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BY THE COMPTROLLER GENERAL

Report To The Congress

OF THE UNITED STATES

Analysis Of Current Trends In U.S. Petroleum And Natural Gas Production

Given the realities of the U.S. resource base, it appears that U.S. petroleum and natural gas production will decline steadily through the 1980s, but could be stabilized in the 1990s provided there is reasonable success in new enhanced oil recovery techniques as well as frontier exploration activities. Failure to develop the frontier areas would result in continued declines in U.S. production through the 1990s. While enhanced oil recovery production will not become significant until the 1990s, it could, in combination with vigorous development of the frontier areas, even provide some limited growth prospects by the end of the century.

Prudhoe Bay and the frontier areas will significantly affect the future trends in U.S. petroleum and natural gas production. For petroleum, frontier production will become critical in the mid-1980s when Prudhoe Bay crude oil production begins to decline steeply. For natural gas, production will continue to decline through the end of the century and not stabilize in the 1990s, unless the proposed levels of Prudhoe Bay gas production can be maintained through the end of the century.

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UNITED STATES GENERAL ACCOUNTING OFFICE

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COMPTROLLER GENERAL OF THE UNITED STATES
WASHINGTON, D.C. 20548

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To the President of the Senate and the
Speaker of the House of Representatives

This report analyzes the future trends in U.S. petroleum and natural gas production in the light of the physical factors affecting that production. These trends can provide a perspective within which to assess (1) the "believability" of particular forecasts, (2) the relative desirability or practicality of particular policy initiatives, and (3) the sources of disagreement between differing forecasts. While these trends are not meant to be a precise forecast of future production, production above or below these trends is, in our view, not sufficiently likely to be used for planning purposes.

Our report indicates that it is very unlikely that U.S. petroleum and natural gas production can be increased above or even held at current levels. The possibility exists, however, that the declines in U.S. petroleum and natural gas production can be halted by the early 1990s and production stabilized through the decade. Such stabilization depends critically on a vigorous and successful exploration and development program on the Outer Continental Shelf in Alaska. If this does not occur both petroleum and natural gas production will continue to decline through the end of the century and possibly beyond.

Because the nature of this report is an analysis of long-term trends and their broad implication for energy policy, we do not make any specific recomendations for Government action. As a result, we have not obtained the comments of any Federal agency.

We are sending copies of this report to the Director, Office of Management and Budget; the Secretary of Energy; the Secretary of the Interior; and the chairmen of congressional energy-related committees and subcommittees.

Elmer B. Staats
Comptroller General
of the United States

COMPTROLLER GENERAL'S REPORT TO THE CONGRESS

ANALYSIS OF CURRENT TRENDS IN U.S. PETROLEUM AND NATURAL GAS PRODUCTION

D I G E S T

Estimates of future U.S. petroleum and natural gas supply are governed by a variety of factors some of which are amenable to policy initiatives (e.g., price, environmental standards, leasing policy) but whose effects and desirability are subject to dispute. However, there are certain physical factors (e.g., resource base, reserve addition profiles) governing energy supply which are not subject to as much dispute. Analysis of these physical factors does not provide a basis to precisely identify future production levels, but they can provide a basis to determine the future trends in petroleum and natural gas production.

These trends provide points of reference against which to assess the "believability" of a particular estimate or relative impact of a particular policy initiative. While production above or below these trends is possible, the likelihood is not large enough in GAO's view to be counted on for purposes of determining National energy policy. The purpose of this report is to develop these trends in the light of the physical factors affecting petroleum and natural gas production. (See pages 1 to 3.)

PETROLEUM PRODUCTION

Domestic petroleum production will probably decline steadily through 1990. Production in the 1990s could stabilize and perhaps begin to grow slightly because of new Alaskan and Outer Continental Shelf (OCS) production along with a significant growth in new enhanced oil recovery (EOR) output. Without the addition of production from these areas, U.S. production would continue to decline to little more than half of 1978 production.

Table 1 shows the expected trends in U.S. petroleum production. (See pages 29 to 30.)

Table 1

Estimated Trend of U.S. Petroleum Production by Sources (millions of barrels per day)

	1978 (actual)	1980	1985	1990	1995	2000
CRUDE OIL						
Lower 48 Onshore	6.3	6.0	5.0	4.2	3.9	3.7
Alaska						
Existing	1.2	1.5	1.6	0.9	0.4	0.2
Frontier	-	-	0.1	0.4	0.9	1.3
Total	1.2	1.5	1.7	1.3	1.3	1.5
Lower 48 Offshore						
Existing	0.7	0.6	0.5	0.4	0.3	0.2
Frontier	-	-	0.1	0.2	0.3	0.4
Total	0.7	0.6	0.6	0.6	0.6	0.6
EOR	-	-	-	0.2	0.5	1.0
NATURAL GAS LIQUIDS	1.9	1.8	1.6	1.7	1.7	1.7
Totals	10.1	9.9	8.9	8.0	8.0	8.5

Lower 48 Onshore

More than half of the recent reserve additions in the Lower 48 onshore have come from revisions to existing reserves, mostly as a result of improvements in oil recovery. Reserve additions from drilling activities have remained relatively constant despite dramatic increases in drilling activity since 1973. This is because 90 percent of new drilling activity is for development, not exploration. Furthermore, the exploration finding rate has fallen one-fourth since 1974. If current trends in drilling activity and revisions continue, the annual decline in Lower 48 onshore production could gradually slow from 3.1 percent a year to about 1 percent by the end of the century. (See pages 12 to 19.)

Lower 48 Offshore

Production from existing Lower 48 offshore areas is expected to continue to decline at about 6 percent a year through the end of the century. Frontier offshore production should stabilize total Lower 48 offshore production by the mid-1980s. (See pages 19 to 20.)

Alaska

Current South Alaskan production is expected to decline to insignificant levels by 1990. Prudhoe Bay production should increase to almost 1.5 million barrels per day (BPD) by the early 1980s. In the mid-1980s, it will decline sharply, falling to 200,000 BPD by 2000. Very little new Alaskan production will begin until almost 1990, and it would only stabilize Alaskan production in the 1990s at about 75 percent of the expected 1985 peak.

Current land use laws and decisions have closed or restricted some of the most promising Arctic Ocean areas. This could result in Alaskan production falling to pre-Prudhoe Bay levels, and continuing the decline in overall U.S. production into the late 1990s. (See pages 21 to 24.)

Enhanced Oil Recovery (EOR)

New EOR technologies have significant economic and technological uncertainties along with lead times approaching 10 years to develop a single field. A major part of the resource base accessible to the new EOR techniques is found in small fields, further complicating the economics and pace of EOR production. It does not appear likely that new EOR production will become significant until about 1990. (See pages 24 to 29.)

NATURAL GAS

The aggregate trends in associated, non-associated and total domestic gas supply from conventional sources are shown in Table 2. The decline in U.S. natural gas production should slow significantly in the mid-1980s as a result of the beginning of natural gas production from Prudhoe Bay and the frontier areas (Alaska and OCS). Throughout the 1990s U.S. natural gas production is likely to be essentially stable. (See pages 41 to 43.)

TABLE 2

Estimated Trend of U.S. Natural Gas Production by Sources 1978 to 2000 (trillion cubic feet)

	1978 (actual)	1980	1985	1990	1995	2000
Associated Gas:						
Lower 48	3.6	3.4	2.8	2.3	2.2	2.0
Frontier OCS & Alaska	-	0.1	0.2	1.2	1.4	1.7
Sub-total	3.6	3.5	3.0	3.5	3.6	3.7
Non-Associated Gas:						
Lower 48	15.5	14.7	13.7	12.5	11.8	11.5
Frontier OCS & Alaska	0.2	0.2	.4	.8	1.4	1.4
Sub-total	15.7	14.9	14.1	13.3	13.2	12.9
Total Gas:						
Lower 48	19.1	18.1	16.5	14.8	14.0	13.5
Frontier OCS & Alaska	0.2	0.3	0.6	2.0	2.8	3.1
Total	19.3	18.4	17.1	16.8	16.8	16.6

Associated Gas

Lower 48 production declines rather steeply through 2000, but Alaska and Frontier OCS production begin to compensate for this decline in the 1990s.

If current industry plans to hold Prudhoe Bay production constant at 2 billion cubic feet a day through the end of the century can occur, associated production could grow back almost to current levels by 2000. (See pages 35 to 36.)

Lower 48 Non-Associated Gas

Negative (downward) revisions have strongly affected non-associated natural gas reserve additions since 1969. The apparent rise in reserve additions since 1973 has been solely due to the gradual disappearance of negative revisions, not to exploration activity. Most natural gas drilling activity has been directed towards production, not finding new reserves. The significant natural gas price increases since 1973 have only served to hold exploratory reserve additions level. Even with increases in drilling activity comparable to those since 1973, it is likely that reserve additions would only average about 11 tcf a year, and this assumes positive revisions on the order of 2 tcf a year. (See pages 36 to 40.)

Frontier OCS and Alaska
Non-Associated Gas

Hostile environments, institutional constraints, and high costs of developing frontier areas makes significant production, even by 1990, somewhat problematic. Nevertheless, production could reach 1.2 tcf by 1995. Existing Alaskan areas are expected to continue to produce at about .2 tcf a year through the end of the century. (See pages 40 to 41.)

COMPARISON WITH OTHER WORK

In general our mid-term petroleum production trends (through 1990) tend to be more conservative than other studies, while our long-term estimates (2000) tend to be somewhat in the middle. On the other hand, our natural gas trends tend to be more optimistic than most of the studies. (See pages 45 to 52.)

GAO OBSERVATIONS

The existing resources realities in the Lower 48 States provide little or no opportunity for increased prices and drilling activity to reverse or even stop the long-term decline in Lower 48 production. However, higher prices will provide an opportunity to slow the rate of decline.

The frontier areas are not likely to counteract the decline in Lower 48 production unless there are significantly more resources than currently expected.

A significant amount of frontier production areas and some future Lower 48 producing areas are on lands which have drilling and exploration restrictions, or even prohibitions. If these lands are not developed, production declines will be even steeper.

Production from the giant Prudhoe Bay field on Alaska's North Slope has temporarily reversed the decline in total U.S. production. However, by 1980 the decline will resume. If insufficient new oil is found in Alaska, the steep decline in Prudhoe output after 1985 will accelerate the decline rate of U.S. output.

New enhanced recovery technologies will not become significant until 1990 because of high costs, long lead times, and field size economies of scale.

Long term trends in petroleum production would tend to be more sensitive to price than natural gas because of the EOR possibilities for petroleum.

The NGPA is unlikely to have any long-term effects on U.S. natural gas supplies simply because the pre-NGPA natural gas prices were at a rate such that effective deregulation might have been achieved by the mid-1980s. (see pages 53 to 56.)

CONCLUSIONS

Any policy designed to encourage petroleum and natural gas production must have two equally important purposes:

--To provide adequate incentives to drill for new reserves and improve recovery in existing fields.

--To provide incentives to focus new drilling activities in the areas where it is most likely to find new large fields (e.g., the frontier areas of Alaska and the OCS).

To aim for one with little attention given to the other will significantly impair the likelihood of success for any Government initiatives to stimulate domestic oil and gas production and thereby restrain oil imports. (See page 56.)

Contents

ABBREVIATIONS

AGA	American Gas Association
API	American Petroleum Institute
bcf	billion cubic feet
BPD	barrels per day
cf	cubic feet
CRS	Congressional Research Service
DOC	Department of Commerce
DOE	Department of Energy
EIA	Energy Information Administration
EOR	enhanced oil recovery
ERDA	Energy Research and Development Administration
GAO	General Accounting Office
Mcf	thousand cubic feet
MMcf	million cubic feet
NGL	natural gas liquids
NGPA	Natural Gas Policy Act of 1978
NPC	National Petroleum Council
NPRA	National Petroleum Reserve in Alaska
OCS	Outer Continental Shelf
OTA	Office of Technology Assessment
PIRF	Petroleum Industry Research Foundation, Inc.
PGC	Potential Gas Committee
RP	reserve-to-production
SHC	Sherman H. Clark, Associates
tcf	trillion cubic feet
USGS	United States Geological Survey
WAES	Workshop on Alternative Energy Strategies

CHAPTER 1

INTRODUCTION

Before 1974 many forecasters saw petroleum supply as primarily demand limited. It was felt that price would largely determine the level of domestic exploration and development activity and the rate of production from a diminishing but still very large and more than adequate domestic resource base. Since 1974, however, there has been a growing awareness that U.S. petroleum and natural gas resources are limited and their future production potential is limited. Price will still have a major influence on future investment decisions and the rate of development of future petroleum and natural gas supplies, but only within the constraints of a finite and diminishing resource base and within the time frames dictated by institutional and physical constraints on resource development. As a result, estimates of future petroleum and natural gas production have become more cautious.

PURPOSE AND SCOPE

The purpose of this report is to identify the key indicators affecting future oil and gas supplies and analyze the current trends of these indicators. The key indicators used in this analysis are: (1) the size and location of the domestic petroleum and natural gas resource base, (2) the trends in reserve additions by category (revisions, extensions, new finds in existing or new fields), (3) the trends in U.S. reserve additions by year of discovery for each field, (4) levels of drilling activity, including reserves discovered per foot drilled, reserves discovered per well, and average new field size, (5) production trends for large oil fields, and (6) experience in frontier exploration. This assessment seeks to weigh these indicators against relevant U.S. petroleum and natural gas data and establish correlations and other relationships that will define the important trends affecting future supply.

Information was obtained from Government, industry, and academic sources. Published data and information obtained through interviews with selected energy forecasters in these organizations are used as a basis for this report. The report includes the following:

--An assessment of the resource implications for future U.S. petroleum and conventional natural gas production (ch. 2).

--The U.S. petroleum supply outlook to the year 2000 (ch. 3).

--The U.S. natural gas supply outlook to the year 2000 (ch. 4).

--A comparison of our results with those of other recently published forecasts representing a reasonable cross-section of institutional views (ch. 5).

--Implications and conclusions drawn from the findings of this analysis (ch. 6).

The future domestic supply estimates presented herein are not considered definitive forecasts, but are intended to serve as a reasonable and prudent basis for national energy planning and comparative analyses of individual policies or programs affecting future supplies. The estimates do not include supplies from non-conventional crude oil (e.g., oil shale and tar sands) and natural gas (e.g., tight formations, coal seams, Devonian shale, geopressurized reservoirs).

