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FISCAL POLICY AND THE ENERGY CRISIS

COMMITTEE ON FINANCE
UNITED STATES SENATE

RUSSELL B. LONG, *Chairman*

Briefing Material Prepared by the Staff of the Committee on Finance for the Use of the

SUBCOMMITTEE ON ENERGY

Mike Gravel, Alaska, *Chairman*

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FISCAL POLICY AND THE ENERGY CRISIS

I. Introduction

The "energy crisis," so long an abstraction of newspaper headlines and Congressional hearings, has become a stark reality for millions of Americans, as well as Europeans and Japanese. Unrestrained consumption, reduced production of domestic oil and gas, and other supply disruptions have created a growing energy gap. Cutbacks in the use of energy, averaging anywhere from 10–20 percent—perhaps higher in some regions—are unavoidable this winter. The duration and severity of the shortages in the coming winter months now depend as much upon the weather as upon remedial public policies.

The Committee on Finance has jurisdiction in the Senate over our nation's tax and trade laws. Changes in these laws may play a major role in alleviating the short term energy problem and in moving toward a policy of developing our nation's huge untapped energy resources over the longer term.

This document has been prepared to furnish background information to the Members of the Subcommittee on Energy in dealing with the following questions:

Should fiscal policy be employed to mitigate the current energy shortage and to assist in the transition to alternative energy sources? If so, how?

Are fiscal incentives needed to stimulate exploration and development of domestic sources of energy?

If so, which would be the most efficient—a tax credit, tax deduction, depletion, etc?

What would be the effects on supply and demand of allowing the price of all fuels to reach their natural level through market forces?

What would be the income distributional, environmental and consumer effects of a tax incentive approach vs. a free market approach?

Given the enormous capital needs to develop fossil fuels and their alternatives, is there a need for both tax inventives and price deregulation?

Is there a need for an "energy trust fund," the monies from which would be used to develop various conventional fossil fuels as well as alternative forms of energy—coal gasification and liquefaction, tar sands, oil shale, geothermal, solar, wind, nuclear, etc.?

If so, how should the fund be financed—consumption taxes on gasoline or automobiles, or production tax on energy at source or some combination?

Who should administer such a fund?

President Nixon has announced a plan designed to mitigate shortages over the near term by reducing demand and encouraging production, and over the longer term by moving toward energy independence." [1]

The highlights of the President's program are as follows:

—Prevent utilities and industrial facilities from switching from coal to petroleum fuels and encourage utilities to switch from residual oil to coal;

—Reduce jet fuel consumption which could curtail airlines flights by 10%;

—Reduce home heating oil consumption by encouraging homeowners to keep their thermostats at 68° Fahrenheit, and by maintaining temperatures in Federal offices heated at between 65°–68°;

—Encourage drivers to use car pools or public transportation whenever feasible;

—Establish 50 mph speed limits;

—Establish daylight saving time year round;

—Relax environmental regulations on a case by case basis;

—Encourage businesses and schools to alter working hours and school schedules whenever possible;

—Open up naval oil reserves at the Elk Hills Naval Petroleum reserves in California;

—Plan for possible rationing or taxation of gasoline;

—Deregulate natural gas prices;

—Speed up energy research and development;

—Enact Alaska pipeline bill;

—Allow surface mining of coal;

—Provide overall planning and coordination through creation of several new energy agencies.

Some of these measures require legislation. Those that involve establishing taxes or "fee schedules" would be within the jurisdiction of the Finance Committee.

II. Defining the Energy Problem

The energy problem cannot simply be defined as a shortage of resources. The U.S. has a large potential resource base of fossil fuels sufficient to meet its needs for several hundred years at present consumption levels. Rather, what exists is a widening gap between

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[1] A White House fact sheet describing the President's emergency energy program is reproduced in Appendix A.

energy consumption and the production of available energy supplies. Although the U.S. has large potential energy resources, most of these resources are a long way from development and consumption.

While there is certainly room for error in estimating the size of our energy resources, responsible studies have concluded that our indigenous resources are truly massive. The table below compares the potential resources base with 1972 U.S. consumption.

TABLE 1.—*U.S. Consumption and Resources of Energy Fuels*

Energy fuels	Potential resources	1972 consumption
Oil [1]	346 billion bbls	6.0 billion bbls.
Natural gas [1]	1,178 trillion cu ft	22.6 trillion cu ft.
Coal [2]	394 billion tons	517 million tons.
Uranium [3]	1.6 million tons	16 thousand tons.
Oil shale [4]	189 billion bbls	None.

[1] U.S. Geological Survey.
[2] U.S. Bureau of Mines.
[3] U.S. Atomic Energy Commission.
[4] National Petroleum Council. *U.S. Energy Outlook, a Mutual Appraisal.*

If we developed all oil and gas resources in this country, we would have more than 100 times our 1973 needs. Our coal resources are 600 times current production. But it will take many years and huge amounts of capital to develop those resources.

It has been estimated by the National Petroleum Council [1] that to meet our energy needs between now and 1985, we shall have to make an investment of between $375 and $547 billion in new productive facilities, more than double the rate of investment over the 1960's and early 1970's.

[1] The National Petroleum Council is an officially established industry advisory board to the Secretary of Interior. The estimates on capital financing needs appear on page 296 of the Council's study: *U.S. Energy Outlook: A Report of the National Petroleum Council Committee on the U.S. Energy Outlook.*

SUMMARY OF CUMULATIVE CAPITAL REQUIREMENTS
U.S. ENERGY INDUSTRIES 1971-1985
(Billions of 1970 Dollars)

	Initial Appraisal	High Supply	Intermediate Supply		Continuation of Current Trends
Oil and Gas					
Exploration & Production	92.4	171.8	144.8	135.1	88.0
Oil Pipelines	3.5	7.5	7.5	7.5	7.5
Gas Transportation	21.0	56.6	46.9	39.8	29.5
Refining*	20.0	19.0	24.0	30.0	38.0
Tankers, Terminals	14.5	2.0	9.0	16.0	23.0
Subtotal	151.4	256.9	232.2	228.4	186.0
Synthetics					
From Petroleum Liquids	–	5.0	5.0	5.0	5.0
From Coal (Plants Only)	1.5	12.0	4.6	4.6	1.7
From Shale (Mines & Plants)	0.5	4.0	2.2	2.2	0.5
Subtotal	2.0	21.0	11.8	11.8	7.2
Coal†					
Production	9.3	14.3	10.4	10.4	9.4
Transportation	6.0	6.0	6.0	6.0	6.0
Subtotal	15.3	20.3	16.4	16.4	15.4
Nuclear					
Production, Processing, Enriching	5.0	13.1	11.0	8.5	6.7
Total All Fuels	173.7	311.3	271.4	265.1	215.3
Electric Generation, Transmission‡	200.0	236.0	235.0	235.0	235.0
Water Requirements	N.A.	1.1	0.8	0.8	0.7
Total Energy Industries	373.7	547.4	507.2	500.9	451.0

* Based on maximum U.S. requirements, some of which may be spent outside the United States

† The last four columns do not include capital requirements for coal production for synthetic fuels. These requirements in billions of 1970 dollars are as follows: High supply—2.0; Intermediate supply—0.8; Continuation of current trends—0.3.

‡ Condition 1; capital requirements under all six conditions postulated by the Electricity Task Group are as follows:

Condition	Cumulative Investment (1971-1985) Billion 1970 Dollars					
	1	2	3	4	5	6
Power Plant Construction	181	183	186	169	196	163
Transmission (estimated at 30% of Condition 1 Cumulative Power Plant Investment)	54	54	54	54	54	54
Total	235	237	240	223	250	217

The high supply column suggests the capital required to finance a policy of maximum development of U.S. energy resources between 1971 and 1985. Intermediate supply cases embrace policies which would slow down but nevertheless continue the growing dependency upon foreign resources. The "continuation of current trends" case would result in a dependency upon foreign sources for over 50 percent of our energy needs. Source: National Petroleum Council, U.S. Energy Outlook, December 1972, p. 296.

In addition to these conventional sources of energy, the United States has the technology to develop alternative sources of energy from the sun (solar), the wind, the earth's crust (geothermal), the power of the atom (nuclear fission and fusion), and others. There are already existing facilities to "gasify" coal and liquefaction of coal is also possible. A strong, well coordinated research and development program is necessary to develop these alternatives and to translate their

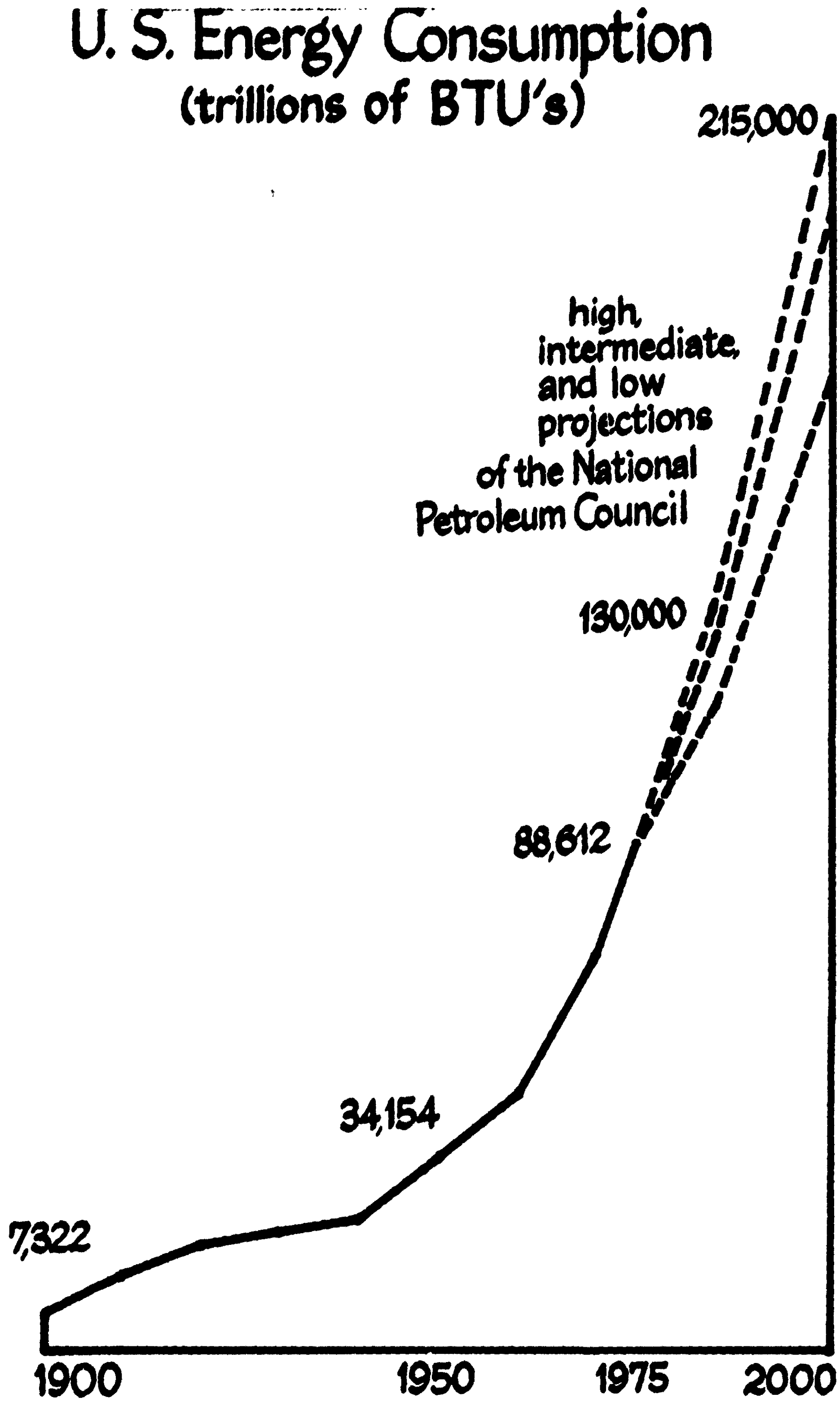
technological feasibility into commercial uses in the most environmentally sensible way possible. These are generally considered longer range solutions and not remedies for the short term problem. The short term problem, it appears, can only be mitigated by cutbacks in U.S. consumption.

With six percent of the world's population, the U.S. consumes almost one third the world's captive energy. The rate of U.S. consumption, moreover, is accelerating, as shown by the following Department of Interior projections:

TABLE 2.—*Per Capita Consumption of Energy*

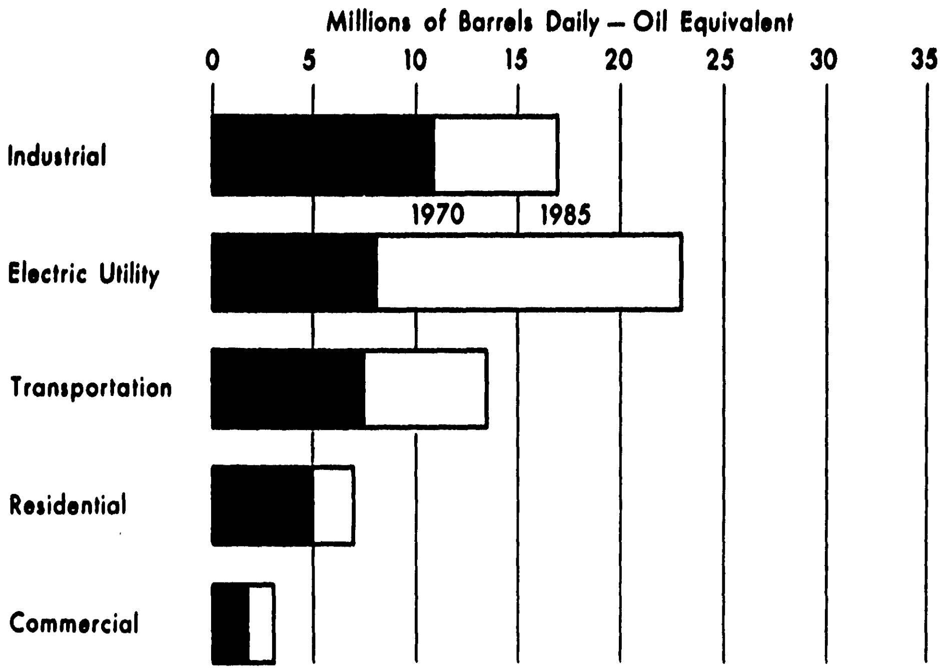
Year	Population (millions)	Total energy consumption (trillion Btu)	Per capita energy consumption (million Btu)
1950	152	34, 154	225
1960	180	44, 960	250
1970	204	68, 810	337
1975	215	88, 612	412
1985	237	133, 396	563
2000	266	191, 556	720

Source: U.S. Department of Interior.


U. S. Energy Consumption
(trillions of BTU's)
215,000
high, intermediate, and low projections of the National Petroleum Council
130,000
88,612
34,154
7,322
1900
1950
1975
2000

Consumers of energy in the U.S. fall into five major categories: industrial (29 percent of energy consumption), electric utilities (26 percent), transportation (25 percent), residential (14 percent) and commercial (6 percent). The energy used by electric utilities is converted to electricity and sold to consumers, two thirds to business and industry and one third to residential consumers. More than two thirds of the total energy used in the U.S. is used for commercial or industrial purposes.

ENERGY USE - By Markets



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Approximately 95 percent of the energy consumed in the U.S. in 1972 derives from three sources: petroleum (46 percent), natural gas (32 percent), and coal (17 percent). Hydroelectric and nuclear power plants contributed four percent and one percent, respectively, to U.S. energy stocks. Other sources of energy exist in various stages of development and application, but it is considered probable that the U.S. will continue to rely on fossil fuels for more than half its energy through the year 2000. The following table and chart give a breakdown of the U.S. energy mix, in 1970 and projected to 1985:

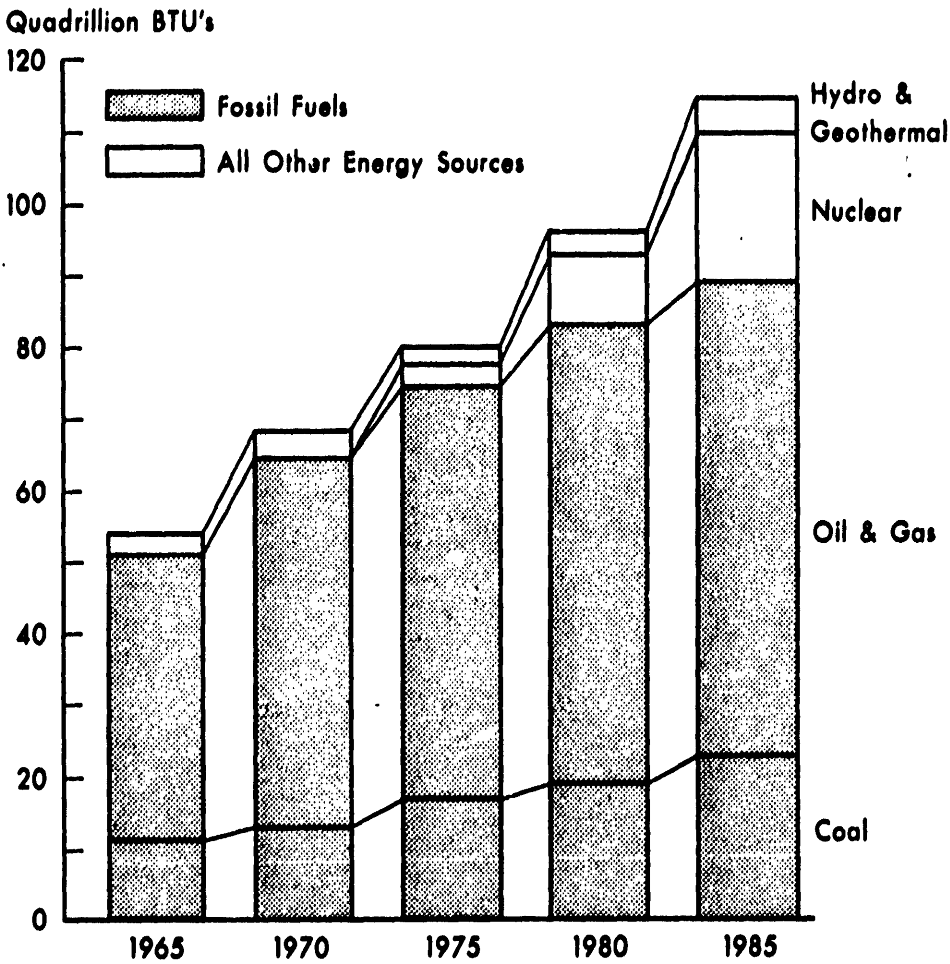
Table 2. United States demand for energy resources by major sources, year 1970 and estimated probable demand in 1975, 1985, and 2000[1]

	1970[2]	1975	1985	2000
Petroleum (includes natural gas liquids)[3]				
Million barrels	5,367	6,550	8,600	12,000
Million barrels per day	14.70	17.9	23.56	32.79
Trillion Btu	29,617	36,145	47,455	66,216
Percent of gross energy inputs	43.0	40.8	35.6	34.6
Natural gas (includes gaseous fuels)				
Billion cubic feet	21,847	27,800	38,200	49,000
Trillion Btu	22,546	28,690	39,422	50,568
Percent of gross energy inputs	32.8	32.4	29.5	26.
Coal, (bituminous, anthracite, lignite)				
Thousand short tons	526,650	615,000	850,000	1,000,000
Trillion Btu	13,792	16,106	22,260	26,188
Percent of gross energy inputs	20.1	18.2	16.7	13.7
Hydropower, utility[4]				
Billion kilowatt-hours	246	282	363	632
Trillion Btu	2,647	2,820	3,448	5,056
Percent of gross energy inputs	3.8	3.2	2.6	2.6
Nuclear power[5]				
Billion kilowatt-hours	19.3	462	1,982	5,441
Trillion Btu	208	4,851	20,811	43,528
Percent of gross energy inputs	0.3	5.4	15.6	22.7
Total gross energy inputs, trillion Btu	68,810	88,612	133,396	191,556

[1] Preliminary estimates by Bureau of Mines staff.
[2] Latest data.
[3] Product demand - includes net processing gain.
[4] Includes pumped storage, internal combustion and gas turbine generation. Converted at prevailing and projected central electric stations average heat rates as follows: 10,769 Btu/Kwhr in 1970; 10,000 Btu in 1975; 9,500 in 1985; and 8,000 in 2000.
[5] Converted at average heat rates of 10,769 Btu/Kwhr in 1970; 10,500 in 1975 and 1985; and 8,000 in 2000.

Factors in the U.S. Energy Situation

DEMAND FOR ENERGY, 1965-1985



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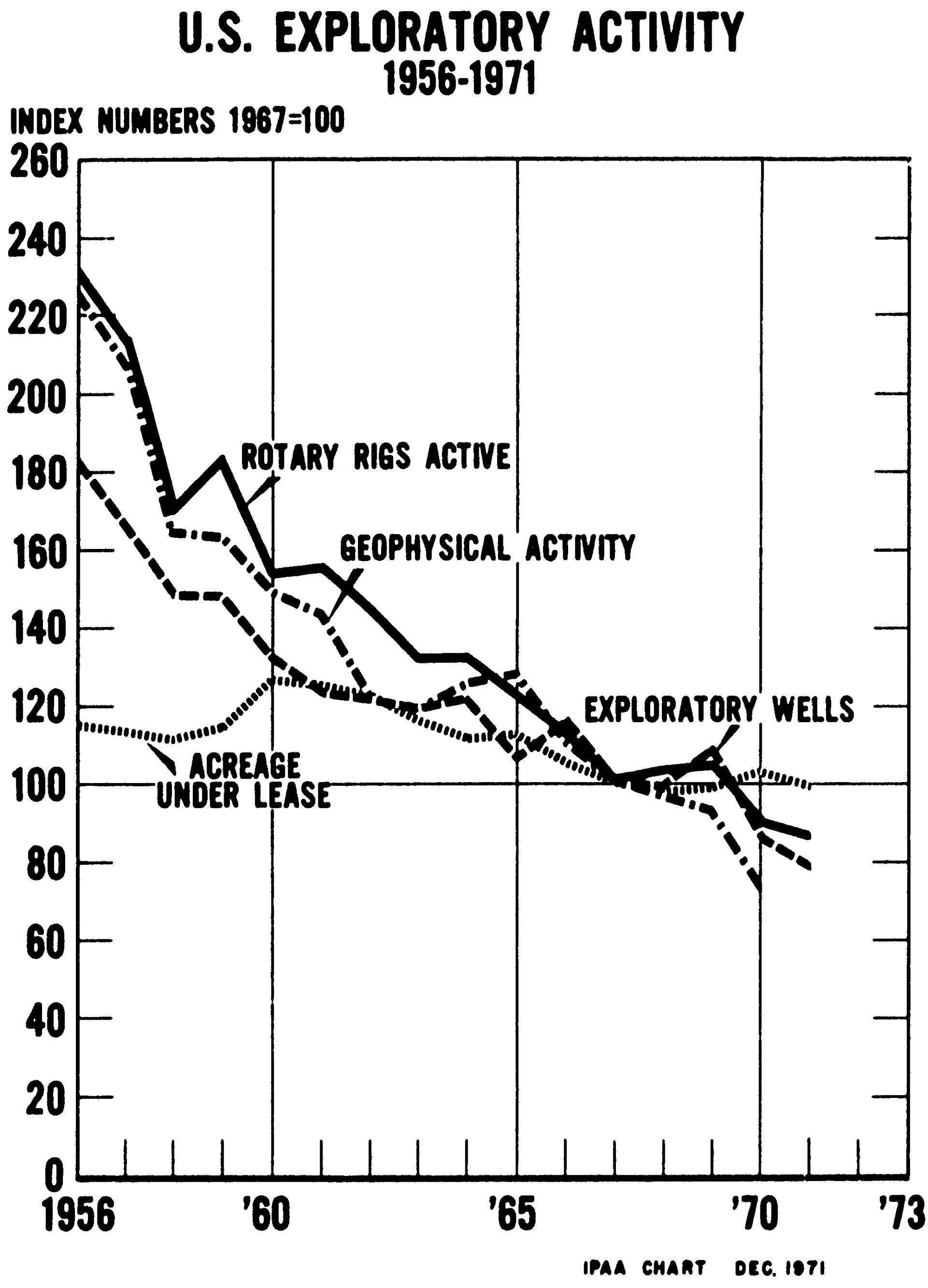
The Conference Board is obliged to Chase Manhattan Bank and the American Mining Congress for permission to reproduce these charts. They appeared originally in the "Outlook for Energy to 1985" (Chase) and the American Mining Congress "Special Situation Report No. 2, May, 1972." See also Appendix I, p. 241.

Despite its huge energy reserves, the U.S. faces a shortage primarily because domestic production of fossil fuels has peaked. The U.S. no longer has excess crude production capacity. The drilling of oil and gas has lagged. In 1956, the postwar peak year, the industry drilled over 57,000 wells. Last year only 29,000 wells were drilled—we are now almost back to the 1946 level of well drilling. Exploratory activities and the service industries associated with those activities have also fallen sharply as shown in the following charts.



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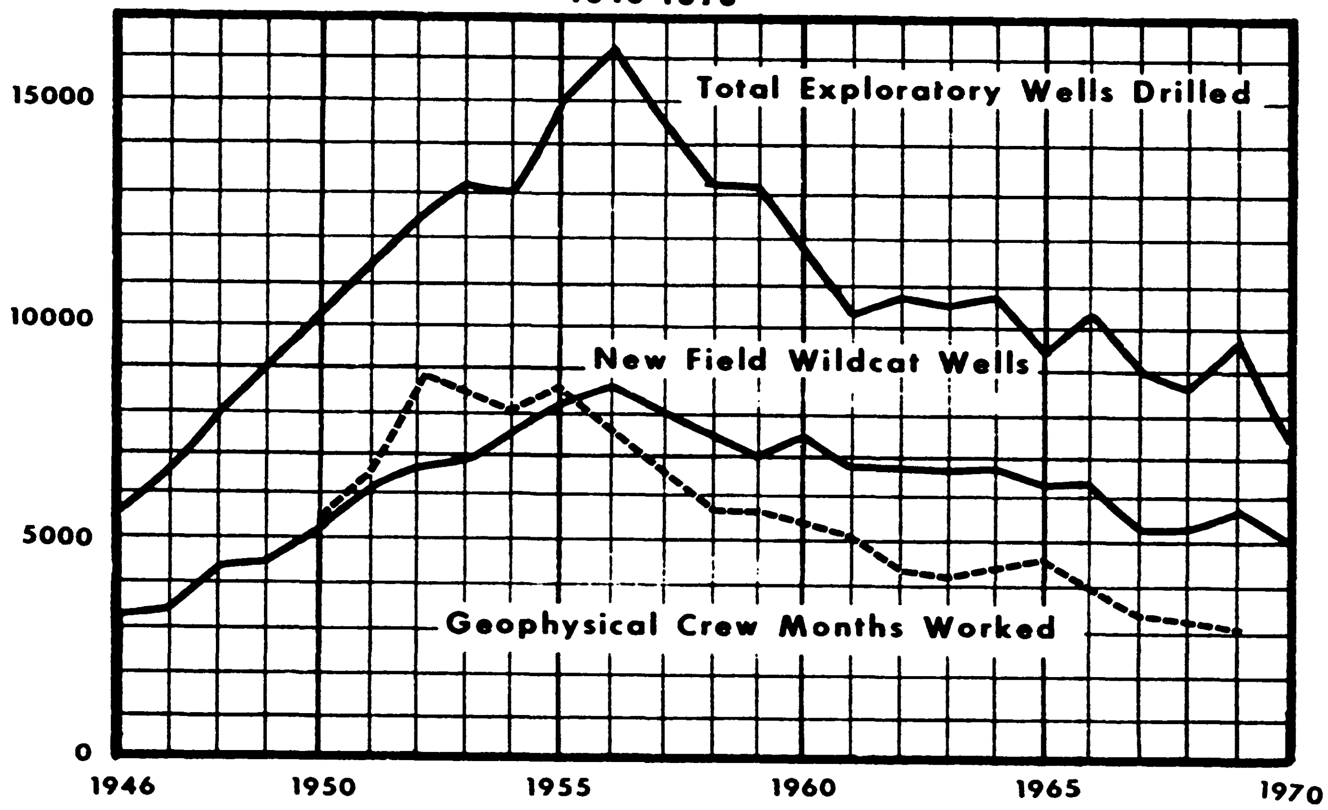
UNITED STATES
EXPLORATORY ACTIVITIES
1946-1970



Environmental concerns have resulted in delays in siting energy facilities and greatly increased the need for scarce low sulphur fuels, displacing high sulphur fuels, particularly coal. New discoveries of natural gas have decreased sharply during the past several years. Since 1966, proven natural gas reserves have decreased 21 percent while consumption increased 37 percent. The U.S. is now producing and consuming about twice as much natural gas each year as it is finding and adding to its proven reserves.

Production of domestic crude oil and natural gas liquids peaked in November, 1970, and decreased in 1972 to an average of 11.6 million barrels per day, down approximately 5 percent from the peak.

In 1972, total U.S. bituminous coal and lignite production was estimated to total 590 million tons, down from 603 million tons in 1970. The use of coal has been greatly hampered by competition from lower cost and less polluting alternative fuels, primarily imported residual fuel oil and low-priced natural gas. About 10 percent of U.S. coal production (60 million tons) is exported. Overall production, however, is restricted due to actual and anticipated constraints on domestic consumption of coal. The coal industry estimates a three year lag before U.S. coal production can be significantly increased.

In 1970, energy imports to the U.S. exceeded reserve capacity; thus the U.S. was no longer self sufficient. In 1972, the U.S. reached essentially 100 percent production (no reserve or shut-in capacity) and foreign petroleum imports totaled 4.7 million barrels per day, accounting for 29 percent of the total oil supply.

IMPORTS—NO SOLUTION

For the short and medium term, imports were viewed until recently as filling the gap between development of proven reserves and consumption. While energy projections are notoriously unreliable, it was widely assumed that by 1980 we would be consuming 24 million barrels of crude oil a day, more than half of which would have to be imported. It was also assumed that most of our import needs would be filled by Middle East and North African oil where 81 percent of the proved free crude oil reserves as of January 1, 1973, are located. (See chart below.) That assumption has all but been destroyed by recent events.

Proved Free World Crude Oil Reserves

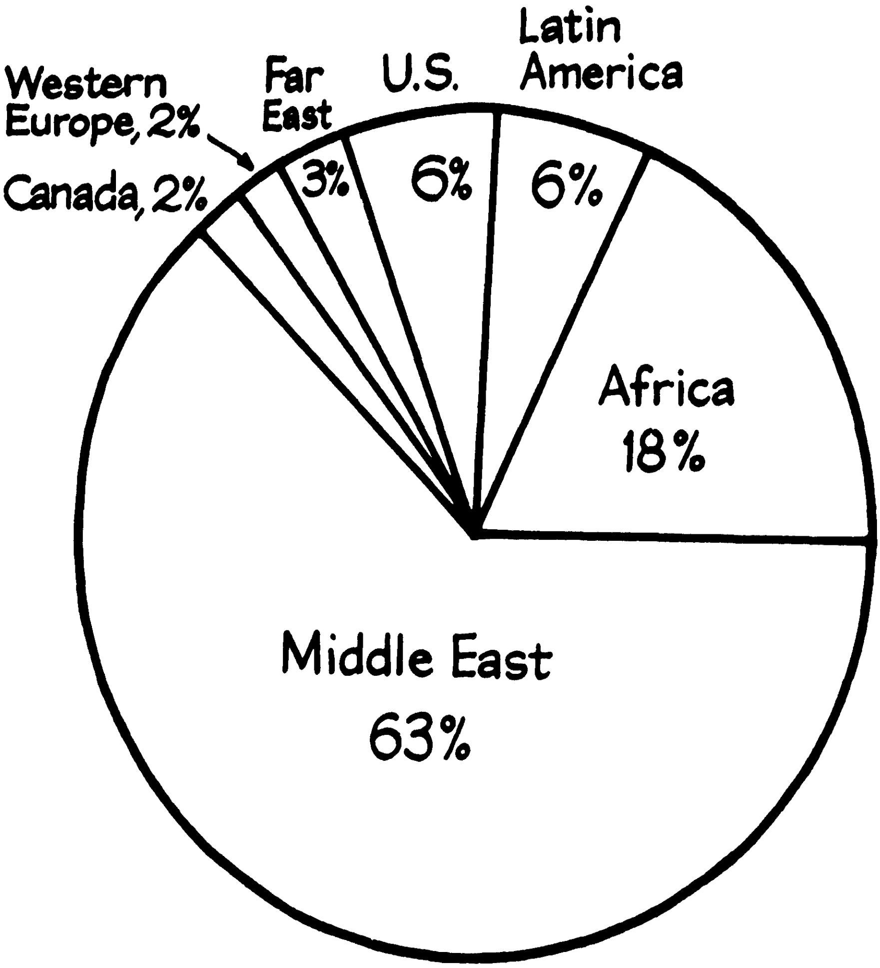


TABLE 3.—*Proved free world crude oil reserves* [1]—*Jan. 1, 1973*

[In billions of barrels]

Area	Reserves	Percent of total
United States	37	6
Canada	10	2
Latin America	33	6
Western Europe	12	2
Africa	106	18
Middle East	356	63
Far East	15	3
Total	569	100

[1] Excluding natural gas liquids.

Source: U.S. Department of Interior.

We will not be able to fill our energy gap with imports from Arab countries in 1973 because of production cutbacks and embargoes. And whatever oil we may be able to import from the rest of the oil producing world will cost us dearly. Europe and Japan are both energy starved and the competition for short energy supplies will drive up crude prices drastically. On October 16 of this year, crude prices were increased 70% by fiat of the producing nations. Thus, no one knows with any degree of certainty what prices of imported crude will be in 1975, 1980, and 1985.

We do know that, in the short run, we face a crunch. Cutbacks in domestic consumption are already a reality. With forecasts of a bitter cold winter, severe hardship to many American households will bring the "energy crisis" home and some frightening possibilities of 20–25 percent cutbacks in fuel consumption are being made.

While the short-run picture is bleak, the longer term outlook is not—providing that this country dedicates itself to a comprehensive energy development program. Such a program may be made consistent with environmental and other goals, but intelligent organization and planning is required for reconciling our energy needs, our environmental concerns, our consumer interests and our foreign policy objectives. Up to now there has been no intelligent and comprehensive planning to reconcile these various concerns into one consistent national policy on energy.

THE FEDERAL BUREAUCRACY

The United States in fact lacks a national energy policy and the U.S. Government lacks the organizational framework with which to implement one. There are presently 64 agencies distributed among nine

Executive Branch departments, 15 independent agencies, and the Executive Office of the President, each concerned with some aspect of energy. Forty-six of these agencies administer programs or implement policies which directly impact the nation's energy system; the other 18 agencies administer programs or policies which indirectly affect the nation's energy system. The President has appointed Governor John Love Assistant to the President for Energy Policy. Yet the office lacks statutory authority over the agencies which actually administer energy programs. On June 29, 1973, the President proposed legislation to establish a Department of Energy and Natural Resources (DENR), a separate and distinct Energy Research and Development Administration, and a Nuclear Energy Commission.

THE NATURAL GAS PRICE REGULATION

Natural gas is of such critical importance to the homeowner, the farmer as well as certain segments of industry that the current natural gas shortage is in large measure most critical energy problem facing the nation. Yet this country has been following a policy whose effects appear totally inconsistent with our energy needs—the Federal Power Commission's regulation of the price of natural gas at the wellhead. MIT's Paul MacAvoy and Robert Pindyck and Harvard's Steven Breyer[1] concluded in their econometric studies that regulation of gas wellhead prices has produced the natural gas shortage that we are experiencing today.

Their study suggests that a phased deregulation would lead to a substantial increase in both reserves and production supply and that excess demand would be significantly reduced in two years and totally eliminated by 1979. These results are shown in Table 4. The study projects that the alternative policy of strict controls (shown in table 5) would result in an increasing gap between production and consumption.

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[1] See Professors Steven Breyer and Paul MacAvoy's article on "The Natural Gas Shortage and the Regulation of Natural Gas Producers." *Harvard Law Review*, Vol. 86, No. 6, April 1973, and MacAvoy and Pindyck's Alternative Regulatory Policies for Dealing with the Natural Gas Shortage, *Bell Journal of Economics & Management Science*, Vol. 4, No. 2. An article by these professors describing the history of the natural gas shortage and the regulation of natural gas producers is reprinted in appendix D.

Paul MacAvoy is a Professor of Economics at the Sloan School of Management at the Massachusetts Institute of Technology and Steven Breyer is a Professor of Law at the Harvard Law School. Professor Robert Pindyck of MIT has joined with Professor MacAvoy in showing the effects of regulating natural gas on the consumer.

