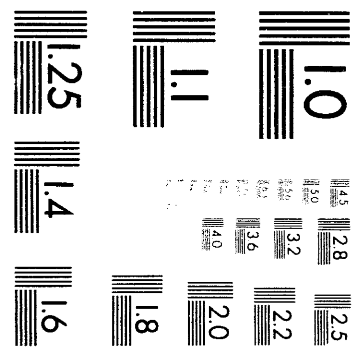
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U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves

1992 Annual Report

October 1993

Energy Information Administration
Office of Oil and Gas
U.S. Department of Energy
Washington, DC 20585

Diskette Information

Historical oil and gas reserves data are available on a 3.5 or 5.25 inch high-density diskette. These data cover the years 1977 through 1992, published in the Energy Information Administration annual reports of *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*. Sixteen separate annual ASCII files are stored on a single diskette. Each of the annual files contains the following data tables:

- **Crude Oil Proved Reserves, Reserves Changes, and Production.**
- **Total Dry Natural Gas Proved Reserves, Reserves Changes, and Production.**
- **Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation.**
- **Nonassociated Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation.**
- **Associated-Dissolved Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation.**
- **Natural Gas Liquids Proved Reserves, Reserves Changes, and Production.**
- **Natural Gas Plant Liquids Proved Reserves and Production.**
- **Lease Condensate Proved Reserves and Production.**

This diskette, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1977-1992, is available from the Energy Information Administration. Please contact Bob King, (202) 586-4787 or Fax (202)586-1076.

Preface

The *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1992 Annual Report* is the 16th prepared by the Energy Information Administration (EIA) to fulfill its responsibilities for gathering and reporting proved reserves data. Data in this publication are used by the Congress, Federal and State agencies, industry, and other interested parties to obtain accurate, updated estimates of the Nation's proved reserves of crude oil, natural gas, and natural gas liquids. These data are essential to the development, implementation, and evaluation of energy policy and legislation. The EIA annual reserves report series is the only source of comprehensive, nationwide proved reserves estimates.

This report presents estimates of proved reserves of crude oil, natural gas, and natural gas liquids as of December 31, 1992, as well as production volumes for the United States, and selected States and State subdivisions for the year 1992. Estimates are presented for the following four categories of natural gas: total gas (wet after lease separation), its two major components (nonassociated and associated-dissolved gas), and total dry gas (wet gas adjusted for the removal of liquids at natural gas processing plants). In addition, two components of natural gas liquids, lease condensate and natural gas plant liquids, have their reserves and production data presented. These estimates are based upon data obtained from two annual EIA surveys: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves" and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." Also included is information on indicated additional crude oil reserves and crude oil, natural gas, and lease condensate reserves in nonproducing reservoirs. A discussion of notable oil and gas exploration and development activities during 1992 is provided.

The appendices contain information on the top 100 oil and gas fields for 1991, report Table 1 converted to metric units, historical data series, a summary of survey operations, a discussion of statistical considerations, methods used to develop the estimates provided in this report, maps of selected State subdivisions, and examples of the survey forms. This year, a new appendix contains data by operator production size class for crude oil and natural gas reserves and production. A glossary of the terms used in this report and in survey Forms EIA-23 and EIA-64A is provided to assist readers in more fully understanding the data.

The annual reserves report is prepared by the Dallas Field Office staff of the Reserves and Production Branch, Reserves and Natural Gas Division, Office of Oil and Gas, Energy Information Administration, under the general direction of Diane W. Lique, Director of the Reserves and Natural Gas Division, Craig H. Cranston, Chief of the Reserves and Production Branch, and John H. Wood, Director of the Dallas Field Office.

General information regarding preparation of the report may be obtained from Diane W. Lique (202) 586-6090 or Craig H. Cranston (202) 586-6023. Specific information regarding the content of the report may be obtained from the authors: John H. Wood, Paul Chapman, and John R. Tower (214) 767-2200.

Other recent reports published by the Energy Information Administration (EIA) offer additional information and analysis related to domestic oil and gas reserves. They may be obtained from the Government Printing Office in the same manner as this reserves report.

EIA Oil and Gas Publications Currently Available

Geologic Distributions of U.S. Oil and Gas
DOE/EIA-0557, July 1992
Important properties of crude oil and nonassociated gas field size distributions, at the end of 1989, are discussed. These data are arranged by geologic provinces. Volumetric distributions of ultimate recovery estimates are discussed across the members of three macrogeologic variable suites: (1) principal lithology of the reservoir rock, (2) principal trapping condition, and (3) geologic age of the reservoir rock.

Largest U.S. Oil and Gas Fields
DOE/EIA-TR-0567, August 1993
This report identifies the largest 1 percent of U.S. oil and gas fields and their general location, year of discovery, and approximate National rankings in several size categories including proved reserves and annual production. Nearly two-thirds of the remaining domestic crude oil proved reserves are found in the largest 100 oil reserves fields. U.S. natural gas proved reserves are not nearly so concentrated, as 45 percent are contained in the top 100 gas reserves fields.

U.S. Oil and Gas Reserves by Year of Field Discovery
DOE/EIA-0534, August 1990
This publication describes and comments on the 1988 year-end estimates of both proved reserves and ultimate recovery, according to the year of field discovery.

Three-Dimensional Seismology - A New Perspective
DOE/EIA-0130(92/12) or DOE/EIA-0109(92/12), both December 1992
This report reviews the history, technology, economics, current application, and probable future of 3-D seismic surveying in oil and gas applications.

Drilling Sideways--A Review of Horizontal Well Technology and Its Domestic Application
DOE/EIA-TR-0565, April 1993
This report reviews the technology, its history, and its current domestic application. It also considers related technologies that will increasingly affect horizontal drilling's future.

Natural Gas 1992: Issues and Trends
DOE/EIA-0560(92), March 1992
Among other issues, this report describes the recent combined impacts on domestic gas supply of lower wellhead prices and improvements in drilling technology. As producers shifted the foci and lowered the levels of their drilling programs, improved finding rates allowed supplies to remain adequate, although increased gas demand caused a shrinkage of excess productive capacity.

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Executive Summary

U.S. proved reserves of crude oil, natural gas, and natural gas liquids all declined again in 1992 as a result of low oil and gas prices. Federal tax incentives helped to keep the decline in natural gas reserves to 1 percent, compared to 4 percent for oil.

Proved reserves are those quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Petroleum engineering and geological judgment is required in estimating reserves; therefore, the results are not precise measurements. This report of 1992 U.S. proved reserves of crude oil, natural gas, and natural gas liquids is the 16th in an annual series prepared by the Energy Information Administration (EIA).

As of December 31, 1992, proved reserves were 165,015 billion cubic feet of dry natural gas (excluding gas in underground storage); 23,745 million barrels of crude oil; and 7,451 million barrels of natural gas liquids (including lease condensate).

Natural Gas

All four leading gas producing areas, Texas, the Gulf of Mexico Federal Offshore, Oklahoma, and Louisiana, had large declines in proved reserves totaling 4,649 billion cubic feet. But partially offsetting these declines were large increases in coalbed methane reserves in Virginia, New Mexico, Colorado, and Alabama. Reserves in these States increased by 1,957 billion cubic feet from last year.

Reserves in coalbed methane fields increased to 10,034 billion cubic feet, a 23-percent increase in 1992, to account for 6 percent of total U.S. natural gas reserves. These reserves expanded rapidly because of a large Federal tax credit incentive.

In recent years, the net amount of revisions and adjustments to reserves played a growing role in sustaining U.S. natural gas proved reserves. This amounted to 8,328 billion cubic feet in 1992. The increasing recovery of gas from the resource base of old fields was enhanced by the application of new technologies, such as 3-D seismology, horizontal drilling, better fracturing treatments, and improved well completion techniques.

U.S. *total discoveries* of dry gas reserves were 7,048 billion cubic feet, a decline of 7 percent from last year. *Total discoveries* are those reserves attributable to field *extensions*, *new field discoveries*, and *new reservoir discoveries in old fields*; they result from drilling exploratory wells. The Gulf of Mexico Federal Offshore and Texas accounted for more than half of U.S. *total discoveries*.

Other natural gas highlights of 1992 were:

- The real natural gas price at the wellhead first dropped to a 15-year monthly low of $1.31 per thousand cubic feet in February before rising rapidly later in 1992.
- Tax credits for new unconventional gas wells spurred drilling for coalbed methane and tight-sand gas to high levels in the last half of 1992.
- Total gas well completions dropped only 16 percent to 7,640.
- *New field discoveries* were 649 billion cubic feet, down 23 percent.
- Field *extensions* were 4,675 billion cubic feet, down 8 percent.
- *New reservoir discoveries in old fields* were 1,724 billion cubic feet, up 7 percent, but still well below the prior 10-year average.
- *Total discoveries* per exploratory well were up, moderating the decline in *total discoveries* for both oil and gas.

Crude Oil

California had the largest percentage drop in crude oil reserves of any major producing area—twice the U.S. average. Low oil prices, along with local and State environmental concerns, contributed to the large California decline. Most of the Nation's thermally enhanced recovery of heavy oil takes place in California.

Total discoveries of crude oil were down to 484 million barrels in 1992. Three areas, Texas, Alaska, and the Gulf of Mexico Federal Offshore, accounted for 74 percent of them.

New field discoveries were an exceptionally low 8 million barrels last year. The United States produces 7 million barrels every day. The prior 10-year average for *new field discoveries* was 15 times as high. Two new discoveries may turn this trend around in 1993. They are the Sunfish prospect in the Cook Inlet of offshore Alaska and the Kuvlum prospect, which is 15 miles offshore of the Arctic National Wildlife Refuge. These prospects are still being evaluated and are not yet proved.

The 10 largest oil and gas producing companies in 1992 had 66 percent of U.S. proved reserves of crude oil. These companies concentrated their U.S. operations on fewer fields and focused more of their resources on foreign operations. Consequently, the top 10 producing companies had a 6-percent decline in their domestic proved reserves of crude oil during 1992. The rest of the producers had a 2-percent increase.

Other crude oil highlights of 1992 were:

- Real oil prices pushed $50 per barrel in 1981, but they dropped in 1991 and dropped again in 1992 to $15.96 per barrel.
- Alaskan North Slope oil was $9.09 per barrel in January 1992 and the California price was $10.97 per barrel in March, with heavy oil prices even lower.
- Low prices caused low drilling that caused low reserve additions.
- Active drilling rigs reached a new 20-year low.
- Oil well completions dropped 28 percent to 8,640, a 20-year low.
- *Total discoveries* per exploratory well were up, moderating the decline in *total discoveries* for both oil and gas.
- Field *extensions* were 391 million barrels, up 7 percent, but still well below the prior 10-year average.
- *New reservoir discoveries in old fields* were 85 million barrels, down 8 percent.

Indicated additional crude oil reserves were 3,782 million barrels, an 11-percent decrease from 1991. These reserves are crude oil volumes that may become economically recoverable from known reservoirs through the application of improved recovery techniques using current technology. The presence of large indicated additional reserves in the Alaskan North Slope, California, west Texas, and New Mexico implies that significant upward revisions to crude oil proved reserves could occur in the future.

Natural Gas Liquids

U.S. natural gas liquids proved reserves decreased slightly to 7,451 million barrels in 1992. Natural gas liquids reserves are the sum of natural gas plant liquids and lease condensate reserves.

Total liquid hydrocarbon proved reserves (crude oil plus natural gas liquids) were 31,196 million barrels in 1992, a 3-percent decline of 950 million barrels from the 1991 level. Natural gas liquids were 24 percent of total liquid hydrocarbon proved reserves in 1992.

Data

These estimates are based upon analysis of data from Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," filed by 3,964 operators of oil and gas wells, and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production," filed by operators of 867 active natural gas processing plants. The U.S. proved reserves estimates for crude oil and natural gas are associated with sampling errors of less than 1 percent at a 95 percent confidence level.

1. Introduction

Background

The primary focus of this report is to provide an accurate estimate of U.S. proved reserves of crude oil, natural gas, and natural gas liquids. These estimates are considered essential to the development, implementation, and evaluation of national energy policy and legislation. In the past, the Government and the public relied upon industry estimates of proved reserves. These estimates had been prepared jointly by the American Petroleum Institute and the American Gas Association and published in their annual report, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada*. However, they ceased publication of reserves estimates after their 1979 report.

By the mid-1970's, various Federal agencies had separately established programs to collect data on, verify, or independently estimate domestic proved reserves of crude oil or natural gas. Each program was narrowly defined to meet the particular needs of the sponsoring agency. In response to a recognized need for unified, comprehensive proved reserves estimates, Congress, in 1977, required the Department of Energy to prepare such estimates. To meet this requirement, the Energy Information Administration's (EIA) reserves program was undertaken to establish a unified, verifiable, comprehensive, and continuing statistical series for proved reserves of crude oil and natural gas. The program was expanded to include proved reserves of natural gas liquids in the 1979 report.

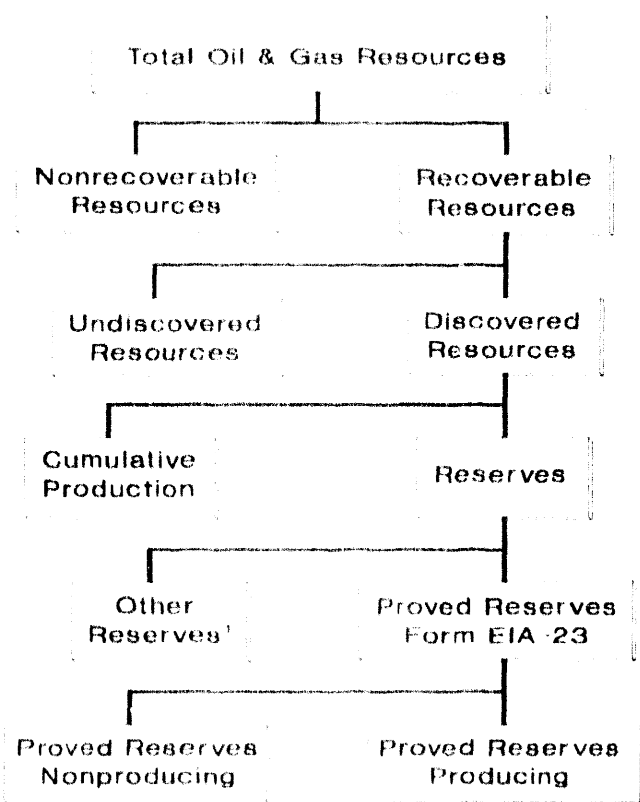
Oil and Gas Resource Base

Our understanding of the earth, while extensive, is still uncertain when estimates of the current and potential resources and reserves are made. The terminology used in classifying petroleum resources and reserves continues to be the subject of much study and discussion in the oil and gas industry. Therefore, it is not surprising that some confusion still surrounds the use and understanding of the terminology developed to describe these quantities. A lack of understanding of the difference between reserves and the more generalized concept of resources causes confusion, as does the variety of definitions that describe various kinds of reserves.

The total resource base of oil and gas is the total volume that was formed and trapped in-place within the earth before production. A portion of this total resource base is nonrecoverable by current or foreseeable technology. A large part is found at very low concentrations throughout the earth's crust. It cannot be extracted short of mining the rock or the application of some other approach that would consume more energy than it produced. An additional portion of the total resource base cannot be recovered because current production techniques cannot extract all of the in-place oil and gas even when it is present in commercial concentrations. This inability to recover 100 percent of the in-place petroleum from a producible deposit occurs because of economics, intractable physical forces, or a combination of both. The concept of recoverable resources excludes these nonrecoverable fractions of the total resource base.

The entire structure presented in Figure 1 represents the total resource base. This total consists of recoverable and nonrecoverable portions discussed above. The next level divides recoverable resources into a discovered segment and an undiscovered segment. Discovered resources are then separated into cumulative production and reserves.

Figure 1. Relationship of Petroleum Resource and Reserve Terms



[1]Of the numerous other reserve classifications, only "Indicated Additional" reserves are in this report.

Source: Energy Information Administration, Office of Oil and Gas.

Further, reserves are subdivided into other reserves and proved reserves. In addition, proved reserves may be in producing reservoirs or in nonproducing reservoirs. Although proved reserves are the focus of this report, the next several paragraphs discuss the spectrum of additional oil and gas estimated to reside in other portions of the recoverable resource base.

Recoverable Resources

Recoverable resources include both discovered and undiscovered resources. Discovered recoverable resources are defined here as those quantities of oil and gas, the locations of which are already known. The locations of undiscovered recoverable resources are not yet known with specificity, but they are thought to exist in geologically favorable settings.

While undiscovered recoverable resource estimates are outside the purview of this report, they merit a brief discussion to provide a sense of scale relative to proved reserves. The official sources of these domestic estimates of undiscovered recoverable resources are the United States Geological Survey and the Minerals Management Service of the Department of the Interior (DOI).

DOI defines undiscovered recoverable conventional resources as accumulations of sufficient size and quality that they could be produced with conventional recovery technologies but without regard to economic viability. Therefore, only part of the undiscovered recoverable conventional resources are economically recoverable under conditions of current technology and imposed economic assumptions.{1}

For the 1989 national assessment, using data as of December 31, 1986, the United States Geological Survey estimated the undiscovered recoverable conventional crude oil, natural gas, and natural gas liquids resources of all onshore areas of the United States, as well as State offshore areas, while the Minerals Management Service was responsible for the Federal Offshore estimates. Their general approach to resource estimation was a complex play analysis technique. A play is a related group of accumulations and/or prospects that have similar reservoir source and trap type. The 1989 DOI range of estimates for domestic undiscovered recoverable conventional resources was 33 to 70 billion barrels of crude oil with a mean estimate of 49 billion barrels, 307 to 507 trillion cubic feet of natural gas with a mean estimate of 399 trillion cubic feet, and 6 to 12 billion barrels of natural gas liquids with a mean estimate of 9 billion barrels.{1} These estimate ranges are stated at the 95 and 5 percent probability levels of occurrence, respectively. This means that there are 19 chances in 20 that more than the lower volume occurs and one chance in 20 that more than the higher volume occurs.

These DOI estimates for undiscovered resources were not intended to include (a) oil and gas extractable by enhanced methods, such as enhanced oil recovery and (b) so-called "unconventional" oil and gas resources, such as gas trapped in low-permeability (tight) formations. Other estimators use criteria that relax this restriction to one degree or another, in essence, speculating as to the effects of present or expected future advanced or enhanced recovery technology on the size of the recoverable resource base. Such estimates are usually made in association with different economic assumptions than those used by DOI, particularly as to future prices. For example, the American Association of Petroleum Geologists included 36 billion barrels of tertiary enhanced oil recovery in its estimate for resources recoverable with existing technology, in the price range of $25 to $50 per barrel.{2}

In 1992, DOE sponsored an assessment of the U.S. oil resource base, which among other categories, estimated from 99 to 130 billion barrels of oil recoverable with existing technology, at respective prices of $20 to $27 per barrel.{3} Also, the DOE Office of Policy, Planning, and Analysis sponsored a one-time assessment effort in May, 1988, which among other gas categories, estimated 259 trillion cubic feet of unconventional gas.{4} These oil and gas amounts were considered recoverable with existing technologies in onshore areas of the lower 48 States as of December 31, 1986. Coalbed methane constituted 48 trillion cubic feet of the 259 trillion cubic feet estimated in the 1988 DOE report. For comparison, the Potential Gas Committee identified 147 trillion cubic feet of coalbed methane as a recoverable resource (sum of probable, possible, and speculative mean values) in its report for data year 1992.{5} For still another comparison and among other natural gas categories, the National Petroleum Council (NPC), in December 1992, estimated 519 trillion cubic feet of unconventional gas as technically recoverable in the lower 48 States. Coalbed methane accounted for 98 trillion cubic feet of this NPC estimate, and natural gas from tight sands accounted for 349 of the 519 trillion cubic feet.{6} While the estimation of undiscovered resources is a relatively imprecise endeavor relative to estimation of proved reserves, and different assumptions as to economics and technology can yield very different results, it is clear that substantial volumes of technically recoverable resources remain to be found.

Discovered Resources

Besides cumulative production, discovered recoverable resources naturally include reserves. Cumulative production is the sum of the current year production and the production for all prior years. Reserves are volumes estimated to exist in known deposits and believed to be recoverable in the future through the application of present or anticipated technology.

Reserves

Reserves include both **proved reserves** and **other reserves**. There are numerous classifications of reserves used by different organizations, such as *measured, indicated, inferred, probable,* and *possible.* Different categorization systems are preferred by different workers. Consequently their definitions sometimes overlap. But however they are categorized, labeled, and defined, other reserves are generally less well known and therefore less precisely quantifiable than proved reserves. Their recovery is also less assured than is that of proved reserves. Measured reserves are defined by DOI as that part of the identified economic resource that is estimated from geologic evidence supported directly by engineering data.{1} Measured reserves are demonstrated with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and are generally equivalent to "proved reserves" (as defined by EIA). Indicated and inferred reserves, because of their uncertain economic or technical recoverability, remain in the other reserves category.

DOI defines inferred reserves as that part of the identified economic resources, over and above measured and indicated reserves, that will be added through extensions, revisions, and the addition of new pay zones in discovered fields.{1} Basically, inferred reserves are also considered probable reserves by many analysts, for example, those of the Potential Gas Committee.

Indicated additional reserves, a separate category, are defined by DOI and EIA as quantities of crude oil that may become economically recoverable in the future from existing productive reservoirs through the application of currently available but not installed recovery technology. When the techniques are successfully applied, the indicated additional reserves are reclassified to the proved category. Of the "other reserves" categories, only those classified as "indicated additional" are estimated by EIA and included in this report.

DOI estimated the sum of indicated and inferred reserves to be 22 billion barrels of crude oil, 99 trillion cubic feet of natural gas, and 4 billion barrels of natural gas liquids.{1} In addition, another DOI report estimated 123 trillion cubic feet of "unconventional" gas resources in several basins thought to be recoverable using existing technology at wellhead prices of roughly $5 a thousand cubic feet.{7}

When estimates of proved reserves are added to amounts estimated for the many other oil and gas resource categories, large volumes result for potentially recoverable remaining resources. Under general conditions of historical prices and existing technology, remaining recoverable resources have been estimated to be as much as 140 billion barrels of crude oil {2} and 1,188 trillion cubic feet of natural gas.{4} Both of these estimated volumes include undiscovered and unconventional resources, and use data as of December 31, 1986. If "advanced" technology considerations are applied, even higher estimates would result. It should be borne in mind that such large resource estimates do not necessarily translate rapidly into large increases in proved reserves or production. That is, many decades will be required to bring such resources incrementally onstream, at great effort and cost.

Proved Reserves

EIA defines proved reserves, the major topic of this report, as those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. There are other categories of reserves, but by definition they are more speculative and less precise than proved reserves. These proved reserves are either proved producing or proved nonproducing (those reserves in reservoirs that did not produce during the report year). The proved nonproducing reserves are included in the proved reserves reported by EIA and may represent a substantial fraction of proved reserves each year. For example, 20 percent of the proved wet natural gas reserves were in nonproducing reservoirs in 1992. Others have issued similar but not identical proved reserves definitions. The Society of Petroleum Engineers, in concert with the Society of Petroleum Evaluation Engineers, has reserves definitions that cover proved reserves and subdivisions thereof, as well as several categories of other reserves. These Society of Petroleum Engineers definitions explicitly restrict proved reserves to those that exist under current government regulations and have operational transportation facilities or a commitment or reasonable expectation that such facilities will be installed in the future. The Securities and Exchange Commission also publishes reserves definitions that are similar to those used by EIA, but the Securities and Exchange Commission definitions state the economic conditions and assumptions more explicitly. Prices and costs are as of the date the estimate is made. Future prices may include consideration of changes in existing prices provided by contractual arrangements, but not escalations based on assumptions about future conditions.

Reserves Changes

Estimates of the discovered volume of proved reserves can be made when an exploratory well penetrates an oil- or gas-bearing zone or reservoir. This estimate is based upon the initial flow data, thickness of the reservoir found, its apparent areal extent, and electrical and other measurements taken inside the hole that provide information about reservoir rock porosity (void space), permeability (ability to conduct fluid flow), fluid saturations, pressures, and temperatures. Initially, the estimate of proved reserves is based on a limited amount of data. These data are only available from exploratory drilling and interpretations of any seismic or other geophysical/geologic data. Therefore, this estimate is only a preliminary judgment as to the amount of oil and gas in place and the amount that can be economically recovered.

As more wells are drilled and placed on production, reservoir performance data become available. These additional wells also provide more information on the thickness, extent, and other properties of the reservoir. Proved reserves estimates are then revised upward or downward, as appropriate, to reflect additional knowledge gained, as well as any improvements in technology, or changes in economic and operating conditions. As a reservoir is developed, upward revisions can occur because of additional wells from infill drilling that often add significant volumes of crude oil and/or natural gas reserves to known reservoirs, especially in tight formations.

The different physical properties of crude oil and natural gas have led to different trends in revisions. Primary recovery factors for crude oil are generally much lower than for natural gas. Therefore, improved recovery technology targeting the remaining oil in place results in relatively higher positive revisions for crude oil than for natural gas.

A field may contain a single reservoir or many reservoirs in its proved area. Changes to the originally estimated proved reserves of a field are usually made over time as revision increases, revision decreases, extensions to its proved area, or new reservoir discoveries occur. Thus, the estimate of proved reserves for any given field usually changes over time and is influenced directly by the amount, kind, and quality of data which become available concerning that field. The more data that are available and the longer the production history, the more accurate or closer to reality the proved reserve estimate becomes. The exact amount of producible oil or gas is not known with certainty until the field is permanently abandoned and the recovered oil and gas have been recorded as cumulative production.

Survey Overview

This report provides proved reserves estimates for the calendar year 1992. It is based on data filed by operators of oil and gas wells on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and by operators of natural gas processing plants on Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production."

Form EIA-23

For Form EIA-23 purposes, an operator is defined as an organization or person responsible for the management and day-to-day operation of oil and/or gas wells. This definition eliminates responses from royalty owners, working interest owners (unless they are also operators), and others not directly responsible for oil and gas production operations. Each company and its parent company or subsidiaries are required to file if they meet the survey's specifications.

Operator size categories were based upon their annual production as indicated in various Federal, State, and commercial records. Category I (large) operators were those that produced at least 1.5 million barrels of crude oil or 15 billion cubic feet of natural gas, or both, during the report year. Category II (intermediate) operators produced less than Category I operators, but more than 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both. Category III (small) operators were those that produced less than did Category II operators. All data are reported on a total operated basis, encompassing all proved reserves and production associated with wells operated by an individual operator. This concept is also called the "gross operated" or "8/8ths" basis.

Large operators and most intermediate sized operators report reserves balance data on Form EIA-23 to show how reserve components changed during the year on a field-by-field basis. Small operators and intermediate sized operators who do not keep reserves data were not asked to provide estimates of reserves at the beginning of the year or annual changes to proved reserves by component of change; i.e., revisions, extensions, and new discoveries. When they did not, these volumes were estimated by applying an algebraic allocation scheme that preserved the relative relationships between these items within each State or State subdivision, as reported by large and intermediate operators.

The published reserve estimates include an additional term, adjustments, calculated by EIA, that preserves an exact annual reserves balance of the form:

Published Proved Reserves at End of Previous Report Year
+ Adjustments
+ Revision Increases
− Revision Decreases
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
− Report Year Production
= Published Proved Reserves at End of Report Year

Adjustments are the yearly changes in the published reserve estimates that cannot be attributed to the estimates for other reserve change categories because of the survey and statistical estimation methods employed. For example, variations caused by changes in the operator frame, different random samples, or imputations for missing or unreported reserve changes could contribute to adjustments.

While the primary topic of this report is proved reserves, information is also presented for crude oil on indicated additional reserves. Indicated additional crude oil reserves are not included in proved reserves because of their uncertain economic recoverability. When economic recoverability is demonstrated, these volumes will be reclassified and transferred to the proved reserves category as positive revisions.

Form EIA-64A

Form EIA-64A data were first collected for the 1979 survey year in order to develop estimates for total natural gas liquids reserves. Data on liquids recovered from natural gas, as reported by natural gas processing plant operators, are combined with lease condensate data collected on Form EIA-23 to provide the total natural gas liquids reserves estimates.

Data Collection Operations

An intensive effort is made each year to maintain an accurate frame of operators of oil and gas wells and of natural gas processing plants. The Form EIA-23 operator frame contained 24,106 probable active operators and the Form EIA-64A plant frame contained 867 probable active natural gas processing plants in the United States when the 1992 survey was initiated. There were additional operators added to the survey as it progressed and many operators in the sample frame were found to be inactive in 1992.

For the report year 1992, EIA mailed 4,257 EIA-23 forms to all known large and intermediate sized operators and to a sample of smaller operators that were expected to be active during 1992. Of these, 338 were nonoperators. Data were received from 3,964 operators, an overall response rate of 99.1 percent of the active operators in the Form EIA-23 survey. EIA mailed 909 EIA-64A forms to natural gas processing plant operators. More than one form is received for a plant that has more than one operator during the year. Forms were received from 100 percent of the operators of the 867 active plants in the Form EIA-64A survey.

National estimates of production volumes for crude oil, lease condensate, natural gas liquids, and dry natural gas based on Form EIA-23 and Form EIA-64A were compared with corresponding official production volumes published by EIA. For report year 1992, the Form EIA-23 national production estimates were 1.2 percent lower than the comparable *Petroleum Supply Annual 1992* volumes for crude oil and lease condensate combined, and were 2 percent lower than the comparable *Natural Gas Monthly August 1993* volume for 1992 dry natural gas. For report year 1992, the Form EIA-64A national estimates were 0.8 percent higher than the *Petroleum Supply Annual 1992* volume for natural gas plant liquids production.

Consistent data filings were fostered by the adoption of a set of specific definitions of proved reserves and related quantities to be followed by respondents in the reserve estimation and reporting process. The definitions were developed through extensive consultation with industry experts and other Government agencies. The definitions used in the Form EIA-23 and Form EIA-64A surveys and this report are presented in the Glossary. See Appendix E for a summary of data collection operations, detailed information on survey response, survey form content, frame maintenance, and data quality control procedures. See Appendix F for an explanation of the sampling and estimation methodologies used.

2. Overview

National Summary

U.S. proved reserves of natural gas, crude oil, and natural gas liquids all declined again in 1992. The decline in natural gas reserves, 1 percent, was smaller than for oil. The uncertainties associated with taxes, regulations, oil prices, gas prices, and gas demand had a strong influence on the changes to proved reserves in 1992.

As of December 31, 1992, proved reserves were 165,015 billion cubic feet of dry natural gas; 23,745 million barrels of crude oil; and 7,451 million barrels of natural gas liquids (including lease condensate). Statistical measures of sampling error of less than 1 percent at the 95 percent confidence level are associated with the crude oil and natural gas reserve estimates. The U.S. proved reserves balances are summarized for 1982 through 1992 in Table 1 and Figures 2 through 7.

Natural Gas Reserves

U.S. proved reserves of dry natural gas declined just over 1 percent or 2,047 billion cubic feet in 1992. All four leading gas producing areas, Texas, the Gulf of Mexico Federal Offshore, Oklahoma, and Louisiana, had large proved reserves declines totaling 4,649 billion cubic feet. Partially offsetting these declines, four States had large increases in their coalbed methane reserves: Virginia, New Mexico, Colorado, and Alabama. Reserves in these States increased by 1,957 billion cubic feet in 1992.

For the year, the average natural gas wellhead price was up to $1.80 per thousand cubic feet, 16 cents higher than in 1991. But during the year, the real gas price at the wellhead first dropped to a 15-year monthly low of $1.31 per thousand cubic feet in February. Then, it almost doubled to a peak of $2.46 per thousand cubic feet in October, after Hurricane Andrew in August raised concerns about the adequacy of gas supplies. The scheduled end, in December, of tax credits for new unconventional gas wells spurred drilling for coalbed methane and tight-sand gas to high levels in the last half of 1992. Therefore, total gas well completions dropped only 16 percent to 7,640. However, exploratory gas well completions reached a new 20-year low after dropping 27 percent during 1992.

Of the several components of change in proved reserves, *total discoveries* are those reserves attributable to *extensions, new fields discoveries,* and *new reservoirs discoveries in old fields.* They result from drilling exploratory wells. U.S. *total discoveries* of dry gas in 1992 were 7,048 billion cubic feet, a decline from the 1991 level and 34 percent lower than the average during the prior 10 years. Over half of them were in Texas and the Gulf of Mexico Federal Offshore.

New field discoveries of 649 billion cubic feet were down substantially from the 1991 level and 59 percent lower than the prior 10-year average of 1,592 billion cubic feet. *Extensions* (4,675 billion cubic feet) were also lower, dropping 31 percent below the prior 10-year average. Gas reserve additions from new reservoirs increased somewhat to 1,724 billion cubic feet, but were much lower than the prior 10-year average.

The net of *revisions* and *adjustments* for natural gas in 1992 was 8,328 billion cubic feet. In recent years, the net of *revisions* and *adjustments* played a growing role in sustaining lower 48 States natural gas proved reserves. In 1992, 7,883 billion cubic feet of these were added, 74 percent more than the lower 48 States average for the prior 10 years. This increasing recovery of gas from the resource base of old fields has been enhanced by the application of new technologies such as three dimensional (3-D) seismology, horizontal drilling, and better fracturing treatments and well completions.

Total discoveries for the lower 48 States were only 6,994 billion cubic feet in 1992. This was the second time since 1977 that lower 48 States *total discoveries* were lower than the net of *revisions* and *adjustments*. There were proved reserves of 34,118 billion cubic feet of natural gas, wet after lease separation, located in nonproducing reservoirs. They are included in the total proved reserves and represent 20 percent of the total.

Crude Oil Reserves

During 1992, crude oil proved reserves decreased by 937 million barrels. This 3.8-percent decline is more than twice the average annual decline of 1.7 percent experienced during the prior 10 years. While most areas had declines, two areas accounted for 73 percent of the U.S. decline, Texas (356 million barrels) and California (324 million barrels). U.S. crude oil production in 1992 was down 3 percent.

Oil prices averaged $15.98 per barrel, a decline from 1991. Both exploratory oil well completions and active drilling rigs reached new 20-year lows. Oil well completions dropped 28 percent to 8,640. Low prices caused low drilling that caused low reserve additions.