Price effects are not explicitly taken into account in this work, although the types of reserve additions and the sources of production most likely to be affected by price will be identified and discussed. Of course, as a general rule, the higher the prices for petroleum and natural gas the more likely it would be that the trends described in this report could be achieved or somewhat exceeded. However, the likelihood that increased prices could result in production trends significantly higher than those developed in this report would depend on the degree of confidence one would have in reversing the trends in production and reserve additions described in this work.

METHODOLOGY AND DEFINITIONS

Our general approach is to: (1) estimate the size, location, and other physical characteristics of the domestic oil and gas resource base, (2) identify and assess the levels of exploration and development drilling and improved recovery technologies, and their most likely impacts on converting the remaining recoverable resources into commercially exploitable reserves; and (3) estimate future producing rates consistent with the physical, technical, economic, environmental, and institutional factors that will govern their rate of development in the various producing regions and categories of production and recovery.

There are various classifications and definitions of petroleum and natural gas resources and reserves, regional breakdowns, and oil production and recovery terms. We have used the petroleum resource classification developed by the U.S. Geological Survey (USGS) and U.S. Bureau of Mines, 1/ modified to incorporate the equivalent of measured reserves as defined by the American Petroleum Institute (API) and American Gas Association (AGA) 2/ as proved reserves, to define crude oil, natural gas liquids, and natural gas resources. A complete list of the major terms used in this report are defined in appendix I.

1/U.S. Department of the Interior, Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the U.S., Geological Survey Circular 725 (1975).

2/American Petroleum Institute, Standard Definitions for Petroleum Statistics, Technical Report No. 1, (Second Edition, 1977).

CHAPTER 2

RESOURCE IMPLICATIONS

Prior to the Arab oil embargo, little attention was given to the fact that the Nation's petroleum and natural gas resources are limited. Today, on the other hand, significant efforts are devoted to assessing the remaining U.S. resource base and its effect on future production. While these assessments, by themselves, cannot provide estimates of future production trends, when combined with other factors, they can establish a basis for such estimates. This chapter assesses the implications of the U.S. resource base for future petroleum and natural gas production.

PETROLEUM

The U.S. petroleum resource base is composed of both discovered and undiscovered deposits that are potentially economically recoverable, if and when the deposits are developed. "Reserves" are discovered resources which have been proved, indicated, or inferred (see app. I for definitions) to be recoverable under current ecomomic, technical, and legal conditions. Undiscovered recoverable resources are those estimated to exist in favorable geological settings.

Discovered resources

As of December 31, 1978, U.S. petroleum reserves stood at 33.7 billion barrels, of which 27.8 billion barrels were crude oil and 5.9 billion barrels natural gas liquids (NGL). 1/ At current production levels, proved reserves would last little more than 9 years. Thus, much of the future U.S. production must come from (1) revisions due to enhanced oil recovery from existing fields, (2) discoveries and extensions to reserves in existing fields, or (3) new finds in the remaining undiscovered resource base.

Indicated and inferred reserves provide a basis on which to estimate the extent to which enhanced oil recovery and discovery of additional reserves in existing fields can

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1/American Petroleum Institute and American Gas Association Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada, published annually.

supplement proved reserves. Such reserve additions have played an important role in U.S. production. From 1948 to 1977, 47.1 percent of U.S. crude oil reserve additions came from fields discovered prior to 1948. Without the additions to the pre-1948 fields, it is very unlikely that U.S. production would have grown much past the mid-1950s. Table 1 summarizes the current situation with respect to remaining reserves of petroleum from known and inferred resources already discovered.

Table 1

Petroleum Reserves from Present Discoveries
(billion barrels)

	Crude	NGL	Total
Proved reserves	27.8	5.9	33.7
Indicated reserves (API) (note a)	3.9		3.9
Inferred reserves (USGS) (note b)	c/18.7	5.9	24.6
Estimated total remaining reserves	50.4	11.8	62.2

a/API, op. cit., p. 9.

b/USGS Circular 725, Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States, (1975).

c/Corrected estimate from USGS 725.

If pre-1978 fields were to account for 47.1 percent of all reserve additions during the next 30, years, U.S. crude reserve additions would average only about 1.6 billion barrels a year. 1/ This reserve addition rate would compensate for the reserve depletion of a production rate of 4.4 million barrels per day (BPD), slightly more than half of 1978 production. This would indicate that production would decline to about 4.4 million BPD over this period.

1/The 22.6 billion barrels of indicated and inferred reserves are 47.1 percent of 473 billion barrels of crude reserve additions over the next 30 years (1.6 billion barrels a year).

Undiscovered recoverable reserves

If U.S. production is not to be cut almost in half in the next 20 to 30 years, new field discoveries must play a significantly larger role than they have in the past. USGS has made many estimates of undiscovered crude resources (1965, 1972, 1974, 1975, and now being revised), 1/ as have others from the petroleum industry itself. They all show a growing conservatism in U.S. undiscovered recoverable resource estimates.

USGS is currently reviewing the 1975 estimates, but interim findings indicate no significant changes are planned in the overall estimates at this time. 2/ Nevertheless, this represents a further downgrading of the U.S. resource base because the 1975 estimate was based on pre-1974 oil prices, which were about 30 percent of late-1978 prices. Thus, it appears that USGS is concluding that more than tripling oil prices has had essentially no net effect on the U.S. resource base.

As a result, resource limitations and physical factors will probably be the main determinants of future U.S. petroleum producing rates. The economic climate, the price of oil and gas, environmental concerns, and other institutional constraints will affect the activity levels and future producing rates, but probably only to the extent that they make the trends discussed in this report more or less likely.

Table 2 shows the 1975 USGS estimates of the undiscovered recoverable U.S. petroleum resource base. It indicates that the estimated undiscovered recoverable resources are about 50 percent larger than discovered reserves (statistical mean of 98 billion barrels versus 64 billion). However, even these additional resources will probably not be able to sustain current levels of production for any length of time. About 120 billion barrels of petroleum would have to be made available for production to sustain current levels of production to the end of the century. At least 68 billion barrels (3.1 billion per year) would have to come from the undiscovered. This is more than double the highest rate of reserve additions from this

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1/USGS, op. cit., p. 9.

2/Charles B. Masters, Recent Estimates of U.S. Oil and Gas Resource Potential, USGS, Open File Report 79-236, p. 8.

Table 2

Estimated Remaining Undiscovered Recoverable Resources of Crude Oil and NGL, by Regions (1975) (billions of barrels)

Region	Range (note a)	Statistical Mean (note b)
Crude oil onshore:		
Lower 48	29-64	44
Alaska	6-19	12
Crude oil offshore: (note c)		
Lower 48	5-18	11
Alaska	3-31	15
Natural gas liquids:		
Onshore and offshore	11-22	16
Totals	d/ 61-147	98

a/The low value is associated with a 95-percent probability, and the high value is a 5-percent probability.

b/The statistical mean is the level where there is equal probability that the actual figure will be higher or lower.

c/Offshore to water depth of 200 meters.

d/The range total does not add arithmetically.

part of the resource base experienced since World War II, and almost triple the rate of the last 23 years.

To average 1.6 billion barrels a year of reserve additions through the end of the century implies the discovery of about 25 billion barrels of proved reserves from the undiscovered resource base which is equivalent to current rates of discovery. However, the past 22 years have seen significant exploration in new provinces (e.g., Alaska, Gulf of Mexico), with the resultant discovery of some large fields. The greatest likelihood of finding large new fields is in the frontier area. However, exploration activities are currently focused largely in the areas that have already been explored to some extent. If this concentration continues, then it would be very unlikely that U.S. crude reserve additions would even average 1.6 billion barrels a year.

Conclusions

In light of the past 30 years of U.S. crude reserve additions, the current estimates of inferred and indicated reserves imply that U.S. crude reserve additions would average about 1.6 billion barrels a year through the end of the century. U.S. production could fall by almost 50 percent by then. If U.S. reserve additions averaged 1.6 billion barrels a year, then only one-fourth of the remaining undiscovered recoverable resource estimated by USGS would be converted into proved reserves by the end of the century. This would indicate that resource limitations would probably not significantly affect the level of reserve additions. As a result estimates of the undiscovered resource base, while interesting, may be largely academic in discussing future prospects of U.S. petroleum production through the end of the century.

NATURAL GAS

Natural gas resources and reserve classifications used in this chapter are essentially the same as those used for petroleum, and are defined in appendix I. The only difference is that there is no category of indicated reserves for natural gas. As mentioned previously, these resources do not include the large potential gas resources in tight sandstones, geopressurized water reservoirs, coal beds, and other sources not now being produced and marketed for economic and technical reasons.

Discovered resources

As of December 31, 1978, the American Gas Association estimated total ultimate recovery of natural gas (associated plus non-associated--see app. I) from already discovered reserves at 754.0 trillion cubic feet (tcf), of which only 200.3 tcf remained to be recovered. Over 73 percent of the proved natural gas reserves have been produced. By comparison, almost 81 percent of discovered oil reserves have been produced.

The current situation with respect to the estimated remaining natural gas reserves from proved and inferred deposits is summarized in table 3.

Table 3

Natural Gas Reserves from Present Discoveries
(tcf)

	Non-associated	Associated	Total
1978 production	15.7	3.6	19.3
Remaining proved reserve	139.0	56.7	a/200.3
Inferred reserves	b/	b/	c/177.5

a/Includes gas in underground storage, 4.6 tcf.
b/Not available.
c/GAO calculation based on USGS 725 estimate.

The total of all natural gas reserves (proved plus inferred) is equivalent to sustaining current production for almost 20 years, or almost to the end of century. Inferred reserves are almost as large as proved reserves. Most of these reserves are probably non-associated. If the inferred oil reserves are a reasonable indication of inferred associated natural gas reserves, only about 15 percent of inferred reserves are associated with oil reserves.

From 1948 to 1977 only about 30 percent of all U.S. natural gas reserve additions came from fields discovered prior to 1948. Thus new fields accounted for a larger proportion of natural gas reserve additions than they did for oil reserve additions. If pre-1978 fields were to account for 30 percent of all reserve additions over the next 30 years, then, correcting for associated gas reserve additions, U.S. natural gas reserve additions could average as much as 15 tcf a year. While this is not sufficient to hold current production levels, it does indicate that the declines in domestic natural gas production might not be as severe as those for crude oil.

Undiscovered recoverable reserves

Unlike oil, there is an industry group, the Potential Gas Committee (PGC), which estimates the natural gas resource base on a regular basis. However, the PGC categories are somewhat different from those of USGS. The inferred reserve category is equivalent to the PGC probable category. The mean estimated undiscovered recoverable resource category is equivalent to the PGC possible category. The sum of the possible and speculative PGC categories is equivalent to the upper USGS estimate. A comparison of the total undiscovered recoverable resource base from the USGS and PGC estimates is shown in table 4.

Table 4

Estimated Undiscovered Recoverable Natural Gas Resources by Region (tcf)

Region	USGS (1975) Range	USGS (1975) Mean	PGC (1978) a/ Maximum (note b)	PGC (1978) a/ Possible
Lower 48				
Onshore	246-453	345	473	283
Offshore	26-111	63	171	76
	286-529	408	644	359
Alaska				
Onshore	16-57	32	48	19
Offshore	8-80	44	128	21
	29-132	76	176	40
Total Alaska and Lower 48	322-655	484	820	399

a/Potential Gas Committee, Potential Supply of Natural Gas in the United States, 1978.

b/Sum of PGC possible and speculative categories.

The PGC estimates are much more optimistic regarding the upper limits of the U.S. resource base than is USGS. At the same time its estimate of the possible resource base is almost 20 percent less than the equivalent USGS estimates. However, most of this difference is compensated for by the PGC probable reserve estimate which is larger than the corrected USGS estimate. Thus in terms of the undiscovered resource base estimates which are usable for planning purposes (PGC probable plus possible, USGS mean undiscovered resources plus inferred resources), the two estimates are within 5 percent of each other.

We have used the USGS estimate of undiscovered recoverable natural gas resources in estimating future trends in natural gas supply. This allows us to use a self-consistent set of estimates for both petroleum and natural gas supplies.

To sustain production near current levels through the end of the century would require the discovery of an additional 500 tcf of natural gas reserves on top of current proved reserves. This is more than 80 percent of the total remaining resource base. The accomplishment of such production levels would require unprecedented discoveries of large new gas fields and a natural gas resource base closer to the "maximum" estimates of USGS and the PGC.

Conclusions

Based on the discovered natural gas resource base, U.S. natural gas production could fall by almost 25 percent by the end of the century. This is not as steep as the declines possible for petroleum.

Averaging 15 tcf of reserve additions through the end of the century indicates that as much as 40 percent of the undiscovered recoverable natural gas resources would have to be discovered. While this is larger than the expected success rates for crude, it is still not large enough to expect that resource limitations in an absolute sense will affect discovery rates to any significant extent.

CHAPTER 3

PETROLEUM PRODUCTION TRENDS

In 1970 U.S. crude oil and natural gas liquids production peaked at 11.3 million barrels per day (4.12 billion barrels for the year). Despite a great upsurge in domestic drilling activity, production had declined to 9.6 million barrels a day by mid-1977. The beginning of production from Prudhoe Bay has reversed this decline, and U.S. production has recovered to 10.2 million barrels a day in 1978. However, the decline is expected to resume in 1980 once Prudhoe Bay has reached its maximum production level.

The trend in future U.S. petroleum production will be estimated by conventional crude oil production in the following major producing regions: Lower 48 Onshore, 1/ Alaska, and the Lower 48 Offshore. In addition to conventional oil production technologies, a separate section discusses oil recovery improvement prospects. Natural gas liquids will be analyzed in terms of total U.S. natural gas production.

LOWER 48 ONSHORE

In 1978, Lower 48 onshore resources accounted for 76 percent of total U.S. crude production. Although this share is expected to decline in the future, the Lower 48 onshore will probably remain the dominant U.S. production factor through the end of the century because almost 60 percent of the remaining resource base is expected to be found in this area.

