The original documents are located in Box 7, folder: "National Energy Outlook - 1976" of the Frank Zarb Papers at the Gerald R. Ford Presidential Library.

Chapter II

OIL

INTRODUCTION

The forecasts of future oil supply contained in the Project Independence Report were conditioned upon numerous policy assumptions and a forecasting technique with many inherent uncertainties. In the ensuing year, several events occurred in rapid succession that affected the basic assumptions and methodology and changed this year's analysis:

- The Tax Reduction Act of 1975 modified the tax and depletion situation.
- Resource estimates were revised downward substantially by the Federal Energy Administration (FEA) and the U.S. Geological Survey (USGS).
- The schedule changed for Federal leasing of Outer Continental Shelf (OCS) lands.
- The rate of development envisioned for Northern Alaska was revised upward.
- The oil and gas price controls debate led to more intensive evaluation of their effects.

The purpose of this chapter is to estimate future oil production possibilities over a range of geological assessments and under different policy assumptions. To do this, an historical perspective is established; the analytical techniques used to forecast oil supply possibilities are explained and areas of uncertainty are identified; and the implications of this analysis for future policy are discussed.

PERSPECTIVE

The outlook for domestic oil supply is clouded with uncertainty. The extent and availability of domestic resources, Federal OCS leasing policy, form and duration of oil price controls, success of tertiary recovery techniques, and participation of State and local governments will determine our future production possibilities.

In recent years, significant changes have occurred in domestic crude oil production, reserves, imports, prices, and consumption. This section discusses the present oil supply situation, the events leading up to it, and the short-term supply and demand outlook.

The Present Situation

The present oil supply situation is best characterized by the following:

- The United States now imports almost 40 percent of the oil it consumes.
- Price controls on domestic production have been in effect since 1973.
- Proved reserves have been steadily declining since 1970 (when nearly 10 billion barrels were added in North Alaska, but no oil has yet been produced).
- Domestic production levels have been decreasing since 1970, but may be beginning to fall more slowly.
- Federal leasing of OCS lands has been stepped up.
- Drilling effort for oil has been increasing since 1972, after declining for 15 years.
- Domestic oil consumption has declined from 1973 levels.

The relevant historical perspective behind these observations can be divided into two parts; the dividing point is the Arab oil embargo of 1973.

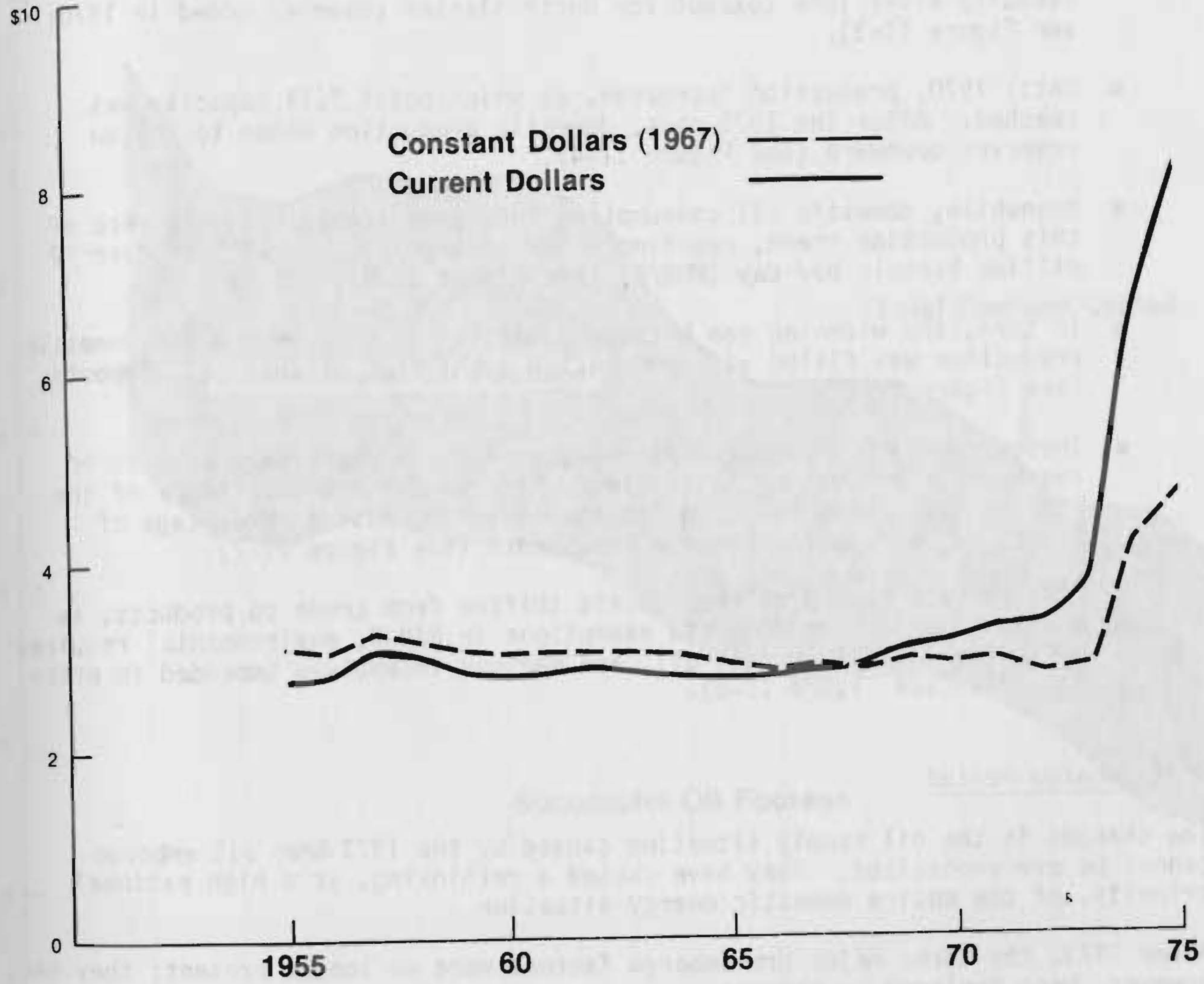
Pre-Embargo Period

Three major factors shaped domestic oil supply from the Fifties to the early Seventies:

- Crude oil prices remained relatively flat (actually declining when adjusted for inflation; see Figure II-1).
- Conservation practices in major producing states held crude oil production well below full capacity until about 1970.
- A large amount of cheap foreign crude oil overshadowed the world petroleum market; its import into the United States, however, was limited severely by mandatory oil import quotas.

Figure II-1

Average Wellhead Price of U.S. Crude



Source: U.S. Bureau of Mines, U.S. Bureau of Labor Statistics, American Petroleum Institute and Federal Energy Administration.

These factors created a pre-embargo domestic oil supply situation with a number of important features:

- Oil drilling declined steadily after 1959 for two major reasons (see Figure II-2): decreased profitability of domestic production in mature producing areas (because of rising costs and flat oil prices in the face of cheap foreign oil); and the lack of access to Federal lands in frontier areas (OCS and Alaska).

- In response to decreased drilling, domestic oil reserves declined steadily after 1966 (except for North Alaskan reserves added in 1970; see Figure II-3).

- Until 1970, production increased, at which point full capacity was reached. After the 1970 peak, domestic production began to follow reserves downward (see Figure II-4).

- Meanwhile, domestic oil consumption increased steadily in the face of this production trend, reaching a pre-embargo peak in 1973 of over 17 million barrels per day (MMB/D) (see Figure II-5).

- In turn, the widening gap between domestic oil consumption and domestic production was filled with increasing quantities of cheap oil imports (see Figure II-6).

- These growing U.S. imports soon caused Western Hemisphere sources to reach their production capacities. Afterwards, the importance of the Western Hemisphere began to decline as an increasing percentage of imports came from the Eastern Hemisphere (see Figure II-7).

- Finally, the makeup of the imports shifted from crude to products, as a by-product of import quota exemptions in PAD I, environmental requirements for low sulfur fuel oil, and various incentives imbedded in price controls (see Figure II-8).

<u>Post-Embargo Period</u>

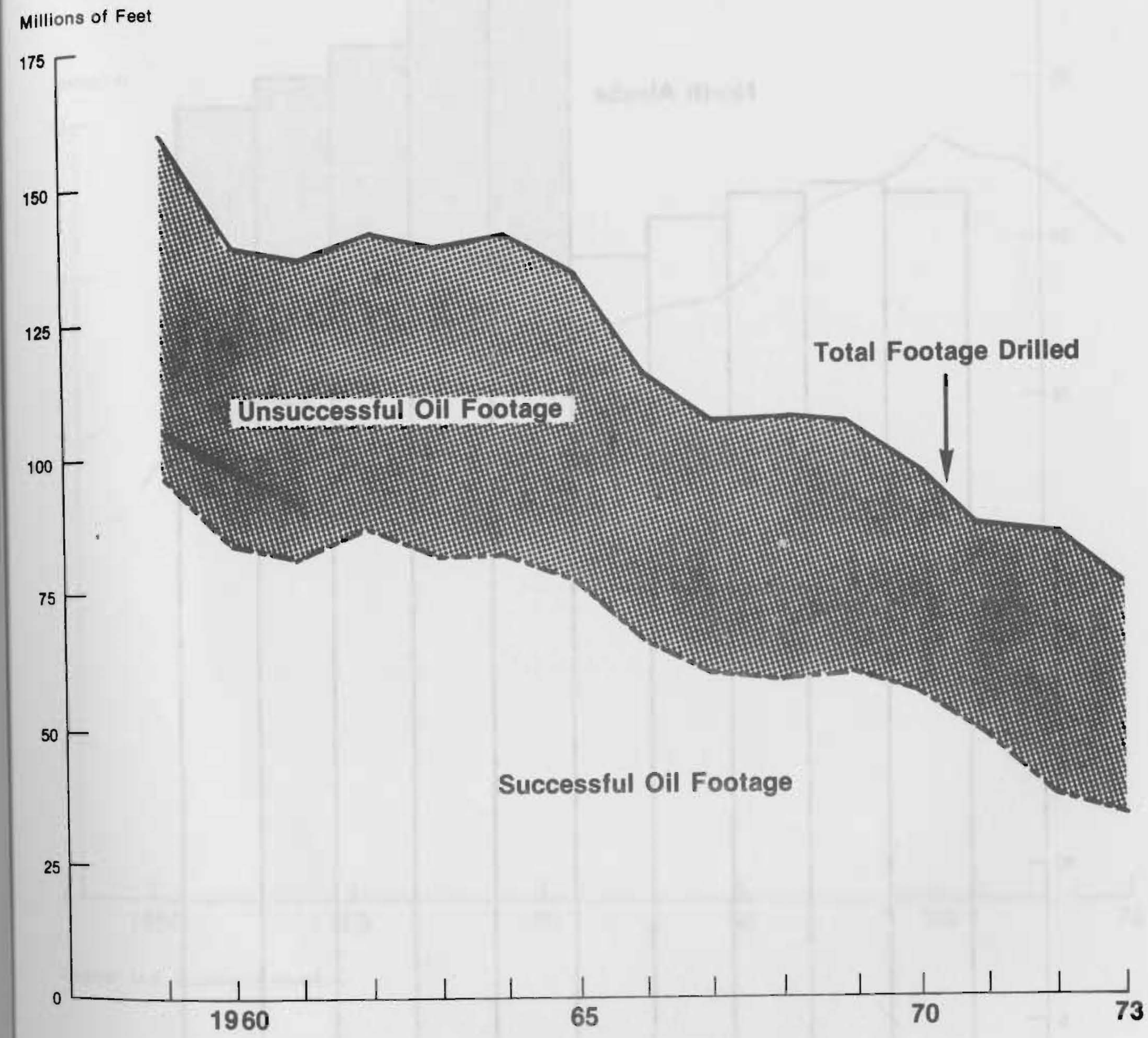
The changes in the oil supply situation caused by the 1973 Arab oil embargo cannot be overemphasized. They have caused a rethinking, at a high national priority, of the entire domestic energy situation.

After 1973, the three major pre-embargo factors were no longer present; they had, however, been replaced by others:

- Imports became expensive -- up to $12 a barrel, excluding any import fees.

Figure II-2

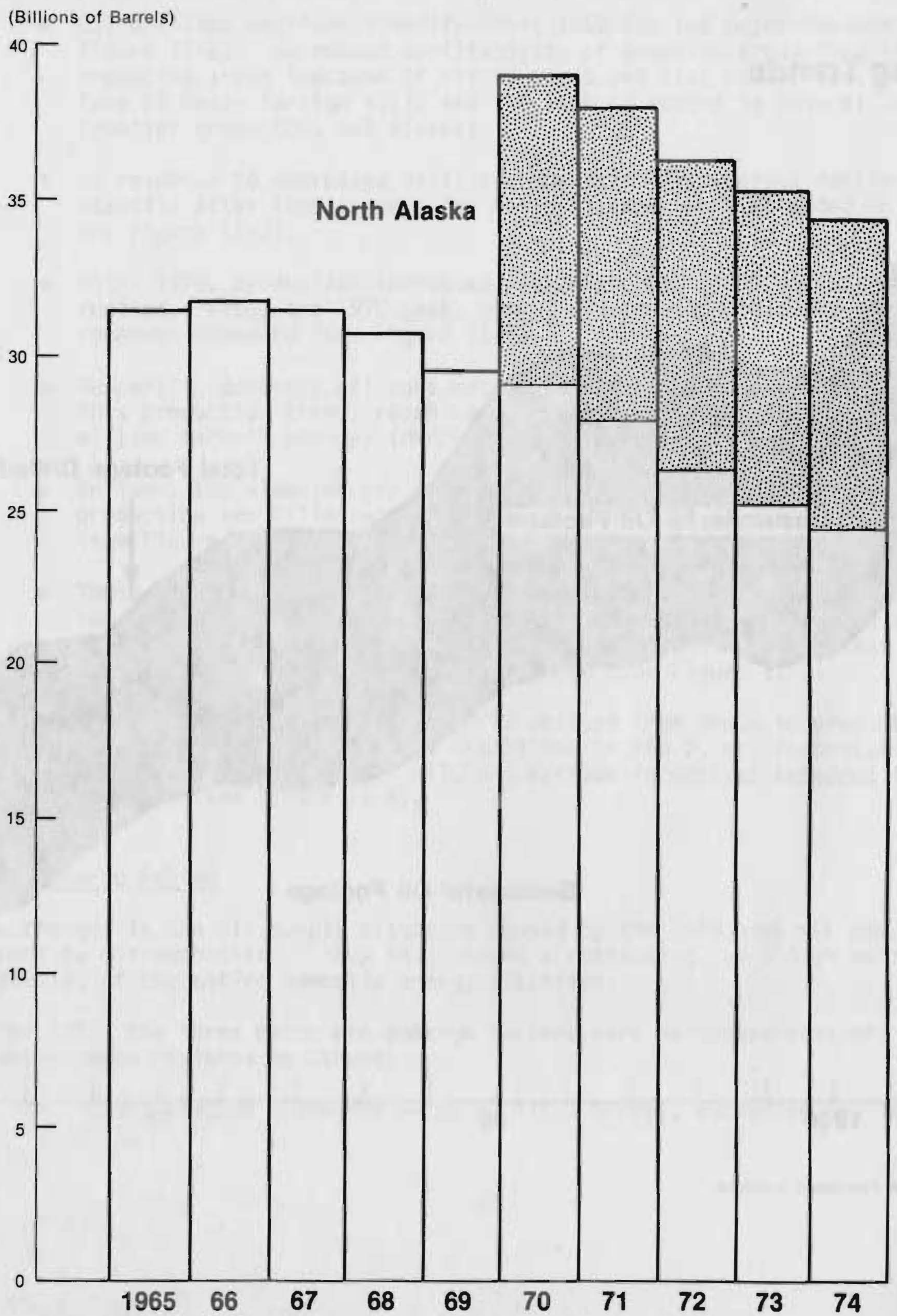
Oil Drilling Trends



Source: American Petroleum Institute.

Figure II-3

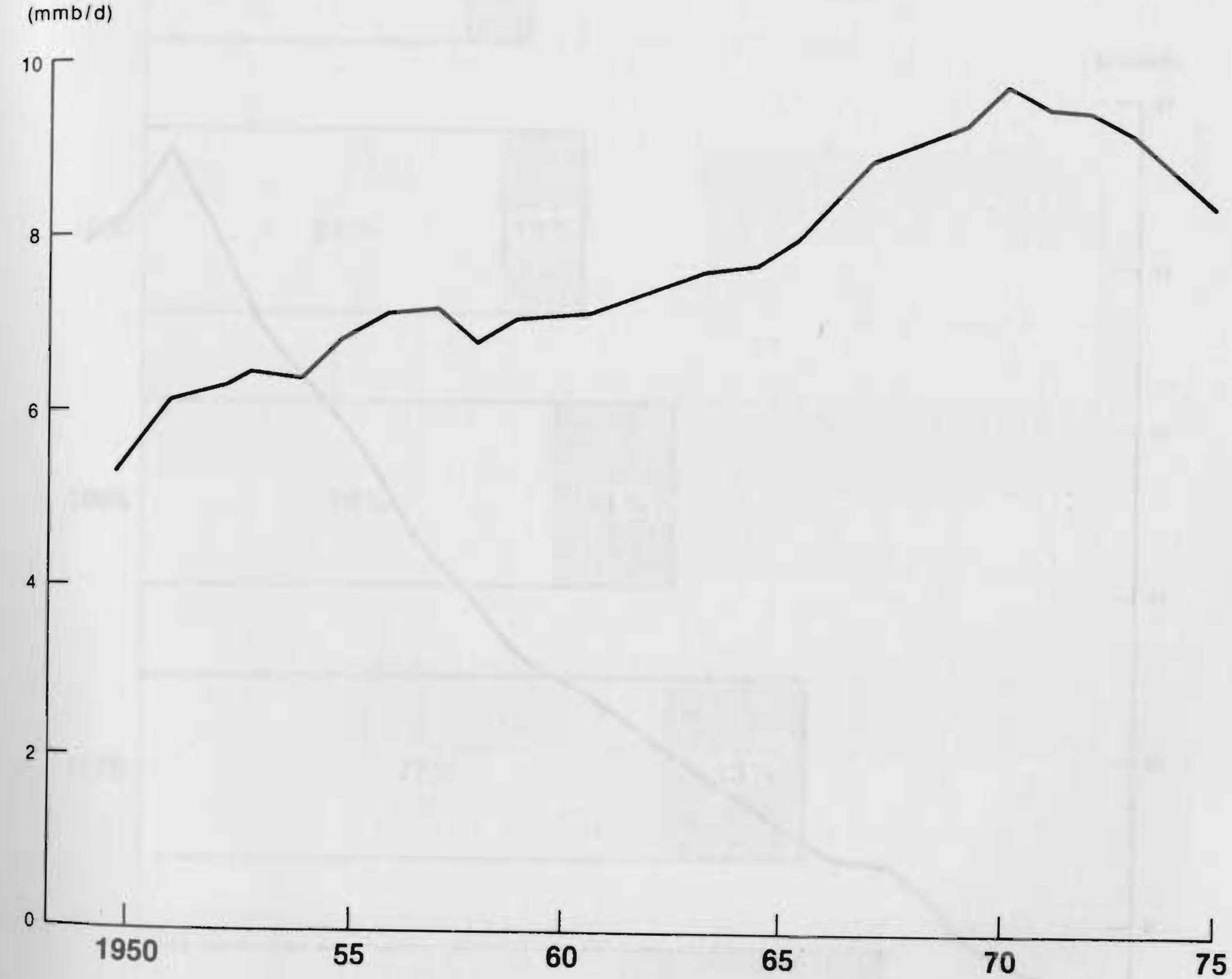
U.S. Proved Reserves of Crude Oil



Source: American Petroleum Institute.