Table 1. Total U.S. Proved Reserves of Crude Oil, Dry Natural Gas, and Natural Gas Liquids, 1982 through 1992

Year	Adjustments (1)	Revision Increases (2)	Revision Decreases (3)	Revisions[a] and Adjustments (4)	Extensions (5)	New Field Discoveries (6)	New Reservoir Discoveries in Old Fields (7)	Total[b] Discoveries (8)	Production (9)	Proved[c] Reserves 12/31 (10)	Change from Prior Year (11)
	Crude Oil (million barrels of 42 U.S. gallons)										
1982	-83	2,245	1,811	351	634	204	193	1,031	2,950	27,858	-1,568
1983	462	2,810	1,299	1,973	629	105	190	924	3,020	27,735	-123
1984	159	3,672	1,227	2,604	744	242	158	1,144	3,037	28,446	+711
1985	429	3,037	1,439	2,027	742	84	169	995	3,052	28,416	-30
1986	57	2,724	1,869	912	405	48	81	534	2,973	26,889	-1,527
1987	233	3,687	1,371	2,549	484	96	111	691	2,873	27,256	+367
1988	364	2,684	1,221	1,827	355	71	127	553	2,811	26,825	-431
1989	213	2,698	1,365	1,546	514	112	90	716	2,586	26,501	-324
1990	86	2,483	1,000	1,569	456	98	135	689	2,505	26,254	-247
1991	163	2,097	1,874	386	365	97	92	554	2,512	24,682	-1,572
1992	290	1,804	1,069	1,025	391	8	85	484	2,446	23,745	-937
	Dry Natural Gas (billion cubic feet, 14.73 psia, 60° Fahrenheit)										
1982	2,378	19,795	19,340	2,833	8,349	2,687	3,419	14,455	17,506	201,512	-218
1983	3,090	17,602	17,617	3,075	6,909	1,574	2,965	11,448	15,788	200,247	-1,265
1984	-2,241	17,841	14,712	888	8,299	2,536	2,686	13,521	17,193	197,463	-2,784
1985	-1,708	18,775	16,304	763	7,169	999	2,960	11,128	15,985	193,369	-4,094
1986	1,320	21,269	17,697	4,892	6,065	1,099	1,771	8,935	15,610	191,586	-1,783
1987	1,268	17,527	14,231	4,564	4,587	1,089	1,499	7,175	16,114	187,211	-4,375
1988	2,193	23,367	[d]38,427	-12,867	6,803	1,638	1,909	10,350	16,670	[d]168,024	-19,187
1989	3,013	26,673	23,643	6,043	6,339	1,450	2,243	10,032	16,983	167,116	-908
1990	1,557	18,981	13,443	7,095	7,952	2,004	2,412	12,368	17,233	169,346	+2,230
1991	2,960	19,890	15,474	7,376	5,090	848	1,604	7,542	17,202	167,062	-2,284
1992	2,235	18,055	11,962	8,328	4,675	649	1,724	7,048	17,423	165,015	-2,047
	Natural Gas Liquids (million barrels of 42 U.S. gallons)										
1982	299	811	832	278	375	112	109	596	721	7,221	+153
1983	849	847	781	915	321	70	99	490	725	7,901	+680
1984	-123	866	724	19	348	55	96	499	776	7,643	-258
1985	426	906	744	588	337	44	85	466	753	7,944	+301
1986	367	1,030	807	590	263	34	72	369	738	8,165	+221
1987	231	847	656	422	213	39	55	307	747	8,147	-18
1988	11	1,168	715	464	268	41	72	381	754	8,238	+91
1989	-277	1,143	1,020	-154	259	83	74	416	731	7,769	-469
1990	-83	827	606	138	299	39	73	411	732	7,586	-183
1991	233	825	695	363	189	25	55	269	754	7,464	-122
1992	225	806	545	486	190	20	64	274	773	7,451	-13

[a]Revisions and adjustments = Col. 1 + Col. 2 - Col. 3.
[b]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[c]Proved reserves = Col. 10 from prior year + Col. 4 + Col. 8 - Col. 9.
[d]An unusually large revision decrease to North Slope dry natural gas reserves was made in 1988. It recognizes some 24.6 trillion cubic feet of downward revisions reported during prior years by operators because of economic and market conditions. The Energy Information Administration (EIA) in previous years carried these reserves in the proved category.

Notes: •Old means discovered in a prior year. •New means discovered during the report year. •The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves" and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." They may differ from the official EIA production data for crude oil, natural gas, and natural gas liquids for 1992 contained in the *Petroleum Supply Annual 1992*, DOE/EIA-0340(92) and the *Natural Gas Annual 1992*, DOE/EIA-0131(92).

Sources: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1982 through 1992 annual reports, DOE/EIA-0216.{13-22}

Figure 2. U.S. Crude Oil Proved Reserves, 1982-1992

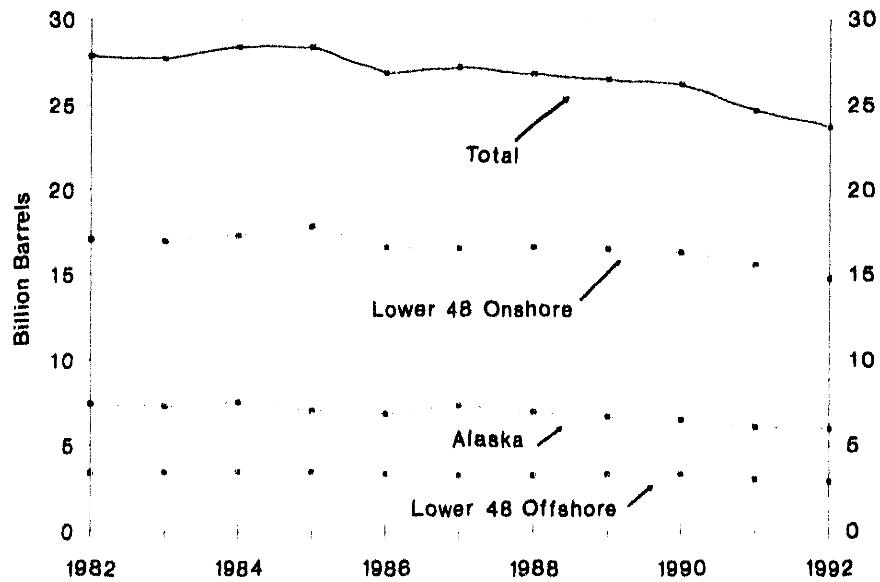
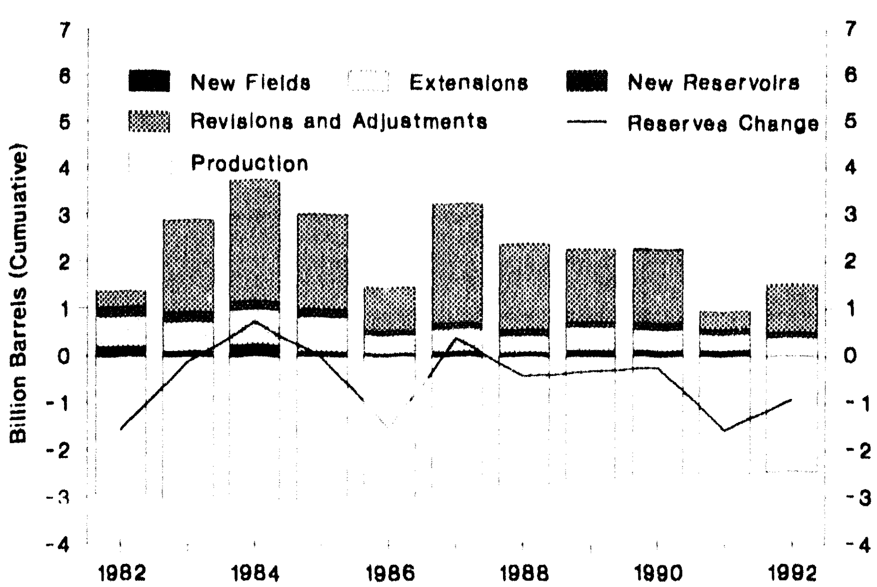


Figure 3. Components of Reserves Changes for Crude Oil, 1982-1992



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1982 through 1992 annual reports, DOE/EIA-0216.{13-22}

Figure 4. U.S. Dry Natural Gas Proved Reserves, 1982-1992

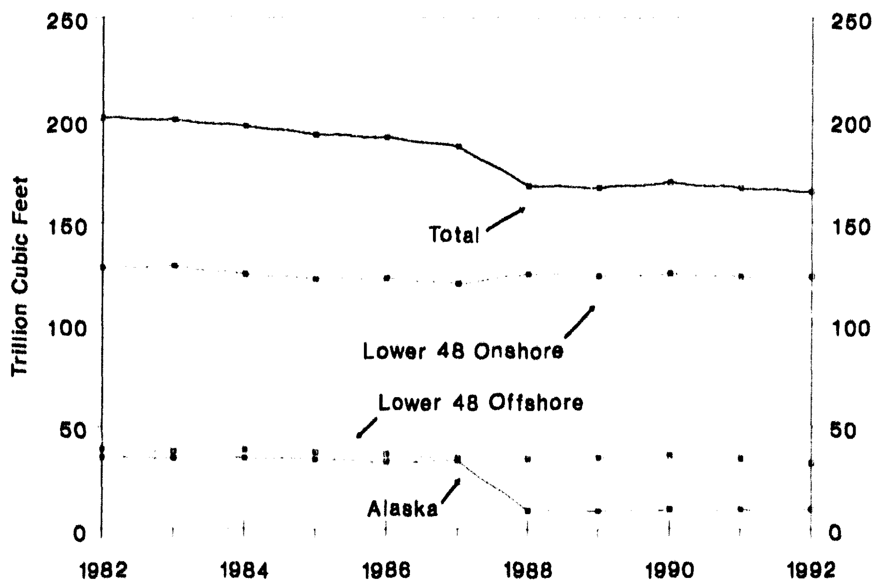
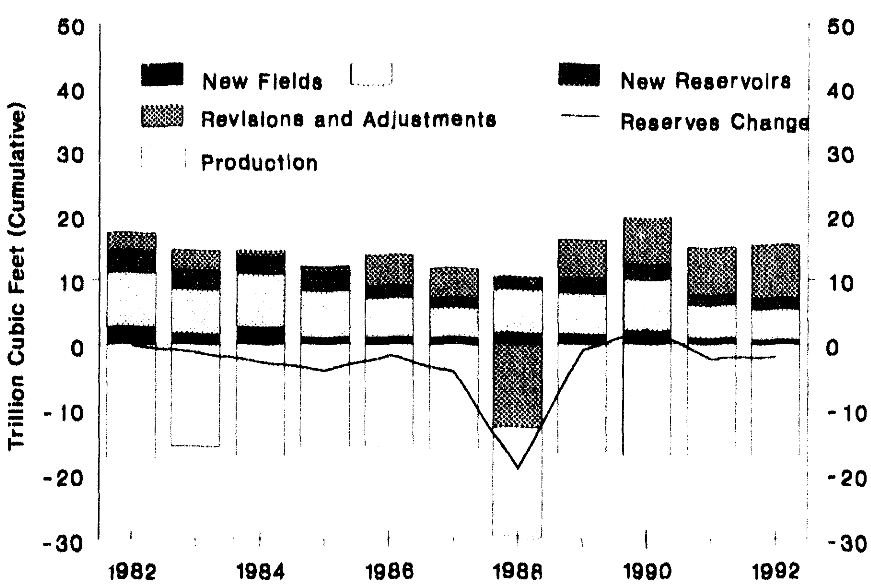


Figure 5. Components of Reserves Changes for Dry Natural Gas, 1982-1992



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1982 through 1992 annual reports, DOE/EIA-0216.{13-22}

Figure 6. U.S. Natural Gas Liquids Proved Reserves, 1982-1992

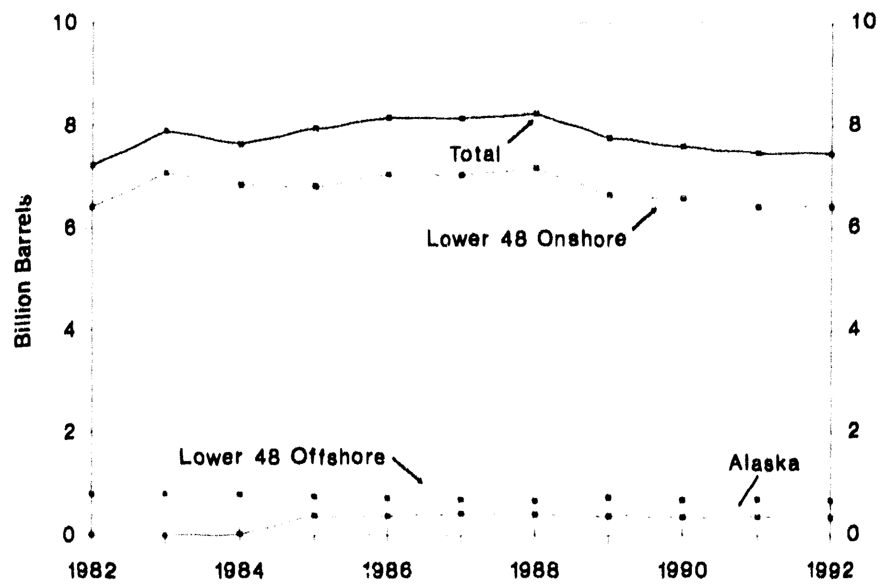
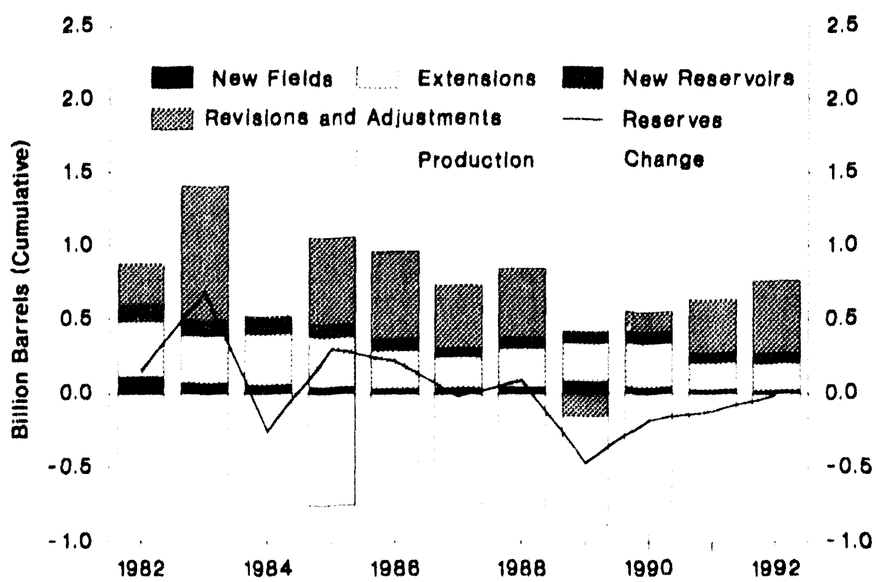


Figure 7. Components of Reserves Changes for Natural Gas Liquids, 1982-1992



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1982 through 1992 annual reports, DOE/EIA-0216.(13-22)

The net of *revisions* and *adjustments* for crude oil in 1992 was 1,025 million barrels. This component of reserves change is usually the largest and has consistently helped to sustain U.S. crude oil proved reserves. But in 1992, it was only 65 percent of the average of 1,574 million barrels for the prior 10 years. Three areas had 71 percent of the positive net of *revisions* and *adjustments*: Alaska (451 million barrels), the Federal Offshore (147 million barrels), and Texas (125 million barrels). California had the largest percentage drop in proved reserves of any major producing area, more than twice the U.S. average. Most of the Nation's thermally enhanced recovery of heavy oil takes place in California. As late as 1989, the net of *revisions* and *adjustments* in California was a positive 241 million barrels. In 1992, it was a negative 45 million barrels. Low oil prices along with local and State environmental concerns contributed to a rapid decline in California offshore oil reserves.

In 1992, *total discoveries* of crude oil were 484 million barrels. This was down from 1991 and 38 percent lower than the 783 million barrel average over the prior 10 years. Just three areas: Texas, Alaska, and the Gulf of Mexico Federal Offshore, accounted for 74 percent of 1992 *total discoveries*. For the last 7 years, *total discoveries* have been relatively low, reflecting a similar trend in exploratory drilling that followed the crude oil price collapse of 1986. In 1985, there were more than four times as many successful exploratory oil wells drilled as in 1992. However, *total discoveries* added per exploratory well have roughly doubled since then, moderating the impact of the drop in drilling.

Proved reserves added by *extensions* (391 million barrels) were up a bit from those in 1991, but substantially below the prior 10-year average of 533 million barrels. Horizontal drilling in the Austin Chalk Formation was a major factor behind the 118 million barrels of extensions in Texas, which accounted for 30 percent of U.S. crude oil *extensions*.

New field discoveries of crude oil have been relatively low since 1985. In 1992, U.S. *new field discoveries* were an exceptionally low 8 million barrels. The United States produces about 7 million barrels every day. The prior 10-year average of *new field discoveries* was 15 times as high. New discoveries, the Sunfish prospect in the Cook Inlet of offshore Alaska and the Kuvlum prospect, 15 miles offshore of the Arctic National Wildlife Refuge, may turn this trend around in 1993. But, they are still being evaluated and are not yet proved.

Proved reserves of *new reservoirs discovered in old fields* (85 million barrels) were down from 1991 and well below the 135 million barrel average for the prior 10 years. There were proved reserves of 2,638 million barrels of crude oil located in nonproducing reservoirs. They are included in the total proved reserves and represent 11 percent of the total.

Indicated additional crude oil reserves were 3,782 million barrels, an 11-percent decrease from 1991. These reserves are crude oil volumes that may become economically recoverable from known reservoirs through the application of improved recovery techniques using current technology. The presence of large indicated additional reserves in the Alaskan North Slope, California, west Texas, and New Mexico implies that significant upward revisions to crude oil proved reserves can continue to occur in the future.

Natural Gas Liquids Reserves

U.S. natural gas liquids proved reserves decreased slightly to 7,451 million barrels in 1992. Natural gas liquids reserves are the sum of natural gas plant liquids and lease condensate reserves.

Total liquid hydrocarbon proved reserves (crude oil plus natural gas liquids) were 31,196 million barrels in 1992, a 3-percent decline of 950 million barrels from their 1991 level. Natural gas liquids were 24 percent of total liquid hydrocarbon proved reserves in 1992.

Reserves by Operator Production Size Class

The oil and gas proved reserves estimates for 1992 are based on data collected from a sample of about 23,000 active operators of oil and gas wells. The 10 largest oil and gas producing operators in 1992 had 66 percent of U.S. proved reserves of crude oil. These operators concentrated their U.S. operations on fewer fields and focused more of their resources on foreign operations during the last several years. Consequently, the top 10 producing operators had a 6-percent decline in their domestic proved reserves of crude oil during 1992. The rest of the operators had a 2-percent increase.

All operators that reported production or reserves to EIA were ranked by production. Operator production was the sum of the barrel of oil equivalent of their crude oil production, lease condensate production, and wet gas production. The operators were placed in the following production size classes: 1-10, 11-20, 21-100, 101-500, 501-2500, and "other". The "other" class contains roughly 20,000 small operators. Operators may change from one size class to another over time. For example, the top 10 class always contains the 10 highest producing operators each year, but it was not necessarily the same 10 operators each year. Tables of production and reserves by operator production size class for the years 1988 through 1992 are presented in Appendix A.

U.S. proved reserves are highly concentrated in the larger operator classes. In 1992, the top 10 had 43 percent of the reserves of natural gas or 74 trillion cubic feet (Figure 8). The next 3 size classes contain 10 operators, 80 operators, and 400 operators. Each of these had roughly comparable percentages of the gas reserves; 16, 22, and 11 percent. The next 2,000 operators had only 4 percent of the gas reserves, as did the smallest 20,000 operators. Therefore, the average top 10 operator had over 2,000 times the gas reserves as the average operator in the "other" class.

Total U.S. gas proved reserves declined only 2 percent from 1988 to 1992. However, the top 10 had a 12-percent decline in their natural gas proved reserves from 1988 to 1992 (Figure 9). Without the top 10, the remaining 23,000 U.S. operators had a 7-percent increase from 1988 to 1992. Most of this came from the second tier of operators, class 11-20. These operators increased their gas proved reserves in 1992, and had a 42-percent increase from 1988 to 1992. A substantial portion of this increase probably came from acquisitions of reserves from other companies. The next three classes had small percentage decreases, while the small operators in the "other" class had an increase from 1988 to 1992.

U.S. gas reserves declined 1 percent from 1991 to 1992. The top 10 had a 4-percent decline in gas reserves in 1992, while the rest of the operators had a 1-percent increase.

Proved reserves of crude oil are more concentrated than those of natural gas. The top 10 had 66 percent of the U.S. oil reserves, or 15.7 billion barrels in 1992 (Figure 10). While the oil and gas reserves are concentrated in the larger operators, the oil and gas industry is not nearly as concentrated as many major U.S. industries, for example, the automobile industry. The 11-20 class and the 80 operators in the 21-100 class both had 10 percent of U.S. reserves of crude oil. The next 400 operators had only 6 percent of the total and the next 2,000 operators in class 501-2500 had 5 percent. The 20,000 operators in the "other" class had only 3 percent of U.S. reserves of crude oil. The average top 10 operator had almost 4,000 times the oil reserves as the average operator in the "other" class.

The top 10 had a 19-percent decline in their oil reserves from 1988 to 1992 (Figure 11), while total U.S. proved reserves of crude oil declined by 12 percent. Without the top 10, the rest of the 23,000 U.S. operators had a 9-percent increase from 1988 to 1992. The large independents, the 80 operators in production size class 21-100, accounted for most of the increase. These operators had a 47-percent increase in their oil reserves during the 1988 through 1992 period. A substantial portion of this increase probably came from property acquisitions. The size 101-500 class had a 19-percent increase in proved reserves of crude oil from 1988 to 1992.

Total U.S. proved reserves of crude oil declined 4 percent from 1991 to 1992. The top 10 operators' oil reserves declined 6 percent in 1992, while the rest of the operators had a 2-percent increase.

During the years 1988 through 1992, many operators bought, sold, and restructured their property positions. A large number of producing properties which were marginal or did not fit into future production strategies were sold by the major operators. Oil and gas exploration has dramatically declined as many operators have reduced personnel and budgets, or altered various portions of their operations. In 1982, about 708,000 employees were engaged in the domestic petroleum extraction industry. By 1992, there were only half as many, 350,000 employees.{23}

The domestic exploration and development expenditures of 23 major energy companies fell 30 percent from 1988 to 1992.{24} During the same period, their foreign expenditures increased 39 percent. Foreign expenditures by these companies were higher than domestic expenditures for the first time in 1991, and were 23 percent higher in 1992.

Large operators produce oil and gas in a large number of fields. The average top 10 operator was active in 350 fields in 1992. In aggregate, they had an operator field count of 3,514 (Figure 12). The 400 operators in class 101-500 had an operator field count of 10,942. However, the top 10 had 4 times the gas reserves and almost 11 times the oil reserves of class 101-500. Obviously, the top 10 have much larger fields.

The top 10 cut the number of fields they operated in by half as they concentrated their activities from 1988 to 1992 (Figure 13). The other classes of large operators also concentrated their activities into fewer fields and had declines of 12 to 15 percent in their operator field counts. The total number of active U.S. fields was relatively stable from 1988 through 1992.

Coalbed Methane

Proved reserves located in coalbed methane fields increased to 10,034 billion cubic feet, or by 23-percent in 1992, to account for 6 percent of total U.S. gas reserves (Figure 14). Coalbed methane production increased almost sixfold in just 3 years to account for 3 percent of U.S. gas production in 1992. Exploitation of the coalbed methane resource has rapidly expanded because of a large tax credit incentive and improved understanding of the underlying production technology. The tax credit in 1992 was roughly

Figure 8. Wet Natural Gas Proved Reserves by Operator Production Size Class in 1992

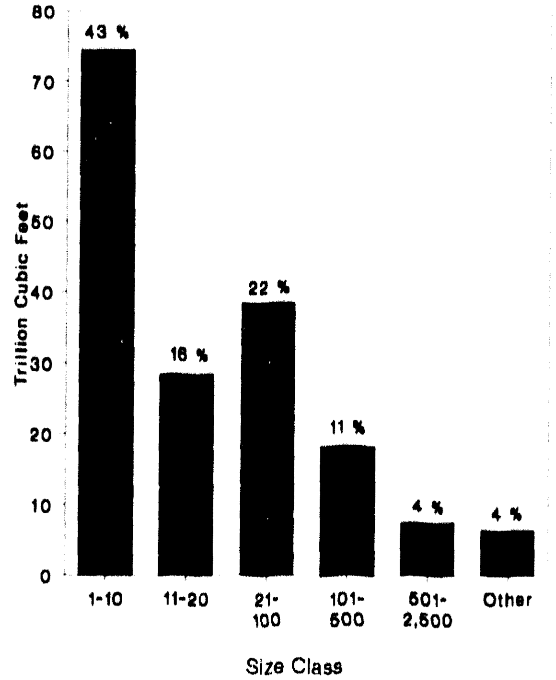


Figure 10. Crude Oil Proved Reserves by Operator Production Size Class in 1992

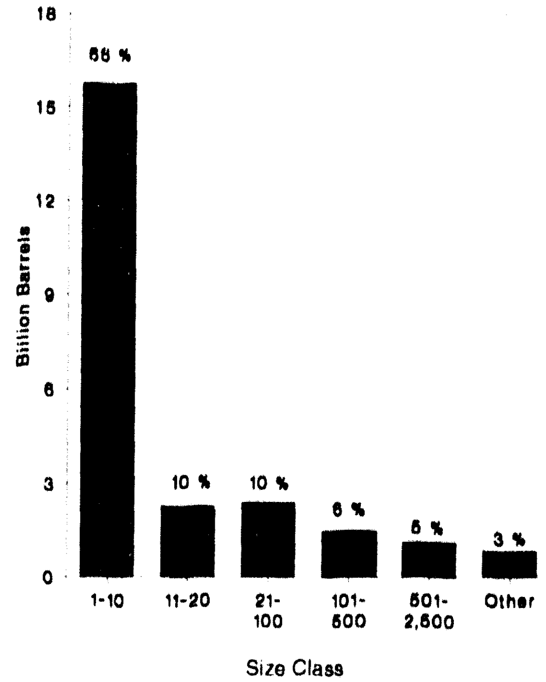


Figure 9. Percentage Change for Wet Natural Gas Proved Reserves by Operator Production Size Class, 1988-1992 and 1991-1992

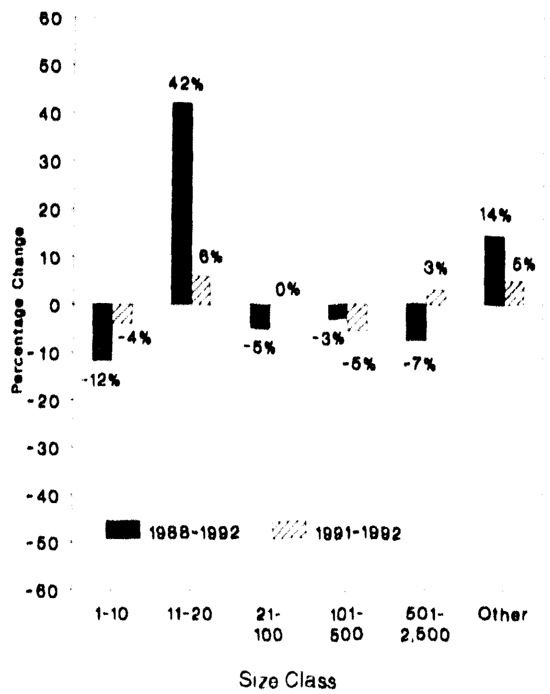
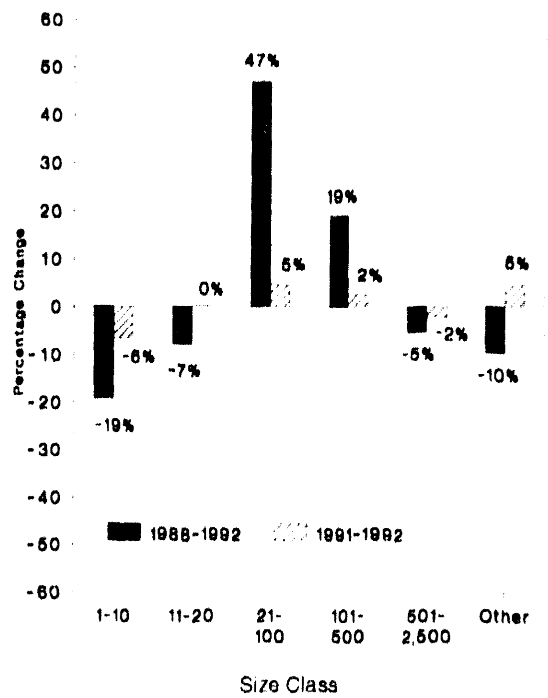
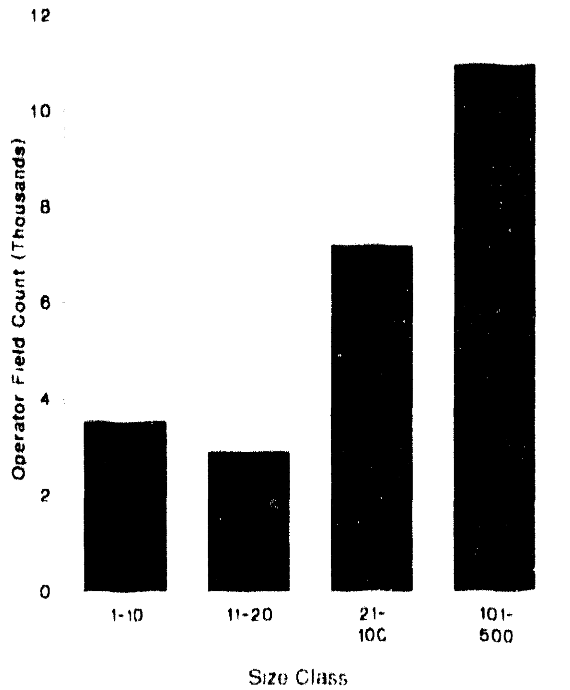


Figure 11. Percentage Change for Crude Oil Proved Reserves by Operator Production Size Class, 1988-1992 and 1991-1992



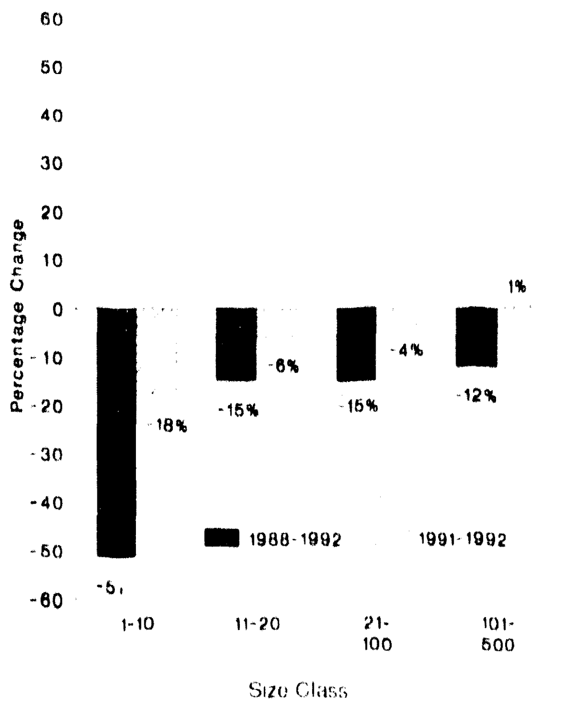
Source: Energy Information Administration, Office of Oil and Gas.

Figure 12. Operator Field Counts by Production Size Class in 1992



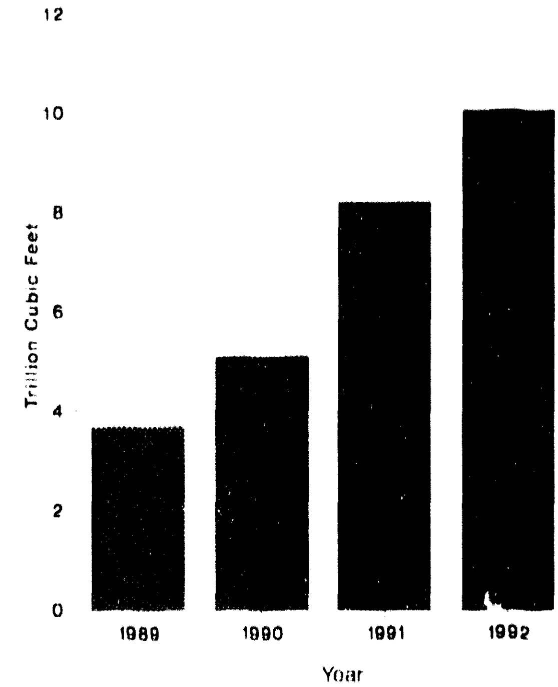
Source: Energy Information Administration, Office of Oil and Gas.

Figure 13. Percentage Change in Operator Field Counts by Production Size Class, 1988-1992



Source: Energy Information Administration, Office of Oil and Gas.

Figure 14. Coalbed Methane Proved Reserves, 1988-1992



Source: Energy Information Administration, Office of Oil and Gas.

$0.90 per thousand cubic feet of coalbed methane produced, about half the average U.S. wellhead price.

Most of the 1992 production increase occurred in the San Juan Basin of Colorado and New Mexico. Coalbed methane proved reserves are principally located in New Mexico, Colorado, and Alabama. However, Virginia, in the Appalachain Basin, had the second largest increase in dry gas reserves in 1992, in large part due to coalbed methane increases.

The industry has long known that coalbeds contain large quantities of methane, the main constituent of natural gas. But the understanding of the geology and engineering needed to produce it was not there. The recovery mechanism for coalbed methane is not the same as that for conventional gas. The rate of conventional gas production is a function of reservoir pressure and gas saturation. Due to initially high pressures and little or no associated water, conventional production rates rapidly build to a peak and then decline. However, in a typical coalbed well, where the gas is primarily adsorbed on the surface of the coal and trapped by reservoir pressure, an inverse production decline curve is the norm, with initially high water production rates and low gas production rates. As the water production rate declines, the gas production rate increases materially, sometimes for several years, before eventually beginning to decline.

An important factor in 1992 gas well drilling was the provision of a special tax credit for nonconventional gas sources (such as coalbed methane) in Section 29 of the Crude Oil Windfall Profits Tax Act of 1980. The credit was applicable to wells started before December 31, 1992. Production from qualifying wells receives the tax credit through the end of 2002. A rush to meet the deadline led to a gas well drilling boom in the last half of 1992.

Reserves Changes

Table 2 displays the reserves changes for crude oil and dry natural gas for the period 1977 through 1992. There have been 35,757 million barrels of reserves additions of crude oil since 1976. Reserves additions from exploratory drilling make up crude oil *total discoveries* of 12,595 million barrels, 35 percent of all reserves additions since 1976. The bulk of post-1976 crude oil reserves additions were the 23,162 million barrels of net of *revisions* and *adjustments* that accounted for 65 percent of all reserves additions. Crude oil reserves and production have been primarily sustained by continuing upward revisions to the reserves of older fields. The estimated ultimate recovery of fields (sum of cumulative production and proved reserves at a given point in time) generally increases over time. Infill drilling, extensions, enhanced oil recovery projects, technological advances, better than expected reservoir performance, and improved economics are major factors in these revisions. However, economic factors do not always improve. Low oil and gas prices can lead to downward revisions of proved reserves.