TABLE 4.—*The effects of phased deregulation*

Year	Field price on new contracts (cents/M. cubic ft.)	Additions to reserves (trillion cubic ft.)	Production supply (trillion cubic ft.)	Production demand (trillion cubic ft.)	Excess demand over production (continental United States trillion cubic ft.)
1972	26.3	9.8	19.3	23.3	4.1
1973	29.6	12.7	22.1	24.4	2.3
1974	44.1	13.8	25.0	25.4	0.3
1975	47.7	15.4	26.0	26.4	0.3
1976	51.3	18.3	27.1	27.4	0.3
1977	54.9	22.2	28.2	28.5	0.3
1978	58.4	25.9	29.5	29.7	0.2
1979	62.0	29.9	31.0	31.0	0.0
1980	65.5	34.6	32.8	32.4	0.3

TABLE 5.—*The effects of strict controls*

Year	Field price on new contracts (cents/M. cubic ft.)	Additions to reserves (trillion cubic ft.)	Production supply (trillion cubic ft.)	Production demand (trillion cubic ft.)	Excess demand over production (continental United States trillion cubic ft.)
1972	26.3	9.8	19.3	23.3	4.0
1973	29.6	12.7	22.0	24.3	2.3
1974	30.5	13.8	22.8	25.6	2.8
1975	31.3	15.2	23.4	26.9	3.6
1976	32.1	16.8	24.0	28.5	4.5
1977	33.0	18.7	24.7	30.3	5.5
1978	33.8	20.8	25.7	32.2	6.6
1979	34.6	23.2	26.7	34.4	7.7
1980	35.5	26.3	28.0	36.9	8.9

Source: Paul W. MacAvoy and Robert S. Pindyck "Alternative Regulatory Policies for Dealing with the Natural Gas Shortage" *Bell Journal of Economics and Management Service*, Vol. 4, No. 2. Autum 1973, pp. 489 and 491.

In any case, the price controls of the past two dozen years have been accompanied by a steady decline in reserves—output is not being fully "replaced" in the supply line by new reserves—coupled with a huge excess in demand at the regulated prices. The underpricing of domestic natural gas and the resulting nonprice rationing imposed by the gas distributions are direct causes of the recent contracts with Algeria and other foreign nations to import liquified gas (LNG) at prices at least triple those on existing domestic gas contracts. Professors James Cox and Arthur Wright of the University of Massachusetts earlier this year stated in testimony before the House Ways and Means Committee:

"The principal cause of the unseemly situation (the natural gas shortage) is wrongheaded price regulation by the Federal Power Commission which has controlled field contract prices of gas for interstate shipment since about 1960. The FPC has held field prices so low that gas companies have not found it profitable to develop and produce gas for interstate shipment from new domestic reserves. Regulatory agencies at the retail level have transmitted the FPC's underpricing to retail markets by basing rates on field prices plus pipeline charges. . . .

"The solution to both the present and future shortages advanced by both industry spokesmen and others not open to conflict of interest, is to deregulate the field price of gas. The major argument for deregulating, aside from doing away with exceedingly cumbersome bureaucratic machinery, is that, on the best available economic evidence, the field prices of natural gas were set by competitive forces before the FPC began fixing prices . . ." [1]

Since natural gas at the wellhead accounts for only 10–15 percent of the cost to the consumer, the price increases at the well head which can be expected from deregulating the price of a commodity in short supply would increase consumer prices modestly. In 1972, the average annual gas bill of the residential consumer amounted to $155.73. A recent study by Foster Associates estimated that with deregulation of gas prices, the cost would increase in the short term by $8.30 per year using a 55 cent field market-price assumption and by $10.03 at a 65 cent estimate. Over the period to 1980, the increase in residential consumer costs owing to rising field prices would be 2.8 or 3.4 percent per year at the 55 and 65 cent market price assumptions.[2] These price assumptions are consistent with the studies of MacAvoy and Pindyck referred to above.

Unless increased production is made more attractive—by lifting price controls or by direct subsidy—the alternative appears to involve running out of sufficient domestic gas to heat homes and relying on

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[1] Paper presented to the House Committee on Ways & Means, reprinted in Part 9 of 11 parts "*General Tax Reform*", 1st Session 93rd Congress, pp. 1392–1492.

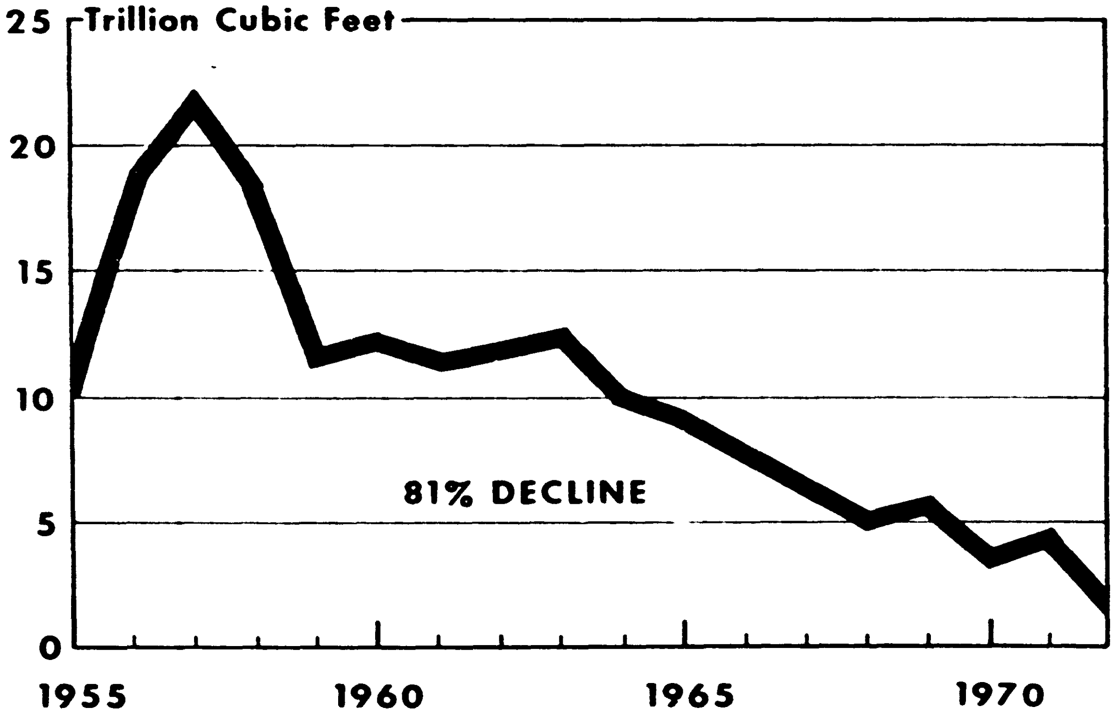
[2] See Foster Associates, Inc., *The Impact of Deregulation on Natural Gas Prices*, August 1973.

Soviet or Algerian gas which, besides the risk of interruption, is triple the domestic prices and would still be higher than domestic prices even after deregulation.

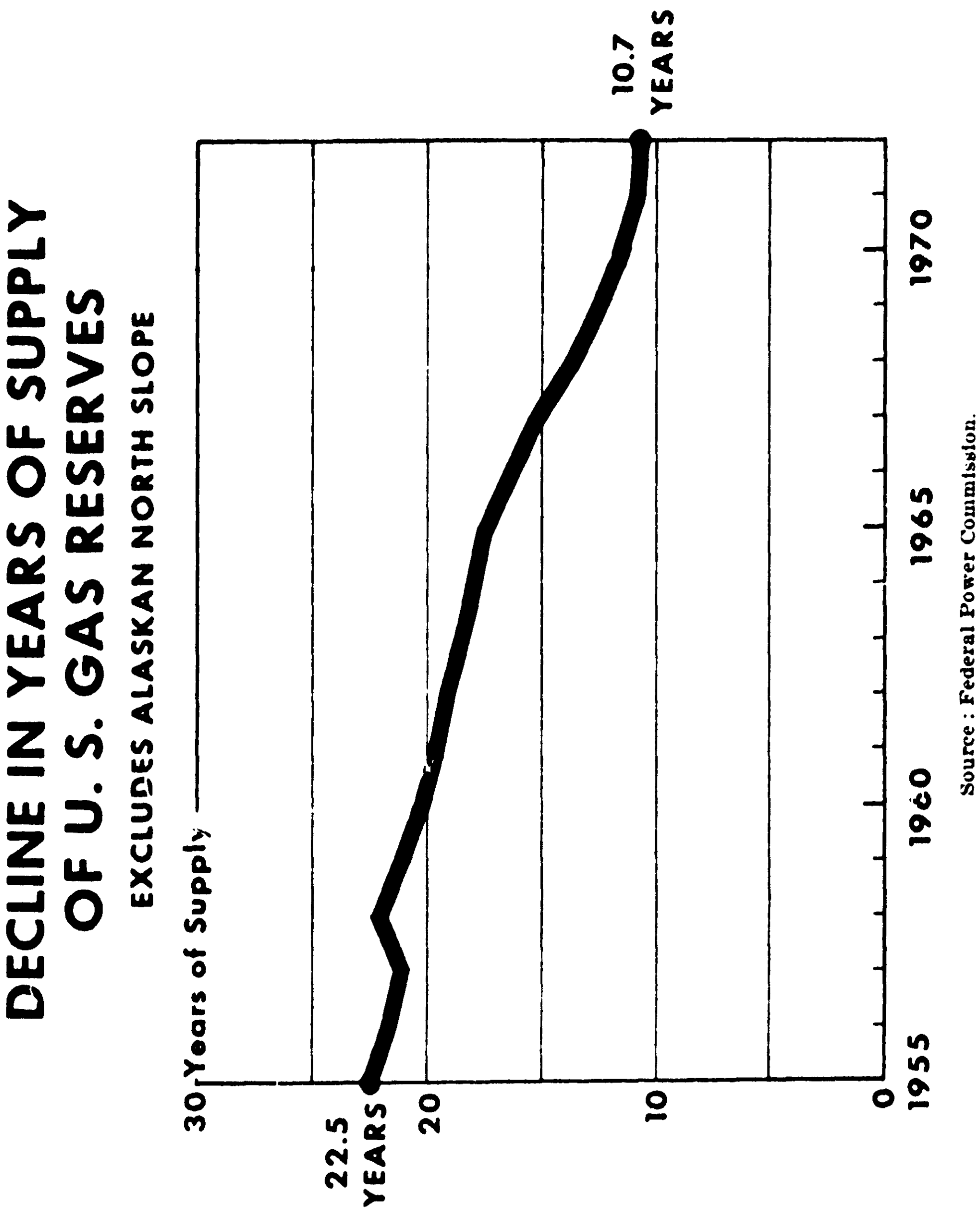
The market price for any commodity must reflect the costs of production and distribution and a reasonable profit expectation. Recent experience with controls on the price of one product and no controls on all costs or market substitutes and the subsequent market distortions caused thereby should be enough evidence to question the wisdom of FPC pricing policies. As had been widely reported in the press last summer, controls over the price of chicken but not the cost of feed, led to the drowning of baby chickens. Similarly, controls over the price of gas but not the cost of producing it, prevents a lot of gas from being found.

NATURAL GAS FINDING RATE IN THE U. S.

EXCLUDES ALASKAN NORTH SLOPE



Source : Federal Power Commission.



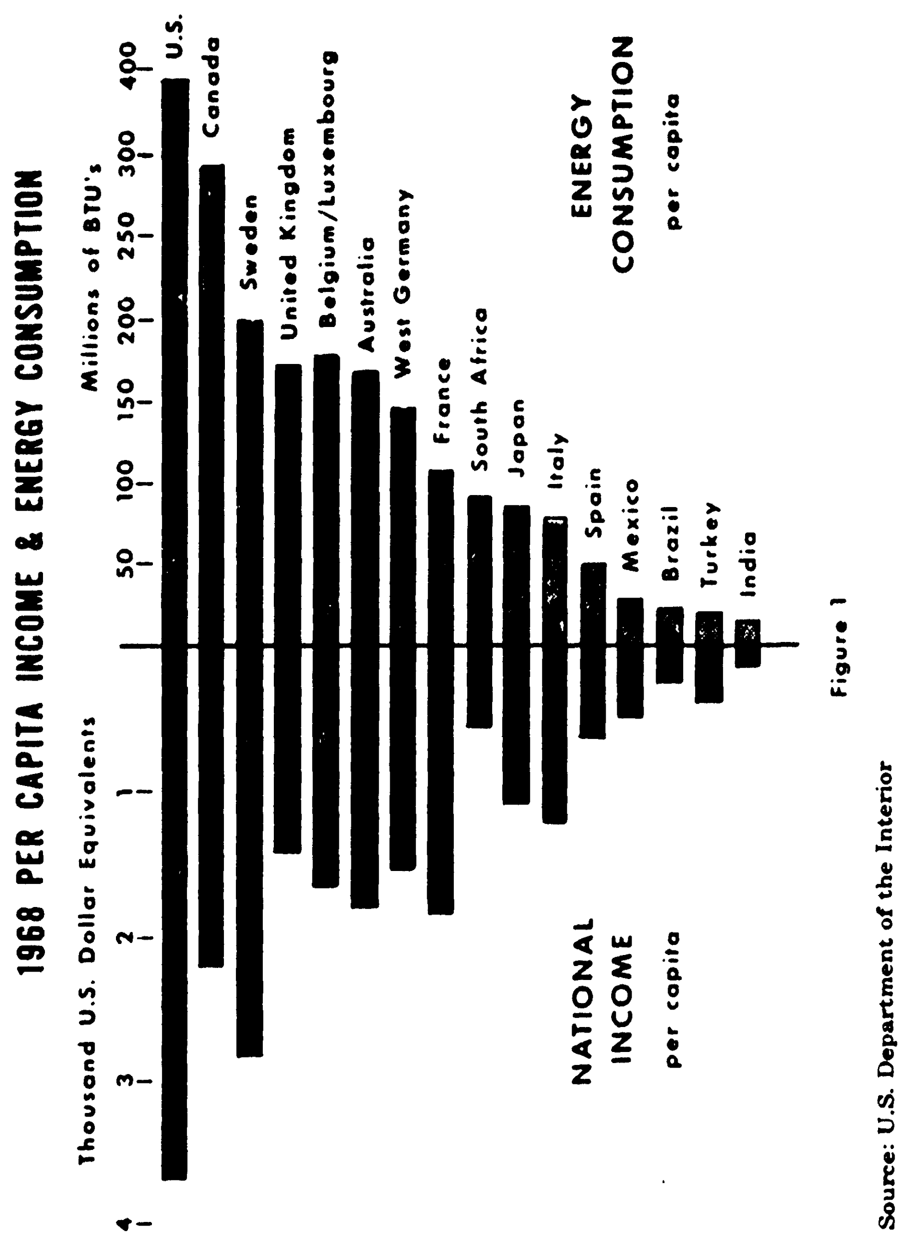
III. Implications of the Energy Shortage

THE NATIONAL ECONOMY

There is a direct correlation between energy consumption and economic growth. The importance of energy to our national economy was aptly stated by the Joint Economic Committee in a September, 1970 report, *Economy, Energy and the Environment:*

> "The economy of the United States and the technologically advanced nations is based on energy. Energy is the ultimate raw material which permits the continued recycle of resources into most of man's requirements for food, clothing and shelter. The productivity (and consumption) of society is directly related to the per capita energy available."

That energy consumption and economic growth go hand in hand is illustrated by the following chart:



The present shortage of available fossil fuels in the U.S. will have an immediate and direct impact on the productivity of the American economy. Many companies will not be able to maintain their current levels of output. Certain industries, such as the petro-chemical industry, are heavily dependent upon energy imports for use as feed stocks. Other sectors of the economy, such as the agricultural and fertilizer industries, similarly use energy resources not only as a fuel but also as a component of production. Thus, the energy shortage not only affects the use of energy as a fuel, in transportation, housing and industry, but also the capacity of farms and factories to continue production. The Executive has already established an industry priority list to allocate fuels according to the assumed importance of each industry to the national economy.

A primary cause of current inflation is the shortage of agricultural and other raw materials. The energy shortage will exacerbate inflationary pressures in the economy, and perhaps eventually lead to a recession. The chain of events may be simply illustrated as follows:

Energy Shortage → Decline in Fuel Consumption → Reduced Output → Unemployment
Reduced Output → Inflation

In short, the current energy shortage (as well as decisions to restrain the consumption of energy) has important implications for the economy, including prices, productivity, employment and growth.

Because the energy shortage so directly affects the national economy, it also affects national goals and commitments. The energy shortage, for example, could seriously impair the country's ability to achieve full employment, or meet housing needs, or to bring about clean air. With our Defense establishment 50 percent dependent on foreign sources for its fuel consumption, there are security implications of a prolonged energy shortage. The Defense Department's fiscal 1974 projection of fuel consumption was 670,000 barrels per day. On November 1, 1973 the President invoked the Defense Production Act to give the Department of Defense first priority over U.S. production.

Environmental concerns offer a good example of a competing, if not conflicting, national priority which will be adversely affected by the shortage of energy and the resort to less desirable fuels. An important aim of this subcommittee is to determine how fiscal policies can be employed to reconcile these apparently conflicting national goals.

THE BALANCE OF PAYMENTS

There is a great deal of uncertainty with respect to the impact of energy requirements on the U.S. balance of payments. Nobody really knows what the price of imported oil and gas will be by 1980 or 1985, or even what U.S. demand will be. The situation is so volatile that long term projections are of questionable validity.

The Commerce Department has devised a model[1] which assumes crude oil price increases from $2.33 per barrel in 1970 to $10.00 per barrel in 1985. As a result of both price increases and import

[1] The Commerce Department model is presented in Appendix C.

demands it is projected that the import bill on a c.i.f. basis would be approximately $40 billion in 1985. These price assumptions seem unrealistic as imported oil is currently going for $9 to $12 a barrel. The Department's model, further, assumes that U.S. exports to oil producers will increase from $1.9 billion in 1970 to $21 billion in 1985 and that the capital inflows from oil producing nations will increase from $0.3 billion to $11.8 billion over this period. As a result, the Commerce Department's model shows the basic balance of payments deficit resulting from oil imports to hit a peak to $12 billion in 1980 and tail off into a surplus by 1985. The projections are highly speculative and several underlying assumptions are questionable. Because of recent price increases the Department changed its 1980 forecast deficit from $3.1 billion to $12 billion.

A large part of the assumed future credits to the U.S. balance of payments labeled as producing company profits or repatriated income may not materialize if U.S. holdings are nationalized, as is already happening in Arab nations. Tanker rates are assumed in one model to be static which seems unrealistic in the light of higher prices, insurance, and wage cost increases generally.

Given the long run imponderables, it may be more reasonable to analyze only the shorter term impact of oil on the balance of payments. Even here the assumptions with regard to price and availability are risky. For example, the volume of imports has risen by more than 50% between 1971 and 1973, while the value of imports has increased by more than 100%. The basic price for foreign oil is generally assumed to be the Persian Gulf f.o.b. price of Arabian crude oil. Since the signing of the Teheran Agreement in February 1971 which brought about a 30% increase in the per barrel revenue of Middle East producing countries, the cost of Saudi Arabian light crude has developed as follows:

TABLE 6.—*Saudi Arabian Posted Prices, Government Revenues and Market Prices, February 1971–October 1973*

	February 1971	Oct. 1, 1973	Oct. 16, 1973
Arabian light 34°:			
Posting	$2.18	$3.01	$5.12
Government take	1.27	1.77	3.05
Market price f.o.b	[1] 1.70	[1] 2.08	3.67

[1] Reported spot price.

Source: Paper presented by John H. Lichtblau, Executive Director, Petroleum Industry Research Foundation, Inc. to Joint Economic Committee on November 7, 1973.

By far the largest of the several price increases occurred on October 16 of this year when governmental revenue in one single step was raised by 70%. With the current Middle East situation still unsettled the producing nations may increase their prices even greater while cutting back on production, and, when the producing spigot is turned on again, hopefully in the near future, the prices are likely to remain at an extremely high level because the demand for Middle East oil is so great. Japan and Europe are almost totally dependent on Middle East oil.

As a result, oil imports which are currently costing in balance of payments terms about $7 billion may double or triple by 1975.

Perhaps the most important issue is not how much we will pay for imported oil but whether or not we will be able to get it at all. Oil in the ground may well be more valuable to Arab producing countries both in economic and political terms than oil exported to the United States and other countries. If the vast reserves of the Middle East are not produced, the world economy faces very serious problems. The last Middle East war led to a sharp cutback in oil production by the Middle East producers. As a result, Western Europe and Japan—to a greater degree than the United States—are facing very serious shortages. In those countries, the choice may not be whether to heat the home at 68 or 72 degrees, or paying 10 cents or 20 cents more for a gallon of gasoline, but between heating a home or running a factory or having a job or running a school.

IV. Fiscal Policy and the Energy Problem

While other Committees of Congress have conducted intensive and lengthy hearings on various aspects of the energy problem, the Finance Committee's jurisdiction over fiscal policies makes it logical for it to look into the fiscal ramifications of the energy problem. The key questions were raised at the outset of this document.

FISCAL INCENTIVES ON THE SUPPLY SIDE

Fiscal incentives have been recommended to increase the domestic supply of fossil fuels (and to develop alternatives) and thereby reduce the dependency on insecure foreign sources of supply as well as lessen the balance of payments drain of imported fuel. The proposals advanced include:

(*a*) Domestic exploratory drilling investment credit and supplementary investment credit for commercially productive wells.

(*b*) Investment credit for research and development aimed at the commercial exploitation of solar energy, geothermal energy, oil from shale and tar sands, gasification or liquefaction of coal, advanced power cycles and other non-nuclear energy sources.

(c) Investment credit for desulfurization equipment and conversion to coal.

Domestic Exploratory Drilling Investment Credit

Domestic exploratory drilling for oil and gas has declined since 1966 both because of the increased cost of domestic drilling (up 133% per well over the past decade) and because of the often greater promise of overseas drilling prospects. Price controls may also have served to discourage domestic drilling.

To encourage the development of new oil and gas production, the Administration has proposed a two-stage investment tax credit:

(a) a 7% credit on the costs of exploration for new wells, and

(b) an additional 5% credit for successful drilling of new wells.

The Administration's tax credit is tied to new field exploratory drilling conducted anywhere within the 50 States, on the continental shelf surrounding the U.S., or within Puerto Rico or territories or possessions of the U.S. or their surrounding waters.

S. 1295 (introduced by Senators Tower, Hansen and Stevens) would provide a 12½% tax credit for expenditures made for exploration and development of new reserves of oil and gas in the U.S., regardless of the commercial success of the exploratory drilling.

Financing Mandatory Conversions From Petroleum to Coal

The President has called for conversion of certain electric power plants, which now burn petroleum or natural gas, to coal. Section 204(a) of S. 2589, the National Energy Emergency Act of 1973, would require such conversions.

Obviously there will be some financial burden on the owners of such power plants. These may be passed on to the customers or shareholders of the companies that incur the costs. On the other hand the benefits of the conversion will probably flow to the entire population of the United States rather than solely to the customers of the companies.

Therefore, Chairman Nassikas of the Federal Power Commission suggests that some consideration may be given to a special credit for costs arising out of the initial conversion and subsequent reconversion of power plants.

ESTABLISHMENT OF AN ENERGY TRUST FUND

Paramount in the effort to come to grips with the energy crisis over the long term is the need to marshal this country's technology and capital resources in a national commitment to research and develop alternative sources of energy. A national effort of the intensity and duration of the Manhattan Project of World War II or the space program of the 1960's could lead to the full utilization of this country's vast fossil fuel resource as well as the development of new energy systems. An energy trust fund would assure that a national energy program would be adequately and consistently funded. Such a trust fund might be supported by the imposition of a tax based upon Btu's of energy, represented in sales of crude oil, petroleum products, natural gas and coal by a producer or importer. Such a tax could be set at different rates for each of the years in which varying levels of funding are necessary or it could be set at a minimum rate providing for a gradual accumulation of funds to meet the anticipated expenditure needs over the life of the trust fund.

S. 2167 (introduced by Senators Cook, Baker and R. Byrd) provides for the establishment of a Federal Energy Research and Development Trust Fund which would be supported by the transfer of revenues payable to the United States under the Outer Continental Shelf Lands Act annually, plus any general revenues necessary to provide $2 billion per year for energy research and development. It appears that this bill may have been introduced to insure funding for the research called for by S. 1283 (introduced by Senator Jackson and others) which calls for a ten-year, $20 billion program to finance non-nuclear energy research and development in the areas of coal gasification, coal liquefaction, advanced power cycles, shale oil and geothermal power. The program would be coordinated through a general manager for non-nuclear research and development at the Atomic Energy Commission and would be carried out through three quasi-public corporations for coal gasification, coal liquefaction and advanced power cycles. Research and development on oil shale extraction, geothermal power, solar, wind, nuclear fusion and other forms of energy would be undertaken by private companies directly subsidized for their research and development expenses or compensated through firm purchase commitments for specific amounts of energy produced. The Administration has indicated support for a $20 billion program for research and development over 10 years and has already committed $1 billion for energy research and development for fiscal year 1974. A summary of that research and development spending plan for fiscal year 1974, is shown below. Over half of the money in fiscal 1974 is committed to nuclear fission. It is not at all clear that this is the safest investment. The breeder reactor has radioactive fallout, the disposal of which has not been solved. Solar energy may be a better long term answer to our energy problems. At any rate, a team of scientists, engineers and economists may be needed to evaluate critically the government's research and development program, showing clearly the costs and benefits of the various alternatives. Appendix E gives a survey of Federal research and development efforts over the past five years.

TABLE 7.—*Energy Research and Development Program Spending*

[In millions of dollars]

	Additional increment [1]	Total, fiscal 1974
Coal	49.5	168.0
Geothermal	7.0	11.1
Environmental control	12.0	58.5
Energy conversion (including solar)	5.0	25.2
Conservation	6.3	15.5
Gas-cooled nuclear reactors	7.1	16.2
Automotive energy R. & D	6.0	22.7
Environmental effects	5.4	43.9
Electric transmission, distribution	3.2	8.0
Nuclear fusion (magnetic confinement)	7.3	54.8
Miscellaneous program increases	6.2	20.5
Energy R. & D. programs not receiving program increase:		
(*a*) Other nuclear fission programs	0	503.5
(*b*) Laser fusion	0	42.9
(*c*) Other	0	4.4
Total	115.0	995.2

[1] Monies requested by the President in November 1973 in addition to the amounts in the original 1974 budget submitted in January 1973.

Source: Office of Management and Budget.

FISCAL DISINCENTIVES ON THE DEMAND SIDE

It appears that the short term energy problem may require a rationing and allocation system (the latter is already in existence). Some have suggested taxing consumption of gasoline, or automobiles based on their gas mileage, or both, as a policy necessary to discourage consumption.

Federal Excise Tax on Gasoline

It has been suggested by Dr. Herbert Stein, chairman of the Council of Economic Advisers that an excise tax on gasoline might be imposed. The effect of such a tax would be to curtail demand. One estimate provided to the staff indicates an excise tax which doubles the cost of gasoline to the consumer could be expected to curtail current demand by 70%.

This assumes, however, that alternative means of transportation exist to get to work and necessary shopping, for desired shifts in driving habits could not be achieved due to the absence of viable transportation alternatives. Accordingly, a national commitment to urban transit systems appears to be an important aspect of the energy problem.

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Federal Excise Tax on New Automobiles Based Upon Their Fuel Consumption Rate

Three bills currently pending in the Senate (S. 2036, introduced by Senator Moss; S. 2428, introduced by Senator Percy; and S. 2595, introduced by Senator Dominick) would impose a tax to serve as an incentive for production of automobiles capable of greater fuel economy. Essentially these bills would impose a progressively higher excise tax on all new vehicles manufactured which obtain less than a rate of 20 miles per gallon of gasoline. As the efficiency of the vehicle declines, the amount of tax is scheduled to increase.

Repeal of Tax Provisions Which Now Indirectly Result in Subsidizing Consumer Prices of Petroleum Products

Dr. Irwin M. Stelzer, in testimony before the Committee on Interior and Insular Affairs, has asserted that tax subsidies have distorted the price structure of our energy supplies and have resulted in price maintenance at uneconomically low levels. Consumers, he argues, have been provided with price signals which fail to reflect the full cost of petroleum products, and have tended to use uneconomically large amounts of gasoline and other related products. It is suggested that any reduction of net return on investment as a result of the repeal of these tax provisions should be recouped through an increase in the price of crude oil which would correct this temporary disequilibrium.

However, in testimony before the House Ways and Means Committee, representatives appearing on behalf of the American Petroleum Institute countered that price elasticity has not kept pace with increasing industry costs and current investment yields from new exploration and development activities are actually lower than returns now being obtained on corporate bonds or long-term certificates of deposit. Therefore, to continue to attract new risk capital they urged that the petroleum industry must be provided with increased tax incentives to stimulate greater domestic exploration and development activity, expanded storage facilities and domestic refinery expansion. In addition, they contended that in the international arena, any changes in the U.S. Federal tax structure would severely hamper American petroleum companies competing in the world oil market and would ultimately result in U.S. dependence on foreign governments for essential foreign oil supplies. They also noted that U.S. petroleum companies operating abroad under the present tax structure are making an important contribution to our balance of payment situation. In 1971, they stated, these companies' remitted earnings exceeded new outlays by approximately $1.5 billion.

The tax incentive approach is aimed at increasing the supply while holding down prices. Such incentives tend to encourage consumption and profitability, thus attracting capital to the industry and benefiting the consumer. The market approach would tend to increase the supply through price increases, hold down consumption and perhaps be less of an incentive to invest in the industry although this latter effect is questionable.

A summary of the principal provisions of the Internal Revenue Code affecting energy resources, production, and consumption is provided in Appendix B.

V. U.S. Trade Policy and the Energy Problem

The United States first became a net importer of petroleum in 1948. Between 1960 and 1970, US oil imports hovered around 20% of consumption, with most of these imports coming from Venezuela and Canada. Up until the mid-1960s the United States had excess domestic production capacity nearly equal to imports. As late as the Arab-Israeli war of 1967, the United States still had some excess production capacity. This was no longer true by March 1972, when Texas and Louisiana removed all production controls. Crude oil production decreased slightly between 1970 and 1972, and we are now producing at full capacity with almost no domestic cushion for emergencies.

No sizable domestic production increase is expected until Alaskan oil from the North Slope reaches the market—by 1977 at the earliest. Alaskan production of about two million bpd will do little more than compensate for declining output in the "lower 48" states by 1980.

By the end of the decade, if present energy policies were continued, as much as half of the oil consumed in the United States would have to be imported—about 11 million bpd out of a total of some 22 million bpd needed. Canada, Venezuela, and other Western Hemisphere sources would probably furnish about four million bpd. The rest would come from the Eastern Hemisphere.

Beginning in 1955, the United States controlled oil imports on national security grounds. At first such controls were on a voluntary basis, but on March 10, 1959, the country adopted a mandatory oil import program.

That program was changed frequently during its lifetime with a growing number of special exemptions granted for one reason or another. With rapid changes in the domestic and international world oil situation, the mandatory quota controls began to unravel during the late 1960's and were officially abandoned this past May.

The history of the mandatory oil import program (MOIP) from its inception on March 10, 1959, through its demise on May 1, 1973 is provided in Appendix F.

The Mandatory Oil Import Program has been the subject of considerable controversy over the years. Whatever its weaknesses and defects were, it is useful to ask the question: Where would we be today in terms of domestic productive capacity and the labor and technology needed to exploit our fossil fuel resources if we had no import re- restraints and if imports now constituted the same portion of our domestic consumption as they do in Europe and Japan?

A further question that should be analyzed is: Given the ability of the major oil-producing nations to price their product at whatever the market will bear, how can we encourage the investment in our own resources of energy, which admittedly will cost more per barrel than those in the Middle East, unless we have a flexible import policy which would prevent foreign producers from undercutting our own investment by sharply reducing their own selling prices?

At present the Arab nations can charge $9–12 a barrel because our existing productive capacities are insufficient to supply our own needs. But if we bring on new production, which may involve costs of $5–$7 a barrel, and the Arab nations then drop the price to $4 a barrel, where will the American producer stand? Given these facts, do we need a flexible tariff instrument to assure U.S. investors in the domestic petroleum market that it would be worthwhile making the investment? The estimated costs of production, shown in the table below, indicate the degree of price flexibility the oil producing nations have.

TABLE 8.—*Estimated cost of production of representative crude oils exported to the United States, f.o.b. port of export, July 1972*

[In U.S. dollars per barrel]

Country	Average real extraction cost	Royalty	Tax	Average total cost
Saudi Arabia	$0.130	$0.310	$1.121	$1.561
Iran	.130	.308	1.116	1.554
Nigeria	.380	.426	1.432	[1] 2.258
Venezuela	.400	.608	1.307	2.315
Libya	.450	.453	1.494	[2] 2.495
Algeria	.750	.473	1.410	2.633
United States [3]	1.080	.370	.770	2.220

[1] Includes harbor dues of $0.020 per barrel.
[2] Includes retroactive buy-out of $0.098 per barrel.
[3] Average data for a west Texas, 4,000-foot well, with an initial production rate of 50 barrels per day and a 15-percent production decline rate. Exploration costs are not included.

Source: Foreign data compiled from statistics of the Office of Oil and Gas, U.S. Department of the Interior. U.S. data based on Bureau of Mines *Information Circular* 8561, 1972.

The current direct and indirect restrictions on the importation and exportation of energy resources are provided below. This information was supplied, upon request, by the General Counsel's office of the Tariff Commission.

REGULATIONS AND RESTRICTIONS ON THE IMPORTATION OF ENERGY RESOURCES

Direct Restrictions

PETROLEUM

The Mandatory Oil Import Program of quantitative restrictions on the importation of crude oil, unfinished oils and petroleum products was replaced by Presidential Proclamation 4210 of April 18, 1973, which instituted a system of license fees. The new control program is administered by the Office of Oil and Gas in the Department of the Interior, which promulgates oil import regulations.

Anyone in the 50 States and Puerto Rico can obtain a license to import any quantity of crude oil, unfinished oils or petroleum products upon payment of the appropriate fee, as set forth below.

Basic fee schedule (Proc. 4210, sec. 3(a))

[In cents per barrel]

	May 1, 1973	Nov. 1, 1973	May 1, 1974	Nov. 1, 1974	May 1, 1975	Nov. 1, 1975
Crude	10.5	13.0	15.5	13.0	21.0	21.0
Motor gasoline	52.0	54.5	57.0	59.5	63.0	63.0
All other finished products and unfinished oils (except ethane, propane, butanes, and asphalt)	15.0	20.0	30.0	42.0	52.0	63.0

Preferential fee schedule for Canadian imports (Proc. 4227, sec. 3(a)(ii))

[Cents per barrel]

	May 1, 1973	Nov. 1, 1973	May 1, 1974	Nov. 1, 1974	May 1, 1975	Nov. 1, 1975	May 1, 1976	Nov. 1, 1976
Motor gasoline	0	0	5.7	6.0	12.6	12.6	22.1	22.1
Other finished products (but not including ethane, propane, butanes, or asphalt)	0	0	3.0	4.2	10.4	12.6	22.1	22.1
	May 1, 1977	**Nov. 1, 1977**	**May 1, 1978**	**Nov. 1, 1978**	**May 1, 1979**	**Nov. 1, 1979**	**May 1, 1980**	**Nov. 1, 1980**
Motor gasoline	31.5	31.5	41.0	41.0	50.4	50.4	63.0	63.0
Other finished products (but not including ethane, propane, butanes, or asphalt)	31.5	31.5	41.0	41.0	50.4	50.4	63.0	63.0

Section 16 of the Presidential Proclamation 4210 temporarily suspends the duties on the products in Schedule 4, Part 10 of the Tariff Schedules of the United States (TSUS). Proclamation 4210 also establishes certain fee-free allowances, which decrease annually until 1980 when they are to be eliminated. Presidential Proclamation 4227 of June 19, 1973, amended Proclamation 4210 by providing a preference for imports from Canada.

The Oil Import Appeals Board is empowered to grant variances in the fee-control system. It can correct errors in allocations, grant modifications in allocations on the ground of exceptional hardships or special circumstances, and review the revocation or suspension of any allocation or license.

The subject of imports of petroleum and products thereof is treated more fully in the Tariff Commission's report of October 1973 to the Committee on Finance of the Senate.

Natural Gas

Under item 475.15 of the Tariff Schedules of the United States (TSUS), natural gas is free of import duty. Such imports arrive from contiguous countries by pipeline and from other countries in liquefied form (LNG).

Under the National Gas Act, a license of the Federal Power Commission is required before natural gas can be imported (15 U.S.C. 717b). Under the Power Commission's regulations an application for a license to import must contain the appropriate fee as prescribed in 18 C.F.R. 159, as well as a statement of the reasons why the proposed importation of natural gas will not be inconsistent with the public interest and will not in any way impair the ability of the applicant to render natural-gas service at reasonable rates to U.S. customers. In making its determination, the Commission considers the economic and technical feasibility of facilities, foreign-policy matters (in consultation with the Department of State), security aspects (in consultation with the Defense Department), environmental factors, and cost of the material to be imported.