Figure III-4

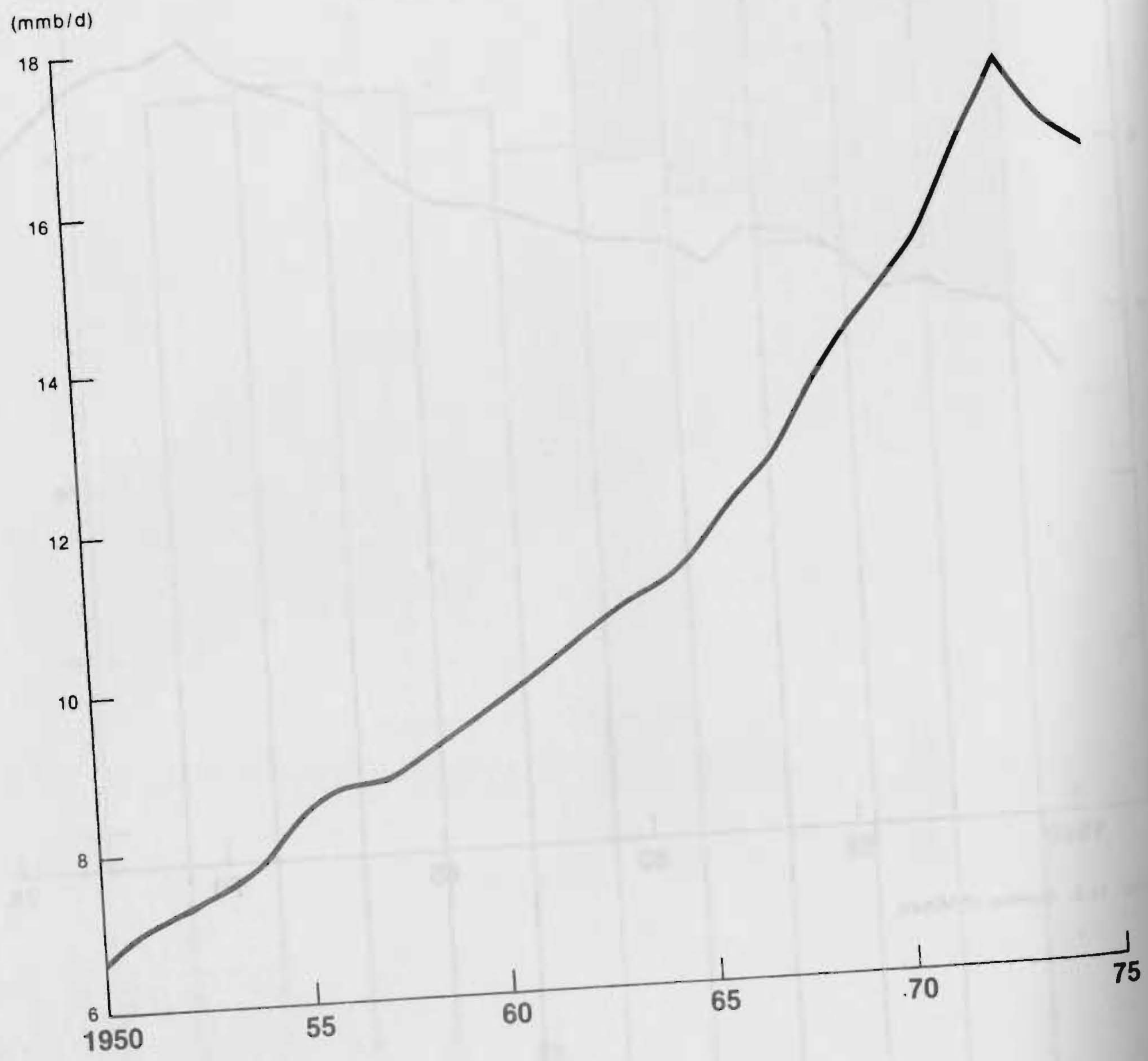
U.S. Crude Oil Production



Source: U.S. Bureau of Mines.

Figure II-5

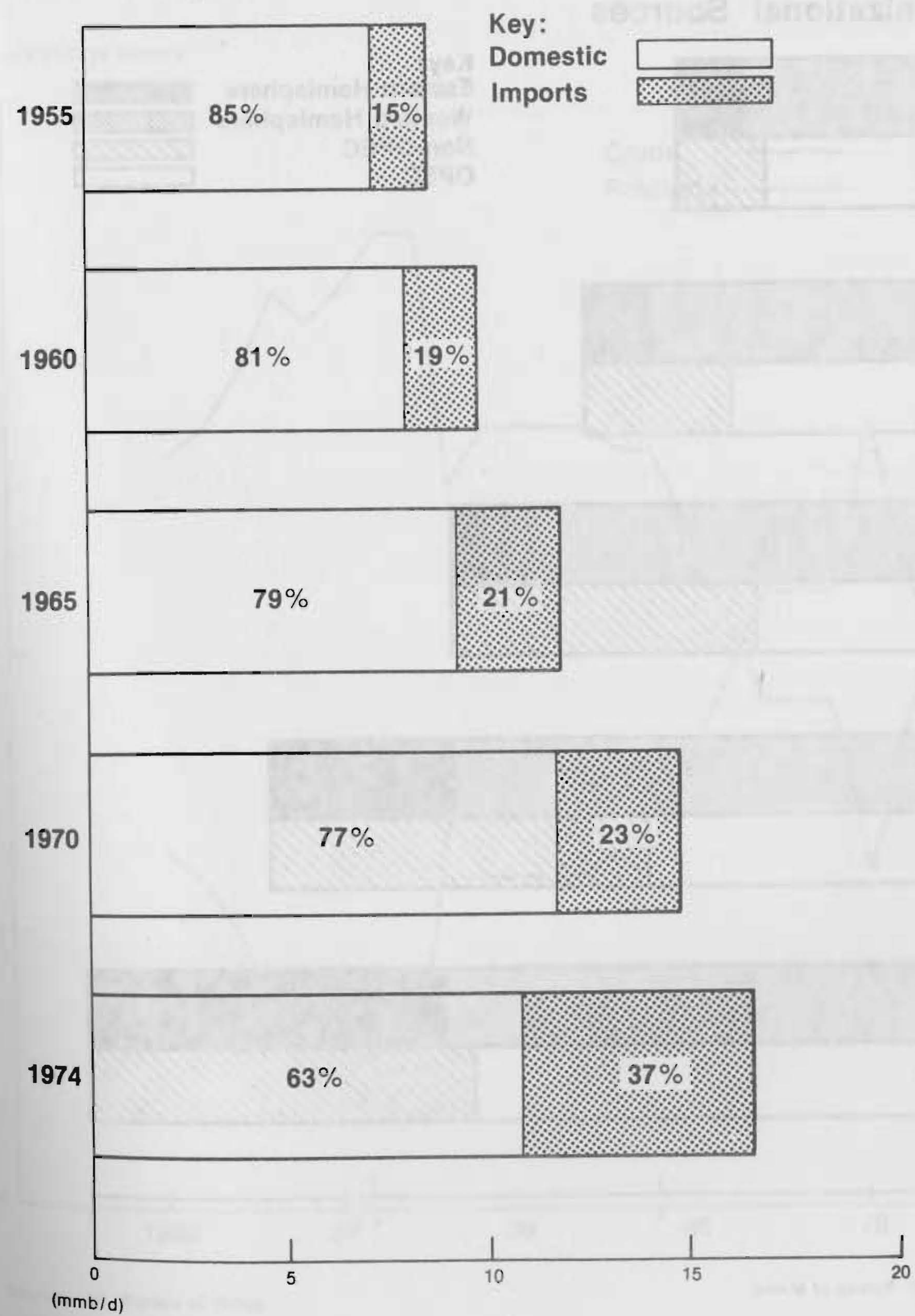
U.S. Petroleum Products Consumption



Source: U.S. Bureau of Mines.

Figure II-6

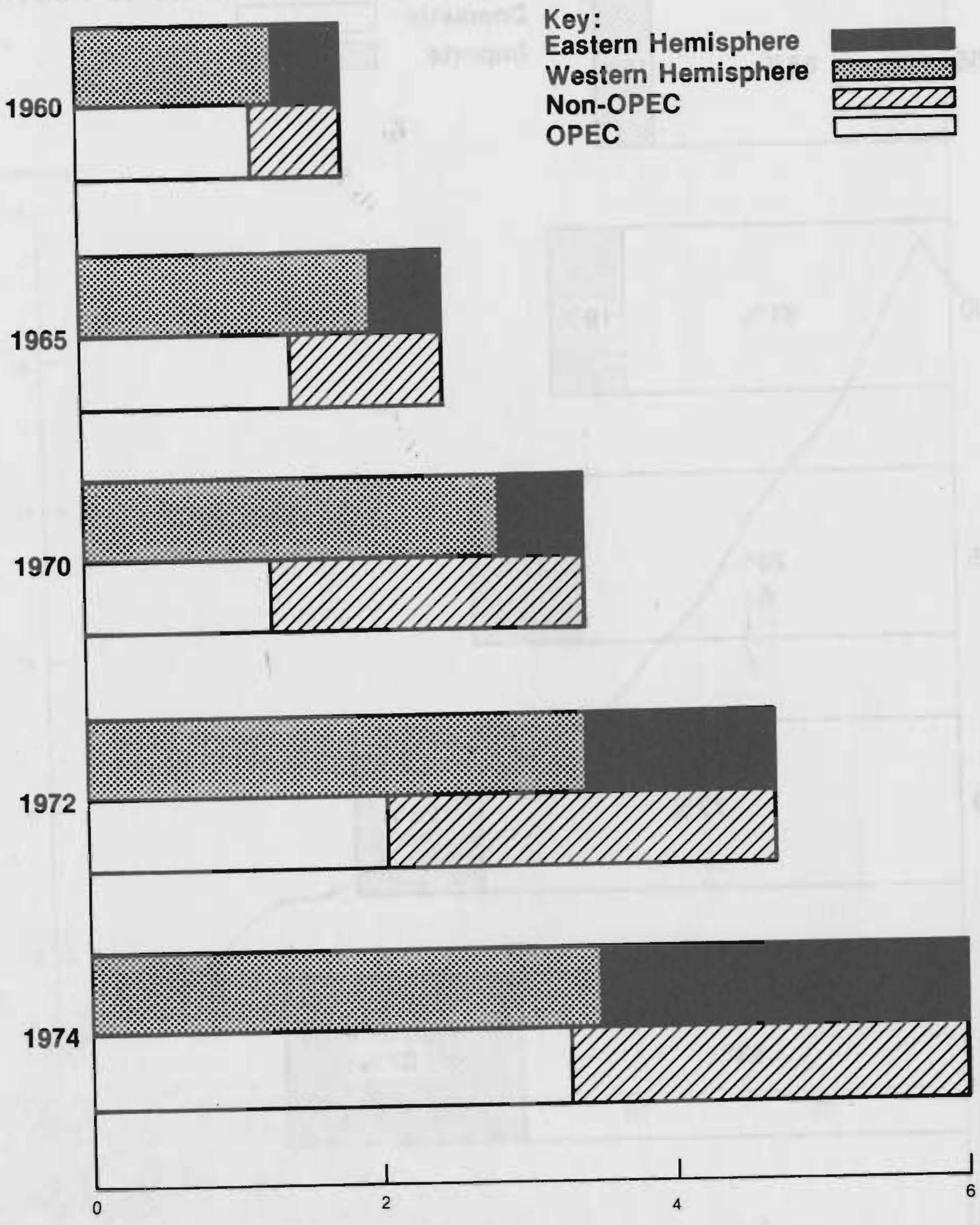
U.S. Oil Consumption By Source



Source: U.S. Bureau of Mines.

Figure II-7

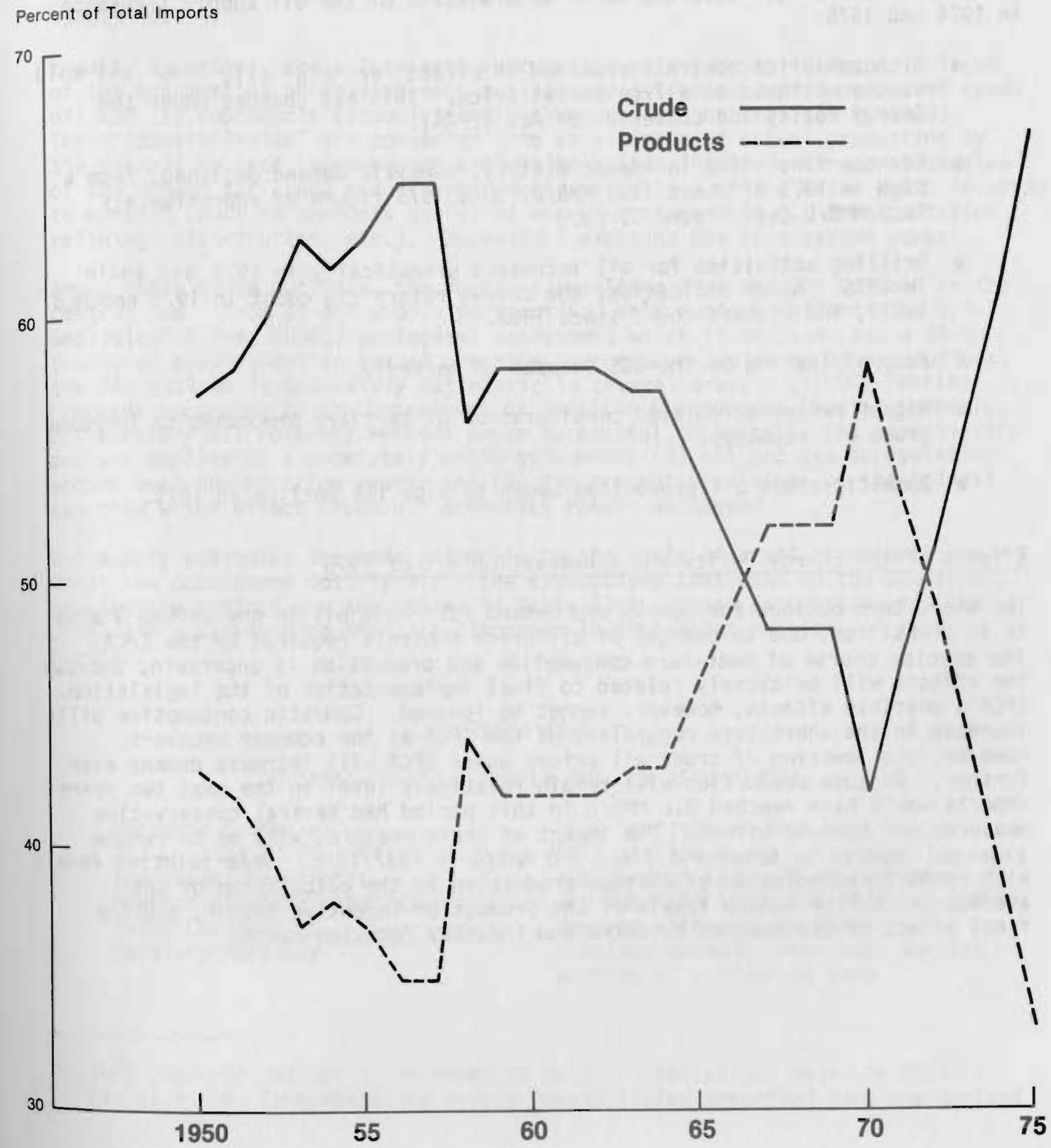
Total U.S. Petroleum Imports by Regional and Organizational Sources



Source: U.S. Bureau of Mines.

Figure II-8

Petroleum Imports



Source: U.S. Bureau of Mines.

- In response, domestic crude oil prices increased sharply, on average from around $3 to over $8 nominally and to nearly $5 in constant dollars (see Figure II-1).

These two factors have been the major determinants of the oil supply situation in 1974 and 1975:

- Although price controls remained in effect for "old" oil, "new" oil sold at the wellhead at a free market price. This has changed under the Energy Policy and Conservation Act (EPCA).

- For the first time in recent history, domestic demand declined, from a high in 1973 of about 17.3 MMB/D, to a 1975 figure of approximately 16.2 MMB/D (see Figure II-5).

- Drilling activities for oil increased dramatically in 1974 and again in 1975. As an indication, the active rotary rig count in 1975 reached 1,877, the highest count since 1962.

- Federal leasing on the OCS stepped up markedly.

- Higher prices stimulated consideration of tertiary processes to increase crude oil recovery.

- Domestic crude oil production began to slow its decline in 1975.

Effects of the Energy Policy and Conservation Act of 1975

The short-term outlook for supply and demand for crude oil in the United States is in transition, due to changes of oil price controls required by the EPCA. The precise course of near-term consumption and production is uncertain, because the effects will be closely related to final implementation of the legislation. EPCA's possible effects, however, cannot be ignored. Domestic consumption will increase in the short term regardless of the EPCA as the economy recovers. However, the lowering of crude oil prices under EPCA will increase demand even further. Because production will remain relatively level in the next two years, imports would have reached 8.0 MMB/D in this period had several conservation measures not been in effect. The impact of these measures will be to reduce expected imports to between 6.0 and 7.0 MMB/D in 1977-1978. Uncertainties remain with respect to inclusion of Alaskan production in the calculation of the average price, the future levels of the production incentive factor, and the final effect of the program on petroleum industry decision-making.

BUSINESS-AS-USUAL SUPPLY OUTLOOK

The future oil supply outlook is estimated for a range of geological assessments and under different policy assumptions. This range of outlooks is indicated by three supply forecasts, entitled: Pessimistic, Business-as-Usual (BAU), and Optimistic. These represent three points on a spectrum of potential future oil supply levels.

Equally important, these forecasts represent supply "possibilities," in light of the assumptions underlying each outlook and different import prices of crude oil and its coproducts (associated-dissolved gas and natural gas liquids). These "possibilities" are converted into an estimate of actual production by the overall Project Independence Evaluation System (PIES), after consideration of the demand for crude and its coproducts as well as of the major costs incurred to convert crude to products useful to energy consumers (e.g., transportation, refining, distribution, etc.). Appendix A explains how this system works.