Newly discovered fields generally have large increases in reserves during the first few years after they are first booked, because extensions, new reservoirs, and revisions add to the estimates of these new fields' ultimate recovery. However, most of the net of *revisions* and *adjustments*, the majority of the *new reservoir discoveries in old fields*, and substantial portions of the *extensions* booked since 1976 came from fields discovered before 1977. An EIA study

Table 2. Reserves Changes, 1977 through 1992

Components of Change	Lower 48 States Volume	Lower 48 States Average per Year	Lower 48 States Percent of Reserve Additions	U.S. Total Volume	U.S. Total Average per Year	U.S. Total Percent of Reserve Additions
	Crude Oil (million barrels of 42 U.S. gallons)					
Proved Reserves as of 12/31/76	**24,928**	—	—	**33,502**	—	—
New Field Discoveries	1,855	116	6.5	2,105	132	5.9
New Reservoir Discoveries in Old Fields	2,066	129	7.2	2,085	130	5.8
Extensions	7,526	470	26.3	8,405	525	23.5
Total Discoveries	**11,447**	**715**	**40.0**	**12,595**	**787**	**35.2**
Revisions and Adjustments	17,204	1,075	60.0	23,162	1,448	64.8
Total Reserve Additions	**28,651**	**1,791**	**100.0**	**35,757**	**2,235**	**100.0**
Production	**35,856**	**2,241**	**125.1**	**45,514**	**2,845**	**127.3**
Net Reserve Change	**–7,205**	**–450**	**–25.1**	**–9,757**	**–610**	**–27.3**
	Dry Natural Gas (billion cubic feet at 14.73 psia and 60° Fahrenheit)					
Proved Reserves as of 12/31/76	**180,838**	—	—	**213,278**	—	—
New Field Discoveries	33,037	2,065	13.3	33,064	2,067	14.4
New Reservoir Discoveries in Old Fields	40,856	2,554	16.5	41,213	2,576	17.9
Extensions	117,925	7,370	47.6	118,746	7,422	51.7
Total Discoveries	**191,818**	**11,989**	**77.4**	**193,023**	**12,064**	**84.0**
Revisions and Adjustments	55,921	3,495	22.6	36,762	2,298	16.0
Total Reserve Additions	**247,739**	**15,484**	**100.0**	**229,785**	**14,362**	**100.0**
Production	**273,200**	**17,075**	**110.3**	**278,048**	**17,378**	**121.0**
Net Reserve Change	**–25,461**	**–1,591**	**–10.3**	**–48,263**	**–3,016**	**–21.0**

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1977 through 1991 annual reports, DOE/EIA-0216.(8-22)

described in the publication *U.S. Oil and Gas Reserves by Year of Field Discovery*{25} found that almost 87 percent of the crude oil and lease condensate reserves additions in 1978 through 1988 came from fields discovered before 1978. This means that just 13 percent of the crude oil and lease condensate reserves were added in fields that had discovery wells completed during the 1978 through 1988 time period.

Due to the nature of the industry's proved reserves booking process, the year that proved reserves are first reported for a field is often later than the actual year of discovery, the year that the discovery well was completed. Therefore, it is probably true that a substantially higher proportion of the total reserve additions for the 1977 through 1991 period came from fields that were first reported as having booked proved reserves during that period than would be true for comparable year of discovery well data. A direct comparison of reserves changes by year of discovery and those in this report cannot currently be made, because it is often the case that fields are not booked as having proved reserves for several years after the discovery well is drilled. Delineation drilling and a commitment to develop the field are often required before a field's reserves are booked as proved and reported on Form EIA-23. This would be particularly true for fields found in frontier areas or the Federal Offshore. Decades can elapse between the discovery well and the year an offshore or frontier area field has its proved reserves booked, especially if economic and technical problems are compounded by regulatory problems or delays.

There have been a total of 229,785 billion cubic feet of reserves additions of dry natural gas since 1976, as shown in Table 2. A markedly different pattern exists for the components of reserves additions for natural gas compared to crude oil. *Total discoveries* of dry natural gas make up 84 percent of all reserves additions compared to 35 percent for crude oil. *New field discoveries* make up 14 percent of all natural gas reserves additions and 17 percent of *total discoveries*. *New reservoir discoveries in old fields* with 21 percent and *extensions* with 62 percent of reserves additions compose the rest of *total discoveries* of dry natural gas. As with crude oil, most *new reservoir discoveries in old fields* and *extensions* from 1976 through 1992 are probably associated with fields discovered before 1977. This is also true for the net of *revisions* and *adjustments* to natural gas reserves.

The percentages given for U.S. reserves additions of natural gas are somewhat distorted due to an unusually large revision decrease of some 24,613 billion cubic feet for Alaskan North Slope proved reserves that was made in 1988 for economic reasons. Without this large negative revision, total reserve additions would have been 254,398 billion cubic feet and the net of *revisions* and *adjustments* would have been 61,375 billion cubic feet, or 24 percent of the total. *Total discoveries* of dry natural gas would have been 76 percent, still well over twice as large a percentage of reserve additions as the equivalent *total discoveries* percentage for crude oil.

For the lower 48 States, proved reserves of dry natural gas have been remarkably stable since 1976. The decline has been under 1 percent, or 1,591 billion cubic feet per year. This is quite different from the decline from 1967 through 1977 for the lower 48 States, as estimated by the American Gas Association.{26} During that 10-year period, natural gas proved reserves for the lower 48 States dropped by an average of 11,252 billion cubic feet a year, or almost 5 percent annually. This excludes small changes for gas in underground storage that the American Gas Association included with its proved gas reserves. The relative stability of lower 48 States reserves after 1977 was brought about by a higher price level for natural gas, substantially more drilling, and a lower demand for natural gas in the 1980's.

Positive revisions played a larger role in sustaining natural gas reserves in the lower 48 States during the last 7 years than in prior years. The 1986 through 1992 average of net of *revisions* and *adjustments* was 6,783 billion cubic feet per year while the 1977 through 1985 average was only 938 billion cubic feet per year. Infill drilling and a surge of recompletions contributed to this phenomenon.

Lower 48 States proved reserves of crude oil have also been declining more slowly since 1976, at 450 million barrels per year, or just over 2 percent. This is again quite different from the decline from 1967 through 1977 estimated by the American Petroleum Institute.{26} During that 10-year period, crude oil proved reserves for the lower 48 States were declining by 1,113 million barrels per year, or over 4 percent. Large net of *revisions* and *adjustments* have been the major factor sustaining oil reserves during the last 15 years. However, it was **the absence** of large revisions and adjustments that caused most of the 6-percent decline in 1991 and 5-percent decline in 1992 for lower 48 States proved oil reserves.

As shown in Table 3, rotary drilling rig activity during 1992 dipped below 1,000 rigs for the sixth time in the last 7 years. The 721 rig count in 1992 was a record low, and was 139 rigs or 16 percent below 1991. The 1992 rig activity represented an 82-percent drop from the 1981 historical peak.

Oil prices declined again in 1992 (Table 3). The U.S. price ranged from $13.93 per barrel in January to $17.95 per barrel in June. In 1981, oil prices pushed $50 per barrel in 1992 dollars. This was 3 times the average 1992 oil price of $15.98. In 1971, before the Arab oil embargo, oil prices were only about $11 per barrel, and 1992 monthly oil

Table 3. U.S. Average Annual Domestic Wellhead Prices for Crude Oil and Natural Gas, and the Average Number of Active Rotary Drilling Rigs, 1970 through 1992

Year	Crude Oil (dollars per barrel)		Natural Gas (dollars per thousand cubic feet)		Number of Rigs
	Current	1992 Constant	Current	1992 Constant	
1970	3.18	10.95	0.17	0.59	1,028
1971	3.39	11.05	0.18	0.59	976
1972	3.39	10.56	0.19	0.59	1,107
1973	3.89	11.39	0.22	0.64	1,194
1974	6.87	18.50	0.30	0.81	1,472
1975	7.67	18.85	0.44	1.08	1,660
1976	8.19	18.93	0.58	1.34	1,658
1977	8.57	18.54	0.79	1.71	2,001
1978	9.00	18.04	0.91	1.82	2,259
1979	12.64	23.33	1.18	2.18	2,177
1980	21.59	36.40	1.59	2.68	2,909
1981	31.77	48.68	1.98	3.03	3,970
1982	28.52	41.15	2.46	3.55	3,105
1983	26.19	36.31	2.59	3.59	2,232
1984	25.88	34.38	2.66	3.53	2,428
1985	24.09	30.85	2.51	3.21	1,980
1986	12.51	15.61	1.94	2.42	964
1987	15.40	18.62	1.67	2.02	936
1988	12.58	14.64	1.69	1.97	936
1989	15.86	17.67	1.69	1.88	869
1990	20.03	21.39	1.71	1.83	1,010
1991	R16.54	16.98	R1.64	1.68	860
1992	15.98	15.98	1.80	1.80	721

R=Revised data.
Sources: •Current dollars and Number of rigs: *Annual Energy Review 1992*, DOE/EIA-0384(92). •1992 constant dollars: U.S. Department of Commerce, Bureau of Economic Anaylsis, Gross Domestic Product Implicit Price Deflators, January 1993.

prices dropped below that level in several areas. Alaskan North Slope oil was $9.09 per barrel in January and the California price was $10.97 per barrel in March, with heavy oil prices even lower.

The average gas prices rose to $1.80 per thousand cubic feet in 1992, but not without a struggle (Table 3). The price was down to $1.31 per thousand cubic feet in February 1992, a 15-year monthly low, before increasing during the rest of the year. There is still substantial month-to-month uncertainty about future natural gas prices, although the closer balance between gas demand and wellhead gas productive capacity is expected to bring about increased gas drilling, which would require higher gas prices.{27} However, natural gas prices were twice as high in 1982 as they were in 1992, in constant dollars.

Table 4 shows the numbers of exploratory and development wells drilled in 1970 through 1992. The 28,840 total exploratory and development wells drilled in 1992 were 21 percent lower than in 1991. This continues the post-1981 trend of declining well completions. Low prices and uncertainties over future prices lead to low drilling. In 1981, total well completions were 90,030 or 4 times as many as in 1992. There were 5 times as many successful exploration wells drilled in 1981 as there were in 1992. Of the wells drilled in 1992, 71 percent were successfully completed as oil or gas wells. Most development wells are successful, while most exploratory wells are not. Dry wells represented 20 percent of development wells, but 77 percent of exploratory wells, during 1992.

Figures 15 and 16 show exploratory gas well and oil well completions for the years 1977 through 1992. Exploratory oil well completions decreased in 1992 to 450. There were six times as many drilled in the peak year of 1981. Crude oil *total discoveries* for the last 3 years have been declining, reflecting the downward trend in exploratory drilling that followed the crude oil price collapse of 1986. Exploratory gas well completions continued to drop in 1992, with only 330 gas well completions. There were roughly 8 times as many drilled in the peak year of 1981. Natural gas

Table 4. U.S. Exploratory and Development Well Completions,[a] 1970 through 1992

Year	Exploratory				Total Exploratory and Development			
	Oil	Gas	Dry	Total	Oil	Gas	Dry	Total
1970	760	480	6,190	7,430	13,040	4,030	11,100	28,170
1971	660	470	6,000	7,130	11,900	3,980	10,380	26,270
1972	690	660	6,200	7,550	11,440	5,480	11,010	27,930
1973	650	1,080	6,040	7,770	10,250	6,980	10,470	27,690
1974	870	1,210	6,890	8,970	13,660	7,170	12,200	33,040
1975	990	1,260	7,210	9,460	16,980	8,170	13,740	38,890
1976	1,100	1,360	6,850	9,320	17,700	9,440	13,810	40,940
1977	1,180	1,560	7,400	10,150	18,700	12,120	15,040	45,860
1978	1,190	1,790	8,050	11,040	19,070	14,410	16,590	50,060
1979	1,340	1,920	7,480	10,730	20,700	15,170	16,040	51,910
1980	1,780	2,090	9,040	12,910	32,280	17,220	20,340	69,840
1981	2,670	2,530	12,300	17,500	42,840	19,910	27,280	90,030
1982	2,470	2,170	11,350	15,980	R39,140	18,940	26,380	R84,470
1983	2,110	1,660	R10,270	R14,040	R37,200	R14,560	R24,340	R76,090
1984	R2,340	1,600	R11,480	R15,420	R42,590	R17,010	R25,800	R85,390
1985	1,880	1,280	R9,450	R12,610	R35,020	R14,250	R21,210	R70,480
1986	990	R730	R5,510	R7,230	R18,700	R8,140	R12,770	R39,600
1987	860	R670	R5,180	R6,710	R16,190	R7,760	R11,480	R35,420
1988	R790	R660	R4,770	R6,220	R13,320	R8,240	R10,240	R31,800
1989	580	650	R4,000	R5,230	R10,340	R9,230	R8,490	R28,060
1990	620	580	R3,780	R4,980	R12,150	R10,440	R8,520	R31,110
1991	540	450	3,300	4,300	R11,920	R9,090	R7,830	R28,840
1992	450	330	2,570	3,350	8,640	7,640	6,560	22,840

[a]Excludes service wells and stratigraphic and core testing.

R=Revised data.

Notes: •Estimates are based on well completions taken from American Petroleum Institute data tapes through August 1993. •Due to the method of estimation, data shown are frequently revised. Totals may not equal the sum of components due to independent rounding.

Sources: •Exploratory wells: Energy Information Administration, Office of Oil and Gas. •Total exploratory and development wells: *Monthly Energy Review*, DOE/EIA-0035(93/08), August 1993.

total discoveries have also been relatively low for the last 6 years, reflecting declining exploratory drilling. *Total discoveries* of natural gas were down in 1992. Peak and low years for *total discoveries* do not necessarily match peak and low years for exploratory drilling because the success of exploratory drilling can vary from year to year.

Figure 17 shows *total discoveries* of dry natural gas per exploratory gas well completion for the years 1977 through 1992. Similarly, Figure 18 shows *total discoveries* of crude oil per exploratory oil well completion. A striking feature is the decline of gas and oil discoveries per exploratory well as exploratory drilling increased rapidly in the late 1970's and early 1980's, followed by increasing discoveries per exploratory well as drilling and prices declined. Oil *total discoveries* per exploratory well were 2.6 times as large in 1992 as in the low year of 1982 and gas *total discoveries* per well were 3 times as large. Without these large increases in *total discoveries* per well to partially compensate for the drops in exploratory drilling in the late 1980's and early 1990's, *total discoveries* would have been much lower.

The 21.4 billion cubic feet of dry gas *total discoveries* per exploratory gas well in 1992 were higher than in 1991. Similarly, the 1.1 million barrels found per exploratory oil well in 1992 were higher.

There are several explanations for this improved reserve additions per exploratory well. With rapid price increases driving a drilling frenzy in the late 1970's and early 1980's, the industry was not as careful in picking exploratory targets and could afford to drill small prospects because they could be profitable at high prices. Lately, the

Figure 15. U.S. Exploratory Gas Well Completions, 1977-1992

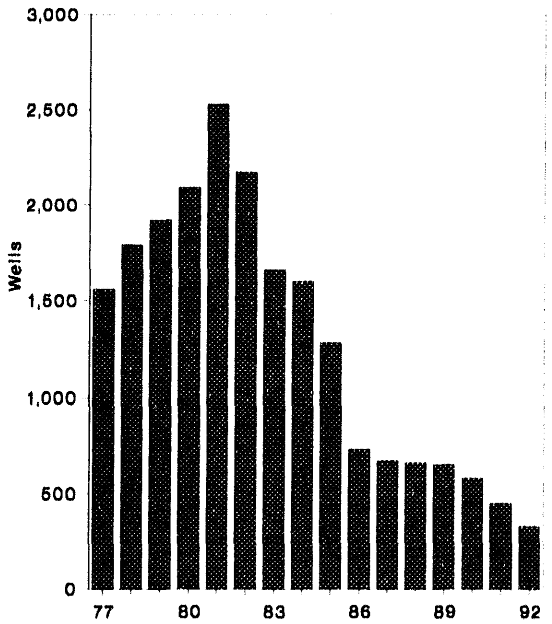


Figure 17. U.S. Total Discoveries of Dry Natural Gas per Exploratory Gas Well Completion, 1977-1992

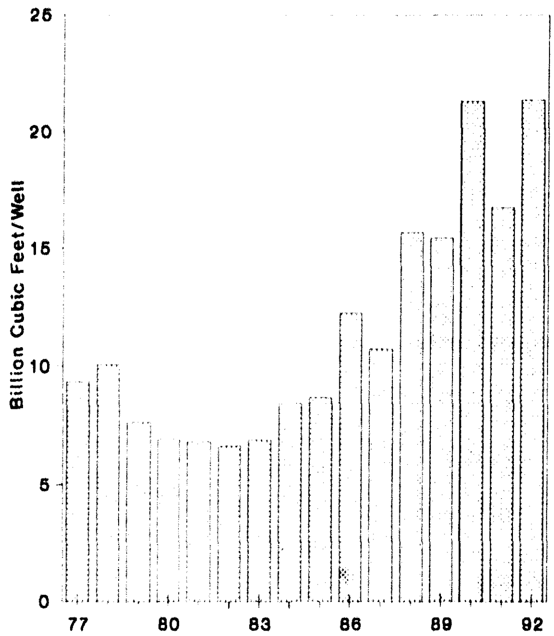


Figure 16. U.S. Exploratory Oil Well Completions, 1977-1992

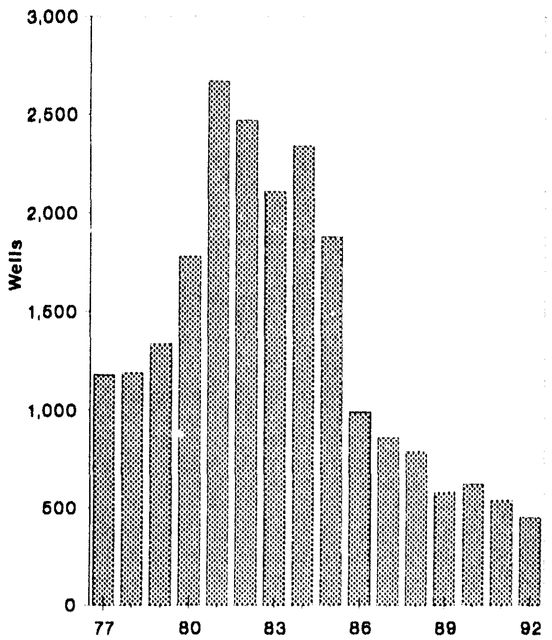
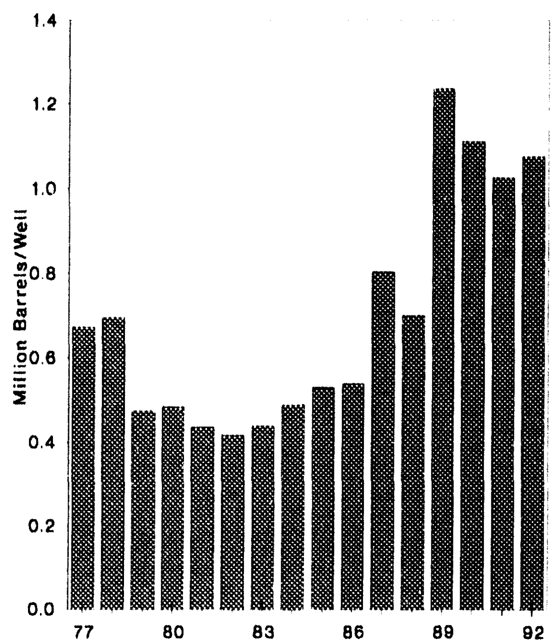


Figure 18. U.S. Total Discoveries of Crude Oil per Exploratory Oil Well Completion, 1977-1992



Source: Energy Information Administration, Office of Oil and Gas.

industry has also tended to focus exploratory activity in areas where a higher payoff per well is expected, like the offshore areas, the rapidly developing Austin Chalk in Texas, and coalbed methane areas. There have also been improvements in exploration technology (such as 3-D seismic imaging) and drilling technology (such as horizontal drilling).

Reserves-to-Production Ratios

The relationship between reserves and production, expressed as the ratio of reserves to production (R/P ratio) is often used in analysis. For a mature producing area, the R/P ratio tends to be reasonably stable, so that the proved reserves at the end of a year serve as a rough indicator of the production level that can be maintained during the following year. Operators report data that yield R/P ratios which vary widely depending upon both the number and type of operators in a given area, the nature of the area, the number and size of new discoveries in an area, and the amount of drilling that has occurred in the area.

R/P ratios are an indication of the state of development in an area and, over a period of time, the ratios change. For example, when the Alaskan North Slope reserves of oil were booked, the U.S. R/P ratio increased, because significant production from these reserves did not begin until 7 years after booking due to the need to first build the Trans-Alaska pipeline. The U.S. R/P ratio went from roughly 11-to-1 to 9-to-1 between 1977 and 1982, as Alaskan North Slope production reached high levels.

As a further example, the Appalachian area of the country has been drilled since Drake's 1859 well came in. This mature area of the country has many marginal oil wells that have an R/P ratio below the current National average of 9.7 to 1. The less developed areas of the country, such as the Pacific offshore and the Rockies, are areas with higher R/P ratios than the National average. Other areas with relatively high R/P ratios are the Permian Basin of Texas and New Mexico, and California, where enhanced recovery techniques such as CO_2 injection or steamflooding have breathed new life into old, mature fields. Areas which have the lowest oil R/P ratios have many older fields, like the Mid-Continent area. There, even new technologies such as horizontal drilling, as practiced in Texas' Pearsall and Giddings oil fields, have only been able to add reserves equivalent to the annual production, keeping the regional reserves and R/P ratio for oil relatively stable.

Figure 19 shows the historical R/P ratio trend for crude oil for the period 1945 to 1992. As can be seen, a change has occurred in the way in which reserves relate to production. After World War II, increased drilling and discoveries led to a greater ratio of reserves to production. Later, when drilling found less reserves than were produced, the ratio became smaller.

A much different picture emerges for wet natural gas R/P ratios as shown in Figure 20. The different marketing and transportation settings of gas versus oil are more clearly seen when looking at regional average R/P ratios, compared to the current National average for natural gas of 9.5 to 1. The areas with the higher range of R/P ratios are the less developed areas of the country such as the Pacific offshore and the Rockies, but also include areas such as Alabama (22 to 1) and New Mexico (17 to 1) where considerable booking of coalbed methane reserves has recently occurred. Several of the major gas producing areas have R/P ratios below the National average such as Texas (8 to 1), the Gulf of Mexico Federal Offshore (6 to 1), and Oklahoma (7 to 1).

Figures 21 and 22 show the successive estimates of ultimate recovery, proved reserves, and cumulative production for oil and wet natural gas from 1977 through 1992. They illustrate the continued growth of estimated ultimate recovery over time. Ultimate recovery is defined as cumulative production plus proved reserves at a particular point in time. In 1976, U.S. proved oil reserves were 33,502 million barrels. Cumulative production from 1977 through 1992 of 43,068 million barrels substantially exceeded those proved reserves, and there were still 23,745 million barrels of proved oil reserves in 1992. Similarly, U.S. proved reserves of dry natural gas were 213,278 billion cubic feet in 1976, and 165,015 billion cubic feet remained in 1992. Cumulative dry gas production during this period was 260,625 billion cubic feet.

Top 100 Oil and Gas Fields for 1991

The American Petroleum Institute, for several years before 1980, published lists of the largest oil fields in its annual report.[26] Until 1991, EIA had not produced a similar listing for either oil or gas fields. Results of EIA's effort to generate such lists now appear in Appendix B as a regular feature of this report. The tables contain estimates of the proved reserves, cumulative production, and ultimate recovery of the top 100 oil fields and the top 100 gas fields ranked by proved reserves for 1991. Also, the field name, location, year of discovery, and an estimate of 1991 annual production are provided. This oil field production and reserve data includes both crude oil and lease condensate. Although there is considerable grouping of field-level statistics within the tables, a rough magnitude can be estimated for the proved reserves, cumulative production, and ultimate recovery of most fields. Because many of the large fields are operated by only one or two operators,

Figure 19. Reserves-to-Production Ratios for Crude Oil, 1945-1992

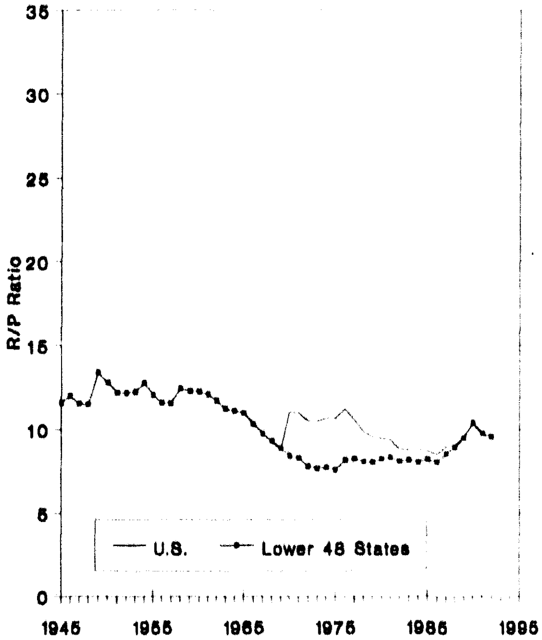


Figure 21. Components of Ultimate Recovery for Crude Oil and Lease Condensate, 1977-1992

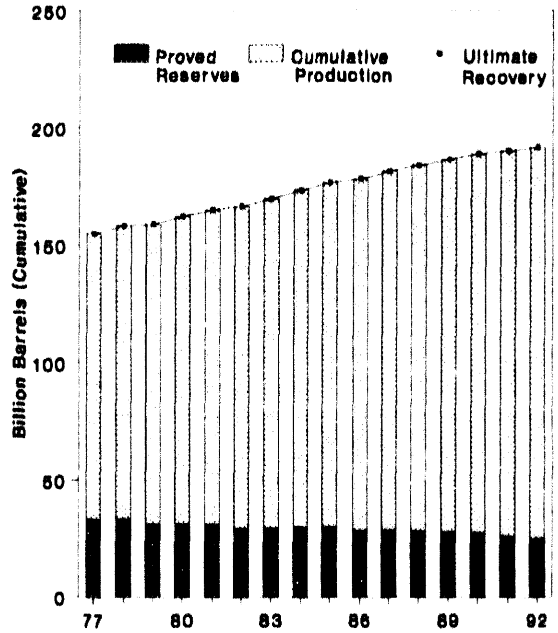


Figure 20. Reserves-to-Production Ratios for Wet Natural Gas, 1945-1992

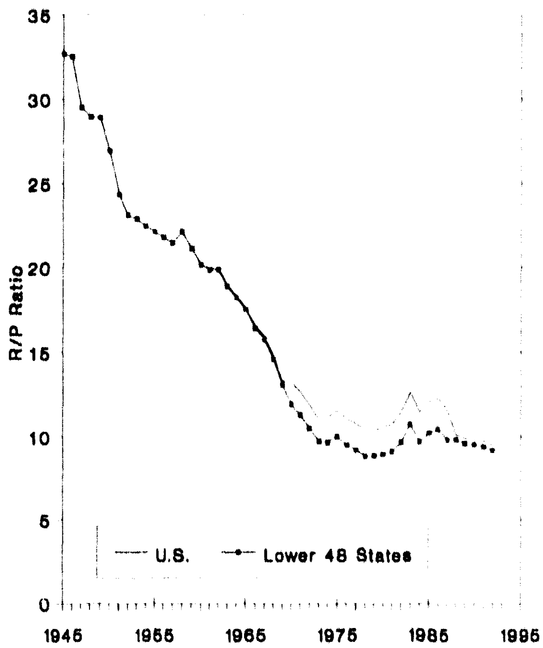
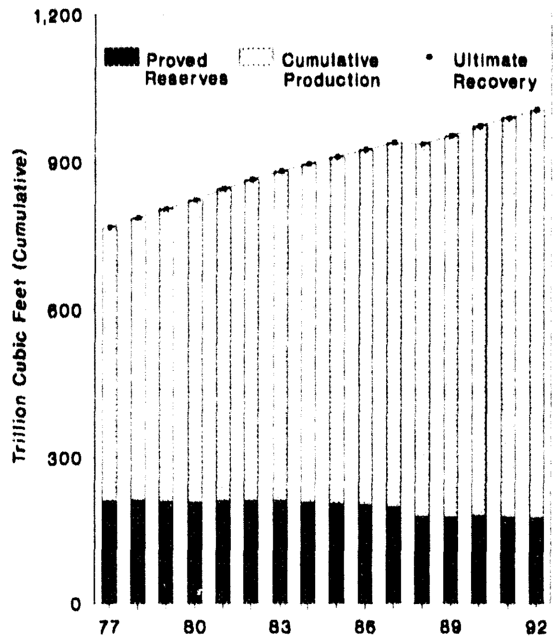


Figure 22. Components of Ultimate Recovery for Wet Natural Gas, 1977-1992



Sources: •Annual reserves and production - American Petroleum Institute and American Gas Association (1945–1976){26} and Energy Information Administration, Office of Oil and Gas (1977–1992){13-22}. •Cumulative production: *U.S. Oil and Gas Reserves by Year of Field Discovery* (1977–1988).{29} proved reserve totals are grouped as top 10, top 20, top 50, and top 100 to avoid disclosing company proprietary data.

There were more than 45,000 oil and gas fields with production, cumulative production, or reserves in the United States in 1991. Table B1 shows the top 100 oil fields as of December 31, 1991. The top 100 oil fields accounted for 66 percent of the total oil proved reserves and for 53 percent of the total oil production including lease condensate in 1991. Just the top 10 oil fields contained 38 percent of U.S. proved reserves of crude oil including lease condensate. Table B2 shows the top 100 U.S. gas fields. The top 100 gas fields show less concentration than the top 100 oil fields. They accounted for 46 percent of the total wet gas proved reserves and 29 percent of the total wet gas production. The top 10 gas fields contained 22 percent of U.S. proved reserves of wet gas in 1991. Some, but not all, of the same fields appear in both tables. As an example, the top gas field, Hugoton Gas Area, is not in the oil table. In contrast, the top oil field, Prudhoe Bay, is the number four field in the gas table.

New features were added to Appendix B this year: Table B3, Historical Production for the Top 100 Oil Fields 1982-1991, and Table B4, Historical Production for the Top 100 Natural Gas Fields 1982-1991. The tables provide 10-year production histories for the same groups of fields shown in Tables B1 and B2. While these are the 100 largest oil and gas fields in terms of proved reserves, their total production was smaller than the production of the top 100 fields ranked by production. In Tables B3 and B4 there are 6 oil and 5 gas fields which had no production in 1991. In most cases, their production started in 1992. The top 100 oil fields accounted for 53 percent of U.S. oil production in 1991. However, this same group of fields accounted for 51 percent of the U.S. oil production in 1982. The top 100 gas fields accounted for 22 percent of U.S. gas production in 1982. This same group of fields accounted for 29 percent of the U.S. gas production in 1991. The 7 percent increase is attributable to the rise in the demand for natural gas. Major fields increased their production of both conventional and unconventional gas. The three largest gas fields, Hugoton Gas Area (discovered in 1922), Basin (discovered in 1947), and Blanco (discovered in 1927) produced 47 percent more gas in 1991 than they did in 1982.

An EIA report, *Largest U.S. Oil and Gas Fields*{28} was published in August 1993. It identifies the largest 1 percent of U.S. oil and gas fields and their general location, year of discovery, and approximate National rankings in several size categories including proved reserves and annual production. Also presented are the proportions of the National crude oil and natural gas proved reserves and production that are attributable to the largest fields. An earlier EIA report, *Geologic Distributions of U.S. Oil and Gas*{29}, was published in July 1992. It provides oil and gas field size distributions by geologic provinces, regions, and the Nation, as well as regional information on the distribution of oil and gas by trap type and the geologic age and lithology of the reservoir rock. The report covers the entire Nation with the exception of the Appalachian Basin. A major conclusion is that only in the Alaskan, Far West, and Gulf of Mexico regions can one expect to continue to locate very many new large fields, particularly where oil is concerned.

Conversion to the Metric System

Public Law 100-418, the Omnibus Trade and Competitiveness Act of 1988, states: "It is the declared policy of the United States

> (1) to designate the metric system of measurement as the preferred system of weights and measures for United States trade and commerce. . . .
>
> (2) to require that each Federal agency, by the end of Fiscal Year 1992, use the metric system of measurement in its procurements, grants, and other business-related activities."{30}

The U.S. petroleum industry is slowly moving in the direction of this law. However, the estimates made by EIA for this report are based on data filed by operators on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves" and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production" using the units that are still common to the U.S. petroleum industry, namely barrels for crude oil and natural gas liquids, and cubic feet for natural gas. It is in keeping with the spirit of this law that Appendix C has been created. Standard metric conversion factors for barrels and cubic feet were used to convert National level volumes in Table 1 to their metric equivalents in Table C1. As shown in Table C1, the U.S. proved reserves as of December 31, 1992 were 3,775.2 million cubic meters of crude oil, 4,672.71 billion cubic meters of dry natural gas, and 1,184.6 million cubic meters of natural gas liquids (including lease condensate).

International Perspective

The EIA estimates domestic oil and gas reserves but does not systematically estimate worldwide reserves. However, a comparison of EIA's proved reserve estimates for the United States with worldwide estimates obtained from other sources indicates that the United States had 2.2 and 3.6 percent, respectively, of the world's total oil and natural gas proved reserves at the end of 1992.

Table 5 summarizes data obtained from two principal public sources of world reserves estimates. The sometimes substantial difference between estimates from these sources indicates a possible variation of a few tenths of a percent in the calculated U.S. share. The *Oil and Gas Journal*{31} and *World Oil*{32} estimates of world oil reserves were up by 0.6 and 13 percent, respectively, from 1991 to 1992. For world natural gas reserves, the *Oil and Gas Journal* and *World Oil* estimates were up 3 and 12 percent, respectively. For the United States, oil reserve estimates by *World Oil* were 3.8 percent lower than those of EIA and natural gas reserves were 0.2 percent lower. The *Oil and Gas Journal* published EIA's 1991 U.S. proved reserves estimates as its 1992 estimates.

Several foreign countries listed in Table 5 have oil reserves considerably larger than those of the United States. For example, Iraq has oil reserves of 100 billion barrels (4 times U.S. reserves) and Kuwait has oil reserves of over 95 billion barrels. Saudi Arabian oil reserves are the largest in the world at over 259 billion barrels which dwarf the U.S. oil reserves. Closer to home, Venezuela has about 63 billion barrels and Mexico has over 51 billion barrels of proved oil reserves.

World Oil reported oil reserves for the former Soviet Union (FSU) of about 189 billion barrels. This was roughly 3 times their 1991 reported value and 3 times the *Oil and Gas Journal* 1992 estimate. But, *World Oil* has included more than proved reserves in its 1992 FSU estimate. This estimate is similar to "proved plus probable plus some possible" in the United States. The U.S. oil reserve estimates include only proved reserves.

