbines with blades of fifty to two hundred feet in length, or possibly even larger, which would be in prominent locations. Previous large-scale efforts have failed due to the structural factors, so tower structures probably would require heavy guying. There would be land surface impacts resulting from the construction and operation of numerous generator sites and access thereto. Since each tower would have to be serviced by transmission lines and related structures to connect the wind generation grid into power grids, there could be considerable environmental disturbance associated with the development and operation of such lines.

g. Solar Energy

Solar energy is a source of both heat and electromagnetic radiation. Although the solar energy density is low, the United States land area intercepts each year about 600 times its total 1970 energy requirements. Such heat can be used for electricity generation, space heating, cooling, and processing of industrial materials. The electromagnetic properties of solar radiation produce photosynthetic conversion and storage of energy in plants and other photochemical reactions which also convert and store energy.

The number and range of potential solar applications are extensive but the present state of the art is such that energy collection efficiencies are low and the requirements for energy storage resulting from the intermittent nature of the source result in costs that are prohibitive for general use. A typical 1,000 MW powerplant operating in a 1,400-Btu/day solar climate would, with present technology, requires 37 square miles of collector surface (assuming efficiency of conversion of solar energy to process heat is 30 percent and to electrical energy is 5 percent). The many square miles of collector surface that would be required for even a medium-sized power generation facility would have significant impact on the land area, its other use or resource values and on the general environment. There would be a major aesthetic intrusion in desert areas which now are generally unmarred by man's activities.

Such large collector areas and low efficiencies make it unlikely that solar energy will have any significant impact as a large-scale source of power within the next 30 or more years as the economics are very unfavorable compared to many alternatives. Even a 300 percent increase in the solar cell efficiency would not result in power costs that would be economically acceptable for general use. A massive research and development effort over an extended period of time would be required to lower costs, increase conversion efficiency and to achieve acceptable system performance.

Examples of other types of solar generation potential include floating power plants which would use the solar-produced temperature differentials which exist between the upper and lower levels of Caribbean waters and the Gulf Stream. A second concept deals with the orbiting of space vehicles for the purpose of creating central power generation. Systems such as these have not yet been developed or tested so they do not represent feasible energy source alternative that can be considered at this time.

h. Biological Energy

Organic wastes in the United States are a potential source of energy of significant magnitude. Of the annual production which is excess of 2 billion tons, some 880 million tons are organic, moisture-and-ash-free material. Animal manure is the largest single organic waste; however, other agricultural wastes and urban refuse and commercial waste add significantly to the total. Bureau of Mines research (93) has shown that it is possible to convert such organic wastes to oil with a potential of 1.25 barrels of oil per ton of waste. If all of this waste could be converted to oil, it would represent over 1.3 billion barrels of oil per year. This compares with a 1970 petroleum demand of 5.4 billion barrels. However, it must be recognized that even if this preliminary technology could be developed to commercial feasibility, only a fraction of the organic wastes could be collected with a reasonable amount of cost and effort for application of this process. Nevertheless, its use does have the potential of providing a significant supplemental source of oil. The process lends itself to essentially pollution-free operation while at the same time offering a solution to a portion of the problem of solid waste disposal. The oil has a low sulphur content and a high heating value. If only one-half of the organic waste could be converted to oil, it could supply an amount equal to current volume of residual fuel oil now used for electrical generation.

Preliminary research has been done in closed, batch autoclaves. Currently, a continuous unit with a capacity of 20 pounds per hour is being operated.

Considerable additional work over a period of years will be required to move from the present early stage research to demonstration operations at a commercial scale to prove technological feasibility and to develop adequate economic data. No cost or estimate of probable commercial-scale production can be made at this time.

The process lends itself to implementation of a waste conversion process which will recycle waste to provide fuel resource values and, at the same time will greatly alleviate many of the critical solid waste disposal situations confronting the Nation. Water quality problems associated with feedlot and agricultural wastes could be mitigated. The need for land fills or other volume forms of disposal would be greatly reduced as the solid residue from the process would consist of the mineral constituents in the original charge. Its quantity would be small and because it would be sterile, it would produce no problem as land fill material. Since the process produces a low sulphur oil with high heat value, it could replace the need for natural oil production with a corresponding reduction in all of the related environmental hazards of such production.