Atomic Energy

Under the Atomic Energy Act of 1954, the Atomic Energy Commission is authorized to issue licenses for the importation and any utilization or production facilities for atomic energy (42 U.S.C. 2121). AEC Regulations establish procedures and criteria for the issuance of licenses to import source material (uranium or thorium) into the United States. A Type 103 license is required for commercial and industrial facilities, and the appropriate fees are set out in 10 C.F.R. 1703. Unimportant quantities of source material are exempted from the license requirement.

Ores of thorium (item 601.45) and uranium (item 601.57) are duty-free under the TSUS, as are radioactive chemical elements, isotopes, and compounds (item 494.50).

COAL

The domestic abundance of coal and its high cost of shipping demonstrate no need for import restrictions on coal. Coal of all classifications, under item 521.31 of the TSUS, is duty-free.

OTHER ENERGY FORMS

Methyl alcohol.—Methyl alcohol has become a matter of interest as a source of energy. This product is presently dutiable under item 427.96 of the TSUS at the rate of 7.6 cents per gallon (column 1) and 18 cents per gallon (column 2). Even though methyl alcohol costs more to produce than liquefied natural gas (LNG), it does not require expensive, specialized tankers for shipment as does LNG. To increase the cost competitiveness of methyl alcohol as a fuel, it has been proposed by some U.S. gas producers that methyl alcohol used to generate energy—either through actual burning of the methyl alcohol or reforming of the methyl alcohol into gas which is then burned—be accorded duty-free status.

Synthetic (or substitute) natural gas (SNG).—This fuel—which to date has not been imported and, as far as can be foreseen, probably never will be imported—results from the gasification of light liquid hydrocarbons, such as naphtha. Under the current oil import program (Pres. Procs. 4210, 4227), naphtha to be used in making SNG is subject to the appropriate license fee, unless the producer holds a fee-free allocation. Proclamation 4210 suspended the duties imposed on naphtha under item 475.35 of the TSUS. It should be noted that once SNG enters an interstate pipeline and becomes mixed with natural gas, it becomes subject to the jurisdiction of the Federal Power Commission.

Indirect Restrictions

FEDERAL

There are restrictions which exert an indirect impact on energy imports. While these indirect restrictions may be less visible than those of a direct nature, they nonetheless also limit what may be imported in the way of energy resources. Environmental concerns delaying the Trans-Alaska Oil and Gas Pipeline, offshore drilling, and sale of Federal lands for exploration of oil and gas have necessitated increased imports. Similar environmental concerns have made it difficult to site refineries and nuclear plants, the former resulting in increased petroleum product imports and the latter causing increased requirements for other fuels.

Control of domestic natural gas prices at an artificially low level has affected the availability of natural gas, resulting, to some extent, in the need for increased imports of oil and of LNG. Cost of Living Council controls on what part of a cost increase can be passed on to the consumer may discourage some importation.

Tax laws also influence imports, as do natural security aspects of the sources of the imports. The Jones Act adds 8 to 10 cents per mcf to the cost of transporting LNG between Alaska and the west coast by American flag vessels as compared to foreign flag vessels. This increased cost could divert LNG from Alaska to other countries, while making it less expensive to import LNG from the South Pacific or Russia to the United States.

Further effects on imports may result from failure to construct superports for handling the economically advantageous very large crude carriers (VLCC's); environmental concerns or jurisdictional disagreement over who is to license and determine where they are to be built are factors in this area. Proposed legislation to require 20 percent of U.S. oil imports to be carried on U.S. flag vessels initially and 30 percent by 1977 would also affect imports.

State and Local

While most of the above restrictions are Federal in nature, some also involve States' rights with an indirect impact on the importation of energy. These include local harbor rules, such as berthing procedures, pilot tugs employment, and local union provisions, safety precautions, and environmental concerns. In this latter area States have been particularly active issuing rules on allowable water and air pollution including the admissible sulfur levels in fuel. In some instances the State rules on air pollution are more restrictive than the Federal and often differ within the State, depending upon the condition of the ambient air and the fuel. In Massachusetts, for example, State standards now limit sulfur content to 0.3 percent in home-heating oil, 0.5 percent in residual fuel oil burned in Boston and some 12 other communities, and 1.0 percent for residual fuel oil burned elsewhere in Massachusetts. New York City, after an LNG tank explosion on Staten Island, imposed a ban on new construction of all tanks over 52,000 gallons capacity until the investigation of the disaster has been completed. Any additional safety measures resulting from the investigation will have to be implemented on all tanks under construction.

There are many other areas where State and other local practices impact indirectly on imports of energy resources. We have not delved into these practices to any extent; in no way is it to be construed that this note exhaustively covers all things impacting energy resource imports either directly or indirectly. Only a thorough study of local and State laws and other practices would uncover all restrictions.

REGULATIONS AND RESTRICTIONS ON THE EXPORTATION OF ENERGY RESOURCES

General

The Export Administration Act of December 30, 1969, 50 App. U.S.C. §§ 2401 et. seq., is the starting point for an analysis of the statutory provisions regulating exports. Two of the United States export policies, for purposes of this Act, are to use export controls "to the extent necessary to protect the domestic economy from the excessive drain of source materials and to reduce the serious inflationary impact of abnormal foreign demand. . . ." and to promote the national security (50 App. U.S.C. § 2402). The authority to effectuate this policy through institutional organization is given to the Secretary of Commerce (50 App. U.S.C. § 2403) and administered by the Office of Export Control. The President is given the authority to prohibit or curtail exportation by issuing rules or regulations, and these rules and regulations "may apply to the financing, transporting, and other servicing of exports. . . ."

15 C.F.R. contains the regulations issued by the Commerce Department for the administration of the Export Administration Act. The Department of Commerce has licensing jurisdiction over all items on its Commodity Control Lists (CCL), which includes petroleum, petroleum products, and coal. The fact that a commodity is on the CCL does not necessarily mean that Commerce will require a license. Part 370 sets out the general export licensing policy. According to 15 C.F.R. 373.5, certain commodities, including petroleum products, are subject to a periodic requirements license if they may be exported for a period of one year from issuance of the license to one or more ultimate consignees in a single country of destination.[1] Part 377 sets out the commodities subject to short supply quota control by the Department of Commerce. At the present time, fossil fuel exports are not so controlled.[2] Fossil fuels are not currently under consideration at the Commerce Department for inclusion in the short supply category.

Executive Order No. 11533 of June 4, 1970 (35 F.R. 8799), provides for the administration of the Export Administration Act. Section 1 delegates Presidential power under the Act to the Secretary of Commerce; section 2 reestablishes the Export Control Review Board of Executive Order No. 10945 of May 24, 1961, as the Export Administration Review Board; section 3 states under what circumstances the Secretary of Commerce may and must refer export license matters to

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[1] However, at the present time only petroleum exports to South Rhodesia, Cuba, North Vietnam, and North Korea require licenses.

[2] Licenses on a worldwide basis are required for eight highly specialized fossil fuel products with national security implications. This list does not include consumer-type products. Exports of these specialized products are but a very small part of the total exports of petroleum products.

the Export Administration Review Board; section 4 gives the President authority to prescribe rules and regulations applicable to section 1.

Although most energy resources could be considered to be in short supply under the Export Administration Act, there is some question as to whether abnormal foreign demand is causing an inflation impact with respect to any particular energy resource. As indicated above, both criteria must be met before export controls may be applied under this Act. However, the Senate Committee on Banking, Housing and Urban Affairs is currently considering legislation, already passed by the House (H.R. 8547), which would amend the Export Administration Act so as to authorize the President to impose export controls during conditions (i) of scarce supply *or* (ii) serious inflation caused by abnormal foreign demand. If passed, the President would have clear authority to regulate the export of any energy resource which was in scarce supply.

The *Defense Production Act of 1950*, as amended, provides the President with broad authority to allocate and control the distribution of any materials in the civilian market if he determines that:

1. such materials are scarce and critical to the national defense, and
2. the national defense requirements for such material cannot otherwise be met without significant dislocation of the civilian market.

On November 1, the President invoked the Defense Production Act to give the U.S. Defense Department absolute priority on U.S. production.

The Defense Department traditionally depends on foreign sources for about 50 percent of its needs. The department projected its fiscal year 1974 consumption to be about 670,000 barrels per day. About half of the consumption is for U.S. use; the rest is consumed abroad by the offshore fleets. The sixth and seventh fleet had depended almost entirely on foreign oil. With the Arab oil embargo, they will have to depend on U.S. sources.

Thus, the priority allocation will preempt about 335,000 barrels a day for Defense purposes that would ordinarily be used in the civilian economy.

Although this act does not provide specific authority to regulate exports, it could conceivably be used by the President to give domestic contracts priority over contracts for foreign delivery in cases where the national defense requirements were met. This could have a significant impact on the export of energy resources, especially with respect to coal where 10 percent of present production is under contract for foreign sale.

Pursuant to Executive Order No. 11423 of August 16, 1968 (33 F.R. 11741), authority over control of certain energy transporting facilities constructed and maintained on U.S. borders was granted to the Secretary of State. Section 1(a) of that order reads:

> Except with respect to facilities covered by Executive Orders No. 10485 and No. 10530, the Secretary of State is hereby designated and empowered to receive all applications for permits for the construction, connection, operation, or maintenance, at the borders of the United States, of: (i) pipelines, conveyor belts, and similar facilities for the exportation or importation of petroleum, petroleum products, coal, minerals, or other products to or from a foreign country. . . .

The Secretary of State is to request the views of appropriate department and agency heads and state and local government officials.

> Note that section 3 of the order asserts that the authority of the Secretary of State hereunder is supplemental, to, and does not supersede, existing authorities or delegation relating to importation, exportation, transmission, or transportation to or from a foreign country.

The Executive order concerns only border facilities and only indirectly affects Commerce's licensing of exports. To date there have been no regulations promulgated under this Executive order.

There are other indirect general export controls, many of the same type as affect import controls. Included in these are Federal and local environmental restrictions, labor laws.

Petroleum

The only legislation which specifically restricts the export of petroleum products was included in the so-called "Alaskan pipeline bill" (S. 1081), which was just enacted by Congress. The bill amends section 28(u) of the Mineral Leasing Act of 1920, as amended, so as to restrict the export of domestically produced crude oil transported by pipeline over public lands. Exports of crude oil transported under these conditions can only be made if the President determines that such exports "will not diminish the total quantity . . . of petroleum available to the United States," are in the national interest and are in accord with the provisions of the Export Administration Act of 1969. Any such determination could be overruled by concurrent resolution of Congress within 60 days of receipt of the determination from the President. This provision would currently apply primarily to petroleum exports to Canada and Mexico shipped by pipeline over public lands. However, the main object of this provision will be the future crude oil brought in from the Alaskan north shore.

The Office of Oil and Gas of the Department of the Interior allocates imports of crude and unfinished oils pursuant to section 9A (allocations based on exports of petrochemicals) of the oil import regulations.

These regulations provide for the allocation of imports of such oils into PAD districts I–IV and district V to persons operating petrochemical plants based on quantities of eligible petrochemicals which those persons manufacture and export. The eligible petrochemicals are listed in section 9A according to the trade classification schedule B number. Complex products are excluded from the list because of the difficulty in assigning allocations.

On October 26, 1973, the Department of Interior issued a regulation (38 F.R. 30572) pursuant to the Defense Production Act (see section A.) which authorizes the Director of the Office of Oil and Gas to issue directives to suppliers during any period of disruption in the military supply of petroleum products. The directives would require the suppliers to supply the required products to the Department of Defense regardless of other existing contracts.

On April 30, 1973 the Economic Stabilization Act of 1970 was amended by P.L. 93–28 to provide the President with authority (this authority has been delegated to the Office of Energy Policy) to allocate supplies of petroleum products in order to meet the essential needs of various sections of the Nation and to prevent anticompetitive effects resulting from shortages of such products. Although the amendment is not specifically concerned with export controls, the new authority could be used to guarantee that the major portion of domestic petroleum production be utilized for domestic consumption. In its report on the recent amending legislation, the Senate Committee on Banking, Housing and Urban Affairs indicated that it:

> . . . recognized the necessity of providing legislative authority to the President to assure that sufficient supplies of petroleum products be made available to consumers this year . . . (S. Report No. 93–63, p. 2).

Control of the prices at which crude oil and petroleum products may be sold domestically adds an incentive to export these materials when a higher price can be realized overseas. This situation exists at present due to a tight worldwide energy supply-demand situation. Accordingly, any price regulation of energy resources might require the allocation of such resources in order to insure that sufficient supplies remain available for domestic consumption.

Pursuant to the new authority, the Director of the Office of Energy Policy (to whom the authority has been delegated) has already put into effect mandatory allocation programs for supplies of propane (EPO Reg. 3, 38 F.R. 27397, October 3, 1973) and middle distillates (EPO Reg. 1, 38 F.R. 28660, October 16, 1973). Middle distillates are defined as any derivative of petroleum, including kerosene, jet fuel, home heating oil, and diesel fuel, which have a fifty percent boiling point in the ASTM D86 standard distillation test between 350° and 700° F. Procedural regulations for these programs have been published as EPO Reg. 7 (38 F.R. 29330, October 24, 1973).

Natural Gas and Electricity

The exportation of natural gas and electric energy is controlled by the Federal Power Commission (FPC) under the authority of the National Gas Act (15 U.S.C. 717b). To obtain a license to export natural gas and electric energy, an application must be filed with the FPC (18 C.F.R. 1.5) and accompanied by a fifty dollar filing fee (18 C.F.R. 159). Executive Order No. 10485 of September 3, 1953 (18 F.R. 5397), empowers the FPC to issue permits for the construction, operation, maintenance, or connection at U.S. borders of facilities for the transmission of electric energy to a foreign country and for the importation or exportation of natural gas. Before issuance of a license, there must be a determination of consistency with the public interest and favorable recommendations by the Secretaries of State and Defense.

Atomic Energy

The Atomic Energy Act of 1954 provides the Atomic Energy Commission with full authority to regulate the export of nuclear energy resources. Nuclear source materials and byproducts may not be exported, except pursuant to license by the Commission.

Exports of Energy Resources

EXPORTS—1968 TO 1972

Crude oil and petroleum products.—Total exports increased annually from 1968 to 1970 and declined in 1971 and 1972. Crude oil exports also peaked in 1970 and since have decreased significantly, going from 4,991,000 barrels in 1970 (or 0.1 percent of production) to 187,000 barrels in 1972 (or 0.005 percent of production). Important petroleum product exports have been of coke, petroleum lubricants, liquefied gases, and residual fuel oils, due to the availability of foreign markets for these commodities. In 1972, coke exports went principally to Europe, Japan, Canada, and Mexico. Petroleum lubricants were exported mainly to Brazil, Canada, Japan, and the United Kingdom; ninety percent of the exports of liquefied gases went to Mexico; and residual fuel oil exports went largely to Canada, Mexico, and the United Kingdom.

Coal.—Coal exports in the period 1968–72 peaked in 1970, thereafter declining. Bituminous coal accounted for 98 percent of total coal exports in 1972 or approximately 10 percent of bituminous production. In 1972, Japan and Canada received 64 percent of the total bituminous coal exports, and Canada received about 64 percent of the total anthracite coal exports.

Natural gas.—Canada, Mexico, and Japan were our only export markets over the 1968–72 period. Canada and Mexico received natural gas via pipeline transmission, while Japan, starting in 1969, received liquefied natural gas shipments from Alaska. Japan was our largest export market in 1972, receiving over 50 percent of out total natural gas exports. Total exports of natural gas in 1972 were but 0.4 percent of production.

Electricity.—For purposes of the Tariff Schedules of the United States (TSUS), electricity is considered an intangible and not subject to the provisions of the schedules, with the result that it is not subject to a duty and, therefore, no statistics are published by the Department of Commerce. Similarly, there is no Schedule B number for electricity exports, so that there are also no Department of Commerce statistics published for exports.

The FPC collects import and export data for electricity as part of their licensing procedure. For 1972, exports to Canada were $2.8 million, while imports were $61.8 million. Essentially all of this trade occurred within the U.S. east coast to Michigan. Exports to Mexico in 1972 were $3.8 million, while there were no imports. The exports all originated in Texas, Arizona, and California.

Exports—1973 vs. 1972

Crude oil and petroleum products.—Total exports for the first seven months of 1973 increased about 10 percent over the same period in 1972. Both petroleum products and crude oil imports increased. However, total exports are only about one percent of production.

Coal.—Total exports of coal decreased in the first seven months of 1973 relative to the first seven months of 1972. Both anthracite and bituminous coal exports decreased.

Natural gas.—Natural gas exports increased about 10 percent in the first seven months of 1973 relative to 1972 but remained small compared to production at less than one half of one percent.

Fossil fuels: U.S. exports summary table, by products, 1968–72

Product	1968	1969	1970	1971	1972
	Quantity [in thousands of barrels]				
Petroleum lubricants	18,001	16,397	16,094	15,823	14,995
Liquefied gases	10,608	12,798	9,955	9,379	11,469
Residual fuel oils	20,013	16,891	19,786	13,186	12,060
SBP naphthas	2,427	2,019	1,585	1,455	1,487
Total gasoline	2,083	2,449	1,368	2,287	954
Distillate fuel oils	1,547	1,753	899	2,924	1,214
Jet fuel	2,092	1,730	2,093	1,536	957
Kerosene	613	154	124	179	89
Crude petroleum	1,802	1,436	4,991	507	187
Other [1]	25,358	29,258	37,348	34,569	38,056
Total	84,544	84,885	94,243	81,845	81,468
	Quantity [in thousands of short tons]				
Anthracite coal	518	627	789	671	780
Bituminous coal	50,637	56,234	70,908	56,633	55,960
Total	51,155	58,681	71,697	57,304	56,740
	Quantity [in billions of cubic feet]				
Natural gas	94	51	68	84	91

[1] Mainly petroleum coke, although other exports of wax, asphalt, road oil, petrochemical feedstock, and other miscellaneous products are included.

Source: Crude petroleum and products statistics compiled from Bureau of Mines data. Coal statistics compiled from Department of Commerce data. Natural gas statistics compiled from FPC and Department of Commerce data.

Fossil fuels: U.S. exports summary table, by products, January–July 1972, and January–July 1973

Product	January–July 1972	January–July 1973
Thousands of barrels:		
Crude oil	360	187
Refined products	49, 860	45, 026
Total	50, 220	45, 213
Thousands of short tons:		
Anthracite coal	392	339
Bituminous coal	28, 360	30, 755
Total	28, 752	31, 094
Billions of cubic feet: Natural gas	52	49

Source: Crude petroleum and products statistics compiled from Bureau of Mines data. Coal statistics compiled from Department of Commerce data. Natural gas statistics compiled from FPC and Department of Commerce data.

VI. Summary of Facts

This document has sought to raise more questions than it answers. Its central theme was raised on the first page: "Should fiscal policy be employed to mitigate the current energy shortage and to assist in the transition to alternative energy sources?" A host of related questions were also raised at the outset which will be the focus of the subcommittee's hearings. The factors pointing to the underlying need for a national energy policy have been made abundantly clear:

The U.S. with 6 percent of the world's population, consumes one-third of the world's captive energy;

Domestic production of fossil fuels peaked in November 1970, and by 1972 was down 5 percent despite removal of all production restraints;

The U.S. has a large resource base of fossil fuels sufficient to meet its needs for several hundred years; but most of these resources are a long way from development;

The capital requirements for developing U.S. resources are enormous—running into the hundreds of billions over the next decade;

While import policies have historically played a major role in preserving stable domestic prices, this is no longer the case;

Imports are not a long-term solution to the energy gap; they will not even be available to cover our short-term needs;

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Foreign oil is now more than twice as expensive as domestic oil; however, given the much lower costs of production in the major oil producing nations of the Middle East, and the ability of these countries to charge whatever the market will bear, a U.S. national energy policy must encourage investment in our own plentifiul resources (for example, through a variable import levy);

Academic studies indicate that Federal regulation of natural gas at the well head has been primarily responsible for the severe natural gas shortage that we are experiencing today;

The implications of the energy shortage for the U.S. economy are quite serious—unemployment and price inflation may result from reduced output;

The balance of payments effects of relying on foreign energy cannot be accurately projected into the future as price and availability of fuel remains uncertain; nevertheless, under reasonable assumptions the effects are large enough to lead to serious international monetary instability;

Perhaps a more important question than the balance of payments effects is whether we will be able to get the fuel when we need it; and at what price?

The United States exports a considerable amount of its coal production;

If utilities and commercial users of energy are to switch from natural gas to coal, they will have to be assured of an available supply of coal; the same can be said of huge investments in coal gasifiers which can become commercially operational in about 2 years;

The implications of the energy shortage on our defense posture have not been fully explored;

The Defense Department traditionally has depended on foreign suppliers for about half its needs (DOD projected consumption in FY 74 was 670,000 barrels per day).

In response to the need to increase supply and decrease demand for energy, the Committee may wish to consider tax measures, both incentives and disincentives. These tax incentives (or disincentives) may be viewed either in conjunction with, or as alternatives to, a free price mechanism for domestic fossil fuels.

On the supply side, various tax incentives have been suggested for:

(*a*) developing our domestic sources of energy;

(*b*) developing alternative sources through research and development programs;

(*c*) financing mandatory conversions of electric power plants from petroleum or natural gas to coal;

(*d*) encouraging capital investment in mid-range energy altenratives.

(*e*) An "energy trust" fund has been suggested as a means of insuring adequate financing of research and development and other expenditures needed over the next decade to insure "energy independence".

On the demand side, tax disincentives have been suggested for restraining overall and/or wasteful consumption.

(*a*) consumption taxes or a tax at the source (BTU tax) have been suggested as a means of financing the energy trust fund;

(*b*) the alternative consumption taxes that have been suggested include: a tax on gasoline at the pump, and/or a manufacturers auto excise tax based on gas mileage;

The U.S. lacks a national energy policy. The country needs a comprehensive program of energy conservation and development—one which is consistent with the nation's environmental, economic and national security goals.

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Appendix A

White House Fact Sheet on Energy

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Office of the White House Press Secretary, The White House

Fact Sheet—the President's energy emergency address
Background.
Current Situation.
Actions now being taken by the Administration.
- Reduce Residual Oil Consumption.
- Reduce Jet Fuel Consumption.
- Reduce Heating Oil Consumption.
- Reduced Gasoline Demand.
- Other Presidential Actions.
- Other State and Local Actions.

Emergency Energy Legislation.
- Current authorities.
- Emergency Authorities Needed.
  - Mandatory energy conservation measures.
  - Imposition of energy conservation fees or taxes.
  - Naval Petroleum Reserves.
  - Daylight Savings Time.
  - Temporary relaxation of air and water quality regulations.
  - Environmental evaluation for actions under emergency act.
  - Regulatory agency authorities (FPC, CAB, REC, FMC, ICC.)

Organization and Funding for Energy R&D.
- Resubmission of ERDA proposal for action this session.
- $10 billion—5 year authorization for ERDA.

Other Administration Legislative Proposals awaiting Congressional action.
Previous Presidential Statements on Energy.
Background Data on Sources and Uses of Energy.
- All energy sources.
- All energy uses.
- Petroleum sources.

BACKGROUND

In the President's Energy Message of April 18, the President characterized the energy situation facing the country as a problem, but not a crisis.

While we were faced with a tight supply situation this winter, particularly in home heating oil, we felt that voluntary conservation efforts, coupled with increased imports would allow us to balance the supply and demand.

However, as a result of the actions taken in the Middle East, our ability to import has not increased, but has in fact declined. Therefore, the energy problem has become much more severe.

CURRENT SITUATION

Recent oil curtailments will mean a shortage this winter of between 2 and 3 million barrels per day of crude oil and products—or 10 to 17% of expected demand.

Current shortages are approximately 10% of demand.

If the oil cutoff continues as petroleum demand increases during the winter, the overall shortage will rise toward the 3 million barrels per day level—17% of demand.

At the current 2 million barrels per day level, the total shortage in major fuels are:

Distillate fuels—including heating oil, diesel fuel and kerosene—at least 450,000 barrels per day or 11% short of expected demand. (Heating oil shortages are expected to be over 15% short of demand.)

Residual fuel oil—which is used primarily by electric utilities, industrial operations and for heating large buildings—is approximately 500 thousand barrels per day or 13% short of expected demand.

Jet fuel—at least 100 thousand barrels per day or 13% short of commercial and private use.

Gasoline—at least 500,000 barrels per day or 7% short of demand. Expected shifts in refinery output to higher production of heating oil at the expense of gasoline could decrease the shortage of heating oil and increase the shortage of gasoline by as much as 200,000 barrels per day.

ACTIONS NOW BEING TAKEN BY THE ADMINISTRATION

The following actions are being taken by the Administration, primarily under the authority of the Economic Stabilization Act of 1970 and the Defense Production Act of 1950.

REDUCE RESIDUAL OIL CONSUMPTION

Regulations are being issued which prevent utilities and industrial facilities from switching from coal to petroleum fuels to reduce the growing demand for residual oil.

Utilities will be encouraged and, where possible, required to convert power plants currently using residual oil to coal.

46 power plants have indicated a capacity to convert within 60 days, with a potential savings of residual oil of 400,000 barrels per day.

Actual conversions will depend upon such factors as the availability of coal, transportation and storage facilities, and variances from State Clean Air restrictions.

REDUCE JET FUEL CONSUMPTION

The Federal Aviation Administration is continuing to work with airlines on actions to reduce fuel consumption, such as reducing speeds and limiting the amount of taxiing. This will save an estimated 20,000 barrels per day.

New steps will be taken under the fuel allocation program to distribute available jet fuel equitably among commercial and other jet fuel users. Shortages could result in a 10% reduction in scheduled flights.

REDUCE HEATING OIL CONSUMPTION

Thermostats in Federal buildings will be reduced to 65–68°, leading to a 19% reduction from last year in energy required for heating—or the equivalent of 40,000 barrels of oil per day during the winter.

The President asked that:

Thermostats in homes be reduced by 6°, to reach a national daytime average of 68°.

Offices, factories and commercial establishments achieve the equivalent of a 10° reduction through lowering thermostats or curtailing working hours. (An estimated 450,000 to 600,000 barrels per day of heating oil could be saved by these actions).

Homeowners and businesses that heat with electricity and natural gas make the same sacrifices as those using oil.

Plans are being developed to control consumption of heating oil through rationing, if that proves necessary. A proposed plan will be published in the *Federal Register* in about 4 weeks. In addition, control fees are being considered to dampen excessive use of natural gas and electricity.

REDUCE GASOLINE DEMAND

The President has directed that operators of all Federal motor vehicles observe a 50 MPH speed limit.

The President asked Governors, Mayors and the general public to take steps to reduce gasoline use. Possible steps include:

Make greater use of mass transit and car pools. An increase in the average car occupancy for commuter trips from the current 1.6 persons to 2.5 persons would save approximately 400 thousand barrels per day.

Reduce speeds on highways within their states to a maximum of 50 MPH.

State and local governments can discourage automobile use by:

Setting aside bus lanes.

Establishing higher parking taxes.

Blocking off certain city sectors to cars with only one occupant.

Providing preferential parking for car pools.

State and local governments can stagger working hours to smooth traffic flow and increase use of public transit.

The President directed the Secretary of Transportation to give priority to grant applications for the purchase of buses for mass transit under the authority of the Federal Aid Highway Act of 1973 and the Urban Mass Transportation Act. (Approximately $1.8 million per-year is available for urban highway and urban mass transit capital assistance).

A plan for rationing of gasoline is being developed and will be implemented if necessary.

OTHER PRESIDENTIAL ACTIONS

Directed the Office of Management and Budget to establish an interagency task force to monitor the allocation and rationing programs and develop plans for dealing with the expected shortage.

Directed the Secretary of Interior to establish a fuel allocation administration to administer all energy allocation and rationing programs.

Directed the Secretary of Commerce to establish a National Industrial Energy Conservation Council to promote conservation in industry.

Directed the Secretary of the Interior to active the Emergency Petroleum Supply Committee, which consists of oil company officials and serves in emergencies to gather information on imported petroleum supplies and their transportation.

Energy companies should not take advantage of the current oil shortages to gain excessive profits. If necessary the Economic Stabilization Act will be used to insure that the companies do not benefit unduly.

OTHER STATE AND LOCAL ACTIONS

Governors and Mayors that have not yet done so are being asked to establish energy emergency offices or committees to:

Determine the energy supply and demand situations in their areas.

Develop and implement actions to reduce energy demand.

Coordinate activities to assist those who do not have adequate fuel supplies.

Work with Federal agencies that are allocating fuel.

EMERGENCY ENERGY LEGISLATION

Current emergency authority available by the President for dealing with the energy emergency is largely limited to:

Defense Production Act of 1950, as amended, which provides broad authority including authority to allocate and control the use of materials for National security purposes.

Economic Stabilization Act of 1970, as amended, which provides authority to allocate petroleum as well as authority to control prices and wages.

Export Administration Act of 1969, as amended, which provides authority to restrict exports.

At the President's direction, Energy Policy Advisor John Love and other Administration officials have been working with the Congress over the past two weeks to identify new authority needed to respond in a timely fashion to an energy emergency.

Legislation is needed for action in an energy emergency in the following areas:

Authorize mandatory energy conservation measures such as:

Curtailing outdoor electrical advertising and ornamental lighting (ornamental gas lights use an amount of natural gas equivalent to 35,000 barrels per day or enough to heat 175,000 homes).

Reducing commercial operating hours.

Reducing speed limits.

Imposition of energy conservation fees or taxes, such as on consumption of natural gas or on excessive uses of electric energy.

Give Congressional approval to:

The finding by the Secretary of the Navy (approved by the President) that increased production from the Elk Hills Naval Petroleum Reserve is needed for national defense purposes. (160,000 barrels of oil per day—8% of current shortages—could be obtained from Elk Hills within 60 days).

Use of proceeds from sale or exchange of the Navy owned oil to fund further development and production from Elk Hills and for exploration and proving Naval Petroleum Reserves, especially NPR #4 in Alaska.

Authorize the use of daylight savings time throughout the year. (This could reduce electricity and heating demands, particularly in Northern areas, by as much as 3%).

Authorize the President, acting through the Administrator of EPA to exempt (grant waivers) stationary sources from Federal and State air and water quality laws and regulations. There would be no change in Federal or State standards. Rather, there would be a case-by-case review by the Environmental Protection Agency with authority for the Administrator of EPA to grant waivers, without notice or hearing, and to override state or local regulations, if necessary. Relaxation would generally be limited to one year except where longer periods are necessary to make conversions to alternative fuel economically feasible.

Authorize the President to exempt actions taken under the proposed energy emergency act from the National Environmental Protection Act (NEPA). However, an environmental evaluation of substantive content similar to an environmental impact statement would be required prior to the action, if possible, but within 60 days in any event. Actions in effect over one year would become subject to the full NEPA requirements.

Upon declaration of an emergency by the President, regulatory agencies (FPC, CAB, ICC, FMC, and AEC) would:

consider energy use and conservation as part of their public interest determinations, and,

in the case of the transportation agencies, be authorized, after summary hearings, to adjust a carrier's operating authority in such respects as: number of trips, points served, and rate schedules, and,

in the case of the FPC, be authorized, for the duration of the energy emergency to suspend the regulation of prices of new production of natural gas, and,

in the case of the AEC, be empowered to grant a temporary (up to 18 months) operating license without a public hearing, but subject to all safety and other requirements of its act.

ORGANIZATION AND FUNDING FOR ENERGY R & D

The President is requesting the Congress to give priority attention to the establishment of ERDA, separate and distinct from DENR in order to move ahead rapidly with the creation of a strong management framework for developing energy technology.

On June 29, 1973, the President proposed to Congress legislation to establish a Department of Energy and Natural Resources (DENR), Energy Research and Development Administration (ERDA), Nuclear Energy Commission (NEC).

The creation of ERDA will also result in a corresponding reorganization of the AEC's regulatory functions into an independent NEC.

The President also directed authorizing legislation for the 5-year—$10 billion energy R & D program that he announced on June 29, 1973 be forwarded to Congress to provide the necessary funds for ERDA.

OTHER ADMINISTRATION LEGISLATIVE PROPOSALS ON ENERGY AWAITING CONGRESSIONAL ACTION

The President again asked that the Congress act on the following legislative proposals needed to improve our longer term energy situation:

During this session:
- Alaska Pipeline
- Natural Gas Supply Act
- Mined Area Protection Act (Surface mining)
- Deepwater Port Facilities
- ERDA/NEC Reorganization

Early next session:
- Electrical facilities siting
- DENR

PREVIOUS PRESIDENTIAL STATEMENTS ON ENERGY

June 20, 1971 Message to the Congress on Clean Energy.

April 18, 1973 Message to Congress on National Energy Policy.

June 29, 1973 statement on Energy Conservation, R & D and Organization.

October 9, 1973 statement on Energy Conservation.

October 11, 1973 statement on Energy R & D, including added funds for FY–74.

Data on sources and uses of energy, 1972

All energy sources:	
Petroleum (including natural gas liquids):	
Million barrels	5, 960
Trillion Btu	32, 812
Percent	46
Natural gas:	
Billion cubic feet	22, 607
Trillion Btu	23, 308
Percent	32
Coal (bituminous, anthracite and lignite):	
Thousand short tons	571, 053
Trillion Btu	12, 428
Percent	17
Hydropower:	
Billion kilowatt-hours	280. 2
Trillion Btu	2, 937
Percent	4
Nuclear power:	
Billion kilowatt-hours	56. 9
Trillion Btu	606
Percent	1
Total gross energy (trillion Btu)	72, 091

All energy uses:

The 1972 figures show that consumption by major consuming sectors was fairly evenly divided:

	Percent
Industrial	28. 8
Electricity generation	25. 6
Transportation	25. 0
Household and commercial	20. 6

When electrical generation is factored into the other sectors, the breakdown is as follows:

Industrial	43. 0
Commercial	14. 0
Residential	19. 0
Transportation	24. 0

Petroleum:

At present the United States depends upon petroleum to meet approximately one-half of its energy demand.

On the average for 1973, petroleum use is approximately 17 million barrels per day.

Imports accounted for approximately 33% of all crude oil and petroleum products prior to the recent curtailments.

The table below shows United States imports of crude oil and products.

U.S. Imports of Crude Oil and Products

[Figures for 2d Quarter 1973—in thousands of barrels per day]

Source	Crude oil	Products	Total
Venezuela	326. 8	599. 5	926. 3
Other Caribbean	62. 5	746. 2	808. 7
Canada	1, 036. 7	330. 2	1, 366. 9
Mexico	2. 7	14. 9	17. 69
Other Western Hemisphere	47. 8	551. 1	598. 9
Non-Communist:			
Europe		183. 2	183. 2
Egypt	20. 8		20. 8
Other North Africa	294. 3	42. 4	336. 7
West Africa	466. 9	13. 1	480. 0
Israel	3. 4		3. 4
Iran	207. 0	2. 6	209. 6
Other Mideast	487. 7	62. 1	549. 8
Japan		2. 2	2. 2
Indonesia	205. 2	3. 5	208. 7
Other Eastern Hemisphere		18. 0	18. 0
Rumania		6. 4	6. 4
U.S.S.R		24. 9	24. 9
Totals	3, 161. 9	2, 600. 3	5, 762. 2

Appendix B

Summary of Principal Provisions of the Internal Revenue Code Affecting Energy Resources, Production, and Consumption

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Summary of Principal Provisions of the Internal Revenue Code Affecting Energy Resources, Production, and Consumption

The following material summarizes the principal provisions of the Internal Revenue Code which directly affect energy resources, production and consumption. Excluded are State and local taxes affecting energy, and a number of minor provisions of the Federal income tax law which relate to energy. Brief mention is made of general provisions such as the investment credit and accelerated depreciation which do not specifically pertain to the energy industry but affect it just as other industries are affected. No discussion is included regarding the use of the tax laws to establish drilling funds as tax shelters.

INCOME TAX PROVISIONS

Depletion

Allowances for the depletion of mineral deposits are made in the from of deductions from gross income by owners of oil and gas wells and of mines (including coal and uranium). These deductions enable the owner to deduct his investment in the well or mine from his income over a period of years for income tax purposes, just as other businesses are allowed deductions for depreciation. In addition, deductions for depreciation are available to operators of mines and wells with respect to certain capital expenditures. The deduction for depletion is authorized under Section 611 of the Internal Revenue Code and must be the larger of cost depletion (Section 612) or percentage depletion (Sections 613–614). Cost depletion is akin to depreciation while percentage depletion is a special method wholly unrelated to actual investment. It is based on gross income.