Among these three outlooks, the forecast resulting from the BAU Outlook is the central one. From an oil supply perspective, this outlook reflects the U.S. Geological Survey (USGS) geological assessment which it believes has a 50-50 chance of proving-out in actual practice over time.* In terms of assumptions, the BAU outlook is moderately optimistic in several areas: (1) OCS leasing proceeds according to the Department of Interior's announced leasing schedule; (2) tertiary oil recovery methods prove successful technically and economically and are applied at a moderately optimistic pace; (3) oil and gas deregulation occurs over the next few years; and (4) the present provisions of the Federal tax code which affect crude oil economics remain unchanged.

Oil supply estimates are made primarily on the basis of a set of assumptions which are considered most likely. The assumptions that make up the BAU supply possibility outlook are summarized in Table II-1. These assumptions and the uncertainty surrounding them are discussed in subsequent sections of this chapter.

Table II-1

BUSINESS-AS-USUAL SUPPLY OUTLOOK ASSUMPTIONS

Resource Estimates	USGS Statistical Mean.
OCS Leasing (1975-1984)	26.8 million acres.
Investment Tax Credit	10% through 1977; 7% thereafter.
Alaskan pipeline capacity	2.0 MMB/D in 1980; 2.5 MMB/D in 1985.
Price Controls	Removed within a few years.
Tertiary Recovery	Tertiary methods prove out, but are applied at a moderate pace.

---

* This resource outlook is referred to as the "statistical mean" in USGS Circular 725, from which the supply possibilities described here are derived.

The Optimistic and Pessimistic outlooks differ from BAU with respect to level of geological success, the rate of leasing offshore, the degree of success and pace of application of tertiary oil recovery, and the fate of the investment tax credit. The specific assumptions underlying each supply outlook are detailed in a later section.

Within the overall PIES, these oil supply outlooks become building blocks of a variety of comprehensive energy scenarios. The connections between PIES scenarios and BAU oil supply possibilities are shown in Table II-2 (the other two oil supply outlooks are also reconciled with PIES scenarios).

Table II-2

OIL SUPPLY OUTLOOKS AND PIES ENERGY SCENARIOS

Energy Scenario	Pessimistic	BAU	Optimistic
Accelerated			X
Reference		X	
Conservation		X	
Regional Limitation		X	
Regulatory		X	
Electrification		X	
Supply Pessimism	X		

Two of these energy scenarios (Regulatory and Supply Pessimism) reflect price regulation. These price regulation scenarios illustrate the way PIES converts supply possibilities into an estimate of actual future oil production. For scenarios which envision price regulation, PIES excludes from the production estimate the supply possibilities which are not economically viable at the regulated oil price.

Business-as-Usual Supply Possibilities

The $13 BAU Oil Supply Trajectory*

Under any one oil supply outlook--for example, BAU--future oil supply possibilities vary over time between geographical areas, between the portion of the overall resource base from which they may be withdrawn (e.g., newly discovered fields versus known fields), and between the mix of recovery

* Throughout this chapter, domestic production will be quoted at the world oil price (in constant 1975 dollars) with which it competes. When these supply possibilities mesh with the consumption input to the main PIES, the actual wellhead price of domestic production would be less than the competitive imported oil price, the difference lying mainly in the transportation cost from wellhead to refinery.

technology employed (e.g., primary, secondary and tertiary methods). Along each of these dimensions the quantities in any future year also vary with the prices of crude and coproducts that the producing industry expects will prevail. At $13 and under BAU conditions, a number of important observations emerge concerning the make-up of future oil supply possibilities (see table II-3 which shows the BAU supply possibilities estimated to be available if the industry expects $13 per barrel import prices (in constant 1975 dollars) and identical prices, on a BTU-equivalent basis, for the crude and its coproducts):

- The main source of today's domestic crude production--lower-48 onshore initial reserves--will shrink by two-thirds by 1985 and by 80 percent by 1989. Before crude production on the lower-48 can expand, the withdrawals which account for this decline must be replaced.

- Sufficient new lower-48 onshore production can become available to approximately sustain today's production rate through 1985.

Through 1980, withdrawals from today's proved reserves will be replaced mainly by fluid injection projects, extensions, and revisions applicable to known fields (labeled Old Field Secondary in Table II-3). By 1985, however, new fields, and more elaborate tertiary recovery technology must replace the further decline in production from existing onshore reserves. This replacement is estimated to occur as follows: 40 percent from new fields, 40 percent from technically straightforward expansion of the production capacity of known fields and 20 percent from tertiary recovery. After 1985, production from new fields and tertiary recovery must accelerate in order to counter the dwindling potential of primary recovery methods in old fields.

Since the lower-48 onshore can just offset further decline at $13 and under BAU conditions, growth in total domestic oil supply at $13 must come from less mature provinces. Two areas, the lower-48 OCS and Alaska (onshore and offshore), are expected to provide growth. Of the two, Alaska has the greater potential.

- In 1985 under BAU assumptions, potential Alaskan crude production is estimated to equal 3.1 MMB/D, or about one-fourth of total domestic production (see Table II-3).

- Of this, at least 1.6 MMB/D--from reserves already proven at Prudhoe Bay--is reasonably well assured. The balance--0.8 MMB/D from the Beaufort Sea and other areas on the Alaskan OCS plus 0.7 MMB/D from other North Slope regions--depends upon reasonable geological fortune, new technology, and substantial institutional effort.

Without more accelerated effort in Alaska and successful results from additional oil search, continued withdrawal of today's proved reserves on the North Slope will cause Alaskan production to decline slightly between 1985 and 1989. One Alaskan area likely to provide growth in response to accelerated effort is NPR-4, whose development is excluded from the BAU Outlook (but is

Table II-3

BAU OIL PRODUCTION POSSIBILITIES AT $13*
(MMB/D)

	1975	1980	1985	1989
Lower-48 Onshore				
New Field Primary/Secondary	--	0.8	1.9	2.2
Old Field Secondary	--	2.0	2.0	1.8
Tertiary	--	0.5	1.0	1.3
Initial Reserves	7.0	4.2	2.4	1.5
Subtotal	7.0	7.5	7.3	6.8
Lower-48 OCS				
Pacific	0.2	0.6	0.6	0.5
Gulf of Mexico	1.0	1.4	1.4	1.1
Atlantic	--	0.1	0.1	0.1
Subtotal	1.2	2.1	2.1	1.7
Alaska				
Beaufort Sea	--	--	0.4	0.8
Other OCS	0.2	0.3	0.4	0.4
North Slope	--	1.7	2.3	1.7
NPR-4	--	--	--	--
Subtotal	0.2	2.0	3.1	2.9
Other				
NPR-1	--	0.2	0.2	0.2
Tar Sands	--	--	--	--
Heavy Hydrocarbons	--	0.1	0.2	0.3
Subtotal	--	0.3	0.4	0.5
Total Crude	8.4	11.9	12.9	11.9
Natural Gas Liquids (NGL)**	1.6	1.9	1.8	1.8
Total Liquids	10.0	13.8	14.7	13.7

* Throughout this chapter, domestic production is presented as a supply possibility at a given equivalent imported oil price. For the actual solutions from the main PIES supply and demand model, which may be different from the supply possibilities at that price, see Chapter I.

** Excludes NGL's produced at refineries.

included in the Optimistic Outlook). In Alaska, the areas next in importance are on the Alaskan OCS, especially the Gulf of Alaska and the Beaufort Sea.

The lower-48 OCS is the second most important area for expanding domestic production.

- Assuming that the BAU leasing schedule is achieved and the geological potential of the OCS has been assessed correctly, lower-48 OCS production can almost double by 1985. If so, this area will account for 16 percent of total crude production that year (see Table II-3).

- Similar to onshore, OCS production growth must follow after replacement of withdrawals from today's OCS reserves--principally in the Gulf of Mexico. For example, the net increase of 0.4 MMB/D in the Gulf of Mexico by 1985 requires gross additions of productive capacity of 1.1 MMB/D.

- By 1985 the balance of the lower-48 OCS increase--0.5 MMB/D--should come from the Atlantic and Pacific.

As will be emphasized later, the assumed rate of leasing limits the lower 48 OCS production estimate over the period of the BAU Outlook. Consequently, an inadequate leasing rate can cause a decline in lower-48 OCS production after 1985.

The balance of any increase in crude production is envisioned to stem from NPR-1 and heavy hydrocarbons. Both make an important contribution to future supply, but certainly one that should be dwarfed by Alaska, the lower-48 OCS and even by replacement of today's productive capacity on the lower-48 onshore.

Finally, the balance of total conventional petroleum liquids available domestically is expected to consist of coproducts of crude production (liquid derivatives of associated-dissolved gas) and of non-associated gas. These additional liquids--NGL's--are expected to account for about 12 percent of total production (see Table II-3).

Effects of Price on BAU Supply

The overall level of BAU oil supply possibilities changes substantially if price expectations are higher or lower than $13 (see Table II-4). This change is the result of different price effects in various geographical areas, different components of the resource base, the rate of drilling and changes between alternative oil recovery methods.

Table II-4

1985 BAU OIL PRODUCTION AT ALTERNATIVE IMPORT PRICES
(MMB/D)

Source	Expected Oil Price $8	$13	$16
Lower-48, Onshore	4.4	7.3	7.7
Lower-48, OCS	1.9	2.1	2.3
Subtotal	6.3	9.4	10.0
Alaska	2.3	3.1	3.1
Other	0.4	0.4	0.6
Total Crude	9.0	12.9	13.7
NGL's	1.1	1.8	2.4
Total Liquids	10.1	14.7	16.1

In 1985, several things concerning the potential response of oil supply to price are important to note (see Figure II-9):

- Between $8 and $13, the estimated crude supply response is large--4.0 MMB/D by 1985.
- Through 1980, however, time lags are estimated to make the response smaller (1.6 MMB/D). By 1985 major time delays should be resolved; thereafter continuing decline in the quality of resources found causes the difference between $8 and $13 to grow further (to 5.3 MMB/D in 1989).

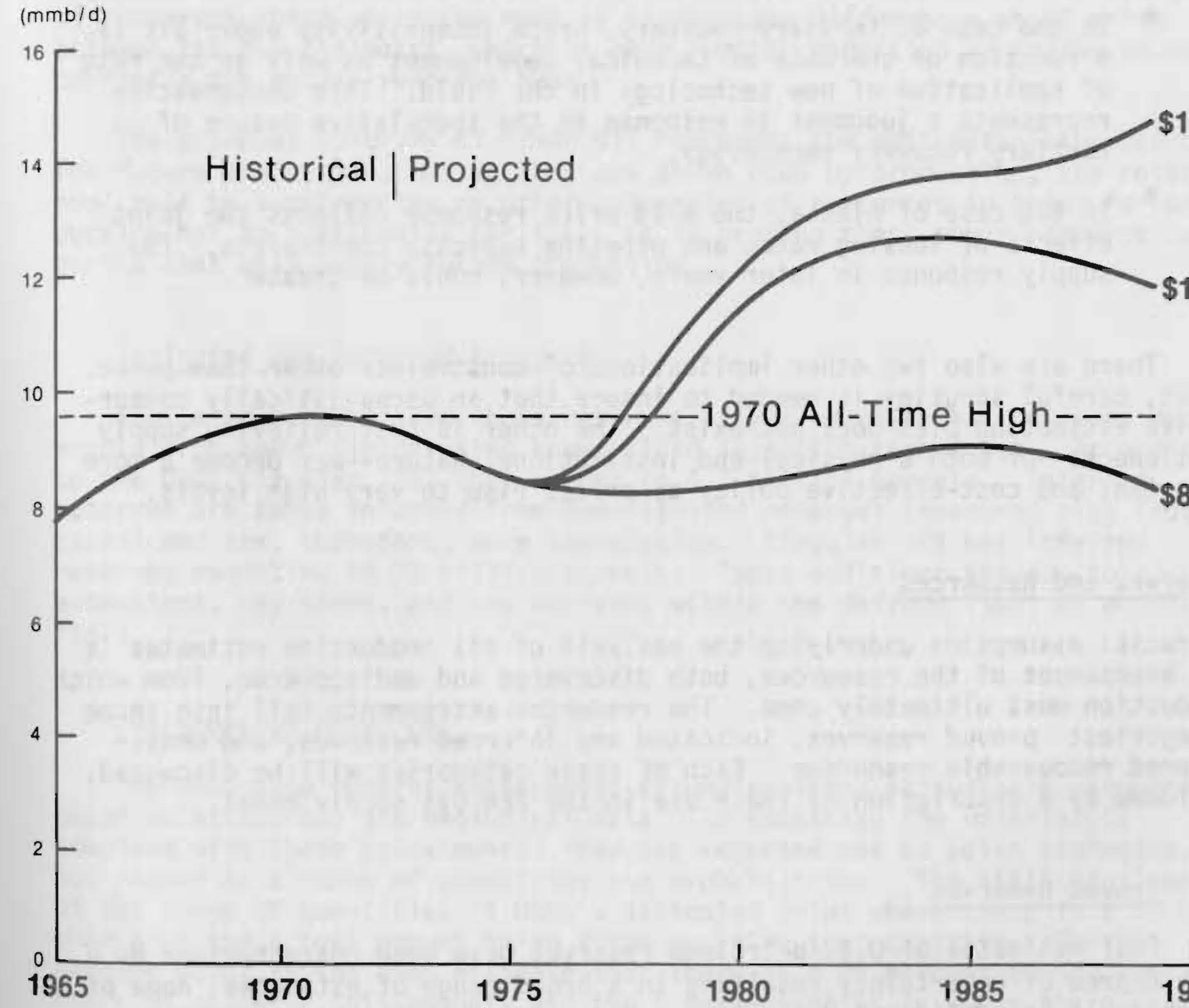
The largest share (75 percent) of the 4.0 MMB/D growth in response to price by 1985 occurs onshore in the lower-48. In these onshore areas, the supply response from $8 to $13 stems from new fields and from more sophisticated tertiary recovery methods.

- The 2.9 MMB/D price response onshore in the lower-48 is made up of 2.0 MMB/D from new fields, primary and secondary, and 1.0 MMB/D from tertiary recovery.
- This indicates that replacing today's productive capacity in the lower-48 states--by 1985 and to an even greater extent beyond 1985--depends on the more expensive components of potential future supply.

The next most important contributions to the supply response between $8 and $13 are Alaska (20 percent) and the lower-48 OCS (5 percent).

Figure II-9

Crude Oil Production at Three Prices (BAU)



The components of future supply which are price insensitive by 1985 need careful interpretation.

- The assumed rate of leasing constrains the estimate from the lower 48 OCS through 1985 (and, generally, through 1989 also).
- This suggests that the result of less leasing is a greater reliance on higher-priced foreign supply sources in lieu of lower cost domestic resources offshore.
- In the case of tertiary recovery, price insensitivity above $12 is a function of the pace of technical development as well as the rate of application of new technology in the field. This conservation represents a judgment in response to the speculative nature of tertiary recovery technology.
- In the case of Alaska, the mild price response reflects the joint effects of leasing rates and pipeline capacity constraints. The supply response in later years, however, could be greater.

There are also two other implications of constraints other than price. First, careful scrutiny is needed to insure that an unrealistically conservative estimating bias does not exist. The other is that relieving supply bottlenecks--of both a physical and institutional nature--may become a more important and cost-effective policy as prices rise to very high levels.

Reserves and Resources

A crucial assumption underlying the analysis of oil production estimates is the assessment of the resources, both discovered and undiscovered, from which production must ultimately come. The resources assessments fall into three categories: proved reserves, indicated and inferred reserves, and undiscovered recoverable resources. Each of these categories will be discussed, followed by a description of their use in the FEA oil supply model.

Proved Reserves

Past estimates of U.S. petroleum reserves have been characterized by a high degree of uncertainty resulting in a broad range of estimates, none of which could be considered definitive. Recognizing that a key element in formulating a national energy policy is the development of a reliable estimate of remaining domestic crude oil and natural gas reserves, the Federal Energy

Administration Act of 1974 required FEA to prepare a ". . .complete and independent analysis of actual oil and gas reserves and resources in the United States and its Outer Continental Shelf. . ." The FEA report on reserves was submitted to the Congress in October, 1975. The FEA survey of reserves estimated that proved oil reserves were 38 billion barrels, with most of the potential contained in Texas, Alaska, California, and Louisiana.

This contrasts with an assessment by the USGS which, using data supplied by the American Petroleum Institute (API), estimated United States crude oil reserves at 34 billion barrels. Even though proved reserves is the category of resources about which the most is known, some differences still exist between the two estimates, which is even further magnified in trying to assess correctly the entire resource base.

These proved reserves of crude oil represent the most definitive source for future production, but as they are drawn down by production, the reserve pool must be supplemented by other categories of resources in order for production not to continually decline. It is proving these other resource categories that will supply future production.

Indicated and Inferred Resources

Indicated reserves are those reserves as yet unproven but believed recoverable from known fields using known fluid injection techniques. According to the USGS Circular 725, they amount to 4.7 billion barrels. Inferred reserves are those inferred from demonstrated reserves (measured plus indicated) and are, therefore, more speculative. Circular 725 has inferred reserves amounting to 23 billion barrels. These additions are due to extensions, revisions, and new horizons within the defined limit of an oil field.

Undiscovered Resources

The USGS also reports assessments of undiscovered recoverable resources based on historical and geological data. To emphasize the uncertainty involved with these assessments, they are reported not as point estimates, but rather as a range of quantities and probabilities. The statistical mean of the range of quantities is USGS's estimated point where there is a 50-50 chance of the actual amount being above or below that quantity. The 95 percent point is the USGS estimate that there is a 95 percent chance that there is at least this amount, and the 5 percent point is where there is only a 5 percent chance that there is at least this amount. As an example of this technique, the USGS estimate for economically recoverable oil resources in the United States has a statistical mean of 89 billion barrels, a 95 percent point of 50 billion barrels, and a 5 percent point of 127 billion barrels (see Table II-5).

Table II-5

USGS-725: RESERVES AND UNDISCOVERED RESOURCES
(Billions of Barrels)

Region	Reserves: Demonstrated: Measured	Reserves: Demonstrated: Indicated	Reserves: Inferred	Resources: Undiscovered Recoverable: Statistical Mean	Resources: Undiscovered Recoverable: 95%-5% Range
Economic Resources*					
Lower-48 onshore	21.1	4.3	14.2	44	29-64
Lower-48 offshore	3.1	0.4	2.6	18**	11-28
Alaska offshore	0.2	0	0.1	15	3-31
Alaska onshore	9.9	negligible	6.1	12	6-19
Subtotal-Economic	34.3	4.7	23.0	89	50-127
Sub-Economic	120	negligible	20	57	44-111

* Economic at pre-embargo prices.
** Adjusted for resources at water depths greater than 200 meters.

Resource Assessments in the Estimation Process

Crucial to the modeling effort for projecting future oil production is the capability of the model to "capture" this entire range of the resource base. The USGS, in Circular 725, delineates the resource base into the various categories (see Figure II-10).

The FEA oil supply model performs six production calculations for each expected price in each region during each year. These six "types" of production correspond to these resource categories into which the domestic resource base is divided by the USGS. The labels the model uses to designate production from each of these categories is also shown in Figure II-10.