It is doubtful if production of significant magnitude could be achieved by 1985 so, pending further research and development, it cannot be considered a viable alternative at this time.

i. Liquid Hydrogen

The use of liquid hydrogen as an alternative to fossil fuel for vehicular power systems appears to be technically feasible. Hydrogen would be separated from oxygen in water by an energy-consuming electrolytic process at a primary fixed-station energy source. The hydrogen then would be liquified, transported and distributed as fuel.

Prior to 1958, liquid hydrogen was produced only in small quantities and was primarily a laboratory curiosity. Owing to demands made by the space program, facilities were constructed in the United States to produce more than 150 tons per day, but costs are relatively high. Cost projections for the electrolytic production of hydrogen range from a low of $0.04 per pound using electrical energy from a large breeder-type reactor to about $0.12 per pound for other energy sources. By comparison, the present cost to produce gasoline is about $0.02 per pound. In addition to the cost of production of liquid hydrogen, it also is essential to consider the cost of developing and implementing the process, storage, transportation and combustion methods. Conversion costs would be extremely large, so development of this alternative internal combustion engine fuel source could take from 20 to 50 years. Accordingly, it is not a viable alternative for consideration within the 1980 time frame. While use of hydrogen as a vehicle power source has the environmental advantage of being pollution free because the combustion product is water, the energy requirements to separate hydrogen from oxygen are considerable with corresponding environmental impacts depending upon the energy source involved.

C. Combinations of Alternatives

In the interest of clarity of presentation, this analysis has discussed separately each potential alternative form of energy as a possible substitute for commercial shale oil production. It is highly unlikely that there will ever be a single definitive choice to be made between any potential energy form and its alternatives. Each may have a role to play; some may make major contributions to our energy supplies, while others may be subordinated to lesser roles. Some alternatives may be developed rapidly; others may evolve more slowly--perhaps to make a more important contribution at a later date. Predictions made on the basis of present knowledge of the relative roles of these potential alternatives and their respective or combined environmental impacts are a highly subjective exercise which must necessarily include a large measure of judgment as to future trends in such variables as the direction and pace of technological development, the identification of usable resources, the rate of natural economic growth, and change in our life style. In actuality, the technology and life style are inseparable, and it is extremely difficult to independently analyze one or the other for the results to be meaningful.

An effective way to view a complex problem with its components and interacting forces is to develop a flow network showing each of the components and the interactions between them. An example of such a diagram showing these complexities for energy planning is given in Figure V-3. This diagram represents an initial framework