1. *Cost depletion.*—Cost depletion is computed in relation to the cost of the property subject to certain adjustments. In a more technical sense it is based on the "adjusted basis" of the property which would be used to determine the gain on the sale or other disposition of the property. Cost depletion is generally used to recover the costs of acquiring the property (leases, geological costs, sales price of land). The cost is reduced each year by any depletion deductions taken. Cost depletion is computed by multiplying the adjusted basis of the property by the ràtio of the units of the product produced and sold during the year to the estimated total units that will be produced over the remaining life of the property. For example, in the case of an oil well, if

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the adjusted basis is $50,000, and 500,000 barrels of oil are expected to be produced over the remaining life of the well and 50,000 are produced and sold during the year, the cost depletion would be:

$$\frac{50{,}000}{500{,}000} \text{ times } \$50{,}000 \text{ equals } \$5{,}000$$

For the next year, the $5,000 cost depletion will reduce the cost basis to $45,000 and the prior year's production of 50,000 barrels will reduce estimated production to 450,000 barrels. Assuming production of 50,000 barrels in the second year the cost depletion will be:

$$\frac{50{,}000}{450{,}000} \text{ times } \$45{,}000 \text{ equals } \$5{,}000$$

The "basis" used for depletion purposes is reduced by cost depletion or percentage depletion taken. When the adjusted basis reaches zero, cost depletion ceases, though percentage depletion is permitted to continue indefinitely. At any time the property becomes abandoned, the entire remaining basis, if any, for cost depletion may be written off in the year of abandonment.

The cost of certain tangible equipment attached to a well, such as pumps, may be either separately depreciated under methods allowable for depreciation, or written off by the "unit production method" at the same rate as applies to cost depletion. Other tangibles are subject to depreciation for purposes of recovering their cost.

2. *Percentage depletion.*—Percentage depletion is not related to the cost of a property but is a percentage of gross income from the property. This method of capital recovery is employed when it exceeds cost depletion. When used it reduces the remaining basis for cost depletion. The percentage depletion rates prescribed in Section 613(b) are 22% for oil, gas, and uranium, and 10% for coal. Gross income from the property is defined in Section 613(c) and means in the case of oil and gas the price at the wellhead. In the case of uranium, coal, and oil shale, certain treatment processes and transportation expense may be applied before determining value of the mineral for purposes of determining "gross income from the property".

In the case of coal, cleaning, breaking, sizing, dust allaying, treating to prevent freezing and loading for shipment are allowed as treatment processes. In the case of uranium, crushing, grinding, beneficiation by concentration, cyanization, leaching, crystallization, precipitation (but not electrolytic deposition, roasting, thermal or electric smelting, or refining) are allowed. In the case of oil shale, extraction, crushing, loading into retort and retorting are allowed but not hydrogenation, refining or any process subsequent to retorting. Ore may be valued for percentage depletion purposes after being transported up to 50 miles (or further if the Secretary of the Treasury determines it is necessary) from the place of extraction to treatment facilities.

Percentage depletion has also been allowed for geothermal wells. As a result of litigation, it has been decided that geothermal wells are gas wells and entitled to a depletion rate of 22%. This result was obtained after it was concluded that the well constituted an exhaustible source of gas (water vapor). It is believed that some geothermal wells may be inexhaustible. Such wells would not be entitled to percentage depletion in that event.

The percentage depletion deduction may not exceed (under Section 613(a)) 50% of taxable income from the property computed before the allowance for depletion, i.e. after all deductions other than depletion. For example, if gross income from a property is $100,000, the depletion deduction in the case of oil would be $22,000. However, if taxable income before depletion (gross income minus any other deductions) is only $40,000, then only $20,000 of the depletion deduction may be taken. Because of this limitation as well as the concept "gross income from the property" the determination of what constitutes a property is important. The general rule is that each separate interest in each mineral deposit in each separate tract or parcel of land is a separate property. However, certain aggregations are allowed. In the case of oil and gas, all operating interests within a single tract may be treated together or separately. This rule is liberalized in the case of operating interests subject to a unitization or pooling arrangement. In the case of other minerals, the taxpayer may elect to aggregate one or more operating interests if the interests are in the same operating unit. However, no interest in a particular mine may be excluded from an aggregation if other interests in the mine are included.

Each taxpayer with a direct economic interest may take percentage depletion on his share of the gross income. The operator deducts royalty payments from the gross income of the property before he computes his depletion allowance and the royalty holder takes depletion on the share of the depletion represented by his royalty. When computing the 50% limitation, the operator begins with the gross income less royalty payments, and computes taxable income by deducting all expenses.

Current Expensing of Certain Costs

The income tax law allows certain expenses of exploration and development of mines and wells to be deducted currently rather than to be capitalized and deducted ratably over the life of the property. The advantage of deducting expenses currently rather than capitalizing them is that current deduction results in deferral of taxes. This advantage is reenforced by the fact that the value of the deferral is increased by the interest effect. In addition, when expenses are deducted, percentage depletion may also be taken, whereas if the expenses are capitalized, only cost depletion would be available. The provisions for oil and gas are quite different from those for the hard minerals.

1. *Expensing of intangible drilling costs (oil and gas).* Certain expenses incurred in bringing a well into production, such as labor, materials, supplies and repairs, are considered intangible drilling costs. (Tangible expenses are those for assets such as tanks, drilling tools, casings, tubing and pipes.) Although intangible drilling costs are actually of a capital nature (expenses for an asset which will produce income over a number of years), Section 263(c) allows the taxpayer the option of deducting them currently (in the year the costs are incurred) rather than capitalizing them and deducting a portion of the costs over each year of useful life. Regulations are prescribed under Section 612. If intangible expenses are currently deducted, they are not added to basis for cost depletion. Moreover, they do not reduce percentage depletion except to the extent they reduce net income for purposes of the 50% limitation. If the election to deduct currently is not made, these expenses are capitalized and must be recovered through cost depletion.

2. *Expensing of exploration and development costs (hard minerals).* Mining exploration and development costs may be deducted currently (Section 616–617). Mining exploration costs are those for the purpose of ascertaining the existence, location, extent or quality of a deposit, paid or incurred before the development stage (such as core drillings and testing of samples). These expenses are limited in the case of foreign exploration so that total foreign exploration costs cannot be expensed after the taxpayer has taken total deductions, foreign and domestic, of $400,000. Development expenses are those incurred during the development stage of the mine and include expenses such as constructing a shaft and tunnel and in some cases drilling and testing to obtain additional information for planning operations. There are no limits on the current deductibility of development expenses.

Deductions of mining development costs are in addition to percentage depletion. Exploration expenditures deducted currently may subsequently reduce percentage depletion deductions. Also, there is a recapture provision for exploration costs deducted but not for development costs deducted. That is to say, if the property is sold, a portion of the gain may be required to be treated as ordinary income.

Capital Gains Treatment of Coal Royalties

Section 631 allows coal royalties to be treated as long term capital gains in cases where the taxpayer held the deposit for at least six months prior to leasing it in exchange for royalties from production. Long term capital gains taxation is at a lower rate than the tax on ordinary income.

Minimum Tax

The minimum tax has the effect of reducing to some degree certain tax advantages available to the energy industry.

Percentage depletion taken after the basis for cost depletion has been reduced to zero is one of the preference items subject to the minimum tax (Sections 56–58). Another tax preference item is the capital gains treatment described above for coal royalties.

The minimum tax is levied on the aggregate of preference items after subtraction of $30,000 of preference income and an additional amount equal to the taxpayer's regular income tax. For example if a taxpayer had tax preferences of $100,000 and regular tax of $50,000, his minimum tax would be $2,000 ($100,000 minus $80,000 times 10%).

Foreign Tax Credit

A second provision which may be said to provide special benefits for the oil and gas industry is the foreign tax credit (Section 901–906). The foreign tax credit is available to all taxpayers and allows them to credit foreign income and similar taxes against their U.S. tax liability, thus reducing the U.S. tax liability dollar for dollar. The purpose of this provision is to prevent double taxation of foreign income brought back to the U.S. The foreign tax credit is limited to the amount of tax paid on income earned in foreign countries and cannot be used to offset tax on U.S. source income. Taxpayers may choose between two methods for determining the extent of the credit: the per-country limitation limits the credit for taxes paid *to each country* to the same proportion of total Federal income taxes that reported income received from that country bears to total income; the overall limitation limits the credit for taxes paid *to all foreign* countries to the same proportion of Federal income tax that all foreign income bears to total income. Allowance of the overall limitation permits the taxpayer to use excess foreign tax credits from a high tax country to offset Federal income tax on foreign income, such as shipping income, subject to little or no foreign tax.

The foreign tax credit is particularly important to international oil companies who account for almost one half of the foreign tax credits claimed by corporations subject to U.S. taxation.

Because of the existence of percentage depletion under U.S. but not foreign law, foreign oil operations are generally taxed at a lower level by the U.S. than by the foreign government. This results in excess foreign tax credits which may offset U.S. tax on foreign non-mineral income. Thus, in 1969, a provision was added to disallow the use of excess foreign tax credits arising from the excess of percentage over cost depletion to reduce U.S. taxes on foreign non-mineral income.

Another area of interest relating to the foreign tax credit as applied to the energy industry is the issue of whether the income tax levied by the foreign government on oil production is in fact a tax. In the foreign oil-producing countries, the rights to land are generally held by the governments rather than private individuals and, therefore, royalties are paid to these governments. However, if these royalties are paid in the form of income taxes then they may be credited against income tax, rather than deducted from income, reducing taxes dollar for dollar rather than 48 cents for each dollar. Moreover, the oil companies may then include these amounts in gross income for purposes of computing percentage depletion. If they were considered royalties, percentage depletion could not be taken on the government's share of the gross income. Some have argued that the large income taxes paid by American companies to the petroleum exporting countries are actually royalties and that treating them as income taxes results in preferential treatment of oil production in foreign countries.

EXCISE TAX PROVISIONS

Excise taxes are imposed at varying rates on a number of fuels. Credits are allowed to the consumer against income tax in some cases where fuel was not used in a certain manner; as for example for non-highway use.

Manufacturer's Excise Taxes

Gasoline.—4 cents a gallon (a credit is allowed if used on a farm for farming purposes or if used for non-highway purposes other than noncommercial aviation; a 2 cent per gallon credit is allowed for use in local mass transit) Section 4081–4084.

Lubricating oil.—6 cents per gallon (a credit is allowed if not used in a highway vehicle) Section 4091–4094.

Retailer's Excise Taxes

Gasoline used in non-commercial aviation—3 cents per gallon Section 4041(c)(1).

Fuels other than gasoline used in non-commercial aviation—6 cents per gallon Section 4041(c)(2).

Diesel fuel used in highway motor vehicles—4 cents per gallon (a credit is allowed if used on a farm for farming purposes or if used in local mass transit)—Section 4041(a).

Special motor fuels (benzene, benzol, naptha, etc.)—4 cents per gallon (if used in a non-highway motor vehicle or motor vehicle or motor boat the tax is 2 cents per gallon)—Section 4041(b).

Although these taxes are imposed on the manufacturer or retailer they are included but generally stated separately in the price to the consumer. Certain types of sales are exempt such as those to State and local governments, tax-exempt educational organizations, sales for export and sales for resale.

Appendix C

Balance of Payments Effects of Energy Imports

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Department of Commerce—Balance of payments, effects of energy imports—Balance on current account and long-term capital (basic balance of payments)

[Billions of dollars]

	1970	1975	1980	1985
Consuming countries:				
United States	2.3	−7.0	−12.0	−0.8
West Europe	−3.9	−17.7	−27.0	−16.4
Japan	−.3	−8.3	−21.8	−39.8
Canada	−0	−0	−1.3	−1.5
Other free world	.3	.2	−3.9	−8.0
Subtotal	−1.7	−32.9	−66.1	−66.5
Producting countries:				
Venezuela	.2	3.7	2.5	−0
Algeria	.0	.9	1.[illegible]	0
Libya	.7	2.8	3[illegible]	.6
Nigeria	0	3.5	7.3	4.1
Iran	0	7.2	10.0	3.6
Iraq	.1	.9	8.3	18.0
Kuwait	.1	1.8	2.5	2.4
Qatar	.1	1.1	1.5	1.1
Saudi Arabia	.3	6.7	19.3	25.8
Union of Arab Emirates	.1	3.3	8.0	11.0
Indonesia	0	1.1	2.3	.1
Subtotal	1.7	32.9	66.1	66.6
Total	−0	0	0	0

N.B.—These data retain the basic assumptions of the attached technical staff paper with the exception of a $1.50 transport fee from the Persian Gulf to the United States and a world price of $5 per barrel in 1973 rising to $10 fob in 1980.

Source: U.S. Department of Commerce.

Balance on current account

[Billions of dollars]

	1970	1975	1980	1985
Consuming countries:				
United States	2.4	−13.2	−25.7	−16.0
West Europe	−4.0	−24.3	−41.8	−33.1
Japan	−.4	−11.4	−30.1	−50.8
Canada	−.2	−.4	−1.7	−1.9
Other free world	−.2	−6.3	−19.3	−27.2
Subtotal	−2.5	−55.6	−118.6	−129.1
Producing countries:				
Venezuela	0	3.7	2.5	0
Algeria	0	1.6	2.1	−.1
Libya	.9	4.5	5.3	.9
Nigeria	−.2	3.3	7.1	3.8
Iran	.1	11.0	15.3	5.4
Iraq	.2	1.4	12.7	27.7
Kuwait	.5	4.5	6.4	5.9
Qatar	.1	1.9	2.6	1.9
Saudi Arabia	.7	16.9	48.3	64.3
Union of Arab Emirates	.2	5.7	14.1	19.2
Indonesia	−0	1.1	2.3	0
Subtotal	2.5	55.6	118.6	129.1
Total	0	0	0	0

Technical Note

ENERGY AND THE BALANCE OF PAYMENTS

(This technical staff paper details the methodology of one analytical tool for understanding the magnitude and direction of the future energy problem. It does not represent the official views of the Department of Commerce or the U.S. Government.)

(Research and Planning Staff, Domestic & International Business Administration, U.S. Department of Commerce, October 18, 1973.)

Energy and the Balance of Payments

Table of Contents

Summary

A comprehensive computer program developed by the DIBA Research and Planning Staff, Department of Commerce, has been designed for the systematic examination of balance of payments impacts of various national and global energy projections. The oil-related current account and basic payments balances and their elements have been projected for 1975, 1980, and 1985 for five oil consuming countries/regions and eleven major oil exporting countries.

Factors taken into account include total energy production and consumption, oil prices, transportation costs and patterns, oil earnings, imports of oil producing countries, and capital flows for oil exploration, participation payments and long-term investments by the producing countries. The analysis has many limitations, and considerable uncertainty surrounds many of the assumptions; accordingly, appropriate sensitivities have been developed.

The computer program and assumptions will be updated periodically as economic environment changes dictate. The program can be used at anytime to examine the balance of payments impacts of variations in underlying policy or economic assumptions, both quickly and at minimal cost.

The "Illustrative Case" described in this paper indicates how the oil-related annual current payments accounts of each of the United States, Western Europe, and Japan react relative to the oil producers' current accounts from 1970 to 1980 under a given set of assumptions. The data used is also illustrative and may not necessarily agree with comparable data used in other applications.

INTRODUCTION

This is a technical staff paper detailing the methodology of one analytical tool for understanding the magnitude and direction of the future energy problem. It does not represent the official views of the Department of Commerce or the U.S. Government.

Starting in February 1973, the Research and Planning Staff of the Domestic and International Business Administration, Department of Commerce, undertook the assembling of appropriate input information and the development of a computer program to calculate current account and basic payments balances for five oil importers and eleven oil exporters. The balances are keyed to oil because oil is the incremental energy source. However, examination of the impact of non-oil energy sources is possible because the input includes all basic energy sources (coal, gas, nuclear, hydroelectric, and other) for the free world.

The main value of the program and the output is the quantification of differential effects for the various countries—over time and relative to each other. The computer program covers the years 1970, 1975, 1980, and 1985, but the time periods can be changed if desired. The absolute balances of each case have been drawn from the assumptions. Considerable effort has been expended to insure that each assumption is stated explicitly. As a result, the differences between cases are meaningful.

METHODOLOGY

The computer program calculates the oil-related current account balances and basic payments balances for the following consuming and producing countries or regions.

Oil consumers (5)	Oil producers (11)
United States	Venezuela.
Western Europe	Algeria.
Japan	Libya.
Canada (also an exporter)	Nigeria.
Other free World	Iran.
	Iraq.
	Kuwait.
	Qatar.
	Saudi Arabia.
	United Arab Emirates.
	Indonesia.

By definition the total, oil-related, current account deficit of the consuming countries matches the total, oil-related, surplus of the producing countries. The total, oil-related, basic balances are also equal and opposite.

Factors taken into account in determining the 1970, 1975, 1980, and 1985 payments balances include:

1. Total energy consumption by country/region
2. Non-oil energy consumption
3. Oil production
4. Oil prices (f.o.b.)
5. Transportation costs and distribution patterns
6. Oil earnings (repatriated)
7. Transportation monies distribution
8. Import potentials of oil producing countries
9. Import patterns of oil producing countries
10. Capital flows to oil producing countries for oil exploration
11. Participation payments and oil ownership
12. Producing countries economic aid and investment patterns.

The above input requires thirteen separate matrices containing about 500 individual pieces of information for each of the four time periods. Additional discussion of the methodology is contained in the Appendix.

Assumptions

An "Illustrative Case" has been developed using a 3–4 percent per year inflation rate and current dollars. The major assumptions are:

U.S. energy consumption increases at 4 percent per year, down from 4.5 percent, reflecting partial success of conservation measures.

Operative nuclear capacity increases to 50 and 132 gigawatts in 1975 and 1980 providing 7 and 13 percent of U.S. energy requirements. (This assumption is consistent with the 1972 AEC projection contained in the May 4, 1973 Joint Committee on Atomic Energy report on the "National Energy Dilemma"). Domestic coal and gas production increase moderately—3 and 1.8 percent per year, respectively.

U.S. oil production declines to 10 million barrels per day in 1975 and increases to 11 million barrels per day in 1980 and 1985.

Persian Gulf crude costs (tax-paid cost plus average margin-f.o.b.) are $3.35, $5.20 and $8.15 per barrel in 1975, 1980, and 1985, representing a $1.00 per barrel increase over the currently agreed-to Persian Gulf crude prices in 1975 and a 10 percent per year increase from 1975 to 1985 for the tax-paid cost of the crude.

Other crude costs maintain current differentials. Sensitivities to $1 per barrel crude cost changes are shown (U.S. c.i.f. equivalents: $4.80, $6.25 and $9.15).

U.S. exports maintain their share (about 20 percent) of oil producers' imports, which increase 15–20 percent per year.

The U.S. capital market remains attractive for foreign investors, and the United States receives 25 percent of oil producers' long-term capital while importing less than 20 percent of their oil.

Additional descriptive information and the detailed assumptions for all the consuming and producing countries are in the Appendix.

RESULTS

The assumptions completely define the oil-related current account and basic payments balances and their elements over the payments situation that would exist but for the energy problem. The results for the given "Illustrative Case" are summarized in Tables 1–6. Appropriate sensitivities are summarized in Table 7. The consuming countries' position follows:

Illustrative case No. 1

[In billions of dollars]

Consuming countries	Current account balances			Basic payments balances		
	1970	1980	1985	1970	1980	1985
United States	2.4	−8.5	−10.0	2.3	−3.1	1.2
Western Europe	−4.0	−14.6	−23.2	−3.9	−9.0	−10.8
Japan	−.4	−12.9	−40.0	−.3	−9.1	−31.4
Canada	−.2	−1.3	−2.0	−0	−.9	−1.6
Other free world	−.2	−7.3	−20.1	.3	−.5	−5.3
Total	−2.5	−44.6	−95.4	−1.7	−22.6	−47.9

Although the changes in payments position are large, they are moderated by such factors as:

North Sea and other Western Europe oil production which is forecast to reach 4 million barrels per day by 1980.

A booming Japanese tanker construction industry that generates $4.4 billion in earnings by 1980, thus offsetting the cost of some oil imports.

Producers' Position

Saudi Arabia has the largest oil reserves and is projected to have the largest oil production—nearly 20 million barrels per day by 1980. This results in oil earnings of $36 billion (Table 3). Even though

Saudi imports are projected to rise at 20 percent per year, the excess revenues grow much faster.

The oil revenues of all producing countries increase from $14 billion in 1970 to $105 and $215 billion in 1980 (Table 4) and 1985. This results in excess revenues (after producing countries' merchandise imports, but before aid distribution or long-term investments) of $55 and $117 billion in 1980 and 1985.

Summaries of Accounts

The payments account summaries (Table 5) show reductions in the current accounts of the consuming countries while Saudi Arabia acquires over half the producing country surplus with the remainder being divided mostly among the United Arab Emirates, Iraq, and Kuwait.

The basic balance total is about half the current account total (Table 6). The assumptions about long-term capital investment favor the United States and reduce the U.S. basic balance deficit to $3 billion in 1980 whereas the western European and Japanese deficits are $9 billion.

Sensitivities

Sensitivities have been developed for many of the important variables. As shown in Table 7—

> Annual increases of 4.5 percent (versus 4 percent) for U.S. total energy consumption increase 1980 oil imports by 2.4 million barrels per day and cause an additional $5 billion reduction of the U.S. current account. At 3.5 percent per year growth, there is $4.5 billion improvement.
>
> If currently-agreed-to crude prices for 1975 are not changed and if Persian Gulf prices escalate at 10 percent per year from 1975 to 1980, the 1980 U.S. current account deficit is improved by $3.2 billion.
>
> A $1 per barrel increase in crude costs would cause a $3.9 billion deterioration in the U.S. 1980 current account balance.
>
> A 25 percent higher (lower) market share for U.S. exports would raise (lower) the U.S. 1980 current account balance by $2.5 billion.

CONCLUSIONS

The selected methodology enables realistic quantification—and projection—of the oil-related balance of payments accounts. Consideration of not only the oil movements but also the associated transportation, merchandise trade, capital, and economic aid accounts provides a meaningful perspective. Although uncertainties exist about energy demand, oil availability, oil prices, transportation rates, global economic conditions, and international capital accounts, these limitations do not preclude a systematic analysis of various energy assumptions.

TABLE 1.—*United States payments summary, illustrative case No. 1*

	1970	1975	1980	1985
Oil imports:				
Millions of barrels per day	$3. 1	8. 4	11. 6	12. 0
C.i.f. price per dollars per barrel	2. 33	4. 8	6. 25	[illegible]. 15
Annual cash flows (billions):				
Oil earnings	$2. 2	$3. 0	$4. 3	$3. 5
Transportation monies	. 8	1. 4	2. 0	2. 7
Exports to oil producers	1. 9	5. 0	10. 0	21. 0
Exports to others	. 1	. 8	1. 7	3. 3
Subtotal	5. 0	10. 2	18. 0	30. 5
Minus oil import (c.i.f.)	2. 6	14. 8	26. 5	40. 5
Current account	2. 4	—4. 6	—8. 5	—10. 0
Minus capital outflows	. 4	. 6	. 6	. 6
Plus participation payments	0	. 5	. 6	0
Plus capital inflows	. 3	2. 7	5. 4	11. 8
Basic balance	2. 3	—2. 0	-3. 1	1. 2
Memo items:				
Balances with no distribution:				
Current account	2. 1	—5. 4	—10. 2	—13. 3
Basic balance	1. 8	—5. 5	—10. 2	—13. 9
Balances with $1 per barrel higher price:				
Current account	2. 5	—7. 2	—11. 6	—12. 8
Basic balance	2. 1	—3. 6	—4. 5	. 5

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TABLE 2.—*1980 consuming countries payments summary illustrative case No. 1*

	United States	Western Europe	Japan	Canada	Other	Total
Oil imports:						
Millions of barrels per day	11.6	20.6	11.5	1.8	9.2	54.7
C.i.f. price, dollar per barrel	6.25	6.35	5.83	6.24	5.83	6.13
Annual cash flow (in billions of dollars):						
Oil earnings	4.3	2.3	0	2.7	0	9.3
Transportation moneys	2.0	3.8	4.4	.1	.9	11.2
Exports to oil producers	10.0	23.1	5.4	0	8.6	47.1
Exports to others	1.7	4.1	1.6	0	2.8	10.2
Subtotal	18.0	33.3	11.4	2.8	12.3	77.8
Minus oil import cost (c.i.f.)	26.5	47.8	24.5	4.1	19.6	122.4
Current account	−8.5	−14.6	−12.9	−1.3	−7.3	−44.6
Minus capital outflows	.6	.5	.1	0	0	1.2
Plus participation payments	.6	.3	0	0	0	.9
Plus capital inflows	5.4	5.8	3.9	.4	6.8	22.3
Basic balance	−3.1	−9.0	−9.0	−.9	−.5	22.6
Memo items:						
Balances with no distribution:						
Current account	−10.2	−18.7	−14.5	−1.3	−10.1	−54.8
Basic balance	−10.2	−18.9	−14.6	−1.3	−10.1	−55.1
Balances with $1 per barrel higher price:						
Current account	−11.6	−20.1	−16.4	−1.4	−9.6	−59.1
Basic balance	−4.5	−12.8	−11.6	−1.0	−.9	−30.8

TABLE 3.—*Saudi Arabia payments summary illustrative case No. 1*

Oil production	1970	1975	1980	1985
Millions of barrels per day	3.8	10.0	19.6	27.0
Export price (dollars per barrel)	1.45	3.35	5.20	8.15
Annual cash flows (in billions of dollars):				
Oil exports	1.9	13.3	36.4	78.4
Plus transportation moneys	.2	.7	1.3	1.8
Minus oil earnings	.6	1.2	2.2	2.0
Minus imports	.7	2.0	5.0	10.5
Minus economic aid	.2	2.7	7.6	17.0
Current account	.7	8.1	22.9	50.8
Plus capital inflows	−.1	.1	.1	.1
Minus participating payments	.0	.2	.2	.0
Minus capital outflows	.4	4.8	13.7	30.5
Basic balance	.3	3.2	9.1	20.4
Memo items: Excess oil revenues	.8	10.7	30.4	67.9
Balances with no distribution:				
Current account	.9	10.8	30.5	67.8
Basic balance	.8	10.7	30.4	67.9
Balances with $1 per barrel higher price:				
Current account	.7	10.8	28.2	58.1
Basic balance	.3	4.3	11.2	23.3

TABLE 4.—*1980 producing countries payments summary illustrative case No. 1* [1]

Oil production	Venezuela	Algeria	Liberia	Nigeria	Iran	Iraq	Kuwait	Qatar	Saudi Arabia	Arab Emirates	Indonesia	Total
Millions of barrels per day	3.5	2.0	3.0	4.0	8.0	4.4	3.0	1.0	19.6	5.0	2.5	56.0
Export price (dollars per barrel)	5.90	6.10	6.10	5.95	5.20	5.20	5.20	5.20	5.20	5.20	6.36	------
Annual cash flows (in billions of dollars):												
Oil exports	6.3	4.2	7.0	8.5	14.0	8.0	5.3	2.0	36.4	9.0	4.3	105.0
Plus transportation moneys			.1	.2	.5	.3	.2	.1	1.3	.3	------	3.0
Minus oil earnings	.3	.1	.2	.4	.9	.5	.3	.1	2.3	.6	.4	6.0
Minus imports	6.0	4.2	4.4	7.0	10.8	2.5	1.7	.6	5.0	1.2	4.3	47.7
Minus economic aid			.6	------	------	------	.9	------	7.6	.8	------	9.9
Current account	0	—.1	2 2	1 3	2.6	5.3	2.7	1.1	22.9	6.7	0	44.0
Plus capital inflows		.1	------	.3	.1	------	------	.1	.1	.1	.1	1.0
Minus participation payments			.3	.1	------	------	.1	------	.2	------	------	1.0
Minus capital outflows			.7	------	1.0	1.9	1.6	.5	13.7	3.0	------	21.0
Basic balance	0	0	1.2	1.5	1.7	3.4	1.0	.6	9.1	3.8	.1	23.0
Memo items: Excess oil revenues			2.5	1.5	2.7	5.3	3.5	1.3	30.4	7.6	------	55.0
Balances with no distribution:												
Current account	0	—.1	2.8	1.3	2.6	5.3	3.6	1.1	30.5	7.4	0	53.9
Basic balance	0	0	2.5	1.5	2.7	5.3	3.5	1.2	30.4	7.5	.1	53.9
Balances with $1 per barrel higher price:												
Current account	0	.1	3.0	2.7	5.2	6.8	3.4	1.4	28.2	8.2	0	59.1
Basic balance	0	.1	1.8	2.9	3.5	4.4	1.3	.8	11.2	4.7	.1	30.8

[1] Venezuela, Algeria, Liberia, Nigeria, Iran, Iraq, Kuwait, Qatar, Saudi Arabia, United Arab Emirates, and Indonesia.

TABLE 5.—*Balances on current account summary, illustrative case No. 1*

[Billions of dollars]

	1970	1975	1980	1985
Consuming countries:				
United States	2.4	−4.6	−8.5	−10.0
West Europe	−4.0	−10.7	−14.6	−23.2
Japan	−.4	−4.5	−12.9	−40.0
Canada	−.2	−.5	−1.3	−2.0
Other free world	−.2	−2.1	−7.3	−20.1
Subtotal	−2.5	−22.3	−44.6	−95.4
Producing countries:				
Venezuela	0	.7	0	0
Algeria	0	.4	−.1	−.1
Libya	.9	2.6	2.2	.1
Nigeria	−.2	1.0	1.3	1.4
Iran	.1	3.7	2.6	.3
Iraq	.2	.1	5.3	21.8
Kuwait	.5	1.9	2.7	4.5
Qatar	.1	.9	1.1	1.3
Saudi Arabia	.7	8.1	22.9	50.8
United Arab Emirates	.2	2.8	6.7	15.2
Indonesia	0	0	0	0
Subtotal	2.5	22.3	44.6	95.4
Total	0	0	0	0

TABLE 6.—*Basic balances of payments summary, illustrative case No. 1*

[Billions of dollars]

	1970	1975	1980	1985
Consuming countries:				
United States	2.3	−2.0	−3.1	1.2
West Europe	−3.9	−8.1	−9.0	−10.8
Japan	−.3	−3.1	−9.1	−31.4
Canada	0	−.1	−.9	−1.6
Other free world	.3	.9	−.5	−5.3
Subtotal	−1.7	−12.4	−22.6	−47.9
Producing countries:				
Venezuela	.2	.7	−0	0
Algeria	0	.2	0	0
Libya	.7	1.6	1.2	.1
Nigeria	0	1.2	1.5	1.7
Iran	0	2.5	1.7	.2
Iraq	.1	.1	3.4	14.2
Kuwait	.1	.8	1	1.8
Qatar	.1	.5	.6	.7
Saudi Arabia	.3	3.2	9.1	20.4
United Arab Emirates	.1	1.6	3.8	8.7
Indonesia	0	0	.1	.1
Subtotal	1.7	12.4	22.6	47.9
Total	0	0	0	0

TABLE 7.—*Sensitivity of assumptions 1980 and 1985 U.S. payments balances*

[Billions of dollars]

Case description	Current account 1980	Current account 1985	Basic balance 1980	Basic balance 1985
Illustrative case No. 1	−8.5	−10.0	−3.1	1.2
Changes in illustrative case for:				
1. U.S. energy consumption increases at 4.5 percent per year instead of 4 percent (2,400,000 and 4,400,000 barrels per day more imports)	−5.0	−13.8	−4.6	−12.5
2. U.S. energy consumption increases at 3.5 percent per year instead of 4 percent (2,200,000 and 4,200,000 barrels per day less imports)	+4.5	+13.2	+4.1	+11.9
3. Already agreed to price changes hold through 1975 ($1 per barrel lower 1975 prices) and and 10 percent per year increase 1975 to 1985	+3.9	+3.9	+1.4	−.7
4. $1 per barrel higher prices	−3.1	−2.8	−1.4	−.2
5. U.S. increases market share of crude producers by 25 percent	+2.5	+5.2	+2.5	+5.2

APPENDIX

BASIC FORMULA

The computer program calculates the oil-related current account balances and basic payments balances for the oil consuming and producing countries according to the following formulas, which are additive both vertically and horizontally.

Consuming countries	+Producing countries	=Total
	Oil exports	Oil exports.
Transportation moneys	+Transportation moneys.	Trans cost.
+Oil earnings	−Oil earnings	Zero.
+Merchandise exports	−Merchandise imports.	Zero.
+Other exports	−Economic aid	Zero.
−Oil import cost		−Oil import cost.
Current account	+Current account	Zero.
−Oil exploration capital outflows.	+Oil exploration capital inflows.	Zero.
+Participation payments.	−Participation payments.	Zero.
Basic Balance	+Basic balance	Zero.

By definition, the total current account deficit of the consuming countries matches the total surplus of the producing countries. The total basic balances are also equal and opposite. A brief discussion of each of the input items follows. The quantitative assumptions are in Attachments 1–12.

Oil Exports

Oil exports represent the value received for the oil in the producing countries. Allowance is made for domestic oil consumption. Included in current dollars are the tax-paid oil cost and the apparent margin. The tax-paid costs for 1970 are a matter of record. For 1975 the Persian Gulf and African oil costs include the escalations agreed to in the Tehran, Tripoli, and Geneva meetings, full adjustment for the recent devaluation, plus $1.00 per barrel to reflect further adjustments. For 1980 and 1985, tax-paid costs are escalated by 10 percent per year from 1975. Apparent margins are held constant, and producing countries are assumed to share the apparent margin as they assume oil ownership. For Venezuela, Indonesia and Canada, constant differentials are based on quality and transportation factors.

Oil Distribution Patterns

Oil is assumed to be imported from traditional country suppliers to the extent that availability considerations permit. Canada exports to the United States, and Canada imports from Western Hemisphere sources—in this case from Venezuela. African crudes go mostly to

Europe, but some Nigerian and Libyan crudes do go to the United States. Indonesian crudes go mostly to Japan, but some also go to the United States. The Middle East supplies crude shortfalls.

Transportation Costs

Transportation costs are based on a viable tanker industry. Long-term rates are consistent with an adequate investment return on very large crude carriers. Subsequent distribution of transportation monies is based on fueling tankers at their loading points, current ownership patterns, and reinvestment of financial flows in new tanker construction. Japan's resulting financial flow on transportation monies is indicative of current tanker building activity, and her 1970 inflows match her income on 1970 tanker deliveries.

Oil Earnings

Oil earnings represent the apparent margin earned by the owners of the producing companies. Oil earnings are distributed to the consuming countries according to ownership. Although the margin per barrel produced is assumed constant, the producing companies' unit earnings fall as participation begins. Presumably, downstream operations will become more profitable. The somewhat optimistic assumption is made that the producing countries will require assistance in selling their oil in 1975 and 1980 and will pay the producing companies one-half of the apparent margin for this service.

Merchandise Exports

Oil producers can use their oil-related receipts for merchandise (consumer, capital, and military goods) imports, for economic aid, for long-term investment, or for building their financial reserves. The populations and/or needs of many countries are large enough so that merchandise imports will require nearly all the foreign exchange. These countries are: Venezuela, Algeria, Libya, Nigeria, Iran and Indonesia. However, the other five countries—Iraq, Kuwait, Qatar, Saudi Arabia, and United Arab Emirates—have spending limitations. Their populations are small, and their revenues are large. Procedural problems, delivery times, and a cautious approach will slow expenditures. Accordingly, maximum import potentials have been estimated for these countries based on their expanding merchandise imports at 15–20 percent per year.

One simplifying assumption is that merchandise exports equal merchandise imports. To the extent that merchandise exports are carried in foreign ships, some consuming countries' (mainly the United States) balances will be slightly overstated, and others' will be understated. This second order factor is believed to be offset by the assumption that no U.S. exports to Canada are associated with U.S. imports of Canadian crude. Although Canada is a net crude importer and Canada has had and should continue to have trade and payments surpluses, about $100–200 million per year of U.S. exports probably are associated with Canadian oil activities.

Aid Assistance

"Other exports" represent those exports to other developing countries bought with economic aid from Libya, Kuwait, Qatar, Saudi Arabia, and United Arab Emirates. These latter countries are assumed to use 10–25 percent of their excess revenues for economic aid. A sub-case is developed for no economic aid. The program contains no provision for other secondary spending of oil monies. Rather the assumption is made that Japanese, Western Europe and Canadian imports will be independent of receipts from their exports. If this secondary effect does come into play, presumably the changes in the rest of the world's trade patterns would be similar to the changes in the oil producers' patterns as all buyers attempt to get the best bargains. This would increase trade and payments swings.

Capital for Oil Exploration and Development

Long-term capital flows include oil exploration and development capital flows from the consuming countries to the producing countries Such capital flows supplement the internal funds generation from depreciation and amortization. At 5¢ per barrel, the funds generated from depreciation and amortization will total about $1 billion per year by 1980. Both consuming countries and producing countries are projected to add about the same amount for oil exploration and development. Sensitivities have been developed for no flows of consuming country capital to the producing countries. In any event a $1 billion per year capital outflow for oil exploration and development is small relative to the excess revenues which are $55 and $117 billion per year in 1980 and 1985.