Table 5. World Oil and Natural Gas Reserves, as of December 31, 1992

Region or Country	Oil & Gas Journal — Oil (million barrels)	World Oil — Oil (million barrels)	Oil & Gas Journal — Natural Gas (billion cubic feet)	World Oil — Natural Gas (billion cubic feet)
North America				
Canada	5,292	5,668	95,734	94,100
Mexico	51,298	51,225	70,900	70,046
United States	24,682	22,845	167,062	164,750
Other	307	330	110	52
Total	**81,579**	**80,067**	**333,806**	**328,948**
Central and South America				
Argentina	1,570	1,630	22,700	23,811
Brazil	3,030	3,667	4,400	4,827
Venezuela	62,650	63,330	126,492	128,948
Other	4,956	5,315	34,870	31,349
Total	**72,206**	**73,942**	**188,462**	**188,934**
Western Europe				
Netherlands	145	329	68,860	68,129
Norway	8,806	16,788	70,629	97,322
United Kingdom	4,144	4,554	19,070	21,542
Other	2,260	2,070	32,603	26,825
Total	**15,354**	**23,741**	**191,162**	**213,819**
Eastern Europe				
Former Soviet Union[a]	57,000	186,923	1,942,300	2,033,417
Romania	1,569	1,245	7,335	5,975
Other	624	653	13,671	11,722
Total	**59,193**	**188,821**	**1,963,306**	**2,051,113**
Middle East				
Abu Dhabi	92,200	63,663	188,400	188,000
Iran	92,860	61,300	699,200	610,000
Iraq	100,000	99,840	109,500	109,300
Kuwait[b]	96,500	94,835	52,900	51,584
Saudi Arabia[b]	260,342	261,007	183,100	185,313
Other	20,364	15,918	287,648	221,771
Total	**662,266**	**596,562**	**1,520,748**	**1,365,967**
Africa				
Algeria	9,200	10,387	128,000	128,899
Egypt	6,200	3,593	15,400	12,299
Libya	22,800	38,190	46,200	43,526
Nigeria	17,900	18,213	120,000	121,870
Other	5,773	4,358	37,265	21,769
Total	**61,872**	**74,742**	**346,865**	**328,363**
Asia-Pacific				
China	24,000	29,600	49,400	45,000
India	6,049	5,935	25,954	23,911
Indonesia	5,779	8,350	64,388	48,535
Other	8,744	10,128	201,271	216,209
Total	**44,572**	**54,013**	**341,013**	**333,654**
Total	**997,042**	**1,091,888**	**4,885,362**	**4,810,798**

[a] *World Oil* chose to use a less restrictive definition for the Former Soviet Union oil reserves. The Former Soviet Union oil reserve estimate is explored reserves and is believed to include proved, probable, and some possible reserves.

[b] Includes one-half of the reserves in the Neutral Zone.

Note: Column totals may not add due to independent rounding.

Sources: *Oil and Gas Journal*, December 28, 1992, pp. 44-45. *World Oil*, August, 1993, p. 30.

3. National and State Crude Oil Statistics

Proved reserves of crude oil were 23,745 million barrels, 3.8 percent (937 million barrels) less than in 1991. This decline was more than twice the average annual decline of 1.7 percent experienced during the prior 10 years. Most of the substantial oil producing areas had proved reserves declines in 1992. U.S. crude oil production in 1992 declined 2.6 percent.

Proved Reserves

Table 6 presents the U.S. proved reserves of crude oil as of December 31, 1992, by selected States and State subdivisions. Five areas accounted for about 80 percent of the Nation's total of crude oil reserves. Texas was the leader with 27 percent, followed closely by Alaska with 25 percent. California was third with 16 percent.

Area	Percent of U.S Oil Reserves
Texas	27.1
Alaska	25.4
California	16.4
Gulf of Mexico Federal Offshore	7.7
New Mexico	3.2
Total	**79.8**

A number of States had small oil reserves increases during 1992, but the majority of the States had declines. The States that had oil reserves declines had combined reserves losses of 1,004 million barrels in 1992. Five of the areas accounted for 85.7 percent of these reserve losses during the year. Texas had the largest share of these losses, 35.5 percent, closely followed by California with 32.3 percent.

Area	Percent of Oil Reserves Losses
Texas	35.5
California	32.3
Wyoming	6.8
Alaska	6.1
Pacific Federal Offshore	5.1
Total	**85.7**

California had the largest percentage decline in crude oil reserves of the five largest reserve areas,—twice the U.S. average. Most of the California loss occurred in the San Joaquin Basin (228 million barrels). Low oil prices along with local and State environmental concerns contributed to a rapid decline in California offshore oil reserves. In Texas, the largest losses in proved reserves were in Texas Districts 8 and 8A in west Texas. Even small percentage declines in States with large reserves cause substantial losses. Alaskan proved reserves declined 1 percent, (61 million barrels), while Wyoming, with a 9-percent decline, lost 68 million barrels.

The net of *revisions* and *adjustments* for crude oil in 1992 was 1,025 million barrels. This was about 65 percent of the average of 1,574 million barrels for the prior 10 years. This component of reserves change is usually the largest and has consistently helped to sustain U.S. crude oil proved reserves. Three areas had 71 percent of the positive net of *revisions* and *adjustments*, Alaska (451 million barrels), the Gulf of Mexico Federal Offshore (156 million barrels), and Texas (125 million barrels). Most of the Nation's thermally enhanced recovery of heavy oil takes place in California. Enhanced recovery from the existing resource base leads to positive reserves revisions. The largest loss in the net of *revisions* and *adjustments* in 1992 was in California. As late as 1989, the net of *revisions* and *adjustments* in California was a positive 241 million barrels. By 1992, it was a negative 45 million barrels.

The Texas and Louisiana Federal Offshore had relatively large *adjustments* of 137 million barrels and negative 86 million barrels, respectively. This occurred because of a change in the way in which their data were processed this year. Last year, EIA changed State codes for the Garden Banks area of the Federal Offshore Gulf of Mexico, in order to be more consistent with the U.S. Department of Interior, Minerals Management Service (MMS) nomenclature. The Garden Banks area reserves were moved from the Louisiana Federal Offshore to the Texas Federal Offshore. Offsetting *adjustments* of 137 million barrels were made to crude oil proved reserves, downward for Louisiana and upward for Texas.

Discoveries

In 1992, *total discoveries* of crude oil were 484 million barrels, down from 554 million barrels in 1991. Just three areas, Texas, Alaska, and the Federal Offshore, accounted for 74 percent or 360 million barrels of the *total discoveries* for the year. For the last 7 years, *total discoveries* have been relatively low, reflecting a similar trend in exploratory drilling that followed the crude oil price collapse of 1986. *New field discoveries* were an exceptionally low 8 million barrels. The United States produces about 7 million barrels every day. The prior 10-year average for *new field discoveries* was 15 times as high. *New field dis-*

Table 6. Crude Oil Proved Reserves, Reserves Changes, and Production, 1992
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	Published Proved Reserves 12/31/91	Changes in Reserves During 1992: Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	Proved Reserves 12/31/92
Alaska	6,083	-7	461	3	112	0	1	625	6,022
Lower 48 States	**18,599**	**297**	**1,343**	**1,066**	**279**	**8**	**84**	**1,821**	**17,723**
Alabama	43	-5	15	4	0	1	0	9	41
Arkansas	[a]70	-3	5	6	1	0	0	9	58
California	4,217	-54	163	154	3	0	20	302	3,893
Coastal Region Onshore	554	-5	11	15	0	0	0	23	522
Los Angeles Basin Onshore	272	-9	16	18	0	0	0	25	236
San Joaquin Basin Onshore	3,126	-42	129	106	3	0	20	232	2,898
State Offshore	265	2	7	15	0	0	0	22	237
Colorado	329	-15	15	11	10	0	5	29	304
Florida	37	2	5	3	0	0	0	5	36
Illinois	128	22	6	2	0	0	0	16	138
Indiana	[a]16	2	1	0	0	0	0	2	17
Kansas	300	44	21	9	4	0	0	50	310
Kentucky	[a]31	4	3	0	0	0	0	4	34
Louisiana	679	24	112	57	14	0	6	110	668
North	127	6	26	14	1	0	0	21	125
South Onshore	408	27	68	37	13	0	6	68	417
State Offshore	144	-9	18	6	0	0	0	21	126
Michigan	119	-1	6	9	0	0	1	14	102
Mississippi	194	8	23	38	1	0	0	23	165
Montana	201	8	13	14	2	0	1	18	193
Nebraska	26	5	3	3	0	0	0	5	26
New Mexico	721	14	144	71	12	0	1	64	757
East	694	5	142	60	10	0	1	61	731
West	27	9	2	11	2	0	0	3	26
North Dakota	232	22	22	21	12	0	1	31	237
Ohio	66	0	1	1	0	0	0	8	58
Oklahoma	700	34	108	71	10	0	2	85	698
Pennsylvania	15	2	0	0	1	0	0	2	16
Texas	6,797	144	398	417	118	5	13	617	6,441
RRC District 1	227	1	29	52	7	0	3	30	185
RRC District 2 Onshore	90	5	7	3	1	0	1	15	86
RRC District 3 Onshore	300	-7	52	25	46	0	8	70	304
RRC District 4 Onshore	52	0	12	6	1	0	0	9	50
RRC District 5	46	11	7	3	3	0	0	8	56
RRC District 6	504	-3	14	23	12	0	0	62	442
RRC District 7B	184	15	5	20	0	0	1	22	163
RRC District 7C	253	27	21	27	8	2	0	29	255
RRC District 8	2,114	20	124	96	29	1	0	161	2,031
RRC District 8A	2,763	35	108	145	9	2	0	173	2,599
RRC District 9	162	33	10	5	1	0	0	25	176
RRC District 10	95	7	8	11	1	0	0	11	89
State Offshore	7	0	1	1	0	0	0	2	5
Utah	233	-2	6	5	3	1	0	19	217
West Virginia	26	-1	3	2	3	0	0	2	27
Wyoming	757	-5	59	42	3	0	1	84	689
Federal Offshore	2,620	52	210	115	77	1	33	309	2,569
Pacific (California)	785	1	3	13	0	0	0	42	734
Gulf of Mexico (Louisiana)	1,775	-86	198	96	74	1	30	253	1,643
Gulf of Mexico (Texas)	60	137	9	6	3	0	3	14	192
Miscellaneous[b]	42	-4	1	11	5	0	0	4	29
U.S. Total	**24,682**	**290**	**1,804**	**1,069**	**391**	**8**	**85**	**2,446**	**23,745**

[a]Indicates the estimate is associated with a sampling error (95 percent confidence interval) that exceeds 20 percent of the estimated value.
[b]Includes Arizona, Missouri, Nevada, New York, South Dakota, Tennessee, and Virginia.

Note: The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves." They may differ from the official Energy Information Administration production data for crude oil for 1992 contained in the *Petroleum Supply Annual 1992*, DOE/EIA-0340(92).

Source: Energy Information Administration, Office of Oil and Gas.

coveries in offshore Alaska that are still being evaluated, the Kuvlum prospect in the Beaufort Sea and the Sunfish prospect in the Cook Inlet, may turn this trend around in 1993.

Proved reserves of *new reservoir discoveries in old fields* (85 million barrels) were down 8 percent from 1991 and well below the 135 million barrel average for the prior 10 years. Over a third of the *new reservoir discoveries in old fields* (33 million barrels) were discovered in the Gulf of Mexico Federal Offshore. Most of the rest were found in California (20 million barrels), Texas (13 million barrels), and Louisiana (6 million barrels). Proved reserves added by *extensions* (391 million barrels) were up 7 percent from those in 1991, but still substantially below the prior 10-year average of 533 million barrels. Horizontal drilling in the Austin Chalk Formation was a large factor behind the 118 million barrels of *extensions* in Texas.

Reserves in Nonproducing Reservoirs

Not all proved reserves of crude oil were contained in reservoirs that were producing. Operators reported 2,638 million barrels of proved reserves in nonproducing reservoirs. This is 16 percent greater than in 1991. These reserves data were filed by Category I and Category II operators that accounted for over 91 percent of the total estimated crude oil production. The reasons for the nonproducing status of these proved reserves have not been surveyed by EIA since 1981. However, prior surveys indicated that most were attributable to wells or reservoirs that were shut-in for operational reasons. These included wells awaiting workover, the need to drill additional development or replacement wells, installation of production or pipeline facilities, or awaiting depletion of other zones or reservoirs before recompletion in reservoirs not yet open for production.

Indicated Additional Reserves

In addition to proved reserves of crude oil, Category I and Category II operators estimate the quantities of crude oil, other than proved reserves, that may become economically recoverable from known reservoirs through the application of improved recovery techniques using current technology. The total 1992 volume, 3,782 million barrels, is 11 percent less than was reported in 1991. Table 7 lists indicated additional reserves by selected States and State subdivisions. The presence of large indicated additional reserves for the Alaskan North Slope, California, west Texas, and New Mexico implies that significant upward revisions to proved crude oil reserves could occur in the future.

Areas of Note

The following State or area discussions summarize notable activities during the year concerning expected new field reserves, development plans, and possible production rates as reported by various trade publications. The citations do not necessarily reflect EIA's concurrence, but are considered important enough to be brought to the reader's attention.

Alaska

Prudhoe Bay Field: Prudhoe Bay, the largest U.S. oil field, produced 471 million barrels of oil in 1992, 30 million less than in 1991. Revision increases by the two operators, Atlantic Richfield Company (ARCO) and British Petroleum (BP), added reserves which should help flatten the decline curve. Prudhoe Bay has now been producing for 15 years. In December 1992 it produced its 8 billionth barrel of oil.[33] Production came off a plateau in 1989, and the field has entered its mature decline phase.

Concerns mounted over declining production from Prudhoe Bay during 1992. Without increased development, ARCO officials estimated that production will continue to fall by 8 to 10 percent per year through the year 2000.[34] In 1992, BP officials estimate the natural underlying decline rate was about 9 percent.[35] One sign of the extent of the decline is the number of producing wells: it now takes 1,100 wells to make the current rate of 1.3 million barrels of oil per day, while 14 years ago, 218 wells could produce 1.5 million barrels per day. However, the field still continues to dominate oil production in Alaska and the United States. Currently production accounts for 1 in every 6 barrels of oil produced in the United States. During the 15 years it has been producing, the field's estimated ultimate recovery has increased from 9.6 billion barrels to 12 billion barrels.

Major contributions to increasing ultimate recovery have come from expanded water flooding, more intensive drilling, and the application of enhanced oil recovery methods. Newly completed gas-handling facilities are expected to slow the decline and increase reserve recovery. This expansion allows the recovery of over 800 million additional barrels of crude oil. As production continued to decline in Alaska's North Slope, operators in Alaska turned their attention toward joint ventures and increased cooperation in 1992. Implementation of plans to ensure the full and efficient development of the field has begun. Operating costs will be reduced by sharing support services. According to one ARCO official, cooperative strategies will focus on: enhancing productivity of existing wells; sharing interest in new developmental wells; expanding facilities to accommodate gas and water production; and improving oil

Table 7. Reported Indicated Additional Crude Oil Reserves,[a] 1992
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	Indicated Additional Reserves	State and Subdivision	Indicated Additional Reserves
Alaska	1,331	North Dakota	3
Lower 48 States	2,451	Ohio	0
Alabama	0	Oklahoma	54
Arkansas	<1	Pennsylvania	0
California	1,299	Texas	612
Coastal Region Onshore	317	RRC District 1	0
Los Angeles Basin Onshore	4	RRC District 2 Onshore	0
San Joaquin Basin Onshore	977	RRC District 3 Onshore	27
State Offshore	1	RRC District 4 Onshore	<1
Colorado	34	RRC District 5	0
Florida	0	RRC District 6	7
Illinois	0	RRC District 7B	11
Indiana	0	RRC District 7C	33
Kansas	0	RRC District 8	260
Kentucky	0	RRC District 8A	273
Louisiana	35	RRC District 9	1
North	<1	RRC District 10	<1
South Onshore	26	State Offshore	0
State Offshore	9	Utah	65
Michigan	0	West Virginia	0
Mississippi	7	Wyoming	18
Montana	0	Federal Offshore	31
Nebraska	0	Pacific (California)	<1
New Mexico	293	Gulf of Mexico (Louisiana)	31
East	293	Gulf of Mexico (Texas)	0
West	0	Miscellaneous[b]	0
		U.S. Total	**3,782**

[a]Includes only those operators who produced 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both, during the report year (Category I or Category II operators).

[b]Includes Arizona, Missouri, Nevada, New York, South Dakota, Tennessee, and Virginia.

Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1992.

recovery technologies. Development drilling through the year 2000 is expected to add another 175 million barrels to ultimate recovery.[34]

Kuparuk River: The Kuparuk River Field, the second largest oil field in America (40 miles west of Prudhoe Bay) celebrated its 10th anniversary last December. Here, production was expected to peak at 250,000 barrels per day, but reached a new high in 1992 when single day production reached a new record of 353,000 barrels, and daily production averaged 322,000 barrels. Reserves are estimated to be 855 million barrels of recoverable oil.[34]

Point McIntyre: Under development is the Point McIntyre Field, a 1988 discovery lying 2 miles north of the Prudhoe Bay producing area. It contains estimated reserves of 300 million barrels of crude oil. A phased start-up is anticipated in late 1993 with production expected to build to over 100,000 barrels of oil per day in late 1994.[36]

Kuvlum: On a positive note, new discoveries on the North Slope, should add reserves in the future, while further development in other fields is replacing the loss of producing capacity at Prudhoe Bay. The best news in 1992 was the discovery of a giant field in the Federal offshore of Alaska. ARCO discovered a potential billion barrel field at the Kuvlum prospect 60 miles east of Prudhoe Bay in 110 feet of water, 15 miles offshore of the Arctic National Wildlife Refuge in the Beaufort Sea. In addition, there were two other oil discoveries west of the Kuparuk River Field in the onshore Colville High area. These discoveries await further evaluation.[37]

Sunfish: At Cook Inlet the good news in 1992 was the Sunfish prospect, 32 miles west of Anchorage, where ARCO drilled a delineation well that confirmed its 1991 Sunfish 1 discovery. Sunfish could contain 750 million barrels of oil reserves.[37]

Niakuk: Development plans for the Niakuk Field in the Beaufort Sea were revived in 1992 by British Petroleum. The company originally had stopped development due to environmental permitting concerns and doubts about economic feasibility. Company officials estimate 50 million barrels of oil reserves could be developed.[35]

No wells were drilled by the industry in the Chukchi Sea in 1992. State lease Sale 68 (Beaufort Sea) drew no bidders. It was the first time an Alaska State sale had no bids.[38]

California

In 1992 California, ranked third among the Nation's oil producing States, at an average production rate of 825,000 barrels of oil per day, a 5 percent decline from 1991. New well permits were down in 1992. The major emphasis in 1992 was on development work in proved fields. Steam injection continued to play a major role in the production of oil. One out of every two barrels of oil produced in the State is incremental oil recovered using steam injection. During 1992 the first export shipment of heavy crude oil was shipped to the Pacific Rim, a long-awaited objective of California independent operators. The 200,000 barrel shipment took some of the pressure off the glutted market caused by the import of Alaskan crude oil into the State.

San Joaquin Region: Kern County's top three fields — Midway-Sunset, Belridge South, and Kern River — retained a firm hold on the distinction of being the top three producing fields in the lower 48 States. Plans for Midway Sunset Field in 1993 include the drilling of approximately 100 development wells and the expansion of steamflood and fireflood projects.[39] More natural gas became available for steamflood operations with the completion of the Mojave Pipeline.

Elk Hills: During the year the Elk Hills Field, operated by the U.S. Department of Energy, celebrated both the 80th anniversary of the establishment of Naval Petroleum Reserve Number 1 and, in May 1992, the production of its one-billionth barrel of crude oil. This makes it one of 14 fields in the country to have produced a billion barrels. Elk Hills, one of the three oil fields operated by the Department of Energy, ranks among the 10 largest fields in the United States.[40]

Kern River Pipeline: Construction on the Kern River Gas Transmission Company pipeline was completed on December 21, 1991. The pipeline originates in Wyoming and terminates in Bakersfield, California. Constructed in less than a year, it began flowing gas commercially in mid-February 1992. The Kern River Pipeline will supply gas from large reserves in Wyoming, Utah, and Canada. This gas will provide the fuel to generate steam for enhanced oil recovery projects in Kern County fields near Bakersfield, California, as well as fuel utility, municipal, and industrial customers in Southern California. The Mojave Pipeline began it's first deliveries of natural gas in the first quarter of 1992, transporting over 200 million cubic feet per day to the San Joaquin Valley from the interconnection at Toprock, Arizona.[41]

Offshore Region: A number of key operators have dropped or suspended State and Federal leases in the California offshore because of continuing controversies surrounding oil development. Other companies have withdrawn or shelved possible development projects in the prolific Santa Barbara and Santa Maria basins. To counter this, MMS, the California State Lands Commission, local agencies, and oil companies have begun a 3 year study to find less controversial methods to develop the large resources lying in the near offshore. Mobil will attempt to gain approval to develop the Coal Oil Point extension of the South Elwood Field by extended reach drilling from onshore.[42]

Federal Offshore

The U.S. Outer Continental Shelf, which is under the jurisdiction of the Federal Government, ranked fourth in crude oil reserves and third in crude oil production among the producing areas in 1992. Its crude oil reserves of 2,569 million barrels were 11 percent of U.S. total reserves, and its production of 309 million barrels was 13 percent of total U.S. crude oil production.

Pacific Federal Offshore

Point Arguello Field: 1992 was the first full year of production from the Point Arguello Field. Production progressively increased during 1992 to average 45,000 barrels per day for the year, and 58,000 barrels per day during the fourth quarter. A higher rate is limited by the availability of pipelines to major markets. If the terms of an interim permit are approved, production will be brought up to full capacity of 85,000 barrels per day.[43]

Santa Ynez Unit: The $2.1 billion Santa Ynez Unit expansion in the Santa Barbara Channel is progressing toward start-up by early 1994. Production from the two new platforms is expected to exceed 50,000 barrels of oil per day by 1995 and to approach 70,000 barrels daily by the year 2000. Total project reserves are estimated to be over 350 million barrels oil-equivalent. Following completion of the project, the offshore storage and treatment vessel, now being used to process oil from the Hondo platform, will be removed from service. All production from the Unit will then be moved by pipeline to the Las Flores Canyon treatment plant.[36]

Gulf of Mexico Federal Offshore

On August 26, 1992, Hurricane Andrew roared across Florida and the Gulf of Mexico causing tremendous damage to persons and property. The MMS requested that all operators in the path of the storm assess the damage to their structures. The path of the hurricane offshore was generally northwesterly through the South Timbalier and

Ship Shoal areas. As of May 1993, the MMS Gulf of Mexico Region, had received structural inspection reports for the structures in the 85 mile wide path of Hurricane Andrew. Fifty operators submitted reports to MMS covering 730 platforms. Eighty platforms had structural damage.[44]

Pennzoil increased its presence in the Gulf when it acquired 266 fields from Chevron in 1992, in exchange for 48 percent of Pennzoil's ownership of Chevron stock, a transaction worth about $1.05 billion. Sixty percent of these fields are in the Gulf of Mexico.[45]

Texas

In 1992, Texas, ranked second among the Nation's oil producing States, produced oil at an average rate of 1,686,000 barrels per day, a 3-percent decline from 1991. The main areas of oil exploration and development activity in 1992 were the Austin Chalk trend and the Permian Basin. With a large number of properties changing hands, the new owners, mostly independents, focused their efforts, on workovers and the drilling of development wells rather than on exploration. Much of their work will continue in 1993. Three dimensional seismic crews were active both in south Texas and in the Permian Basin. Despite the drilling of several hundred horizontal wells in the Austin Chalk, oil production in the trend declined from 54.6 million barrels in 1991 to 53.5 million barrels in 1992. In the Permian Basin, despite active drilling in 1992, oil production declined 5 percent from the year earlier's 394 million barrels to 373 million barrels.

The 62 year old East Texas Field, which produced 32.9 million barrels of oil in 1992, continued to be the largest oil producer in the State, barely edging out the 32.6 million barrels produced by the Giddings Field. At the Yates Field in west Texas, Marathon has been able to slow oil production decline by using ultra-short-radius horizontal drilling and other techniques. One of the largest fields in the United States, it had a decline rate of about 10 percent during 1992 compared with approximately 20 percent between 1988 and 1990. The operator continues to apply and evaluate existing and new technologies to extend production life and maximize ultimate oil recovery.[46]

Other Areas

Alabama: Considerable activity in Alabama's Frisco City North Field resulted in several oil wells that gauged some of the highest flowing capacities in U.S. onshore operations. Six wells were completed in 1992, producing mainly from the Jurassic Haynesville formation. The use of 3-D seismic technology has enabled the operator to more than double its drilling success rate.

Appalachian Basin: Active rigs in the Appalachian Basin were down nearly 28 percent based on Baker Hughes data. The Petroleum Information Corporation reports that 95 percent of the region's drilling was developmental drilling. Available completion data listed 512 completions: (71 oil wells, 366 gas wells and 75 dry holes).[47]

Illinois Basin: Most 1992 indicators of oil and gas activity in the Illinois Basin were ahead of comparable 1991 figures. Petroleum Information reported a 23 percent increase in permits for oil and gas wells. The total of 78 new field wildcats was up 18 percent over 1991. Active rigs were up 10 percent. There were 820 well completions: (393 oil wells, 13 gas wells and 414 dry holes). The 1992 discovery of an Cambro-Ordovician oil source in the Illinois Basin could fuel increased exploration in the State. The Illinois State Geological Survey confirmed that this discovery marks the first documentation of a deep source in the Illinois Basin.[47]

Oklahoma: The Oklahoma State Senate passed a bill to establish a Marginal Oil and Gas Well Commission to curtail the abandonment of stripper wells across the State. About 70,000 of Oklahoma's producing wells are classified as stripper wells, those producing less than 3 barrels per day. Estimates of the number of wells plugged annually run as high as 2,000.

Wyoming: Production from the Silo Field in southeastern Wyoming for 1992 should be double the 1991 total of 373 thousand barrels. The reason for the rise is the completion of horizontal wells in the Niobrara Formation, a Cretaceous chalk similar to the Austin Chalk of south Texas. Like the Austin Chalk, the Silo Field area contains oil-filled vertical fractures which are the target of horizontal drilling.[47]

3-D Seismic Activity

New areas of potential reserves are being identified with greater precision through the use of 3-D seismic surveys and the application of new and improved imaging techniques. Reserves are continuing to be added by operators in areas of low-risk development drilling, enhanced by the successful use of new 3-D seismic techniques. The year 1992 saw increased use of 3-D seismology. Geologists made extensive use of 3-D technology in exploratory and development programs in such areas as the Appalachian Basin, Permian Basin, south Texas, and east Texas tight-sand areas, as well as in large areas of the Gulf of Mexico. In the Permian Basin of west Texas seismic crews have been in short supply. This technology continues to play a key role in reserve replacement in the Gulf of Mexico where several companies have joined in surveys which covered large areas of 33, 55, and 67 blocks. Using the new technology enables better targeting of prospects and the drilling of fewer dry holes. In both exploration and production phases, the use of 3-D seismology improves total hydrocarbon recovery. It is especially useful for development work around the many complex salt dome structures found in the Gulf of Mexico. Operators use it in the Permian Basin and in Michigan to target reef pinnacles missed in the past because of their small area. Successful application of 3-D seismic techniques to infield exploration has resulted in finding previously undetected reserves. One company uses the technology near existing fields in the Gulf of Mexico and elsewhere to find new reserves that can be brought on production quickly.

Horizontal Drilling

Horizontal drilling historically has been centered in the United States, mainly in the Austin Chalk of south Texas. Over 80 percent of the 2,708 horizontal well completions listed by Petroleum Information as of June 1992 were drilled into the Austin Chalk. Because of the higher cost, the technique has been used sparingly in the United States for applications other than fractured reservoirs. Horizontal drilling's share of the total U. S. drilling activity has remained fairly constant at 4 to 5 percent over the last 2 years.{48} Rigs drilling horizontal wells dropped again last year as oil and horizontal activity slowed. In south Texas the rig count in District 1 fell 79 percent from 1991 as activity tapered off in the Pearsall Field and moved to other areas. Horizontal drilling remained fairly strong further east in the Giddings Field. Fields in the Austin Chalk produced 53.5 million barrels of oil in 1992, down from 54.6 million in 1991. Of the total, Giddings produced 32.6 million barrels and Pearsall 13.3 million barrels. During the year, Giddings gained 166 producing wells while Pearsall lost 148 wells. From December 1991 to December 1992 the Giddings Field oil production increased from 60,100 to 92,600 barrels per day, while at Pearsall production declined from 50,700 to 24,900 barrels per day. By the end of 1992, cumulative production from the Giddings Field had reached more than 250 million barrels of oil and nearly a trillion cubic feet of gas. There were 2,385 producing oil wells in the Giddings Field and 847 in the Pearsall Field.

In other areas, the Meridian Corporation drilled 22 horizontal wells into the Williston Basin's Bakken shale in 1992, bringing the total number of wells to 104 through December 31, 1992.{41} Several operators were active in the Silo Field in the Denver Julesburg Basin's Niobrara Shale in southeastern Wyoming, which now has a total of 31 horizontal wells. Outside the above areas, horizontal drilling was used sparingly.

At this time, horizontal drilling appears to be levelling off, but the interest in the technology is not.{49} The costs must continue to come down for horizontal drilling to have the impact on improved oil recovery that many experts have predicted. One approach being used to reduce costs is the use of re-entry techniques on previously drilled vertical wells and the subsequent drilling of dual opposing laterals—two or more horizontal sections in the same well.

4. National and State Natural Gas Statistics

The Nation's proved reserves of dry natural gas were 165,015 billion cubic feet, 1.2 percent (2,047 billion cubic feet) less than 1991. In the lower 48 States they decreased by 1.4 percent (2,132 billion cubic feet). Reserves in coalbed methane fields increased to 10,034 billion cubic feet, a 23 percent increase over 1991. They now account for 6 percent of total U.S. gas reserves. Coalbed methane production has increased almost sixfold in just 3 years and now accounts for 3 percent of all U.S. natural gas production. Exploitation of the coalbed methane resource has rapidly expanded because of tax incentives and improved understanding of the underlying production technology. The ending of eligibility for these credits at midnight December 31, 1992, spurred drilling for coalbed methane, together with tight-sand gas, to high levels in the last half of the year. The tax credit of about $0.90 per thousand cubic feet of coalbed methane produced was about half the average U.S. 1992 wellhead price of $1.80 per thousand cubic feet.

[All natural gas proved reserves data shown in this report exclude natural gas held in underground storage.]

Dry Natural Gas

Proved Reserves

Proved reserves of dry natural gas as of December 31, 1992, by selected States and State subdivisions appear in Table 8. Five areas account for approximately 64 percent of the Nation's dry natural gas proved reserves.

Area	Percent of U.S. Gas Reserves
Texas	21.3
Gulf of Mexico Federal Offshore	16.1
New Mexico	11.5
Oklahoma	8.4
Wyoming	6.6
Total	**63.9**

States that had gas reserves declines had combined reserves losses of 5,584 billion cubic feet during 1992. The following five gas producing areas accounted for 87 percent of the U.S. gas reserves loss during the year. Their combined reserve losses were 4,875 billion cubic feet.

Area	Percent of Gas Reserves Losses
Gulf of Mexico Federal Offshore	29.3
Louisiana	20.3
Texas	19.4
Oklahoma	14.3
California	4.0
Total	**87.3**

States with increased gas reserves had total reserves gains of 3,606 billion cubic feet during 1992. Five areas accounted for 79 percent of this reserves increase. Virginia's dry gas reserves quadrupled while the other four States had moderate increases. A large portion of the increase was due to active drilling in areas which were eligible for tight-sand and coalbed methane tax credits. The increases for the five States totalled 2,842 billion cubic feet, offsetting, in part, the losses from other Areas.

Area	Percent of Gas Reserves Gains
Wyoming	24.5
Virginia	18.8
New Mexico	12.7
Colorado	12.0
Alabama	10.8
Total	**78.8**

Production

Dry natural gas production increased 1.3 percent to 17,423 billion cubic feet in 1992. The Gulf of Mexico Federal Offshore and Texas, each with 26 percent of the U.S total, were the leading producers of dry natural gas in 1992. Oklahoma (11 percent), Louisiana (8.5 percent), New Mexico (6.5 percent), and Wyoming (4 percent) contributed another 30 percent.

Discoveries

Total discoveries of dry natural gas reserves were 7,048 billion cubic feet, a decrease of 6.5 percent (494 billion cubic feet) from that reported in 1991. Areas with the largest *total discoveries* were Texas, the Gulf of Mexico Federal Offshore, Oklahoma, Colorado, and Wyoming. *New field discoveries* (649 billion cubic feet) were 23 percent lower than in 1991. Areas with the largest *new field discoveries* were the Gulf of Mexico Federal Offshore,

Table 8. Total Dry Natural Gas Proved Reserves, Reserves Changes, and Production, 1992
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/91	Changes in Reserves During 1992: Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	Proved Reserves 12/31/92
Alaska	9,553	289	177	21	54	0	0	414	9,638
Lower 48 States	**157,509**	**1,946**	**17,878**	**11,941**	**4,621**	**649**	**1,724**	**17,009**	**155,377**
Alabama	5,414	159	545	191	35	95	1	256	5,802
Arkansas	1,669	183	182	175	88	1	6	204	1,750
California	3,004	-24	185	164	27	22	13	285	2,778
Coastal Region Onshore	216	6	16	15	0	0	0	20	203
Los Angeles Basin Onshore	115	-13	13	8	0	0	0	10	97
San Joaquin Basin Onshore	2,614	-20	138	134	27	22	13	245	2,415
State Offshore	59	3	18	7	0	0	0	10	63
Colorado	5,767	-159	718	288	413	5	62	320	6,198
Florida	38	6	11	1	0	0	0	7	47
Kansas	9,356	184	1,054	385	35	1	24	590	9,681
Kentucky	1,155	-107	73	12	35	0	1	61	1,084
Louisiana	10,912	-273	1,472	1,222	206	75	104	1,494	9,780
North	2,384	-41	483	234	50	0	3	334	2,311
South Onshore	7,504	-111	847	835	155	75	101	1,043	6,693
State Offshore	1,024	-121	142	153	1	0	0	117	776
Michigan	1,334	95	148	248	29	7	3	145	1,223
Mississippi	1,057	-102	121	121	9	5	9	109	869
Montana	831	58	22	21	16	0	5	52	859
New Mexico	18,539	313	1,757	898	412	3	15	1,143	18,998
East	3,206	79	532	287	31	3	3	437	3,130
West	15,333	234	1,225	611	381	0	12	706	15,868
New York	331	9	23	17	5	0	0	[a]22	329
North Dakota	472	44	61	57	17	0	2	43	496
Ohio	1,181	89	21	27	3	1	10	117	1,161
Oklahoma	14,725	-121	1,988	1,263	382	0	110	1,895	13,926
Pennsylvania	1,629	28	136	155	24	0	5	139	1,528
Texas	36,174	903	3,743	3,235	1,729	127	197	4,545	35,093
RRC District 1	1,030	37	95	102	13	0	1	141	933
RRC District 2 Onshore	1,393	37	231	129	60	10	33	246	1,389
RRC District 3 Onshore	2,885	-67	401	312	233	13	33	502	2,684
RRC District 4 Onshore	7,048	294	881	1,001	464	79	98	1,124	6,739
RRC District 5	1,863	51	55	105	51	0	3	171	1,747
RRC District 6	5,233	50	604	533	466	7	22	532	5,317
RRC District 7B	423	97	9	6	0	0	0	68	455
RRC District 7C	3,291	56	324	213	57	6	3	285	3,239
RRC District 8	6,133	109	581	376	165	5	0	693	5,924
RRC District 8A	1,073	191	94	32	14	0	0	101	1,239
RRC District 9	738	-26	45	37	49	0	0	99	670
RRC District 10	4,589	137	348	304	137	7	4	509	4,409
State Offshore	475	-63	75	85	20	0	0	74	348
Utah	1,702	136	161	99	37	0	4	111	1,830
Virginia	225	196	373	1	136	0	0	25	904
West Virginia	2,528	-153	163	75	32	25	6	170	2,356
Wyoming	9,941	568	996	437	297	6	169	714	10,826
Federal Offshore[b]	29,448	-71	3,887	2,849	654	276	978	4,556	27,767
Pacific (California)	1,162	-2	18	12	0	0	0	48	1,118
Gulf of Mexico (Louisiana)[b]	21,611	-698	2,627	2,167	470	206	837	3,233	19,653
Gulf of Mexico (Texas)	6,675	629	1,242	670	184	70	141	1,275	6,996
Miscellaneous[c]	75	-15	38	0	0	0	0	6	92
U.S. Total	**167,062**	**2,235**	**18,055**	**11,962**	**4,675**	**649**	**1,724**	**17,423**	**165,015**

[a]Indicates the estimate is associated with a sampling error (95 percent confidence interval) that exceeds 20 percent of the estimated value.
[b]Includes Federal offshore Alabama.
[c]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada,Oregon, South Dakota, and Tennessee.