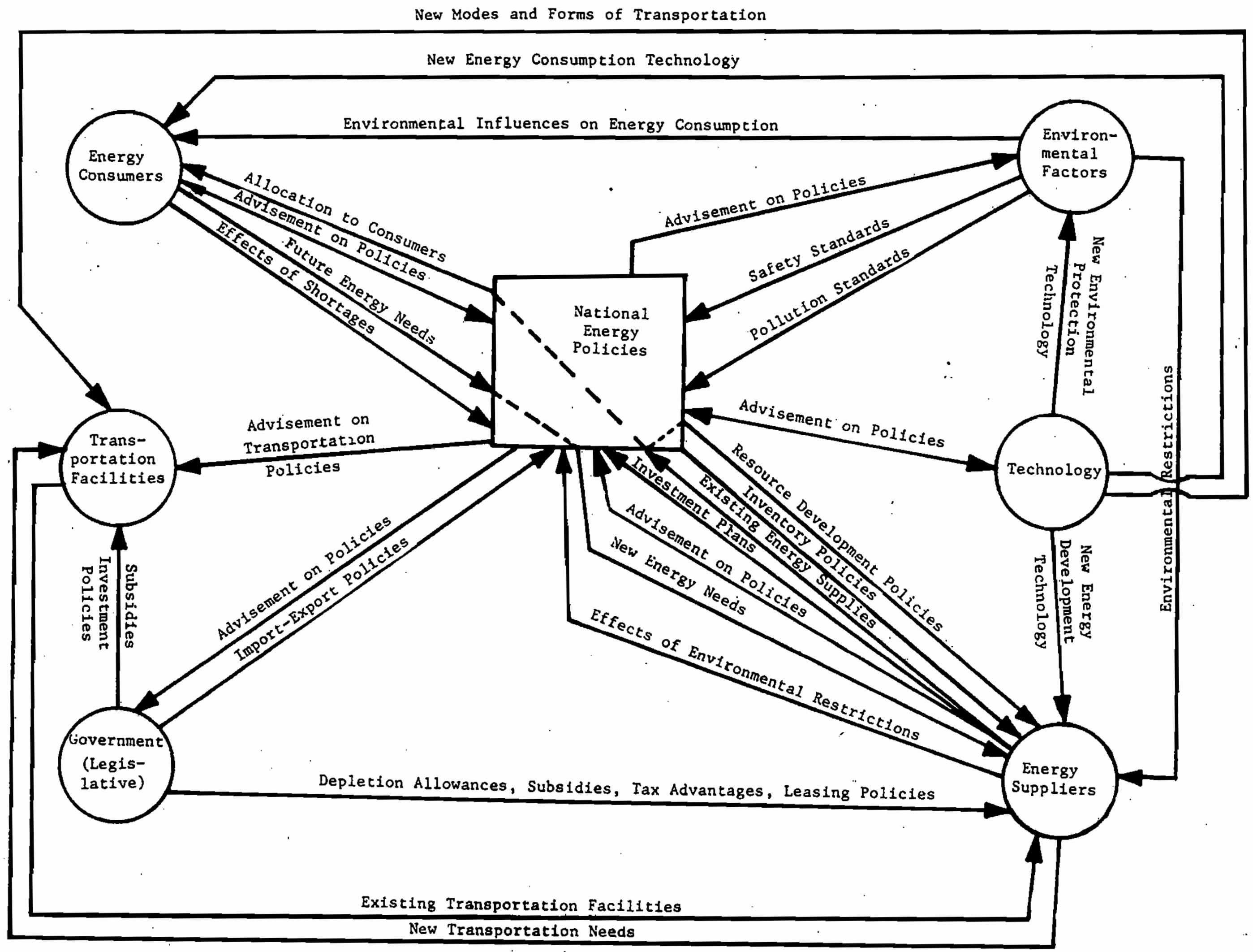

Figure V-3 - Energy Policy Interactions.

Source: (Ref. 122)

from which to understand a total energy system and is not necessarily final nor complete.

The various energy subsystems interact with one another through several important linkages. These individual subsystems are represented by energy consumers and suppliers, environmental factors, new and improved technology, transportation facilities, and legislative actions. Economic considerations would also be an integral part of the total energy system. Although this flow network is somewhat idealized, it depicts the complicated structure which must be considered for effective energy planning. For example, consider the commercial development of new energy resources. As these new energy systems enter the total market flow they will not only interact with one another but will be controlled by environmental constraints and new and improved technology. At the same time, existing fuels may become more acceptable by technology improvement in reducing environmental effects, while changes in transportation modes may decrease or increase the need for fuels. The changing needs of the energy consumer will largely dictate the requirements for the amount of energy needed. Government policies and the dynamic nature of energy demand and supply make the energy system extremely complex. All energy alternatives and their combinations should be considered for optimum use within this system, but this ideal realization will not likely come about in the foreseeable future.

Table V-4 summarizes the pertinent data developed in other sections of this statement as to the possible alternatives to provide the energy equivalent to shale oil development. Examination of this table will facilitate consideration of possible combinations of alternatives. It seems most probable that many of the alternatives outlined in the table will be developed to some degree. Understanding of the extent to which they may replace or complement shale oil requires reference to the characteristics of our total national energy planning system.

As indicated, there are at least five alternatives which appear to be potentially feasible for equaling this energy supply from oil shale for the 1985 time frame. These are: (1) reduced energy demand, (2) increased foreign imports, (3) increased domestic conventional oil and gas production, (4) coal gasification, and (5) replacement of liquid fuels with equivalent quantities of electricity generated by coal and/or by nuclear power. The other alternatives shown are not considered viable short-term energy replacements because of limited technology.

Factors most relevant to the issues at hand are as follows:

1. Historical relationships indicate that energy requirements will grow at approximately the same rate as gross national product.
2. Energy requirements can be constrained to some degree through the price mechanism in a free market or by more direct constraints. Reduction in energy requirements may be accomplished through substitution of capital investment in lieu of energy;