Lower 48 onshore crude production peaked in 1970 at 7.85 million barrels a day, and remained at about this level through 1973. Since 1973 Lower 48 onshore crude production has fallen 3 percent a year to 6.33 million barrels a day in 1978. This was accompanied by an even sharper decline in reserves, from 25.9 billion barrels to 16.8 billion barrels in 1978.

These declines have occurred because reserve additions have not kept pace with production. Lower 48 reserve additions last exceeded production in 1966. Since 1975 they

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1/Because of data reasons, the California offshore producing areas are included in the Lower 48 onshore discussion.

have been less than half of production despite large increases in drilling activity.

Reserve additions have undergone three changes of character since 1946. This is illustrated in figure 1. From 1946 through 1960, drilling exploration activity accounted for from 60 percent to 80 percent of total reserve additions, with revisions to reserves accounting for the remainder. During this period reserve additions fell slowly as the results of drilling activity declined.

For most of the 1960s reserve additions recovered because revisions increased by more than 50 percent as greater use was made of enhanced recovery techniques. 1/ However, reserve additions from drilling activity continued to decline, such that by the mid-1960s they accounted for about 40 percent of total reserve additions.

The decline in reserve additions resumed in the late 1960s, but at a steeper rate, largely as a result of the fall-off in revisions. The greatly increased drilling activity since 1973 appears to have stabilized reserve additions from drilling activities at about .63 billion barrels a year. Revisions, however, have continued to fall, resulting in a continued decline in total U.S. reserve additions.

The future trends in Lower 48 onshore reserve additions will be discussed in terms of those resulting from: (1) revisions, and (2) drilling activity.

Revisions

Revisions to reserves in the Lower 48 onshore have averaged .689 billion barrels a year since 1975, down by more than a factor of two since 1970. The decreasing size of Lower 48 fields indicates that there is a decreasing opportunity for revisions as a result of increased knowledge of the reservoir (e.g., thicker pay zones, reservoir pressure not falling as fast as originally expected). Thus Lower 48 onshore revisions will probably come from increased recovery of original-oil-in-place in a reservoir. This

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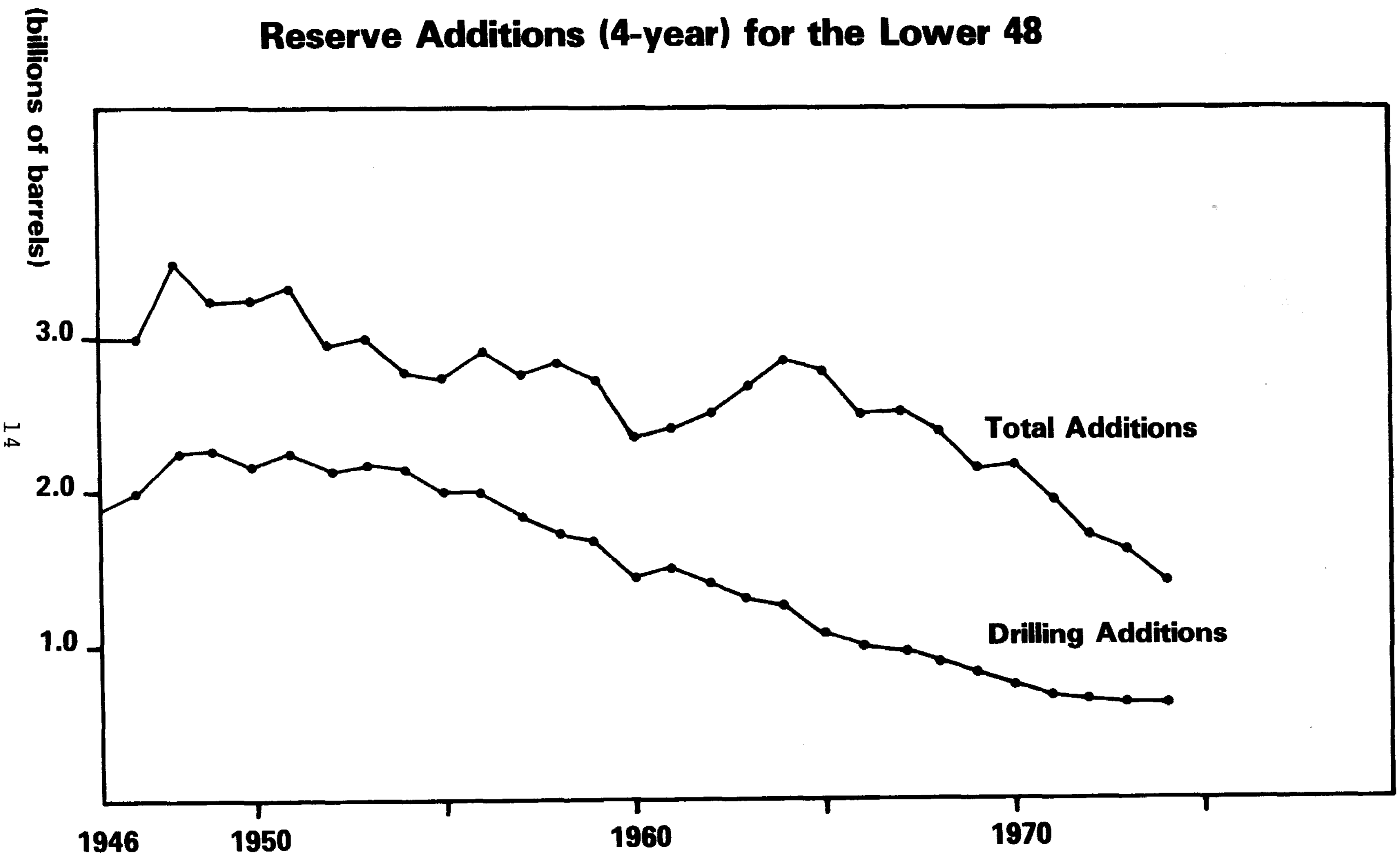
1/M. Carrales and Velton, T. Funk, Liquid Hydrocarbon Production in the United States, 1946-1975 and 1980 Projected, Highlighting Enhanced Recovery, Department of Interior (IC8734), 1977.

Figure 1

Reserve Additions (4-year) for the Lower 48



will come from two principal sources,

--postponing well abandonment, that is sustaining stripper well production, and

--producer activities (e.g. pressure maintenance) to increase recovery of original oil in place.

The latter will probably be the dominant source of revisions because stripper reserve additions are often reported on a year-to-year basis.

Since 1970 the recovery factor of oil-in-place has increased about 1 percent to 31.1 percent. Continuation of this trend would increase the recovery factor to 34.4 percent by the end of the century. Given the recent decontrol of heavy oil, such a trend appears reasonably achievable. This would add about 13.5 billion barrels of reserves to the current inventory, or 0.59 billion barrels a year.

If future revisions continue to average about 0.70 billion barrels a year, this would indicate that the improvement in oil recovery would average about 84 percent of revisions. This is higher than what has been observed since 1973. Based on the assumption that improvement in oil recovery remains at its 1975-1978 level of about 70 percent of total revisions, it appears reasonable to expect that revisions will average about 0.85 billion barrels a year.

Drilling activity

Spurred by higher prices and Federal regulatory price differentials for new oil, the number of wells drilled has risen dramatically since 1974 to the highest levels in 20 years. However, almost 90 percent of the increased drilling activity has been development wells. Exploratory drilling activity has increased only one-third as fast as developmental drilling. Thus most of the oil drilling activity has been directed towards holding current production level rather than finding new reserves.

Exploratory drilling adds reserves by finding new fields, new reservoirs in existing fields, or extensions to existing reserves. The exploratory well success rate has improved since 1974. The relative success rates for exploratory drilling are shown in table 5 for 1974 and 1977.

Table 5

Exploratory Success Rate
(percent)

Year	Wildcat (note a)	Other (note b)	All Exploration
1974	14.2	40.6	23.3
1975	14.4	40.7	23.2
1976	16.9	43.1	26.5
1977	16.5	43.5	27.0

a/New field discoveries.

b/New reservoir discoveries and extensions to existing reservoirs.

Despite the increased number of exploratory holes drilled with record success, the current exploratory drilling boom has not been successful in adding significant new reserves. Since 1974 the finding rate per foot drilled for exploratory wells has fallen a fourth from 35 barrels per foot to 26. This decline has been largely due to a recent decline of reserve additions from non-wildcat exploratory wells, even though its success rate has improved by almost 10 percent since 1974.

Figure 2 shows the average reserve additions per successful exploratory well. Reserve additions per successful wildcat well have averaged 4 to 5 million barrels since the mid-1960s. On the other hand, reserve additions per successful non-wildcat, while stable from the mid-1960s through 1972, have declined steeply since 1972.

Future trends in non-wildcat reserve additions will be determined by the sizes of recent and future field discoveries. In the past 10 years, only about 2 percent of new-field wildcats have discovered fields with at least 1 million barrels of recoverable reserves. 1/ This indicates that the currently disappointing non-wildcat exploration results will probably continue well into the future.

This conclusion is supported by a comprehensive analysis of the Permian Basin producing area of the United States by

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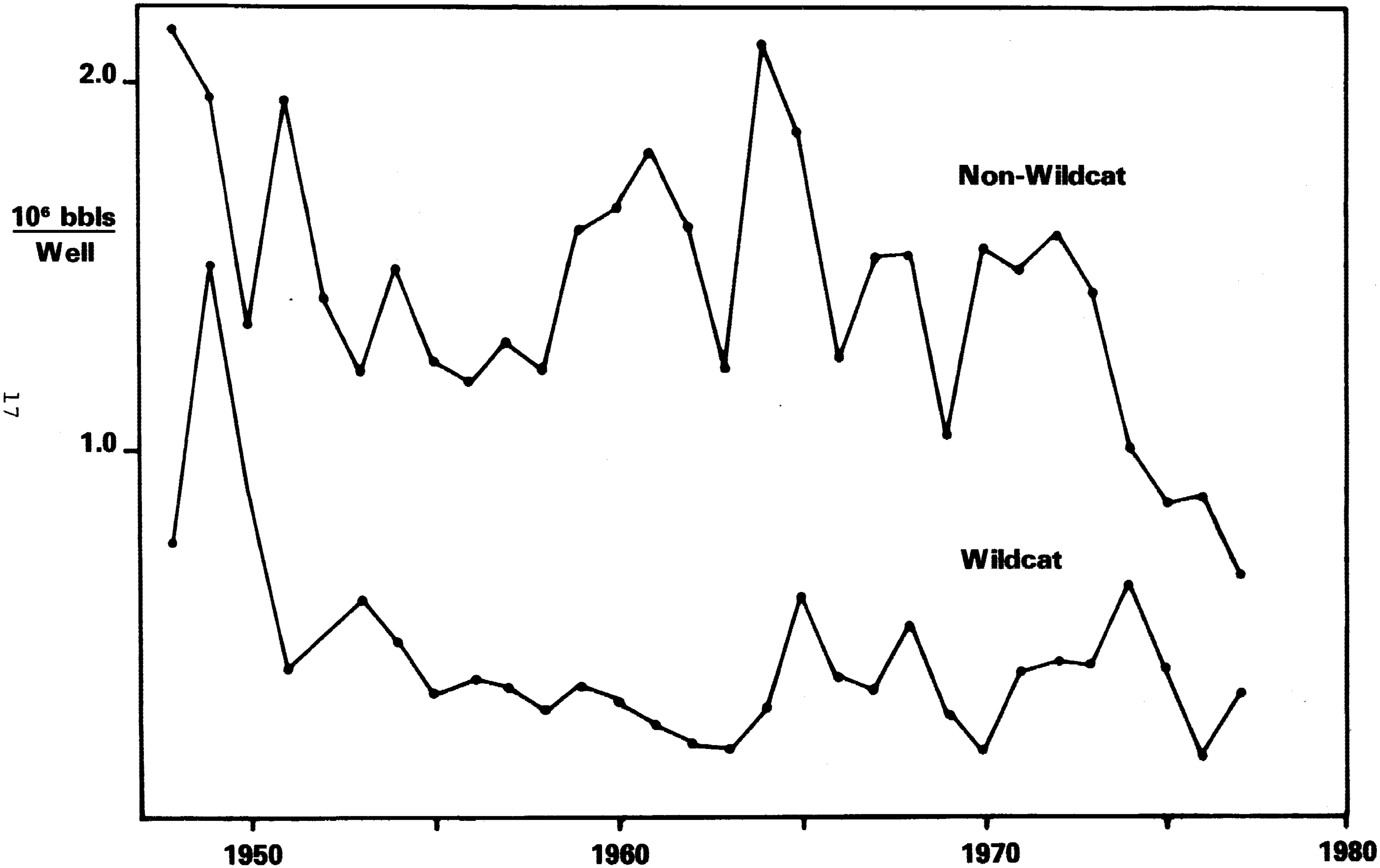
1/In general, a 1- million barrel field contributes only about 300 b/d to production during its first 5 years of development and production normally declines thereafter.

Figure 2

Average Reserve Addition Per Successful Exploratory Well



a Federal interagency committee. 1/ This study shows that the Permian Basin, which contains about one-fourth of U.S. proven oil reserves in the Lower 48, is extensively explored. Some 30,000 exploration wells have found about 3,000 fields at depths up to 20,000 feet. These fields contain about 37.4 billion barrels of oil and oil-equivalent natural gas. Using finding trends for various depth brackets and findings-per-foot trends, a model incorporating physical factors in the basin was developed to determine the likely results of future exploratory efforts.

The study concludes that an additional 46,000 wells would be needed to find an additional recoverable reserve of 4.6 billion barrels of oil equivalent (1.4 billion barrels of oil and 16.9 trillion cubic feet (tcf) of gas). This is drop of a factor of 12 in discovery per exploratory well.

Finding and development costs were generated to determine whether the new reserves were economically recoverable. These indicate that the ultimately recoverable reserves may cost $40 per barrel or more.

Although the Permian results cannot be extrapolated to the Lower 48, they do confirm the steady downward trend in reserve additions through exploration drilling. This implies that, unless new large basins are found, current trends of drilling more and finding less will continue, particularly for non-wildcat exploration activities.

Our analysis indicates that continuation of the current trends in the finding rates of oil per foot drilled would require almost a four-fold increase in drilling by the end of the century to even hold drilling reserve additions at their current level of about 0.45 billion barrels a year. While such expansions of drilling activity are somewhat optimistic, it is reasonable to expect that reserve additions from drilling activities in the Lower 48 will continue to average 0.45 billion barrels a year through the end of the century.