Note: The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." They may differ from the official Energy Information Administration production data for natural gas for 1992 contained in the *Natural Gas Annual 1992*, DOE/EIA-0131(92).

Source: Energy Information Administration, Office of Oil and Gas.

Texas, Alabama, and Louisiana. *New reservoir discoveries in old fields* were 1,724 billion cubic feet, 7.5 percent higher than 1991. Among the areas with the largest *new reservoir discoveries in old fields* were the Gulf of Mexico Federal Offshore, Texas, Wyoming, Oklahoma, and Louisiana. *Extensions* were 4,675 billion cubic feet, 8.2 percent lower than 1991. Areas with the largest *extensions* were Texas, the Gulf of Mexico Federal Offshore, Colorado, New Mexico, and Oklahoma.

The Texas and Louisiana Federal Offshore had relatively large *adjustments* of 629 billion cubic feet and negative 698 billion cubic feet, respectively. These adjustments occurred because of a change in the way in which the data were processed this year. Last year, EIA changed State codes for the Garden Banks area of the Federal Offshore Gulf of Mexico, in order to be more consistent with the U.S. Department of Interior, Minerals Management Service (MMS) nomenclature.

Wet Natural Gas

Proved Reserves

United States proved reserves of wet natural gas, as of December 31, 1992, were 173,309 billion cubic feet, a decrease of 1.2 percent or, 2,016 billion cubic feet, from that reported in 1991 (Table 9). End of year 1992 proved wet natural gas reserves for the lower 48 States were lower than in 1991, while those of Alaska increased.

The volumetric differences between the estimates reported in Table 8 and Table 9 results from the removal of natural gas liquids at natural gas processing plants.

Nonassociated Natural Gas

Proved Reserves

Proved reserves of nonassociated (NA) natural gas, wet after lease separation, as of December 31, 1992, by selected States and State subdivisions, are presented in Table 10. Proved reserves of NA wet natural gas in the United States decreased by 1,623 billion cubic feet (1.1 percent) in 1992 to 141,885 billion cubic feet, while the lower 48 States NA wet natural gas proved reserves decreased by 1,701 billion cubic feet, or 1.2 percent. Those areas with the largest increases in NA wet natural gas reserves were Wyoming, Virginia, New Mexico, Alabama, Kansas, and Colorado. The increases in New Mexico, Virginia, Colorado, and Alabama resulted from the search for natural gas qualifying for tax credits. The increase in Wyoming was mainly associated with drilling for tight-sand gas. There were large decreases in NA wet natural gas reserves in Texas, the Gulf of Mexico Federal Offshore, Oklahoma, and Louisiana.

Production

U.S. production of NA wet natural gas increased by 1.3 percent (194 billion cubic feet) in 1992. While most areas showed some production increases, the areas which showed the largest decreases were the Gulf of Mexico Federal Offshore, Texas, Louisiana, and Oklahoma. These accounted for 73 percent of total U.S. NA wet natural gas production.

Discoveries

NA wet natural gas *total discoveries* of 6,271 billion cubic feet decreased 6.1 percent (413 billion cubic feet) from 1991. Texas, the Gulf of Mexico Federal Offshore, and New Mexico accounted for 58 percent of U.S. NA wet natural gas *extensions* in 1992.

Associated-Dissolved Natural Gas

Proved Reserves

Table 11 presents the proved reserves of associated-dissolved (AD) natural gas, wet after lease separation, as of December 31, 1992, by selected States and State subdivisions. Proved reserves of AD wet natural gas in the United States decreased by 1.2 percent to 31,424 billion cubic feet, while production of AD wet natural gas increased by 2.1 percent. Proved reserves of AD wet natural gas in the lower 48 States declined by 387 billion cubic feet to 24,701 billion cubic feet.

Production

Production of AD wet natural gas in the lower 48 States increased by 1.3 percent to 2,832 billion cubic feet. The areas of the country with the largest AD wet natural gas reserves were Texas, Alaska, Gulf of Mexico Federal Offshore, California, New Mexico, Oklahoma, and Louisiana. These areas correspond to the areas of the country with the largest volumes of crude oil reserves and production.

Coalbed Methane

The EIA estimates that the 1992 proved gas reserves of fields identified as having coalbed methane were 10,034 billion cubic feet. This is nearly double the 5,087 billion cubic feet reported only 2 years ago (Table 12). Coalbed

Table 9. Total Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation, 1992 (Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/91	Changes in Reserves During 1992							Proved Reserves 12/31/92		
		Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production ( )	Total Gas	Non-associated Gas	Associated Dissolved Gas
Alaska	9,653	278	178	21	55	0	0	418	9,725	3,002	6,723
Lower 48 States	**165,672**	**2,265**	**18,728**	**12,511**	**4,840**	**668**	**1,773**	**17,851**	**163,584**	**138,883**	**24,701**
Alabama	5,460	174	562	195	35	95	1	262	5,870	5,840	30
Arkansas	1,672	183	182	175	88	1	6	205	1,752	1,619	133
California	3,114	-14	194	172	29	23	14	296	2,892	799	2,093
Coastal Region Onshore	231	4	17	16	0	0	0	21	215	19	196
Los Angeles Basin Onshore	120	-12	14	9	0	0	0	10	103	3	100
San Joaquin Basin Onshore	2,703	-7	144	140	29	23	14	255	2,511	773	1,738
State Offshore	60	1	19	7	0	0	0	10	63	4	59
Colorado	6,011	-149	754	306	423	5	64	339	6,463	5,701	762
Florida	45	6	13	1	0	0	0	8	55	0	55
Kansas	9,946	208	1,121	410	37	1	26	627	10,302	10,208	94
Kentucky	1,187	-99	76	13	37	0	1	63	1,126	1,118	8
Louisiana	11,363	-232	1,538	1,282	215	79	109	1,563	10,227	9,060	1,167
North	2,435	-39	494	239	51	0	3	342	2,363	2,203	160
South Onshore	7,846	-93	888	876	162	79	106	1,093	7,019	6,166	853
State Offshore	1,082	-100	156	167	2	0	0	128	845	691	154
Michigan	1,404	104	156	261	31	7	3	154	1,290	938	352
Mississippi	1,061	-101	121	122	9	5	9	109	873	788	85
Montana	848	59	22	21	16	0	5	54	875	814	61
New Mexico	19,758	518	1,843	943	423	3	15	1,218	20,399	18,802	1,597
East	3,471	119	581	315	33	3	3	477	3,418	1,948	1,470
West	16,287	399	1,262	628	390	0	12	741	16,981	16,854	127
New York	331	9	23	17	5	0	0	[a]22	329	329	0
North Dakota	533	56	70	65	20	0	2	49	567	301	266
Ohio	1,181	89	21	27	3	1	10	117	1,161	780	381
Oklahoma	15,518	-71	2,103	1,337	405	0	118	2,004	14,732	13,249	1,483
Pennsylvania	1,631	32	136	155	24	0	5	140	1,533	1,523	10
Texas	39,288	994	4,047	3,467	1,855	135	207	4,918	38,141	29,474	8,667
RRC District 1	1,061	43	100	106	13	0	1	145	967	606	361
RRC District 2 Onshore	1,479	49	247	138	64	11	35	263	1,484	1,176	308
RRC District 3 Onshore	3,110	-34	438	341	254	14	36	548	2,929	1,723	1,206
RRC District 4 Onshore	7,339	332	920	1,045	485	83	102	1,175	7,041	6,813	228
RRC District 5	1,930	63	57	109	53	0	3	179	1,818	1,692	126
RRC District 6	5,494	62	636	559	490	7	23	560	5,593	4,987	606
RRC District 7B	536	93	11	9	1	0	0	82	550	380	170
RRC District 7C	3,592	151	362	239	64	7	3	319	3,621	2,873	748
RRC District 8	6,793	93	642	415	181	5	0	765	6,534	3,792	2,742
RRC District 8A	1,542	87	121	41	19	1	0	131	1,598	13	1,585
RRC District 9	874	-29	54	44	59	0	0	117	797	613	184
RRC District 10	5,061	147	384	336	152	7	4	560	4,859	4,463	396
State Offshore	477	-63	75	85	20	0	0	74	350	343	7
Utah	2,001	24	177	109	42	1	4	122	2,018	1,709	309
Virginia	225	196	373	1	136	0	0	25	904	904	0
West Virginia	2,672	-162	173	79	34	26	6	179	2,491	2,293	198
Wyoming	10,433	543	1,040	457	310	7	176	747	11,305	10,681	624
Federal Offshore[b]	29,914	-87	3,945	2,896	663	279	992	4,624	28,186	21,871	6,315
Pacific (California)	1,174	5	18	13	0	0	0	48	1,136	149	987
Gulf of Mexico (Louisiana)[b]	22,028	-733	2,676	2,208	478	208	849	3,292	20,006	15,369	4,637
Gulf of Mexico (Texas)	6,712	641	1,251	675	185	71	143	1,284	7,044	6,353	691
Miscellaneous[c]	76	-15	38	0	0	0	0	6	93	82	11
U.S. Total	**175,325**	**2,543**	**18,906**	**12,532**	**4,895**	**668**	**1,773**	**18,269**	**173,309**	**141,885**	**31,424**

[a]Indicates the estimate is associated with a sampling error (95 percent confidence interval) that exceeds 20 percent of the estimated value.
[b]Includes Federal offshore Alabama.
[c]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.
Note: The production estimates in this table are based on data reported on Form EIA-23. They may differ from the official Energy Information Administration production data for natural gas for 1992 contained in the *Natural Gas Annual 1992*, DOE/EIA-0131(92).
Source: Energy Information Administration, Office of Oil and Gas.

Table 10. Nonassociated Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation, 1992

(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/91	Changes in Reserves During 1992: Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	Proved Reserves 12/31/92
Alaska	2,924	201	94	2	4	0	0	219	3,002
Lower 48 States	**140,584**	**1,775**	**15,962**	**10,686**	**4,131**	**655**	**1,481**	**15,019**	**138,883**
Alabama	5,437	173	546	192	35	94	1	254	5,840
Arkansas	1,536	160	179	171	88	1	6	180	1,619
California	901	15	81	120	21	23	9	131	799
Coastal Region Onshore	11	15	0	5	0	0	0	2	19
Los Angeles Basin Onshore	0	5	0	2	0	0	0	0	3
San Joaquin Basin Onshore	885	-5	81	113	21	23	9	128	773
State Offshore	5	0	0	0	0	0	0	1	4
Colorado	5,329	-188	695	259	341	5	49	271	5,701
Florida	0	0	0	0	0	0	0	0	0
Kansas	9,831	227	1,099	394	29	1	25	610	10,208
Kentucky	1,177	-97	74	11	37	0	1	63	1,118
Louisiana	9,969	-188	1,351	1,084	188	78	104	1,358	9,060
North	2,243	-59	463	182	48	0	3	313	2,203
South Onshore	6,851	-59	761	763	139	78	101	942	6,166
State Offshore	875	-70	127	139	1	0	0	103	691
Michigan	967	134	139	233	31	7	3	110	938
Mississippi	953	-97	111	98	9	5	2	97	788
Montana	782	56	15	13	15	0	5	46	814
New Mexico	18,204	471	1,543	807	401	3	14	1,027	18,802
East	2,073	70	289	205	14	3	2	298	1,948
West	16,131	401	1,254	602	387	0	12	729	16,854
New York	331	9	23	17	5	0	0	[a]22	329
North Dakota	290	-3	29	15	12	0	0	12	301
Ohio	805	50	10	20	0	0	3	68	780
Oklahoma	14,112	-173	1,782	1,196	380	0	111	1,767	13,249
Pennsylvania	1,611	41	135	155	24	0	5	138	1,523
Texas	30,729	606	3,167	2,867	1,449	127	180	3,917	29,474
RRC District 1	660	8	68	32	0	0	0	98	606
RRC District 2 Onshore	1,127	57	229	107	62	11	27	230	1,176
RRC District 3 Onshore	1,987	-63	279	263	137	14	20	388	1,723
RRC District 4 Onshore	7,096	324	882	1,025	484	83	102	1,133	6,813
RRC District 5	1,841	15	49	103	52	0	3	165	1,692
RRC District 6	4,856	74	603	521	448	7	21	501	4,987
RRC District 7B	379	55	5	7	1	0	0	53	380
RRC District 7C	2,833	114	293	180	36	1	3	227	2,873
RRC District 8	4,023	91	326	216	13	4	0	449	3,792
RRC District 8A	21	-7	2	1	0	0	0	2	13
RRC District 9	674	-23	29	31	48	0	0	84	613
RRC District 10	4,763	25	329	297	148	7	4	516	4,463
State Offshore	469	-64	73	84	20	0	0	71	343
Utah	1,532	150	141	75	38	0	0	77	1,709
Virginia	225	196	373	1	136	0	0	25	904
West Virginia	2,513	-211	159	77	34	26	6	157	2,293
Wyoming	9,861	447	932	417	295	7	175	619	10,681
Federal Offshore[b]	23,427	9	3,342	2,464	563	278	782	4,066	21,871
Pacific (California)	179	-20	11	7	0	0	0	14	149
Gulf of Mexico (Louisiana)[b]	16,943	-353	2,164	1,803	383	207	649	2,821	15,369
Gulf of Mexico (Texas)	6,305	382	1,167	654	180	71	133	1,231	6,353
Miscellaneous[c]	62	-12	36	0	0	0	0	4	82
U.S. Total	**143,508**	**1,976**	**16,056**	**10,688**	**4,135**	**655**	**1,481**	**15,238**	**141,885**

[a]Indicates the estimate is associated with a sampling error (95 percent confidence interval) that exceeds 20 percent of the estimated value.
[b]Includes Federal offshore Alabama.
[c]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Novada, Oregon, South Dakota, and Tennessee.

Note: The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves." They may differ from the official Energy Information Administration production data for natural gas for 1992 contained in the *Natural Gas Annual 1992*, DOE/EIA-0131(92).

Source: Energy Information Administration, Office of Oil and Gas.

Table 11. Associated-Dissolved Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation, 1992

(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/91	Changes in Reserves During 1992							Proved Reserves 12/31/92
		Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	
Alaska	6,729	77	84	19	51	0	0	199	6,723
Lower 48 States	**25,088**	**490**	**2,766**	**1,825**	**709**	**13**	**292**	**2,832**	**24,701**
Alabama	23	1	16	3	0	1	0	8	30
Arkansas	136	23	3	4	0	0	0	25	133
California	2,213	-29	113	52	8	0	5	165	2,093
Coastal Region Onshore	220	-11	17	11	0	0	0	19	196
Los Angeles Basin Onshore	120	-17	14	7	0	0	0	10	100
San Joaquin Basin Onshore	1,018	-2	63	27	8	0	5	127	1,738
State Offshore	55	1	19	7	0	0	0	9	59
Colorado	682	39	59	47	82	0	15	68	762
Florida	45	6	13	1	0	0	0	8	55
Kansas	115	-19	22	16	8	0	1	17	94
Kentucky	10	-2	2	2	0	0	0	0	8
Louisiana	1,394	-44	187	198	27	1	5	205	1,167
North	192	20	31	57	3	0	0	29	160
South Onshore	995	-34	127	113	23	1	5	151	853
State Offshore	207	-30	29	28	1	0	0	25	154
Michigan	437	-30	17	28	0	0	0	44	352
Mississippi	108	-4	10	24	0	0	7	12	85
Montana	66	3	7	8	1	0	0	8	61
New Mexico	1,554	47	300	136	22	0	1	191	1,597
East	1,398	49	292	110	19	0	1	179	1,470
West	156	-2	8	26	3	0	0	12	127
New York	0	0	0	0	0	0	0	0	0
North Dakota	243	59	41	50	8	0	2	37	266
Ohio	376	39	11	7	3	1	7	49	381
Oklahoma	1,406	102	321	141	25	0	7	237	1,483
Pennsylvania	20	-9	1	0	0	0	0	2	10
Texas	8,559	388	880	600	406	8	27	1,001	8,667
RRC District 1	401	35	32	74	13	0	1	47	361
RRC District 2 Onshore	352	-8	18	31	2	0	8	33	308
RRC District 3 Onshore	1 123	29	159	78	117	0	16	160	1,206
RRC District 4 Onshore	243	8	38	20	1	0	0	42	228
RRC District 5	89	48	8	6	1	0	0	14	126
RRC District 6	638	-12	33	38	42	0	2	59	606
RRC District 7B	157	38	6	2	0	0	0	29	170
RRC District 7C	759	37	69	59	28	6	0	92	748
RRC District 8	2,770	2	316	199	168	1	0	316	2,742
RRC District 8A	1,521	94	119	40	19	1	0	129	1,585
RRC District 9	200	-6	25	13	11	0	0	33	184
RRC District 10	298	122	55	39	4	0	0	44	396
State Offshore	8	1	2	1	0	0	0	3	7
Utah	469	-126	36	34	4	1	4	45	309
Virginia	0	0	0	0	0	0	0	0	0
West Virginia	159	49	14	2	0	0	0	22	198
Wyoming	572	96	108	40	15	0	1	128	624
Federal Offshore[a]	6,487	-96	603	432	100	1	210	558	6,315
Pacific (California)	995	25	7	6	0	0	0	34	987
Gulf of Mexico (Louisiana)[a]	5,085	-380	512	405	95	1	200	471	4,637
Gulf of Mexico (Texas)	407	259	84	21	5	0	10	53	691
Miscellaneous[b]	14	-3	2	0	0	0	0	2	11
U.S. Total	**31,817**	**567**	**2,850**	**1,844**	**760**	**13**	**292**	**3,031**	**31,424**

[a]Includes Federal offshore Alabama.

[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.

Note: The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves." They may differ from the official Energy Information Administration production data for natural gas for 1992 contained in the *Natural Gas Annual 1992*, DOE/EIA-0131(92).

Source: Energy Information Administration, Office of Oil and Gas.

methane proved reserves are principally located in New Mexico, Colorado, and Alabama. However, Virginia has recently had large increases in its coalbed methane reserves. Production of coalbed methane increased by 191 billion cubic feet (55 percent) in 1992. Most of the production increase occurred in the San Juan Basin. Currently coalbed methane production represents 3 percent of the Nation's total gas production.

The major fields in the San Juan Basin are Basin Fruitland Coal in New Mexico and Ignacio-Blanco in Colorado. Major coal degasification fields in the Black Warrior Basin in Alabama are Brookwood, Cedar Cove, Gurnee, Oak Grove, and Robinson's Bend. An important incentive for the production of coalbed methane was the provision of a special tax credit for nonconventional gas sources (such as coalbed methane) in Section 29 of the Crude Oil Windfall Profits Tax Act of 1980. The credit was applicable to wells drilled after December 31, 1979, and before January 1, 1993.

Reserves in Nonproducing Reservoirs

Table 13 presents the proved reserves of total wet natural gas in nonproducing reservoirs as of December 31, 1992, by selected States and State subdivisions. Proved natural gas reserves, wet after lease separation, of 34,118 billion cubic feet were reported in nonproducing reservoirs. This was an increase of 4.1 percent over 1991. Of these reserves, about 34 percent were located in the Gulf of Mexico Federal Offshore area.

Proved reserves in nonproducing reservoirs were reported by Category I and II operators, who collectively account for about 90 percent of the estimated total wet natural gas production in the United States. The reasons for the nonproducing status of these proved reserves are not collected by EIA. However, previous surveys showed that most of the wells or reservoirs were not producing for operational reasons. These included waiting for well workovers, drilling additional development or replacement wells, installing production or pipeline facilities, and awaiting depletion of other zones or reservoirs before recompletion in reservoirs not currently open to production.

Areas of Note

The following State or area discussions summarize notable activities during the year concerning expected new field reserves, development plans, and possible production rates as reported by various trade publications. The citations do not necessarily reflect EIA's concurrence, but are considered important enough to be brought to the reader's attention.

Federal Offshore

The U.S. Outer Continental Shelf (OCS), which is under the jurisdiction of the Federal Government, ranked second in natural gas reserves and fourth in crude oil reserves among producing areas in 1992. Its natural gas reserves of 27,767 billion cubic feet were 17 percent of total U.S. dry natural gas reserves. During 1992, 4,556 billion cubic feet of natural gas were produced from the OCS, which accounted for 26 percent of the U.S. total.

A 1992 lease sale for the Central Gulf of Mexico region resulted in 196 bids, for which the high bids totalled $56.2 million for 151 blocks. Also in 1992, a lease sale for the Western Gulf of Mexico region resulted in 81 bids, for which the high bids totalled $30.6 million for 61 blocks.[50]

Norphlet Trend: This is the most significant recent development along the Gulf Coast and adjacent Federal

Table 12. U.S. Coalbed Methane Proved Reserves and Production, 1989 through 1992
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State	1989 Reserves	1989 Production	1990 Reserves	1990 Production	1991 Reserves	1991 Production	1992 Reserves	1992 Production
Alabama	537	23	1,224	36	1,714	68	1,968	89
Colorado	1,117	12	1,320	26	2,076	48	2,716	82
New Mexico	2,022	56	2,510	133	4,206	229	4,724	358
Others[a]	0	0	33	1	167	3	626	10
Total	**3,676**	**91**	**5,087**	**196**	**8,163**	**348**	**10,034**	**539**

[a] Includes Kansas, Oklahoma, Virginia, and Wyoming.
Source: Energy Information Administration, Office of Oil and Gas.

Table 13. Reported Reserves of Natural Gas, Wet After Lease Separation, in Nonproducing Reservoirs, 1992[a]
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Nonassociated Gas	Associated-Dissolved Gas	Total
Alaska	458	185	643
Lower 48 States	**29,625**	**3,850**	**33,475**
Alabama	2,771	1	2,772
Arkansas	204	9	213
California	109	62	171
Coastal Region Onshore	1	43	44
Los Angeles Basin Onshore	2	9	11
San Joaquin Basin Onshore	106	8	114
State Offshore	0	2	2
Colorado	975	184	1,159
Florida	0	0	0
Kansas	180	7	187
Kentucky	101	0	101
Louisiana	2,664	217	2,881
North	545	5	550
South Onshore	1,842	185	2,027
South State Offshore	277	27	304
Michigan	206	21	227
Mississippi	49	11	60
Montana	123	3	126
New Mexico	3,087	97	3,184
East	194	87	281
West	2,893	10	2,903
New York	24	0	24
North Dakota	154	22	176
Ohio	59	3	62
Oklahoma	925	120	1,045
Pennsylvania	34	1	35
Texas	5,988	767	6,755
District 1	44	42	86
District 2 Onshore	217	82	299
District 3 Onshore	314	65	379
District 4 Onshore	2,276	56	2,332
District 5	637	2	639
District 6	1,312	24	1,336
District 7B	32	4	36
District 7C	543	33	576
District 8	280	255	535
District 8A	2	106	108
District 9	33	2	35
District 10	191	96	287
State Offshore	107	<1	107
Utah	284	75	359
Virginia	3	0	3
West Virginia	125	5	130
Wyoming	1,770	27	1,797
Federal Offshore[b]	9,784	2,218	12,002
Pacific (California)	74	192	266
Gulf of Mexico (Texas)	2,562	282	2,844
Gulf of Mexico (Louisiana)[b]	7,148	1,744	8,892
Miscellaneous[c]	6	<1	6
U.S Total	**30,083**	**4,035**	**34,118**

[a]Includes only those operators who produced 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both, during the report year (Category I or Category II operators).

[b]Includes Federal Offshore Alabama.

[c]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.

Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1992.

Offshore. The trend stretches 80 miles from the Destin Dome area of the Florida Panhandle to the southeast corner of Mississippi. Efforts are continuing to obtain approval to drill and develop reserves already found in the Destin Dome area.{45} In 1989 the Norphlet was reported to contain 10 trillion cubic feet of dry gas.{51} Nothing has occurred since then to lower the estimate. There are now 4 fields (2 in State waters and 2 in Federal waters) producing gas from the Norphlet at depths of about 21,000 feet. Dry gas production from these fields averaged 501 million cubic feet per day in December 1992. Individual wells produce at rates of 25 to 60 million cubic feet per day. New discoveries are actively being developed. Exxon estimates that its 11-well development program will be completed for production in late 1993.{36}

Deep Water: The deep water Gulf of Mexico continues to show significant potential for the development of natural gas. A number of major projects are underway, or in advanced planning stages, to move out into the deep water off the continental shelf. A number of companies plan to utilize state of the art subsea producing technology. Subsea technology allows the commercial development of deep water prospects that lack the size to support the cost of surface structures. Major announced projects in the deep water areas are: (1) Auger, 2,870 feet, Garden Banks Block 426, (2) Cooper, 2,375 feet, Garden Banks Block 387, (3) Lobster, 675 feet, Ewing Bank Block 873, (4) Mars, 3,250 feet, Mississippi Canyon Block 807, (5) Popeye, 2,320 feet, Green Canyon Block 116, (6) Tahoe, 1,450 feet, Viosca Knoll Block 783, (7) Zinc, 1,500 feet, Mississippi Canyon Block 354, (8) Ram-Powell, 3,000 feet, Viosca Knoll Block 912. In 1992 the MMS reported 27 discoveries and "reactivated" 2 fields. This compares with 28 discoveries in 1991 and 48 in 1990.{52}

Chevron-Pennzoil: Chevron completed the most significant energy-related transaction of the 1992 calendar year with Pennzoil Co. On October 30, 1992, Pennzoil transferred and delivered to Chevron 15,750,000 shares of the common stock of Chevron, and Chevron transferred and delivered to Pennzoil all issued and outstanding stock of a Chevron subsidiary subsequently renamed Pennzoil Petroleum, which owns Gulf of Mexico, Gulf Coast, Permian Basin, and other domestic oil and gas producing properties. The sale involved an estimated $1.05 billion and 266 U.S. oil and gas fields. Sixty percent of the reserves involved were located in the Gulf of Mexico and most of these reserves were natural gas.{53} Pennzoil originally accumulated Chevron's stock in 1989 as the proceeds of a $3 billion legal settlement of a law suit with Texaco. Chevron noted that it "... continues to rationalize its domestic exploration program in the light of the current business environment. The most promising offshore and onshore frontiers, such as portions of offshore Florida, North Carolina, Bristol Bay, and the Arctic National Wildlife Refuge in Alaska continue to be off limits for environmental and political reasons."{45}

Texas

There was a mini-boom in the drilling of tight-sand gas wells in the Lobo trend of south Texas, and the Travis Peak and Cotton Valley formations of east Texas. Much of this activity was the result of operators trying to beat the deadline to qualify new wells for the Section 29 tax credit. In both areas, 3-D seismic crews were active. The Carthage Field, in east Texas, emerged as the top natural gas producing field in Texas, superseding the 1991 leader Panhandle West Field (167 billion cubic feet versus 161 billion cubic feet). Virtually all of the Carthage Field drilling has been development work in relatively tight reservoirs.

The Rockies

The Rocky Mountain region contributed more than 27 percent of the Nation's new gas well completions in 1992. Permits for new oil and gas wells were up 27 percent for the year, with a third of them completed in the last quarter. A large portion of the drilling focused on developing natural gas from tight-sand reservoirs and coal seams to qualify for Section 29 tax credits. The main areas of activity in the region were the Denver-Julesburg Basin of northeastern Colorado, the San Juan Basin in southern Colorado, the Uinta Basin of northeastern Utah, the Bowdoin Dome and Bearpaw Arch in the northern part of Montana, and the Washakie Basin and Moxa Arch of southwestern Wyoming.

Colorado: The State's completed gas well total was second only to Texas with 779 gas producers — more than Oklahoma and Louisiana combined (696). Northeastern Colorado's Weld County had 602 gas wells, 10 oil wells, and 19 dry holes. This was mainly due to high levels of drilling in the Wattenberg Field, much of which qualifies for tight-sand gas tax credits. Wattenberg Field ranked first both in the region and in the United States with 621 well completions in 1992.{47}

Montana: The State of Montana reported 259 well completions. Of these, 144 were gas wells and 37 were oil wells. Most of the activity was centered on gas development in northern Montana in the shallow (1,200-2,500 feet) Bowdoin Dome and Tiger Ridge Field.

New Mexico: Coalbed methane activity continued throughout 1992 in New Mexico's San Juan Basin, which has experienced increased production since 1989. In 1992, New Mexico enacted incentive legislation concerning enhanced oil recovery. The law stipulates that a 1.87 percent tax incentive will be provided for secondary and tertiary production enhancement programs that are certified in advance of drilling. Tertiary projects are presently eligible, while secondary projects will not qualify until 1994. Drilling was down sharply from 1991. There were a total of 219 completions of which 169 were gas, 34 were oil, and 16 were dry holes. This was 55 percent below 1991's levels.{47}

Utah: Utah is one of a handful of States which has experienced an increase in rig activity over the past several years, mainly as the result of favorable State tax incentives, coalbed methane development, and horizontal drilling. Utah's increased activity in 1992 is attributed to Section 29 tight-sand tax credits for locations in the Uinta Basin and to successful horizontal drilling in the Paradox Basin. There were 228 well completions, 30 percent more than in 1991. Of these, 133 were gas wells, 49 were oil wells, and 46 were dry holes. Of the 133 gas wells, 128 were drilled in the Natural Buttes Field in northeastern Utah.{47}

Wyoming: Production of natural gas in Wyoming began a steady climb after 1986 even though there were many shut-in gas wells. Increased gas prices in 1992 were reflected in the accelerated drilling in the southwestern part of the State. By the end of the year, 434 completions had been reported. Of these, there were 157 gas wells, 125 oil wells, and 152 dry holes. Most of the drilling for gas was centered in southwestern Wyoming, an area which qualifies for the Section 29 tax credits. Wyoming has large potential resources of coalbed methane, although drilling projects were still in the planning stages in 1992. The necessity of obtaining environmental clearances had slowed permitting, but drilling will start on some projects in 1993.{47}

Other Areas

Kansas: Coalbed methane production was reported in southeastern Kansas. Wildcatting continued in the northeastern part of the State as companies staked new coalbed methane wildcats. Development efforts in the mature oil and gas areas of southeast Kansas showed particular promise for further production.

Michigan: Drilling permits reached record numbers in 1992 as operators took advantage of the tax credit for gas drilling in the shallow Devonian Antrim Shale. The issuance of more than 1,600 new permits topped the previous record of 1,465 permits as operators rushed to start Antrim Shale gas wells prior to the expiration of Section 29 tax credits. Gas production from Antrim Shale gas wells increased from 55 billion cubic feet in 1991 to 74 billion cubic feet in 1992. At the end of the year there were over 3,000 Antrim shale gas wells spread over eight counties. However, the future of drilling in the Antrim is clouded because of low producing rates, typically only 25 to 100 thousand cubic feet per day, and the loss of tax credits for new wells. Permitting was down 95 percent in January 1993.{47}

Alabama: Coalbed methane activity continued in Alabama's Black Warrior Basin. In 1992, coalbed methane wells produced 92 billion cubic feet of gas. The two top producing fields were Cedar Cove Degas and Blue Creek Coal Degas, each of which produced just over 20 billion cubic feet of dry gas during the year.

Virginia: Developments in 1992 were highlighted by coalbed methane development in the Nora and Oakwood fields.

5. National and State Natural Gas Liquids Statistics

Natural Gas Liquids

Proved reserves of natural gas liquids (NGL), as of December 31, 1992, are presented in Table 14 by selected States and State subdivisions. The volumes of NGL proved reserves and production shown in Table 14 are the sum of the natural gas plant liquid volumes listed in Table 15 and the lease condensate volumes listed in Table 16.

Proved Reserves

Natural gas liquids proved reserves decreased in 1992 by 0.2 percent to 7,451 million barrels. The 13 million barrel decrease was entirely in Alaska as the lower 48 States remained the same at 7,104 million barrels. The reserves in five areas account for approximately 72 percent of the Nation's natural gas liquids proved reserves. Of these, Texas had 32 percent, New Mexico had 14 percent, Utah-Wyoming had 9 percent, and the Gulf of Mexico Federal Offshore and Oklahoma had 8 percent each.

Production

Natural gas liquids production increased by 2.5 percent to 773 million barrels in 1992. Five areas accounted for approximately 79 percent of the Nation's natural gas liquids production. Of these, Texas had 38 percent, the Gulf of Mexico Federal Offshore had 12 percent, Oklahoma had 11 percent, Louisiana had 10 percent, and New Mexico had 7 percent.

Discoveries

Total discoveries of natural gas liquids reserves increased by 1.8 percent to 274 million barrels in 1992. Areas with the largest *total discoveries* were Texas, the Federal Offshore, Louisiana, Oklahoma, and Utah-Wyoming. *New field discoveries* (20 million barrels) were 20 percent lower than in 1991. Areas with the largest amount of *new field discoveries* were Louisiana and Texas with 65 percent of the total. *New reservoir discoveries in old fields* were 64 million barrels, 16.4 percent higher than in 1991. Among the areas with the largest amounts of *new reservoir discoveries in old fields* were the Gulf of Mexico Federal Offshore, Texas, Louisiana, Utah-Wyoming, and Oklahoma.

Extensions were 190 million barrels, essentially the same as in 1991. Areas with the largest *extensions* were Texas, Oklahoma, the Gulf of Mexico Federal Offshore, and Utah-Wyoming.

Natural Gas Plant Liquids

Proved Reserves

Table 15 presents the proved reserves of natural gas plant liquids as of December 31, 1992, by selected States and State subdivisions. Natural gas plant liquids proved reserves increased in 1992, by 0.1 percent from 6,220 million barrels to 6,225 million barrels. Five areas accounted for approximately 75 percent of the Nation's natural gas plant liquids proved reserves: Texas (35 percent), New Mexico (16 percent), Oklahoma (9 percent), Utah-Wyoming (8 percent), and Kansas (7 percent).