Table V-5

Incremental Production of Shale Oil and Alternatives to Shale Oil

Alternative	Production Potential			
	1980		1985	
	Physical Units	Btu (billions)	Physical Units	Btu (billions)
Shale Oil	250 mb/d	1,450	1000 mb/d	5,800
Imports				
Crude Oil (Persian Gulf)	250 mb/d	1,450	1000 mb/d	5,800
LNG	1.4 bcf/d	1,450	5.6 bcf/d	5,800
Reduction in Demand	1/	1/	1/	1/
Traditional Sources				
Modification of Natural Gas Pricing	1.4 bcf/d	1,450	5.6 bcf/d	5,800
Offshore Oil Production	200 mb/d	1,160	1000 mb/d	5,800
Onshore Oil Production				
Elk Hills	250 mb/d	1,450	160 mb/d	930
Price Rise	250 mb/d	1,450	1000 mb/d	5,800
Improved Recovery	1/	1/	1/	1/
Coal (bituminous)	66 m tons/d	1,450	260 m tons/s	5,800
Nuclear	250 mb/d	1,450	1000 mb/d	5,800
Hydro	250 mb/d	1,450	1000 mb/d	5,800
North Slope Oil (Trans-Canada PL)	250 mb/d	1,450	1000 mb/d	5,800
Non-traditional Sources				
Coal Gasification	90 m tons/d	1,450	360 m tons/d	5,800
Coal Liquefaction	None	None	126 m tons/d	1,450
Tar Sands	None	None	None	None
Geothermal Steam	250 mb/d	1,450	780 mb/d	4,500
Nuclear Stimulation of Gas Sands	1.4 bcf/d	1,450	5.6 bcf/d	5,800

Note: mb/d = thousand barrels per day
m tons/d = thousand tons per day
bcf/d = billion cubic feet per day

1/ Not estimated

1 barrel of oil contains 5,800,000 Btu of energy
1 cubic foot of gas contains 1,032 Btu
1 ton of bituminous coal contains 26,000,000 Btu
1 kilowatt hour of electricity output is equivalent to 3,412 Btu at 100 percent efficiency (representing replacement of fossil fuel by electricity in end-use), or 10,582 Btu of energy input at prevailing heat rates (representing replacement of fossil fuels as inputs to electric generation).

e.g., insulation to save fuel. Other potentials for lower energy use have more far-reaching impacts and may be long range in their implementation--they include rationing, altered transportation modes, and major changes in living conditions and life styles. Even severe constraints on energy use can be expected to only slow, not halt, the growth in energy requirements within the time frame of this Statement.

3. Energy needs are not monolithic. Solid fuels cannot be used directly in internal combustion engines, for example. Fuel conversion potentials are severely limited in the short term although somewhat greater flexibility exists in the longer run and generally involve choices in energy-consuming capital goods (See Section II, Part C of this Volume).

   The principal competitive interface between fuels is in electric powerplants. Moreover, the full range of flexibility in energy use is limited by environmental considerations.

4. A broad spectrum of research and development is being directed to energy conversion--more efficient nuclear reactors, coal gasification and liquefaction, liquified natural gas (LNG), and shale retorting, among others. Several of these should assume important roles in supplying future energy requirements, though their future competitive relationship is not yet predictable.

5. Major potentials for filling the gap from domestic resources are as follows:

- More efficient use of energy
- Environmentally acceptable systems which will permit production and use of larger volumes of domestic coal.
- Accelerated exploration and development of all domestic oil and gas resources.
- Development of the Nation's oil shale resources.

Of the foregoing, increased domestic oil and gas production offers considerable possibilities, since indicated and undiscovered domestic resources total some 417 billion barrels of oil and 2,100 trillion cu. ft. of gas which are estimated to be producible under current technology. However, the feasibility of providing adequate incentive and reducing the uncertainties inherent in petroleum exploration are not known.

6. The acceptability of oil and gas imports as an alternative is diminished by the following:
   - A narrowing gap between costs of foreign and domestic oil.
   - Apparent high costs of liquefying and transporting natural gas other than overland by pipeline.
   - The security risks inherent in placing reliance for essential energy supplies on sources which have demonstrated themselves to be politically unstable and not unwilling to interrupt petroleum supplies to exert economic and political pressure on their customers.

- The aggravation of unfavorable international trade and payments balances which would accompany substantial increases in oil and gas imports.

Potential environmental impacts were discussed separately with each of their respective alternatives. The net impact of a combination alternative cannot now be predicted, but would be similar to the total impacts described in the previous sections and be approximately in the same proportion (to the combination impact) as the alternative is in the alternative mixture.

In view of the foregoing it seems reasonable to postulate that for some time to come the basic alternative to the production of one million barrels of shale oil would be one million barrels of imported petroleum (See Section II, Part C of this Volume).

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