Several observations emerge regarding reserve and resource assessments (see Table II-5):

- Using the USGS "statistical mean" for undiscovered resources, 151 billion barrels of "undiscovered" and "identified" (demonstrated plus inferred) resources remain economically recoverable. Another 197 billion barrels potential (classified as sub-economic) might ultimately become recoverable at prices above pre-embargo levels with new technology and time. Both amounts compare to cumulative domestic oil production to date of about 105 billion barrels.

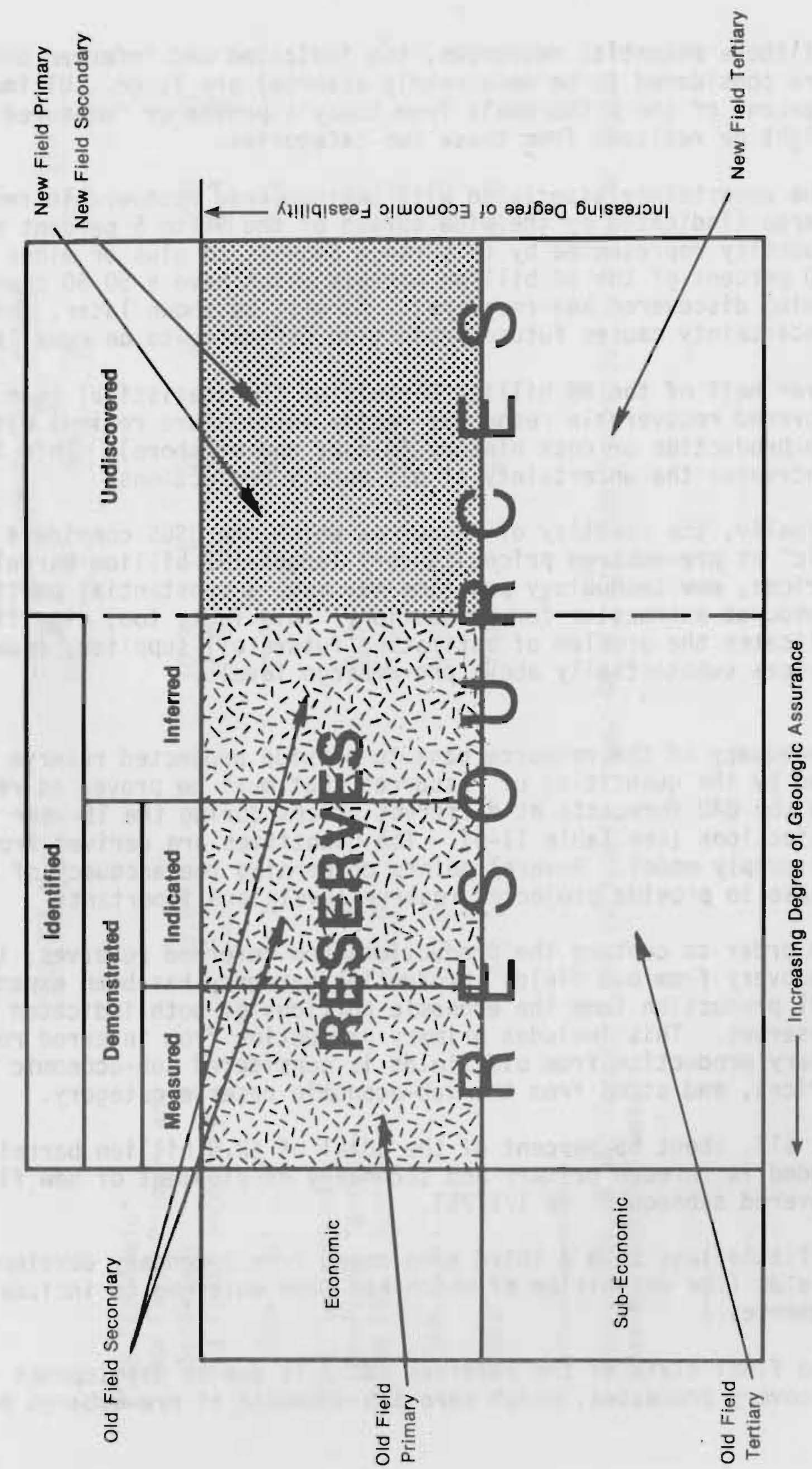


Figure II-10
Petroleum Resources Of The United States

- Of these potential resources, the indicated and inferred portion (which are considered to be more nearly assured) are large. Ultimately, 80 percent of the withdrawals from today's proved or "measured" reserves might be replaced from these two categories.

- The uncertainty associated with undiscovered recoverable resources is large (indicated by the wide spread of the 95 to 5 percent range). The quantity represented by this range amounts to plus or minus more than 40 percent of the 89 billion barrels which have a 50-50 chance of being discovered and recovered. As will be shown later, this resource uncertainty causes future production estimates to be equally uncertain.

- Over half of the 89 billion barrels of the statistical mean of undiscovered recoverable resources reside in immature regions with little or no production or cost history (Alaska and offshore). This fact further increases the uncertainty of oil supply projections.

- Finally, the quantity of resources which the USGS considers "sub-economic" at pre-embargo prices is very large--197 billion barrels. Higher prices, new technology and time may make a substantial portion of this resource attractive for production. This fact, too, significantly complicates the problem of estimating future oil supplies, especially at prices substantially above pre-embargo levels.

The adequacy of the resource base to provide projected reserve levels is illustrated by the quantities of resources that must be proved as reserves to achieve the BAU forecasts at different prices during the 15-year time span of the projections (see Table II-6). The quantities are derived from results of the oil supply model. Several points concerning the adequacy of the resource base to provide projected reserve levels are important:

- In order to capture the production from inferred reserves, the "secondary recovery from old fields" production category has been expanded to include all production from the economic portions of both indicated and inferred reserves. This includes primary production from inferred reserves. Tertiary production from old fields is considered sub-economic at pre-embargo prices, and stems from the sub-economic reserve category.

- At $13, about 55 percent of the total of 48.9 billion barrels of reserves added is through primary and secondary development of new fields (discovered subsequent to 1/1/75).

- A little less than a third more comes from secondary development of old fields (the definition of which has been enlarged to include inferred reserves.)

- The final sixth of the reserves added is due to development of tertiary recovery processes, which were sub-economic at pre-embargo prices.

Table II-6

BAU PROVED RESERVES ADDED, 1975-1989
(Billions of Barrels)

		Expected Oil Price					
		$8		$13		$16	
	USGS-725 Mean	Bbl.	%	Bbl.	%	Bbl.	%
USGS "Economic"							
New Field Primary and Secondary	73.6*	10.8	14	26.7	35	32.0	43
Old Field Secondary	21.5	14.4	67	14.4	67	14.4	67
Sub-total	98.1	27.2	28%	41.1	42%	46.4	47%
USGS "sub-economic"							
New Field Tertiary	57.0	0.0		0.3		0.7	
Old Field Tertiary	120.0	0.6		7.5		10.2	
Sub-total	177.0	0.6		7.8		10.9	
Total	275.1	27.8		48.9		57.3	

* Alaska onshore and Beaufort Sea excluded. Lower-48 OCS adjusted for resources at water depths greater than 200 meters.

- Even at $16, less than half of the economically recoverable resources available are proved as reserves, which is only about 21 percent of the total resources available (both economic and sub-economic).

- Tertiary reserves, which are derived from a resource category of potentially enormous size (177 billion barrels), has reached only a very low level by 1989 (10.9 billion barrels).

The results of the fifteen year projections depend upon the resource base assumptions and also on the effort required to convert resources into reserves and subsequently to produce them.

OCS Leasing

During 1974, 1.8 million acres of OCS lands were leased, or about 26 percent of the total of 6.8 million acres leased between 1964 and 1974. The assumed Business-as-Usual OCS leasing will amount to 34.4 million acres between 1975 and 1989 (see Table II-7).

Table II-7

BUSINESS-AS-USUAL LEASING
(Millions of Acres)

Period	Total MM Acres	% of Total	Alaska* MM Acres	California MM Acres	Gulf of Mexico MM Acres	Atlantic MM Acres
1975-79	15.8	46	4.5	3.1	4.1	4.2
1980-84	11.0	32	2.6	0.9	4.6	2.9
1985-89	7.6	22	2.0	0.6	2.8	2.2
Total	34.4	100	9.1	4.6	11.5	9.3
Percent of total			26%	13%	33%	27%

* Excludes Beaufort Sea

The schedules were based on assumptions concerning lease sales and the attractiveness of the areas offered to the industry. These assumptions include:

- There will be six sales per year through 1990.

- 800,000 acres will be offered in each sale.

- The percentage of acres leased of those offered in each sale will be:
  - 1976 and 1977 75%
  - 1978 through 1982 55%
  - 1982 through 1989 35%

The rationable for the higher percentage leased figure in the early years is based on the fact that the early nominations of acreage will be those with the most attractive structures.

Several points are important:

- The percentage of acreage leased assumption leads to nearly half of the acreage to be leased in the first five years.

- The acreage leased in the 15-year period is divided almost equally between mature and frontier areas, i.e., 46 percent in California and the Gulf of Mexico, and 54 percent in Alaska and Atlantic areas.

- The lead time between acres leased and production is long; consequently the effects of the increased leasing in the early years is not felt until much later.

- The number of sales per year and percentage of acres leased may be optimistic in light of recent experience.

Drilling Capacity

Annual drilling rates respond to many factors, including:

- Industry expectations of oil price and its translation into demand for drilling equipment.

- Present supply of drilling rigs and their expected usage over time.

- Current rig manufacturing capability.

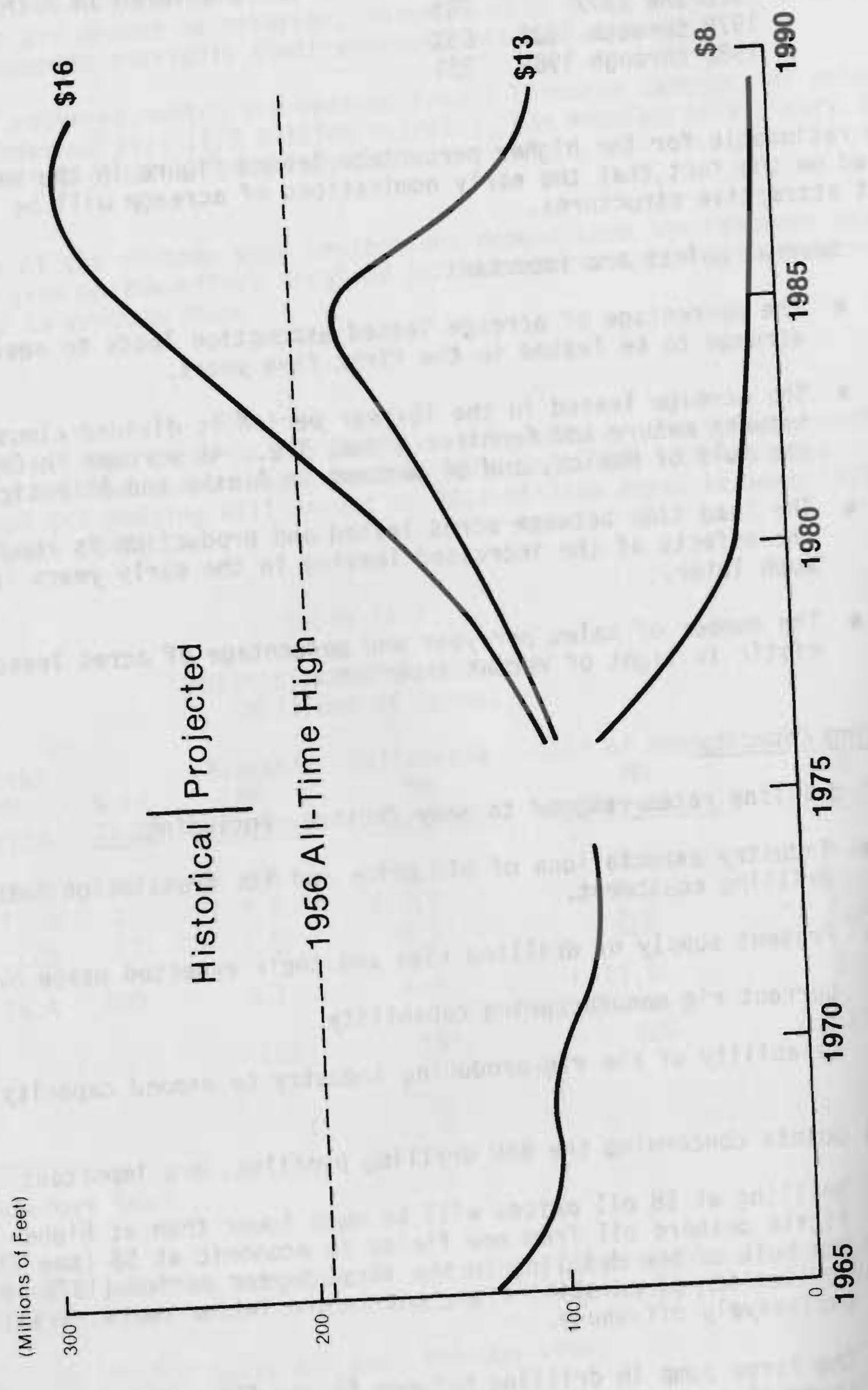
- Capability of the rig-producing industry to expand capacity over time.

Several points concerning the BAU drilling profiles, are important:

- Drilling at $8 oil prices will be much lower than at higher prices since little onshore oil from new fields is economic at $8 (see Figure II-11). The bulk of the drilling in the first 5-year period (1975-1979) is utilization of existing rigs, and in the latter years, drilling is exclusively off-shore.

- The large jump in drilling between $8 and $13 reflects the fact that the lower-48 onshore regions have a large amount of undiscovered oil that is economic only at prices above $8.

Figure II-11
Drilling Activities for Oil (BAU)



- In the preceding 15-year period (1959-1973), drilling activities for oil declined steadily from over 150 million feet to a low of 75 million feet per year. The $13 drilling trajectory reverses that decline and peaks in 1985 at nearly 160 million feet. Drilling activities for oil at $13 in the period 1975 to 1989 are expected to average about 120 million feet per year, compared to a yearly average in the preceding 15 years of about 108 million feet.

- At an expected oil price of $16, drilling is constrained early by rig availability. The greatest production response at $16 occurs later in the forecast as $13 opportunities decline.

<u>Enhanced Recovery</u>

Any discussion of enhanced oil recovery first requires a clarification of the terms involved, due to the current differences regarding definitions. For the purpose of this report the following apply:

SECONDARY RECOVERY:	Waterflooding and non-miscible gas injection, including pressure maintenance
TERTIARY RECOVERY:	All thermal techniques, including: • Cyclic steam injection (steam soak, huff & puff) • Steam drive • In Situ combustion Improved water or gas drives • Surfactant (miceller slug, caustic, etc.) • Miscible (carbon dioxide, high pressure gas, etc.) • Polymer

Enhanced recovery projects generally are initiated while the field is still producing under primary drive. Thus, while approximately 50 percent of U.S. production, or 4.25 MMB/D, is currently being produced from fields under enhanced recovery, only about 25 percent (slightly over 2 MMB/D) is attributable incrementally to the enhanced recovery projects. In the FEA forecasts, only the incremental amount of oil produced from a field under enhanced recovery is that directly attributable to the technique.

Several observations emerge:

- Enhanced recovery production rises to approximately 26 to 30 percent of total crude production--a slight increase over the present 25 percent (see Table II-8).

- The bulk of enhanced recovery production remains secondary methods; these are generally feasible in old fields at prices below the $8 level.
- Tertiary methods show a large price response between $8 and $13. Above $13, tertiary production in 1985 is constrained by lags in research, planning and commercialization, not prices.

Table II-8

1985 BAU PRODUCTION FROM ENHANCED RECOVERY AT ALTERNATIVE OIL PRICES (MMB/D)

Type Recovery	Crude Oil Price $8	$13	$16
Secondary			
Old fields*	2.2	2.2	2.2
New fields	0.4	0.4	0.4
Subtotal	2.6	2.6	2.6
Tertiary			
Old fields	0.1	0.9	0.9
New fields	negligible	negligible	negligible
Subtotal	0.1	1.0	1.0
Total Enhanced	2.7	3.6	3.6
Total Crude Production	9.0	12.9	13.7
% Enhanced of Total	30%	28%	26%

* Also contains production from inferred reserves.

Increased tertiary production is expected to be largely the result of steam or CO_2 injection which, of all the tertiary techniques, are best understood and provide the fastest response. This outlook, however, remains speculative due to the dearth of data and the range of theories concerning tertiary recovery potential.

Available data suggest that near-term production rates (1980) from tertiary recovery cannot be increased by increasing the expected oil price (see Table II-9). The reason for short-term production constraints is that tertiary recovery is essentially in the research and planning stage as a commercial recovery technique.

Table II-9

POTENTIAL TERTIARY RESERVE ADDITIONS AND PRODUCTION

Marginal Oil Price	Incremental Reserves Added (Billions of Barrels)	Total Tertiary Production (MMB/D) 1980	1985	1989
$ 8	0.6	0.1	0.1	0.1
10	3.4	0.4	0.6	0.5
12	3.9	0.4	0.9	1.3
14	3.1	0.4	0.9	1.9

Several years must be spent in screening prospective fields, designing displacement mechanisms, customizing chemicals, conducting pilot projects, lining up equipment, materials, and trained manpower. Thereafter, a delay of one to four years will occur while the recovery agent works its way through the reservoir, displacing the oil toward the producing wells. This short term delay, however, does not mean that higher prices are unproductive with regard to tertiary technology. A higher price immediately will accelerate the overall rate of tertiary recovery applications so that more sophisticated tertiary projects will yield production by 1985, rather than in some later period.

North Alaskan Development

In mid-1975, Alaskan crude production averaged 190 thousand barrels per day. This production occurred almost entirely within state waters offshore in South Alaska.

Under the BAU Outlook and with $13 import prices,* Alaskan crude production possibilities reach 3.1 MMB/D by 1985--a sixteen-fold increase in ten years (see Table II-3). Of these, 2.7 MMB/D depend upon North Alaskan development, principally in and around the Prudhoe Bay area of the North Slope. Major producing areas expected in North Alaska and the route of the Trans Alaska Pipeline System (TAPS) are shown in Figure II-12.

These North Alaskan supply possibilities account for about 21 percent of total potential domestic BAU crude production in 1985. Without further effort, however, fully exploiting these possibilities by 1985 would lead by 1989 to a production decline of 0.6 MMB/D in North Alaska. This factor--coupled with the economics of North Alaskan oil and gas logistics--complicate the Alaskan outlook, and require the careful evaluation of the reserve development potential and the difficult transportation problems.

* Throughout, when import prices are expected to be $13, North Alaskan production is limited to reserves economically viable up to about $10 at the wellhead. This is done to represent, in this chapter, the substantially higher transport costs of North Alaskan oil.