Production

Natural gas plant liquids production increased 4.2 percent to 626 million barrels in 1992. Five areas accounted for approximately 79 percent of the Nation's natural gas plant liquids production: Texas (42 percent), Oklahoma (12 percent), New Mexico (9 percent), Louisiana (8 percent), and the Gulf of Mexico Federal Offshore (8 percent). The production of gas plant liquids increased in 1992 as did U.S. natural gas production. There was a strong market for natural gas plant liquids in 1992 that is expected to improve over the next several years due to the shift to cleaner motor fuels in metropolitan regions, as mandated by the Clean Air Act. These liquids are used to produce additives that reduce gasoline emissions. The processing plants are usually located in the same general area where the natural gas is produced. As shown in Table E4, of the 16.2 trillion cubic feet of natural gas processed in plants, about 15.5 trillion cubic feet is both produced and processed in the same State.

Table 14. Natural Gas Liquids Proved Reserves, Reserves Changes, and Production, 1992
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	Published Proved Reserves 12/31/91	Changes in Reserves During 1992: Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	Proved Reserves 12/31/92
Alaska	360	0	10	3	7	0	0	27	347
Lower 48 States	**7,104**	**225**	**796**	**542**	**183**	**20**	**64**	**746**	**7,104**
Alabama	145	13	34	7	0	0	0	14	171
Arkansas	5	-1	0	0	0	0	0	0	4
California	92	14	6	5	1	1	0	10	99
Coastal Region Onshore	12	-1	1	1	0	0	0	1	10
Los Angeles Basin Onshore	4	1	1	0	0	0	0	1	5
San Joaquin Basin Onshore	75	14	4	4	1	1	0	8	83
State Offshore	1	0	0	0	0	0	0	0	1
Colorado	197	4	45	14	7	0	1	14	226
Florida	7	0	2	0	0	0	0	1	8
Kansas	428	10	48	18	2	0	1	27	444
Kentucky	24	7	2	0	1	0	0	2	32
Louisiana	526	22	70	71	9	8	8	77	495
North	59	2	13	7	2	0	0	9	60
South Onshore	417	7	46	53	7	8	8	60	380
State Offshore	50	13	11	11	0	0	0	8	55
Michigan	72	9	8	14	1	0	0	8	68
Mississippi	10	0	2	3	1	0	0	1	9
Montana	14	-1	0	0	0	0	0	1	12
New Mexico	908	170	70	34	9	0	0	57	1,066
East	205	28	39	21	2	0	0	30	223
West	703	142	31	13	7	0	0	27	843
North Dakota	56	11	8	7	2	0	0	6	64
Oklahoma	628	22	99	60	19	0	6	85	629
Texas	2,493	55	244	208	100	5	10	297	2,402
RRC District 1	28	5	3	4	0	0	0	5	27
RRC District 2 Onshore	75	7	14	8	4	0	3	15	80
RRC District 3 Onshore	208	21	32	31	18	1	2	40	211
RRC District 4 Onshore	273	25	38	43	18	3	4	46	272
RRC District 5	71	7	3	5	2	0	0	7	71
RRC District 6	243	11	30	30	21	0	1	25	251
RRC District 7B	82	-4	1	1	0	0	0	10	68
RRC District 7C	241	57	28	19	5	1	0	24	289
RRC District 8	477	-7	43	29	12	0	0	52	444
RRC District 8A	333	-70	19	7	3	0	0	21	257
RRC District 9	101	-3	6	6	7	0	0	13	92
RRC District 10	356	6	27	24	10	0	0	39	336
State Offshore	5	0	0	1	0	0	0	0	4
Utah and Wyoming	748	-90	55	28	14	0	8	47	660
West Virginia	103	-5	7	3	1	1	0	7	97
Federal Offshore[a]	640	-16	96	69	16	5	30	92	610
Pacific (California)	16	5	0	0	0	0	0	1	20
Gulf of Mexico (Louisiana)[a]	545	-60	80	61	13	4	27	76	472
Gulf of Mexico (Texas)	79	39	16	8	3	1	3	15	118
Miscellaneous[b]	8	1	0	1	0	0	0	0	8
U.S. Total	**7,464**	**225**	**806**	**545**	**190**	**20**	**64**	**773**	**7,451**

[a]Includes Federal offshore Alabama.

[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, and Virginia.

Note: The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." They may differ from the official Energy Information Administration production data for natural gas and natural gas liquids for 1992 contained in the publications *Petroleum Supply Annual 1992*, DOE/EIA-0340(92) and *Natural Gas Annual 1992*, DOE/EIA-0131(92).

Source: Energy Information Administration, Office of Oil and Gas.

Table 16. Natural Gas Plant Liquids Proved Reserves and Production, 1992
(Million Barrels of 42 U S Gallons)

State and Subdivision	1992 Reserves	1992 Production	State and Subdivision	1992 Reserves	1992 Production
Alaska	347	27	North Dakota	54	5
Lower 48 States	**5,878**	**599**	Oklahoma	566	77
Alabama	53	4	Texas	2,162	264
Arkansas	2	0	RRC District 1	24	4
California	94	10	RRC District 2 Onshore	66	12
Coastal Region Onshore	9	1	RRC District 3 Onshore	172	32
Los Angeles Basin Onshore	5	1	RRC District 4 Onshore	207	35
San Joaquin Basin Onshore	79	8	RRC District 5	55	5
State Offshore	1	0	RRC District 6	205	21
Colorado	193	13	RRC District 7B	67	10
Florida	8	1	RRC District 7C	266	23
Kansas	442	27	RRC District 8	426	50
Kentucky	32	2	RRC District 8A	257	21
Louisiana	317	49	RRC District 9	89	13
North	41	6	RRC District 10	327	38
South Onshore	229	36	State Offshore	1	0
State Offshore	47	7	Utah and Wyoming	497	32
Michigan	52	6	West Virginia	96	7
Mississippi	3	0	Federal Offshore[a]	295	48
Montana	12	1	Pacific (California)	15	1
New Mexico	994	53	Gulf of Mexico (Louisiana)[a]	246	41
East	204	28	Gulf of Mexico (Texas)	34	6
West	790	25	Miscellaneous[b]	6	0
			U.S. Total	**6,225**	**626**

[a]Includes Federal Offshore Alabama.

[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, and Virginia.

Note. The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." They may differ from the official Energy Information Administration production data for natural gas plant liquids for 1992 contained in the publications *Petroleum Supply Annual 1992* DOE/EIA-0340(92) and *Natural Gas Annual 1992* DOE/EIA-0131(92).

Source: Energy Information Administration, Office of Oil and Gas.

Lease Condensate

Proved Reserves

Table 16 presents the proved reserves of lease condensate, as of December 31, 1992, by selected States and State subdivisions. Proved reserves of lease condensate for the United States were 1,226 million barrels. This was 18 million barrels or 1.4 percent lower than reported in 1991.

Production

Production of lease condensate was 147 million barrels, a decrease of 6 million barrels, or 3 percent, from 1991.

Reserves in Nonproducing Reservoirs

Like crude oil and natural gas, not all lease condensate proved reserves were contained in reservoirs that were producing during 1992. Proved reserves of 392 million barrels of lease condensate, a 10.1 percent increase from 1991, were reported in nonproducing reservoirs. These reserves were reported by Category I and Category II operators, who collectively accounted for more than 96 percent of total lease condensate production. About 46 percent of the nonproducing lease condensate reserves were located in the Gulf of Mexico Federal Offshore.

Table 16. Lease Condensate Proved Reserves and Production, 1992
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	1992 Reserves	1992 Production	State and Subdivision	1992 Reserves	1992 Production
Alaska	0	0	North Dakota	10	1
Lower 48 States	**1,226**	**147**	Oklahoma	63	8
Alabama	118	10	Texas	240	33
Arkansas	2	0	RRC District 1	3	1
California	5	0	RRC District 2 Onshore	14	3
Coastal Region Onshore	1	0	RRC District 3 Onshore	39	8
Los Angeles Basin Onshore	0	0	RRC District 4 Onshore	65	11
San Joaquin Basin Onshore	4	0	RRC District 5	16	2
State Offshore	0	0	RRC District 6	46	4
Colorado	33	1	RRC District 7B	1	0
Florida	0	0	RRC District 7C	23	1
Kansas	2	0	RRC District 8	18	2
Kentucky	0	0	RRC District 8A	0	0
Louisiana	178	28	RRC District 9	3	0
North	19	3	RRC District 10	9	1
South Onshore	151	24	State Offshore	3	0
State Offshore	8	1	Utah and Wyoming	163	15
Michigan	16	2	West Virginia	1	0
Mississippi	6	1	Federal Offshore[a]	315	44
Montana	0	0	Pacific (California)	5	0
New Mexico	72	4	Gulf of Mexico (Louisiana)[a]	226	35
East	19	2	Gulf of Mexico (Texas)	84	9
West	53	2	Miscellaneous[b]	2	0
			U.S. Total	**1,226**	**147**

[a]Includes Federal Offshore Alabama.
[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, and Virginia.

Note: The estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves" 1992.

Source: Energy Information Administration, Office of Oil and Gas.

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Appendix A

Operator Data by Size Class

Appendix A

Operator Data by Size Class

Appendix A presents for the first time a series of tables that contain estimates of the proved reserves and production of the top 2,500 oil and gas operators by operator production size class. Operator field counts, the sum of the number of fields that each operator was active in, are also presented. This Appendix will be a regular feature of this report. It documents changes in industry structure over the past 5 years. In addition the tables show the volumetric change and percent change from the previous year and from 1988.

All companies operating in the United States that reported production or reserves to EIA were ranked by production size for each of the five years. Production was computed as the sum of the barrel of oil equivalent of crude oil production, lease condensate production, and wet gas production for each operator. The operators were then placed in the following production size classes: 1-10, 11-20, 21-100, 101-500, 501-2500, and all "other" active oil and gas operators. The "other" class contains more than 20,000 small operators each year. The production and reserves of this class are estimated each year from a sample of approximately 8 percent of these operators. Operators may change from one size class to another over time. The 1-10 class always contains the 10 highest producing operators each year, but not necessarily the same 10 operators each year.

Natural Gas

Table A1 shows the natural gas proved reserves reported by operator production size class for the years 1988 through 1992. Proved reserves are highly concentrated in the larger operators. In 1992, the top 10 producing operators had 42.9 percent of the proved reserves of natural gas or 74 trillion cubic feet. The next 3 size classes contain 10 operators, 80 operators, and 400 operators. Each of these three classes had roughly comparable percentages of the total gas reserves; 16.4, 22.2, and 10.5 percent. The next 2,000 operators had only 4.3 percent of the gas reserves and the "other" operators had 3.7 percent. The average top 10 operator had more than 2,000 times the gas reserves of the average operator in the "other" class, which contains only small operators. The top 10 operators had an 11.6 percent decline in their natural gas proved reserves from 1988 to 1992. Without the top 10, the rest of the operators had a 6.6 percent increase from 1988 to 1992. From 1988 to 1992, total U.S. natural gas proved reserves only declined 2.1 percent. In 1992, the top 10 operators' natural gas reserves declined 3.9 percent. The rest of the operators had a 1.0 percent increase from 1991 to 1992. Most of the increase came from the second tier of operators, class 11-20. These operators increased their gas proved reserves 5.9 percent in 1992, and had a 41.9 percent increase from 1988 to 1992. A large part of this increase resulted from acquisitions of reserves from other operators.

Table A2 shows the natural gas production reported by operator production size class for 1988-1992. Gas production is less concentrated than gas reserves. In 1992, the top 10 operators had 36.2 percent of the production of natural gas or 6.6 trillion cubic feet, while having 42.9 percent of the proved reserves. The next 3 size classes had roughly comparable percentages of the gas production: 16.7, 25.1, and 13.2 percent. The next 2,000 operators had only 5.3 percent of the gas production and the "other" operators had 3.4 percent. The average top 10 operator had more than 2,000 times the gas production of the average operator in the "other" class. The top 10 operators had a 7.1 percent decline in their natural gas production from 1988 to 1992. Without the top 10, the rest of the U.S. operators had a 13.0 percent increase from 1988 to 1992. Total U.S. natural gas production increased 4.8 percent from 1988 to 1992. Gas production from the top 10 declined 2.7 percent in 1992, while the rest of the operators had a 1.6 percent increase. Most of the increase came from the second tier of operators, class 11-20. These operators increased their gas production 5.3 percent in 1992, and had a 30.4 percent increase from 1988 to 1992.

Crude Oil

Table A3 shows the crude oil proved reserves reported by operator production size class for 1988-1992. The 20 largest oil and gas producing operators in 1992 had 75.8 percent of U.S. proved reserves of crude oil, as opposed to natural gas, where 59.3 percent of the total is operated by these same producers. These operators had concentrated their U.S. operations on fewer fields and focused more of their resources on foreign operations. The top 10 operators had a 6.5 percent decline in their domestic proved reserves of crude oil during 1992, while the rest of the operators had a 2.0 percent increase. Proved reserves of crude oil are more concentrated than those of natural gas. The top 10 operators had 66.3 percent of the U.S. proved reserves, or 15.7 billion barrels, in 1992. While both oil and gas reserves are concentrated in the larger operators, this industry is no where near as concentrated as most major U.S. industries, for example, the automobile industry. The 11-20 class and the 80 operators in the 21-100 class had 9.5 percent and 10.0 percent of U.S. proved reserves of crude oil. The next 400 operators had only 6.2 percent of the total and the next 2,000 operators in class 501-2,500 had 4.7 percent. The operators in the "other" class had only 3.4 percent of U.S. proved reserves of crude oil. The average top 10 operator had almost 4,000 times the oil reserves of the average operator in the "other" class. The top 10 class had a 19.2 percent decline in their crude oil proved reserves from 1988 to 1992. Their reserves declined 6.5 percent in 1992. U.S. proved reserves of crude oil declined by 11.5 percent from 1988 to 1992 and declined 3.8 percent in 1992. Without the top 10, the rest of the U.S. operators had a 8.9 percent increase from 1988-1992. The rest of the operators also had a 2-percent increase in crude oil proved reserves in 1992. The large independents, the 80 operators in production size class 21-100, accounted for most of the increase. These operators had a 46.7 percent increase in their oil reserves during the 1988-1992 period. A substantial portion of this increase came from property acquisitions. Size class 101-500 had an 18.9 percent increase in proved reserves of crude oil from 1988 to 1992. During the 1988-1992 period, many operators bought, sold, and restructured their property positions.

Table A4 shows the crude oil production reported by operator production size class for 1988-1992. The 20 largest oil and gas producing operators in 1992 had 69.0 percent of U.S. production of crude oil, as opposed to natural gas where 52.9 percent of the total is operated by these same operators. The top 10 had a 5.6 percent decline in their domestic production of crude oil during 1992, while the rest of the operators had a 2.1 percent increase.

Production of crude oil is more concentrated in the large operators than it is for natural gas. The top 10 class had 59.6 percent of U.S. production, or 1.5 billion barrels, in 1992. The 11-20 class and the 80 operators in the 21-100 class had 9.4 percent and 11.1 percent of U.S. production of crude oil. The next 400 operators had only 8.7 percent of the total and the next 2,000 operators in class 501-2,500 had 6.3 percent. The more than 20,000 operators in the "other" class had only 4.9 percent of the U.S. production of crude oil. The average top 10 operator had about 2,500 times the oil production of the average operator in the "other" class. The top 10 had a 20.5 percent decline in their oil production from 1988 to 1992. Their production also declined 5.6 percent in 1992. U.S. production of crude oil declined by 13.0 percent from 1988 to 1992 and declined 2.6 percent in 1992. Without the top 10, the rest of the U.S. operators had a 1.0 percent increase from 1988 to 1992. The rest of the operators also had an increase in crude oil production of 2.1 percent in 1992. The large independents, the 80 operators in production size class 21-100, accounted for most of the increase. These operators had a 21.4 percent increase in their oil production during the 1988-1992 period. A substantial portion of this increase came from property acquisitions. Size class 101-500 had a 16.9 percent increase in production of crude oil from 1988-1992.

Large operators produce oil and gas in a large number of fields. In 1992, the average top 10 operator was active in 351 fields. In aggregate, the top 10 had an operator field count of 3,514 (Table A5). Operators report field level information on Form EIA-23 if their production of crude oil exceeds 400,000 barrels per year or natural gas production exceeds 2 billion cubic feet per year, or both. During the 1988-1992 period, the operator field count dropped by 6,730, or 21.0 percent, while in 1992, it dropped 5.6 percent or 1,493 fields. For the top 10 operators during the 1988-1992 period, the operator field count dropped 51.2 percent. It dropped 17.8 percent in 1992.

Table A1. Natural Gas Proved Reserves, Wet After Lease Separation, by Operator Production Size Class, 1988-1992
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Size Class	1988	1989	1990	1991	1992	1991-1992 Volume and Percent Change	1988-1992 Volume and Percent Change	1992 Average Reserves per Operator (million cubic feet)
Class 1-10	84,140	80,608	80,373	77,393	74,350	-3,043	-9,790	7,434,985
Percent of Total	47.5%	45.9%	45.3%	44.1%	42.9%	-3.9%	-11.6%	
Class 11-20	20,045	23,883	26,809	26,861	28,442	1,581	8,397	2,844,156
Percent of Total	11.3%	13.6%	15.1%	15.3%	16.4%	5.9%	41.9%	
Class 21-100	40,368	37,802	36,468	38,415	38,417	2	-1,951	480,207
Percent of Total	22.8%	21.5%	20.5%	21.9%	22.2%	0.0%	-4.8%	
Class 101-500	18,807	19,239	19,535	19,345	18,268	-1,077	-539	228,347
Percent of Total	10.6%	11.0%	11.0%	11.0%	10.5%	-5.6%	-2.9%	
Class 501-2,500	8,068	7,740	7,885	7,245	7,468	223	-600	18,669
Percent of Total	4.6%	4.4%	4.4%	4.1%	4.3%	3.1%	-7.4%	
Class Other	5,570	6,157	6,506	6,066	6,366	300	796	3,183
Percent of Total	3.1%	3.5%	3.7%	3.5%	3.7%	4.9%	14.3%	
Category I	146,417	145,451	145,687	145,172	144,335	-837	-2,082	919,330
Percent of Total	82.7%	82.9%	82.0%	82.8%	83.3%	-0.6%	-1.4%	
Category II	16,694	15,502	17,602	16,219	16,020	-199	-674	33,375
Percent of Total	9.4%	8.8%	9.9%	9.3%	9.2%	-1.2%	-4.0%	
Category III	13,888	14,475	14,287	13,934	12,954	-980	-934	552
Percent of Total	7.8%	8.3%	8.0%	7.9%	7.5%	-7.0%	-6.7%	
Total Published	**176,999**	**175,428**	**177,576**	**175,325**	**173,309**	**-2,016**	**-3,690**	**7,189**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**-1.1%**	**-2.1%**	

Source: Energy Information Administration, Office of Oil and Gas

Table A2. Natural Gas Production, Wet After Lease Separation, by Operator Production Size Class, 1988-1992
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Class	1988	1989	1990	1991	1992	1991-1992 Volume and Percent Change	1988-1992 Volume and Percent Change	1992 Average Production per Operator (million cubic feet)
Class 1-10	7,131	7,030	6,904	6,808	6,626	-182	-505	662,607
Percent of Total	40.8%	39.6%	38.3%	37.8%	36.2%	-2.7%	-7.1%	
Class 11-20	2,344	2,545	2,815	2,902	3,057	155	713	305,660
Percent of Total	13.4%	14.[illegible]	15.6%	16.1%	16.7%	5.3%	30.4%	
Class 21-100	4,104	4,28[illegible]	4,371	4,408	4,595	187	491	57,439
Percent of Total	23.5%	24.1%	24.3%	24.5%	25.1%	4.2%	12.0%	
Class 101-500	2,357	2,369	2,460	2,390	2,422	32	65	30,271
Percent of Total	13.5%	13.3%	13.7%	13.3%	13.2%	1.3%	2.8%	
Class 501-2,500	1,022	971	920	960	977	17	-45	2,443
Percent of Total	5.9%	5.5%	5.1%	5.3%	5.3%	1.8%	-4.4%	
Class Other	508	550	533	544	627	82	119	314
Percent of Total	2.9%	3.1%	3.0%	3.0%	3.4%	1.5%	23.4%	
Category I	13,714	14,084	14,287	14,454	14,792	338	1,078	94,215
Percent of Total	78.5%	79.3%	79.4%	80.2%	80.8%	2.3%	7.9%	
Category II	2,264	2,081	2,249	2,156	2,033	-123	-231	4,234
Percent of Total	13.0%	11.7%	12.5%	12.0%	11.1%	-5.7%	-10.2%	
Category III	1,487	1,587	1,467	1,401	1,480	79	-7	63
Percent of Total	8.5%	8.9%	8.1%	7.8%	8.1%	5.6%	-0.5%	
Total Published	**17,466**	**17,752**	**18,003**	**18,012**	**18,304**	**292**	**838**	**759**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**1.6%**	**4.8%**	

Source Energy Information Administration, Office of Oil and Gas

Table A3. Crude Oil Proved Reserves by Operator Production Size Class, 1988-1992
(Million Barrels of 42 U.S. Gallons)

Class	1988	1989	1990	1991	1992	1991-1992 Volume and Percent Change	1988-1992 Volume and Percent Change	1992 Average Reserves per Operator (thousand barrels)
Class 1-10	19,466	19,085	18,639	16,825	15,733	-1,092	-3,733	1,573,300
Percent of Total	72.6%	72.0%	71.0%	68.2%	66.3%	-6.5%	-19.2%	
Class 11-20	2,438	2,398	1,892	2,247	2,250	3	-188	225,014
Percent of Total	9.1%	9.0%	7.2%	9.1%	9.5%	0.1%	-7.7%	
Class 21-100	1,615	1,735	2,329	2,265	2,370	105	755	29,622
Percent of Total	6.0%	6.5%	8.9%	9.2%	10.0%	4.6%	46.7%	
Class 101-500	1,236	1,295	1,397	1,434	1,469	35	233	18,368
Percent of Total	4.6%	4.9%	5.3%	5.8%	6.2%	2.4%	18.9%	
Class 501-2,500	1,168	1,096	1,212	1,133	1,108	-25	-60	2,769
Percent of Total	4.4%	4.1%	4.6%	4.6%	4.7%	-2.2%	-5.1%	
Class Other	902	893	785	779	815	36	-87	408
Percent of Total	3.4%	3.4%	3.0%	3.2%	3.4%	4.6%	-9.6%	
Category I	23,797	23,365	23,209	21,714	20,767	-947	-3,030	132,276
Percent of Total	88.7%	88.2%	88.4%	88.0%	87.5%	-4.4%	-12.7%	
Category II	1,057	1,056	1,057	1,099	1,142	43	85	2,379
Percent of Total	3.9%	4.0%	4.0%	4.5%	4.8%	3.9%	8.0%	
Category III	1,971	2,079	1,988	1,869	1,836	-33	-135	78
Percent of Total	7.3%	7.8%	7.6%	7.6%	7.7%	-1.8%	-6.8%	
Total Published	**26,825**	**26,501**	**26,254**	**24,682**	**23,745**	**-937**	**-3,080**	**985**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**-3.8%**	**-11.5%**	

Source: Energy Information Administration, Office of Oil and Gas

Table A4. Crude Oil Production by Operator Production Size Class, 1988-1992
(Million Barrels of 42 U.S. Gallons)

Class	1988	1989	1990	1991	1992	1991-1992 Volume and Percent Change	1988-1992 Volume and Percent Change	1992 Average Production per Operator (thousand barrels)
Class 1-10	1,833	1,683	1,574	1,544	1,458	-86	-375	145,825
Percent of Total	65.2%	65.1%	62.8%	61.5%	59.6%	-5.6%	-20.5%	
Class 11-20	255	235	215	218	231	13	-24	23,113
Percent of Total	9.1%	9.1%	8.6%	8.7%	9.4%	6.0%	-9.4%	
Class 21-100	224	227	244	257	272	15	48	3,406
Percent of Total	8.0%	8.8%	9.7%	10.2%	11.1%	5.8%	21.4%	
Class 101-500	183	175	195	211	214	3	31	2,677
Percent of Total	6.5%	6.8%	7.8%	8.4%	8.7%	1.4%	16.9%	
Class 501-2,500	173	159	165	169	153	-16	-20	383
Percent of Total	6.2%	6.1%	6.6%	6.7%	6.3%	-9.5%	-11.6%	
Class Other	142	107	112	113	117	4	-25	58
Percent of Total	5.1%	4.11	4.5%	4.5%	4.8%	3.5%	-17.6%	
Category I	2,346	2,159	2,075	2,068	2,022	-46	-324	12,879
Percent of Total	83.5%	83.5%	82.8%	82.3%	82.7%	-2.3%	-13.8%	
Category II	164	150	149	167	162	-5	-2	339
Percent of Total	5.5%	5.5%	5.6%	6.3%	6.6%	-3.0%	-1.2%	
Category III	301	277	281	277	262	-15	39	11
Percent of Total	10.1%	10.1%	10.6%	10.4%	10.7%	-5.4%	-13.0%	
Total Published	**2,811**	**2,586**	**2,505**	**2,512**	**2,446**	**-66**	**-365**	**101**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**-2.6%**	**-13.0%**	

Source Energy Information Administration, Office of Oil and Gas)

Table A5. Operator Field Count by Operator Production Size Class. 1988-1992

Class	1988	1989	1990	1991	1992	1991-1992 Number of Percent Change	1988-1992 Number of Percent Change	1992 Average Number of Fields per Class
Class 1-10	7,198	6,661	5,272	4,276	3,514	-762	-3,684	351
Percent of Total	22.4%	21.4%	19.1%	15.9%	13.9%	-17.8%	-51.2%	
Class 11-20	3,393	3,194	2,987	3,069	2,889	-180	-504	289
Percent of Total	10.6%	10.3%	10.8%	11.4%	11.4%	-5.9%	-14.9%	
Class 21-100	8,463	8,736	7,100	7,462	7,190	-272	-1,273	90
Percent of Total	26.4%	28.1%	25.8%	27.8%	28.4%	-3.6%	-15.0%	
Class 101-500	12,447	12,345	11,699	10,884	10,942	58	-1,505	27
Percent of Total	38.8%	39.7%	42.5%	40.6%	43.2%	0.5%	-12.1%	
Rest	1,833	1,314	1,628	1,725	1,951	226	118	14
Percent of Total	5.7%	4.2%	5.9%	6.4%	7.7%	13.1%	6.4%	
Category I	19,690	19,493	16,850	16,258	15,429	-829	-4,261	98
Percent of Total	61.4%	62.7%	61.2%	60.6%	60.9%	-5.1%	-21.6%	
Category II	12,381	11,583	10,701	10,576	9,912	-664	-2,469	20
Percent of Total	38.6%	37.3%	38.8%	39.4%	39.1%	-6.3%	-19.9%	
Total	**32,071**	**31,076**	**27,551**	**26,834**	**25,341**	**-1,493**	**-6,730**	**39**
Percent of Total	**100%**	**100%**	**100%**	**100%**	**100%**	**-5.60%**	**-21.00%**	

Note Includes only those operators who produced 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both, during the report year

Source Energy Information Administration, Office of Oil and Gas

Appendix B

Top 100 Oil and Gas Fields for 1991

Top 100 Oil and Gas Fields for 1991

For several years before 1980, the American Petroleum Institute published lists of the largest oil fields in its annual report.[26] Until 1992, the Energy Information Administration (EIA) had not produced a similar listing for either oil or gas fields. Such lists now appear as Tables B1 and B2 of this Appendix. They contain estimates of the proved reserves, cumulative production, and ultimate recovery of the top 100 oil and gas fields. The field name, location, year of discovery, and an estimate of 1991 annual production are also provided. Where two or more States are listed, the field name shown is that recognized by the first listed State, which also contains the largest part of the total hydrocarbons in the field. The additional States listed may recognize an alternative field name. A list of all U.S. oil and gas fields that cross State boundaries is included in the annual EIA report *Oil and Gas Field Code Master List*, published each year.

The top 100 field lists lag one year behind the report data on which this publication focuses. This lag reflects the analysis needed to estimate field totals beyond that which is associated with preparation of the annual reserves report. There were two difficulties encountered in constructing the lists. The first was that Form EIA-23 survey data, from which the National and State estimates are derived, do not always provide field totals, nor do they show the degree of field coverage attained by the survey. The second is that there is a significantly greater chance of releasing proprietary data when presenting field-by-field statistics, as compared to State and State Subdivision statistics.

The coverage problem was solved by using an EIA data base system, the Oil and Gas Integrated Field File (OGIFF) System. It matches fields reported in Form EIA-23 with two oil and gas data bases acquired from Dwight's Energydata, Inc., of Richardson, Texas. The measure of Form EIA-23 coverage for a given field is determined by comparing the volumes of oil and gas annual production available from each source. One of several methods of imputing the reserves associated with production missed by Form EIA-23 is carried out when necessary. The resultant total field reserves estimates are then subjected to small adjustments to force the field totals within a State to sum to those reported by EIA. The oil field production and reserves data include both crude oil and lease condensate. The gas field production and reserves data are wet, after lease separation.

The OGIFF data base system contained information on more than 45,000 fields in 1991. It is also being used in preparation of a series of special reports illustrating selected oil and gas distributions not found in the annual oil and gas reserves report. Three reports have already been published: *U.S. Oil and Gas Reserves by Year of Discovery* [25], *Geologic Distributions of U.S. Oil and Gas*[29], and *Largest U.S. Oil and Gas Fields*[28]. The latter publication is the newest in the series and was released in July 1993. This report identifies the largest one percent of U.S. oil and gas fields and their general location, year of discovery, and approximate national rankings in several size categories including proved (remaining and economically recoverable) reserves and annual production. The report also presents the proportions of the national crude oil and natural gas proved reserves and production that are attributable to the largest fields. Nearly two-thirds of the remaining domestic crude oil proved reserves are found in the largest 100 oil reserves fields. U.S. natural gas proved reserves are not nearly so concentrated, as 45 percent are contained in the top 100 gas reserves fields.

Table B1 shows the top 100 oil fields in the United States as of December 31, 1991. Although there is considerable grouping of field-level statistics within the tables, rough magnitudes can be estimated for the proved reserves, cumulative production, and ultimate recovery of most fields. Because many of the fields in the top 100 group are operated by only one or two operators, totals for proved reserves are grouped as top 10, top 20, top 50, and top 100 to avoid disclosing proprietary data. The top 100 oil fields accounted for 66 percent of total proved oil reserves and 53 percent of total oil production in the United States in 1991.

Table B2 shows the top 100 gas fields in the United States as of December 31, 1991. The top 100 gas fields show less concentration than the top 100 oil fields. Many, but not all, of the same fields are in both tables. As an example, the top gas field, Hugoton Gas Area, is not in the oil table. The top 100 gas fields accounted for 45 percent of total proved gas reserves and 28 percent of total gas production in the United States in 1991.

Table B3, Historical Production for the Top 100 Oil Fields 1982-1991, and Table B4, Historical Production for the Top 100 Natural Gas Fields 1982-1991 have been added this year. They reflect the production for the last 10 years for the same groups of fields shown in Tables B1 and B2.

While these are the 100 largest oil and gas fields in terms of 1991 proved reserves, their production was smaller than the production of the top 100 fields ranked by production. In Tables B3 and B4 there are 6 oil and 5 gas fields which had no production in 1991. In most cases their production started in 1992. The top 100 oil fields accounted for 53 percent of total oil production in the United States in 1991. The same group of fields accounted for 51 percent of the total oil production in 1982.

The top 100 gas fields accounted for 28 percent of total gas production in the United States in 1991. However, the same group of fields only accounted for 21 percent of the total gas production in 1982. Between 1982 and 1991, crude oil production in the 1991 top 100 oil fields dropped 11 percent. In contrast, natural gas production in the top 100 gas fields jumped 32 percent over the same period.