Participation Payments

Participation payments for acquiring 51 percent of their oil production have been agreed to by Kuwait, Qatar, Saudi Arabia, and the United Arab Emirates. A similar arrangement is envisioned for Nigeria. Different arrangements appear likely in the other oil producing countries. These payments are included in the long-term capital flows. Just as with the oil exploration monies, the participation payments are small relative to excess oil revenues.

Producers' Long-Term Capital Investments

The assumptions about long-term capital investments by the oil producers are critical to the analysis. In this "illustrative case," where oil prices increase 10 percent per year, excess funds are generated at phenomenal rates—$55 billion in 1980 and $117 billion in 1985. About 20 percent of these funds are assumed to be used for economic assistance, and the rest are available for long-term investments or for increasing financial reserves.

Illustrative Case Assumptions

A methodology summary showing the formulas is on the next page. The assumptions—or input—for the "Illustrative Case" are summarized in Attachments 1–12.

ENERGY BALANCE OF PAYMENTS

Methodology summary formulas

Item	*Formula* ([1])
I. Total oil consumption	I=1−2.
II. Oil imports	II=I−3.[2]
III. Oil exports	III=3−I.[2]
IV. Oil import cost	IV=II(4+5).
V. Oil investment earnings	V=(3)(6).
VI. Transportation earnings	VI=II(5)(7).
VII. Imports of oil producers by source.	VII≤(9)(8) or [9](III(4)+VI−V+10−11.
VIII. Current account balances:	
VIIIc Consuming countries	VIIIc=V+VI+VII−IV+12_c.
VIIIp Producing countries	VIIIp=(III) (4)+VI−V−VII−12_c.
IX. Excess oil revenues	IX=(VIIIp+10−11).
X. Basic balances:	
Xc Consuming countries	Xc=(VIIIc−10+11+12_b).
Xp Producing countries	Xp=(VIIIp+10−11−12_b).

[1] Arabic numbers refer to input attachments which follow.
[2] Except for Canada.

Methodology summary list of attachments

Attachment and item	Units	Source
1. Energy consumption by country.	Million barrels per day.	National Petroleum Council, Statistics, OECD, Interior.
2. Nonoil energy consumption.	do	Do.
3. Domestic oil production.	do	Do.
4. Oil export prices (f.o.b.)	Dollar per barrel	Interior.
5. Transportation costs	do	Estimated.
6. Oil earnings	do	Do.
7. Distribution of transportation monies.	do	Do.
8. Import potentials of oil exporters.	Dollars—Billions	Do.
9. Import patterns of oil exporters.	Percent	OECD and Commerce.
10. Capital flows for oil exploration.	Dollars—Billions	Estimated.
11. Participation payments	do	Do.
12. Capital flows for excess oil revenues.	do	Do.
13. Methodology Summary Formulas.		

Attachment 1

Total energy consumption illustrative case No. 1

Country	Per capita consumption (barrels per day)		Percent per year growth rate, 1970–85	Total consumption (million barrels per day equivalent)			
	1970	1985		1970	1975	1980	1985
United States	58. 5	89. 7	4	32. 8	39. 8	48. 5	59. 0
Western Europe	24. 5	45. 3	5	22. 4	28. 6	36. 5	46. 5
Japan	20. 5	72. 7	10	5. 8	9. 3	15. 0	24. 2
Canada	46. 0	86. 0	6	2. 7	3. 6	4. 9	6. 5
Other free world	4. 1	6. 5	6	11. 3	15. 1	20. 3	27. 2
Subtotal	16. 5	26. 0		75. 0	96. 4	125. 2	163. 4
Venezuela	10. 5	25. 9	10	. 3	. 5	. 81	1. 35
Algeria	1. 5	3. 6	10	. 06	. 1	. 16	. 25
Libya	5. 6	13. 8	10	. 03	. 05	. 08	. 13
Nigeria	. 2	. 8	10	. 04	. 06	. 10	. 17
Iran	4. 7	12. 8	10	. 37	. 62	1. 0	1. 51
Iraq	3. 5	9. 0	10	. 09	. 15	. 23	. 38
Kuwait	81. 6	110. 0	5	. 17	. 25	. 30	. 35
Qatar							
Saudi Arabia	9. 4	26. 0	10	. 2	. 32	. 53	. 84
United Arab Emirates	. 1	. 5	10	. 14	. 23	. 36	. 58
Indonesia	. 6	1. 6	10	. 2	. 32	. 53	. 84
Subtotal	2. 3	6. 1		1. 6	2. 6	4. 1	6. 4
Total	14. 6	23. 2		76. 6	99. 0	129. 3	169. 8

ATTACHMENT 2

Nonoil energy consumption, illustrative case No. 1

[Million barrels per day equivalent]

	1970	1975	1980	1985
United States:				
Coal	6.3	7.0	8.0	10.0
Gas	10.7	11.5	12.0	14.0
Water	1.3	1.4	1.5	1.6
Nuclear	.1	1.5	3.9	8.0
Other			.5	2.4
Subtotal	18.4	21.4	25.9	36.0
Western Europe:				
Coal	6.1	5.5	5.0	4.0
Gas	1.4	2.5	4.0	6.0
Water	1.8	2.0	2.5	3.0
Nuclear	.3	.7	1.6	3.0
Other	.1	.1	.3	.5
Subtotal	9.7	10.8	13.4	16.5
Japan:				
Coal	1.2	1.6	2.1	3.0
Gas	.1	.2	.3	.4
Water	.4	.5	.6	.7
Nuclear		.2	.5	1.0
Other				
Subtotal	1.7	2.5	3.5	5.1
Canada:				
Coal	.3	.4	.5	.6
Gas	.6	.8	1.0	1.3
Water	.3	.3	.4	.5
Nuclear		.1	.2	.3
Other				
Subtotal	1.2	1.6	2.1	2.7
Oil exporter: Gas [1]	.5	.8	1.3	2.1
Other free world:				
Coal	3.6	3.6	3.6	3.6
Gas	.4	.6	.8	1.0
Water	1.0	1.2	1.4	1.6
Nuclear			.3	.6
Other				
Subtotal	5.0	5.4	6.1	6.8

Footnote at end of table.

ATTACHMENT 2—Continued

Nonoil energy consumption, illustrative case No. 1—Con.

[Million barrels per day equivalent]

	1970	1975	1980	1985
Free world:				
Coal	17.5	18.1	19.2	21.2
Gas	13.7	16.4	19.4	24.8
Water	4.8	5.4	6.4	7.4
Nuclear	.4	2.5	6.5	12.9
Other	.1	.1	.8	2.9
Subtotal	36.5	42.5	52.3	69.2

[1] See attachment 2A.

ATTACHMENT 2A

Gas usage by exporter countries, illustrative case No. 1

[Million barrels per day oil equivalent]

	1970	1975	1980	1985
Venezuela	0.11	0.18	0.28	0.45
Algeria	.02	.03	.05	.08
Libya	.01	.02	.03	.04
Nigeria	.01	.02	.03	.04
Iran	.10	.16	.26	.42
Iraq	.02	.03	.05	.08
Kuwait	.05	.06	.13	.20
Qatar				
Saudi Arabia	.05	.08	.13	.22
United Arab Emirates	.05	.08	.13	.22
Indonesia	.08	.14	.21	.35
Total	.50	.8	1.3	2.1

Oil production, illustrative case No. 1

[Million barrels per day]

	1970	1975	1980	1985
Exporting countries:				
Venezuela	3.8	3.5	3.5	3.5
Algeria	1.0	1.5	2.0	2.5
Libya	3.3	3.0	3.0	3.0
Nigeria	1.1	2.5	4.0	6.0
Iran	3.8	6.6	8.0	10.0
Iraq	1.6	2.9	4.4	9.0
Kuwait	3.0	3.0	3.0	3.0
Qatar	.4	1.0	1.0	1.0
Saudi Arabia	3.8	10.0	19.6	27.0
United Arab Emirates	1.3	3.0	5.0	7.0
Indonesia	.9	1.5	2.5	3.6
Subtotal exporters	24.0	38.5	56.0	75.6
Consuming countries:				
United States	11.3	10.0	11.0	11.0
West Europe [1]	.3	2.0	2.5	4.0
Japan				
Canada	1.3	2.0	2.5	3.5
Other free world	3.2	4.0	5.0	6.5
Subtotal	16.1	18.0	21.0	25.0
Total	40.1	56.5	77.0	100.6

[1] Includes Soviet imports.

ATTACHMENT 4

Oil export prices, illustrative case No. 1

[Dollars per barrel f.o.b.]

	1970 [1]	1975 [2]	1980 [3]	1985 [3]
Venezuela	1.90	4.05	5.90	8.85
Algeria	2.10	4.27	6.10	9.07
Libya	1.78	4.27	6.10	9.07
Nigeria	1.74	4.10	5.95	8.90
All Persian Gulf	1.45	3.35	5.20	8.15
Indonesia	1.60	4.51	6.36	9.31
Canada	2.80	5.00	6.66	9.70

[1] 1970 basis—1970 tax-paid cost plus 1970 apparent margin.

[2] 1975 basis—Tax-paid cost per various agreements plus 10 percent for devaluation plus constant 1970 apparent margin for Mideast and African crudes plus $1 per barrel. Venezuela, Indonesia and Canadian crudes reflect quality and transportation differentials.

[3] 1980–85 basis—1975 tax-paid cost increased by 10 percent per year for All Persian Gulf crudes; margins and crude differentials remain constant for other crudes.

Attachment 5

Transportation costs and distribution patterns, illustrative case No. 1

Destination	United States	West Europe	Japan	Canada	Other
Transportation costs, per barrel (Percent of world scale rate):					
Venezuela	0.24 (90)			0.40 (110)	0.26 (100)
Nigeria	.62 (100)	0.57 (100)			
Mediterranean	.57 (100)	.39 (100)			
Persian Gulf	1.13 (85)	1.07 (85)	0.60 (85)		.62 (100)
Indonesia	.82 (90)		.38 (90)		.38 (90)
Distribution patterns, percent of oil exports:					
Venezuela	[b] 70			([a])	[a] 30
Algeria		[a] 100			
Libya	[e] 10	[b] 90			
Nigeria	[d] 20	[c] 80			
Persian Gulf	(*[f])	(*[d])	(*[b])		(*[c])
Indonesia	[c] 20		[a] 70		[b] 10
Canada	[a] 100				

TRANSPORTATION NOTES

(1) World scale rates have been increased to reflect the 1973 dollar devaluation.
(2) Rates should allow adequate return for new tankers.
(3) Suez remains closed.

DISTRIBUTION NOTES

(1) Lower case letters indicate sequential patterns for oil imports.
(2) Venezuela supplies Canada before supplying United States and "other."
(3) Star indicates that Persian Gulf supplies any shortfall.

ATTACHMENT 6

Oil earnings to consuming countries illustrative case No. 1

	Percent distribution		Total earnings (cents per barrel produced)			
	United States	Western Europe	1970 [1, 2]	[3] 1975	[3] 1980	[4] 1985
Venezuela	80	20	40	40	36	0
Algeria		100	17	17	10	10
Libya	90	10	30	22	19	8
Nigeria	20	80	40	35	32	20
Iran	40	60	40	35	32	20
Iraq	20	80	40	35	32	20
Kuwait	50	50	40	35	32	20
Qater		100	40	35	32	20
Saudi Arabia	100		40	35	32	20
United Arab Emirates	20	80	40	35	32	20
Indonesia	100		10	10	10	10
Canada	100		50	50	50	50

[1] 1970 oil earnings or apparent margin based on above earnings and attachment 3 production:

[In millions of dollars]

	Total	United States	Survey of current business	Comments on the survey
Venezuela	555	445	417	Includes all Latin America.
Africa	584	358	600	Tanker earnings.
Mid East	2, 060	1, 170	1, 178	Good check.
Canada	237	237	342	Gas and refinery earnings.
Total	3, 469	2, 243	2, 537	

[2] 1970 basis: Distribution of 1970 apparent margin per ownership.

[3] 1975 and 1980 basis: Same margin as 1970 on oil companies' barrel and 50 percent of same margin on producing countries' barrels per attachment 11.

[4] 1985 basis: No oil company revenue on producing countries' barrels.

NOTE.—Other ranges to be investigated include constant earnings and increasing earnings.

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Attachment 7

Distribution of transportation moneys, illustrative case No. 2

[Percent]

Item	Total	Oil exporting countries	United States	Western Europe	Japan	Others
Fuel	15	15				
Crews	5	1	1	1	1	1
Financing	40	5	5	10	20	
Profit and taxes	20	2	5	5	4	4
Other	20		3	10	5	2
Total	100	23	14	26	30	7

Note: These approximate distributions are based on: (1) Largely foreign construction and foreign financing of new tankers; (2) foreign fueling; (3) European and Japanese maintenance, and largely European insurance.

Attachment 8

Import potentials of oil exporting countries illustrative case No. 1

Oil producers	Actual imports (in billions of dollars)		Projected potential imports (in billions)			Percent per year growth rate (1970–85)
	1966	1970	1975	1980	1985	
Venezuela	1.5	2.0	4.0	8.0	16.0	15
Algeria	.6	1.2	1.4	4.8	9.6	15
Libya	.4	.6	1.5	3.7	9.5	20
Nigeria	.7	1.1	2.8	7.0	17.5	20
Iran	.9	1.7	4.3	10.8	27.0	20
Iraq	.5	.5	1.0	2.0	4.0	15
Kuwait	.5	.7	1.4	2.8	5.6	15
Qatar	.0	.1	.3	.6	1.5	20
Saudi Arabi	.6	.7	2.0	5.0	10.5	20
United Arab Emirates	.2	.3	.6	1.2	2.4	15
Indonesia	.5	.9	2.3	5.7	14.0	20
Canada			0	0	0	

ATTACHMENT 9

Import patterns of oil exporting countries, illustrative case No. 1

[Percent share of total import market]

Base case (1970 pattern)	Import source			
	United States	Western Europe	Japan	Other
Venezuela	40	29	7	24
Algeria	7	78	2	13
Libya	21	64	6	9
Nigeria	13	54	7	26
Iran	22	52	12	14
Iraq	5	44	4	47
Kuwait [1]	18	37	18	27
Qatar	17	58	14	11
Saudi Arabia [1]	25	44	13	18
United Arab Emirates	17	58	14	11
Indonesia [1]	30	29	37	4

[1] 1970 U.S. share adjusted to be more consistent with historical pattern.

Attachment 10

Capital flows for oil exploration—Illustrative Case No. 1

	Percent distribution from consuming country sources			Total capital from outside (millions of dollars)				
	United States	West Europe	Japan	1970	United States	1975	1980	1985
Venezuela	80	20		200	160			
Algeria		100		50		100	100	100
Libya	90	10		100	90			
Nigeria	20	80		200	40	300	300	300
Iran	40	60		−100	−40	100	100	100
Iraq	20	80						
Kuwait	50	50		−100	−50			
Qatar		50	50	60		50	50	
Saudi Arabia	80	10	10	−100	−80	100	100	100
United Arab Emirates	20	60	20	50	10	100	100	100
Indonesia	80		20	25	20	50	50	50
Canada	100			200	200	400	400	400
Total				585	350	1,200	1,200	1,150

NOTE.—These capital flows are for exploration and development investments that increase foreign capitalization; i.e., funds over and above depreciation or amortization.

ATTACHMENT 11

Participation payments and oil ownership, illustrative case No. 1

	1975	1980	1985
Estimated participation payments (millions of dollars):			
Venezuela			
Algeria			
Libya	300	300	
Nigeria	100	100	
Iran			
Iraq			
Kuwait	57	67	
Qatar	27	33	
Saudi Arabia	193	220	
United Arab Emirates	88	100	
Indonesia			
Total	765	720	
Estimated producing country ownership (percent):			
Venezuela	0	10	100
Algeria	77	90	90
Libya	51	75	75
Nigeria	25	40	51
Iran	10	40	51
Iraq	100	100	100
Kuwait	25	40	51
Qatar	25	40	51
Saudi Arabia	25	40	51
United Arab Emirates	25	40	51
Indonesia	100	100	100

Note.—Participation payments are current as of February 1973 (Petroleum Press Service) and include adjustment for Feb. 12 devaluation. Nigeria and Libya are assumed to make indicated participation agreements. Iran and Venezuela are assumed to take partial and total ownership at end of current concessions. Iraq nationalization assumed to have no net exchange of funds, but a lower purchase price that allows continued profits to former owners.

ATTACHMENT 12

Disposition of excess oil revenues, illustrative case No. 1

[In percent]

Producing country	Current account items including aid to foreign countries [1]				Long-term capital investment [2]				Reserves and short-term investment
	United States	Western Europe	Japan	Other	United States	Western Europe	Japan	Other	
Venezuela									100
Algeria					10	40			50
Libya	5	10	3	7	5	5		15	50
Nigeria									100
Iran					15	15		5	65
Iraq					10	15		10	65
Kuwait	4	10	4	7	15	15		15	30
Qatar	2	5	2	3	10	10	10	8	50
Saudi Arabia	4	10	4	7	10	10	10	15	30
United Arab Emirates	2	5	2	3	10	10	10	8	50
Indonesia									100
Canada									100

[1] These items are 12c in attachment 13.

[2] These items are 12b in attachment 13.

Appendix D

The Natural Gas Shortage and the Regulation of Natural Gas Producers—Reprinted From the Harvard Law Review

ARTICLE

THE NATURAL GAS SHORTAGE AND THE REGULATION OF NATURAL GAS PRODUCERS

by

STEPHEN BREYER
PAUL W. MACAVOY

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THE NATURAL GAS SHORTAGE AND THE REGULATION OF NATURAL GAS PRODUCERS †

*Stephen Breyer * and Paul W. MacAvoy ***

In an attack upon the current natural gas shortage, President Nixon has recently urged an end to much of the Federal Power Commission's regulation of the price of natural gas at the wellhead. From the perspectives of both the lawyer and the economist, Professors Breyer and MacAvoy lend support to a policy change in this direction. They show that regulation of gas wellhead prices raises problems substantially different from the regulation of traditional public utilities. They argue that the policies the Commission has pursued were almost inevitably bound to result in wellhead prices below the market level that would call forth supplies sufficient to meet demand, and, through econometric analysis, they demonstrate the extent to which the Commission's pricing practices produced the shortage. While the Commission's policies were aimed at helping home consumers, data gathered by the authors indicate that regulation has brought about precisely the opposite result. The Commission's experience may well cast light on the wisdom of adopting regulatory techniques to redistribute income when serious economic efficiency losses are likely to arise.

IN 1954, somewhat to the Federal Power Commission's (FPC's) surprise, the Supreme Court held in *Phillips Petroleum Company v. Wisconsin*[1] that the Commission had authority to regulate the prices at which natural gas field producers sold gas to interstate pipeline companies.[2] In the past decade, the FPC has devoted much of its energy and about 30 percent of its budget to such regulation [3] and has been remarkably effective in holding down producers' selling prices.[4] Whether this regulation has benefited the nation or even the consumers it was designed to help, however, is another matter. It is the purpose of this article to evaluate the results of the Court's decision [5] and the FPC's

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[1] 347 U.S. 672 (1954).

[2] Prior to this decision, FPC regulation of the natural gas industry extended only to the regulation of prices for the transporting of gas across state lines for the purposes of resale.

[3] MacAvoy, *The Effectiveness of the Federal Power Commission*, 1 BELL J. OF ECON. & MANAGEMENT SCI. 271, 303 n.22 (1970).

[4] *See* Table I, p. 975 *infra*.

[5] Although in debates over the wisdom of FPC regulatory policy the *Phillips* decision itself is often violently attacked, the Court's logic in that case was not

ensuing regulatory effort. Such an evaluation is especially timely because President Nixon has recently proposed the discontinuance of much wellhead price regulation.[6]

Natural gas now supplies more than a third of America's energy needs[7] and exists in the ground in sufficient quantities to forestall any danger in the foreseeable future of its extinction as a natural resource.[8] Nevertheless, there is now, in the early

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wholly unreasonable, though neither was it totally satisfying. Whether the FPC should have jurisdiction over producer prices is not clear from the statutory language of the Natural Gas Act. 15 U.S.C. §§ 717-717w (1970). The Act states that

> [t]he provisions of this chapter shall apply to . . . the sale in interstate commerce of natural gas for resale . . . but shall not apply to . . . the production or gathering of natural gas.

15 U.S.C. § 717b (1970). To be sure, a field producer's sale to an interstate pipeline is "a sale in interstate commerce for resale." But whether the exemption for "production and gathering" applies to the physical production and gathering operations only *or* to those operations and also the *sale* of what is gathered, is not clear.

While the legislative history of the Act has little to say about producer regulation, what is said seems to support the Court's decision. The House of Representatives Committee Report states that the words "production or gathering" are "not actually necessary, as the matters specified therein could not be said fairly to be covered by the language affirmatively stating the jurisdiction of the Commission . . . ." H.R. REP. NO. 709, 75th Cong., 1st Sess. 3 (1937). *See generally* Note, *Legislative History of the Natural Gas Act*, 44 GEO. L.J. 695 (1956). This statement suggests that Congress did not mean to exempt from regulation sales by producers to pipelines, for such sales surely could be said "to be covered by the language affirmatively stating the jurisdiction of the Commission" over sales for resale in interstate commerce. Moreover, although the FPC consistently refused before 1954 to regulate producers, at their urging Congress passed a bill granting a clear producer exemption — a bill that President Truman vetoed. Thus the producers, the Congress, and the President arguably acted as if the producers might be regulated by existing law. For an excellent discussion of this point, and of producer price regulation generally, see Kitch, *Regulation in the Field Market for Natural Gas by the Federal Power Commission*, 11 J. LAW & ECON. 243, 254-55 (1968).

Despite this support for the Court's position, however, the *Phillips* decision can be criticized. The Court did not examine, more than superficially, the economic purposes that producer regulation might serve. Without such an examination, the Court could not tell what sense producer regulation made economically or whether it was consistent with a general regulatory policy which provides for the supervision of the prices of monopoly (or oligoply) gas transmission companies and of monopoly retail gas distributing companies. If producer regulation is not consistent with this general regulatory policy, then to assume a congressional intent to regulate producers in the face of ambiguous statutory language and a near-silent legislative history was not warranted, and produced bad law. To what extent the Court in 1954 could have been aware of the facts and arguments concerning the economic rationale for regulation, we leave to the reader to judge.

[6] N.Y. Times, April 19, 1973, at 1, col. 1; *see* note 134 *infra*.

[7] Southern Louisiana Area Rate Cases v. FPC, 428 F.2d 407, 418 n.10 (5th Cir.), *cert. denied*, 400 U.S. 950 (1970).

[8] Recent estimates place potential reserves in the U.S. at 1,227 trillion cubic feet in addition to the present proven reserve inventory of 275.1 trillion cubic

1970's, no lack of evidence that the United States is in the throes of a serious natural gas shortage.[9] This article will show that that shortage is a direct result of FPC regulation of producers' prices and that the shortage has been disproportionately borne by home consumers. Moreover, the article will show that the losses arising from the shortage have been so great that they cannot rationally be worth the pursuit of whatever valid purposes might be served by lower user prices. To explain how this state of affairs has come about, we shall explore the objectives of producer price regulation and the methods used by the FPC to achieve them. We shall then describe the results that FPC regulation has brought about. We shall conclude that the harms regulation has produced so far outweigh the benefits of lower price that gas price regulation at the wellhead should be substantially abandoned.

The article has another, more general purpose. It is becoming increasingly common to think of price and profit regulation as designed to achieve not simply economic efficiency, but also a more nearly equal income distribution.[10] Of course, these two objectives often peacefully coexist: to limit a monopolist's prices increases output and also redistributes income, probably towards equality. Sometimes, however, these goals directly conflict: to hold prices below the competitive level may lead to a more equal income distribution, but it may also wastefully create excess demand. When faced with such a conflict, some may argue that the "income distribution" objective should be favored over "economic efficiency."

This seemingly has been the view of the FPC in regulating producer gas prices. We shall argue, however, that the FPC's efforts to hold prices down for the residential gas consumer have not helped him; in fact, they have simply led to a gas shortage that has hurt him more. If redistribution of income is a proper regulatory goal, the FPC has failed to achieve it. Our discussion of the reasons for this failure shows the extreme practical difficulties that face an agency trying to use prices to pursue such a goal. And these practical difficulties should explain our grave doubts about whether generally such a goal is proper when serious efficiency losses are at stake.

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feet. FEDERAL POWER COMMISSION, 1970 ANNUAL REPORT 52 (1971). Of course, much of the potential reserves exists in high-risk, high-cost areas. *Id.* at 52. But these figures for potential resources do not include the possibility of expansion by way of technological advances in obtaining gas from coal and in stimulating low-productivity gas reservoirs through the use of nuclear power. *Id.* at 53–54.

[9] *See* pp. 965–66.

[10] *See, e.g.*, Posner, *Taxation by Regulation*, 2 BELL J. OF ECON. & MANAGEMENT SCI. 22 (1971).

Before turning to an assessment of FPC regulation of gas producer prices, a brief description of the field market for natural gas may be helpful.[11] Most producers search for gas by drilling wells on leased land. The gas is brought to the surface where it is sometimes "refined," producing liquid byproducts which can be sold separately. The gas itself may be sold directly to intrastate users and distributors, but most is sold to interstate pipeline companies.[12] These transmission companies transport the gas from the field and resell it either directly to industrial users or to distributing companies, which in turn resell to industry or to home consumers. Before World War II, gas was discovered and exploited mainly as a byproduct of the search for oil [13] and was sold at prices that had only to pay the ascertainable separate costs of gas production.[14] However, the growth of pipelines capable of bringing gas from fields in Texas, Oklahoma, and Louisiana to coastal markets increased the demand for gas to the point where today less than 25 percent of all gas produced comes from oil wells; most comes from wells that produce only gas, found in the search for gas itself.[15]

I. The Objectives of Producer Price Regulation

In order to evaluate the FPC's policy of regulating natural gas prices at the wellhead, it is necessary first to determine what the objectives of such a policy could be. There are two conceptually distinct purposes that regulation of gas producers might serve: reduction of market power and redistribution of income. That neither the Commission nor the courts have made much effort to distinguish between these purposes makes the task of evaluating regulation more difficult.

A. Control of Market Power

Control of market power constitutes the traditional economic rationale for regulation. Stated in simple and direct fashion, where one firm, or possibly a small group of firms, produces the entire output of an industry, the industry's output tends to be

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[11] For general background on the production of natural gas, see J. Kornfeld, Natural Gas Economics (1950); S. Pirson, Oil Reservoir Engineering (1959); L. Uren, Petroleum Production Engineering (1934).

[12] *See* Table II, p. 978 *infra*.

[13] *See* P. MacAvoy, Price Formation in Natural Gas Fields chs. 5–7 (1962) [hereinafter cited as Price Formation].

[14] *See* pp. 954–57 *infra*.

[15] *See* C. Hawkins, The Field Price Regulation of Natural Gas 221 (1969) [hereinafter cited as Hawkins].

less — and profits more — than that which would be provided by competitive suppliers. This is so because the monopoly (or oligopoly) firm will restrict its output in order to increase the market price of its products — so as to add to net revenues via a higher price-cost margin more than is lost by restricting output. The government may seek to reduce prices and increase output by attacking market power directly through antitrust actions designed to create competition in the industry. If, however, such a policy is too costly because economies of scale make production by more firms less efficient, the government may try to combat market power by regulation of industry prices. In either instance, a major motivating force of the government's initiatives is to achieve efficient resource allocation; the objectives in setting lower prices at the margin are to reduce profits and to expand output, allowing buyers willing to pay the cost of extra units of goods to receive those goods.

Such a market power theory was advanced by supporters of gas producer regulation. They asserted that gas production was concentrated in the hands of a few producing companies — so few that the largest producers could raise the price of gas to the interstate pipelines above the level that competition would otherwise dictate.[16] Unless market power at the wellhead was checked, pipeline regulation would not be wholly effective in protecting consumers from noncompetitive prices; consumers would still have to pay monopoly wellhead prices for gas, since these prices would be passed through to retail distributors as "costs" of the pipelines. In the words of the Supreme Court,[17]

> the rates charged [by producers] may have a direct and substantial effect on the price paid by the ultimate consumers. Protection of consumers against exploitation at the hands of natural-gas companies was the primary aim of the Natural Gas Act.

Thus, the argument ran, the FPC should determine the price at which gas would be sold under competitive production conditions and should forbid producers to sell at higher prices.

However, while the question of market power played an important role in the early history of the debate over producer regulation, it has become less significant in more recent years as accumulated evidence has created a strong presumption that gas producers do not possess monopolistic or oligopolistic market

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[16] *See, e.g.*, Douglas, *The Case for the Consumer of Natural Gas*, 44 Geo. L.J. 566, 589 (1955) ("Competition is limited by the domination of supply and reserves by a very few major companies . . . .").

[17] Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672, 685 (1954).

power. As the U.S. Court of Appeals for the Fifth Circuit has recently said,[18] "[T]here seems to be general agreement that the [field] market is at least structurally competitive." Federal Power Commission statistics show that in the early 1960's the largest gas producer accounted for less than 10 percent, and the 15 largest for less than 50 percent, of national production.[19] Nor in general has production in more narrow geographic markets been highly concentrated; in the Permian Basin, for example, the five largest producers have accounted for somewhat less than 50 percent of production.[20] This degree of production concentration in the narrow market has been characterized as "lower than that in 75–85 percent of industries in manufactured products."[21] And, even if concentration were higher here than elsewhere, it has been shown that entry into the industry is so free that the largest producers would not be able systematically to charge higher than competitive prices.[22]

One rejoinder to this evidence of structural competitiveness is that ownership of *production* is not really relevant to the price of natural gas at the wellhead. Rather, the market relevant for field prices is that in the sale to pipelines of *rights* to take gas from *new reserves*. Petroleum companies sell gas under long term contracts which commit to pipelines 10 to 20 years worth of production from new reserves.[23] While such a contract typically contains a specified initial price, many used to have a "most favored nation" clause under which the actual price to be paid for the gas produced at any given time was pegged to the pipeline's then newest, most expensive contract.[24] Thus, once a production contract was signed, only the *level* of production was "locked in"; the *price* for gas produced under the contract would depend on the market for the sale and dedication of new reserves. Proponents of regulation have argued that ownership of uncommitted reserves was so concentrated that a few petroleum companies were able to raise the specified prices in new contracts by con-

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[18] Southern Louisiana Area Rate Cases, 428 F.2d 407, 416 n.10 (5th Cir.), *cert. denied*, 400 U.S. 950 (1970).

[19] HAWKINS 248.

[20] Permian Basin Area Rate Proceeding, 34 F.P.C. 159, 182 n.17 (1956), *aff'd in part and rev'd in part sub nom.* Skelly Oil Co. v. FPC, 375 F.2d 6 (10th Cir. 1967), *aff'd in part and rev'd in part sub nom.* Permian Basin Area Rate Cases, 390 U.S. 747 (1968) (approving FPC decision in its entirety).

[21] P. MACAVOY, THE CRISIS OF THE REGULATORY COMMISSIONS 156 (1970), quoting Champlin Oil & Refining Co., Docket No. G-9277, at 458 (FPC 1969) (testimony of Professor M.A. Adelman).

[22] *See* McKie, *Market Structure and Uncertainty in Oil and Gas Exploration*, 74 QUARTERLY J. OF ECON. 543 (1960).

[23] *See* HAWKINS 227; pp. 966–67 *infra*.

[24] *See* PRICE FORMATION 29–31.

trolling the supply of available natural gas reserves.[25] These higher prices were then passed through by triggering "favored nation" clauses in existing contracts, resulting in comparable prices for gas produced from previously dedicated reserves.

This argument, however, has little basis in fact. The available evidence[26] shows, for example, that the four largest production companies provided only 37–44 percent of new reserve sales in the West Texas-New Mexico producing area, 26–28 percent in the Texas Gulf region, and less than 32 percent in the Midcontinent region — all in the 1950–54 period just before the *Phillips* decision. These levels of concentration on the supply side of the market for new reserves were all less than half the concentration on the demand side, accounted for by the four largest pipeline buyers in each of these regions. Power to control new contract prices probably did not exist on either side of the market, but if the scales tipped at all, then surely the balance lay with the pipeline companies rather than with the producers.

Of course one can still argue that despite its apparently competitive structure, the producing segment of the industry has *behaved* noncompetitively. Certain proponents of producer regulation[27] have pointed to the rapid rise in the field price of natural gas between 1950 and 1958[28] as evidence of such noncompetitive performance. But economic studies of the markets for new contracts suggest that anticompetitive producer behavior did not cause this price increase.[29] During the early 1950's the presence of only one pipeline in many gas fields effectively allowed the setting of monopoly buyers' (monopsony) prices for new gas contracts, thus often depressing the field price below the competitive level. During the next few years, several pipelines sought new reserves in old field regions where previously there had been such a single buyer. This new entry of buyers raised the field prices to a competitive level from the previously depressed monopsonistic level. In short, competition — not market power — accounted for much of the price spiral that has been claimed to show the need for regulation.

A further argument offered by those asserting the need to control the market power of gas producers was that producer

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[25] *Cf.* Champlin Oil & Refining Co., Docket No. G-9277, at 489 (FPC 1969) (testimony of Professor A.E. Kahn).

[26] *See* PRICE FORMATION 93–242.

[27] *See, e.g.*, Dirlam, *Natural Gas: Cost, Conservation, and Pricing*, 48 AMERICAN ECON. REV. 491 (No. 2, 1958); Douglas, *supra* note 16; Kahn, *Economic Issues in Regulating the Field Price of Natural Gas*, 50 AMERICAN ECON. REV. 506 (No. 2, 1960).

[28] HAWKINS 223 (prices at the wellhead increased 83% during this period).

[29] *See* PRICE FORMATION 243–73.

competition was ineffective in bringing about competitive prices because the producers' customers — the pipelines — did not have enough incentive to bargain for low prices.[30] Since pipeline final sales prices were (and are) regulated on the basis of costs plus a fixed profit on capital, it was argued that the pipelines failed to resist producer price increases and simply passed them on as "costs" to be paid by the consumer.

This argument is theoretically suspect, however, for strict regulatory supervision should make the pipelines worry about whether they will be able to pass along producer price increases, and weak regulatory supervision might allow them to keep any extra profits they earn through hard bargaining with producers — at least until "regulatory lag" catches up with them. In either case they should wish to keep producers' prices low. More important, given some limit on price increases set by some combination of consumer demand and regulatory awareness, pipelines should prefer to keep fuel costs (on which they earn no return) low in favor of enhancement of capital costs (on which they earn a return).[31] Furthermore, the evidence available suggests that pipelines in fact bargained for minimum prices. In the 1950's pipelines pushed field prices below competitive levels wherever possible. When low prices threatened to drive producers out of exploration and development, the pipelines themselves went into the exploration business rather than allowing producers to raise their prices. The transmission companies selectively produced higher-cost gas while paying monopsony prices for the low-cost gas from petroleum companies, thus keeping payment of excess returns to producers to the minimum.[32] In sum, empirical study provides little evidence to support the theory that unregulated field prices were noncompetitive.[33]

If the view that unregulated producer markets were in fact competitive is correct, then to regulate as if firms had market power would in principle only cause trouble. The FPC, with the monopoly rationale in mind, would reduce prices below the level

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[30] *See, e.g.*, Douglas, *supra* note 16; Spritzer, *Changing Elements in the Natural Gas Picture: Implications for the Regulatory Scheme*, in REGULATION OF THE NATURAL GAS PRODUCING INDUSTRY 118 (K. Brown ed. 1972).

[31] On this point, most of the economic theories of the regulated firm agree. *See, e.g.*, Averch & Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AMERICAN ECON. REV. 1052 (No. 1, 1962). *See also* Baumol & Klevorick, *Input Choices and Rate-of-Return Regulation: An Overview of the Discussion*, 1 BELL J. OF ECON. MANAGEMENT SCI. 162 (1970).

[32] *See* PRICE FORMATION 93–145.

[33] Those favoring regulation have also pointed to producer profits as evidence of market power. To be sure, profits would appear to have been higher here than in some industries. Economic experts appearing for the distributing companies in the Permian Basin Area proceedings reported average returns on capital between 12

found in the unregulated market. But, since unregulated market prices were already the product of competition, any regulation would set prices below the competitive level. A lower than competitive price would stimulate demand, leading some buyers to use natural gas even though the economy could provide for their needs with other fuels at lower real costs. The lower price would also reduce the incentive of suppliers to provide new reserves and production, for the regulated price would not allow sufficient returns to producers at the margin. In short, the regulation-required price reduction would increase the quantity demanded and decrease the quantity supplied, thus causing a shortage.