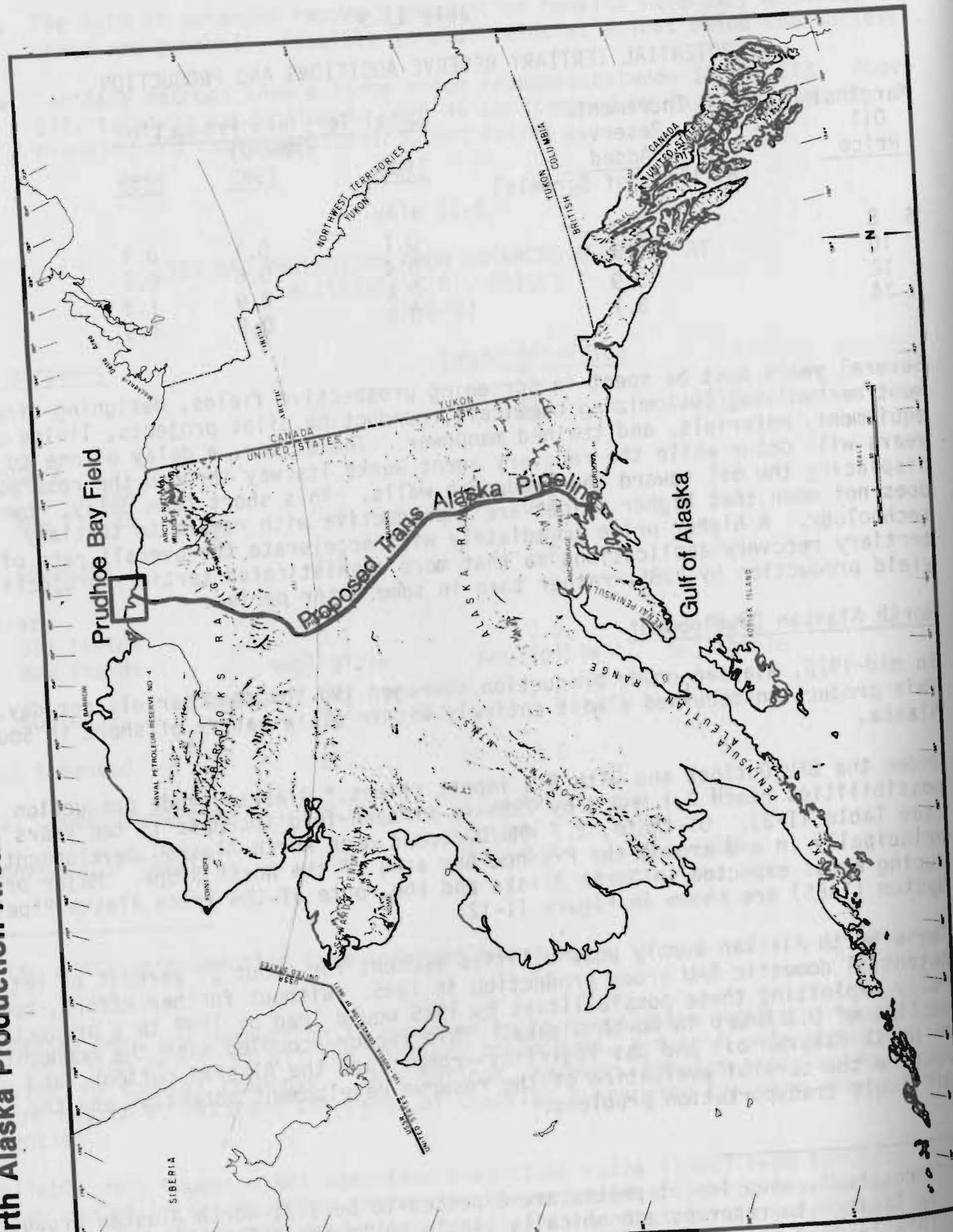


Figure II-12
North Alaska Production Areas

North Alaska Resource and Reserve Potential

Onshore Alaska oil production possibilities--as well as those from the Beaufort Sea--are estimated outside of the FEA model through field-by-field engineering assessments (This methodology, however, produces economically comparable results plus more geographical detail).

Of the 27 billion barrels of undiscovered, recoverable resources estimated by the USGS to exist onshore and offshore in Alaska, the overwhelming share of the potential stems from northern Alaska (see Table II-5). At $13, the BAU outlook envisions that North Alaskan development will convert approximately 50 percent of this resource potential into proved reserves by 1989.

In turn, about 9.6 billion barrels in the Prudhoe Bay field is well-assured with respect to its actual existence and to its economic viability. The confidence associated with the balance of the reserves envisioned under BAU contrasts sharply with the Prudhoe Bay Field (see Table II-10). The majority of the remainder (Other North Slope Private) is discovered, but its extent--and, consequently, the ultimate volume of reserves forthcoming--is only partially delineated. In turn, its performance under production (especially the producing rate of each well, to which economics in north Alaska are critically sensitive) mainly is assumed by analogy with Prudhoe Bay. Consequently, its economics tend to be speculative.

Table II-10

POSSIBLE NORTH ALASKA RESERVES AT $13
(Billions of Barrels)

Area	Reserves** Expected	Discovered	Status Delineated	Developed
Prudhoe Bay	9.6	Yes	Yes	10%
Other North Slope Private*	3.2	Yes	Partially	No
Beaufort Sea	2.3	Not Leased	No	No
Subtotal: BAU	15.1			
NPR-4***	4.0	No	No	No

* Consists of four fields: Gwndyr Bay, North Prudhoe, Kuparuk, and Lisburne.
** Higher prices and technology could increase this amount by about 2.4 billion barrels. Of this, half is estimated to be too expensive at $13; it consists of undiscovered oil around Kavik and a heavy hydrocarbon deposit overlaying the Prudhoe Bay Field. The balance is technically infeasible, awaiting the capacity to drill in waters deeper than 20 feet in the Beaufort Sea.
*** NPR-4 which is included only under the Optimistic Outlook, is also illustrated here.

The final portion (the Beaufort Sea) underlies waters not yet leased. Accordingly, not only is its existence geologically uncertain and its economic performance in question, but its accessibility is speculative.

Production Possibilities in North Alaska

Production possibilities in North Alaska depend upon the amount of reserves available at various minimum acceptable import prices for crude and its coproducts. The economics of north Alaska logistics, however, generally will control the rate at which production possibilities are translated over time into actual production.

Pipeline capacity to serve North Alaska oil fields must be bought in large increments, each of which represents a large capital expenditure. For example, TAPS (2.0 MMB/D of pipeline capacity) is expected to cost about $6 billion in 1975 dollars. A two-step looping program--that is, adding loops to increase the flow in uphill segments to expand TAPS to 3.0 MMB/D--would require an additional $3 billion. Additional capacity would necessitate a second pipeline, perhaps, at an additional $6 billion, or more, depending on its route.

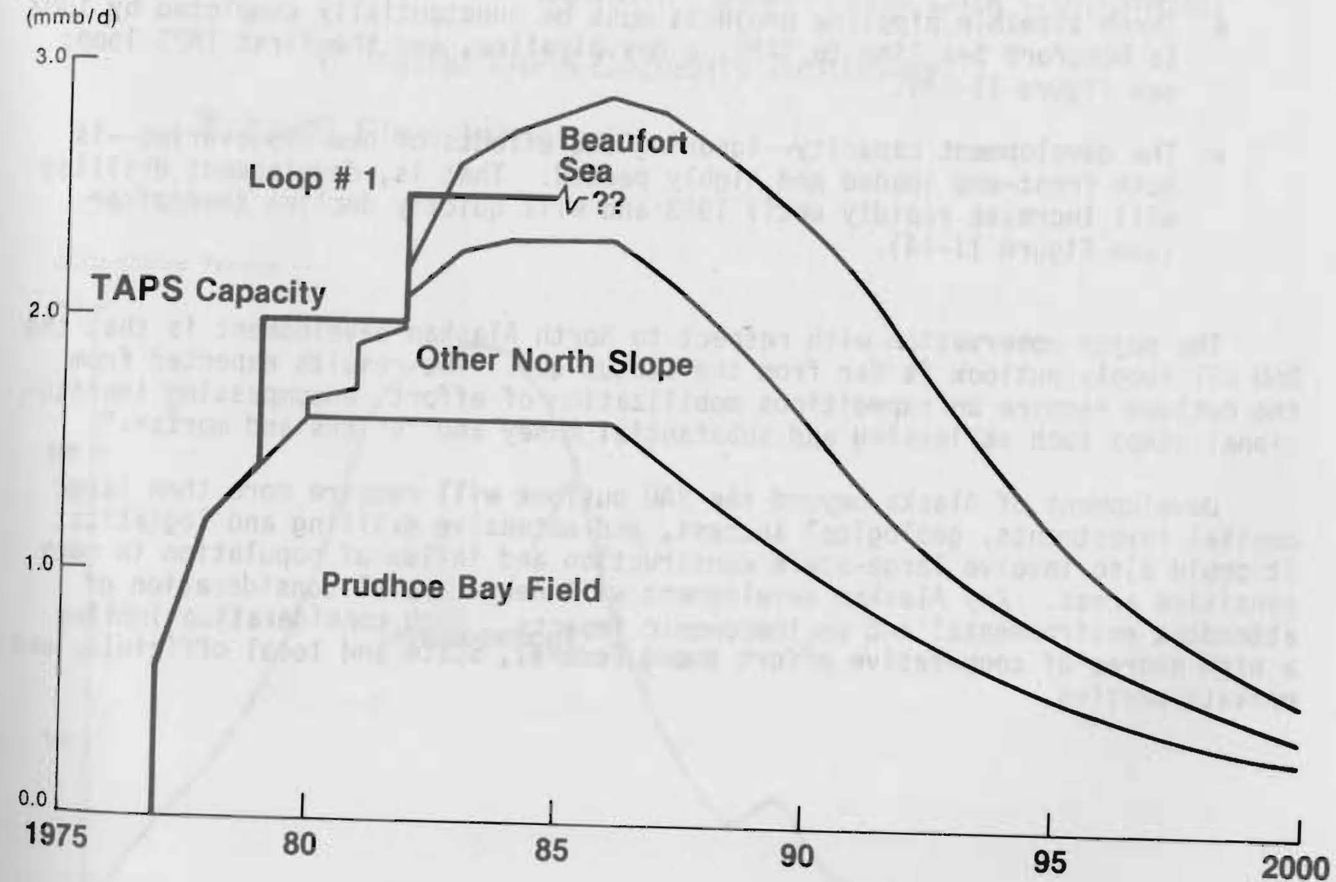
Normally, outlays for pipeline capacity are planned to be recovered over an operating life of no less than 10 years; a 15-year life, however, is more typical. Consequently, the reserves to keep full existing planned capacity (2.0 MMB/D) as well as to sustain the incremental capacity (0.5 MMB/D) for a minimum of 10 years must be reasonably well in hand in order to promote consideration of looping TAPS.

The key features for North Alaskan development and likely evolution of TAPS' capacity under the BAU Outlook are as follows:

- Expansion of TAPS under the BAU Outlook (and in turn, the actual crude production to be expected from Alaska in the 1980's) depends on the Beaufort Sea (see Figure II-13).
- Even if the Beaufort Sea proves prolific, and is exploited according to the moderately optimistic schedule envisioned under BAU, north Alaska production barely can fill a 2.5 MMB/D TAPS for the minimum 10-year economic life of the first loop.
- Any looping of TAPS above 2.5 MMB/D (and, perhaps even occupying fully its 2.5 or 2.0 MMB/D capacity) depends on greater geological fortune from the already discovered fields as well as on substantial new findings to add production during the post-1985 period. Potential sources of additional north Alaska production possibilities, such as NPR-4, are discussed further under the Optimistic Outlook.
- Maintaining the flow through a looped TAPS after 1985 is particularly dependent upon production from new findings. New findings must occur soon, because construction lead times generally require that the looping decision be made within the next three to four years.

Figure II-13

North Alaska Crude Production (BAU)



Magnitude of the Developmental Effort

Since construction of TAPS was initiated in 1973, the pace of development at the Prudhoe Bay field in North Alaska has accelerated dramatically. To complete the development of Prudhoe and to further attain the BAU outlook, the current pace must quicken substantially.

Several things concerning the BAU development effort in North Alaska are important to note:

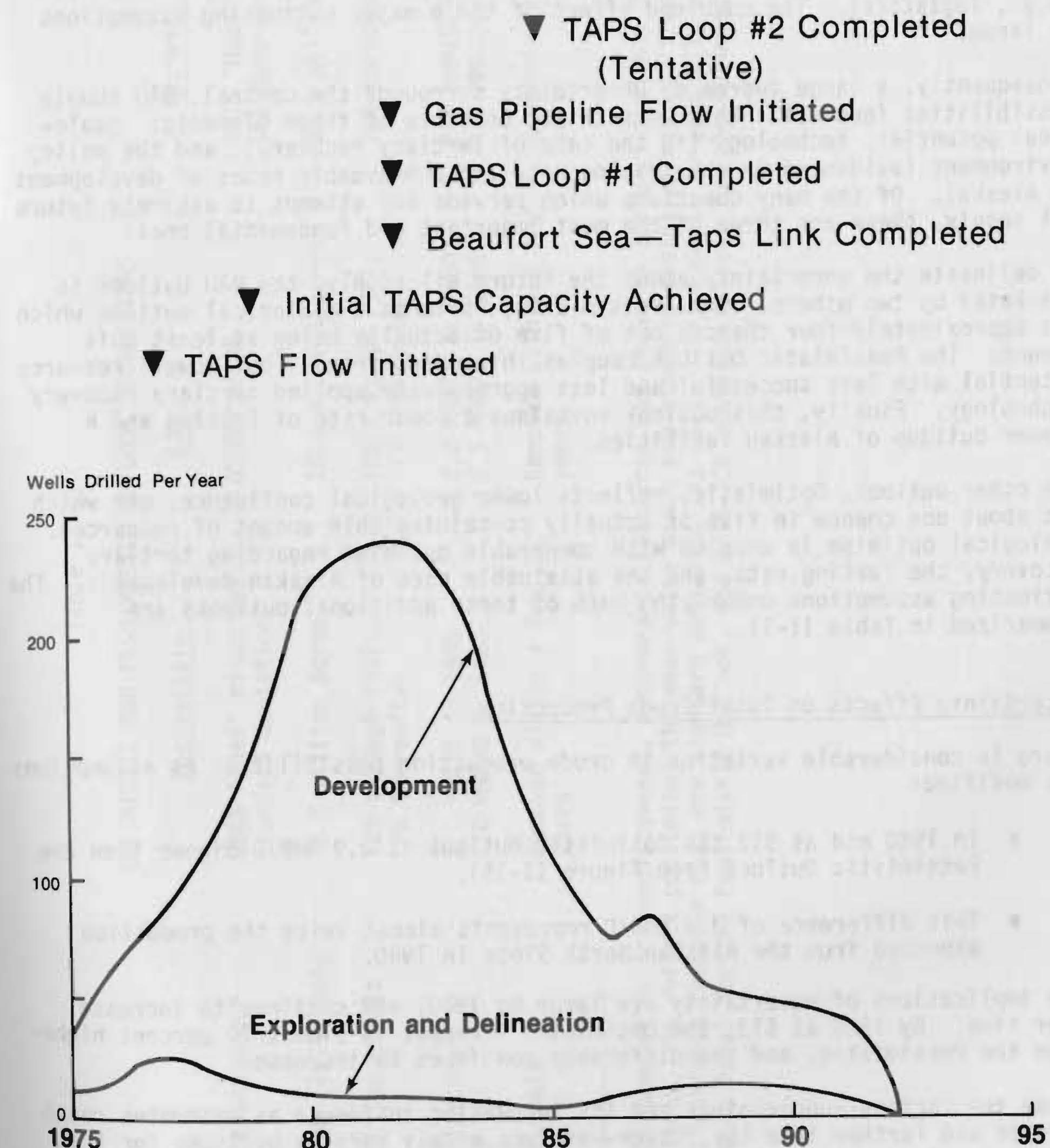
- First, the effort requires substantially faster drilling than experienced through 1975. Developmental drilling from 1975 through 1989 (about 1,765 wells) must be more than 20 times larger than has been accomplished to date (75 wells).
- Three sizeable pipeline projects must be substantially completed by 1982 (a Beaufort Sea link to TAPS, a gas pipeline, and the first TAPS loop; see Figure II-14).
- The development capacity--ignoring the effects of new discoveries--is both front-end loaded and highly peaked. That is, development drilling will increase rapidly until 1983 and will quickly decline thereafter (see Figure II-14).

The major observation with respect to North Alaskan development is that the BAU oil supply outlook is far from the status quo. The results expected from the outlook require an expeditious mobilization of effort, encompassing institutional steps such as leasing and substantial money and "bricks and mortar."

Development of Alaska beyond the BAU outlook will require more than large capital investments, geological success, and extensive drilling and logistics; it could also involve large-scale construction and influx of population in many sensitive areas. Any Alaskan development will need careful consideration of attendant environmental and socioeconomic impacts. Such consideration implies a high degree of cooperative effort among Federal, State and local officials, and private parties.

Figure II-14

North Alaska Drilling and Logistical Effort (BAU)



SUPPLY UNCERTAINTIES: THE OPTIMISTIC AND PESSIMISTIC SUPPLY OUTLOOKS

The description of the BAU supply outlook discussed the influence of geology on the price response of lower-48 onshore supply. It also noted the non-price constraints which bind tertiary recovery supply possibilities (e.g., speculative technology) as well as the lower-48 OCS (e.g., leasing rate) and Alaska (e.g., logistics). The combined effect of these major estimating assumptions is large.

Consequently, a large degree of uncertainty surrounds the central, BAU supply possibilities forecast. This uncertainty consists of three elements: geological potential, technology (in the case of tertiary recovery), and the policy environment (evidenced in the leasing rate and achieveable rates of development in Alaska). Of the many questions which pervade any attempt to estimate future oil supply, these are three of the most important and fundamental ones.

To delineate the uncertainty about the future oil supply, the BAU Outlook is bracketed by two others. One, Pessimistic, reflects a geological outlook which has approximately four chances out of five of actually being at least this amount. The Pessimistic Outlook couples this more certain (but lower) resource potential with less successful and less aggressively applied tertiary recovery technology. Finally, this outlook envisions a lower rate of leasing and a slower buildup of Alaskan facilities.

The other outlook, Optimistic, reflects lower geological confidence, one which has about one chance in five of actually containing this amount of resources. Geological optimism is coupled with comparable optimism regarding tertiary recovery, the leasing rate, and the attainable pace of Alaskan development. The estimating assumptions underlying both of these additional outlooks are summarized in Table II-11.

Uncertainty Effects on Total Crude Production

There is considerable variation in crude production possibilities as assumptions are modified:

- In 1980 and at $13 the Optimistic Outlook is 3.9 MMB/D higher than the Pessimistic Outlook (see Figure II-15).
- This difference of 3.9 MMB/D represents almost twice the production expected from the Alaskan North Slope in 1980.

The implications of uncertainty are large by 1980, and continue to increase over time. By 1985 at $13, the Optimistic forecast is almost 70 percent higher than the Pessimistic, and the difference continues to increase.