To achieve exploratory reserve additions on the order of 1 billion barrels would probably require a more than eightfold increase in drilling activities by the end of the century (about 10 percent a year), as well as significant

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1/E. D. Atlanasi, et al., Economics and Resource Appraisal: The Case of the Permian Basin. Feb. 1979, Society of Petroleum Engineers, SPE 7738.

activity in the remaining relatively unexplored Lower 48 onshore areas such as the Overthrust Belt. Current Government land use restrictions limit exploration in the Overthrust Belt and other regions in the Rockies.

Large sustained additions in excess of 1 billion barrels would require the equivalent of a new Permian Basin in the Lower 48. No basins comparable to the Permian Basin have been discovered in the Lower 48 since before World War II.

Production trend

Our analysis of current trends in U.S. reserve additions due to revisions and exploratory activities indicates that reserve additions in the Lower 48 onshore areas should average about 1.3 billion barrels a year. The production profile expected as a result of the 1.3-billion-barrel average annual reserve addition rate is estimated on the basis that the current Lower 48 reserve-to-production (RP) ratio declines to 6.5 by 1982 and remains constant thereafter. While production profiles between 1978 and 2000 can differ depending upon assumptions regarding RP ratios, they differ by less than 10 percent at their maximum, and usually are much less. By 2000 there is very little difference.

The resulting Lower 48 production profile is shown below in table 6. Table 6 indicates that the 3-percent annual decline in Lower 48 onshore production will continue

Table 6

Lower 48 Onshore Production
(millions of barrels a day)

Year	Production
1978	6.3 (actual)
1980	6.0
1985	5.0
1990	4.2
2000	3.7

into the mid-1980s, after which it will begin to slow. By the mid-1990s production will only be declining by about 1 percent a year.

LOWER 48 OFFSHORE

Production from the Lower 48 offshore peaked in the late 1960s and early 1970s at slightlv more than 1 million barrels per day. The lack of new field discoveries has resulted in a steady and rapid decline in this Outer Continental Shelf (OCS) production. Since 1971 Gulf of Mexico production has fallen about 6.3 percent a year. Since 1975, only one commercial discovery was reported for the Gulf and one in the California OCS.

Proved oil reserves as of December 31, 1978, in the Gulf of Mexico were estimated at 1.75 billion barrels; indicated and inferred reserves are estimated at about 2.0 billion barrels. USGS estimates that the potential undiscovered recoverable resources of the Lower 48 range from 5 to 18 billion barrels, with a mean of 11 billion.

In the past 3 years, exploratory drilling in frontier OCS areas in the eastern Gulf of Mexico has produced 18 dry holes; 11 dry holes and 1 oil discovery in the Southern California OCS; and 14 dry holes, 1 gas discovery, and 1 oil and gas discovery in the Atlantic OCS. In the light of these failures, we would suggest that for planning purposes only about one-third of the statistical mean for the Lower 48 frontier OCS should be counted on as being producible by 2000. This amounts to about 4 billion barrels of reserves. This would permit a producing rate at a reasonable RP ratio (10 or 12 to 1) of about 400,000 barrels a day by the end of the century.

Table 7 shows the estimated production trends from the Lower 48 OCS through 2000. As in the case of Alaska, frontier

Table 7

Lower 48 OCS
Production Trends
(millions of barrels a day)

Year	1978 (actual)	1980	1985	1990	1995	2000
Existing	0.75	0.6	0.5	0.4	0.3	0.2
Frontier	-	-	0.1	0.2	0.4	0.4
Total	0.75	0.6	0.6	0.6	0.7	0.6

production will provide an opportunity to stabilize Lower 48 OCS production, but it is very unlikely that it would make this area a growth factor again in the U.S. crude supplies.

ALASKA

Alaskan production trends can be assessed in terms of production from 3 areas: (1) South Alaska, (2) existing North Slope areas, and (3) frontier areas.

South Alaska

Production in South Alaska (Cook Inlet area) began in 1957 with the discovery of the Swanson River field. Production grew to 227,000 barrels a day in 1970, but since then has steadily declined at an average rate of 5.4 percent a year. By 1977 production had fallen to 154,000 barrels a day. Even at this low rate of production the remaining reserves would not last 6 years.

The future production prospects for South Alaska are not good. No significant new oil discoveries have been made in the area, either onshore or offshore, since 1967 despite considerable exploratory drilling. In 1975, USGS estimated that the remaining undiscovered resource base in this area could have been as much as 4 billion barrels. The dismal results indicate that this estimate may have been too high.

Current recovery of oil-in-place in South Alaska fields averages 35.9 percent. Even if recovery were raised to 40 percent, the expected Prudhoe Bay recovery, this would only provide additional reserves equal to about 2 years of current production. Thus improved recovery would probably only have a marginal impact on South Alaska production.

Given the dismal results from exploration and the limited prospects for enhanced recovery, it is likely that South Alaska production will continue to decline at about its current rate. As a result South Alaska should reach insignificant levels (less than 50,000 barrels a day) by about 1990.

Existing North Slope

The Prudhoe Bay field is the only commercially producing North Slope (Arctic Ocean coastal area) field. Production began in July, 1977, and by September 1978 it had reached 1.2 million barrels a day. Industry plans to increase production to 1.35 million barrels a day in 1980.

In the mid-1980s Prudhoe Bay production will begin to decline, falling to about 200,000 barrels a day by 2000. 1/ Thus production from new fields or from other formations in the Prudhoe Bay field will be necessary to stabilize North Slope production, let alone increase it.

There have been other finds of oil and gas on the North Slope, but with the exception of the Kuparuk River formation in Prudhoe Bay, none are yet considered commercial. Industry plans to begin production from Kuparuk in 1982 at 60,000 barrels a day. If the formation proves to be as large as 600 million barrels, production could rise to somewhat more than 100,000 barrels a day later on. But this will have little effect on the overall trend of Prudhoe Bay production.

Frontier areas

USGS estimates that undiscovered recoverable oil resources in Alaska range from 12 to 49 billion barrels, with an even chance of finding 27 billion barrels. A little more than 40 percent of this resource base (12 billion barrels) is expected to be found onshore. Almost 75 percent of the resource base (20 billion barrels) is expected to be found on the North Slope (onshore or offshore) along the Arctic Ocean.

Although 25 percent of the undiscovered Alaskan oil is expected to be outside of the North Slope, it is doubtful whether production from these areas will be significant. Half of the resource area is in South Alaska where exploration results have been dismal, with 11 dry holes in the once promising Gulf of Alaska. The Bering Sea has some potential, but given its environment and long distances from oil transportation and consuming centers, we do not believe it should be used in any current long-range trend estimates. Therefore, long-term trends in frontier Alaskan production will probably be dominated by production from Northern Alaska along the Arctic Ocean.

The area west of Prudhoe Bay, the National Petroleum Reserve in Alaska (NPRA), was thought to be a very promising area to explore. USGS estimated it could contain 2 billion barrels or more of crude. Since 1974, the Government has drilled 14 wells in this area, all of which were unsuccessful. At this point the Government is planning to complete

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1/Declines are based on an assessment of simulations of Prudhoe Bay production done by Core Labs and Van Poolen & Associates.

its exploration program, and if it is unsuccessful close much of the area to future exploration.

Some promising oil finds have been obtained northeast of Prudhoe Bay on the Arctic Ocean shoreline. The Canadian Arctic has also had some excellent exploratory results. In the light of the disappointments west of Prudhoe Bay it appears that if the USGS undiscovered resources are to be found, it is more likely they will be mostly east of Prudhoe, both onshore and offshore.

However, a significant part of this area is closed to exploration because it lies within the Arctic National Wildlife Range. Furthermore, the Wildlife Range may effectively close parts of the Beaufort Sea to exploration because many new offshore fields might be opposite the Wildlife Range. As a result, any production could not be brought directly to shore, but would have to be carried undersea until non-Wildlife Range shore could be reached. This would significantly raise the cost of production and possibly prevent the production of anything but a "super-giant" field (billions of barrels).

Any future producing rate estimates for Alaska, outside of current producing areas, are highly speculative because of future discovery uncertainties and land restrictions. A single find as large as Prudhoe Bay cannot be counted on. If the land restrictions are assumed to have no significant effect upon drilling activity, it appears that, based on experience in the Lower 48 States, a prudent planning estimate would be the development of almost half the current USGS estimates of the undiscovered Alaska Arctic resource base, or 9 billion barrels. 1/ This would permit a producing rate at a reasonable RP ratio (10 or 12 to 1) of almost 1.3 million barrels a day by 2000.

Producing rates

Table 8 shows the expected trends in production from Alaska. Production from the frontier areas will probably stabilize overall Alaska production, although there will be some decline in overall production. The estimates for new fields production are based on essentially no delays

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1/We are defining development in these areas to mean ready for production. Because of the long lead times necessary to get a field ready for production, it is likely that more than 9 billion barrels would actually have to be discovered.

Table 8

Estimated Future Alaskan
Onshore Producing Rates
1980 to 2000
(millions of b/d)

Year	South Alaska	Prudhoe Bay	New fields	Total
1977 (actual)	.1	1.1		1.2
1980	.1	1.4		1.5
1985	.1	1.5	0.1	1.7
1990		0.8	0.5	1.3
1995		0.4	0.9	1.3
2000		0.2	1.3	1.5

in the exploration of the frontier areas. The extent to which there are delays will bring about a lengthening and increasing of the decline in Alaskan production. As shown in table 8 this decline lasts into the mid-1990s and amounts to 400,000 barrels a day. Of course, restrictive land use laws could reduce Alaskan production further.

ENHANCED OIL RECOVERY

The discouragingly low efficiency of conventional primary and enhanced oil recovery (EOR) methods which have been applied for 30 to 40 years have long provided incentives to the petroleum industry to develop new and improved recovery technologies and processes that eventually led to their successful commercial application. Government and industry interest in stimulating U.S. oil recovery efficiency has increased notably since 1973 because of massive world and domestic oil price hikes and declining domestic production. Most of this interest is focused upon the large potential resource target for new enhanced oil recovery processes.

Conventional primary-secondary production (as defined herein includes all oil recovery from primary and normal pressure maintenance, cycling, gas injection, waterflooding, and thermal steam enhanced oil recovery techniques) has recovered only 32 percent of the already discovered original oil-in-place of 450 billion barrels in the United States. Thus, the target for "new enhanced oil recovery" (that production beyond the conventional primary-secondary production defined above) exceeds 300 billion barrels or more than a century of production at current levels. The problem is that new EOR processes must be based on applied technologies that are economic or likely to become so, but that has not been the case with most of the more promising techniques now being intensively researched and pilot tested.

The new EOR technologies fall into three broad categories: chemical, thermal, and improved waterflooding or polymer flooding. Chemical floods involve the use of surfactants or caustics to reduce interfacial liquid-liquid and liquid-solid tension or the injection of carbon dioxide (CO_2), hydrocarbon gases, or other gases to achieve miscibility with the reservoir fluids and reduce interfacial tension. Thermal methods introduce heat, either by in-situ ignition of a portion of the reservoir oil or by injecting steam or hot water, to lower the viscosity of the heavier oils. Polymers are emulsifiers or thickeners to improve the areal sweep and displacement efficiencies of waterflooding processes.

Four comprehensive studies to assess the ultimate recovery and future production rates from the application of new EOR processes have been completed in the past three years. They are the Lewin study for the old Federal Energy Administration 1/ and an expanded Lewin study for the former Energy Research and Development Administration (ERDA), 2/ a National Petroleum Council (NPC), 3/ study and a study by the Office of Technology Assessment (OTA). 4/ Potential reservoirs for new EOR applications assessed in the studies ranged from 245 in the first Lewin study and the NPC study to 835 for the OTA study.

Wide variations in the projections of ultimate recovery and in producing rates are found among the studies, as is shown in table 9. The estimates are for low and high performance ranges for various oil prices ($10 to $15 per barrel) and rates of return (10 to 20 percent).

1/Lewin and Associates, Inc., The Potential and Economics of Enhanced Oil Recovery, Apr. 1976.

2/Lewin and Associates, Inc., Research and Development in Enhanced Oil Recovery, Nov. 1976.

3/National Petroleum Council, Enhanced Oil Recovery, Dec. 1976.

4/Office of Technology Assessment, Enhanced Oil Recovery Potential in the U.S., Jan. 1978.

Table 9

Estimates of New EOR Potential
1985

	Ultimate recovery (billion barrels)	Producing rate (million b/d)
Lewin-FEA	15.6 - 30.5	1.0 - 2.0
Lewin-ERDA	11.9 - 30.1	0.6 - 2.1
NPC	3.1 - 26.9	0.5 - 1.5
OTA	8.0 - 29.4	0.4 - 1.0

The studies are not directly comparable because of very different economic scenarios used to approximate commercial new EOR development and the prospective future oil prices and rates of return on investment. Nevertheless, each study was less optimistic than the previous one.

Chemical floods are being extensively field tested; however, no significant quantities of oil are expected to be available by 1985. The long time frames involved in developing a given reservoir (at least 10 years) indicate that unless many large-scale projects are started in the next 2 to 3 years, oil production from surfactant flooding will be virtually non-existent by 1990. Furthermore the high costs of surfactants and other chemicals and the limited supply of naturally produced and relatively inexpensive carbon dioxide (CO_2) will further constrain widespread applications of these processes.

Thermal processes, mostly using conventional steam or cyclic steam or hot water injection, now account for 260,000 barrels a day, or 70 percent, of total 1977 estimated EOR production of 373,000 barrels a day from 196 projects surveyed 1/ in the spring of 1978. However, this production is included in our conventional estimates of Lower 48 production. Only about 10,000 barrels a day of the total thermal production comes from truly new EOR combustion or fire-flood processes, but these processes will have

1/The Oil and Gas Journal, U.S. Enhanced Recovery Marked by Uncertainty, Sept. 11, 1978.

their greatest potential for in-situ recoveries of oil shale and tar sands. The future production aspects of these resources will be discussed in subsequent work. There appears to be little prospect for significant new thermal EOR production from "conventional" (i.e., pumpable, however limited) oil reserves.