B. Regulation to Reduce Rents and Windfalls

Under certain special circumstances one might want to regulate prices even in a competitive market. One would do so not to correct resource misallocations, but in order to redistribute income.[34] In principle, price in a competitive market will equal the cost of producing marginal output — the last units that can

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and 18% for oil and gas companies at a time when the average return in manufacturing was less than 8%. But such comparisons are not enough to suggest the presence of monopoly pricing, due to three special features of returns in the gas producing industry. First, without regulation, marginal producers must earn a return on their capital at least equal to what they could earn by investing elsewhere. But lower costs on more fortunate discoveries in a world of uncertainty might earn much more, and this "rent" earned by unusually efficient or fortunate producers would create an upward bias in industry average profit rates. Such "rent" is more likely to be prevalent in natural gas production than in most other industries because of the characteristics of discovery of an uncertain resource. *See* p. 950 *infra*. Second, the Permian Basin figures reflect profits only of firms still in business, not of those that have failed. The uncertainty in exploring and developing gas suggests that risks of failure have been unusually high. *See* HAWKINS 222 (showing high percentage of exploratory wells which have been dry). Thus, measuring industry returns on the basis of those that are able to remain in it results in an upward bias. Third, profit figures in the Permian Basin proceedings overstated the true return to capital because of the accounting procedures used. The rate of return estimates were calculated simply by dividing total profits that producers reported they had received by the total capital that they reported they had invested. However, this method does not account for the extensive time lag in the industry before an investment begins to earn a return. The accounting return on a dollar invested must be far lower in real terms here than elsewhere simply because payment begins 5 years, rather than 1 year, after the investment is made; the simple accounting profit rate must be adjusted to take the long lag between exploration and production into account. Producer witnesses in the Permian Basin case estimated that an "apparent yield" of 16 to 18% was due to the lag in production, equivalent to a "true yield" of about 10%. Thus, not much can be concluded about market power from the profit figures alone.

[34] Of course, regulation designed to allocate resources efficiently and regulation directed at income redistribution are not necessarily mutually exclusive policies. *See* p. 943 *supra*.

be sold. Some producers can sell at that market price intramarginal units that are far less costly to produce, perhaps because the producer has special skill, knowledge, or expertise, or controls a resource that cannot easily be duplicated. Such producers realize "rents" or excess returns, and the objective of regulation in such circumstances would be to transfer to consumers some of the income that low-cost producers would otherwise receive. It has been claimed that these rents are exceptionally high in the oil and gas industries, so that price control systems should be devised that would deprive producers of these excess returns and give them to consumers in the form of lower prices.[35]

Although no one has measured the amount of rent that gas producers would earn without regulation, there are reasons to believe that rents would be large compared to those earned in other industries. First, gas is a wasting resource, and its presence in the ground in commercial quantities is uncertain until exploration and development are complete. At that point, the value or price of gas is in theory set by the cost of marginal additional exploration and development (at least when demand for gas is increasing sharply, as it has been in the last two decades [36]). The difference between this cost of marginal additional exploration and development and the exploration and development costs of, let us say, the "lucky" producer who may have paid little for his land may constitute a considerable windfall. Of course, windfalls of this sort go in part to landowners who do not themselves produce gas but who have the ownership rights to the ultimate scarce resource (the location or site of the in-ground reserves). Strict control of producer prices, however, would prevent producers from paying these windfalls over to the landholders. Second, the cost of finding and developing gas reserves has increased considerably over the past two decades.[37] Thus, gas found and sold to pipelines 15 years ago in reserve commitments, but still not delivered, would have lower overall production costs than new reserves; such "old gas" may have even been found accidentally as part of the search for oil.[38] If production prices for this "old gas" were set at currently prevailing long term marginal exploration and development costs, its owners would receive appreciable windfalls or rents.

To eliminate these windfalls without interfering with the amount of gas produced, regulation would have to hold down

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[35] *See, e.g.*, Kahn, *supra* note 27.

[36] *See* Tables I and II, pp. 975, 978 *infra*. *See also* HAWKINS 220.

[37] Rising trends in costs of inputs and falling trends in productivity per unit of drilling are reported in NATIONAL PETROLEUM COUNCIL, U.S. ENERGY OUTLOOK ch. 6 (2d Interim Report 1971).

[38] *See* p. 944 *supra*.

the price charged to pipelines for intramarginal volumes of gas while allowing marginal units to be sold at a price equal to long term exploration and development costs. In effect, regulation would set different prices for different units of supply. Of course, such regulation would produce excess demand for the lower-priced intramarginal units received by the pipelines. To "clear" such excess demand by having the pipelines auction off these volumes would simply give windfall rents to the pipelines taking the highest bids. Rationing, on the other hand, might pass the windfall along to the retail distributor and presumably ultimately to the consumer.

This "tier" type of regulation is unusual, but not unheard of. Differential regulated prices are most commonly found in housing; rent control may hold down the price of existing housing while allowing the price of new housing units to rise so as not to discourage new building and to clear the market of demand for new rental units. But it is extraordinarily difficult to bring about the transfer of excess profits without affecting output. With regard to regulation of gas field prices, this requires extensive knowledge of the location and shape of the supply curve for both established production and new reserves. Moreover, if the reduced prices for intramarginal gas bring about the expected increase in the quantity demanded, then the excess demand has to be limited by recourse to such rationing devices as classifying users and designating one or more classes as "inferior" for purposes of allocating the lower-priced gas. To make such classification without reference to users' "willingness to pay," as measured by prices bid by users for the low-cost gas, is difficult, to say the least. In short, tier price regulation requires extraordinary sensitivity to changes in supply in order to react with necessary price changes, and, even in the best of conditions, it requires also a complicated rationing procedure.

Neither the Federal Power Commission nor the courts have clearly distinguished the two separate regulatory objectives of controlling market power and transferring rents to consumers, and often write as if they were trying to achieve both of them at once. Still, in view of the lack of empirical support for the "monopoly power" theory, we shall assume that regulating producers' market power is not a sensible regulatory goal. In fact, the Commission's writings in the past few years suggest that it has not pursued this goal with much fervor and indicate that the concern for income distribution predominates. For one thing, the Commission [39] and the courts [40] have expressed the belief or

[39] *See* Southern Louisiana Area Rate Proceeding, 46 F.P.C. 86, 110–11 (1971).

[40] *See* Southern Louisiana Area Rate Cases v. FPC, 428 F.2d 407, 426 (5th Cir.), *cert. denied*, 400 U.S. 950 (1970).

fear that efforts to limit price have reduced, rather than increased, the supply of new reserves and the actual level of gas production. Lowering prices from "monopoly" to "competitive" levels should have had just the opposite effect. The Commission's continued efforts to regulate, while holding this belief, suggest that it no longer sees itself as basically trying to control monopoly power. For another thing, the Commission has set two price levels in the area rate proceedings [41] — higher prices on "new" gas, and lower prices on "old" gas.[42] Its doing so, while at the same time expressing the hope that the new gas price would be high enough to cover the costs of producing new supplies,[43] indicates that limiting producer rents and windfalls is the more important concern underlying more recent regulation.[44] We shall assume that this is what the Commission has ultimately been trying to do.

II. Alternative Methods of Regulating Field Prices

After the Supreme Court's decision in *Phillips Petroleum Co. v. Wisconsin*,[45] the Federal Power Commission began to struggle with the problem of *how* to regulate.[46] The first approach was to treat producers as individual public utilities and to set limits on each producer's prices individually according to his "costs of service." After this approach proved unwieldy, the Commission set area-wide ceiling prices, allowing all individual producers within each gas production area to charge no more than the area ceiling.

A. Regulating Producers Individually

In attempting to regulate each gas producer, the Commission

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[41] *See* pp. 958–59 *infra*.

[42] This pattern appeared in the first complete area rate decision. Permian Basin Area Rate Proceeding, 34 F.P.C. 159 (1956), *aff'd in part and rev'd in part sub nom.* Skelly Oil Co. v. FPC, 375 F.2d 6 (10th Cir. 1967), *aff'd in part and rev'd in part sub. nom.* Permian Basin Area Rate Cases, 390 U.S. 747 (1968) (approving FPC decision in its entirety).

[43] *See* 34 F.P.C. at 188.

[44] Additionally, economists favoring regulation upon whom the Commission has closely relied have often rested their case upon a belief that the supply of gas is inelastic — that price has little effect on outputs. *See, e.g.*, Kahn, *supra* note 27, at 508–09. If regulation-induced price changes would not affect output, then the only reason to set price ceilings would be to transfer rents.

[45] 347 U.S. 672 (1954).

[46] Soon after the *Phillips* decision, Congress passed a bill exempting field sales of natural gas from regulation. The bill was vetoed, however, by President Eisenhower, not because he favored regulation, but because he disapproved of certain producer lobbying tactics. *See* Kitch, *supra* note 5, at 256.

followed the same procedure it used to set prices for each gas pipeline. It sought the producer's "costs of service" and allowed prices sufficient for the company to recover these costs, but no more. This approach seemed to promise that no producing company would earn more than a reasonable return on its capital; producers with unusually low costs would not receive windfalls, but, instead, would have to charge their customers lower prices. This method of regulation also seemed to avoid the risk of a serious gas shortage. If costs increased producers could raise their prices, and, as long as there was demand for the higher-cost (and higher-priced) reserves, regulation would not inhibit production.

However, this summary description of individual producer regulation hides enormous problems. Although individual producer regulation allowed producers with different costs to sell at different prices, it provided no way to determine which gas users should get the more expensive gas and which the cheaper. And, even setting aside the difficulty of rationing the lower-priced gas, regulation of individual producers proved unwieldy because of the immense administrative burden it placed on the Commission. Most important, there were basic conceptual deficiencies in the regulatory method. Cost-of-service regulation was based on the assumption that it was possible to obtain detailed, accurate information about producer costs. It presumed that the cost of finding gas could be determined from accounting records, as can the costs of, say, gas pipelines, electricity generating companies, and telephone companies. Moreover, in searching for a proper rate of return on investment, the Commission assumed that gas producers' costs of capital could be rationally determined. But, as the Commission discovered, determining the costs of gas production and a proper rate of return to gas producers raises issues far less easy to resolve here — issues which require considerably more use of the regulator's subjective judgment — than in the case of traditional public utilities.

The difficulties the Commission experienced with individual producer regulation are typically attributed to management failure. The administrative burden placed on the Commission arose from the vast number of natural gas producers. In 1954 there were more than 4,500 producers,[47] and by 1962 they had submitted more than 2,900 applications for increased prices.[48] The individual price or "rate" case approach to regulation required finding which of the joint costs of oil and gas exploration and de-

[47] HAWKINS 37.
[48] *Id.*

velopment were attributable to gas alone, a judgment about the fairness of a particular rate of return on investment, and a determination of the proper amount of investment (or "rate base") for each of the 2,900 applications. To accomplish these tasks would have taken an interminable amount of time. The first producer rate case undertaken — the *Phillips* case itself — took 82 hearing days, with testimony filling 10,626 pages and a record including 235 exhibits.[49] Although later cases might have been handled more quickly, differences from case to case in both levels of costs and degrees of risk (and therefore in allowable rates of return) were such as to require some individual attention to each application. By 1960, the Commission had completed only 10 of these cases.[50] The backlog led the Landis Commission, appointed by President Kennedy to study the regulatory agencies, to conclude that "[t]he Federal Power Commission without question represents the outstanding example in the federal government of the breakdown of the administrative process." [51]

Management failure alone, however, does not account for the Commission's difficulties, for the problems of individual producer regulation went much deeper. Even if the Commission had had ten times the staff, it would have encountered severe conceptual difficulties in trying to separate the costs of oil and gas production and in setting a proper rate of return.

Finding the cost of natural gas posed several extraordinary difficulties which arose from the fact that gas is often produced in conjunction with petroleum liquids. Money spent by petroleum companies on *exploration* leads to the discovery of some gas wells, some oil wells that produce gas too, some pure oil wells, and many dry holes. Expenditures on *separate development* of gas fields often yield gas together with petroleum liquids, and expenditures on *gas refining* produce both "dry" gas and saleable liquid. Expenditures such as these, which yield two products but which are equally necessary to produce either one, complicate a regulatory process based on costs because there is no logical way to decide whether, or to what extent, a specific dollar outlay should be considered part of the "cost of gas production," or part of the "cost of liquid production."

This problem of joint cost allocation is distinctly a regulatory one. Without price controls and under competitive conditions, producers would recover marginal joint costs from the sale of

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[49] *Id.* at 26.

[50] *Id.* at 78.

[51] SUBCOMMITTEE ON ADMINISTRATIVE PRACTICE AND PROCEDURE OF THE SENATE COMM. ON THE JUDICIARY, 86TH CONG., 2D SESS., REPORT ON THE REGULATORY AGENCIES TO THE PRESIDENT-ELECT 54 (Comm. Print 1960) (Landis report).

gas and oil, with the relative amounts recouped from each varying from firm to firm.[52] If a regulatory agency controlled *both* oil and gas production, it might try to reproduce these competitive market results simply by requiring that the combined revenues from the sale of the two products be equal to their combined costs, including, of course, return to capital. Any combination of prices that would do no more than return total costs would meet this requirement.[53] The distinct regulatory problem in controlling field market prices for gas, however, was that liquid prices were not regulated by the FPC. Therefore, in order for the Commission to eliminate excess returns on gas production, it would have had either to find the "exact" costs of one of the joint products — something logically impossible to do — or to regulate indirectly the earnings on the unregulated sales of liquids — something it could not legally do.[54]

[52] Assume that to find and to produce a certain volume of gas and oil from a marginal well costs a certain producer $100,000. Assume further that of this cost, $70,000 is joint, $20,000 represents the ascertainable separate cost of extracting oil, and $10,000 the separate cost of extracting gas. The producer will develop this well and sell both gas and oil provided he can sell the oil for at least $20,000, the gas for at least $10,000, and the two together for at least $100,000. But he will not care whether the extra $70,000 comes entirely from gas sales, entirely from oil sales, or from some combination of the two. The source of the $70,000 will depend upon the relative strength of the demands of gas buyers and oil buyers for the producer's supplies — a factor which will depend upon supply and demand in each industry. *See, e.g.*, 1 A. KAHN, THE ECONOMICS OF REGULATION 79-83 (1970).

[53] Thus, the agency regulating the producer described in note 52, *supra*, would permit the well owner to recover $100,000, allowing him to set whatever combination of gas and oil prices would be necessary to obtain this revenue. Similarly, the regulator would allow the owner of an intramarginal well with, say, joint costs of $40,000, separate gas costs of $5,000, and separate oil costs of $10,000, to set whatever prices would obtain a total of $55,000. Since in the latter case total production could be sold for $100,000 in an unregulated market, the producer would lose $45,000 in rent, and gas and oil consumers *together* would pay $45,000 less than the free market price.

[54] The problem of trying to regulate one industry without regulating the other becomes clear if one considers the following procedure. Suppose the Commission were to require producers to submit prices that covered the costs of producing gas only, but which included (1) the ascertainable separate costs of gas extraction, plus (2) joint costs only insofar as they would not be covered by revenues received from the sale of petroleum. Thus, for example, a firm with joint costs of $70,000, separate oil costs of $20,000, and separate gas costs of $10,000, would be allowed to earn up to $80,000 from gas sales which would be calculated as the sum of $10,000 plus the difference between oil revenues (less $20,000 for covering *separate* oil costs) and $70,000. For every dollar less that it earned from oil sales, the company would be allowed to earn a dollar more from gas sales.

Considering the Commission's inability to regulate liquid sales, such a system for regulating gas production prices would have obvious drawbacks. First, it would require information on petroleum sales of the sort that is required of regulated sales. To ask the company to provide estimates of future oil prices would be to ask for exceptionally costly and uncertain information. Second, the Com-

The Commission's efforts to overcome the joint cost problem in gas production in fact simply involved the application in various combinations of several traditional methods for allocating joint costs for accounting purposes.[55] But these methods only created the illusion that the joint costs of gas and oil production were separable and bore no particular relation to the problem of determining costs for rate setting. One method allocated joint costs according to the ratio of the separable cost of producing a barrel of oil to the separable cost of producing a thousand cubic feet (Mcf) of gas.[56] A second method allocated joint costs in proportion to the number of heating units (BTU's) contained respectively in the oil and gas produced.[57] A third method recognized that BTU's of oil and gas might not be of equal value in the marketplace, and therefore multiplied the BTU's by a factor representing relative value.[58]

None of the three procedures could yield either the long term costs of future gas production or the historical costs of past exploration and development. As methodology, they simply carried on a charade of implying separable costs when costs were joint and inseparable. In fact, if producers, in the absence of regulation, tended to recover most joint costs from oil revenues, and priced gas close to its ascertainable separate costs, the Commission's techniques, in allocating large shares of joint costs to gas, would force it to conclude that gas prices were too low. This fact may help to explain why the Commission held in the

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mission would have to regulate the price of oil eventually if it were to squeeze rents out of gas production. Under such a system, the producer would be indifferent as to whether he earned a dollar of rent from an oil or a gas sale. It is possible that he would try to cover as many of the well's costs as possible from gas sales, for if the Commission forced him to charge a lower gas price, he would not know whether he could cover a well's remaining joint costs from oil sales until the oil was sold, perhaps sometime in the future. He might therefore decide to maintain gas prices that included rents and reduce his oil prices, as a strategy to increase total sales or, perhaps, in order to allocate his low-priced oil arbitrarily on the basis of personal favors or otherwise.

[55] *See generally* HAWKINS 44–74.

[56] If, for example, it costs $1.50 to produce a barrel of oil and $0.15 to produce an Mcf of gas, joint costs would be allocated according to the ratio:

$$\frac{10 \times \text{the number of barrels of oil}}{\text{number of Mcf's of gas}}$$

[57] Under this method, if a barrel of oil yielded one million BTU's and an Mcf of gas yielded ½ million, then a company's joint costs would be allocated according to the ratio: $\frac{2 \times \text{number of barrels of oil}}{\text{number of Mcf's of gas}}$

[58] Thus, if an oil BTU was worth four times a gas BTU, the ratio for allocating joint costs would be: $\frac{4 \times \text{number of barrels of oil}}{\text{number of Mcf's of gas}}$

Note that this is a potentially circular method, since "costs" are partly tied to existing prices. *See* HAWKINS 46–47.

10 pre-1960 individual producer rate cases that it completed that producers' proposed prices would not generate enough revenue to cover costs.[59] In short, as Justice Jackson said in a slightly different context:[60]

> The case before us demonstrates the lack of rational relationship between conventional rate-base formulas and natural gas production . . . .[61]

A second theoretical problem which the Commision had to confront in attempting to regulate gas producers individually was that of determining a proper rate of return for each of them. While such determinations are usually difficult, here the difficulties were of more than usual magnitude. For one thing, there was no simple process for choosing industries with comparable risks. To be sure, producing gas is probably riskier than running a telephone company; but is it as risky as mining copper or making steel? Arguably, the cost of capital can be determined directly by watching share prices fluctuate on an exchange (or, possibly, comparable risk can be measured in this way[62]); but few producers sold shares on exchanges, and those that did were obviously the larger firms which produced both gas and oil. Nor was it possible to determine costs of capital by looking to producers' debt, because gas producers had issued insignificant amounts of debt securities.[63] Finally, because of different degrees of expertise and different quality of land options, risks varied tremendously among gas producers themselves. To determine the rate of return needed to cover producers' opportunity costs of capital would have therefore required many highly subjective judgmental decisions about thousands of different producers. These problems were compounded by the fact that capital costs accounted for a high portion of total production costs,[64] and thus posed a problem at least as serious as allocation of joint costs for individual producer regulation.

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[59] *See* HAWKINS 78.

[60] FPC v. Hope Natural Gas Co., 320 U.S. 591, 645 (1944).

[61] Since the number of joint wells has diminished to the point where gas output from them accounts for only about 25% of total gas production, *see* p. 944 *supra*, the problem of allocating joint costs became somewhat less important in the 1960's than it was in the 1950's. Nonetheless, joint expenditures were and are still sufficiently important to make a pricing system that allocates them via these accounting methods an exercise in the arbitrary.

[62] *See generally* W. SHARPE, PORTFOLIO THEORY AND CAPITAL MARKETS (1970).

[63] Because of special tax incentives, much new investment by gas production companies is financed out of internally generated funds. *See, e.g.*, INT. REV. CODE of 1954, §§ 611–13 (depletion allowance).

[64] *See* NATIONAL PETROLEUM COUNCIL, U.S. ENERGY OUTLOOK 115 (1972) (showing exploration, development, and overhead costs to be $6.4 billion of $8.9 billion total outlay).

The problems of determining the costs of production and the proper rate of return continued to plague the Commission as it turned to an administratively simpler regulatory method. And the Commission also continued to be plagued by the need to ration low-priced gas — as is any agency that tries to regulate competitive markets by setting different producer prices for sales of the same product at the same place and time.

B. *Setting Area Rates*

After regulation of individual producer prices proved unwieldy, the Commission embarked upon a policy of setting areawide ceiling prices, allowing all individual producers within a given gas production area to charge up to, but not above, the area ceiling. In 1960, the major gas producing regions were divided into five geographical areas,[65] and hearings were begun to determine the legally binding ceiling prices for each. Because of statutory limitations on Commission authority,[66] the area rate proceedings could set limits on prices only prospectively, *i.e.*, from the time an area rate proceeding was completed. Therefore, to control producer prices during the many years that the proceedings would be in progress, the Commission worked out a legally complex, though operationally simple, procedure which set "interim ceiling prices" at the 1959-60 levels for new contracts.[67] During the 1960's rate proceedings were completed only for the Permian Basin and Southern Louisiana areas.[68] In these and the remaining production areas, contracts for new reserves were written throughout much of the entire decade as if economic conditions had not changed since the late 1950's.

[65] The five areas were: (1) The Permian Basin (Texas and part of New Mexico); (2) Southern Louisiana (including the offshore area in the Gulf of Mexico); (3) Hugoton-Anadarko (part of Oklahoma and Kansas); (4) Texas Gulf Coast; and (5) Other Southwest (Mississippi, Arkansas, and parts of Alabama, Texas, and Oklahoma).

[66] 15 U.S.C. § 717d (1970).

[67] With regard to increases in existing contracts, proposed price increases would take effect subject to an obligation of the producer to refund any excess above the "reasonable rate" which the area rate proceeding was eventually to find. Thus, producers tended not to ask for increases above the interim ceiling rate. With regard to new supply contracts, the Commission used its licensing power over producer entry, 15 U.S.C. § 717 (1970), to withhold certificates allowing production to begin unless the producer agreed to sell the gas at the interim ceilings proposed by the Commission as (provisionally) reasonable. While the Commission did not rigidly adhere to these interim guidelines, its object was to hold new gas prices "in line" with those charged in the late 1950's and in 1960. *See generally* FPC, Statement of General Policy, No. 61-1, 24 F.P.C. 818 (1960).

[68] Permian Basin Area Rate Proceeding, 34 F.P.C. 159 (1965), *aff'd in part and rev'd in part sub nom.* Skelly Oil Co. v. FPC, 375 F.2d 6 (10th Cir. 1967), *aff'd*

In its area rate proceedings, the Commission sought to determine for each area two separate price ceilings: one for "new" gas from gas wells (new gas-well gas), and a second, lower ceiling that applied both to "old" gas from gas wells (old gas-well gas) and to all gas from oil wells. This two-tier area pricing system was designed to provide a fairly simple way to transfer rents from producers to consumers without seriously discouraging gas production and without imposing upon the Commission the administrative burdens of the multitier system of regulating producers individually. In embarking upon this new regulatory approach, the Commission assumed that gas found in conjunction with oil and old gas-well gas found several years before an area proceeding cost less to produce than new gas-well gas. It also assumed that the lower prices for old gas-well gas and gas found in conjunction with oil would not discourage their production, given that their supply was relatively fixed. Thus, lower prices for the old gas- and oil-well gas would deprive producers of rents from the sale of these supplies to the benefit of the consumer, while higher prices for new gas-well gas would, at the same time, encourage enough additional gas production to meet total consumer demands.

Despite its apparent logic and simplicity, however, the two-tier pricing system contained potentially serious flaws. First, given that excess demand would be generated for the cheaper "old" gas,[69] the FPC had to devise a way of rationing the available supply which would give it to those potential users who valued it most highly.[70] Home users, for example, value gas highly for cooking and heat, while industrial users may be nearly indifferent to the choice among gas, coal, and petroleum. An

in part and rev'd in part sub nom. Permian Basin Area Rate Cases, 390 U.S. 747 (1968) (approving FPC decision in its entirety); Southern Louisiana Area Rate Proceeding, 40 F.P.C. 530 (1968), *aff'd*, Southern Louisiana Area Rate Cases, 428 F.2d 407 (5th Cir.), *cert. denied*, 400 U.S. 950 (1970). The latter case was reopened to raise the ceiling by 25%. Southern Louisiana Area Rate Proceeding, 46 F.P.C. 86 (1971); *see* p. 964 *infra*.

[69] *See* p. 951 *supra*.

[70] The English have solved this problem by making the gas distributor a single nationalized company, with both monopoly and monopsony power. It can thus offer differential prices to producers based upon their production costs, including prices equal to marginal costs for producers at the margin. It can then ration the cheaper gas by selling to those consumers who bid the most. To be sure, the nationalized distribution company earns large rents, but these rents are simply transferred over to the treasury. *See generally* Dam, *The Pricing of North Sea Gas in Britain*, 13 J. LAW & ECON. 11 (1970). Of course, allowing private pipeline or distributing companies in the United States to ration the cheaper "old" gas on the basis of consumers' willingness to pay would be undesirable, since producer rents would then be transferred to these private companies, rather than to consumers.

auction system, by allocating the old gas on the basis of willingness to pay, would insure that it went to those who placed the highest value upon it. But an auction system would quickly drive the price of the "old" gas up to "new" gas price levels. In fact, the methods of rationing chosen by the Commission — allocating the cheaper gas on an historical basis (old customers before new ones) [71] or on the basis of an FPC determination that some *end* uses of gas were "inferior" to others [72] — do not seem to reflect an attempt to make careful distinctions among users according to their potential willingness to pay higher prices for the low-priced gas. These choices are important, since preferences made by the allocation system according to economically inefficient criteria are likely to spill over and affect other areas of economic activity; for example, insofar as historically-based differential prices at the wellhead are reflected in different pipeline resale prices, they may distort competition among industrial customers (*e.g.*, two chemical companies paying different prices for identical gas) or choices as to plant location.

Second, the competitive conditions of the unregulated gas production market suggest the strong possibility that, in a two-tier system where prices at both levels were set by regulatory action, the price of the higher tier would be set too low.[73] If so, then exploration and development of new gas would be discouraged, and there would be excess demand for the new gas as well as the old.[74] Here, again, if regulation-induced shortages occurred, additional economic inefficiencies would arise from any allocation system based other than on users' willingness to pay.

Third, this potential for economic harm from the two-tier system created by the inevitable excess demand for the lower-priced product and the probable regulation-induced shortage of the higher-priced product, was compounded by jurisdictional limitations on the FPC's power to regulate field market prices. Although the Commission could regulate producers' interstate sales, it could not regulate the prices at which they sold gas intrastate in the production region.[75] Intrastate sales were made pri-

[71] The FPC has generally chosen to increase the reserve backing of existing pipeline customers when given the choice of certifying new pipeline construction with only marginal backing.

[72] *See, e.g.*, FPC v. Transcontinental Gas Pipe Line Corp., 365 U.S. 1 (1961) (upholding FPC decision to deny delivery of gas to utility company for use under boilers in place of coal, partially on ground that this was an "inferior" use); p. 984 *infra*.

[73] *See* pp. 948–49 *supra*.

[74] A deficiency in the supply of the new gas might still occur even if the Commission regulated the old gas only, so long as producers suspected that there would be *future* designations as "old" of gas now "new." *See* pp. 984–85 *infra*.

[75] 15 U.S.C. § 717b (1970).

marily to industrial purchasers[76] who would seemingly be relatively indifferent as among various fuel sources available at equal prices. In times of shortage, the gas that these industries purchased would likely be diverted from retail distributors willing but unable under regulation to pay a higher price. Thus, both the certain scarce supply of old gas and the potential scarce supply of new gas likely would be disproportionately given over to certain industrial users by default, since other users who valued the gas more highly would not be allowed to bid up its price.

While the Commission may have intended the price of new gas to be set at market-clearing levels, the methods it used for setting new gas area prices made it highly likely that a significant gas shortage would arise by virtue of the new gas price — the "high" price — being set below the long term costs of natural gas production.[77] The basic method first used by the Commission to find a ceiling price for new gas-well gas was to determine by survey for given base years the recent cost of finding and producing new gas.[78] In both of the area rate cases completed in the 1960's, the final new gas price ceilings established on the basis of these estimates of recent costs turned out to be roughly equal to the interim prices set in the early 1960's.[79]

Given this recent cost survey method of setting the final ceiling prices, their similarity to the old interim prices is not at all surprising (even though one might have expected costs to rise during the 1960's), for the interim price ceilings themselves strongly biased the effort to determine the recent cost of new production. Producers unable to sell gas at more than the interim

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[76] *See* p. 977 & note 118 *infra*.

[77] Note that the discussion here is limited to the Commission's determination of prices for new *gas-well* gas, and that since no joint cost problem would be involved, it was unlikely the Commission would find the market price too low, as was the case in the former individual producer proceedings. *See* p. 957 *supra*.

[78] Thus in the Permian Basin Area Rate Proceeding, 34 F.P.C. 159 (1965), *aff'd in part and rev'd in part sub nom.* Skelly Oil Co. v. FPC, 375 F.2d 6 (10th Cir. 1967), *aff'd in part and rev'd in part sub nom.* Permian Basin Area Rate Cases, 390 U.S. 747 (1968) (approving FPC decision in its entirety), the Commission staff surveyed both major and minor producers to discover their annual total costs for producing new gas for the base year of 1960. Experts employed by the producers, and some employed by retail distributors, made similar surveys. Together they produced a range of estimates of exploration and development costs for each of several different years. *See* HAWKINS 91–107. Similarly, in the Southern Louisiana Area Rate Proceeding, 40 F.P.C. 530 (1968), *aff'd*, Southern Louisiana Area Rate Cases v. FPC, 428 F.2d 407 (5th Cir.), *cert denied*, 400 U.S. 950 (1970), such analyses were undertaken for the base year 1963.

[79] In Permian Basin Area Rate Proceeding, 34 F.P.C. 159 (1965), the Commission set a new gas ceiling price of approximately 16.5¢ per Mcf. In Southern Louisiana Area Rate Proceeding, 40 F.P.C. 530 (1968), it set a new gas ceiling price of 20.0¢ per Mcf. The interim ceilings had been 16.0¢ and 21.0¢ respectively.

price levels most likely developed only those reserves having marginal costs lower than such prices. Companies with higher costs would not be producing, while those with cheap, lucky finds would still be in business. Thus it is not surprising that the recent costs of new reserves were slightly lower than the Commission's interim price ceilings. Taken together, the interim ceiling and later cost survey constituted simply two elements of a self-fulfilling prophecy; using recent costs to set future prices may, in reality, have been using interim prices to set permanent ones. In short, given the interim ceiling, a survey of the costs of producing new gas in the early 1960's could not tell the Commission with any assurance what price would be needed to elicit additional production for growing demand in the late 1960's and early 1970's.

Quite apart from the existence of interim ceilings, the probability that regulation would induce a natural gas shortage was increased by the specific calculation the Commission made to determine the recent costs of new gas production. If the Commission were not to discourage future production, it should have been certain that the ceiling prices it was setting were as high as prospective development and extraction costs. One indicator of such prospective outlays would be the cost curve derived from the historical marginal production costs in each drilling region of a production area during the test years. Even these historical marginal costs would of course understate future production outlays, because of increases in drilling and other expenses. But the Commission further compounded the possibility of understating prospective development and extraction outlays by *averaging* the marginal costs of recent production across all the drilling regions of a production area. Given a wasting resource from a fixed stock of uncertain size, it is highly probable that the costs of producing the very final units of recent output were greater than the average costs of finding and developing new reserves during the test years.[80] The higher-cost producers most likely included not only the unlucky or less skillful, but also those forced to search farther afield or deeper underground after having exhausted their more promising leaseholds. Averaging their costs in with the new gas production costs of the more fortunate or unusually skillful producers would understate the likely costs of future new gas production and would therefore increase the probability that exploration and development of marginal reserves would not take place.

The Commission tried to take these problems into account by

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[80] *See generally* P. BRADLEY, THE COSTS OF PETROLEUM (1968).

adding an "allowance for growth" to the historical average costs of finding new gas. In the *Permian Basin* proceedings, for example, the Commision added 1.11 cents per Mcf to the ceiling price in recognition that producing enough new gas in the future to meet growing demands would probably require the exploitation of more expensive reserve sources.[81] But it did not determine the size of this premium by analyzing producers' probable marginal costs. Rather, an expert appearing for the gas distributing companies presented this figure as a judgmental observation, and experts for the gas producing companies in turn concluded judgmentally that the proper figure was 2.15 cents per Mcf.[82] The Commission simply chose between these two judgments, and, by acceptance of the distributors' estimate of the proper growth allowance, made it likely that the Commission's choice would be on the low side. To be sure, trying to determine the marginal costs of future gas production would have to involve *some* guesswork. But the need to guess inevitably introduces the risk of error — error difficult to correct once prices are set. The Commission's determination of the proper "allowance for growth" did not reflect any guidelines of its own concerning the impact of such factors as increases in drilling costs, decreases in the probability of finding gas, and changes in the rate of return needed to attract speculative capital into future gas production. Of course, as indicated earlier, these matters are highly speculative. It is therefore perhaps understandable that a Commission interested in regulating producers' prices would, when given only the alternative of accepting the producers' own figures, accept the growth figure offered by those interested in keeping producers' prices low.[83] But, nevertheless, the Commission's acceptance of the distributors' estimate of the premiums needed to encourage marginal production, along with its own calculation of the historical average costs of new production, created a considerable risk that the "new gas" price would be too low and would engender a gas shortage of some scope.

Faced with the extraordinary difficulty of determining the costs of "new gas" at levels of production that would clear the market and with a new-found shortage of gas production in the late 1960's, the Commission has more recently shown greater reliance on a process of direct negotiations to set area prices. In the original *Southern Louisiana* case, representatives of the producers, distributors, and other customers bargained out a "settlement" which was presented to the Commission for approval. The

[81] Permian Basin Area Rate Proceeding, 34 F.P.C. 159, 194 (1965).

[82] *See* HAWKINS 106–07.

[83] *Cf.* p. 948 *supra*.

Commission [84] and the appeals court [85] took the negotiation under advisement, however, along with a great deal of information on historical costs, and decided to set price ceilings slightly below the settlement figures. When the gas shortage in the late 1960's led the Commission to reopen the *Southern Louisiana* proceedings, once again the parties negotiated a settlement. This time the Commission adopted the settlement figures as its own, holding that they constituted reasonable ceiling prices.[86]

To be sure, one undeniable advantage of setting prices through such negotiation is administrative simplicity. The Commission need not spend as much time gathering evidence, the number of warring parties is reduced, and it is less likely that a disappointed party will convince a court to overturn a Commission decision. But to set ceiling prices in reliance upon industry settlements comes close to abandoning the Commission's espoused regulatory goals — whether they be to control market power or to eliminate windfall profits — and comes even closer to admitting an inability to achieve them. Negotiation among interested parties can hardly control monopoly power, for it bears little resemblance to the bargaining among buyers and sellers that takes place in a competitive market. Rather than competing individually for purchases or sales, the parties bargain in blocs — the buyers together in one bloc bargaining with producers in the other bloc. Whether the negotiated price ends up higher than, lower than, or equal to the competitive market price will vary depending on the skill of particular bargainers and the bargaining atmosphere surrounding the negotiation. The parties are likely to be constrained in the bargaining by their knowledge that the Commission and the courts must approve the result and may produce little more than what they perceive their regulators as wanting.[87] For these same reasons, negotiation is unlikely to pro-

[84] Southern Louisiana Area Rate Proceeding, 40 F.P.C. 530, 543 (1968).

[85] Southern Louisiana Area Rate Cases v. FPC, 428 F.2d 407, 419 (5th Cir.), *cert. denied*, 400 U.S. 950 (1970).

[86] Southern Louisiana Area Rate Proceeding, 46 F.P.C. 86, 110 (1971); *see* Hugoton-Anadarko Area Rate Proceeding, 44 F.P.C. 761, 769–72 (1970) (ceiling price based on settlement). *But see* Texas Gulf Coast Area Rate Proceedings, 45 F.P.C. 674 (1971) (ceiling price based on independent FPC determination).

[87] Thus, for example, in the first *Southern Louisiana* case, the industry probably surmised that the Commission was unlikely to approve any price out of line with past prices or that departed too radically from average historical new gas production costs. It is therefore not surprising that the settlement offered in that case came very close to the "interim" ceiling price. *See* Southern Louisiana Area Rate Proceeding, 40 F.P.C. 530, 630 (1968). Once the Commission reopened the proceeding, however, and thereby indicated its willingness to raise the ceiling price to alleviate the gas shortage, the settlement offer produced a price 20–25% higher than the price previously allowed. Southern Louisiana Area Rate Proceeding, 46 F.P.C. 86, 110 (1971).

vide "accurate" two-tier prices in an effort to drive out producer rents.