These two factors--uncertainty and its increasing influence as estimates reach farther and farther into the future--produce widely varying outlooks for the direction of domestic oil supply and prices in the longer term. Specifically:

Table II-11

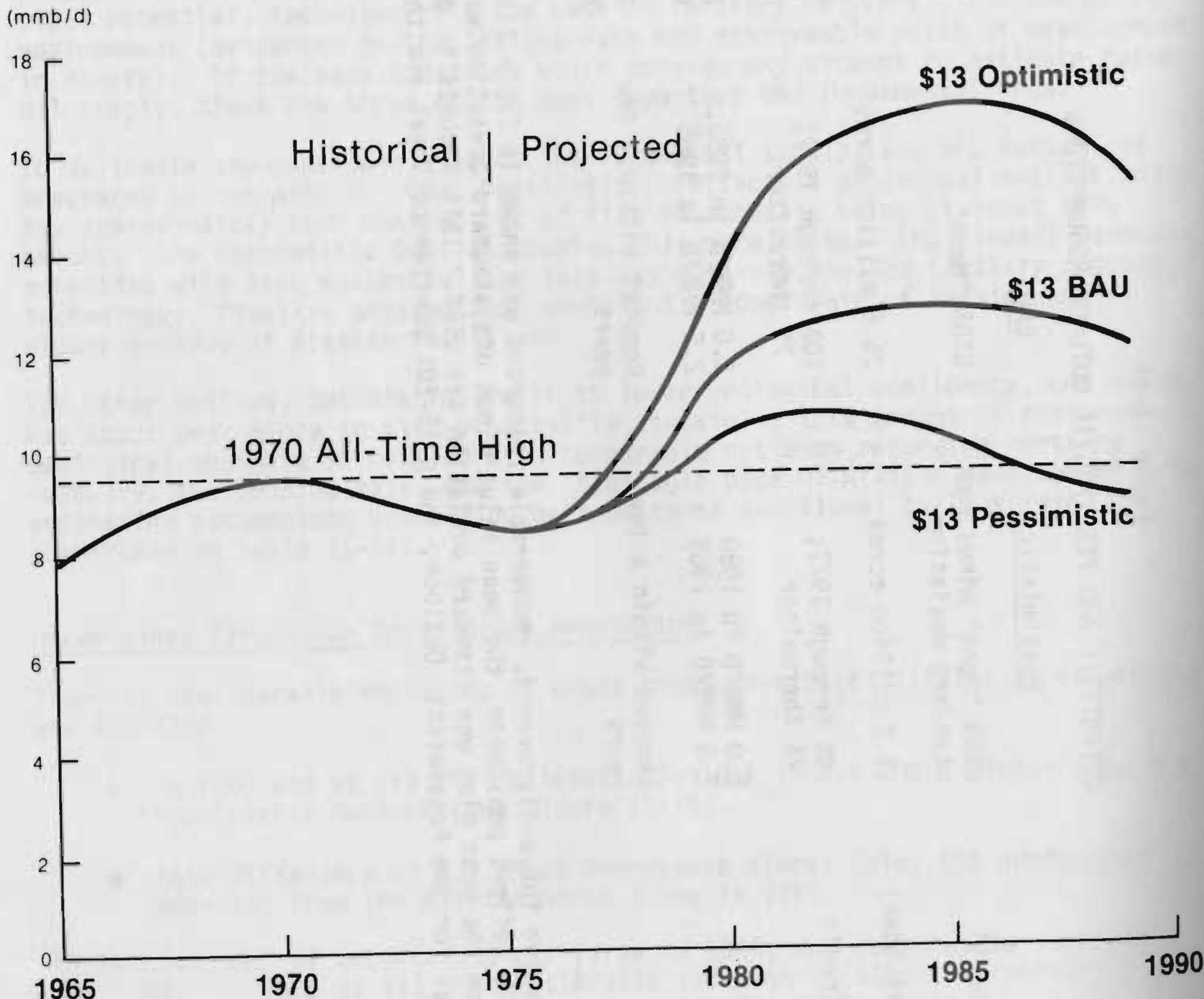
OPTIMISTIC AND PESSIMISTIC OUTLOOK ASSUMPTIONS

	Pessimistic	BAU	Optimistic
Resource Assessment*	USGS "Mean" minus one standard deviation	USGS "Mean"	USGS "Mean" plus one standard deviation
OCS Leasing (1975-1984)	18.2 million acres	26.8 million acres	38.2 million acres
Investment Tax Credit	10% through 1977; 7% thereafter	10% through 1977; 7% thereafter	10% throughout
Alaskan Pipeline Capacity	2.0 MMB/D in 1980 2.0 MMB/D in 1985	2.0 MMB/D in 1980; 2.5 MMB/D in 1985	2.0 MMB/D in 1980 4.5 MMB/D in 1985
Prince Controls	Removed within a few years	Removed within a few years	Removed within a few years

* The USGS mean value for undiscovered, recoverable resources was shown in Table II-5 with a 95-5% confidence level. To reflect pessimism, the mean value minus one standard deviation was utilized, and to reflect optimism the mean plus one standard deviation was used. This amounts to generally an 80-85% confidence level for the Pessimistic Outlook, and a 15-20% confidence level for the Optimistic Outlook.

Figure II-15

Crude Oil Production Under Alternative Outlooks



- At $8, all but the Optimistic Outlook show a steady decline from today's production levels throughout the forecast period.

- At $13, all outlooks evidence some potential supply increase through 1980. After 1980, however, Pessimistic declines rapidly and BAU remains steady. The Optimistic Outlook increases until 1985, then a slow decline commences (see Figure II-15).

- At $16, the Pessimistic Outlook still reflects a supply potential somewhat akin to today's levels through 1989. The other two outlooks increase over the entire forecast period.

<u>Components of Oil Supply Uncertainty</u>

The changes in the oil supply possibilities across the three supply outlooks have geographical, resource base, and recovery method implications (see Table II-12). The following observations are important:

- Most importantly, uncertainty occurs evenly across all of the major components of potential supply, on both the Pessimistic side and the Optimistic side of BAU.

- On the Pessimistic side, however, less fortunate geological experience on the lower-48 onshore (0.8 MMB/D), the rate of OCS leasing (0.4 MMB/D), and the production rate which can be sustained on the North Slope (0.9 MMB/D) stand out as the major uncertainties. These three elements account for 75 percent of the lower supply possibilities represented in the Pessimistic Outlook.

- Alternatively, on the Optimistic side, better tertiary recovery results combine with more fortunate geological experience to cause a 1.4 MMB/D higher estimated supply potential. Offshore leasing (0.9 MMB/D) and the combination of access to and successful results in NPR-4 (0.9 MMB/D) add another 3.2 MMB/D to the Optimistic Outlook compared to BAU. These three elements again account for about 75 percent of the elevated potential estimated under the Optimistic Outlook.

An important twofold message lies behind these widely varying production outlooks. First, geological uncertainty of the magnitude reflected in USGS Circular 725, coupled with the economic unknowns in untried frontier areas, produce major uncertainty in future production estimates. It may be that even very large sums expended in refining geological assessments and hypothetical petroleum engineering estimates could not reduce substantially the intrinsic uncertainty underlying domestic oil resource potentials.

Second, a large degree of this uncertainty is not intrinsic to nature but rather is policy-determined. Geological uncertainty may not respond dramatically to a much larger effort; the reliability of tertiary technology and the availability of supply from the OCS and Alaska--through leasing and more intensive development--probably will. Thus, the importance of resolving outstanding policy questions on these subjects is very clear.

Table II-12

ALTERNATIVE 1985 PRODUCTION AT $13 PRICE
(MMB/D)

	Supply Outlook		
	Pessimistic	BAU	Optimistic
Lower-48 Onshore			
New Field Primary/Secondary	1.3	1.9	2.1
Old Field Secondary	2.0	2.0	2.7
Tertiary	0.8	1.0	1.5
Initial Reserves	2.4	2.4	2.4
Subtotal	6.5	7.3	8.7
Lower-48 OCS			
Pacific	0.5	0.6	0.9
Gulf of Mexico	1.1	1.4	1.9
Atlantic	0.1	0.1	0.2
Subtotal	1.7	2.1	3.0
Alaska			
Beaufort Sea	--	0.4	0.7
Other OCS	0.3	0.4	0.5
North Slope	1.4	2.3	2.7
NPR-4	--	--	0.9
Subtotal	1.7	3.1	4.8
Other			
NPR-1	--	0.2	0.2
Tar Sands	--	--	--
Heavy Hydrocarbons	0.2	0.2	0.3
Subtotal	0.2	0.4	0.5
Total Crude	10.1	12.9	17.0
Natural Gas Liquids	1.7	1.8	2.1
Total Liquids	11.8	14.7	19.1

Major Areas of Uncertainty in the Oil Supply Outlook

The four major areas of uncertainty in the oil supply outlook are the resource base, drilling effort, OCS leasing schedules, and enhanced recovery. The Optimistic and Pessimistic supply possibilities incorporate different assumptions concerning these factors. The incremental impact on 1985 crude oil production at $13 varies with these assumptions (see Table II-13).

Table II-13

CONTRIBUTION TO ESTIMATING UNCERTAINTY FROM GEOLOGIC, DRILLING, LEASING AND ALASKA SCENARIOS
(1985 Crude Oil Production (MMB/D)

	Scenario	
	Optimistic	Pessimistic
BAU Base Production	12.9	12.9
Geological*	+1.1	-0.7
Drilling	+0.3	-0.1
Leasing	+0.9	-0.4
Alaska and other	+1.8	-1.6
Scenario production	17.0	10.1

* Enhanced recovery is implicit in these figures.

Inferred Reserves and Undiscovered Recoverable Resources

Several points to be noted concerning resource levels chosen for each scenario are (see Table II-14):

- The Optimistic resource levels are determined statistically and correspond to about a one in five chance that they are this high.
- The Pessimistic resource levels have approximately a four in five chance to be at least this much.
- The higher inferred reserve level in the Optimistic supply outlook is a result of subjective judgment by the USGS concerning inferred reserves in East Texas, which departed from its normal statistical procedure to report a more optimistic quantity. The more conservative statistical estimate was used for the BAU and Pessimistic outlooks.

Drilling Levels

There are several important points with respect to drilling levels:

- Increased drilling is largely the result of the higher resource base, but also the result of other factors which are varied for each outlook (see Table II-15).
- OCS drilling increases because of increased leasing which will be discussed as the next area of uncertainty.

- The largest part of the drilling difference onshore occurs late in the forecast as drilling "builds up" or "runs down," which consequently lessens the impact on 1985 production (see Figure II-16).

Table II-14

USGS-725: ALTERNATIVE GEOLOGICAL OUTLOOKS
(Billions of Barrels)

	Pessimistic	BAU	Optimistic
Measured Reserves	34.3	34.3	34.3
Inferred Reserves	18.5*	18.5*	23.1
Subtotal: Reserves	52.8	52.8	57.4
Undiscovered Recoverable	28.0	44.0	60.0
Lower-48 Onshore	15.6	33.0	49.6
OCS**	7.7	12.0	16.3
Alaska - Onshore			
Subtotal	51.3	89.0	125.9
Total	104.1	141.8	183.3

* Adjusted to reflect lower East Texas inferred.
** Adjusted to include water depths greater than 200 meters.

Table II-15

IMPACT OF ALTERNATIVE SUPPLY OUTLOOKS ON DRILLING ACTIVITY AT $13
(Millions of Feet Drilled: 1975-1985)

	Pessimistic	BAU	Optimistic
Lower-48 Onshore	833.4	1,144.3	1,405.8
OCS	151.8	212.1	297.0
Total	985.2	1,356.4	1,702.8

OCS Leasing

The difference in OCS leasing schedules occurs solely because of a variance in the assumed acreage per lease sale. The BAU Outlook assumed 800,000 acres per sale would be offered; whereas the Optimistic assumed 1,200,000 acres and the Pessimistic 500,000 acres (see Table II-16).

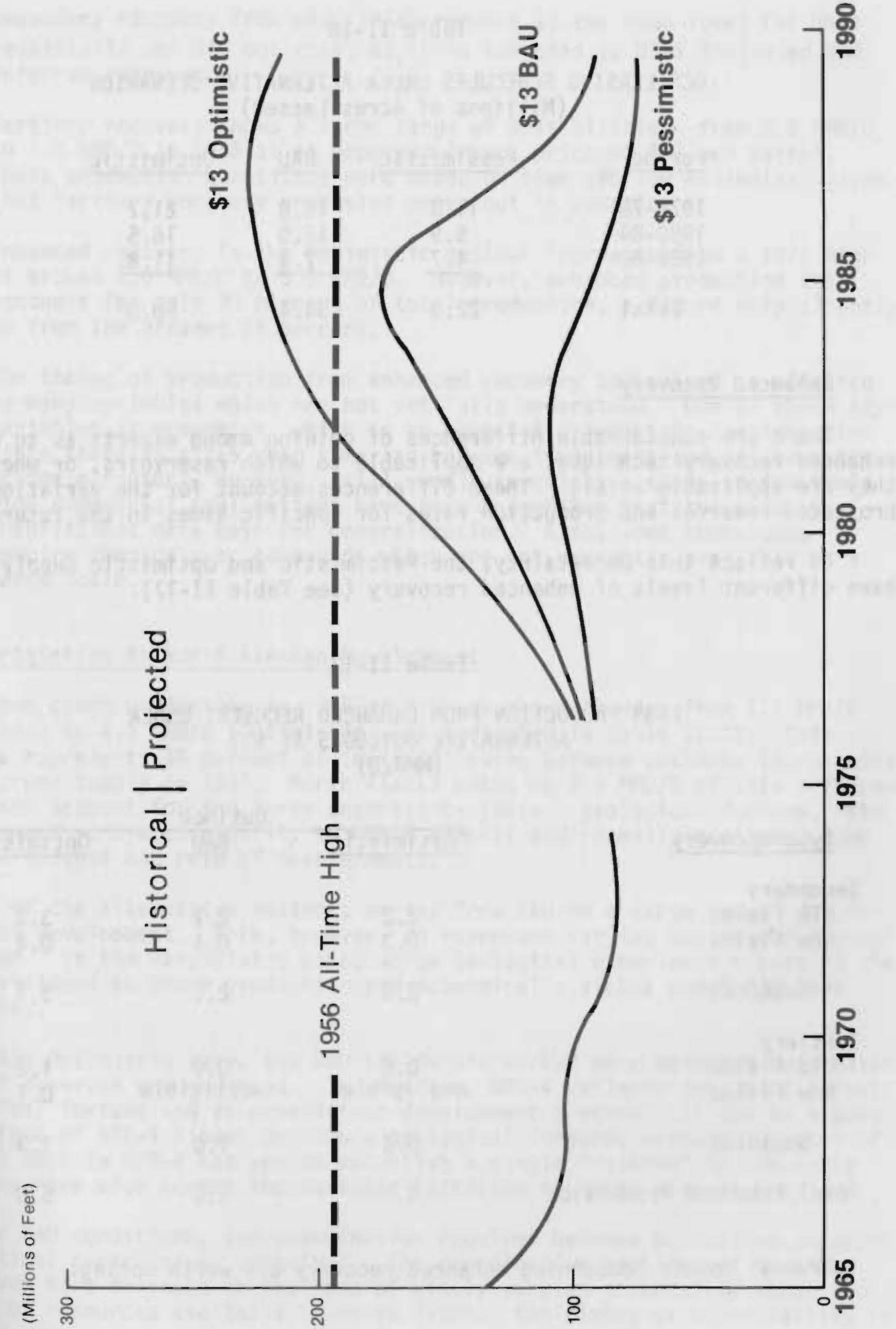


Figure II-16
Drilling Activities for Oil Under Alternative Outlooks

Table II-16

OCS LEASING SCHEDULES UNDER ALTERNATIVE SCENARIOS
(Millions of Acres Leased)

Period	Pessimistic	BAU	Optimistic
1975-79	11.3	15.8	21.7
1980-84	6.9	11.0	16.5
1985-89	4.7	7.6	11.8
Total	22.9	34.4	50.0

Enhanced Recovery

There are considerable differences of opinion among experts as to which enhanced recovery techniques are applicable to which reservoirs, or whether they are applicable at all. These differences account for the variations in projected reserves and production rates for specific times in the future.

To reflect this uncertainty, the Pessimistic and Optimistic supply outlooks have different levels of enhanced recovery (see Table II-17).

Table II-17

1985 PRODUCTION FROM ENHANCED RECOVERY UNDER
ALTERNATIVE OUTLOOKS AT $13
(MMB/D)

	Outlook		
Type Recovery	Pessimistic	BAU	Optimistic
Secondary			
Old Fields	2.2	2.2	3.3
New Fields	0.3	0.4	0.4
Subtotal	2.5	2.6	3.7
Tertiary			
Old Fields	0.6	0.9	1.2
New Fields	negligible	negligible	0.1
Subtotal	0.6	1.0	1.3
Total Enhanced Production	3.1	3.6	5.0

Several points concerning enhanced recovery are worth noting:

- Secondary recovery from old fields remains at the same level for both Pessimistic and BAU outlooks, as it is targeted to USGS indicated and inferred reserves.
- Tertiary recovery shows a large range of possibilities--from 0.6 MMB/D to 1.3 MMB/D in 1985 at an expected import price of $13 per barrel. These production quantities were based on high and low estimates, given that tertiary recovery processes prove out in practice.
- Enhanced recovery in the Optimistic outlook increases from a 1975 high of around 2.0 MMB/D to 5.0 MMB/D. However, enhanced production still accounts for only 30 percent of total production, a figure only slightly up from the present 25 percent.
- The timing of production from enhanced recovery technology is affected by many variables which are not yet fully understood. One of these key variables is economics, which is an especially important consideration since there is a 3-5 year time lag between investment and oil recovery. Economic factors, however, still remain speculative since so few field-wide commercial applications have been undertaken that there is an insufficient data base for generalization. Also, some techniques require chemicals or compounds which are not currently available on a large scale.

Uncertainties in North Alaskan Development

Alaskan crude production in 1985 at $13 was shown to vary from 1.7 MMB/D (Pessimistic) to 4.8 MMB/D (Optimistic), as indicated in Table II-12. This difference represents 45 percent of the total swing between outlooks in potential domestic crude supply in 1985. North Alaska makes up 2.9 MMB/D of this difference. Three things account for the large uncertainty there: geological fortune, rate of development, and accessibility to NPR-4 (itself additionally contigent upon geological success and rate of development).

Each of the alternative outlooks varies from BAU to a large extent due to the rate of development. Both, however, do represent varying degrees of geological fortune. In the Pessimistic case, worse geological experience occurs in the fields envisioned to prove productive and economically viable under BAU (see Table II-18).

For the Optimistic case, the BAU fields are worked more quickly; no greater amounts of reserves are expected. In contrast, NPR-4 reflects the joint effects of geological fortune and an expeditious development program. It can be argued that the fate of NPR-4 hinges on future geological fortune, because 30 years of geological work in NPR-4 has yet to establish a single "reserve" in the sense applied anywhere else across the domestic petroleum resource picture.