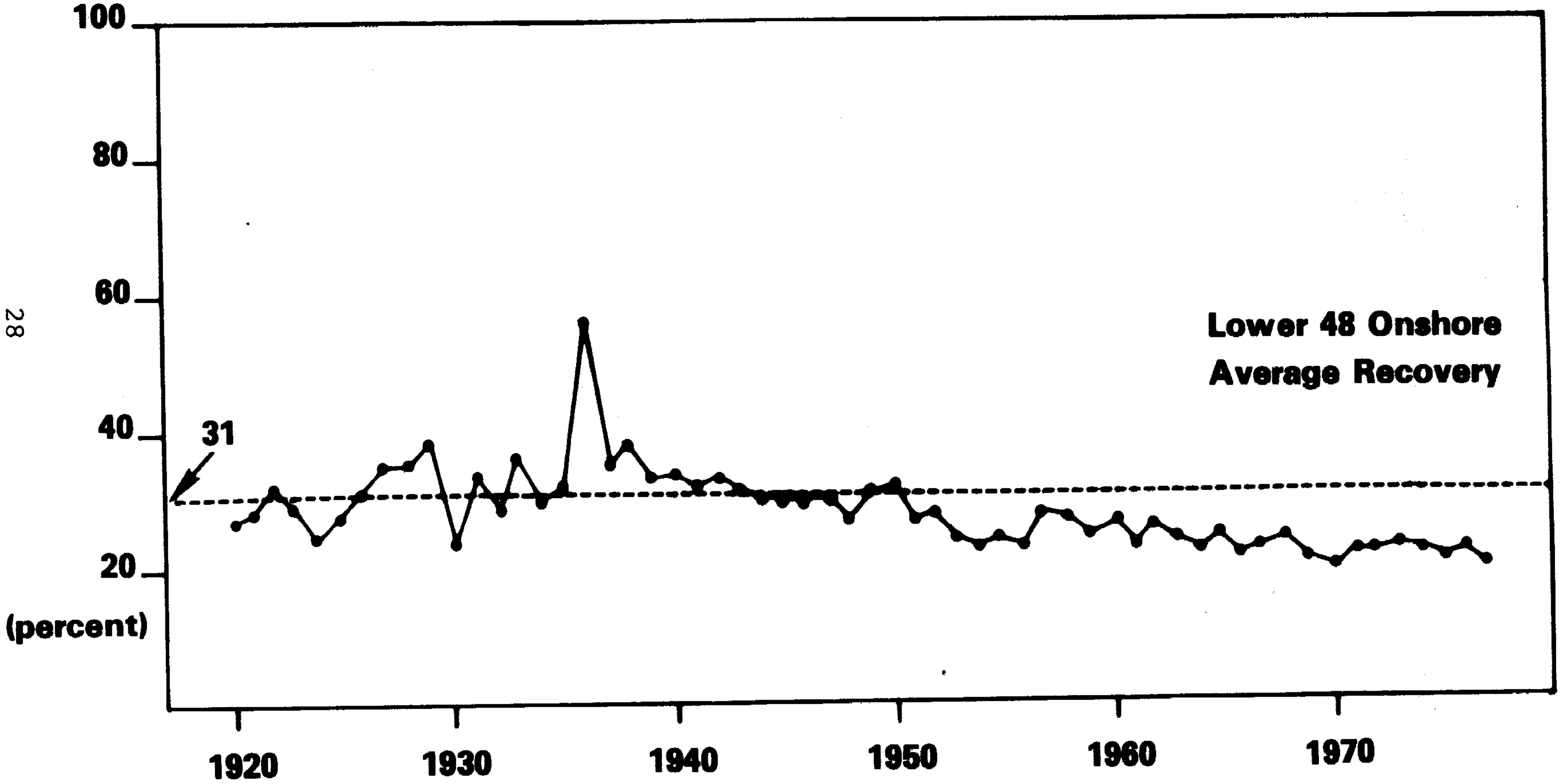
Polymer flooding does not materially increase ultimate oil recovery over that obtained by conventional waterflooding. As a result, its contribution to improved efficiency is expected to have essentially negligible impacts on increasing new EOR producing rates. Estimates of incremental recovery resulting from polymer flooding range from .3 to .5 billion barrels.

An analysis of recovery of oil-in-place in existing fields indicates a significant economy of scale in enhanced oil recovery. The larger a field, the more attractive its prospects will tend to be. Unfortunately most large fields average 45 percent recovery, close to the ultimate theoretical recoveries. The remaining large fields are composed of the California heavy oil fields, which are being produced using existing EOR techniques. Their production is included in the "conventional" Lower 48 onshore production. The only remaining large field is Spraberry Trend, and that would be a story in itself.

Therefore, enhanced oil recovery in existing fields must focus on the "non-large" fields, and principally the post-1946 fields. The recovery factor for these fields by year of discovery is shown in figure 3. The figure illustrates the declining "quality" of the recently discovered fields. Since 1965 the recovery of oil-in-place for non-large fields has not exceeded 25 percent. Because the new EOR techniques will mostly have to deal initially with the less than optimal non-large fields, it will be a long and tedious process to develop new EOR techniques. Coupled with time frames on the order of 10 years to get many of the more promising chemical floods operating in a single field, it is unlikely that any significant new EOR production will begin until about 1990.

On the assumption that production from new EOR does not become significant until 1990, it is not likely that the average Lewin-ERDA, NPC, and OTA low-performance producing rates of 500,000 barrels a day would be achieved until 1995. On this basis, only 200,000 barrels a day is indicated by 1990 and about 1 million barrels a day by the year 2000, assuming a rather steady growth past 1995. While our estimates are significantly more pessimistic than those of the previously cited studies, these estimates

Figure 3
Percentage of Oil Recoverable
(Exclusive of Large Fields) for Fields by year of Discovery



included ongoing EOR efforts, particularly the heavy oil recovery projects in Calfornia. Our estimates include such efforts in conventional production.

NATURAL GAS LIQUIDS

Natural gas liquids are those hydrocarbons contained in reservoir natural gas that are recovered through the process of condensation, absorption, or other methods in various types of field gas processing plants. They consist mostly of condensate, natural gasoline, and liquid petroleum gases heavier than ethane.

Natural gas liquids reserves and production are directly a function of natural gas reserves and their recoverable liquids content and recovery rates. Thus, natural gas liquids producing rates are calculated by applying a liquids content factor to projected natural gas producing rates, based upon the expected recovery efficiency of installed or planned processing facilities.

Since 1966 non-associated NGL production has averaged 27.8 barrels per million cubic feet (MMcf) of non-associated gas produced. Associated NGL production per MMcf associated gas produced has increased steadily from 1966 through 1975, since 1975 the NGL production has averaged 68.5 barrels per MMcf of associated natural gas. These average factors are assumed to hold in the future and are applied to natural gas production estimates (these are derived in ch. 3) to derive the natural gas liquids production trend presented herein.

OUTLOOK

Based upon the preceding assessments and conclusions concerning the Nation's resource base and the physical, technical, and other factors that will most probably determine the sources and levels of future domestic petroleum production, the aggregated trend of U.S. petroleum production and individual sources is as estimated in table 10.

Table 10

Estimated Trend in U.S. Petroleum Production by Sources
(millions of barrels per day)

	1978 (actual)	1980	1985	1990	1995	2000
Crude oil						
Lower 48 Onshore	6.3	6.0	5.0	4.2	3.9	3.7
Alaska:						
Existing	1.2	1.5	1.6	0.8	0.4	0.2
Frontier	-	-	0.1	0.5	0.9	1.3
Total	1.2	1.5	1.7	1.3	1.3	1.5
Lower 48 Offshore:						
Existing	0.7	0.6	0.5	0.4	0.3	0.2
Frontier	-	-	0.1	0.2	0.3	0.4
	0.7	0.6	0.6	0.6	0.6	0.6
EOR				.2	.5	1.0
Natural gas liquids	1.9	1.8	1.6	1.7	1.7	1.7
Total	10.1	9.9	8.9	8.0	8.0	8.5

Table 10 shows that by the 1990s overall U.S. petroleum production should stabilize, and could actually increase slightly towards the end of the century. Without significant frontier production and new EOR success, U.S. production would probably continue to fall to little more than half of 1978 production.

The Lower 48 onshore region (including EOR) will continue as the main source of production, although its share of total U.S. crude output will fall to about 70 percent. Drilling activity is expected to continue at high levels, but finding rates, sizes of new discoveries, and total additions to reserves are not expected to keep pace with production.

IMPLICATIONS OF PRICE DECONTROL ON PETROLEUM

In general, higher prices can affect petroleum production in three ways: (1) encourage additional exploration, (2) make formerly sub-economic fields economically producible, and (3) make EOR of oil-in-place in existing fields economically viable.

Despite price controls which have held the U.S. price for upper-tier oil 51 to 20 percent below world oil prices, U.S. exploratory wells have increased more than 7 percent a year since 1973. Nevertheless, the additional reserves have been relatively disappointing when considered in the light of the exploration effort.

This is not surprising when one considers the fact that large structures account for the vast majority of U.S. reserves. A recent Department of Energy (DOE) study indicated that 78 percent of Lower 48 production came from only 8 percent of the fields. These large fields are relatively insensitive to price, that is, most if not all would be producible even under lower tier prices ($5.75 a barrel) simply because of the economy of scale resulting from their large size.

Increasing prices, while significantly increasing the number of new fields discovered, may only have marginal effects on the overall U.S. reserve picture simply because almost all the new fields would be relatively small. Of course, the term "small" is relative. The Kuparuk reservoir in Prudhoe Bay is small and marginally economic, but its size ranges from about 100 million barrels to as much as 600 million barrels. On the Lower 48 onshore, this would be one of the largest reservoirs found since 1945. On the Lower 48 onshore such marginally economic fields are only on the order of 1 million barrels or less in size.

Thus it would appear that increased prices for new field exploration and development would have limited effects on Lower 48 production simply because the marginal field is very small. On the other hand, higher prices could have some visible effects on frontier production because the marginal fields are larger, but this assumes that marginal field exploration could occur.

If there is a major short-term effect on production as a result of price decontrol, it will show up most visibly in revisions to reserves. This is because higher prices might justify significant investment to enhance the recovery of oil-in-place. Many of these fields where revisions could occur are lower-tier production. As they decline there is no economic incentive to sustain oil production, particularly when this field becomes decontrolled as its production falls below 10 barrels a day per well, and it becomes a stripper field.

Higher prices could serve to delay the point at which such fields enter the stripper category. Today, the economic incentives encourage a "premature" decline into stripper categories from existing fields. However, the impact of higher prices could be constrained by the technological constraints to EOR.

CHAPTER 4

NATURAL GAS

Historically, natural gas resources were developed as a result of and in association with petroleum resources. In the early days of the petroleum industry, gas was a by-product that had small markets only in producing areas. Most associated gas (that dissolved in solution or in contact with oil in the producing reservoirs) was flared. Non-associated or dry gas reservoirs were largely accidental finds in the search for oil. However, in the past 50 years, new long-distance pipeline technologies and use of gas as a petrochemical feedstock have opened up vast markets for natural gas. This led to more and more exploratory drilling directed solely at finding new gas reserves.

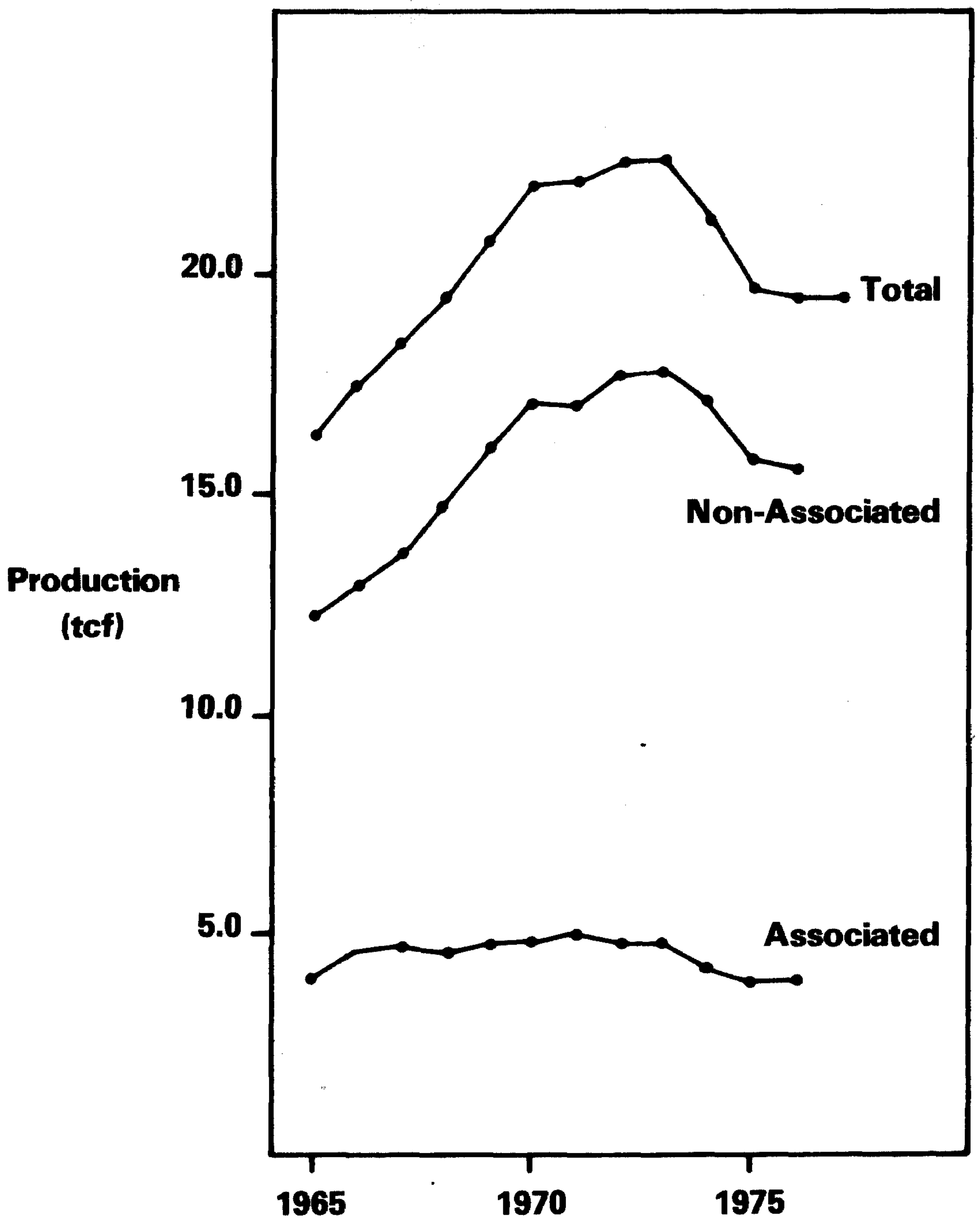
Associated gas reserves are directly dependent on the amount of oil resources found and their average gas content, or gas-oil ratio. Their producing rate is directly related to the levels of oil production. Non-associated or dry gas reserves are developed and produced independently of oil recovery rates. These dry gas reserves are characterized by high recovery efficiencies (80 percent or more of the original gas-in-place) which are relatively rate insensitive (i.e., many non-associated gas fields have production rates limited only by the number of wells that are drilled).