In sum, the difficulty of designing a two-tier system for regulating field prices for natural gas made it unlikely from the outset that the Commission would set the "high" price for new gas at a market-clearing level if that was what it intended to do. However, it is also possible that the Commission in fact *wanted* to set the "high," new gas price below competitive rates. Much new gas-well gas production as well as old gas- and oil-well gas production probably returns rents to its producers.[88] If the Commission wanted to return these rents to users, while setting a *single* area price for all new gas-well gas, it *had* to set the price below the marginal cost of new production in that area. The Commission may have felt that any necessarily resulting shortage would not be serious and would be worth the benefits of lower prices to consumers who could obtain the gas that would be made available. If this was the Commission's reasoning, though, it did not expressly state it. Moreover, even if Commission policy could be attributed to such a purpose, the wisdom of that policy would still depend upon the precise extent and impact of the gas shortage created by it. It is to that question that we now turn.

III. The Extent and Impact of the Natural Gas Shortage

The expectation that FPC regulation of gas production was likely to produce a substantial gas shortage has been proven accurate by subsequent events. Thus, pipeline buyers have reported to the Commission instances during the summer and winter of 1971–72 in which their contracts obliged them to deliver gas but they lacked the necessary supply.[89] The FPC staff has shown deliveries falling short of gas demanded by 3.6 percent in 1971 and by 5.1 percent in 1972, and has predicted that production will fall short of demand by 12.1 percent in 1975.[90] Moreover, those feeling the pinch have tended to blame FPC regulation for the shortage.[91] And the FPC has not only acknowledged the existence of a substantial shortage,[92] but has also suggested

[88] *See* p. 950 *supra*.

[89] *See Proceedings on Curtailment of Gas Deliveries of Interstate Pipelines Before the Federal Power Commission* (1972).

[90] FEDERAL POWER COMMISSION, BUREAU OF NATURAL GAS, NATIONAL GAS SUPPLY AND DEMAND 1971–1990, at 123 (1972).

[91] *See* MacAvoy, *The Regulation-Induced Shortage of Natural Gas*, 14 J. LAW & ECON. 167, 169–70 (1971) [hereinafter cited as *Regulation-Induced Shortage*].

[92] *See* NATURAL GAS SUPPLY AND DEMAND, *supra* note 90, at xi; FEDERAL POWER COMMISSION, BUREAU OF NATURAL GAS, THE GAS SUPPLIES OF INTERSTATE NATURAL GAS PIPELINE COMPANIES 1968, at 34–39 (1970).

that regulated prices are a cause.[93]

Production "shortfalls" alone, however, do not accurately describe the extent of the gas shortage, because gas is purchased by and sold to pipeline companies before the time of its actual production. Gas delivered during any given year is "backed up" by considerable volumes of reserves which are originally committed in long term contracts to pipeline companies demanding a guarantee as to future supplies. Obviously, pipelines will demand more than a few years of reserve backup, for only with a fairly long term supply guarantee is establishing a pipeline worthwhile. More importantly, retail distributors and industrial consumers normally demand that pipelines themselves guarantee a specific rate of delivery over time and therefore demand substantial reserve backing as security against default by the pipelines on their promised deliveries.[94] Thus, an inability of transmission companies to acquire sufficient supplies to meet contract delivery requirements in any given year should signal the earlier existence of a deficiency in the volume of backup reserves committed at the time the original production contracts were undertaken. If this view is correct, a shortage in production levels in the 1970's would have been prefaced by a deficiency of reserve commitments made to back up new production undertaken in the early and mid-1960's. The extent of this predicted reserve shortage in the 1960's should be measurable as the difference between an "optimal" level of reserves which would have been demanded by pipeline companies to back up new production undertaken in that period and the level of reserves actually supplied by regulated producers and acquired by the pipelines.

Rough calculations previously made by one of these authors in fact show the shortage of reserve inventory of natural gas during the 1960's to have been substantial.[95] This conclusion was reached by first determining an approximate "optimal" volume of gas reserves, in terms of years of backup supply, which would be dedicated to secure new production commitments undertaken in any single year. The FPC has considered the proper amount of reserves to be 20 times initial production, so that regulated pipeline demands for new reserves have been based on "the assumption that each new market commitment is backed by a

[93] *See* Southern Louisiana Area Rate Proceeding, 46 F.P.C. 86, 110–11 (1971).

[94] In theory at least, this demand for reserves should be reflected in higher contract prices to the pipelines, because a longer waiting period for production imposes higher costs on the supplier. This cost increase was not reflected in significantly higher prices on longer term contracts, however, during the period just before area rate regulation. *See* PRICE FORMATION 262–65.

[95] *Regulation-Induced Shortage* 171–75.

20 year gas supply."[96] Similarly, pipelines' actual demands for reserves from 1947 to 1954 — before the Commission had much influence on the field markets — were on average equivalent to a 20-year backup of production, with the lowest backing in any single year equal to 14.5 times new production.[97] It was therefore concluded that, on the most conservative of assumptions, a simple, rough estimate of demands for reserve inventory under ceiling prices could be obtained by multiplying total new production — including all new contracts plus any renewals of expiring contracts — by 14.5 to obtain the "lowest" demands for reserve backing in the unregulated market. Alternatively, on more liberal assumptions, total new production could be multiplied by the FPC's suggested reserve ratio. These calculations were done for the years 1964 through 1968 to determine the volume of natural gas which would have been demanded by pipelines as reserves to back up new production under "optimal" conditions for that period. These high and low "optimal" volumes were then compared to the actual new-reserve-to-new-production ratio for the same years. Taking the 5-year period as a whole, it was found that the total demand for reserves was 1.5 to 2.2 times higher than the actual reserves acquired under FPC price ceilings; therefore, *excess* demand for reserves was 50 percent to 120 percent of realized levels of commitments.

In an attempt to determine whether this reserve shortage was the result of field price regulation, we shall construct a model of supply and demand for new reserves, based upon market clearing conditions in the 1950's. These conditions will then be extrapolated into the 1960's in order to predict what supply and demand behavior would have been like during that decade under competitive conditions and whether FPC ceiling prices were too low to clear the market.[98] Then we shall proceed to determine who received gas and who suffered the shortage. It will be shown that, in fact, as suggested earlier the home consumer suffered the brunt of an FPC-created reserve shortage, while the unregulated industrial consumer received a disproportionate share of the gas that was available.[99]

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[96] FEDERAL POWER COMMISSION, A STAFF REPORT ON NATIONAL GAS SUPPLY AND DEMAND 18 (1969). Note that 20 years of reserve backing will support only 12 years of delivery at the full initial production rate, because the rate of delivery out of a reserve must fall as gas pressure falls. *See* HAWKINS 42.

[97] *Regulation-Induced Shortage* 172.

[98] Obviously, the proposed model is fallible due to the many problems involved in acquiring data — problems that the Commission itself faced in trying to set prices. Yet we believe that such models should be used by policymakers as evidence that is probative, though not conclusive, of which policies ought to be followed.

[99] ED. — Professor MacAvoy has previously published a supply and demand

A. A Supply and Demand Analysis of the Insufficiency of FPC Ceiling Prices

The proposed model of supply and demand in the field markets for natural gas in the 1960's tries to assess more accurately the extent to which field price regulation caused the gas shortage. The model tests the fairly plausible view that, without regulation, field prices for natural gas would have increased substantially, producing correlative increases in the supply of and decreases in the demand for natural gas reserves. These higher prices would have called forth enough new supply to fill at least part of what has been shown to be the excess demand for reserve inventories. And, by more carefully rationing the available supply, the higher prices would have eliminated whatever additional excess demand would have still remained.

The proposed model applies to gas which is supplied by pipeline to the East Coast and Midwest.[100] To test the model's accuracy, we first construct supply and demand schedules to characterize unregulated market behavior in the latter half of the 1950's and use these schedules to predict market-clearing prices in that period. This is done by fitting 1950's data to the proposed supply and demand relations to predict the amount of reserves added in year "t" in producing district "j" (ΔR_{tj}) and the average new contract price at the same time and place (P_{tj}). The values of ΔR_{tj} and P_{tj} that "clear" this supply-demand system for the 1950's describe with considerable accuracy both the actual prices at which natural gas was sold and the actual amount of new reserves added in the test areas during that period. The

model intended to measure the extent to which field price regulation has caused the natural gas shortage. MacAvoy, *The Regulation-Induced Shortage of Natural Gas*, 14 J. LAW & ECON. 167 (1971). Since that time, his thoughts on the subject have somewhat modified, and the model presented herein is a considerably revised and updated version of that previously published and yields different results.

For those familiar with Professor MacAvoy's earlier model, the revised version presented here specifically differs in the following respects. First, the long term pattern of reserve discoveries and wells sunk in a drilling region is taken to be a better indicator of the geological conditions of that region than is the pattern of discoveries and drilling the year before the test year. Second, the level of the crude oil price index replaces that of the all fuels price retail price index as a condition of drilling activity. Third, the capital stock of gas burning furnaces is taken to be a closer measurement of the size of the final market for natural gas than changes in per capita income and population.

In addition, the data used to examine the relative effects of the gas shortage on industrial and residential users has been developed more fully and separates intrastate from interstate production insofar as it is possible to do so.

[100] The test field market is delimited by the pipelines taking gas for resale along the East Coast and in the Middle Atlantic states. The area roughly comprises Texas Railroad Commission Districts 1–7 and 10, Louisiana, Kansas, and Oklahoma.

model is then applied to the 1960's by inserting 1961–68 data into the supply and demand equations and then solving the system for market-clearing values ΔR^*_{tj} and P^*_{tj}. The model's values for the 1960's are then compared to the actual reserves added and prices existing during that period. The comparison shows regulated prices to be less than P^*_{tj} and actual reserves supplied to be less than one-third of ΔR^*_{tj}. Most of the difference can be attributed to the FPC's regulatory efforts.

1. The Supply Equations. — As previously indicated, the supply of natural gas is measured both by the volume of new reserves *and* by the level of production added from new contracts each year.[101] Looking first at the supply functions for new gas reserves, the volume of new reserves discovered and developed in any given year depends on geological and technical factors, as well as economic ones. Thus, the supply equations of the proposed model relate observable data to the supply of new reserves on the following assumptions.

First, the volume of gas added to known reserves in a district depends quite plainly on the extent of hydrocarbon deposits in that district; gas discovery, in other words, cannot occur where the deposits are not present. Because of the relative permanence of geological characteristics, the most concrete determinant of general hydrocarbon availability in a district is the long term pattern of reserve discoveries there. Thus, it may be said that the supply of new reserves in year "t" in district "j" (ΔR_{tj}) is a function (f) of the geological characteristics of district "j" itself. This relationship can be expressed by the equation $\Delta R_{tj} = f(j)$.[102]

The second condition of new reserve supply is that inputs are required — principally drilling inputs — to bring unknown hydrocarbons to the point of being producible reserves. The only available data on such inputs are the number of gas development wells sunk in the 1950's and 1960's, by drilling district. To be sure, such data are not indicative of all necessary inputs, but the wells do reflect the amount of capital invested in a hydrocarbon field and do provide producers with additional knowledge of surrounding geological conditions. Thus, the supply of new reserves in year "t" in district "j" (ΔR_{tj}) is also a function of the number of development wells sunk in the same time and place (W_{tj}). In sum, the equation $\Delta R_{tj} = f(j, W_{tj})$ can be taken to indicate, even if somewhat imperfectly, a number of important "engineering" factors in the supply of new reserves.

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[101] *See* p. 966 *supra*.

[102] The actual values of "j" are determined for purposes of the supply and demand equations by treating it as a "dummy" variable. *See* note 109 *infra*.

Third, the supply of newly discovered reserves also depends upon economic factors. This relationship can be most immediately seen as a condition of the number of development wells sunk in a drilling district. Thus, as prices for new gas reserves increase, it can be expected that more gas drilling will occur, and this additional drilling of regions likely to contain gas will increase the amount of new gas reserves dscovered. If average new reserve contract prices in year "t" in district "j" (P_{tj}) are good surrogates for the prices forecast by the drilling companies before development begins, then the amount of actual drilling (W_{tj}) will be a function of these prices. In addition, as noted previously, gas reserves may be discovered incidentally in the search for oil.[103] Oil price increases are likely to produce more drilling in areas likely to contain hydrocarbon deposits, and such drilling may produce gas, as well as oil, finds. Therefore, the number of development wells sunk (W_{tj}) may be said to be also a function of the level of the crude oil price throughout the Southwest (op_t). Thus, the response of drilling activity, and indirectly of new reserve supply,[104] to economic factors can be expressed by the equation $W_{tj} = f(P_{tj}, op_t)$.

Finally, the analysis of drilling, as well as that of reserves, should recognize that geological factors, as represented by the long term pattern of drilling in a region, are important. Thus, the drilling equation we have developed thus far, $W_{tj} = f(P_{tj}, op_t)$, should include the geological characteristic j as well.

In sum, the supply functions for new gas reserves in each drilling region "j" supplying the East Coast and Midwest markets in year "t" within the late 1950's can be taken to be:

$$\Delta R_{tj} = f(j, W_{tj}), \text{ where}$$
$$W_{tj} = f(P_{tj}, op_t, j).$$

Turning to the supply of new production, as opposed to new reserves, the proposed model is based on the assumption that the quantity of additional production from new contracts signed in year "t" for gas in district "j" (ΔQ_{tj}) depends upon three factors. First, the quantity of additional production obviously is a function of the volume of newly discovered reserves at the same time and place (ΔR_{tj}). Second, production depends upon the costs of production itself. These costs may be roughly represented by the current rate of interest (i_t), since the interest rate

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[103] *See* p. 944 *supra*.

[104] The effect of these economic factors on new reserve supply arises, of course, because ΔR_{tj} is partly a function of W_{tj}.

may be assumed to be a measure of capital costs for drilling. As these costs increase, the production rate out of new reserves should decrease. Third, the quantity of additional production from new contracts signed each year is a function of short term consumer demand for immediate gas delivery. One of the factors influencing short term consumer demand can be represented by the all fuels retail price index (fp_t). This index will indicate not only whether the price of substitute fuels is rising, thereby making gas more desirable, but perhaps also whether personal consumption of fuel generally is on the rise, increasing the demand for gas as one among a number of alternative fuel sources. In short, additional gas production from new purchase contracts signed each year (ΔQ_{tj}) is taken roughly to be a function of the availability of new reserves (ΔR_{tj}), production costs (i_t), and consumer demand (fp_t), and can be represented by the equation $\Delta Q_{tj} = f(\Delta R_{tj}, i_t, fp_t)$.

2. The Demand Equation. — Demand or "willingness to pay" is represented by the prices bid by pipelines to purchase new gas reserves. These bids are determined primarily by pipeline costs and the pipelines' opportunities for resale. Thus, the proposed model is based on the assumption that average new contract prices for gas reserves of district "j" in year "t" (P_{tj}) depend upon pipeline costs and the demand for gas in final consumer markets.

The price a pipeline is willing to offer for newly discovered gas is in part a function of the pipeline's transport costs. These costs depend both upon the volume of new reserves discovered in a district and the distance between the field and the point of resale to retail distributors. As the volume of new reserve discoveries in a district (ΔR_{tj}) increases, companies will be able to install larger scale gathering lines, thereby reducing unit transport costs. On the other hand, costs will rise as the number of miles between the field and the point of resale to retail distributors (M_j) increases.[105] Thus, the relation between field prices in district "j" in year "t" (P_{tj}) and pipeline transport costs can be expressed by the equation $P_{tj} = f(\Delta R_{tj}, M_j)$.

A more important determinant of the prices pipelines will bid, however, is final consumer demand. As pointed out earlier,[106] the index of all fuel retail prices (fp_t) provides a rough measure of such user demand for gas; the prices which pipelines are willing to pay for producer gas are likely to increase directly with increases in this index. On the other hand, user demand will be limited by the total size of the final user market, and measure-

[105] A diagrammatic exposition of this argument is presented in PRICE FORMATION 37-41.

[106] P. 971 *supra*.

ment of demand can be made more accurate by considering the extent of this market. The size of the market can be initially estimated by the capital stock of all gas-burning furnaces in the country (K_t). Moreover, since there are limits to the level of resales by pipeline companies, the prices which these companies are willing to pay in any year will depend on the sum total of *all* new reserves that year ($\Sigma\Delta R_{tj}$). Thus, as the capital stock of gas burning furnaces (K_t) increases, so will the likely price bid by the pipelines; but as total new reserves offered in any year ($\Sigma\Delta R_{tj}$) increases, the likely price bid will decrease. Therefore, the relation between average new contract prices (P_{tj}) and the demand and size of final markets can be expressed by the equation $P_{tj} = f(fp_t, \Sigma\Delta R_{tj}, K_t)$.

In sum, putting together both the cost and user demand determinants of the prices pipelines are willing to pay, the proposed demand relation (for the same regions and time periods as for the supply functions) is: $P_{tj} = f(\Delta R_{tj}, M_j, fp_t, \Sigma\Delta R_{tj}, K_t)$.

3. Application of the Model to the Field Market for Gas.— The four equations of the proposed model together make up an equilibrium system that describes well the actual prices and supplies of new reserves in the late 1950's. Data from the period 1955–60 were used to fit "least squares" equations[107] to the structural relations explained above for new reserves (ΔR_{tj}), wells sunk (W_{tj}), new production (ΔQ_{tj}), and average contract price (P_{tj}).[108] The closeness with which the fitted equations describe reality is indicated by the accuracy with which equilibrium

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[107] A "least squares" equation is a common statistical method which minimizes the sum of the squared differences between the actual observations and the estimates provided by the fitted equation.

[108] The market-clearing solutions for the endogenous variables ΔR_{tj}, ΔQ_{tj}, W_{tj}, and P_{tj} depend on the outside or "exogenous" variables j, op_t $\Sigma\Delta R_{tj}$, K_t, fp_t, M_j, and i_t. Data series for each of these variables were constructed for the preregulatory period in the eleven drilling regions that provided gas on contracts to pipelines serving the East Coast and Midwest. The data used in the calculations were all obtained from publicly available sources. For the variables ΔR_{tj}, ΔQ_{tj}, W_{tj}, P_{tj}, fp_t, M_j, and i_t, the sources used are summarized in *Regulation Induced Shortage* 197–99. Data for the variables K_t and op_t were obtained from U.S. DEP'T OF COMMERCE, CURRENT BUSINESS STATISTICS, as accumulated over the period 1954–68. For the method of estimating the value of the "dummy" variable j, see note 109 *infra*.

These data were used to fit the supply and demand relations by first stage least squares equations for each of the endogenous variables separately, given the exogenous variables, and then the fitted values $\Delta\hat{R}_{tj}$, $\Delta\hat{Q}_{tj}$, $\hat{W}_{tj}$, and $\hat{P}_{tj}$ from the first stage were used to find the second stage least squares supply and demand equations. The fitted supply and demand equations were therefore four least squares regressions, one for the supply of new reserves, the second for the supply of wells, the third for new production, and the last for the demand for new reserves.

in the four-equation system reproduced the actual volumes of new reserves supplied and prices paid during the period.[109] The difference between the "simulated" (four-equation equilibrium) price and the actual annual average price in any given year was at most 1.6 cents per Mcf and the average difference over the

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[109] The equations for the number of wells sunk and for the supply of new reserves for the 1955–60 period were as follows:

$$W_{ij} = -648.60 + \underset{(1.73)}{11.46}\, \hat{P}_{ij} + \underset{(1.75)}{175.52}\, op_i + \sum_{1}^{10} a_i J_i\,; \qquad R^2 = 0.734$$

$$\Delta R_{ij} = -5.41 + \underset{(0.98)}{2.45}\, \hat{W}_{ij} + \sum_{1}^{10} b_i J_i\,; \qquad R^2 = 0.831$$

The sets of variables $\Sigma a_i j_i$ and $\Sigma b_i j_i$ are district dummy variables taking the value "one" for observations from district j and "zero" otherwise. This method of treatment of the geological differences between districts follows from F. FISHER, SUPPLY COSTS IN THE U.S. PETROLEUM INDUSTRY (1964).

As these equations show, there were positive cumulative effects from well drilling, new gas contract prices, and the crude oil retail price index. The elasticity of reserve supply with respect to new contract gas prices was estimated to be equal to 0.51 at the average 1956 price and level of new reserves, so that a 10% price increase would lead to a general 5.1% increase in discovery of new reserves.

The equation for additional production was as follows:

$$\Delta Q_{ij} = -34.33 + \underset{(2.89)}{0.015}\, \Delta\hat{R}_{ij} - \underset{(-2.27)}{27.49}\, i_t + \underset{(2.75)}{11.37}\, fp_i\,; \qquad R^2 = 0.693$$

This shows a positive production-reserve relation, a negative production-interest relation, and a positive production-fuel price relation. The elasticity of production with respect to reserves was approximately 0.40, and was quasi-statistically significant. The elasticity with respect to interest rates was negative, and with respect to the fuel price index was positive. Both coefficients were quasi-significant and had the expected effect on production: the higher the capital cost (i_t), the lower the production rate; and the higher the price of alternative fuels (fp_t), the higher the gas production rate.

The demand equation was also estimated in the second stage of two stage least squares as follows:

$$P_{ij} = \underset{(8.43)}{12.22} + \underset{(-1.12)}{0.0012}\, \Delta\hat{R}_{ij} - \underset{(-1.95)}{0.00094}\, \Sigma\Delta R_{ij} - 0.0013\, M_j$$
$$+ \underset{(0.99)}{0.088}\, fp_t + \underset{(5.02)}{0.00083}\, K_t\,; \qquad R^2 = 0.616$$

As the equation shows, there were positive coefficients for three variables and negative coefficients for two variables. The elasticity of gas prices with respect to the fuels price index was +0.02, and with respect to the "size" of the resale market (K_t) was +0.05. These values are low, indicating small responsiveness of bid prices to change in the values of these variables. However, the elasticity of demand was substantial; a small change in prices P_{ij} brought forth large changes in total new reserves demanded ($\Sigma\Delta R_{ij}$) so that this elasticity equalled at least —1.6. The other elasticities — for variables ΔR_{ij} and M_j differentiating the drilling regions — were as expected from the economics of pipeline costs and demand.

entire 6-year period was only 0.7 cents per Mcf.[110] Similarly, while the volumes of actual new reserves exceeded simulated new reserves by approximately 3 trillion cubic feet in both 1955 and 1957, the average difference over the 6-year period was less than ½ trillion cubic feet (or less than 0.7 percent of total new additions to actual reserves).[111] The model thus suggests that markets "cleared" — or operated at equilibrium — in the 1950's before producer price regulation.[112]

In order to test whether the gas shortage in the following decade developed from price controls, the model was then applied to the 1960's. The four equations were used, along with 1961–68 figures for the "outside" or exogenous variables,[113] to find the values for ΔR^*_{tj}, ΔQ^*_{tj}, W^*_{tj}, and P^*_{tj} which "solve" the equations — *i.e.*, the values which "clear" the gas market as if there were no price ceilings. These "unregulated" values are compared with the actual values in Table I.

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[110] The results for each of the test years in the late 1950's are as follows:

	Actual Average Price (¢ Mcf)	Simulated Average Price (¢ Mcf)
1955	15.5	16.6
1956	17.0	17.9
1957	18.1	18.4
1958	19.3	18.8
1959	19.1	19.7
1960	18.4	20.0
6-year	17.9	18.6

[111] The actual additions to reserves, and the simulated "unregulated" additions in the 1955–60 period, are as follows:

	Actual Reserves (billions cu. ft.)	Simulated Reserves (billions cu. ft.)
1955	7,354	10,678
1956	14,439	10,935
1957	15,236	12,361
1958	13,604	12,578
1959	11,239	12,381
1960	10,036	12,481
6-year	71,908	71,414

The tendency seems to have been for more new reserves to have actually been provided in the earlier years than simulated by the model. This tendency was reversed in the later years. Anticipation of the approaching price controls — with consequent reductions in supply — could have had much to do with this trend.

[112] Three other equation sets were fitted to the data as well. One set used the pattern of reserve discoveries and drilling the year before the test year as an indicator of geological conditions; thus, lagged values of the dependent variables, *i.e.*, $R_{t-1,j}$ and $W_{t-1,j}$, were used in place of the district "dummy" variable "j." *See* note 109 *supra*. A second set was fitted in the logarithms of all variables, and the third was fitted in the logarithms of the demand variables only. Of the four systems, the one reported in the text and the previous footnotes simulates best the 1955–60 experience in reserves, production, and prices.

[113] *See* note 108 *supra*.

TABLE I

PRICES AND PRODUCTION OF GAS FOR THE EAST COAST AND THE MIDWEST, 1961–1968

Year	Average Price (¢/Mcf)		New Production (billions cu. ft.)		New Reserves (billions cu. ft.)	
	Actual	Simulated	Actual	Simulated	Actual	Simulated
1961	17.7	20.0	292	817	5,567	12,480
1962	19.0	21.1	230	755	5,805	12,858
1963	16.5	22.4	447	688	4,884	13,077
1964	16.7	22.9	200	814	5,512	13,221
1965	17.4	24.1	348	750	6,015	13,621
1966	17.2	25.5	347	627	4,204	14,147
1967	17.4	26.7	575	520	3,693	15,026
1968	18.0	27.8	434	548	951	15,572
8 years	17.5	23.8	2,873	5,519	36,631	110,002

The simulated or "unregulated" prices that would have cleared the reserve market were on the average 6 cents per Mcf higher than ceiling prices for the entire period, and more than 7 cents higher for the period following 1962, when the full effect of price ceilings seems to have taken hold in the test region. On the supply side, the higher prices — if they had been allowed — would have provided considerable incentive to add to the volume of new reserves. The level of simulated new reserves is more than three times the level of actual new reserves over both periods. Another indication of the impact of clearing prices on supply appears in the difference between actual and simulated new production. Actual new production is approximately one-half of simulated new production over the 8-year period. Given that higher unregulated prices would have brought forth a much higher level of new reserves, this higher level of simulated new production is not surprising. On the demand side, the higher simulated (market-clearing) price would have significantly reduced the amount of reserves sought. To be sure, the amounts which would actually have been demanded at various prices are not known, since only the new reserves both demanded *and* supplied are shown by the annual simulations. But that excess reserve demand would have been reduced is indicated by the fact that the total demand for new reserves proved to be elastic with respect to price.[114] Total new reserve demand was reduced by approximately 10 trillion cubic feet for each cent of price increase.[115]

[114] *See* note 109 *supra*.

[115] It is interesting to use the data in Table I to try to compare roughly the

As it was, a serious reserve shortage developed in the 1960's, which at that time revealed itself in the pipelines' reduction of their new-reserve-to-new-production ratio. This reduction in the security of service, shared by all those connected to interstate pipelines, was translated in the early 1970's into a more tangible actual production shortage; pipelines had to curtail deliveries in 1971 and 1972 because they could not take gas from their reserves fast enough to meet their contract commitments. This production shortage has been plainly visible. It followed directly from the earlier reserve shortage which in turn was a creature of FPC regulatory policy.

B. The Impact of the Shortage

At the same time that field price regulation has meant lower gas prices, it has also brought about a reserve — and now a production — shortage. Determining who has been helped and who

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extent of reserve backing for actual and simulated new production in the test region. Taking the 8-year period as a whole, simulated additional production is 5% of simulated new reserves, and during the period 1963–68, it is 5.2% of new reserves. This would seem to indicate approximately between 19 and 20 years reserve backing for new production under "unregulated" conditions. *See* pp. 966–67 *supra*.

However, this calculation really overstates the extent of reserve backing supplied to guarantee new production, because the production figures provided by the model are for *additional* production only — *i.e.*, the quantity of production in excess of production the previous year. The figures do not include the extent of new production in the test years which would have been supplied under "unregulated" conditions to *replace* production contracts expiring in those years. It has been previously estimated that such replacement demand equals 1/14 of *total* production in any one year, based upon the depletion rate of new reserves in 1947. *See Regulation-Induced Shortage* 173–74 & n. 15. Figures for total production in the test region under "unregulated" conditions are not provided by the model, and therefore replacement production cannot be calculated from the data in Table I. To be sure, inclusion of replacement production would reduce the reserve-to-production ratio below the level of 20 years reserve backing for new production. But, since the model predicts conditions which would "clear" the "unregulated" market, the higher simulated prices would have reduced demand for new reserve backing down to the level of that supplied. And, given higher prices, replacement production is unlikely to be so high as to take reserve backing under "unregulated" conditions outside the range of 14.5 to 20 years considered "optimal" to guarantee future service. *See* pp. 966–67 *supra*.

The *actual* reserve backup provided for new production in the test years was far lower. For the 8-year period as a whole, actual *additional* production was backed up by 12.8 years of reserves, and during the period 1963–68, reserve backup was only 10.7 years. Because of the necessity eventually to reduce the rate of production out of a reserve as a result of falling pressures, *see* note 96 *supra*, this means that reserves supplied during the latter period would support only about 6.4 years of production at the initial rate. And, of course, if the new-reserve-to-new-production ratio were decreased to reflect new *replacement* production, this figure would be even lower.

has been hurt by this FPC regulatory policy is necessary in order to assess whether the lower prices were "worth" the shortage. Information is not yet available to allow a definitive finding on this issue. Nevertheless, there is enough evidence inferentially to support the view that the result of FPC policy in the 1960's was to deplete the gas reserves of interstate home consumers in favor of the demands of intrastate industrial customers to whom sales were unregulated.

First, the regulated pipelines — those selling interstate for resale to distributors for most home customers — did not obtain their proportionate share of new gas reserves in the late 1960's. In 1965 these lines possessed more than 70 percent of the nation's reserves. But between 1965 and 1971, the interstate pipelines obtained less than half the volume of the new reserves developed, and the overall percentage of reserves possessed by them fell to 67 percent.[116]

Second, as Table II shows, what variation there was in the division of total annual gas production between residential and industrial users indicates that over the course of the 1960's proportionately more went to industrial users. The percentage of gas sold by pipelines and distributors to residential users declined 1.6 percentage points between 1962 and 1968.[117] This decline was caused in large measure by a substantial increase in industrial sales by unregulated intrastate pipelines and by producers themselves. Between 1962 and 1968, total industrial consumption of natural gas increased 43.5 percent, while intrastate pipelines and distributors increased their industrial sales by almost 62 percent.[118] Moreover, of the increase in industrial consumption, more than half can be attributed to sales by intrastate pipelines and distributors, while less than 13 percent is accounted for by direct industrial sales of the interstate pipelines. The remaining 37 percent of the increase was the result of direct sales by the producers.

[116] *Hearings on Natural Gas Policy Issues Before the Senate Comm. on Interior & Insular Affairs*, 92d Cong., 2d Sess., pt. 1, at 192, 268, 270 (1972) (Statement of FPC Chairman Nassikas).

[117] *See* P. BALESTRA, THE DEMAND FOR NATURAL GAS IN THE UNITED STATES: A DYNAMIC APPROACH FOR THE PRESIDENTIAL AND COMMERCIAL MARKET (1967). Balestra describes the period referred to in text as that in which gas sales were "reallocated" between classes of customers. He describes 1950–57 as an "innovating" period in which pipelines were built and service begun and 1957–62 as a "maturing" period in which more gas was sold to the same customers.

[118] The substantial increase in the category "Distributors and Intrastate Pipelines" came primarily from sales by unregulated transmission companies. This is demonstrated by data gathered by the authors which show that sales by regulated pipelines to distributors for resale to industry increased at a rate only slightly greater than the rate of increase for "Total U.S. Industrial Consumption." By

TABLE II
NATURAL GAS SALES TO ULTIMATE USERS [a]

Class of Service or Seller	1962 Quantity (mil. Mcf) [b]	1962 Percent of Total	1968 Quantity (mil. Mcf) [b]	1968 Percent of Total	Percent Increase
SALES BY ALL PIPELINES AND DISTRIBUTORS					
Residential and Commercial	4,320	44.5	5,966	42.9	+38.2
Industrial and Other	5,396	55.5	7,925	57.1	+46.9
Total	9,716	100.0	13,891	100.0	+43.0
SALES TO INDUSTRIAL AND OTHER NONRESIDENTIAL CONSUMERS					
Direct Sales by Interstate Pipelines [c]	2,129	23.2	2,641	20.0	+24.0
Intrastate Pipelines and Distributors (est.) [d]	3,267	35.5	5,284	40.0	+61.7
Producers [e]	3,809	41.3	5,284	40.0	+38.7
Total U.S. Industrial Consumption	9,205	100.0	13,209	100.0	+43.5

[a] Much of the data in the table is derived from AMERICAN GAS ASSOCIATION, GAS FACTS 1971, at 82, 119 (1972).

[b] This figure was converted from million therms to million Mcf based on 1,031 BTU's per cubic foot of natural gas.

[c] *See* FEDERAL POWER COMMISSION, STATISTICS OF INTERSTATE NATURAL GAS PIPELINE COMPANIES 1962, at XXII (1963); FEDERAL POWER COMMISSION, STATISTICS OF INTERSTATE NATURAL GAS PIPELINE COMPANIES, 1968, at XV (1969).

[d] These figures are derived by subtracting "Direct Sales by Interstate Pipelines" from the figures for "Industrial and Other" sales by all pipelines and distributors.

[e] These figures are derived by subtracting "Direct Sales by Industrial and Other" sales by all pipelines and distributors from the figures for "Total U.S. Industrial Consumption."

Third, that the reserve shortage hit most seriously the residential buyer supplied by a regulated pipeline becomes still more evident when certain particular gas regions are examined. The Permian Basin in West Texas, for example, accounted for about 2.5 percent of total U.S. gas reserves in the early 1960's. In the late 1960's, additional discoveries raised this figure to about 10.5 percent.[119] Six large interstate pipelines, two intrastate pipelines, and many direct industrial buyers bid for the new reserves.[120] From 1966 onwards, the intrastate lines and the direct industrial buyers obtained almost all of the uncommitted volumes available. In fact, interstate pipelines, which accounted for 80 percent of production from the new reserves in this area in 1966, accounted for only 9 percent in the first half of 1970.[121] The reason for the interstate pipelines' decline in reserve holdings is not difficult to find. Prices offered by intrastate buyers for the new gas in this area rose from 17 cents per Mcf in 1966 to 20.3 cents per Mcf in 1970, and toward the end of 1970, the intrastate pipelines bought more than 200 billion cubic feet of reserves at initial delivery prices of 26.5 cents per Mcf.[122] At the same time, prices paid by interstate pipelines could not exceed the regulatory ceiling and therefore remained between 16 and 17 cents per Mcf. The inescapable conclusion is that the interstate pipelines were simply outbid.

In sum, as a result of regulation in the 1960's buyers for interstate consumption obtained fewer reserves than they wished. For the most part, those buyers were pipelines ultimately serving primarily residential consumers. The short reserve supplies were bid away from these buyers by intrastate gas users. This was a predictable result of FPC two-tier regulation of field gas markets in light of the Commission's jurisdictional limitations.

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compiling the interstate pipelines' Form 2 Reports to the FPC, state totals for all pipeline sales were obtained. The percentage of sales to industry in each state was obtained from BUREAU OF MINES, ANNUAL REPORTS ON GAS CONSUMPTION and applied to those state totals to produce the figures, by state, for pipeline sales to distributors for industry. These sales increased by 50% from 1962 to 1968, significantly below the 62% increase registered for total industrial sales by "Intrastate Pipelines and Distributors" given in Table II.

[119] *See* AMERICAN PETROLEUM INSTITUTE, AMERICAN GAS ASSOCIATION, PROVED RESERVES OF OIL AND NATURAL GAS IN THE U.S. (Annual Volumes 1965-70).

[120] PRICE FORMATION ch. 5.

[121] *Hearings, supra* note 116, at 295, 298 (testimony of J. C. Swidler, Chairman, N.Y. Public Service Commission).

[122] Reply Submittal of the Office of Economics, Federal Power Commission, Initial Rates for Future Sales of Natural Gas for All Areas, Docket No. R-389A, at 12, 19 (Oct., 1970).

IV. The Costs of Regulation

Showing that ceiling prices created a substantial gas shortage and that this shortage was disproportionately borne by residential gas consumers is not enough by itself to condemn FPC regulatory policy. At the same time that FPC regulation of field markets created a shortage, it also reduced prices 6 cents per Mcf below what we have simulated market-clearing prices to be during the 1960's. To calculate the gains to consumers who actually received gas as a result of this regulatory policy, one might simply multiply average annual production of regulated gas from, say, 1962–68 (about 11 trillion cubic feet),[123] by 6 cents per Mcf and claim that regulation saved those consumers who received gas about $660 million annually. Of course, such a calculation contains heroic assumptions and oversimplifications. For one thing, it assumes that every cent of price reduction at the wellhead was passed through to ultimate consumers; in light of the fact that sales by retail distributors are intrastate and therefore subject only to state regulation, the assumption may not be valid.[124] For another thing, had producers received a higher price, at least some of their additional revenues would have been taxed away and, therefore, indirectly returned to consumers anyway. Nonetheless, even assuming that the entire 6 cents per Mcf was returned to consumers who actually received gas, we still doubt that this benefit outweighed the losses arising from regulation, even from the point of view of the consumer class itself.