Table B1. Top 100 U.S. Oil[a] Fields as Ranked by Production within Proved Reserves Group, 1991
(Million Barrels of 42 U.S. Gallons)

Field Name	Location	Discovery Year	Proved Reserves 12/31/91 Rank Group	Annual Production Rank	Production Volume	Cumulative Recovery Rank	Ultimate Rank Group
Prudhoe Bay	AK	1967	1-10	1	478.7	1	1-10
Kuparuk River	AK	1969	1-10	2	113.4	17	1-10
Midway-Sunset	CA	1901	1-10	3	61.3	4	1-10
Belridge South	CA	1911	1-10	4	55.1	18	11-20
Kern River	CA	1899	1-10	5	44.7	8	1-10
Endicott	AK	1978	1-10	6	41.3	175	51-100
Elk Hills	CA	1919	1-10	8	26.4	13	11-20
Wasson	TX	1937	1-10	11	24.6	5	1-10
Yates	TX	1926	1-10	13	20.0	10	1-10
Slaughter	TX	1937	1-10	15	17.3	12	11-20
Top 10 Volume Subtotal			**9,765.7**		**882.7**	**17,789.5**	**27,555.2**
Top 10 Percentage of U.S. Total			**37.7%**		**32.6%**	**11.0%**	**14.6%**
East Texas	TX	1930	11-20	7	33.5	2	1-10
Wilmington	CA	1932	11-20	10	24.8	3	1-10
Spraberry Trend Area	TX	1950	11-20	14	19.6	27	11-20
Levelland	TX	1945	11-20	18	16.3	38	21-50
Cowden North	TX	1930	11-20	20	13.8	41	21-50
Rangely	CO	1902	11-20	21	12.8	21	11-20
Hondo	PF	1969	11-20	32	7.7	239	51-100
Point Arguello	PF	1981	11-20	52	5.5	> 1,000	101-200
Point McIntyre	AK	1988	11-20	-	0	-	101-200
Pescado	PF	1970	11-20	-	0	-	101-200
Top 20 Volume Subtotal			**11,971.8**		**1,016.7**	**27,981.4**	**39,953.2**
Top 20 Percentage of U.S. Total			**46.2%**		**37.6%**	**17.2%**	**21.2%**
Pearsall	TX	1924	21-50	9	26.3	226	101-200
Sho-Vel-Tum	OK	1905	21-50	16	16.5	7	1-10
Seminole	TX	1936	21-50	17	16.3	44	21-50
Bay Marchand Blk 2	GF & LA	1949	21-50	19	13.8	22	21-50
Coalinga	CA	1887	21-50	22	12.4	20	11-20
Cymric	CA	1916	21-50	23	10.4	115	51-100
Salt Creek	TX	1942	21-50	24	9.5	84	51-100
Vacuum	NM	1929	21-50	25	8.7	49	21-50
McElroy	TX	1926	21-50	26	8.4	34	21-50
Green Canyon Blk 65	GF	1983	21-50	27	8.2	> 1,000	301-400
South Pass SA Blk 89	GF	1969	21-50	28	8.2	246	101-200
Lost Hills	CA	1910	21-50	30	8.0	138	51-100
Fullerton	TX	1942	21-50	33	7.5	67	51-100
Milne Point	AK	1982	21-50	36	7.5	932	201-300
Mississippi Canyon Blk 194	GF	1975	21-50	42	6.3	216	101-200
Ventura	CA	1916	21-50	43	6.2	15	11-20
Howard-Glasscock	TX	1925	21-50	48	5.8	53	51-100
Robertson North	TX	1956	21-50	50	5.7	312	101-200
Greater Aneth	UT	1956	21-50	54	5.4	65	51-100
Prentice	TX	1950	21-50	57	5.3	160	101-200
Beta	PF	1976	21-50	68	4.2	486	101-200
Wasson 72	TX	1940	21-50	74	3.9	264	101-200
Huntington Beach	CA	1920	21-50	76	3.8	11	11-20
San Ardo	CA	1947	21-50	82	3.7	52	21-50
Elk Basin	WY & MT	1915	21-50	103	3.0	43	21-50
Main Pass SA Blk 299	GF	1967	21-50	110	2.8	414	201-300
Eunice Monument	NM	1929	21-50	146	2.2	64	51-100
Arroyo Grande	CA	1906	21-50	525	0.6	> 1,000	301-400
Garden Banks Blk 426	GF	1987	21-50	-	0	-	201-300
Viosca Knoll Blk 990	GF	1981	21-50	-	0	-	301-400
Top 50 Volume Subtotal			**14,934.3**		**1,237.2**	**38,489.4**	**53,423.7**
Top 50 Percentage of U.S. Total			**57.6%**		**45.7%**	**23.7%**	**28.4%**

Table B1. Top 100 U.S. Oil[a] Fields as Ranked by Production within Proved Reserves Group, 1991 (Continued)

(Million Barrels of 42 U.S. Gallons)

Field Name	Location	Discovery Year	Proved Reserves 12/31/91 Rank Group	Annual Production Rank	Production Volume	Cumulative Recovery Rank	Ultimate Rank Group
Giddings	TX	1960	51-100	12	20.9	103	51-100
High Island SA Blk A573	GF	1973	51-100	29	8.0	446	301-400
South Pass Blk 61	GF & LA	1955	51-100	34	7.5	140	101-200
Kelly-Snyder	TX	1948	51-100	35	7.5	9	11-20
McArthur River	AK	1965	51-100	38	7.4	40	21-50
Oregon Basin	WY	1912	51-100	39	6.7	54	51-100
Panhandle	TX	1910	51-100	41	6.6	6	1-10
Eugene Island SA Blk 330	GF	1971	51-100	44	6.0	77	51-100
West Delta Blk 30	GF	1949	51-100	45	6.0	47	21-50
Anschutz Ranch East	UT & WY	1979	51-100	46	5.9	277	201-300
Means	TX	1934	51-100	47	5.8	114	101-200
Hawkins	TX	1940	51-100	49	5.7	19	21-50
Hobbs	NM	1928	51-100	51	5.6	74	51-100
South Marsh Is SA Blk 130	GF	1973	51-100	53	5.4	191	101-200
Goldsmith	TX	1935	51-100	55	5.4	26	21-50
Tom OConnor	TX	1934	51-100	56	5.3	24	21-50
Point Pedernales	PF	1983	51-100	59	5.0	807	401-500
Stephens County Regular	TX	1915	51-100	60	5.0	100	51-100
Hartzog Draw	WY	1976	51-100	71	4.1	352	201-300
Jay	FL & AL	1970	51-100	73	3.9	51	51-100
Port Hudson	LA	1977	51-100	78	3.8	636	401-500
Salt Creek	WY	1889	51-100	81	3.8	30	21-50
Bluebell	UT	1949	51-100	84	3.7	221	101-200
Dollarhide	TX & NM	1945	51-100	89	3.4	106	51-100
Wattenberg	CO	1970	51-100	90	3.3	913	301-400
South Pass Blk 27	GF & LA	1954	51-100	98	3.1	66	51-100
Dos Cuadras	PF	1968	51-100	100	3.1	118	101-200
Foster	TX	1932	51-100	101	3.1	91	51-100
Welch	TX	1942	51-100	108	2.9	190	101-200
Pennel	MT	1955	51-100	109	2.8	353	201-300
Belridge North	CA	1912	51-100	117	2.7	299	201-300
Kern Front	CA	1925	51-100	119	2.7	156	101-200
Middle Ground Shoal	AK	1963	51-100	120	2.7	170	101-200
Anton-Irish	TX	1944	51-100	121	2.7	153	101-200
Chunchula	AL	1974	51-100	127	2.5	525	301-400
Cedar Lake	TX	1939	51-100	128	2.5	333	201-300
Mabee	TX	1944	51-100	138	2.3	295	201-300
Granite Point	AK	1965	51-100	155	2.1	237	201-300
Brea-Olinda	CA	1897	51-100	193	1.7	58	51-100
Maljamar	NM	1926	51-100	213	1.6	111	101-200
McKittrick	CA	1887	51-100	224	1.5	88	51-100
T X L	TX	1944	51-100	237	1.4	92	51-100
Cat Canyon	CA	1909	51-100	254	1.3	81	51-100
Pegasus	TX	1949	51-100	272	1.2	189	101-200
Placerita	CA	1920	51-100	389	0.8	545	301-400
Drinkard	NM	1944	51-100	565	0.5	329	201-300
Monument	NM	1935	51-100	> 1,000	0.2	127	101-200
Mississippi Canyon Blk 109	GF	1984	51-100	> 1,000	0.1	> 1,000	801-900
Ewing Bank Blk 873	GF	1991	51-100	-	0	-	501-600
Niakuk	AK	1984	51-100	-	0	-	501-600
Top 100 Volume Subtotal			**17,063.5**		**1,434.2**	**52,329.8**	**69,393.3**
Top 100 Percentage of U.S. Total			**65.8%**		**53.0%**	**32.2%**	**36.9%**

[a]Includes lease condensate.

– = Not Applicable.

Note: Fields are grouped in "proved reserves rank groups" and then listed within that group in ascending order by National 1991 annual production rank. The U.S. total production estimate in this table is from the official Energy Information Administration production data for crude oil and lease condensate for 1991 contained in the *Petroleum Supply Annual 1991*, DOE/EIA-0340(91). They differ from the U.S. total data reported in this publication.

Source: Energy Information Administration, Office of Oil and Gas.

Table B2. Top 100 U.S. Gas[a] Fields as Ranked by Production within Proved Reserves Group, 1991

(Billion Cubic Feet)

Field Name	Location	Discovery Year	Proved Reserves 12/31/91 Rank Group	Annual Production Rank	Annual Production Volume	Cumulative Production Rank	Ultimate Recovery Rank Group
Hugoton Gas Area	KS & OK & TX	1922	1-10	1	516.8	1	1-10
Basin	NM	1947	1-10	2	305.7	9	1-10
Blanco	NM & CO	1927	1-10	3	238.7	4	1-10
Prudhoe Bay	AK	1967	1-10	4	206.3	70	1-10
Carthage	TX	1936	1-10	5	171.3	5	1-10
Panhandle West	TX	1918	1-10	6	164.4	2	1-10
Mocane-Laverne Gas Area	OK & KS & TX	1946	1-10	7	145.0	7	1-10
Panoma Gas Area	KS	1956	1-10	9	108.8	52	21-50
Wattenberg	CO	1970	1-10	14	87.7	157	51-100
Red Oak-Norris	OK	1910	1-10	21	68.2	91	21-50
Top 10 Volume Subtotal			**39,770.3**		**2,012.7**	**92,899.0**	**132,669.3**
Top 10 Percentage of U.S. Total			**22.7%**		**10.8%**	**11.4%**	**13.4%**
Watonga-Chickasha Trend	OK	1948	11-20	8	131.8	13	11-20
Gomez	TX	1963	11-20	15	86.2	12	11-20
McArthur River	AK	1965	11-20	26	61.2	280	101-200
Cook Inlet North	AK	1962	11-20	38	44.7	125	51-100
Elk Hills	CA	1919	11-20	39	43.8	106	51-100
Beluga River	AK	1962	11-20	49	38.5	343	51-100
Fogarty Creek	WY	1975	11-20	79	31.4	821	101-200
Lake Ridge	WY	1981	11-20	281	12.5	> 1,000	101-200
Northwest Gulf	AL & GF	1983	11-20	> 1,000	2.7	> 1,000	101-200
North Central Gulf	AL & GF	1985	11-20	-	0.0	-	201-300
Top 20 Volume Subtotal			**48,495.6**		**2,465.5**	**104,535.9**	**153,031.5**
Top 20 Percentage of U.S. Total			**27.7%**		**13.2%**	**12.9%**	**15.5%**
Wilburton	OK	1941	21-50	10	103.9	86	51-100
Whitney Canyon-Carter Crk	WY	1978	21-50	11	100.9	150	51-100
Kinta	OK	1914	21-50	12	94.1	38	21-50
McAllen Ranch	TX	1960	21-50	16	81.6	113	51-100
Lake Arthur South	LA	1955	21-50	17	80.1	270	101-200
Coyanosa	TX	1959	21-50	18	79.0	48	21-50
Headlee	TX	1953	21-50	22	67.3	54	21-50
Spraberry Trend Area	TX	1950	21-50	24	61.9	68	51-100
Boonsville	TX	1945	21-50	27	58.0	27	21-50
Vermilion Blk 14	GF & LA	1956	21-50	28	57.2	16	11-20
Elk City	OK	1947	21-50	32	50.5	112	51-100
Oak Hill	TX	1958	21-50	33	49.0	278	101-200
Sawyer	TX	1960	21-50	37	45.4	182	51-100
Brown-Bassett	TX	1953	21-50	42	43.5	58	51-100
Big Sandy	KY	1881	21-50	46	39.3	64	51-100
LaBarge	WY	1924	21-50	52	38.0	456	201-300
Lower Mobile Bay-Mary Ann	AL	1979	21-50	100	26.2	> 1,000	201-300
Natural Buttes	UT	1940	21-50	116	23.4	438	201-300
Madden	WY	1968	21-50	131	21.4	408	101-200
Wasson	TX	1937	21-50	143	19.9	93	51-100
Lisbon	UT	1960	21-50	146	19.7	391	101-200
Hondo	PF	1969	21-50	183	16.7	> 1,000	201-300
Mississippi Canyon Blk 194	GF	1975	21-50	286	12.3	499	201-300
Blanco South	NM	1951	21-50	288	12.2	110	51-100
Anschutz Ranch East	UT & WY	1979	21-50	467	8.2	> 1,000	201-300
Fairway	AL	1986	21-50	> 1,000	3.4	> 1,000	201-300
Gurnee Coal Degas	AL	1990	21-50	> 1,000	0.7	> 1,000	201-300
Bon Secour Bay	AL	1983	21-50	-	0.0	-	201-300
Garden Banks Blk 426	GF	1987	21-50	-	0.0	-	301-400
Green Canyon Blk 116	GF	1983	21-50	-	0.0	-	301-400
Top 50 Volume Subtotal			**64,839.8**		**3,679.2**	**131,021.7**	**195,861.4**
Top 50 Percentage of U.S. Total			**37.0%**		**19.7%**	**16.1%**	**19.8%**

Table B2. Top 100 U.S. Gas[a] Fields as Ranked by Production within Proved Reserves Group, 1991 (Continued)
(Billion Cubic Feet)

Field Name	Location	Discovery Year	Proved Reserves 12/31/91 Rank Group	Annual Production Rank	Annual Production Volume	Cumulative Production Rank	Ultimate Recovery Rank Group
Giddings	TX	1960	51-100	13	92.1	88	51-100
Tiger Shoal	GF	1958	51-100	19	77.7	23	11-20
Golden Trend	OK	1945	51-100	20	68.6	8	1-10
La Perla Ranch	TX	1976	51-100	23	63.6	447	301-400
Sooner Trend	OK	1938	51-100	25	61.7	10	11-20
South Timbalier Blk 172	GF	1965	51-100	29	56.3	73	51-100
Matagorda Island Blk 668	GF	1981	51-100	30	55.4	238	101-200
Strong City District	OK	1966	51-100	31	50.6	338	201-300
High Island SA Blk A573	GF	1973	51-100	36	46.3	334	201-300
Puckett	TX	1952	51-100	41	43.6	14	11-20
Matagorda Island Blk 623	GF	1980	51-100	47	38.9	591	201-300
Sho-Vel-Tum	OK	1905	51-100	50	38.4	122	101-200
Chalkley	LA	1938	51-100	57	37.7	321	101-200
Cheyenne West	OK	1971	51-100	59	37.1	275	201-300
Ozona	TX	1953	51-100	60	35.9	196	101-200
Indian Basin	NM	1963	51-100	61	35.8	80	51-100
Eumont	NM	1929	51-100	62	35.5	47	21-50
High Island SA Blk A571	GF	1974	51-100	63	34.7	295	201-300
Ship Shoal Blk 176	GF	1956	51-100	64	34.5	79	51-100
Port Hudson	LA	1977	51-100	65	34.5	448	301-400
Waskom	TX & LA	1916	51-100	67	33.1	63	51-100
Bruff	WY	1974	51-100	69	32.9	765	301-400
Carpenter	OK	1951	51-100	70	32.8	435	201-300
Reydon	OK	1962	51-100	73	32.1	212	101-200
Panhandle	TX	1910	51-100	75	31.6	49	21-50
Eugene Island SA Blk 330	GF	1971	51-100	78	31.4	67	51-100
Conger	TX	1973	51-100	83	31.0	329	201-300
Panola South	OK	1990	51-100	84	30.3	> 1,000	401-500
Garden Banks Blk 236	GF	1977	51-100	91	28.3	> 1,000	301-400
Kuparuk River	AK	1969	51-100	95	27.2	680	201-300
South Pass SA Blk 89	GF	1969	51-100	98	26.5	694	201-300
Main Pass Blk 41	GF	1956	51-100	106	25.5	115	101-200
Opelika	TX	1937	51-100	124	22.3	95	51-100
Laredo	TX	1973	51-100	125	22.3	224	101-200
Painter Reservoir	WY	1977	51-100	129	21.9	674	301-400
Rosita NW	TX	1976	51-100	133	21.2	839	401-500
Fresh Water Bayou North	LA	1958	51-100	138	20.3	251	201-300
Bryans Mill	TX	1960	51-100	187	16.3	271	201-300
Cedar Cove Coal Degas	AL	1983	51-100	204	15.6	> 1,000	601-700
Willow Springs	TX	1938	51-100	223	14.6	162	101-200
Oak Grove Coal Degas	AL	1980	51-100	232	14.2	> 1,000	501-600
Tri-Cities	TX	1941	51-100	386	9.8	418	301-400
Lake Pagie	LA	1958	51-100	396	9.6	94	51-100
Anahuac	TX	1935	51-100	445	8.5	192	101-200
Whelan	TX	1937	51-100	642	5.8	493	301-400
Bowdoin	MT	1917	51-100	846	4.4	> 1,000	401-500
Pegasus	TX	1949	51-100	854	4.3	384	201-300
Big Piney-LaBarge	WY	1924	51-100	989	3.6	99	51-100
Robinsons Bend Coal Degas	AL	1985	51-100	> 1,000	1.1	> 1,000	501-600
Mississippi Canyon Blk 397	GF	1984	51-100	-	0.0	-	501-600
Top 100 Volume Subtotal			**79,348.2**		**5,236.7**	**175,836.8**	**255,185.0**
Top 100 Percentage of U.S. Total			**45.3%**		**28.0%**	**21.6%**	**25.8%**

[a]Wet after lease separation.

– = Not Applicable.

Note: Fields are grouped in "proved reserves rank groups" and then listed within that group in ascending order by National 1991 annual production rank. The U.S. total production estimate in this table is from the official Energy Information Administration production data for natural gas for 1991 contained in the *Natural Gas Annual 1991*, DOE/EIA-0131(91). They differ from the U.S. total data reported in this publication.

Source: Energy Information Administration, Office of Oil and Gas.

Table B3. Annual Production, 1982-1991, for the Top 100 U.S. Oil[a] Fields in 1991
(Million Barrels of 42 U.S. Gallons)

State	Field Name	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
AK	Prudhoe Bay	559.1	560.9	563.1	571.7	566.2	588.2	574.5	519.0	484.6	478.7
AK	Kuparuk River	32.4	39.9	46.2	79.2	93.9	102.4	110.9	110.1	107.2	113.4
CA	Midway-Sunset	45.6	47.5	50.9	55.1	56.7	57.7	57.9	56.6	59.1	61.3
CA	Belridge South	66.0	73.1	89.3	55.2	60.9	63.6	60.3	56.8	54.4	55.1
CA	Kern River	44.9	48.3	49.4	51.7	47.7	45.7	47.3	45.2	44.1	44.7
AK	Endicott	-	-	-	-	-	8.8	37.4	36.1	37.7	41.3
CA	Elk Hills	59.3	55.2	49.3	46.6	39.7	40.3	38.1	34.0	28.7	26.4
TX	Wasson	47.0	41.3	35.5	30.8	29.0	28.4	27.8	27.1	25.6	24.6
TX	Yates	45.7	45.5	45.9	44.6	41.4	35.8	32.7	27.3	21.9	20.0
TX	Slaughter	26.7	25.0	24.6	22.8	20.8	20.1	19.9	18.8	17.7	17.3
Top 10 Volume Subtotal		**926.7**	**936.8**	**954.0**	**957.6**	**956.3**	**991.0**	**1,006.8**	**931.0**	**881.0**	**882.7**
Top 10 Percentage of U.S. Total		**29.1%**	**29.1%**	**28.9%**	**29.4%**	**30.1%**	**32.7%**	**33.8%**	**33.6%**	**32.8%**	**32.6%**
TX	East Texas	52.9	51.0	49.1	46.9	44.4	41.7	39.5	37.2	35.6	33.5
CA	Wilmington	68.7	69.8	74.8	41.6	36.6	32.2	29.4	27.3	25.9	24.8
TX	Spraberry Trend Area	17.1	17.6	19.9	21.4	21.5	20.3	20.4	19.1	18.7	19.6
TX	Levelland	19.1	18.9	19.0	18.6	18.1	17.3	17.0	16.7	16.8	16.3
TX	Cowden North	14.1	13.9	13.8	13.9	13.7	14.1	14.7	14.5	13.7	13.8
CO	Rangely	15.0	13.9	13.4	12.2	11.4	12.1	12.4	12.0	12.5	12.8
PF	Hondo	11.9	13.2	11.1	12.0	11.1	9.6	9.9	8.7	8.2	7.7
PF	Point Arguello	-	-	-	-	-	0.1	-	-	-	5.5
AK	Point Mcintyre	-	-	-	-	-	-	-	-	-	-
PF	Pescado	-	-	-	-	-	-	-	-	-	-
Top 20 Volume Subtotal		**1,125.5**	**1,135.1**	**1,155.1**	**1,124.2**	**1,113.1**	**1,138.4**	**1,150.1**	**1,066.4**	**1,012.4**	**1,016.7**
Top 20 Percentage of U.S. Total		**35.4%**	**35.3%**	**35.0%**	**34.5%**	**35.0%**	**37.5%**	**38.6%**	**38.5%**	**37.7%**	**37.6%**
TX	Pearsall	3.7	2.8	2.4	2.2	2.2	1.8	1.6	2.5	22.6	26.3
OK	Sho-Vel-Tum	19.2	20.5	19.9	19.5	18.7	18.0	18.7	17.5	17.0	16.5
TX	Seminole	18.3	14.6	12.6	12.9	13.8	14.5	15.2	15.9	16.4	16.3
GF/LA	Bay Marchand Blk 2	12.0	10.7	9.1	9.1	9.6	9.3	9.8	8.8	13.1	13.8
CA	Coalinga	8.8	9.6	10.1	11.4	11.4	10.4	10.0	10.7	11.6	12.4
CA	Cymric	4.5	5.1	5.7	6.4	7.0	7.2	8.8	8.9	9.0	10.4
TX	Salt Creek	7.9	7.4	7.1	6.9	7.3	9.1	10.7	10.5	10.0	9.5
NM	Vacuum	14.0	16.2	15.4	13.9	11.5	10.6	10.2	9.4	9.1	8.7
TX	McElroy	9.9	9.6	9.4	9.2	8.5	7.9	7.7	7.5	8.1	8.4
GF	Green Canyon Blk 65	-	-	-	-	-	-	-	0.9	4.7	8.2
GF	South Pass SA Blk 89	2.5	5.9	10.1	13.5	17.8	13.8	16.6	11.2	9.3	8.2
CA	Lost Hills	6.6	5.8	5.2	5.0	4.7	5.2	5.5	6.0	6.6	8.0
TX	Fullerton	7.1	6.6	6.8	7.7	7.9	7.1	7.6	7.8	7.9	7.5
AK	Milne Point	-	-	-	0.7	4.7	-	-	3.7	6.6	7.5
GF	Mississippi Canyon Blk 194	13.1	26.1	20.0	18.2	12.9	8.5	4.9	2.4	0.0	6.3
CA	Ventura	7.2	7.3	7.4	7.4	7.5	7.3	7.0	6.5	6.5	6.2
TX	Howard-Glasscock	6.0	6.0	5.9	5.7	5.9	5.9	5.7	5.6	6.0	5.8
TX	Robertson North	4.5	4.7	4.7	4.4	4.1	4.1	4.7	5.3	5.6	5.7
UT	Greater Aneth	6.1	5.9	6.1	6.4	5.8	5.3	5.3	5.4	5.7	5.4
TX	Prentice	3.7	3.6	4.0	4.5	5.0	5.6	5.7	5.3	5.0	5.3
PF	Beta	3.2	3.9	5.2	6.2	7.0	6.6	6.0	5.6	5.3	4.2
TX	Wasson 72	1.3	1.6	2.3	3.3	4.1	4.0	4.1	3.9	3.9	3.9
CA	Huntington Beach	10.1	9.0	8.7	8.1	7.1	6.0	5.5	4.8	3.8	3.8
CA	San Ardo	9.4	8.1	7.7	8.1	6.9	4.9	4.6	3.8	4.1	3.7
WY/MT	Elk Basin	4.2	4.2	3.9	3.9	3.7	3.5	3.5	3.4	3.2	3.0
GF	Main Pass SA Blk 299	2.4	1.9	1.7	1.5	1.4	2.0	2.1	2.3	2.6	2.8
NM	Eunice Monument	2.8	2.9	3.0	2.8	2.7	2.4	2.3	2.3	2.3	2.2
CA	Arroyo Grande	0.5	0.3	0.3	0.3	0.2	0.2	0.3	0.4	0.5	0.6
GF	Garden Banks Blk 426	-	-	-	-	-	-	-	-	-	-
GF	Viosca Knoll Blk 990	-	-	-	-	-	-	-	-	-	-
Top 50 Volume Subtotal		**1,314.3**	**1,335.3**	**1,349.7**	**1,323.3**	**1,312.4**	**1,319.4**	**1,334.1**	**1,244.6**	**1,218.9**	**1,237.2**
Top 50 Percentage of U.S. Total		**41.3%**	**41.5%**	**40.9%**	**40.6%**	**41.3%**	**43.5%**	**44.7%**	**45.0%**	**45.3%**	**45.7%**

Table B3. Annual Production, 1982-1991, for the Top 100 U.S. Oil[a] Fields in 1991 (Continued)
(Million Barrels of 42 U.S. Gallons)

State	Field Name	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
TX	Giddings	34.0	23.6	21.2	18.8	13.9	10.3	9.3	8.9	10.5	20.9
GF	High Island SA Blk A573	2.6	2.5	3.7	3.9	4.8	6.1	7.3	8.7	7.3	8.0
GF/LA	South Pass Blk 61	12.7	10.6	11.9	12.0	12.8	9.3	8.5	4.9	5.2	7.5
TX	Kelly-Snyder	23.2	22.1	19.8	17.7	14.6	12.0	10.8	9.7	8.6	7.5
AK	McArthur River	15.8	13.6	11.8	7.5	8.0	7.4	7.1	7.0	4.3	7.4
WY	Oregon Basin	9.9	9.7	9.2	9.7	10.0	9.1	8.5	7.9	7.2	6.7
TX	Panhandle	9.8	9.4	10.4	9.9	8.7	8.0	7.7	7.2	6.8	6.6
GF	Eugene Island SA Blk 330	11.5	10.5	11.3	10.7	10.5	9.1	8.0	7.5	6.1	6.0
GF	West Delta Blk 30	8.7	8.1	10.3	9.6	8.4	7.1	6.6	5.6	5.7	6.0
UT/WY	Anschutz Ranch East	0.7	8.6	11.2	14.5	15.8	14.5	12.1	9.1	7.7	5.9
TX	Means	4.1	3.8	4.8	6.3	6.4	6.5	6.4	6.0	6.1	5.8
TX	Hawkins	11.9	10.7	11.1	11.4	11.0	9.5	8.0	6.8	6.3	5.8
NM	Hobbs	3.9	4.8	6.0	6.6	7.0	7.9	7.9	7.3	6.4	5.6
GF	South Marsh Is SA Blk 130	13.4	13.3	9.7	10.2	12.2	11.1	8.4	6.5	4.8	5.4
TX	Goldsmith	8.1	7.8	7.9	7.4	6.8	6.3	6.0	5.7	5.5	5.4
TX	Tom OConnor	17.8	17.2	16.7	15.6	13.4	9.2	7.3	6.6	5.8	5.3
PF	Point Pedernales	-	-	-	-	-	4.7	6.2	7.3	5.5	5.0
TX	Stephens County Regular	4.4	4.8	5.5	6.3	6.5	6.1	5.9	5.4	5.3	5.0
WY	Hartzog Draw	2.5	2.7	3.5	5.2	6.5	6.8	6.3	5.6	4.7	4.1
FL/AL	Jay	19.9	15.2	10.6	8.5	7.6	6.8	6.4	6.1	4.8	3.9
LA	Port Hudson	3.6	2.8	3.1	2.1	2.1	3.5	4.2	4.5	4.2	3.8
WY	Salt Creek	5.5	6.0	5.7	6.1	5.9	5.0	5.1	4.5	4.3	3.8
UT	Bluebell	4.4	5.0	6.2	5.7	4.7	4.4	4.0	3.6	3.8	3.7
TX/NM	Dollarhide	2.8	2.5	2.6	2.6	2.6	2.7	3.4	3.2	3.2	3.4
CO	Wattenberg	0.5	0.7	1.3	2.1	2.7	2.8	2.7	2.5	2.7	3.3
GF/LA	South Pass Blk 27	5.2	5.1	5.1	4.6	4.8	4.3	3.6	3.8	3.1	3.1
PF	Dos Cuadras	6.7	6.4	5.9	5.5	5.1	4.7	4.5	3.9	3.4	3.1
TX	Foster	6.0	5.5	5.0	4.6	4.3	4.0	3.9	3.6	3.4	3.1
TX	Welch	3.3	3.2	3.4	3.4	3.2	3.0	3.0	3.0	3.0	2.9
MT	Pennel	3.1	3.1	3.4	3.6	3.2	3.0	3.0	2.9	2.8	2.8
CA	Belridge North	1.2	1.5	1.1	1.3	1.8	2.4	3.6	2.5	2.8	2.7
CA	Kern Front	2.5	2.5	2.8	2.8	2.2	1.7	1.5	1.7	2.3	2.7
AK	Middle Ground Shoal	3.6	3.4	3.2	3.1	3.2	2.9	2.8	2.8	2.7	2.7
TX	Anton-Irish	6.0	5.2	5.0	4.8	4.4	4.0	3.6	3.2	3.0	2.7
AL	Chunchula	4.2	3.9	3.6	3.9	3.8	3.6	3.2	2.9	2.6	2.5
TX	Cedar Lake	1.6	1.5	1.4	1.2	1.2	1.2	1.7	2.3	2.4	2.5
TX	Mabee	3.7	3.2	2.7	2.6	2.5	2.3	2.5	2.7	2.8	2.3
AK	Granite Point	3.5	3.6	3.3	3.1	3.2	2.8	2.7	2.3	1.5	2.1
CA	Brea-Olinda	2.8	2.6	2.6	2.5	2.4	2.3	2.1	1.9	1.9	1.7
NM	Maljamar	2.4	2.4	2.2	2.0	1.9	1.8	1.9	1.8	1.7	1.6
CA	McKittrick	4.8	4.5	4.2	4.1	3.6	2.9	2.5	1.9	1.6	1.5
TX	T X L	1.5	1.5	1.4	1.7	2.0	1.7	1.9	1.6	1.5	1.4
CA	Cat Canyon	5.1	5.1	5.0	4.7	3.4	3.1	2.4	1.5	1.3	1.3
TX	Pegasus	1.8	1.6	1.5	1.3	1.5	1.5	1.3	1.2	1.1	1.2
CA	Placerita	0.4	0.5	0.5	0.5	0.4	0.5	0.9	0.6	0.7	0.8
NM	Drinkard	0.9	0.8	0.8	0.8	0.8	0.7	0.7	0.6	0.6	0.5
TX	Monument	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
GF	Mississippi Canyon Blk 109	-	-	-	-	-	-	-	-	-	0.1
GF	Ewing Bank Blk 873	-	-	-	-	-	-	-	-	-	-
AK	Niakuk	-	-	-	-	-	-	-	-	-	-
Top 100 Volume Subtotal		**1,616.6**	**1,618.7**	**1,629.7**	**1,595.8**	**1,574.3**	**1,560.2**	**1,561.6**	**1,451.6**	**1,407.6**	**1,434.2**
Top 100 Percentage of U.S. Total		**50.8%**	**50.4%**	**49.4%**	**49.0%**	**49.6%**	**51.4%**	**52.4%**	**52.5%**	**52.4%**	**53.0%**

[a]Includes lease condensate.

– = Not Applicable.

Note: Fields are grouped in "proved reserves rank groups" and then listed within that group in ascending order by National 1991 annual production rank. The U.S. total production estimates in this table for 1982 through 1991 are from the official Energy Information Administration production data for crude oil and lease condensate for 1982 through 1991 contained in the *Petroleum Supply Annual*, DOE/EIA-0340. They differ from the U.S. total data reported in this publication.

Source: Energy Information Administration, Office of Oil and Gas.

Table B4. Annual Production, 1982-1991, for the Top 100 U.S. Natural Gas[a] Fields in 1991
(Billion Cubic Feet)

State	Field Name	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
KS/OK/TX	Hugoton Gas Area	328.0	341.1	410.4	426.3	396.6	369.4	468.8	483.2	461.0	516.8
NM	Basin	144.9	75.3	135.9	134.5	88.5	116.6	108.1	102.4	229.7	305.7
NM/CO	Blanco	248.6	201.3	225.9	219.9	174.9	225.4	204.1	216.1	240.0	238.7
AK	Prudhoe Bay	59.4	65.1	78.1	91.7	53.3	131.8	166.4	171.1	174.2	206.3
TX	Carthage	82.6	74.5	99.5	98.1	95.8	93.1	83.8	118.0	163.9	171.3
TX	Panhandle West	246.2	211.6	207.7	170.2	132.4	128.0	146.2	157.3	158.4	164.4
OK/KS/TX	Mocane-Laverne Gas Area	118.2	106.0	123.1	118.9	93.7	108.7	130.6	141.1	149.4	145.0
KS	Panoma Gas Area	67.9	59.3	68.7	83.7	84.8	68.7	88.5	87.8	92.8	108.8
CO	Wattenberg	40.3	25.2	37.3	44.7	47.3	53.5	62.8	62.8	74.2	87.7
OK	Red Oak-Norris	25.4	22.1	28.7	21.0	19.6	47.2	75.8	65.1	66.4	68.2
Top 10 Volume Subtotal		**1,361.7**	**1,181.5**	**1,415.5**	**1,409.0**	**1,186.9**	**1,342.4**	**1,535.1**	**1,604.8**	**1,810.0**	**2,012.7**
Top 10 Percentage of U.S. Total		**7.3%**	**7.0%**	**7.7%**	**8.1%**	**7.0%**	**7.6%**	**8.5%**	**8.8%**	**9.7%**	**10.8%**
OK	Watonga-Chickasha Trend	142.3	162.8	170.6	160.0	169.2	164.7	154.8	157.0	141.9	131.8
TX	Gomez	88.2	85.6	83.9	70.7	69.1	71.8	98.6	93.3	93.7	86.2
AK	McArthur River	16.2	14.4	15.1	10.7	13.6	13.3	16.7	31.0	51.5	61.2
AK	Cook Inlet North	45.4	47.9	47.0	45.8	43.8	42.9	45.0	45.3	45.0	44.7
CA	Elk Hills	68.6	67.9	68.7	73.4	63.3	63.5	60.6	61.5	49.1	43.8
AK	Beluga River	18.7	18.1	19.8	22.6	25.4	24.0	25.6	30.1	39.5	38.5
WY	Fogarty Creek	0.3	0.3	0.2	0.1	7.0	25.6	23.8	30.3	31.2	31.4
WY	Lake Ridge	-	-	-	-	0.6	10.7	10.0	10.0	9.8	12.5
AL/GF	Northwest Gulf	-	-	-	-	-	-	-	-	-	2.7
AL/GF	North Central Gulf	-	-	-	-	-	-	-	-	-	-
Top 20 Volume Subtotal		**1,741.3**	**1,578.5**	**1,820.7**	**1,792.3**	**1,578.9**	**1,758.8**	**1,970.1**	**2,063.3**	**2,271.7**	**2,465.5**
Top 20 Percentage of U.S. Total		**9.3%**	**9.3%**	**9.9%**	**10.3%**	**9.3%**	**10.0%**	**10.9%**	**11.3%**	**12.1%**	**13.2%**
OK	Wilburton	23.8	21.8	20.6	20.0	20.2	36.3	68.3	112.9	130.1	103.9
WY	Whitney Canyon-Carter Creek	7.0	97.7	67.7	112.7	89.8	99.8	100.1	112.3	58.4	100.9
OK	Kinta	49.8	38.6	48.9	44.0	45.7	62.6	71.9	82.0	89.0	94.1
TX	McAllen Ranch	21.6	22.2	18.9	36.5	46.9	67.2	72.0	58.4	63.6	81.6
LA	Lake Arthur South	2.3	3.3	5.3	7.3	9.1	30.3	72.9	88.2	82.9	80.1
TX	Coyanosa	48.6	42.2	9.0	7.0	9.2	10.0	8.2	4.4	25.6	79.0
TX	Headlee	69.0	67.7	66.9	66.9	69.4	68.7	69.8	69.6	69.0	67.3
TX	Spraberry Trend Area	50.3	52.8	57.4	62.7	65.3	65.9	64.1	61.5	60.7	61.9
TX	Boonsville	77.5	72.8	76.0	79.6	75.0	58.6	66.9	61.1	61.2	58.0
GF/LA	Vermilion Blk 14	201.2	108.3	93.6	95.7	71.9	72.2	66.1	55.1	57.8	57.2
OK	Elk City	51.8	45.6	51.9	63.8	74.1	62.2	49.0	59.1	57.6	50.5
TX	Oak Hill	32.0	39.2	39.3	29.6	38.1	36.3	43.7	39.1	46.6	49.0
TX	Sawyer	32.1	30.1	31.8	40.1	33.6	33.3	34.8	36.5	39.7	45.4
TX	Brown-Bassett	34.4	30.5	35.1	31.1	8.7	18.4	24.8	33.6	36.1	43.5
KY	Big Sandy	25.9	27.7	31.2	31.6	32.6	35.4	32.4	34.9	37.4	39.3
WY	LaBarge	10.3	8.6	8.7	6.1	15.4	25.7	27.3	25.5	37.8	38.0
AL	Lower Mobile Bay-Mary Ann	-	-	-	-	-	-	9.3	14.1	21.3	26.2
UT	Natural Buttes	23.9	20.4	26.2	21.3	20.9	17.7	17.4	19.0	22.7	23.4
WY	Madden	17.8	12.7	14.1	11.3	11.7	21.5	15.1	19.0	21.8	21.4
TX	Wasson	30.1	26.9	24.4	24.5	21.9	21.0	19.7	27.9	19.2	19.9
UT	Lisbon	1.6	1.6	1.4	1.5	1.4	0.7	1.6	1.9	20.8	19.7
PF	Hondo	0.6	0.8	5.5	9.6	14.8	11.2	11.0	10.7	9.6	16.7
GF	Mississippi Canyon Blk 194	15.5	40.8	32.1	30.6	34.2	35.0	21.1	8.8	0.0	12.3
NM	Blanco South	19.4	18.0	18.4	18.7	7.9	9.4	14.7	15.4	14.5	12.2
UT/WY	Anschutz Ranch East	1.4	5.7	9.0	11.7	14.7	8.3	0.1	6.3	5.7	8.2
AL	Fairway	-	-	-	-	-	-	-	-	-	3.4
AL	Gurnee Coal Degas	-	-	-	-	-	-	-	-	0.3	0.7
AL	Bon Secour Bay	-	-	-	-	-	-	-	-	-	-
GF	Garden Banks Blk 426	-	-	-	-	-	-	-	-	-	-
GF	Green Canyon Blk 116	-	-	-	-	-	-	-	-	-	-
Top 50 Volume Subtotal		**2,589.3**	**2,414.6**	**2,614.2**	**2,656.0**	**2,411.4**	**2,666.5**	**2,952.3**	**3,120.9**	**3,361.1**	**3,679.2**
Top 50 Percentage of U.S. Total		**13.9%**	**14.2%**	**14.2%**	**15.3%**	**14.2%**	**15.2%**	**16.3%**	**17.1%**	**17.9%**	**19.7%**