This chapter will assess the trends in conventional natural gas production in the United States. It will not consider the future prospects of production from the large potential gas resources in tight sandstones, geopressurized water zones, coal beds, and other sources not now being produced and marketed because of economic and technical reasons. Discussion of these sources along with synthetic natural gas manufactured from oil, coal, or biomass will be done in a subsequent work.

Production of natural gas peaked in 1973 at 22.6 tcf. Since then it has fallen slightly more than 3 percent a year to 19.3 tcf in 1978. Almost all increases or decreases in natural gas production since World War II have resulted from the changes in non-associated gas production. This can be easily seen in figure 4, which shows the historical trends in natural gas production since 1965.

Since 1966 the share of associated natural gas production has fallen steadily, from 26 percent to less than 20 percent in 1977. Because the majority of both discovered reserves and undiscovered recoverable resources are non-associated gas, it is likely that associated production will

Figure 4
Natural Gas Production



continue to have a definite minority share of future natural gas production.

ASSOCIATED GAS

Associated gas production is controlled by the level of crude production. In the late 1960s and early 1970s, about 1,500 to 1,600 cubic feet (cf) of natural gas were produced with the average barrel of crude. Since 1974, however, associated gas production has averaged only 1,400 cf per barrel of crude. Our estimates for future associated gas production trends from all fields other than Prudhoe Bay assume that 1,400 cf of associated natural gas will be produced per barrel of crude.

Current plans for Prudhoe Bay call for a steady gas production of about 2.25 bcf a day until oil production is uneconomic, of which 2 bcf will be sold through the proposed Alaskan pipeline. The remaining production is used for field operations and pipeline fuel. When oil production is no longer economic, the remaining gas cap will be produced as though the field were non-associated. Because this will probably not occur until the next century under current industry plans, our analysis assumes that Prudhoe Bay output will begin about 1987 and remain level at 2.25 bcf per day through the end of the century.

The trend in total associated natural gas production is shown in table 11. The table shows that, although the Lower 48 production declines rather steeply over the period, Alaska and Frontier OCS production will begin to compensate for this decline by the late 1980s. As a result, associated gas production will begin to grow slightly in the 1990s as Prudhoe Bay production is held steady and frontier OCS production comes on line. Of course, if Prudhoe Bay output cannot

Table 11

Estimated Associated Gas Production
1978 to 2000
(tcf)

Year	Lower 48	Alaska and frontier OCS	Total
1978 (actual)	3.6		3.6
1980	3.4	0.1	3.5
1985	2.8	0.2	3.0
1990	2.3	1.2	3.5
1995	2.2	1.4	3.6
2000	2.0	1.7	3.7

be held constant, then associated gas production would probably only stabilize in the 1990s, not grow.

NON-ASSOCIATED GAS

Marketed production of non-associated gas peaked at 17.8 tcf in 1973. By 1977 production had fallen to 15.6 tcf, a decline of 3.2 percent a year, because of an inability to discover new natural gas reserves to compensate for production. Since 1967 U.S. non-associated natural gas reserves have declined steadily from their peak of 221.8 tcf to the 1978 value of 139.0 tcf. This decline is illustrated in figure 5.

The trends in U.S. non-associated natural gas production will be assessed for the Lower 48 States, the frontier OCS, and Alaska.

Lower 48

Spurred by steadily increasing gas prices, the total number of gas wells drilled has increased more than 50 percent since 1974. As in the case of oil wells, however, the overwhelming part of the increase has been in development wells. The rate of increase in exploratory drilling over this period has been less than one-third that of the rate of increase in developmental drilling. Thus most of the gas drilling activity has also been directed towards holding production rather than finding new reserves.

This is reflected in the fact that since 1973 the average gas production per gas well has fallen more than 25 percent to 107.5 MMcf per year. This is less than the average output per well in 1966. While continued drilling of development wells can slow the rate of decline, this is only a temporary measure. In the long run, without adequate reserve additions, continued expansion of development drilling will only result in the decline rate increasing significantly in the future.

Non-associated natural gas reserve additions since 1969 have been strongly affected by negative revisions. Only twice, in 1978 and in 1975, have there been positive revisions to reserves. The apparent rise in reserve addition since 1973 has been solely due to changes in revisions. This is illustrated in figure 6. Reserve additions from exploratory activities have averaged 9.15 tcf a year since 1973, even though the number of exploratory wells has increased 64 percent and footage drilled 21 percent.

Thus it would appear that the significant increases in natural gas prices have only served to hold exploratory

Figure 5
Non-Associated Natural Gas Reserves

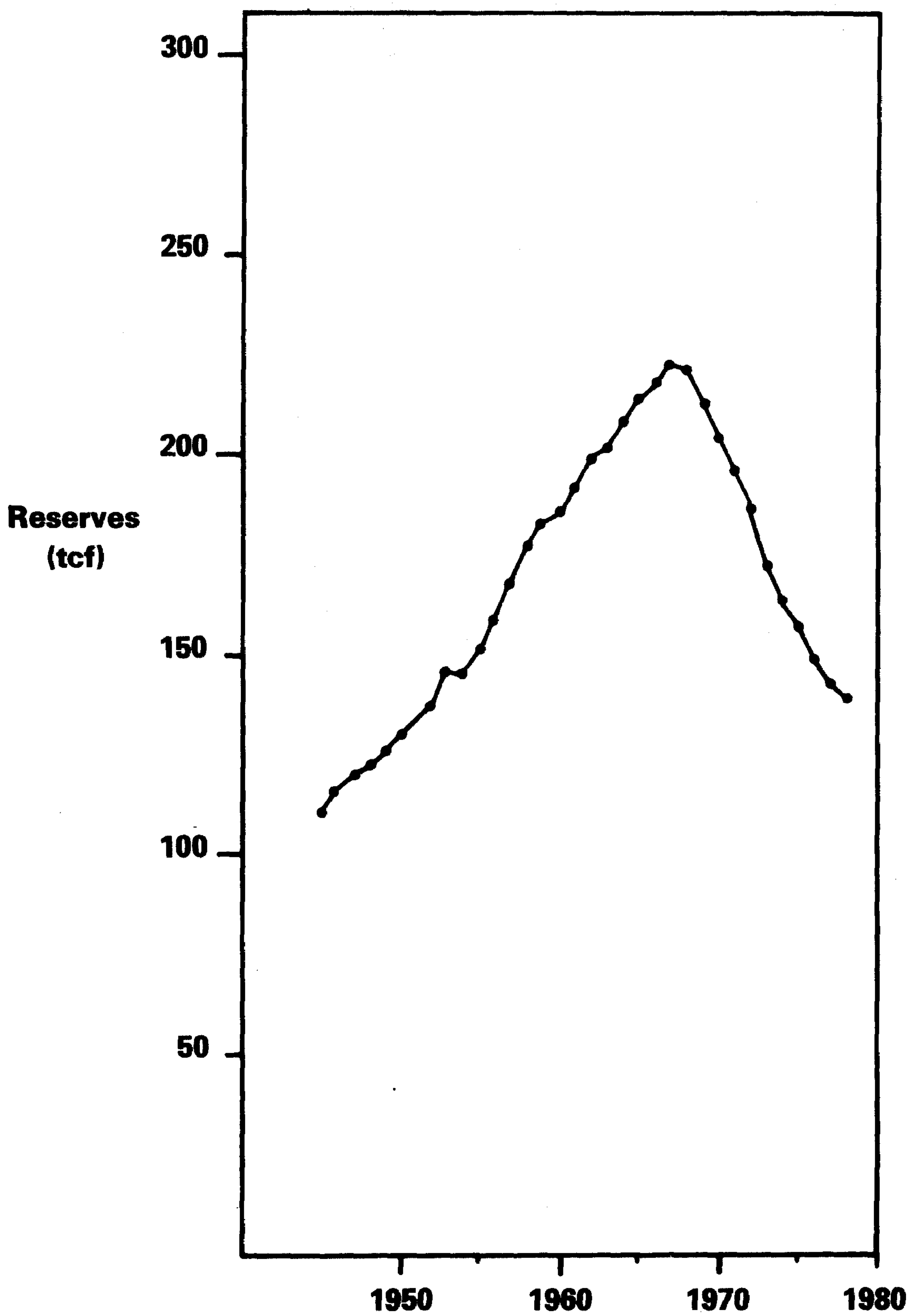
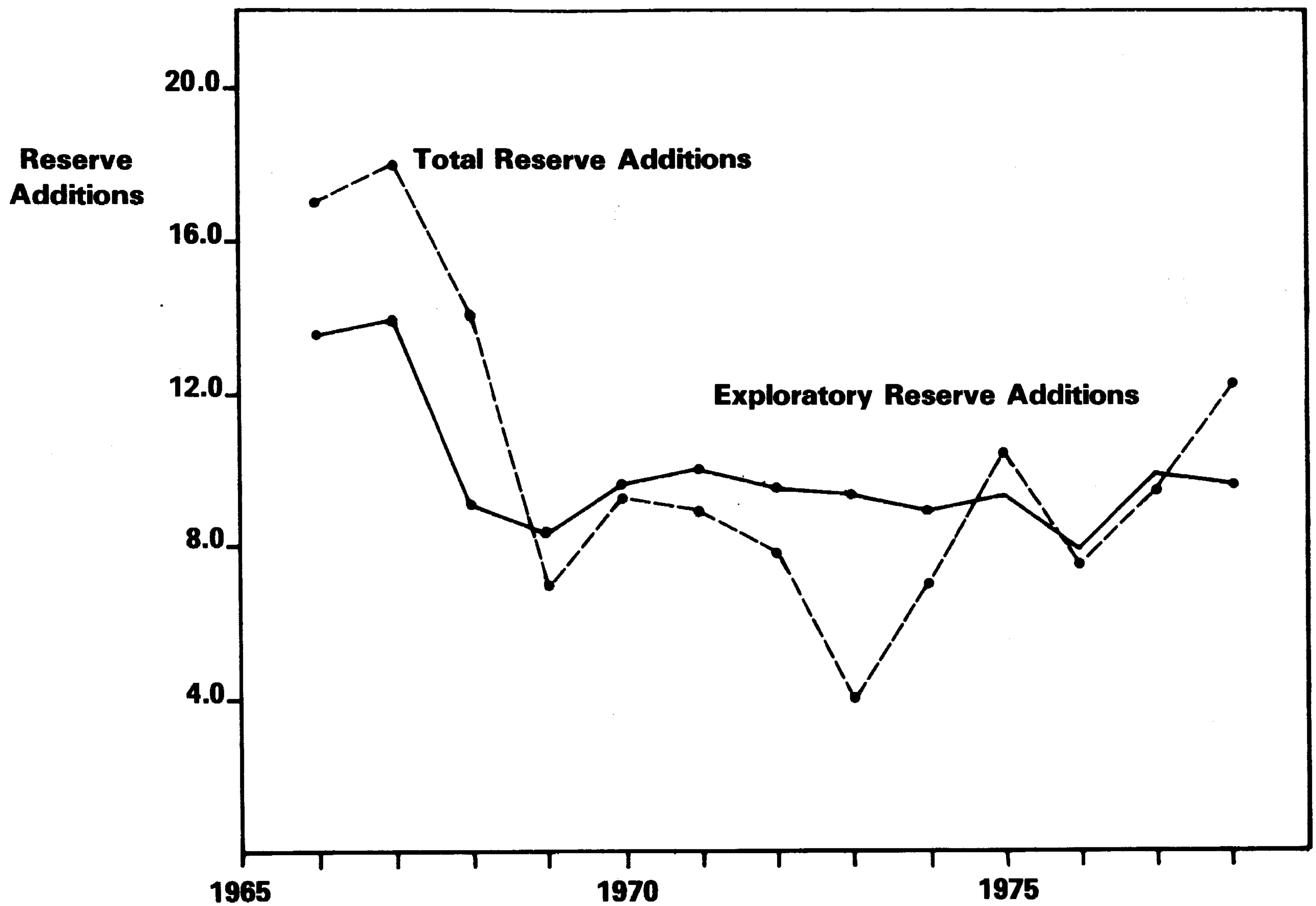


Figure 6
Non-Associated Natural Gas Reserve Additions



reserve additions at slightly more than 9 tcf a year. During this period there has been a large, relatively successful exploration effort in the Overthrust Belt, one of the more promising relatively unexplored areas remaining in the Lower 48. In the light of these trends it appears unrealistic to plan on anything more than holding current exploratory reserve additions at 9 tcf a year, even with an increase in drilling footage on the order of 5 percent a year and the opening of a new potentially rich natural gas province to exploration.

Projecting future revisions is very difficult. Qualitatively we can say that it appears that most of the large negative revisions are probably behind us, and there is a reasonable possibility that future revisions might be largely positive. However, given the decreasing size of natural gas fields, it is unrealistic to expect significant contributions from revisions in the future. Based on experience with positive revisions when natural gas fields were larger, we believe that at this time it would be unrealistic to plan on averaging more than 2 tcf a year of reserve additions from revisions.

Our analysis of current trends in non-associated gas reserve additions indicates that reserve additions should average at most 11 tcf a year through the end of the century. It could be lower if revisions do not recover very much. Reserve additions in excess of this would require growths in drilling rates far in excess of the explosive growths experienced over the past 4 years as well as the discovery of some very large new fields.