In order to calculate the costs of wellhead price regulation to gas users, it must first be established that the behavior of pipelines in the field market is representative of consumers' interests. Table I [125] showed that the additional 6 cents per Mcf which pipelines would have paid for gas produced under unregulated conditions would have purchased a joint product: *both* additional production *and* additional reserves. These hypothesized purchases of additional supply by pipeline companies likely represent what the pipelines conceived to be final consumer demands for additional current deliveries and for additional insurance of future deliveries. Obviously, pipelines would not overstate demands for current production, since they clearly have no interest in purchasing gas which they cannot resell. Similarly, it is difficult to see why pipelines would deliberately overstate demand for reserves, given that the costs of dedicated

[123] *Hearings, supra* note 116, at 163, 192, 270 (Statement of FPC Chairman Nassikas).

[124] *Cf.* Hawkins 212.

[125] *See* p. 975 *supra*.

reserves are not included in their rate base and demanding excessive reserves would increase contract prices and therefore ultimately reduce sales to consumers.[126]

If this assumption of the representative quality of the pipelines' field market demands is correct, then the cash returned to gas users by virtue of FPC regulation was probably less than the cash consumers were willing to give up for additional deliveries and reserve backing. First, the gains to those paying lower prices for gas they actually received must be offset by the losses to others who had to do without gas and find other sources of energy. Residential and commercial users unable to receive gas because distributors lacked supply — usually those consumers in new or growing population centers — were forced to use less desirable, or more expensive, fuels such as oil or electricity. The cost, in real terms, to these consumers of using such alternative energy sources can be roughly measured by the amount which they were willing to pay for additional gas. Therefore, the loss they suffered from regulation is the difference between what they *were willing to pay* for gas rather than go without it and *what they would have actually paid* under equilibrium conditions for the market-clearing level of gas deliveries. If this difference or "premium" which consumers suffering the shortage were willing to pay was on *average* 6 cents per Mcf, then the losses of those doing without gas were as great as the gains of others receiving gas at 6 cents per Mcf below market-clearing prices; this is so because the hypothesized *shortage* of new production (the difference between simulated and actual production out of new reserves in Table I) was approximately as large as *actual* new production.[127] In fact, it appears from the supply and demand model

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[126] *See* p. 948 *supra*.

[127] The discussion in text describes in layman's terms what the economist calls "consumers' surplus." Consumers' surplus is defined as the excess over the price paid which consumers are willing to pay for a given amount of a product rather than do without it. *See, e.g.*, G. STIGLER, THE THEORY OF PRICE 78 (3d ed. 1966). When a market is at equilibrium, the market-clearing price equals what consumers are willing to pay for the last or marginal unit of output. Since consumers would normally be willing to pay more for intramarginal units of output, the equilibrium price affords them a savings or "surplus" on these intramarginal units. This savings which gas consumers suffering the shortage would have had under unregulated conditions is a measure of the cost to them of the FPC policy. It can be represented diagrammatically as follows on p. 982, note 127 *infra*.

At the level of production supplied under price ceilings (Q_{fpc}), consumers, as represented by the pipelines, were willing to pay a price for gas not only above the FPC ceiling (P_{fpc}), but considerably above the market-clearing price (P_{market}) as well. Moreover, for each unit of additional production up to market-clearing levels (Q_{market}), consumers were willing to pay more than the market-clearing price. Thus, the area of the triangle ABF is equal to the difference between what that consumers suffering that shortage would by 1967 or 1968 have been willing to pay an average premium of 6 cents per Mcf rather than do without gas entirely.[128] Therefore, the losses from the shortage (equal to what consumers in the aggregate were willing to pay to recover lost gas production) simply made too many consumers worse off to allow the conclusion to be drawn that reduction in prices was worth the shortage it created.[129]

Second, the argument that consumers who actually received

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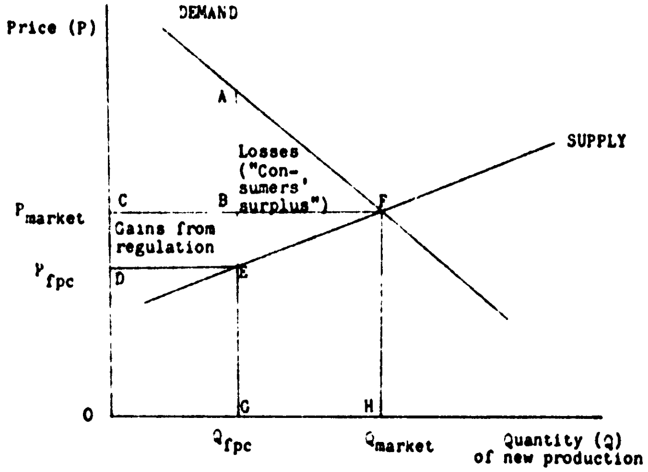
consumers doing without gas were willing to pay for additional production ($Q_{market} - Q_{fpc}$) and what they would have actually had to pay for it under market-clearing conditions (equivalent to the rectangle BFHG). This surplus which consumers who actually did without gas would have obtained under hypothesized market-clearing conditions represents the losses to them from FPC price ceilings.

These losses to consumers doing without gas can be compared to the gains by consumers who obtained new gas production. These gains are represented by the area of the rectangle CBED. This area is the difference between the market-clearing and FPC price ($P_{market} - P_{fpc}$) multiplied by the quantity of new gas production they received (Q_{fpc}). Thus, if the area of triangle ABF is at least equal to the area of rectangle CBED, then the gains to those who received gas were offset by the losses by those who had to do without.



[128] In other words, in the diagram given in the previous footnote, the length of line AB was, in fact, at least twice the length of line BE by the last years of the test period. Since the shortage of new production by 1967-68 exceeded the actual supply of new production, line BF was greater than line CB.. Thus, the area of the triangle ABF was at least equal to the area of the rectangle CBED.

[129] Of course, this is somewhat of an overstatement, since the model shows consumer losses being at least equal to consumer gains only with regard to *additional* production during the test years. In reality, the 6 cents per Mcf reduction in price brought about by FPC ceilings was a gain realized by consumers on other gas as well — *i.e.*, the amount produced under old contracts which would have sold for higher prices when "favored nation" clauses were triggered. *See* p. 946 *supra*. This amount is unknown.

gas obtained a 6 cents per Mcf saving as a result of FPC regulation is itself fallacious, because these consumers were, in fact, purchasing *less* — an inferior product — than they would have under unregulated conditions. As we have shown, the price which consumers pay for deliveries, when translated into the price pipelines pay for production at the wellhead, purchases not only current production, but also a reserve backing which provides a certain level of insurance of future deliveries. Since FPC price ceilings brought forth only a third of the new reserves which would have been developed under market-clearing conditions, those consumers who received gas at lower prices *gave up* a substantial amount of their guarantee of future service. To be sure, this loss was not observable by these consumers, since it took the form only of reduced backing for production which they were currently receiving. Nevertheless, it is likely that these reserves were worth a considerable amount to them. The man who makes a large investment in gas appliances, for example, obviously wants an assurance that he will not have to switch to oil or electricity for many years, if at all. Reserves promise him this and also provide him with security from possible temporary interruptions of service. On conservative assumptions, these buyers, as represented by the pipelines, wanted at least 14.5 years of reserve backup to provide them with a sufficient production guarantee.[130] Under unregulated conditions, this insurance would have been obtained by them; under FPC price ceilings, it was not.[131] The 6 additional cents per Mcf which consumers receiving gas would have had to pay in an unregulated market was, from the perspective of their interests, at least in part a premium for insurance which FPC price ceilings did not provide. For every 6 cents in cash which FPC regulation saved these consumers on actual deliveries, it took away reserves which they might well have desired at least as much as the money. In short, the extent to which FPC regulation actually helped even those receiving gas at lower prices is problematical; it simply gave them a short term windfall at the cost of long term insecurity.

These losses to both those who did not obtain gas and those who did, moreover, are not all the costs of the FPC's regulatory policy. For example, further costs probably resulted from the displacement of industry. Some industrial firms for whom energy costs were a large part of total costs moved to the producing states solely to obtain natural gas not available on the interstate market due to FPC price ceilings. Moreover, further distortion arose from competitors' paying different prices for their fuel sources, either because one had an intrastate gas supplier, or because of FPC

[130] *See* p. 967 *supra*.

[131] *See* note 115 *supra*.

policies for rationing the cheaper "old" gas. And the economic and administrative costs of litigation and delay from the price proceedings themselves have been substantial as well.[132]

Despite these strong indications of the failure of FPC regulation of field gas prices, some consumers' groups have argued that the Commission should deal with the problems that have arisen from its present regulatory efforts by introducing still more regulation. The Commission might, for example, seek to expand its jurisdiction over intrastate sales to end the "leakage of supply" to intrastate industrial users and then establish "end use" controls, specifically allocating gas to particular individuals or classes of customers.[133] Such an approach, however, would not solve the problems raised here. Not only would it fail to reduce the aggregate shortage of gas, but it would require the Commission to determine on a larger scale than it now does which end uses of gas are "superior" and which "inferior." Such a task is difficult, to say the least, and there is little reason to believe that a Commission that was unable to set area prices in the field without creating massive shortages would find a "proper" solution to the still more complex problem of rationing on a grand scale. Once prices were abandoned as a measure of value, the number of claimants for special preferences, citing a variety of economic and social imperatives, would become large indeed. In all probability, the Commission would have to continue its past practices and simply arrange for a series of compromises among these various claimants. Such compromises would inevitably lead to continued excess demand for gas and to shortages in which, if the future resembles the past, those intended to benefit from gas regulation would still be injured.

Neither would it be completely satisfactory for the Commission to follow a partial policy of income redistribution by trying to squeeze rents only from old gas- and oil-well gas production while leaving new gas-well gas production unregulated.[134] To be sure, there would be little danger of shortage if the Commission set ceiling prices only on the production of gas *now* classified as "old," since there is *ex hypothesi* a fixed supply of these hydrocarbons. But such regulation would accomplish merely a temporary, minimal transfer of rents, because the supply of this "old" gas will run out in the next few years. In order to accomplish this temporary income transfer, the Commission would

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[132] *See, e.g.*, Gerwig, *Natural Gas Production: A Study of Costs of Regulation*, 5 J. LAW & ECON. 69 (1962).

[133] *See Hearings, supra* note 116, at 302 (testimony of J. C. Swidler).

[134] President Nixon's recent proposal, *see* p. 942 *supra*, seems to contemplate adoption of this alternative.

still have to solve the problems of determining the costs of producing old gas and of rationing the cheaper supplies. The administrative burden of solving these problems might not be worth the income redistribution which such a policy would bring about. On the other hand, if the Commission embarked upon a *permanent* policy of regulating "old" gas prices by continuously reclassifying further supplies as "old," it would not only have to develop a dynamic standard to separate "old" from "new" gas, but it would also be confronted with all the problems of the present regulatory system. Producers seeing that the prices of their new supplies would *eventually* be subject to ceilings would be likely to take these future price regulations into account. Therefore, while the prices of new reserves would not be directly regulated, further exploration and development would still be discouraged, and thus a shortage would still arise.

The alternative that we favor is eliminating field price regulation designed to transfer producer rents. If income is to be redistributed, rents can be transferred from producers to consumers without regulation. For example, tax policy can be used to accomplish the same objectives. Indeed, much of the alleged justification for the depletion allowance [135] in this area — the need to encourage exploration and development — would seemingly vanish if producer prices were set competitively. In contrast to the tax system, area price ceilings cannot help but be an indiscriminate method of income redistribution. While it takes *some* income from those producers realizing excess profits, its impact falls most heavily on those producers without excess profits — those right at the margin, perhaps forcing them out of the market entirely. In contrast, redistribution through taxation aims more directly at those producers with excessive incomes. While we are aware that redistribution through tax policy has many problems of its own, we doubt that they could be as serious as those that have accompanied the effort to control field prices. In short, it is difficult to see the virtue of a price control system, particularly when, as was proven during the 1960's, it is likely that those consumers the system is designed to benefit will not be benefited at all. With the example of producer price regulation in mind, one might well question the advisability of using microeconomic methods — such as regulation of the firm — solely to accomplish macroeconomic objectives — such as income redistribution.

To be sure, elimination of regulation intended to redistribute income would effectively mean deregulation of much of the field market for natural gas, since the market structure of most, if not all, producing regions is decentralized and competitive. De-

[135] INT. REV. CODE of 1954, §§ 611–14.

regulation of this sort, however, would not deprive the Commission of all power over producer rates in those regions where producers do possess monopoly power. At the same time that the Commission would allow prices in competitive regions to approach market-clearing levels, it could selectively regulate prices in those few producer regions where market power turns out to be present by using the prices in the competitive areas as benchmarks.

Of course, one potential obstacle to this proposed regulatory policy is that a court might hold that for the Commission to allow market forces to determine producer prices would be inconsistent with the mandate of the Natural Gas Act to regulate "sale[s] in interstate commerce of natural gas . . . ." [136] To be sure, in the *CATCO* case,[137] the Court held that the Commission could not license a producer to sell gas without conditioning the license on the producer's promise to charge a reasonable price. But the Court's decision in that case was predicated on the inadequacy of the Commission's findings respecting the need to issue an unconditional license, and on the harms to consumers which would attend the inordinate delay before the Commission on its own could determine a just and reasonable rate. Certainly, the case cannot be taken as precedent for disturbing Commission judgment that market forces can ordinarily be relied upon to set just and reasonable rates and that any attempt to interfere with market forces to transfer rents would do the consumer more harm than good. A decision to "deregulate" producer prices as proposed would be a determination that selective rather than pervasive interference with field market transactions was the most appropriate way to regulate this portion of the natural gas industry. Such a determination would seemingly comply with the fundamental purposes of the Natural Gas Act, and, being based upon 15 years of experience with different methods of regulation, it would almost certainly be supported by substantial evidence.[138] Nothing in the *Phillips Petroleum* decision [139] *requires* the FPC to set prices; the decision simply gives the Commission jurisdiction to do so. As the U.S. Court of Appeals for the Fifth Circuit has recently stated: [140]

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[136] 15 U.S.C. § 717(b) (1970); *see* note 5 *supra*.

[137] Atlantic Refining Co. v. Public Service Comm'n of New York, 360 U.S. 378 (1954).

[138] Courts will normally review administrative decisions to see if they are in compliance with law and are supported by substantial evidence on the whole record. *See* Universal Camera Corp. v. NLRB, 340 U.S. 474 (1951).

[139] *See* p. 941 and note 5 *supra*.

[140] Southern Louisiana Area Rate Cases, 428 F.2d 407, 416 n.9 (5th Cir.), *cert. denied*, 400 U.S. 950 (1970). *See also* Permian Basin Area Rate Cases, 390 U.S.

> [T]he decisions of the Supreme Court definitely indicate the Commission has a responsibility to take the steps necessary to assure that wellhead prices are in the public interest. The Commission does not have to employ the area rate method or for that matter regulate prices directly at all, but it has chosen to fulfill its duty in that manner here.

In sum, the arguments against the present system of gas field market regulation are compelling. Price control is not needed to check monopoly power, and efforts to control rents require impossible calculations of producer costs and lead to arbitrary allocation of cheap gas supplies. In practice, regulation has led to a virtually inevitable gas shortage. It has brought about a variety of economically wasteful results, and it has ended up by hurting those whom it was designed to benefit. Thus, less, not more, regulation is required.

747, 766–67 (1968) (one who would overturn FPC finding of fact bears heavy burden of proof); Wisconsin v. FPC, 373 U.S. 294, 309 (1963) ("[I]t has repeatedly been stated that no single method need be followed by the Commission in considering the justness and reasonableness of rates"); FPC v. Hope Natural Gas Co., 320 U.S. 591, 602 (1944) ("Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling.")

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Appendix E

Federal Energy Research and Development Funding

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Executive Office of the President, Office of Science and Technology

FEDERAL ENERGY R&D FUNDING*

The Federal Government each year spends significant sums on research and development aimed at improving the methods for locating, producing, converting and transporting both the primary energy sources—petroleum, gas, coal, uranium and water power—and the secondary energy source—electricity. Research is also underway to develop new advanced sources such as oil shale, fusion energy geothermal steam, and solar energy. The government also supports research on energy in high demand fields such as transportation, housing, etc.

During the past several years, there has been major new emphasis and significant funding increases in energy R&D. A major source of this emphasis has been concern over how the nation is to meet its growing demands for energy without degrading the environment.

Five-Year Survey of Federal Energy R&D

Federal energy R&D funding for the past five years has been assessed by staff members of the Office of Science and Technology, and their results are presented by major categories in Tables I and II. In summary, however, energy R&D funding increased over 72%, or $261 million, from FY 1969 to FY 1973. This represents a compounded growth rate of more than 11%. The increase is due in part to expansion of several key efforts including the fast breeder nuclear reactor, coal gasification, sulfur oxide removal from fossil fuel stack gases and controlled thermonuclear fusion.

Although the funding increase is probably the survey's most striking feature, another is an obvious trend toward a Federal R&D program which balances the energy resources of the nation and the engineering R&D required to utilize those resources most effectively. For example, coal resource R&D funding has been growing at a much faster rate than nuclear power funding, 305% compared to 29% over the five-year period. Significant increases in funding for stack gas cleanup

*This memorandum does not reflect increased Federal energy research and development funding announced by President Nixon in November, 1973. See Table 7, page 27.

technology and coal gasification are aimed at making the nations abundant coal resources available for both electric generation and industry. Where nuclear fission accounted for 77% of the FY 1969 energy R&D budget, it now accounts for only 58%. In the meantime, funding for the liquid metal fast breeder reactor has grown by 97% thus reflecting its changing status as a national priority program. Controlled thermonuclear fusion, geothermal steam, and solar energy have also received considerably more attention as funding patterns evolved.

The FY 1973 Federal Energy R&D Budget

In his Energy Message to Congress on June 4, 1971, the President announced a broad range of actions including a forward-looking agenda for research to ensure adequate future supplies of clean energy. To meet the challenge spelled out in the Energy Message, Federal agencies have vigorously expanded their efforts in critical areas and the overall energy R&D budget for fiscal 1973 was increased by $96.9 million or about 18.4%.

The major increases were aimed primarily at developing adequate supplies of clean electrical energy while simultaneously enhancing the quality of national life through long and short term R&D. Coal gasification and liquefaction, magnetohydrodynamics, the liquid metal fast breeder, controlled thermonuclear fusion, cryogenic generation and transmission, geothermal steam and solar energy account for 74%, or $72.0 million, of the increase.

R&D programs are underway to provide new technological options for resolving conflicts between energy needs and environmental protection. For instance, to help meet stricter air and water quality standards related to energy use, FY 1973 funding will be expanded $21.5 million or 22.5%.

The FY 1973 funding pattern clearly reflects the objective of achieving a more strategic approach to our national R&D investment. A stronger R&D partnership between government and industry is a crucial component of this approach. The Atomic Energy Commission and the electric utilities are building a demonstration fast breeder reactor and the Department of Interior and the American Gas Association are working on coal gasification, both efforts excellent examples of such partnerships.

The utilization of the outstanding capabilities of the high technology agencies to deal with domestic problems such as energy needs is another key component. Examples include the Atomic Energy Commission's work on high energy density storage batteries, dry cooling towers, and underground transmission lines and the National Bureau of Standard's research on cryogenic generation.

Industrial Energy R&D

In addition to the electric utility industry's major cooperative commitments to the demonstration breeder reactor, it is also planning a vast exapnsion of the Electric Research Council's voluntary, private sector R&D activities as described in a recent report entitled "Electric Utilities Industry R&D Goals Through the Year 2000." Private research and development efforts in the petroleum industry are less well documented due to the tradition of properietary research and development. Historically, however, the petrolum industry has spent considerably more on research and development than the other sectors of the energy industry combined.

Highlights of Major Energy R&D for FY 1973—Nuclear Fission R&D

The largest single high priority item in the energy R&D budget is for the development of the liquid metal fast breeder reactor (LMFBR) by the Atomic Energy Commission and industry. The anticipated Federal funding for FY 1973 is approximately $260 million. The LMFBR will expand, by a factor of 30 to 40, the energy obtainable from natural uranium thus assuring abundant supply of low-cost electrical energy for centuries. A demonstration of LMFBR plant by 1980 is a mid-term goal. The long-term objective is to develop a broad technological and engineering base with extensive utility and industrial involvement. This will lead to an economic breeder design and the establishment of a strong commercial breeder industry in the mid-1980's.

The first demonstration plant, a joint Government/industry undertaking, is expected to be built by the TVA and Commonwealth Edison of Chicago using funds from all segments of the electric utility industry and the Government. The Fast Flux Test Facility in Hanford, Washington, and other engineering test and development facilities are included in the AEC budget. The AEC fission power program is not limited to the LMFBR. Other efforts are aimed at other breeders—the fast, gas-cooled reactor, the molten-salt breeder and the light water breeder. The first two are technology development efforts with modest funding. The light water breeder effort is aimed at an early demonstration of a prototype core for the Shippingport plant in Pennsylvania.

The AEC budget also includes a R&D program on the safety of current light water reactors. This program has been significantly expanded during the past two years to assure continuance of the excellent safety record of civilian nuclear power.

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TABLE 1.—*Federal energy R. & D. funding, fiscal years 1969 through 1973* [1]

[In millions of dollars]

	Fiscal year—					1-year increase (percent)	5-year increase (percent)
	1969	1970	1971	1972	1973		
Coal resources development	$23.3	$30.4	$49.0	$76.8	$94.4	22.9	305.0
Petroleum and natural gas	13.5	14.8	17.5	23.8	26.1	9.7	93.3
Nuclear fission:							
LMFBR [2]	132.5	144.3	167.9	237.4	261.5	10.2	97.4
Other civilian nuclear power [2]	144.6	109.1	97.7	90.7	94.8	4.5	−34.4
Nuclear fusion:							
Magnetic confinement [2]	29.7	34.3	32.3	33.2	40.3	21.3	35.6
Laser-pellet [2] [3]	2.1	3.2	9.3	14.0	25.1	79.2	1,095.2
Energy conversion with less environmental impact	12.3	22.9	22.8	33.4	55.3	66.0	350.0
General energy R. & D.	3.0	4.2	8.7	15.4	24.1	66.2	753.3
Total	361.0	363.2	405.2	524.7	621.6	[4] 18.4	[4] 72.2

[1] The funding listed in these tables cover the Federal R. & D. programs in development-exploration and production, conversion, and transmission of our energy resources. This funding includes energy conversion R. & D. for stationary applications only; R. & D. funding for improved mobile applications (e.g., automotive, rail, seagoing) are not included. Fundamental research on environmental health effects of combustion products and low-dose radiation exposure) is not included.

[2] This funding includes operating, equipment, and construction costs.

[3] The primary applications of the multipurpose laser-pellet effort are for other than energy production (see text).

[4] Average.

NOTE.—The totals in tables I and II differ from the earlier total reported at the time the fiscal year 1973 budget was released (p. 57, *the Budget of the United States Government for Fiscal Year 1973*). The data presented in tables I and II include additional budget components, viz., coal mine health and safety research is included in the Bureau of Mines budget and capital and equipment as well as operations are included in the Atomic Energy Commission budget.

TABLE II.—*Federal energy R. & D. funding,*[1] *fiscal year 1969 through fiscal year 1973*

[In millions of dollars]

	Agency	Fiscal year— 1969	1970	1971	1972	1973
Coal resources development:						
Production and utilization R. & D., includes gasification, liquifaction and MHD.	DOI–BOM	$12.3	$13.2	$15.4	$14.7	$19.0
	DOI–OCR	8.7	13.5	18.8	31.1	45.3
Mining health and safety research	DOI–BOM	2.3	3.7	14.8	31.0	30.1
Petroleum and natural gas:						
Petroleum extraction technology	DOI–BOM	2.6	2.7	2.7	3.2	3.1
Nuclear gas stimulation [2]	AEC	2.4	3.7	6.1	7.0	7.5
Oil shale	DOI–BOM	2.5	2.4	2.7	2.6	2.5
Continental shelf mapping	DOI–GS				5.0	7.0
	DOC	6.0	6.0	6.0	6.0	6.0
Nuclear fission:						
LMFBR [2]	AEC	132.5	144.3	167.9	236.6	259.9
	TVA				.8	1.6
Other civilian nuclear power [2]	AEC	144.6	109.1	97.7	90.7	94.8
Nuclear fusion:						
Magnetic confinement [2]	AEC	29.7	34.3	32.3	33.2	40.3
Laser-Pellet [2] [3]	AEC	2.1	3.2	9.3	14.0	25.1
Energy conversion with less environmental impact:						
Cleaner fuels R. & D.-stationary sources	EPA	10.7	19.8	17.4	24.5	29.5
SO_x removal	TVA				2.6	15.2
Improved energy systems	HUD	.3	.8	3.0	2.4	2.8
Thermal effects R. & D	EPA	.5	.8	.6	.7	1.0
	AEC	.8	1.5	1.8	3.2	[4] 6.8

Footnotes at end of table.

TABLE II.—*Federal energy R. & D. funding,[1] fiscal year 1969 through fiscal year 1973*—Continued

[In millions of dollars]

	Agency	Fiscal year— 1969	1970	1971	1972	1973
General energy R. & D.:						
Energy resources research [5]	NSF	--------	1.1	5.0	9.8	13.4
Geothermal resources	DOI	.1	.2	.2	.7	2.5
Engineering energetics research	NSF	2.9	2.9	2.7	4.0	4.7
Underground transmission	DOI	--------	--------	.8	.9	1.0
Cryogenic generation	NBS	--------	--------	--------	--------	1.0
Non-nuclear energy R. & D.	AEC	--------	--------	--------	--------	1.5
Total		361.0	363.2	405.2	524.7	621.6

[1] The funding listed in these tables cover the Federal R. & D. programs in development-exploration and production, conversion, and transmission of our energy resources. This funding includes energy conversion R. & D. for stationary applications only; R. & D. funding for improved mobile applications (e.g., automotive, rail, seagoing) are not included. Fundamental research on environmental health effects of combustion products and low-dose radiation exposure) is not included.

[2] This funding includes operating, equipment, and construction costs.

[3] The primary applications of the multipurpose laser-pellet effort are for other than energy production (see text).

[4] This entry includes $1,500,000 for dry cooling tower R. & D. under the AEC's new non-nuclear energy R. & D. category. Other related work is carried out under other civilian nuclear power.

[5] The NSF RANN program includes research on solar energy as well as fundamental energy policy studies.

Note: The totals in tables I and II differ from the earlier total reported at the time the fiscal year 1973 budget was released (p. 57, *the Budget of the United States Government for Fiscal Year 1973*). The data presented in tables I and II include additional budget components, viz., Coal Mine Health and Safety Research is included in the Bureau of Mines budget and capital and equipment as well as operations are included in the Atomic Energy Commission budget.

Legend: DOI—Department of the Interior, BOM—Bureau of Mines, OCR—Office of Coal Research, AEC—Atomic Energy Commission, GS—U.S. Geodetic Survey, DOC—Department of Commerce, TVA—Tennessee Valley Authority, EPA—Environmental Protection Agency, HUD—Housing and Urban Development, NSF—National Science Foundation, NBS—National Bureau of Standards.

Coal Research and Development

Although the Federal Government's energy R&D efforts began with coal well over a half century ago, this resource has until recently been supported as a poor stepchild. The Office of Coal Research (OCR), Department of the Interior, and the American Gas Association have jointly undertaken, subject to the approval of Congress, a $30 million accelerated pilot plant program for deriving high Btu gas from coal. The division of costs is two-thirds government and one-third industry. The program life of four years will lead to either a demonstration plant or, if feasible, direct commercial application. Three pilot plants associated with this program are in various stages of development. The first has already produced a small amount of gas. The second, is in its shakedown period. Groundbreaking for the third is scheduled for early summer of 1972.

OCR is also accelerating its R&D effort aimed at converting coal to clean fuel gases using combined cycles, clean liquid hydrocarbons, solvent refined coal, and the magnetohydrodynamic (MHD) generation of electric power.

The Bureau of Mines is conducting smaller scale R&D to extract high Btu gas from coal and to develop other clean fuels and MHD. The Bureau, as a result of the Coal Mine Health and Safety Act of 1969, increased its efforts on coal mine health and safety research by an order of magnitude in five years, approximately $30 million per year in FY 1972–73.

Closely related to Interior's work on coal mining and utilization are efforts by EPA and TVA to control air pollutants from coal and other fossil fuel combustion in stationary power plants. Nearly all of this effort has been applied to sulfur oxide controls, particularly by means of stack gas cleaning systems. The FY 73 budget includes a large increase to allow TVA to install a stack gas cleaning system on one of its large power plants and increases for EPA efforts on advanced, more efficient means for controlling sulfur oxides and other pollutants.

Nuclear Fusion Research

The AEC conducts the major portion of Federal research on controlled thermonuclear fusion. Its ultimate goal is to provide mankind with a new and different kind of energy source as the long term approach to the energy problem. Some of the reasons for pursuing fusion are:

(1) The possibility of unlimited low cost fuel—deuterium from sea water;

(2) Inherent safety against runaway reactions;

(3) Manageable radioactivity problems;

(4) High thermal efficiencies.

The fusion effort has been aimed at understanding the physics of plasmas and demonstrating the scientific feasibility of confining plasma long enough to produce useful amounts of energy. Most of this work involves magnetic systems for confining the plasma. Funding for this research has increased nearly 36%, or $10.6 million, in the five-year period.

In recent years, the use of high powered lasers to initiate the thermonuclear fusion reaction has been under study. It offers a possible additional approach to a fusion reactor, one which would supplement the three major magnetic confinement techniques now being studied. The multipurpose laser-fuel pellet effort has grown significantly in the last three years to over $25 million in FY 1973. Neither approach will see commercial use before the 1990's.

Petroleum and Natural Gas R&D

As mentioned previously, Federal efforts in petroleum and natural gas have been relatively modest in comparison with those of industry. The Bureau of Mines has long worked on oil shale and secondary petroleum extraction. The AEC's Plowshare Program has recently been directed almost exclusively at gas stimulation by nuclear devices. This technology offers a good deal of promise provided the related environmental questions are answered and objections to nuclear explosions are met satisfactorily.

Other Energy R & D Efforts

The National Science Foundation has for a number of years sponsored basic R&D on energy-related issues as part of its Engineering Energetics effort. With the establishment of the RANN (Research Applied to National Needs) Program, NSF's involvement has now moved from basic laboratory studies to advanced energy conversion systems such as solar power and policy studies related to energy and transmission systems research. The NSF's budget for energy studies has increased 31.2%, or $4.3 million, in FY 1973.

The Department of the Interior jointly sponsors, with the utility industry and through the Electric Research Council, an expanding program on underground transmission. It also has increased its efforts in the field of geothermal energy by 260%, or $1.8 million, in the FY 1973 budget.

The National Bureau of Standards and HUD also have expanded efforts involving civilian energy production and utilization.

Summary

The development of the technology to provide an adequate supply of electrical energy with minimal environmental impact is a critical factor in the nation's economic future. To attain that goal while simultaneously balancing energy needs and environmental concerns is a fundamental factor in the evolution of energy R&D programs. As presently constituted, that program has the following two salient components:

(1) A Federal energy R&D budget which has been growing at the compounded rate of 11% during the last five years;

(2) A pattern of funding which is continually being adjusted to reflect a realistic balance between domestic energy resources and the R&D required to utilize those resources most effectively.

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Appendix F

Chronology of the Mandatory Oil Import Program, 1959–73

Chronology of the Mandatory Oil Import Program (MOIP), 1959–73

Phase of program	Presidential proclamations or Executive orders		
	Number	Date	Principal provisions
I. Establishment of the MOIP.	Proclamation 3279.	Mar. 10, 1959	Established program with stated national security objective. Defined districts I–IV (east of Rocky Mountains) and V (west of Rockies) as domestic crude-surplus and crude-deficit areas, respectively. Imports into districts I–IV set at 9 percent of total demand, those into district V at amounts needed to satisfy demand above domestic supply. Gave Secretary of the Interior authority to issue regulations and establish Appeal Board, plus redelegation authority. Made first attempt to define crude, unfinished oils, and finished products. Allocated quotas to refiners.
II. Implementation and adjustment.	Proclamation 3290.	Apr. 30, 1959	Excepted overland imports from quotas.
	Proclamation 3328.	Dec. 10, 1959	Canadian imports for districts I–IV were includable for calculating allowable imports. Extended Appeals Board's authority to cover finished product imports in hardship cases.
	Proclamation 3386.	Dec. 24, 1960	Increased flexibility of quota calculations on demand basis for each allocation period to allow variation of ± 9 percent of gap between allocations and actual demand for districts I–IV.

Chronology of the Mandatory Oil Import Program (MOIP), 1959–73—Continued

Phase of program	Presidential proclamations or Executive orders		
	Number	Date	Principal provisions
	Proclamation 3389.	Jan. 17, 1961	Changed allocation system for residual fuel oil to be used as fuel oil into district I (east coast), allocating between historical importers (1957 base) and importers/distributors at deepwater terminal in district I.
	Executive Order 11051.	Sept. 27, 1962	Involved Office of Emergency Planning (OEP) indirectly in MOIP on national security grounds and made Director of OEP Chairman of Oil Policy Committee to advise on further action.
	Proclamation 3509.	Nov. 30, 1962	Changed districts I–IV quota from 9 percent of demand to 12.2 percent of production. Redefined crude oil and introduced natural gas products.
	Proclamation 4531.	Apr. 19, 1963	Established the Appeals Board to consider petitions by persons affected by the regulations issued pursuant to sec. 3 of Proclamation 3531.
	Proclamation 3541.	June 10, 1963	Amended Proclamation 3279 to shift basis of quota from historical basis to one based on estimated future production, as determined by Secretary of the Interior for districts I–IV.
III. Use of MOIP for expanded objectives.	Proclamation 3693.	Dec. 10, 1965	Extensively amended Proclamation 3279. Authorized sliding-scale allocations to chemical firms having petrochemical plants in all 5 districts. Revised program for Puerto Rico to permit greater crude imports to the island as a means of stimulating growth of Puerto Rican refining capacity and eco-

			nomic development. Restricted imports into free trade zones (FTZ).
	Proclamation 3779.	Apr. 10, 1967	Freed asphalt of import restrictions.
	Proclamation 3794.	July 17, 1967	Began system of bonus-quotas of crude oil and unfinished oils for importers that manufacture in the United States, residual fuel oil to be used as fuel with a sulfur level acceptable to the Secretary. Redefined residual fuel oil, thus easing quota restraints on the latter. Also favored imports of low-sulfur fuel oil.
	Proclamation 3820.	Nov. 9, 1967	Instituted exceptions for Virgin Islands similar to those established in Proclamation 3693 for Puerto Rico.
	Proclamation 3823.	Jan. 29, 1968	Broadened Puerto Rican programs. Also brought liquids produced from tar sands under the MOIP to control importation of tar sand crudes from Canada.
	Proclamation 3969.	Mar. 10, 1970	Set fixed crude and unfinished oil quotas for Canada, to be chargeable to overall quotas for districts I–IV.
IV. Modifications necessary to meet the gap between domestic supply and demand.	Proclamation 3990.	June 17, 1970	
	Proclamation 4018.	Oct. 16, 1970	
	Proclamation 4025.	Dec. 22, 1970	All concerned with progressive increases in or exemption from quotas for various products and crude oil imported from various areas.
	Proclamation 4092.	Nov. 5, 1971	
	Proclamation 4099.	Dec. 5, 1971	

Chronology of the Mandatory Oil Import Program (MOIP), 1959–73—Continued

Phase of program	Presidential proclamations or Executive orders		
	Number	Date	Principal provisions
	Proclamation 4133.	May 11, 1972	
	Proclamation 4156.	Sept. 18, 1972	
	Proclamation 4175.	Dec. 16, 1972	
	Proclamation 4178.	Jan. 17, 1973	
	Executive Order 11703.	Feb. 7, 1973	Reorganized Oil Policy Committee, replacing Director of OEP with Deputy Secretary of the Treasury as chairman.
	Proclamation 4202.	Mar. 23, 1973	Broadened role of OIAB to handle growing numbers of requests for greater imports by easing criteria for allocations and removing limits on quota allocations allowable to OIAB.
V. End of mandatory import program.	Proclamation 4212.	May 1, 1973	Suspended the tariffs on imports of crude petroleum and petroleum products through 1980 and instituted a license-fee system as a replacement for the quota system.

Source: U.S. Tariff Commission.