Under BAU conditions, the coordination required between production capacity and logistical capacity was described. The coordination problem, of course, becomes even more delicate in the face of widely varying uncertainty about the magnitude of resources available in North Alaska, the timing of accessibility to them, and rates of productive capacity build-up that might be achieved (see Figure II-17 which portrays trajectories of the three alternative production possibilities for North Alaska as well as the implications of the Optimistic Outlook for TAPS capacity requirements).

Table II-18

1985 COMPONENTS OF NORTH ALASKA UNCERTAINTY
(MMB/D)

	Alternative Outlook	
	Pessimistic	Optimistic
Business-as-Usual	2.7	2.7
Geological Fortune	-0.5	--
Rate of Development	-0.8	+0.7
NPR-4	--	+0.9
Alternative Outlook	1.4	4.3

The most important points which emerge from the figure concern the maximum production likely to be realized under the Optimistic Outlook. Although peak production possibilities of about 4.5 MMB/D are estimated, expansion of TAPS beyond loop #2 (3.0 MMB/D) looks doubtful for two major reasons:

- Coincident production peaks, caused by rapid buildup of North Alaskan production from all likely fields through 1985, lead to an equally sharp decline thereafter.
- Since achieving the 4.5 MMB/D peak requires bringing 60 percent of the USGS-estimated resource base into play, finding reserves to fill another pipeline more than temporarily, while maintaining 3.0 MMB/D throughput for a doubly-looped TAPS, will be difficult.*

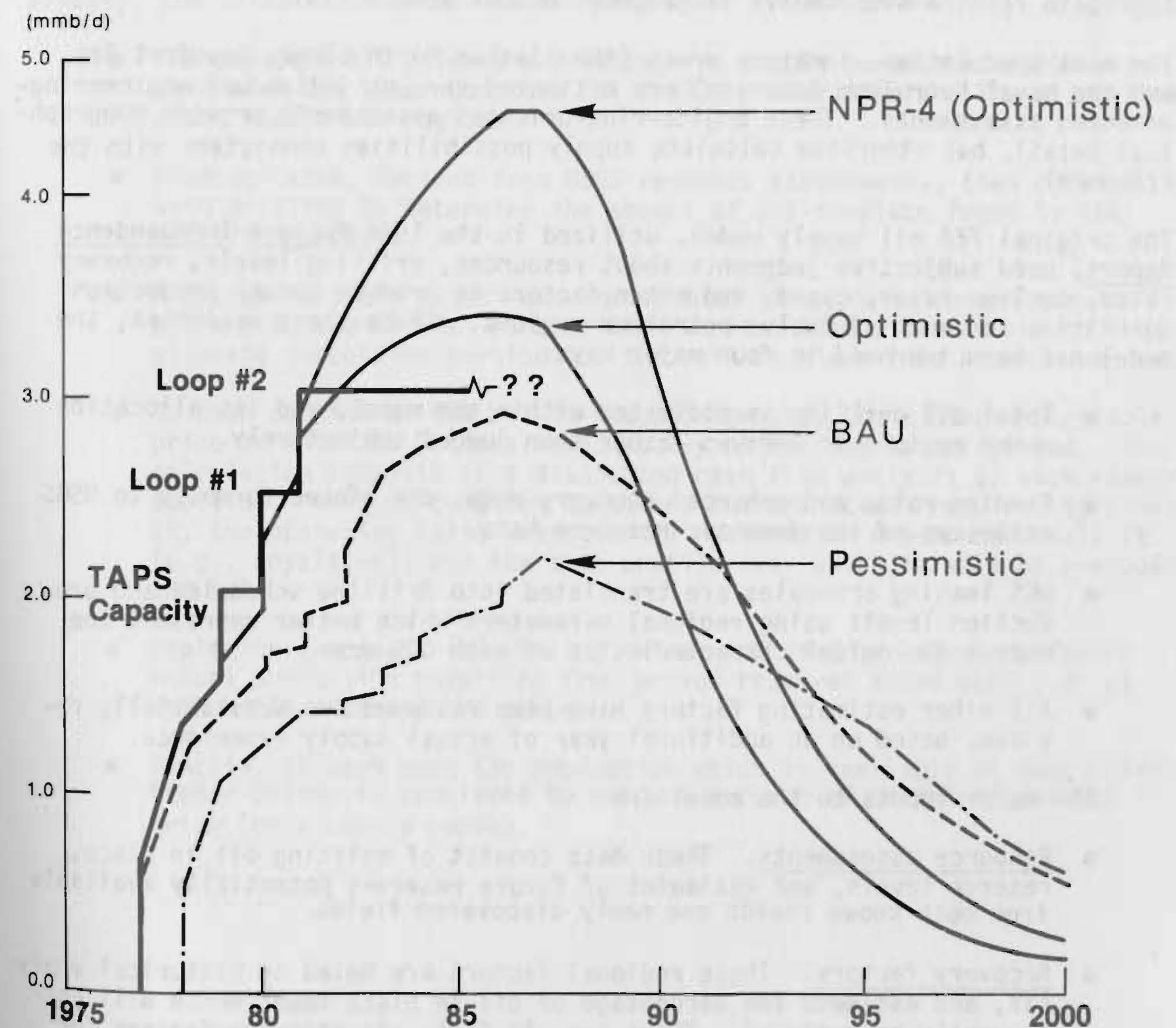
From this perspective, the likelihood of loop #2 appears to depend heavily on either NPR-4 or the portion of the resource base not covered in this outlook. The same point made earlier under BAU concerning TAPS loop #1 obtains equally here: The expansion of TAPS' capacity to 3.0 MMB/D by 1985 requires that the reserves to support it be identified soon.

Toward the Pessimistic end of the spectrum of North Alaskan production possibilities, incremental TAPS capacity is a lesser issue. There, it appears that the disposition of NPR-4--with institutional difficulty due partly to the requirement for a major, 400-mile pipeline required to link up with TAPS--may control the future of loop #1.

* Perhaps additional recovery and inclusion of additional deposits in the recoverable resource base, at higher prices than imagined in USGS-725, would alter this assessment.

Figure II-17

Outlooks for North Alaska Crude Production



The major point here, however, concerns the uncertainty, not the wisdom of any one specific TAPS capacity. At this juncture, the question of appropriate TAPS capacity for 1985 is impossible to calculate. The key to the solution is more tangible knowledge about the resource base, both how much is there, and at what price it becomes economically viable. In turn, obtaining tangible knowledge requires geological/geophysical work and exploratory drilling.

THE ESTIMATING APPROACH AND THE FEA MODEL

The BAU estimating assumptions are converted to oil supply estimates through two separate estimating tools. Oil supply estimates for the lower-48 states and most of the Alaskan OCS are derived using an FEA model, which deals in aggregate fashion with twelve large geographical areas.

The most speculative, immature areas (the Alaskan North Slope, Beaufort Sea, and the Naval Petroleum Reserves) are estimated through individual engineering-oriented assessments. These engineering-oriented assessments provide geographical detail, but otherwise calculate supply possibilities consistent with the FEA model.

The original FEA oil supply model, utilized in the 1974 Project Independence Report, used subjective judgments about resources, drilling levels, recovery rates, decline rates, costs, and other factors to produce annual production quantities for each of twelve petroleum regions. Since these estimates, the model has been improved in four major ways:

- Total oil drilling is estimated within the model, and its allocation among regions is derived rather than judged subjectively.
- Finding rates and enhanced recovery rates are linked formally to USGS estimates of the domestic resource base.
- OCS leasing schedules are translated into drilling schedules and production levels using regional parameters which better represent the unique geological characteristics of each OCS area.
- All other estimating factors have been reviewed and substantially revised, based on an additional year of actual supply experience.

The major inputs to the model are:

- Resource assessments. These data consist of existing oil in place, reserve levels, and estimates of future reserves potentially available from both known fields and newly discovered fields.
- Recovery factors. These regional factors are based on historical analysis, and estimate the percentage of oil in place found which will consequently be produced. There are, in fact, six recovery factors for each region, one for each "type" of production.

- Depletion fractions. These regional factors are based on 1974 production history, and pertain to the rate that crude oil is produced from reserves. These factors provide for a systematic dwindling of existing reserves which have to be replaced by new discoveries in order to maintain production levels.
- Costs. Costs are of two types: drilling costs and other investments necessary to find oil and convert it to proved reserves, and operating costs necessary to produce the oil from reserves, once proved. These cost factors have been estimated from historical analyses and from judgmental decisions concerning cost escalation due to, say, deep wells.

These four major inputs (and many other less critical factors) permit the model to derive annual regional production figures at different price levels. Briefly, the calculation procedure consists of six broad steps:

- The expected oil price and drilling rig supply parameters combine to determine the total domestic oil drilling over time and its allocation among twelve oil regions.
- Finding rates, derived from USGS resource assessments, then combine with drilling to determine the amount of oil-in-place found by the drilling process.
- Regional recovery rates--one for each of three recovery methods in old and in new fields--combine with various lead time factors to allocate successive portions of this oil-in-place into proved reserves.
- As each portion of the oil-in-place is proved, the minimum-acceptable price at which it becomes economically attractive is calculated. The calculation consists of a discounted cash flow analysis of each reserve addition. This calculation considers the investment required to prove it, the operating costs subsequently required to produce and sell it (e.g., royalties), and the time profile over which it will be produced and sold.
- Depletion fractions--or decline rates--are used to calculate future annual production resulting from proved reserves added each year at each minimum-acceptable price.
- Finally, in each year the production which is available at successively higher prices is cumulated to produce a curve of production versus price (or a supply curve).

LONG TERM DEMAND FORECAST

The Project Independence Evaluation System (PIES) links the supply projections delineated in this chapter with demand scenarios for each sector of the economy. The linkage is accomplished in the main PIES linear programming model which finds an equilibrium solution for domestic consumption and total supply of all energy resources. It determines this equilibrium solution by considering the flow of energy resources from areas of supply to areas of consumption, and supplements any shortfall in domestic production with imports. The PIES model does this for a range of energy scenarios and for several prices.

Under the PIES Reference Scenario, there is a wide variation between demand growth rates at three imported oil prices: $8, $13, and $16 (see Figure II-18). This growth is based on BAU supply possibilities at these same prices. Several points are important:

- At $8 world oil prices, domestic consumption rises at a compounded growth rate of 3.9 percent between 1974 and 1985. Imports of nearly 14.0 MMB/D must be brought in to fill the gap between consumption and domestic production.
- At $13 domestic consumption increases at about half the historical pace, or about 2.0 percent compounded annually. Domestic production fills 70 percent of this demand in 1985, and imports of only about 6.0 MMB/D are necessary to fill the gap.
- At $16 world oil prices, consumption grows at a slower rate of only 1.4 percent per year, and domestic production supplies all but about 3.0 MMB/D of that amount by 1985.

These same consumption solutions can also be broken down by consuming sector (see Figure II-19).

Several observations regarding sector demand at $13 world oil prices are important (see Table II-19):

- The transportation sector is quantitatively the largest of the final consuming sectors, accounting for about half of total oil demand. The trend towards smaller, more fuel-efficient automobiles is expected to continue and to have a major impact in reducing demand growth between now and 1985.
- At $13 world oil prices, consumption of oil by electric utilities is expected to decline substantially as coal and nuclear plants replace oil in base-loaded generation. At higher or lower prices, electric utilities show the greatest level of demand elasticity of all the sectors, and at $8, consumption by this sector rises from 6.5 to 16.0 percent of total consumption.
- In the household/commercial sector, the effect of a substantial rise in delivered oil prices is partially offset by an equivalent rise in de-

Figure II-18

Projected Petroleum Consumption (Reference Scenario)

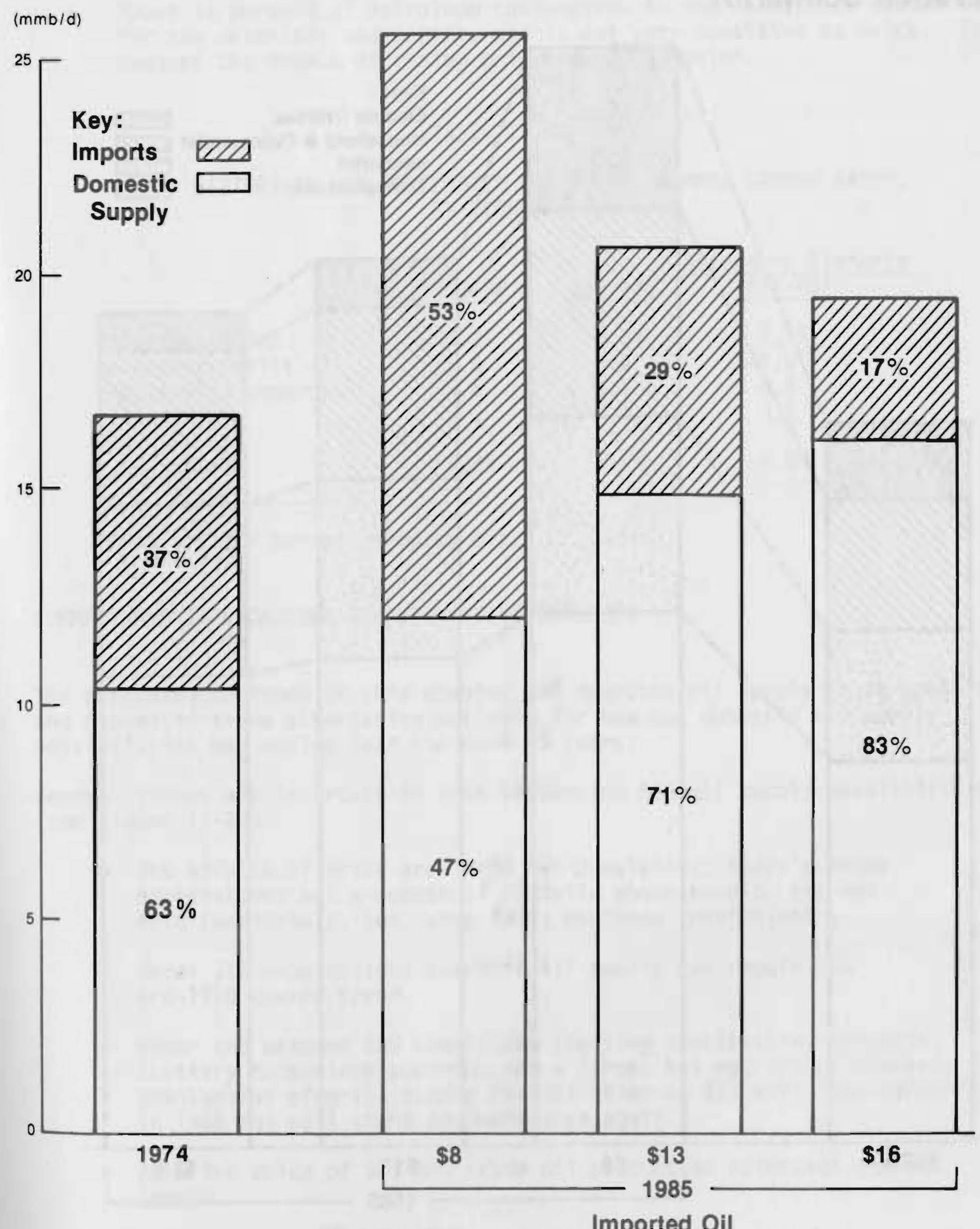
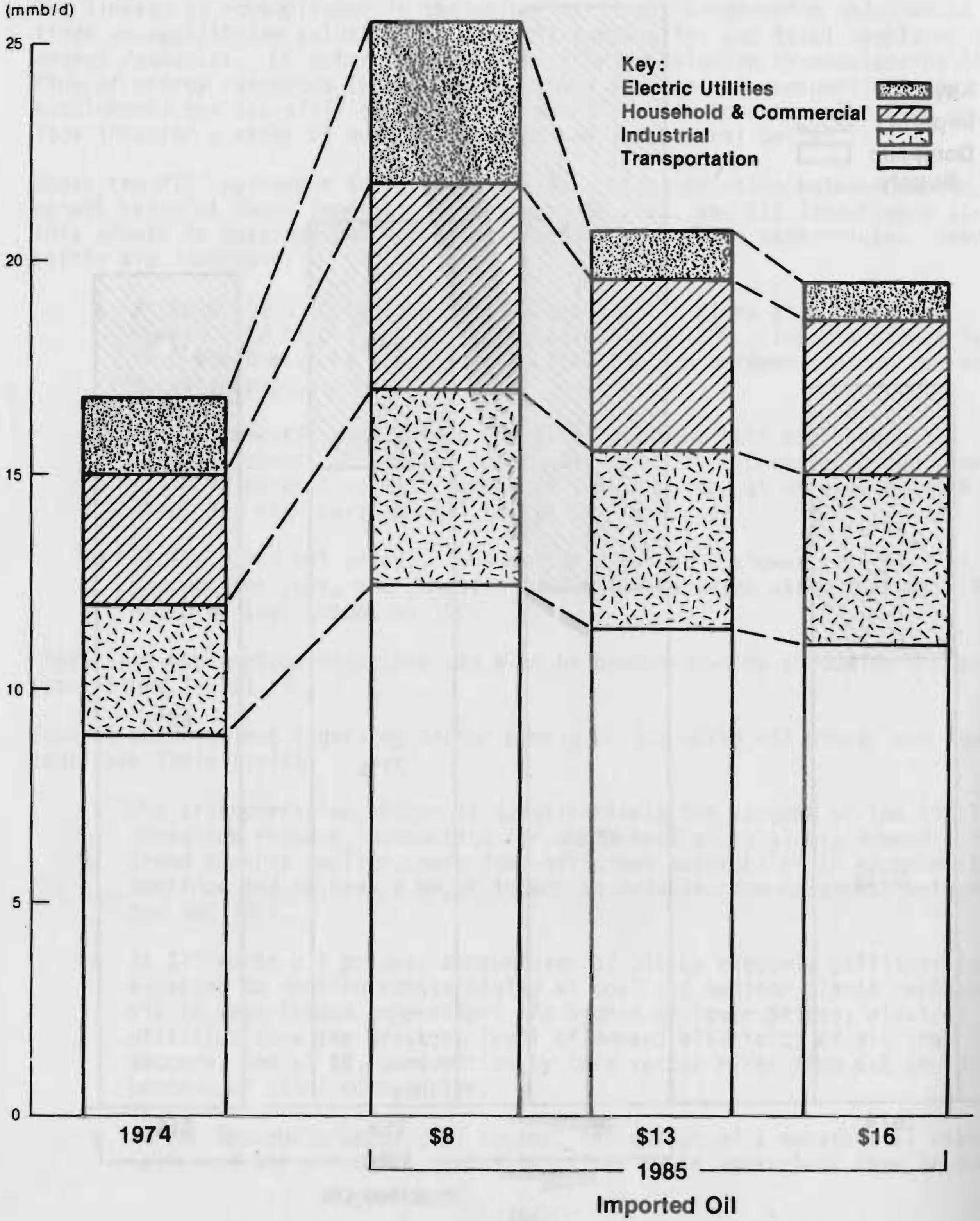


Figure II-19

Outlook for Petroleum Consumption by Sector (Reference Scenario)



controlled natural gas prices, thus maintaining oil's share for heating in the 1974-85 period.