The production profile is calculated on the basis that the RP ratio declines to 8 by 1985 from its 1977 value of 8.8. While some claim that the RP ratio could fall even faster, we do not believe it prudent to plan on such an occurrence at this time for two reasons:

--An RP ratio of 8 or 9 years reserves to 1 year's production is considered by the industry as the minimum required to assure continuous deliveries of gas without curtailments of essential service during winter peak deliveries. Even with higher RP ratios, there have been curtailments during excessively cold winters in recent years.

--The permeability (relative ease with which the gas can flow through the reservoir rock) is decreasing for the new fields. This means it would be effectively impossible to produce them at very low RP ratios.

The expected trends in Lower 48 natural gas supply are shown in table 12.

Table 12

Estimated Lower 48 Non-associated Gas Production
1978 to 2000
(tcf)

Year	Production
1978 (actual)	15.5
1980	14.7
1985	13.7
1990	12.5
1995	11.8
2000	11.5

Frontier OCS and Alaska

USGS has estimated that the undiscovered gas resources of the Lower 48 frontier OCS areas range from 26 to 111 tcf, with a statistical mean of 63 tcf. This is appoximately 59 percent of the total offshore (including Alaska) potential of 107 tcf. For Alaska, onshore and offshore, the comparable figures are 29 to 132 tcf, with a mean of 76 tcf.

As shown in chapter 2, exploratory drilling in the past 3 years in the frontier OCS areas and Alaska have produced only 2 gas discoveries (Atlantic OCS) out of 31 wells drilled, whereas exploratory drilling onshore was 20 to 25 percent successful. And at this point the Atlantic discoveries cannot be considered commercial. In view of the disappointing results in areas such as the Eastern Gulf of Mexico, Gulf of Alaska, Southern California, and the Atlantic OCS, the USGS resource estimates for these areas may be somewhat optimistic.

As a result it appears prudent to plan on the development of only about one-third of the frontier OCS (21 tcf) through the end of the century. In Alaska, approximately 40 percent, or 30 tcf, is assumed to be developed. Of the 51 tcf, approximately 29 tcf should be non-associated. 1/

The hostile environments, institutional constraints, and high costs of developing frontier areas makes significant production before 1985 very unlikely. Even 1990 is somewhat problematic. Utilizing the same production profiles as those developed for the frontier petroleum production results in an initial production of about .2 tcf by 1985. Production increases to 1.2 tcf by 1995 and remains at that level through the end of century. Existing Alaskan areas are expected to continue to produce at about .2 tcf a year through the end of the century. The trend in non-associated gas production for the frontier regions is summarized in table 13.

Table 13

Estimated Frontier Non-Associated Gas Production (tcf)

Year	Production
1978 (actual)	0.2
1980	0.2
1985	0.4
1990	0.8
1995	1.4
2000	1.4

OUTLOOK

The aggregate trend in associated, non-associated and total domestic gas supply from conventional sources is shown in table 14. The cumulative reserves required to sustain total natural gas production at the rates indicated in table 14 to the year 2000 amount to about 540 tcf. This implies discovery of approximately 60 percent of the remaining mean resource base of 862 tcf estimated by USGS. The average reserve addition rate

1/The proportion of undiscovered natural gas resource which is developed is identical to that of petroleum. For Alaska the 40-percent development factor is a result of applying the petroleum proportions to the onshore plus the offshore. The non-associated share is estimated by subtracting the associated gas expected from the petroleum discoveries.

Table 14

Estimated Trend of U.S. Natural Gas
Production by Sources
1977 to 2000
(tcf per year)

	1977	1980	1985	1990	1995	2000
Associated Gas:						
Lower 48	3.8	3.4	2.8	2.3	2.2	2.0
Frontier OCS & Alaska	---	0.1	0.2	1.2	1.4	1.7
Subtotal	3.8	3.5	3.0	3.5	3.6	3.7
Non-Associated Gas:						
Lower 48	15.5	14.7	13.7	12.5	11.8	11.5
Frontier OCS & Alaska	0.2	0.2	.4	.8	1.4	1.4
Subtotal	15.7	14.9	14.1	13.3	13.2	12.9
Total Gas:						
Lower 48	19.3	18.1	16.5	14.8	14.0	13.5
Frontier OCS & Alaska	0.2	0.3	0.6	2.0	2.8	3.1
Total	19.5	18.4	17.1	16.8	16.8	16.6

for the entire United States for both associated and non-associated gas is almost 15 tcf a year. This is consistent with the average reserve additions expected from an analysis of the resource base alone.

Table 14 indicates that overall U.S. natural gas production may stabilize in the 1990s, mostly because production from Prudhoe Bay holds constant and there is reasonable success in the frontier OCS and Alaska. As we have mentioned previously, frontier production in Alaska is somewhat speculative because of the current Government land use restrictions, particularly in the Arctic area. If these restrictions were to preclude significant new Alaskan production, then its U.S. natural gas production would continue to decline until the next century.

Lower 48 natural gas production will continue to dominate overall U.S. production, even though its share of U.S. production will continue to decline. The average rate of reserve additions in this area will not be sufficient to stabilize Lower 48 production until after the end of the century.

ANALYSIS OF THE EFFECT OF THE NATURAL GAS POLICY ACT OF 1978

The Natural Gas Policy Act (NGPA) of 1978 provides for the phased deregulation of Federal price controls on natural gas. The act is an extremely comprehensive and complex piece of legislation that is expected to have a significant impact on the natural gas market. However, the law is so complex and new that data do not exist to permit detailed quantitative assessments of the future impacts of this act on natural gas supplies.

In general, the act is expected to accelerate the already high level of gas well drilling activity of recent years. This has been factored into the estimated supply trends presented previously, for which we have assumed an expansion of drilling activity on the order of 5 percent a year. However, despite the increase in drilling activity, reserve additions will probably remain constant simply because of the realities of the U.S. resource base.

While this might appear to be a disappointing trend in reserve additions, it should be understood that without the increased drilling, reserve additions would probably only average between 7 and 8 tcf a year through the end of the century instead of 11 tcf. As a result, production from the Lower 48 would probably be cut in half by the end of the century.

The major impacts of the NGPA will be (1) to increase exploration activity, (2) make sub-marginal natural gas fields economic, and (3) make stripper production more attractive. None of these elements, given the realities of the U.S. natural gas resource base, will have any significant effects on long-term trends in U.S. natural gas production.

At best there may be some limited short-term effects, particularly for small fields which can be discovered, produced, and abandoned in less than 10 years. But these fields will have very small effects on overall production trends simply because of their size. The introduction of a separate stripper category for natural gas production, while delaying abandonment and thus getting more production, could also result in losing production as fields are allowed to decrease faster to bring their wells into a stripper category. Thus in the short term positive and negative stripper effects will probably cancel each other out.

Whatever the price effects of the NGPA, we believe that they will have largely disappeared by the mid-1980s because the price differences between the NGPA and current trends will have virtually disappeared. Natural gas prices in the interstate market have risen at a very rapid rate since 1974. The average wellhead price for interstate gas has increased 200 percent from $.34 per thousand cubic feet (Mcf) in 1974 to over $.84 per Mcf in mid-1978. The highest price allowed for interstate gas had climbed even faster, going from $.20 to $.35 per Mcf in 1973 to $1.51 per Mcf just before the passage of the act. It seems likely that this trend would have continued such that by the mid-1980's natural gas prices would have reached the neighborhood of oil equivalent prices. As a result the differences in prices under continued regulation and those under the act would probably have become quite close by the mid-1980's. This essentially would remove the differential price effects of the act over the current regulations.

This analysis is contrary to claims by the administration and others that there would be 1 tcf more gas by about 1980 and 2 to 3 tcf more gas by 1985. Such an occurrence would be likely only if reserve additions under regulations remained at less than 9 tcf a year or if reserve additions under the act increased to well over 11 tcf as a result of the discovery of some relatively giant fields. It is not likely that the first possibility would occur unless regulated prices suddenly stopped climbing, of which there was no indication. The second, while possible, is not likely enough to be used for a planning base. Therefore, we would conclude that these claims probably overstate the impact of the act by considerable margin, particularly in the light of current administration policies which may close off the possibilities of significant Alaskan frontier production until the 1990s.

CHAPTER 5

COMPARATIVE ANALYSIS

OTHER FORECASTS

In response to growing energy concerns, a large number of energy supply-demand assessments and forecasts have been prepared in recent years by national and international institutions, select committees of experts, oil companies and other energy industry organizations, and individuals. They represent a variety of individual and/or collective interests and are based upon so many different assumptions and employ such varied forecasting methodologies that direct comparison of results is rendered impossible. Nevertheless, they represent such a wide spectrum of analytical investigation, informed opinion, and perspectives that they are extremely useful in trying to narrow the range of uncertainty in future energy supply.

While many of the forecasters rely mainly upon econometric techniques to forecast supply responses to general economic activity and price changes, the analysis presented in this paper is based upon an assessment of the current trends in the petroleum and natural gas resource base, the physical activities likely to control its rate of development, and an estimate of probable future production trends consistent with the technical, economic, and institutional factors which will govern its level. The effect of prices operates within the boundaries established by these factors.

For comparison purposes, the 10 studies listed in table 15 were selected for review and assessment. Criteria used in their selection were that:

--They were sufficiently current to take into account most of the latest surge in oil and gas exploration and development activity and other physical operations affecting supply.

--They were reflective of or considered the effect of recent Governmental price, regulatory, and legislative actions affecting supply.

--They represent a reasonable cross-section of views and institutions generally recognized as the most authoritative.

--They were sufficiently explicit and comprehensive to provide a long-range comparison.

The comparative assessment was limited to petroleum and natural gas supply estimates only, even though all of the studies presented total energy supply-demand forecasts including all fuel and energy sources, which were the sum of individual fuel and energy estimates.

OIL PRODUCTION COMPARISONS

The U.S. petroleum supply estimates from the various studies are shown in table 16. Where appropriate ranges were used in the absence of mean or most probable estimates. Our estimate is the result of our analysis of the current trends discussed in the previous chapters. The other studies were adjusted to eliminate oil or gas supplies from coal synthesis, oil shale, biomass conversion, and other non-conventional or marginal resources, where necessary.

As shown, our estimate is in substantial agreement with the other 1980 estimates. Thereafter, there is a growing divergence among the estimates.

In 1985 our estimate is consistent with some industry estimates (e.g., Exxon and Shell), but it is lower than the other estimate. By 1990 only the Exxon estimate is lower than ours. The major reason for the difference in the estimates is the degree of optimism for frontier production.

Our estimate is influenced by the failure of Government exploratory drilling in the National Petroleum Reserve (formerly Naval Petroleum Reserve No. 4), where 11 straight dry holes have been drilled in recent years. This considerably downgrades that whole Alaskan onshore potential. The drilling by industry has been equally disappointing, as evidenced by 11 straight dry holes in the Gulf of Alaska. Furthermore, current Government land use policies make Alaska onshore production outside of Prudhoe Bay even more speculative.

In our view current trends do not support the more optimistic forecasts which expect Alaskan production of up to 3.2 million barrels a day. Because of the disappointing results in South Alaska and in the NPRA, almost all the new Alaskan production will have to come from the North Slope. Production approaching 3 million barrels a day would imply the discovery and development of almost the entire North Slope petroleum resource base as estimated by USGS in 1975. We believe that such optimism is not warranted in the light of recent experience.

On the other hand, the extremely pessimistic Exxon estimate is based on writing off almost any chance of

Table 15

Studies Assessed

Study	Abbreviation	Issuance date
American Gas Association: The Future for Gas Energy in the U.S.	AGA	1979
Exxon: U.S.A.'s Energy Outlook 1979 - 1980	Exxon	December 1978
Congressional Research Service: Project Interdependence: U.S. and World Energy Outlook through 1990	CRS	November 1977
Department of Commerce: Forecast of Likely U.S. Energy Supply/Demand Balances for 1985 and 2000 and Implications for U.S. Energy Policy	DOC	January 1977
Petroleum Industry Research Foundation, Inc.: U.S. Oil Supply and Demand to 1990	PIRF	October 1977
Shell: The National Energy Outlook 1980 - 1990	Shell	February 1979
Workshop on Alternative Energy Strategies	WAES	1977
Sherman H. Clark, Associates Evaluation of World Energy Developments Their Economic Significance	SHC	January 1977
Department of Energy: EIA Administrator s Annual Report, 1978	DOE	July 1979
Tenneco: Energy 1979-2000	Tenneco	June 1979

Table 16

Estimated U.S. Petroleum Production
from Selected Studies
1980 to 2000
(millions b/d oil equivalent)

Year	Shell	Exxon	Tenneco	PIRF	DOE	CRS	DOC	WAES	SHC	GAO
1980	9.9	10.0	10.2	10.4	9.8-10.4	9.5-10.3		10.3	10.3	9.9
1985	8.5	8.5	11.1	10.8	10.9	9.5-12.9	10.0	10.0-12.7	11.2	8.9
1990	9.3	7.2	11.5	10.4	11.5	10.1-13.2	-	-	11.7	8.0
1995	-	-	10.8	-	11.8	-	-	-		8.0
2000	-	-	10.0	-	11.6	-	7.2	6.4-7.2	11.7	8.5

frontier OCS and Alaska production by 1990. If our analysis did this, it would be consistent with Exxon. However, we believe such pessimism may be premature, although if land restrictions continue on the North Slope of Alaska and the OCS continues to be disappointing, we would probably downgrade our estimates in the next year or two.

It is to be emphasized that Alaska still is a highly prospective oil and gas area with a large potential. Vast areas with large potentials remain to be explored and it continues to be the Nation's best hope for large oil discoveries. The discovery of the giant Prudhoe Bay field created higher expectations than now are warranted by the realities of subsequent exploration. While large new sources of production from Alaska comparable to Prudhoe Bay are possible, they are not very likely. The more likely rate of development of new Alaskan production will probably not begin to counteract the steep decline in Prudhoe Bay production until the 1990s.

We conclude that the consensus of these studies is more representative of an upper limit of supply through 1990. Current trends indicate that our estimate is a more prudent basis for planning purposes.