- About 30 percent of petroleum consumption in the industrial sector is for raw materials and coking, and is not very sensitive to price. This reduces the impact of rising prices on consumption.

Table II-19

HISTORICAL AND FORECASTED ANNUAL OIL DEMAND GROWTH RATES, BY ECONOMIC SECTOR

	1960-72	1972-74	Reference Scenario 1974-85*
Transportation	4.3%	1.3%	2.1%
Electric Utilities	15.4	5.4	-2.3
Household/Commercial	2.6	-4.7	2.8
Industrial	3.7	2.1	3.1
Total	4.2%	0.7%	2.0%

* At $13 per barrel imported oil.

SUMMARY AND IMPLICATIONS OF ALTERNATIVE OUTLOOKS

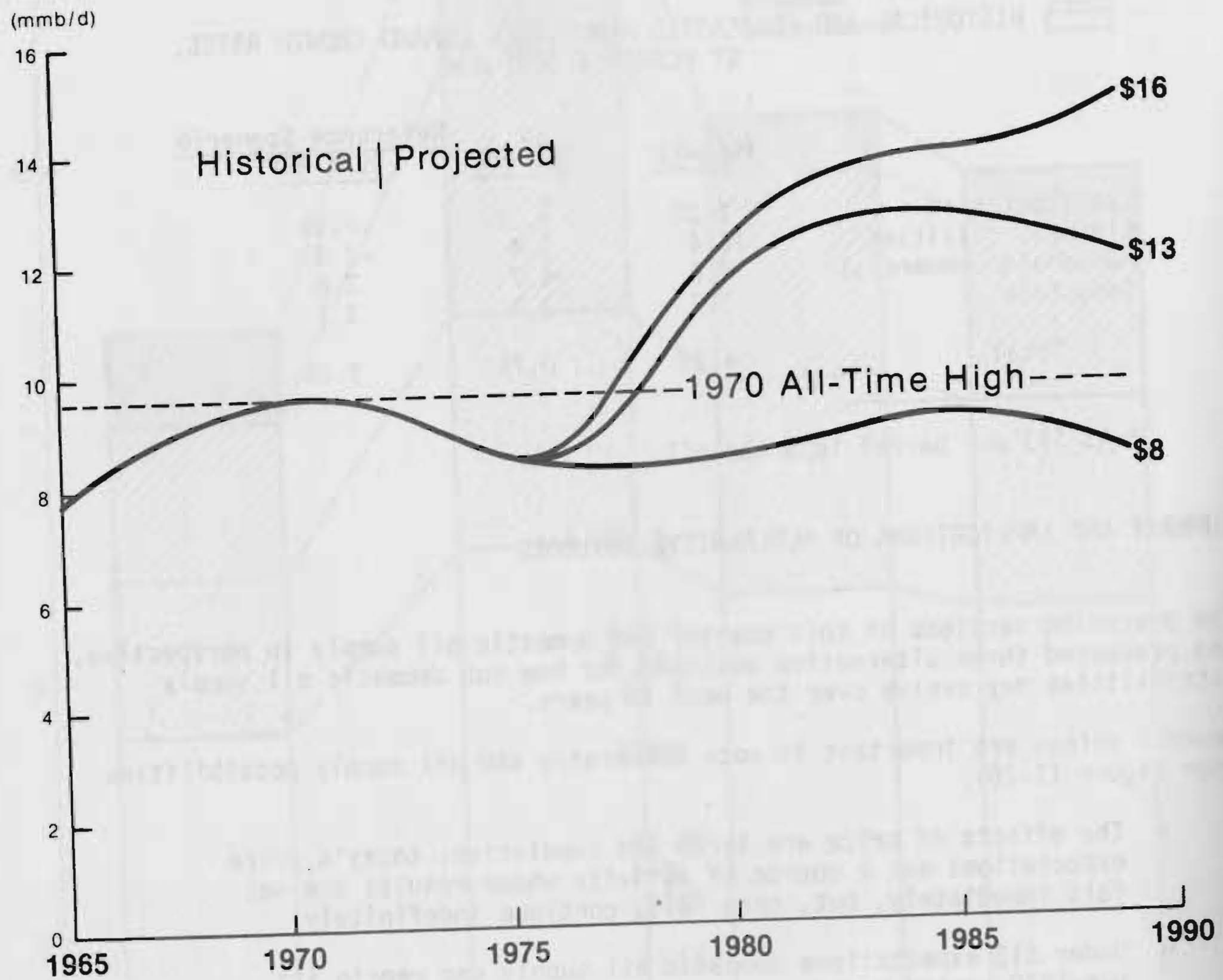
The preceding sections of this chapter put domestic oil supply in perspective, and presented three alternative outlooks for how our domestic oil supply possibilities may evolve over the next 15 years.

Several things are important to note concerning BAU oil supply possibilities (see Figure II-20):

- The effects of price are large and cumulative; today's price expectations set a course of activity whose results are not felt immediately, but, once felt, continue indefinitely.
- Under $13 expectations domestic oil supply can regain its pre-1970 upward trend.
- Under the assumed BAU conditions (leasing constraints, moderate tertiary technology success, and a large, but not crash, Alaskan development effort), supply possibilities at $13 will have peaked in 1985 and will trend downward once again.
- At a low price of $8, BAU crude oil production maintains current levels.

Figure II-20

Crude Oil Production at Three Prices (BAU)



- At a higher price of $16, crude oil production until 1985 proceeds on a slightly higher trajectory than at $13, averaging about 0.5 MMB/D higher. By 1985, however, when the $13 supply trajectory peaks and begins to decline, supply possibilities at $16 continue to trend upward to peak at a point beyond 1990.

The effort necessary to produce these BAU oil supply possibilities is large by historical standards (see Figures II-21 through II-23):

- A massive exploratory and developmental drilling effort is required. Annual oil drilling must more than double by 1985, to approach its all-time high reached in 1956.

- In addition to drilling, accomplishment of these supply possibilities requires a high level of Federal OCS leasing.

- The most comprehensive measure of the total effort is the capital required to fuel it. Capital expenditures for oil must more than double (in constant 1975 dollars) by 1985.

- Tertiary recovery must succeed technically and economically, and must be applied at a moderately brisk pace.

- North Alaskan development must proceed at a rate capable of expanding Alaskan crude production sixteen-fold over ten years.

With respect to the oil supply possibility outlooks estimated here, the final results will depend on three things: geological fortune, technology (in the case of tertiary recovery) and the policy environment. It is in these areas that the large uncertainty in future potentials appears impossible to resolve at this point. Unfortunately, the implications of this range of outcomes for oil supply possibilities is very large (see Figure II-24).

Previous comments on uncertainty bear repeating here. First, a large share (about half) of this variation across outlooks accurately portrays the fundamental geological unknowns inherent in the oil business. These are revealed directly in USGS Circular 725. These geological unknowns--and the economic uncertaintly they create in a forecast dominated as is this one by frontier areas--can only be expected to produce an uncertain forecast of oil production possibilities 15 years forward in time. Large geological/geophysical expenditures and hypothetical petroleum engineering estimates of economic potential may not substantially reduce the uncertainty intrinsic to domestic oil resources.

A large degree of uncertainty, however, is not natural, but rather, is policy-determined. Geological uncertainty may not respond dramatically to our will. In contrast, policy-determined uncertainty should respond to effort.

Figure II-21

Drilling Activities for Oil (BAU)

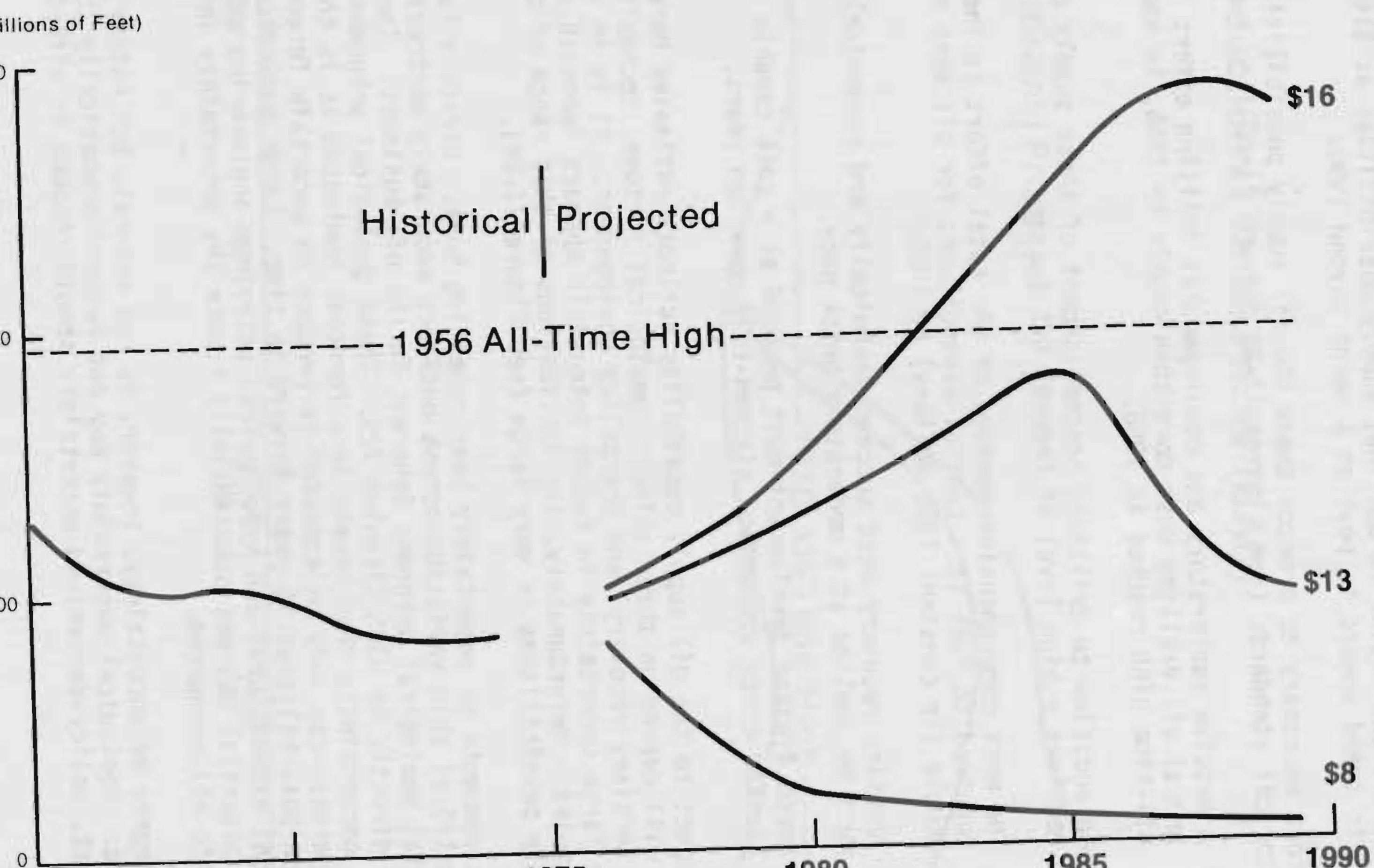


Figure II-22

Outer Continental Shelf Leasing Schedules

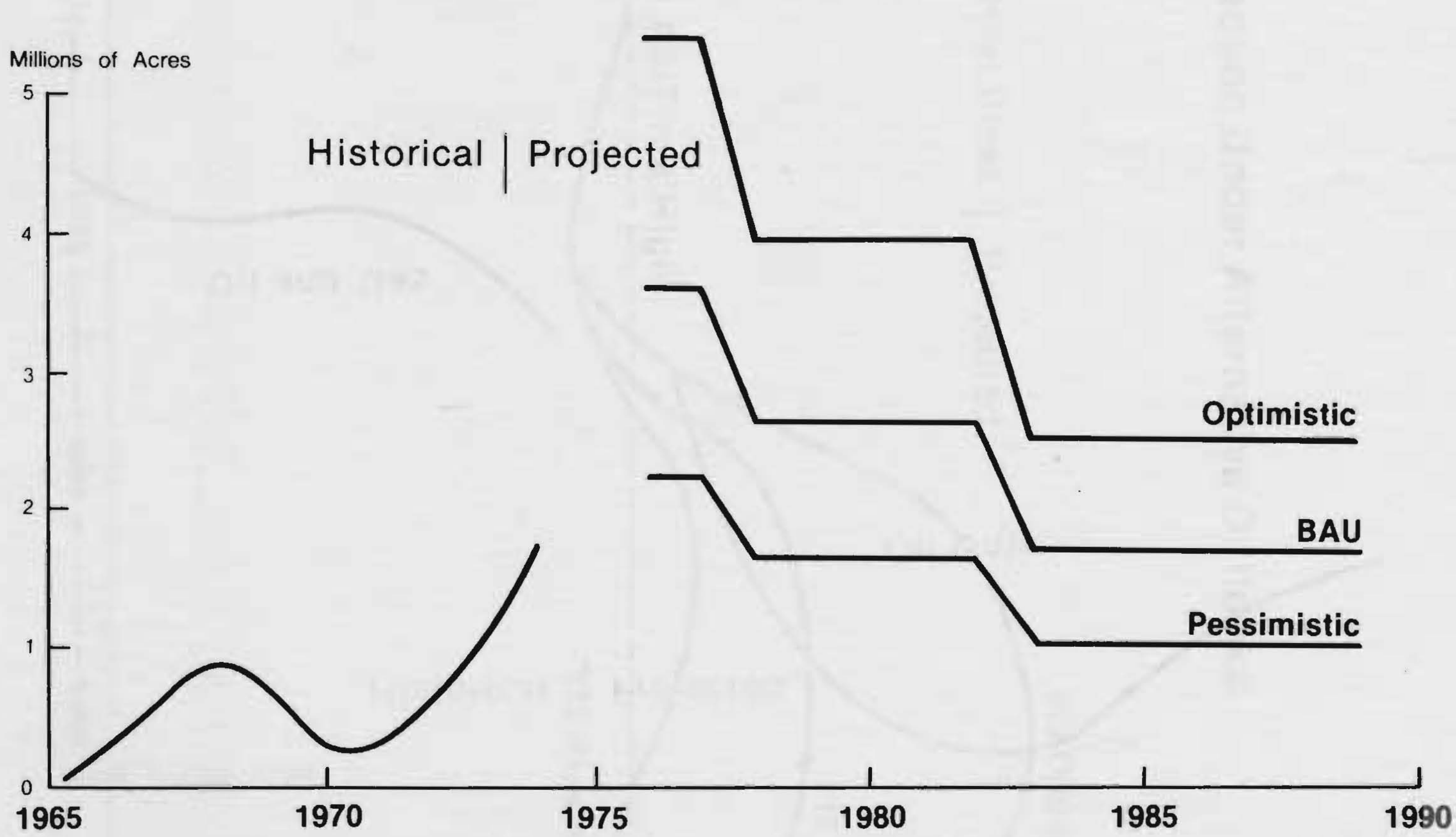
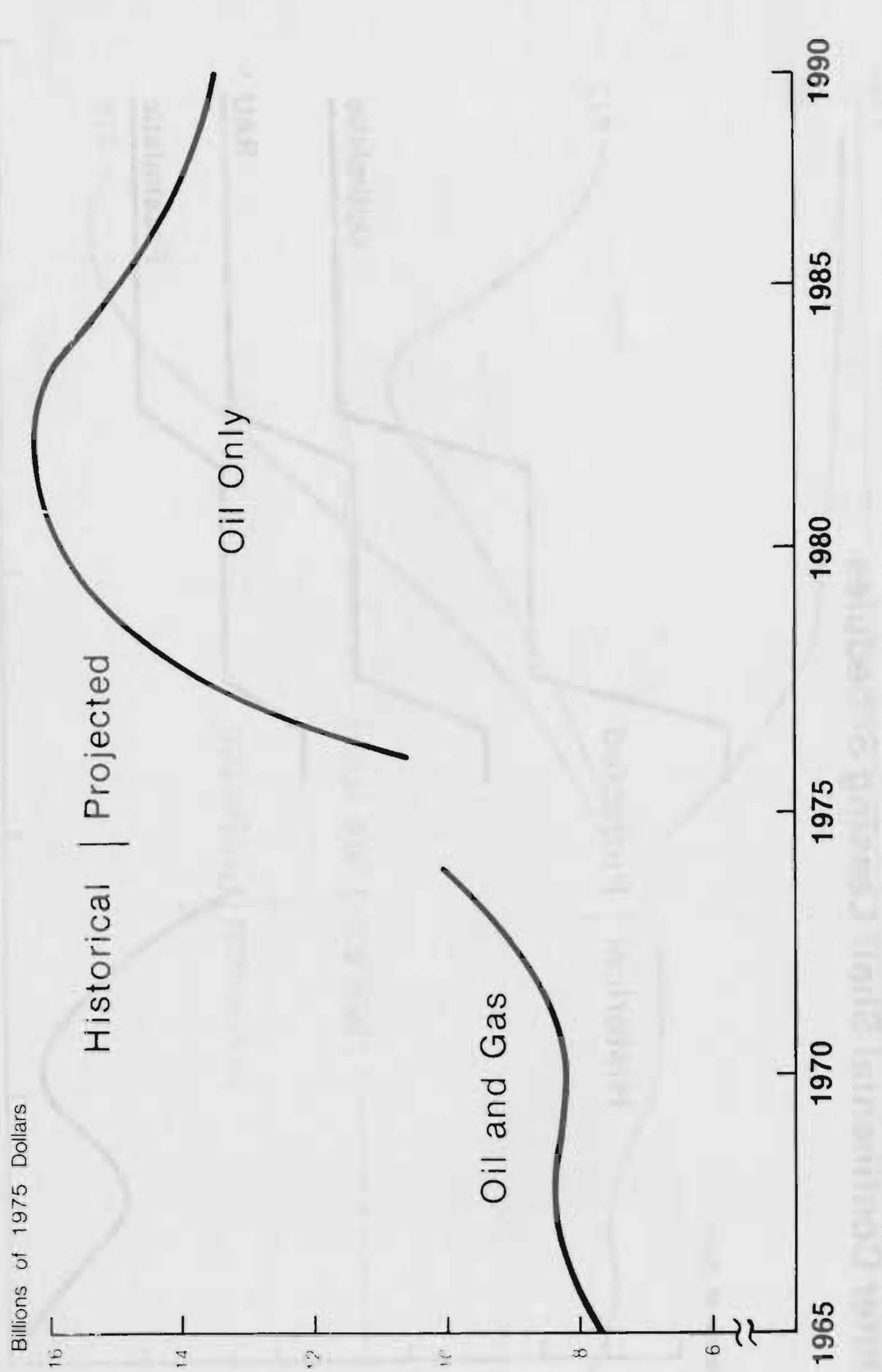


Figure II-23

Capital Expenditures by the Petroleum Industry



Source: Annual Financial Analysis of a Group of Petroleum Companies, 1974. Energy Economics Division, Chase Manhattan Bank, September 1975. Projections from PIES Oil Supply Model.

Figure II-24

Crude Oil Production Under Alternative Outlooks