Five of the studies estimated petroleum output to the year 2000. Three are highly optimistic that domestic output would remain high. The other two more nearly reflect our estimates.

While estimates to 2000 have a much greater uncertainty than those for shorter periods, their reasonableness can be assessed by comparing total petroleum output through 2000 with the domestic resource base. USGS estimates that the total domestic petroleum resource base (this includes proved and inferred reserves along with undiscovered resources) ranges from 125 to 211 billion barrels with a statistical mean of 162.1 billion barrels. Table 17 presents the required cumulative reserves to sustain the estimated petroleum outputs of table 10 between 1976 and 2000. The cumulative reserves are a sum of petroleum production from 1977 to 2000 plus estimated proved reserves in 2000.

Table 17

Cumulative Reserve Requirements
(billion barrels)

Study	Reserve requirements
DOC	97
DOE	136
WAES	93-97
Tenneco	127
SHC	141
GAO	101

Table 17 indicates that to sustain petroleum production above 10 million barrels a day through 2000 (which the SHC and Tenneco studies estimate) would require discovering 80 to 90 percent of the mean U.S. resource base estimated by USGS at 159 billion barrels. This indicates that there is a possibility that a 10-million-barrel-a-day production rate through 2000 would virtually exhaust the total resource base. Because most of the industry estimates of the reserve base are even lower, this possibility becomes even more likely. If this production were achieved, reserve additions might virtually cease after 2000. As a result, after 2000 U.S. petroleum production would begin to fall very steeply, thus presenting the United States with a new and rapidly growing shortfall.

The DOE estimate is as optimistic as Tenneco and SHC, but it does not draw down the undiscovered resource base as much. Of the approximately 136 billion barrels of petroleum needed to sustain the DOE production, about 36 billion barrels will come from new EOR which was not included in the USGS 725 estimate. By 2000 over half of U.S. crude production is derived from new EOR in the DOE estimate. Given the current realities of EOR techniques, such an estimate should be seen as extremely optimistic.

The WAES and DOC estimates are consistent with ours. The optimism they show for 1985 production results in significantly lower production in 2000 than we would estimate.

NATURAL GAS PRODUCTION COMPARISONS

Estimated U.S. natural gas production from the selected studies is presented along with our estimate in table 18. All the estimates, with the exception of GAO and AGA, show steep declines in U.S. natural gas output. In general, our estimates are increasingly optimistic as years progress regarding U.S. conventional natural gas production. This is directly opposite to the petroleum comparisons.

The relatively good agreement between our estimate and the AGA estimate is largely fortuitous. We are more optimistic than AGA regarding Lower 48 production, but they are much more optimistic regarding Alaska. We do not believe such optimism is justifiable in the light of recent experience and current estimates of the resource base.

The major source of the differences between our estimates and the others in table 18 is the pessimism regarding Lower 48 and Alaska production. We do not believe such pessimism is justified at this time, particularly in the light of the relative optimistic estimates for Alaskan petroleum production trends and the large Canadian gas discoveries in the McKenzie Delta. The current level of inferred Lower 48 natural gas reserves is relatively higher than inferred petroleum reserves. On this basis it would be reasonable to be more optimistic for Lower 48 natural gas production than petroleum production.

The estimates of production through 2000 by most of the studies are so low that they could be sustained solely from the proved and inferred reserves. Unless the resource base estimates are much too large, such estimates appear to us to be overly pessimistic.

SUMMARY

On the basis of remaining resources, it seems more logical that natural gas production would hold steady or decline more slowly than petroleum. To date, over 65 percent of the expected USGS estimates of the petroleum resource base have already been discovered or produced, compared to only 51 percent of those for natural gas. This suggests that the petroleum production estimates of the comparison studies are overly optimistic or upper limits, while the gas estimates are nearer lower limits. Furthermore, some question needs to be raised regarding the internal self-consistency of those studies which have estimated both petroleum and natural gas production, unless analysts feel that the NGPA will work to discourage exploration.

Table 18

Estimated U.S. Natural Gas Production from Selected Studies 1980 to 2000 (tcf per year)

Year	Shell (note a)	Exxon	Tenneco	PIRF	DOE	CRS	AGA	DOC (note a)	WAES	SHC	GAO
1980	17.8	17.8	18.0	16.9	18.7	17.4	18-19	-	-		18.4
1985	16.2	15.3	16.0	16.1	17.6	16.9	16.8-18.8	16.9	13.7-19.6	16	17.1
1990	14.5	14.3	16.0	15.7	16.6	16.9	16.6-18.6				16.8
1995	-	-	15.0	-	15.2	-	16-18				16.8
2000	-	-	13.0	-	15.8	-	15.6-17.6	11.7	b/11.2-13.7	b/ 15	16.6

a/Corrected for coal gasification.

b/Corrected for biomass energy contributions.

CHAPTER 6

FINDINGS AND CONCLUSIONS

Although the United States has a large remaining petroleum and natural gas resource base, it is very unlikely that these resources could reverse the long-term declines in U.S. petroleum and natural gas production. Policy options available to the Nation can only allow a slowing of the decline in the near and mid-term, with some limited prospects for stabilizing production at the end of the century.

FINDINGS

While many of our findings are particular to either oil or natural gas, some are applicable to both. They are:

--The Lower 48 States (onshore and producing offshore) will continue to be the dominant factors in future U.S. production, despite their expected continued declines.

--In the Lower 48 States, the existing resource realities provide little likelihood for prices and drilling to do more than slow the declines in petroleum and natural gas production. However, the lack of adequate prices or drilling activity could result in significantly faster production declines.

--Unless some extraordinarily rich petroleum and natural gas provinces are discovered, the trends in U.S. production through the end of this century will be dominated by the level of inferred and indicated reserves, not the undiscovered recoverable resource base.

--The frontier areas are not likely to counteract the decline in overall U.S. production unless there are significantly more resources than currently expected. Although frontier areas cannot stop or reverse the overall decline, without their production the decline would be even steeper.

--Many potential frontier production areas and some future Lower 48 producing areas are on lands which have drilling and exploration restrictions, or even prohibitions. If these lands are not developed, production declines could be even steeper.

--Because of production lead times, frontier area production will probably not become significant until the late 1980s at the earliest. However, this production would begin at a time when the world supply is likely to become increasingly constricted; as such it could play an important role in carrying the Nation through this period.

--Long-term trends in petroleum production would tend to be more sensitive to price than conventional natural gas because of the possibility of EOR for petroleum.

Petroleum

Our findings applicable to petroleum alone are these:

--Future petroleum producing rates will be largely determined by the level of exploration and development drilling and its success in finding new reservoirs or extensions to existing ones. It will also depend importantly on the successful application of new enhanced oil recovery technologies to existing fields.

--The dramatic increases in drilling activity have only served to stabilize reserve additions. Unless a new Permian Basin or two is found, drilling activity will probably have to continue its dramatic growth just to hold reserve additions in the Lower 48 level.

--Despite the bleak prospects for Lower 48 reserve additions, the Lower 48 production decline should slow significantly by the 1990s. The growing contribution from EOR should provide some limited growth prospects near the end of the century.

--New enhanced recovery technologies will come slowly because of high costs, long lead times, and field size economies of scale. New EOR techniques will not make important contributions to supplies until the 1990s.

--Despite disappointing exploration results in the Gulf of Alaska and in the National Petroleum Reserve, Alaska remains the single most highly prospective area for new oil discoveries. However, Government land restrictions could inhibit the timely development of some Alaskan areas and result in an accelerated fall-off in U.S. production as Prudhoe Bay begins to decline in the mid-1980s.

--Frontier offshore areas have a high potential but high costs and long development lead times will limit output to the 1-million-barrel-a-day level by 1995 and 2000.

--Decontrol of oil prices may have some limited short-term impacts on revisions to reserves. It would have limited effects on increasing reserve additions from exploration because most of the marginal fields which would become economic are very small.

--Natural gas liquids production is directly related to natural gas, especially associated gas, producing levels. NGL production is expected to be relatively stable largely because of stable gas production from Prudhoe Bay.

Natural gas

Our findings are as follows:

--The remaining recoverable natural gas resource base is considerably larger than that of petroleum.

--The upsurge in total drilling activity and higher gas prices has stimulated gas drilling; however, as in the case of oil, non-associated gas reserve additions from exploratory activities have remained stable at about 9 tcf.

--The apparent improvement in non-associated natural gas reserve additions in the last 4 years has resulted solely from a gradual disappearance of negative revisions to reserves. In the light of trends in gas field sizes, it is unlikely revisions would become a significant positive factor; they probably will not be negative in the future.

--The aggregate trend in total domestic natural gas output is for a steady decline through the late 1980s. Production may then begin to stabilize at slightly less than 17 tcf a year through the end of the century. This occurs because of (1) the introduction of Prudhoe Bay production and (2) the growth in frontier OCS and Alaska production.

--Failure to develop the frontier areas and produce the Prudhoe Bay gas in a timely manner is likely to prolong the current decline in U.S. production into the 1990s.

--The recently enacted phased deregulation of natural gas prices will have some limited impacts on making sub-marginal fields economic in the short term. But because these fields are small, they will have little impact on overall production. The act is unlikely to have any long-term effects on U.S. natural gas supplies simply because the trend in natural gas prices was toward effective deregulation by the mid-1980s.

CONCLUSIONS

Current policies are providing price and other incentives to stimulate and accelerate the rate of development of conventional petroleum and natural gas supplies. Further price increases might stimulate some additional short-term petroleum production, but little additional natural gas. This is mostly because the trends in prices, even under regulations, would have effectively removed most production from the low price categories by the mid-1980s.

Drilling activity is at near-record levels, but it is directed largely at proven areas. As a result the supply response has been quite poor, i.e., industry is drilling more but finding and producing less. On the other hand, exploratory activity in frontier OCS and Alaskan onshore areas has been limited and initial results have been quite disappointing.

Our analysis indicates that the likelihood of even slowing the decline in U.S. petroleum and natural gas production will strongly depend not just on the likelihood of finding large amounts of oil and gas reserves, but finding these reserves in large fields or reservoirs. Any Government policy designed to encourage oil and gas production must have two equally important purposes:

1. To provide adequate incentives to drill for new reserves and improve recovery in existing fields.

2. To provide incentives to focus those new drilling activities in the areas where it is most likely to find new large fields (e.g., the frontier areas of Alaska and the OCS).

To do one without the other will significantly impair the likelihood of the success of any Government activities to stimulate U.S. oil and gas production and slow the decline in domestic production.

DEFINITION OF TERMS

Associated gas or associated-dissolved gas (API)--That gas produced with crude oil, which may exist as free gas or in solution in the reservoir.

Crude oil--All hydrocarbon liquids recovered from natural underground reservoirs that remain liquid at atmospheric pressures and liquids recovered in lease separators as condensate from hydrocarbons that existed in the gaseous phase in the reservoir, but are liquid after being recovered and co-mingled with crude at surface lease separators.

Discoveries--New fields or new reservoirs in oil fields that find proved reserves as a result of successful exploratory drilling.

Enhanced recovery or improved recovery techniques (API)--All recovery techniques for supplementing natural reservoir forces and energy to enhance or increase recovery. This includes pressure maintenance, cycling, conventional fluid injection in secondary recovery methods, conventional thermal, as well as tertiary or exotic thermal, chemical or miscible displacement technologies.

Field--Any productive area consisting of one or more reservoirs, all grouped in, or related to, the same geological structure or stratigraphic condition.

Indicated reserves or indicated additional reserves (API)--Includes potential reserves in known producing reservoirs which are expected to respond to improved recovery techniques, if and when they can be successfully applied. Their economic certainty is not sufficiently assured to be classified as "proved reserves" but is sufficient to be potentially so.

Inferred reserves--Reserves in addition to those above that will eventually be added through extensions, revisions based on new information, or from new zones or pays that are shut in or behind-the-pipe reservoirs. Included are API and AGA "extensions" and "revisions" classifications.

Natural gas--The mixture of hydrocarbons and small quantities of non-hydrocarbons existing in the gaseous phase or in solution in oil in underground reservoirs.

Natural gas liquids--All natural gas liquids recovered separately from crude oil in lease facilities and natural gas processing plants.

Non-associated gas--"Free" or "dry" gas not in contact with crude oil in the reservoir.

Original stock-tank oil-in-place--The estimated number of barrels of oil-in-place in known reservoirs prior to any production, as measured as liquid petroleum in lease stock tanks following removal of dissolved gases in lease gas-oil separators.

Primary recovery--Production resulting from or expected to be obtained solely from natural energy drive mechanisms and/or artificial lift, without any application or extraneous energy to increase ultimate recovery.

Primary-secondary recovery--For purposes of analyzing reserves and producing rates in this study, all reserves and production which include primary recovery and conventionally applied enhanced recovery techniques are considered in this "primary-secondary recovery" category. This includes all conventionally applied pressure maintenance, water-flooding, and other secondary recovery technologies, steam and related thermal methods, and conventional miscible recovery techniques. Only "tertiary" and truly advanced thermal, fire-flood, or chemical recovery technologies are considered as "new enhanced oil recovery" reserves or production.

Proved reserves--Those resources at the end of any given year, reported by the API and AGA 1/ as statistically defined conventional hydrocarbons, which geological and engineering data demonstrate can be removed in future years from known reservoirs under existing economic and operating conditions.

1/American Petroleum Institute and American Gas Association, Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada, published annually.

Reservoir--A porous and permeable underground formation containing a single and separate natural accumulation of producible hydrocarbons and having a single natural pressure system.

Resources--Those naturally occurring deposits of minerals, such as crude oil, in or on the Earth's crust in such form that economic extraction is currently or potentially feasible. This includes both identified and undiscovered resources which are surmised to be economically recoverable. Only "conventional" liquid or gaseous hydrocarbons (crude oil, natural gas liquids, and natural gas) are considered herein. Specifically excluded are tar sands, oil shales, undeveloped tight gas sands, gas in coal beds, and gas in geopressured water zones.

Stripper wells and production--These are those wells, producing from largely depleted fields, whose average producing rate is less than 10 b/d.

Ultimate recovery--The estimated quantity of hydrocarbons (oil, natural gas liquids, or gas) which has been produced or is expected to be produced under present economic and operating conditions. It is the sum of cumulative production to date plus the current proved reserve estimate.

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