Table B4. Annual Production, 1982-1991, for the Top 100 U.S. Natural Gas[a] Fields in 1991 (Continued)
(Billion Cubic Feet)

State	Field Name	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
TX	Giddings	157.2	130.5	120.7	133.6	115.1	84.7	70.8	62.4	61.7	92.1
GF	Tiger Shoal	116.5	98.5	121.2	77.7	46.1	64.1	76.7	69.2	76.6	77.7
OK	Golden Trend	23.9	21.9	25.4	37.9	49.3	54.7	58.9	64.4	65.1	68.6
TX	La Perla Ranch	14.5	18.2	20.3	16.5	16.6	21.7	19.1	27.8	49.0	63.6
OK	Sooner Trend	102.2	90.8	93.2	91.6	83.1	81.1	75.2	76.8	66.5	61.7
GF	South Timbalier Blk 172	98.3	47.8	82.0	50.9	55.2	48.5	65.1	78.8	69.0	56.3
GF	Matagorda Island Blk 668	-	-	-	8.1	62.1	89.1	118.3	140.3	89.8	55.4
OK	Strong City District	15.5	27.0	34.2	35.2	33.3	35.5	40.4	49.1	51.6	50.6
GF	High Island SA Blk A573	36.3	25.7	30.0	21.9	22.0	18.9	37.3	41.7	31.7	46.3
TX	Puckett	66.0	38.7	29.7	40.9	33.5	35.6	42.7	40.0	44.3	43.6
GF	Matagorda Island Blk 623	-	-	15.2	25.8	28.2	32.9	42.1	31.2	25.9	38.9
OK	Sho-Vel-Tum	30.0	30.2	26.7	32.1	44.1	42.5	21.1	34.6	38.3	38.4
LA	Chalkley	3.3	2.8	2.6	3.6	5.1	3.0	2.5	2.5	12.2	37.7
OK	Cheyenne West	24.1	18.5	21.2	18.6	26.6	36.3	32.6	37.0	38.9	37.1
TX	Ozona	28.9	21.3	20.0	24.0	20.7	24.1	30.1	31.3	35.9	35.9
NM	Indian Basin	40.8	31.7	41.6	35.4	24.2	27.1	34.4	35.9	37.7	35.8
NM	Eumont	36.5	26.7	26.4	25.8	19.8	24.6	22.9	25.9	30.2	35.5
GF	High Island SA Blk A571	17.7	40.4	48.9	50.6	53.4	43.2	52.9	38.0	36.2	34.7
GF	Ship Shoal Blk 176	69.6	55.4	71.1	32.0	35.5	65.7	50.5	35.5	38.8	34.5
LA	Port Hudson	25.6	19.4	12.0	16.5	15.4	19.2	29.2	32.5	37.2	34.5
TX/LA	Waskom	13.5	12.0	13.3	15.6	19.7	27.8	34.9	34.2	32.5	33.1
WY	Bruff	16.0	12.0	10.5	11.4	10.3	9.5	8.3	8.8	15.4	32.9
OK	Carpenter	24.9	20.8	22.3	19.7	21.7	19.1	26.4	35.7	33.6	32.8
OK	Reydon	49.1	50.1	57.4	41.6	39.5	36.6	29.5	29.1	29.4	32.1
TX	Panhandle	84.1	92.8	107.4	89.7	68.4	60.8	56.7	47.4	36.9	31.6
GF	Eugene Island SA Blk 330	80.2	58.9	67.6	59.1	48.1	47.4	50.3	46.6	33.3	31.4
TX	Conger	26.1	27.4	31.3	32.2	24.5	28.4	27.5	27.3	30.5	31.0
OK	Panola South	-	-	-	-	-	-	-	-	1.8	30.3
GF	Garden Banks Blk 236	-	-	-	-	-	-	6.9	28.6	35.7	28.3
AK	Kuparuk River	5.2	6.1	9.7	18.5	24.5	35.9	32.0	24.2	25.3	27.2
GF	South Pass SA Blk 89	2.5	6.8	12.7	19.6	24.5	16.9	32.7	37.6	21.0	26.5
GF	Main Pass Blk 41	40.5	44.3	54.5	43.1	46.7	36.1	32.6	32.3	32.0	25.5
TX	Opelika	18.1	19.8	27.9	30.1	32.8	42.2	33.2	29.0	26.9	22.3
TX	Laredo	31.5	32.3	35.6	29.5	32.2	27.6	29.0	28.6	24.7	22.3
WY	Painter Reservoir	5.9	13.4	15.9	14.5	20.1	15.1	20.3	26.0	40.9	21.9
TX	Rosita NW	7.7	6.7	11.7	10.1	9.2	9.6	17.2	21.4	22.0	21.2
LA	Fresh Water Bayou North	6.2	8.6	7.3	5.0	3.6	4.5	11.8	20.9	23.3	20.3
TX	Bryans Mill	18.4	17.6	17.6	17.6	17.8	18.0	15.7	17.2	9.6	16.3
AL	Cedar Cove Coal Degas	-	-	0.1	0.5	0.8	0.7	0.8	0.9	4.7	15.6
TX	Willow Springs	8.1	8.0	7.3	8.2	4.7	5.6	8.9	11.1	12.9	14.6
AL	Oak Grove Coal Degas	0.5	0.8	0.7	0.7	1.2	3.4	5.4	8.0	10.9	14.2
TX	Tri-Cities	6.8	11.8	15.7	15.6	18.0	16.3	13.9	10.7	9.6	9.8
LA	Lake Pagie	13.4	8.7	7.5	5.7	8.1	7.1	8.6	9.4	9.9	9.6
TX	Anahuac	9.5	8.5	4.7	6.3	5.5	4.6	4.3	2.0	1.6	8.5
TX	Whelan	6.5	6.5	6.1	4.6	4.6	9.3	9.2	7.5	6.0	5.8
MT	Bowdoin	2.7	0.8	0.7	0.9	0.9	0.7	1.7	2.0	2.4	4.4
TX	Pegasus	3.9	4.3	5.3	5.9	10.0	8.1	3.0	9.1	4.0	4.3
WY	Big Piney-LaBarge	3.3	2.6	2.8	2.0	2.2	2.9	1.9	1.6	1.8	3.6
AL	Robinsons Bend Coal Degas	-	-	-	0.0	0.2	0.1	0.2	0.1	0.1	1.1
GF	Mississippi Canyon Blk 397	-	-	-	-	-	-	-	-	-	-
Top 100 Volume Subtotal		**3,980.7**	**3,641.5**	**4,010.3**	**3,942.6**	**3,700.5**	**4,013.4**	**4,398.1**	**4,633.2**	**4,836.3**	**5,236.7**
Top 100 Percentage of U.S. Total		**21.3%**	**21.4%**	**21.8%**	**22.7%**	**21.8%**	**22.9%**	**24.4%**	**25.4%**	**25.8%**	**28.0%**

1[a]Wet after lease separation.

– = Not Applicable.

Note: Fields are grouped in "proved reserves rank groups" and then listed within that group in ascending order by National 1991 annual production rank. The U.S. total production estimates in this table for 1982 through 1991 are from the official Energy Information Administration production data for natural gas for 1982 through 1991 contained in the *Natural Gas Annual*, DOE/EIA-0131. They differ from the U.S. total data reported in this publication.

Source: Energy Information Administration, Office of Oil and Gas.

Appendix C

Conversion to the Metric System

Appendix C

Conversion to the Metric System

Public Law 100-418, the Omnibus Trade and Competitiveness Act of 1988, states: "It is the declared policy of the United States—

(1) to designate the metric system of measurement as the preferred system of weights and measures for United States trade and commerce. . . .

(2) to require that each Federal agency, by the end of Fiscal Year 1992, use the metric system of measurement in its procurements, grants, and other business-related activities."{13}

It is in keeping with the spirit of this law that the following table has been created. The petroleum industry in the United States is slowly moving in the direction of this law; however, the data collected by EIA in these surveys were in the units that are still common to the U.S. petroleum industry, namely barrels and cubic feet. Standard metric conversion factors for barrels and cubic feet were used to convert National level volumes in Table 1 to the metric equivalents for Table C1. Barrels were multiplied by 0.1589873 to convert to cubic meters and cubic feet were multiplied by 0.02831685 to convert to cubic meters.

Table C1. Total U.S. Proved Reserves of Crude Oil, Dry Natural Gas, and Natural Gas Liquids, in Metric Units, 1982 through 1992

Year	Adjustments[a] (1)	Revision Increases (2)	Revision Decreases (3)	Revisions[b] and Adjustments (4)	Extensions (5)	New Field Discoveries (6)	New Reservoir Discoveries in Old Fields (7)	Total[c] Discoveries (8)	Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
					Crude Oil (million cubic meters)						
1982	-13.2	356.9	287.9	55.8	100.8	32.4	30.7	163.9	469.0	4,429.1	249.3
1983	73.3	446.8	206.5	313.6	100.0	16.7	30.2	146.9	480.1	4,409.5	-19.6
1984	25.3	583.8	195.1	414.0	118.3	38.5	25.1	181.9	482.8	4,522.6	+113.1
1985	68.1	482.8	228.8	322.1	118.0	13.4	26.9	158.3	485.2	4,517.8	-4.8
1986	9.0	433.1	297.1	145.0	64.4	7.6	12.9	84.9	472.7	4,275.0	-242.8
1987	37.2	586.2	218.0	405.4	76.9	15.3	17.6	109.8	456.8	4,333.4	+58.4
1988	57.8	426.7	194.1	290.4	56.4	11.3	20.2	87.9	446.9	4,264.8	-68.6
1989	33.9	428.9	217.0	245.8	81.7	17.8	14.3	113.8	411.1	4,213.3	-51.5
1990	13.7	394.8	159.0	249.5	72.5	15.6	21.5	109.6	398.3	4,174.1	-39.2
1991	25.9	333.4	297.9	61.4	58.0	15.4	14.6	88.0	399.4	3,924.1	-250.0
1992	46.1	286.8	170.0	162.9	62.2	1.3	13.5	77.0	388.9	3,775.2	-148.9
					Dry Natural Gas (billion cubic meters)						
1982	67.33	560.53	547.65	80.21	236.42	76.09	96.82	409.33	495.71	5,706.19	6.17
1983	87.50	498.43	498.86	87.07	195.64	44.57	83.96	324.17	447.07	5,670.36	-35.83
1984	-63.45	505.20	416.60	25.15	235.00	71.81	76.06	382.87	486.85	5,591.53	-78.83
1985	-48.37	531.65	461.68	21.60	203.00	28.29	83.82	315.11	452.64	5,475.60	-115.93
1986	37.38	602.27	501.12	138.53	171.74	31.12	50.15	253.01	442.03	5,425.11	-50.49
1987	35.91	496.31	402.98	129.24	129.89	30.84	42.45	203.18	456.30	5,301.23	-123.88
1988	62.09	661.68	[e]1,088.13	-364.36	192.64	46.38	54.06	293.08	472.04	[e]4,757.91	-543.32
1989	85.33	755.30	669.50	171.13	179.50	41.06	63.51	284.07	480.91	4,732.20	-25.71
1990	44.08	537.48	380.66	200.90	225.18	56.75	68.30	350.23	487.98	4,795.35	+63.15
1991	83.82	563.22	438.17	208.87	144.13	24.01	45.42	213.56	487.11	4,730.67	-64.68
1992	63.29	511.26	338.73	235.82	132.38	18.38	48.82	199.58	493.36	4,672.71	-57.96
					Natural Gas Liquids (million cubic meters)						
1982	47.6	128.9	132.3	44.2	59.6	17.8	17.3	94.7	114.6	1,148.0	+24.3
1983	135.2	134.7	124.2	145.7	51.0	11.1	15.7	77.8	115.3	1,256.2	+108.2
1984	-19.6	137.7	115.1	3.0	55.3	8.7	15.3	70.3	123.4	1,215.1	-41.1
1985	67.8	144.0	118.3	93.5	53.6	7.0	13.5	74.1	119.7	1,263.0	+47.9
1986	58.3	163.8	128.3	93.8	41.8	5.4	11.4	58.6	117.3	1,298.1	+35.1
1987	36.8	134.7	104.3	67.2	33.9	6.2	8.7	48.8	118.8	1,295.3	-2.8
1988	1.8	185.7	113.7	73.8	42.6	6.5	11.4	60.5	119.9	1,309.7	+14.4
1989	-44.0	181.7	162.2	-24.5	41.2	13.2	11.8	66.2	116.2	1,235.2	-74.5
1990	-13.2	131.5	96.3	22.0	47.5	6.2	11.6	65.3	116.4	1,206.1	-29.1
1991	37.1	131.2	110.5	57.8	30.0	4.0	8.7	42.7	119.9	1,186.7	-19.4
1992	35.8	128.1	86.6	77.3	30.2	3.2	10.2	43.6	122.9	1,184.6	-2.1

[a]Includes operator reported corrections for year 1981. After 1981, operators included corrections with revisions. Adjustments included any necessary changes to maintain an exact line balance for each year.

[b]Revisions and adjustments = Col. 1 + Col. 2 - Col. 3

[c]Total discoveries = Col. 5 + Col. 6 + Col. 7

[d]Proved reserves = Col. 10 from prior year + Col. 4 + Col. 8 - Col. 9

[e]An unusually large revision decrease to North Slope dry natural gas reserves was made in 1988. It recognizes some 696.59 billion cubic meters of downward revisions reported during prior years by operators because of economic and market conditions. EIA in previous years carried these reserves in the proved category.

Notes: ▪ Old means discovered in a prior year. ▪ New means discovered during the report year. ▪ The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves" and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." They may differ from the official Energy Information Administration production data for crude oil, natural gas, and natural gas liquids for 1992 contained in the publications *Petroleum Supply Annual 1992*, DOE/EIA-0340(92) and *Natural Gas Annual 1992*, DOE/EIA-0131(92). ▪ The following conversion factors were used to convert data in Columns 2, 3, 5, 6, 7, 9, and 10: barrels = 0.1589873 per cubic meter, cubic feet = 0.02831685 per cubic meter. ▪ Number of decimal digits varies in order to accurately reproduce corresponding equivalents shown on Table 1.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1982 through 1991 annual reports, DOE/EIA-0216.(xx)

Appendix D

Historical Reserves Statistics

Appendix D

Historical Reserves Statistics

These are selected historical data presented at the State and National level. All historical statistics included have previously been published in the annual reports of 1977 through 1991 of the EIA publication *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216, references 8 through 22.

Notes: •Liquid volumes are in million barrels of 42 U.S. gallons. •Gas volumes are in billion cubic feet (Bcf), at 14.73 psia and 60° Fahrenheit. •NA appears in this appendix wherever data are not available or are withheld to avoid disclosure of data which may be proprietary. •An asterisk (*) marks those estimates associated with sampling errors (95 percent confidence interval) greater than 20 percent of the value estimated.

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
		Alabama		
1977	85	0	530	NA
1978	*74	0	514	NA
1979	45	NA	652	213
1980	54	NA	636	226
1981	55	NA	648	192
1982	54	NA	[a]648	193
1983	51	NA	[a]785	216
1984	*68	NA	[a]961	200
1985	69	NA	[a]821	182
1986	55	20	[b]951	177
1987	55	20	[b]842	166
1988	54	20	[b]809	166
1989	43	20	[b]819	168
1990	44	<1	[c]4,125	170
1991	43	<1	[c]5,414	145
1992	41	0	[c]5,802	171

[a]Onshore only, offshore included in Louisiana
[b]Onshore only, offshore included in Federal Offshore Gulf of Mexico (Louisiana)
[c]Includes State Offshore 2,519 Bcf in 1990, 3,191 Bcf in 1991, 3,233 Bcf in 1992

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
		Alaska		
1977	8,413	846	32,243	NA
1978	9,384	398	32,045	NA
1979	8,875	398	32,259	23
1980	8,751	0	33,382	11
1981	8,283	0	33,037	10
1982	7,406	60	34,990	9
1983	7,307	576	34,283	8
1984	7,563	369	34,476	19
1985	7,056	379	33,847	383
1986	6,875	902	32,664	381
1987	7,378	566	33,225	418
1988	6,959	431	9,078	401
1989	6,674	750	8,939	380
1990	6,524	969	9,300	340
1991	6,083	1,456	9,553	360
1992	6,022	1,331	9,638	347

Note See 1988 Chapter 4 discussion "Alaskan North Slope Natural Gas Reserves."

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Arkansas				
1977	116	17	1,660	NA
1978	111	8	1,681	NA
1979	107	8	1,703	17
1980	107	11	1,774	16
1981	113	11	1,801	16
1982	107	4	1,958	15
1983	120	4	2,069	11
1984	114	6	2,227	12
1985	97	11	2,019	11
1986	88	9	1,992	16
1987	82	0	1,997	16
1988	77	<1	1,986	13
1989	66	1	1,772	9
1990	60	1	1,731	9
1991	•70	0	1,669	5
1992	58	<1	1,750	4

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
California - Coastal Region Onshore				
1977	679	NA	334	NA
1978	602	NA	350	NA
1979	578	NA	365	22
1980	652	NA	299	23
1981	621	NA	306	14
1982	580	NA	362	16
1983	559	NA	381	17
1984	628	140	265	15
1985	631	152	256	16
1986	592	164	255	15
1987	625	298	238	13
1988	576	299	215	13
1989	731	361	224	11
1990	588	310	217	12
1991	554	327	216	12
1992	522	317	203	10

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
California - Total				
1977	5,005	1,047	4,737	NA
1978	4,974	968	4,947	NA
1979	5,265	960	5,022	111
1980	5,4[illegible]0	891	5,414	120
1981	5,441	660	5,617	82
1982	5,405	616	5,552	154
1983	5,348	576	5,781	151
1984	5,707	674	5,554	141
1985	[d]4,810	590	[d]4,325	[d]146
1986	[d]4,734	[d]616	[d]3,928	[d]134
1987	[d]4,709	[d]1,493	[d]3,740	[d]130
1988	[d]4,879	[d]1,440	[d]3,519	[d]123
1989	[d]4,816	[d]1,608	[d]3,374	[d]113
1990	[d]4,658	[d]1,425	[d]3,185	[d]105
1991	[d]4,217	[d]1,471	[d]3,004	[d]92
1992	[d]3,893	[d]1,299	[d]2,778	[d]99

[d]Excludes Federal offshore, now included in Federal Offshore Pacific (California).

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
California - Los Angeles Basin Onshore				
1977	910	NA	255	NA
1978	493	NA	178	NA
1979	513	NA	163	10
1980	454	NA	193	15
1981	412	NA	154	6
1982	370	NA	96	6
1983	343	NA	107	6
1984	373	126	156	5
1985	420	86	181	6
1986	330	66	142	8
1987	361	105	148	8
1988	391	106	151	7
1989	342	32	137	4
1990	316	3	106	5
1991	272	4	115	4
1992	236	4	97	5

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
California - San Joaquin Basin Onshore				
1977	2,965	NA	3,784	NA
1978	3,099	NA	3,960	NA
1979	3,294	NA	3,941	77
1980	3,360	NA	4,344	81
1981	3,225	NA	4,163	57
1982	3,081	NA	3,901	124
1983	3,032	NA	3,819	117
1984	3,197	384	3,685	105
1985	3,258	350	3,574	120
1986	3,270	368	3,277	109
1987	3,208	1,070	3,102	107
1988	3,439	1,029	2,912	101
1989	3,301	1,210	2,782	95
1990	3,334	1,109	2,670	86
1991	3,126	1,139	2,614	75
1992	2,898	977	2,415	83

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
California - State Offshore				
1977	181	NA	114	NA
1978	519	NA	213	NA
1979	632	NA	231	2
1980	604	NA	164	1
1981	NA	NA	NA	NA
1982	NA	NA	NA	NA
1983	NA	NA	NA	NA
1984	NA	25	NA	NA
1985	501	0	314	4
1986	542	18	254	2
1987	515	18	252	2
1988	473	6	241	2
1989	442	5	231	3
1990	420	3	192	2
1991	265	1	59	1
1992	237	1	63	1

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
California-State and Federal Offshore				
1977	451	NA	364	NA
1978	780	NA	457	NA
1979	880	NA	553	2
1980	1,004	NA	578	1
1981	1,183	NA	994	5
1982	1,374	NA	1,193	8
1983	1,414	NA	1,474	11
1984	1,509	25	1,448	16
1985	1,492	2	1,433	16
1986	1,516	19	1,579	17
1987	1,552	20	1,704	19
1988	1,497	6	1,793	23
1989	1,429	5	1,727	28
1990	1,382	3	1,646	20
1991	1,050	1	1,221	19
1992	971	1	1,181	21

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
California - Federal Offshore				
1977	270	NA	250	NA
1978	261	NA	246	NA
1979	248	NA	322	0
1980	400	NA	414	0
1981	NA	NA	NA	NA
1982	NA	NA	NA	NA
1983	NA	NA	NA	NA
1984	NA	0	NA	NA
1985	991	2	1,119	12
1986	974	1	1,325	15
1987	1,037	2	1,452	17
1988	1,024	0	1,552	21
1989	987	0	1,496	25
1990	962	0	1,454	18
1991	785	0	1,162	18
1992	734	<1	1,118	20

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
		Colorado		
1977	230	73	2,512	NA
1978	194	75	2,765	NA
1979	159	43	2,608	177
1980	*183	46	2,922	194
1981	147	47	2,961	204
1982	169	100	3,314	186
1983	186	113	3,148	183
1984	198	119	*2,943	155
1985	198	119	2,881	173
1986	207	95	3,027	148
1987	272	67	2,942	166
1988	257	67	3,535	181
1989	359	8	4,274	209
1990	305	8	4,555	169
1991	329	33	5,767	197
1992	304	34	6,198	226
		Florida		
1977	213	1	151	NA
1978	168	1	119	NA
1979	128	1	77	21
1980	134	1	84	27
1981	109	1	69	NA
1982	97	1	64	17
1983	78	4	49	11
1984	82	2	65	17
1985	77	2	55	17
1986	67	2	49	14
1987	61	0	49	9
1988	59	0	51	16
1989	50	0	46	10
1990	42	0	45	8
1991	37	0	38	7
1992	36	0	47	8

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
		Illinois		
1977	*150	1	NA	NA
1978	*158	1	NA	NA
1979	*136	1	NA	NA
1980	113	2	NA	NA
1981	129	1	NA	NA
1982	150	1	NA	NA
1983	135	1	NA	NA
1984	153	1	NA	NA
1985	136	1	NA	NA
1986	135	1	NA	NA
1987	153	5	NA	NA
1988	143	<1	NA	NA
1989	123	<1	NA	NA
1990	131	0	NA	NA
1991	128	52	NA	NA
1992	138	0	NA	NA
		Indiana		
1977	*20	0	NA	NA
1978	*29	0	NA	NA
1979	*40	0	NA	NA
1980	23	0	NA	NA
1981	23	0	NA	NA
1982	28	1	NA	NA
1983	34	3	NA	NA
1984	*33	2	NA	NA
1985	*35	2	NA	NA
1986	*32	2	NA	NA
1987	23	2	NA	NA
1988	*22	0	NA	NA
1989	*16	0	NA	NA
1990	12	0	NA	NA
1991	*16	0	NA	NA
1992	17	0	NA	NA

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Kansas				
1977	*349	3	11,457	NA
1978	303	3	10,992	NA
1979	*377	3	10,243	402
1980	310	2	9,508	389
1981	371	2	9,860	409
1982	378	13	9,724	302
1983	344	13	9,553	443
1984	377	2	9,387	424
1985	423	<1	9,337	373
1986	312	<1	10,509	440
1987	357	<1	10,494	462
1988	327	<1	10,104	345
1989	338	3	10,091	329
1990	321	<1	9,614	313
1991	300	<1	9,358	428
1992	310	0	9,681	444

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Kentucky				
1977	30	0	451	NA
1978	*40	0	545	NA
1979	25	0	468	26
1980	*35	12	508	25
1981	29	13	530	25
1982	*36	13	551	35
1983	35	12	554	31
1984	*41	0	613	24
1985	*42	0	766	27
1986	*31	0	841	29
1987	25	0	909	23
1988	*34	0	923	24
1989	33	0	992	16
1990	33	0	1,016	25
1991	*31	0	1,155	24
1992	34	0	1,084	32

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Louisiana - Total				
1977	3,600	139	57,010	NA
1978	3,448	143	55,725	NA
1979	2,780	76	50,042	1,424
1980	2,751	62	47,325	1,346
1981	2,985	50	47,377	1,327
1982	2,728	49	[e]44,916	1,295
1983	2,707	45	[e]42,561	1,332
1984	2,661	55	[e]41,399	1,188
1985	[f]883	[f]35	[f]14,038	[f]546
1986	[f]826	[f]47	[f]12,930	[f]524
1987	[f]807	[f]56	[f]12,430	[f]525
1988	[f]800	[f]69	[f]12,224	[f]517
1989	[f]745	[f]63	[f]12,516	[f]522
1990	[f]705	[f]22	[f]11,728	[f]538
1991	[f]679	[f]44	[f]10,912	[f]526
1992	[f]668	[f]35	[f]9,780	[f]495

[e]Includes State and Federal offshore Alabama.
[f]Excludes Federal offshore; now included in Federal Offshore-Gulf of Mexico (Louisiana).

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Louisiana - North				
1977	244	78	3,135	NA
1978	255	78	3,203	NA
1979	216	NA	2,798	96
1980	248	NA	3,076	95
1981	* 317	NA	3,270	99
1982	* 240	NA	2,912	85
1983	223	NA	2,939	74
1984	165	9	2,494	57
1985	196	5	2,587	65
1986	160	7	2,515	57
1987	175	3	2,306	50
1988	154	23	2,398	56
1989	123	22	2,652	60
1990	120	<1	2,588	58
1991	127	<1	2,384	59
1992	125	<1	2,311	60

Louisiana - South Onshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	1,382	46	18,580	NA
1978	1,242	38	17,755	NA
1979	682	NA	13,994	676
1980	682	NA	13,026	540
1981	642	NA	12,645	544
1982	611	NA	11,801	501
1983	569	NA	11,142	527
1984	585	20	10,331	454
1985	565	16	9,808	442
1986	547	30	9,103	428
1987	505	22	8,693	429
1988	511	35	8,654	421
1989	479	30	8,645	411
1990	435	11	8,171	431
1991	408	33	7,504	417
1992	417	26	6,693	380

Michigan

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	*233	0	*1,386	NA
1978	*220	9	*1,422	NA
1979	159	23	1,204	112
1980	*205	14	*1,406	112
1981	*240	17	1,118	102
1982	184	34	1,084	97
1983	209	48	1,219	105
1984	180	46	1,112	84
1985	191	37	985	67
1986	146	34	1,139	88
1987	151	27	1,451	111
1988	132	27	1,323	99
1989	128	8	1,342	97
1990	124	3	1,243	81
1991	119	0	1,334	72
1992	102	0	1,223	68

Louisiana - State Offshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	1,974	15	35,295	NA
1978	1,951	27	34,767	NA
1979	1,882	14	33,250	652
1980	1,821	13	31,223	711
1981	2,026	16	31,462	684
1982	1,877	21	[e]30,203	709
1983	1,915	15	[e]28,480	731
1984	1,911	27	[e]28,574	677
1985	[f]122	2	[f]1,643	[f]39
1986	[f]119	[f]10	[f]1,312	[f]39
1987	[f]127	[f]22	[f]1,431	[f]46
1988	[f]135	[f]11	[f]1,172	[f]40
1989	[f]143	[f]11	[f]1,219	[f]51
1990	[f]150	[f]11	[f]969	[f]49
1991	[f]144	[f]11	[f]1,024	[f]50
1992	[f]126	[f]9	[f]776	[f]55

[e]Includes State and Federal offshore Alabama.
[f]Excludes Federal offshore; now included in Federal Offshore-Gulf of Mexico (Louisiana).

Mississippi

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	241	9	1,437	NA
1978	*250	27	1,635	NA
1979	238	24	1,504	16
1980	202	36	1,769	20
1981	209	93	2,035	18
1982	223	85	1,796	18
1983	205	77	1,596	19
1984	201	50	1,491	15
1985	184	53	1,360	12
1986	199	16	1,300	11
1987	202	12	1,220	11
1988	221	10	1,143	12
1989	218	6	1,104	12
1990	227	8	1,126	11
1991	194	8	1,057	10
1992	165	7	869	9

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Montana				
1977	175	27	*887	NA
1978	158	27	926	NA
1979	152	38	825	10
1980	179	13	*1,287	16
1981	186	11	*1,321	11
1982	216	6	847	18
1983	234	8	896	19
1984	224	4	802	18
1985	232	3	857	21
1986	248	27	803	16
1987	246	<1	780	16
1988	241	0	819	11
1989	225	<1	867	16
1990	221	0	899	15
1991	201	0	831	14
1992	193	0	859	12
Nebraska				
1977	22	0	NA	NA
1978	30	1	NA	NA
1979	25	0	NA	NA
1980	*46	0	NA	NA
1981	41	0	NA	NA
1982	*32	0	NA	NA
1983	44	0	NA	NA
1984	*46	0	NA	NA
1985	42	0	NA	NA
1986	*45	7	NA	NA
1987	33	0	NA	NA
1988	42	0	NA	NA
1989	32	0	NA	NA
1990	26	0	NA	NA
1991	26	0	NA	NA
1992	26	0	NA	NA

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
New Mexico - Total				
1977	605	97	12,000	NA
1978	579	90	12,688	NA
1979	563	77	13,724	530
1980	547	58	13,287	541
1981	555	93	13,870	560
1982	563	76	12,418	531
1983	576	75	11,676	551
1984	660	87	11,364	511
1985	688	99	10,900	445
1986	644	225	11,808	577
1987	654	235	11,620	771
1988	661	241	17,166	1,023
1989	665	256	15,434	933
1990	687	256	17,260	990
1991	721	275	18,539	908
1992	757	293	18,998	1,066
New Mexico - East				
1977	576	95	3,848	NA
1978	554	88	3,889	NA
1979	542	77	4,031	209
1980	518	58	3,530	209
1981	522	93	3,598	214
1982	537	76	3,432	209
1983	542	75	3,230	232
1984	625	87	3,197	221
1985	643	98	3,034	209
1986	593	225	2,694	217
1987	608	230	2,881	192
1988	621	235	2,945	208
1989	619	252	3,075	196
1990	633	253	3,256	222
1991	694	275	3,206	205
1992	731	293	3,130	223

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
New Mexico - West				
1977	*29	2	8,152	NA
1978	*25	2	8,799	NA
1979	21	0	9,693	321
1980	*29	0	9,757	332
1981	*33	0	10,272	346
1982	26	0	8,986	322
1983	34	0	8,446	319
1984	35	0	8,167	290
1985	45	1	7,866	236
1986	51	0	9,114	360
1987	46	5	8,739	579
1988	40	6	14,221	815
1989	46	4	12,359	737
1990	54	3	14,004	768
1991	27	0	15,333	703
1992	26	0	15,868	843

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
North Dakota				
1977	155	10	361	NA
1978	162	4	374	NA
1979	211	6	439	47
1980	214	6	537	61
1981	223	8	581	68
1982	237	8	629	71
1983	258	53	600	69
1984	260	54	566	73
1985	255	34	569	74
1986	218	35	541	69
1987	215	33	508	67
1988	216	39	541	52
1989	246	31	561	59
1990	285	0	586	60
1991	232	4	472	56
1992	237	3	496	64

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
New York				
1977	NA	NA	165	NA
1978	NA	NA	193	NA
1979	NA	NA	211	0
1980	NA	NA	208	0
1981	NA	NA	*264	0
1982	NA	NA	229	NA
1983	NA	NA	295	NA
1984	NA	NA	389	NA
1985	NA	NA	*369	NA
1986	NA	NA	*457	NA
1987	NA	NA	410	NA
1988	NA	NA	351	NA
1989	NA	NA	368	NA
1990	NA	NA	354	NA
1991	NA	NA	331	NA
1992	NA	NA	329	NA

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Ohio				
1977	*74	0	495	NA
1978	69	0	684	NA
1979	*82	0	*1,479	0
1980	*116	0	*1,699	0
1981	*112	0	965	0
1982	111	0	1,141	NA
1983	130	0	2,030	NA
1984	*116	0	1,541	NA
1985	79	0	1,331	NA
1986	72	0	1,420	NA
1987	66	0	1,069	NA
1988	64	0	1,229	NA
1989	56	0	1,275	NA
1990	65	0	1,214	NA
1991	66	0	1,181	NA
1992	58	0	1,161	NA

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Oklahoma				
1977	1,109	69	13,889	NA
1978	979	33	14,417	NA
1979	1,014	35	13,816	583
1980	930	27	13,138	604
1981	950	43	14,699	631
1982	971	25	16,207	745
1983	931	27	16,211	829
1984	940	40	16,126	769
1985	935	37	16,040	826
1986	874	35	16,685	857
1987	788	56	16,711	781
1988	796	79	16,495	765
1989	789	63	15,916	654
1990	734	37	16,151	657
1991	700	54	14,725	628
1992	698	54	13,926	629

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Pennsylvania				
1977	*57	0	769	NA
1978	27	0	899	NA
1979	33	0	*1,515	1
1980	35	0	951	0
1981	32	0	*1,264	0
1982	37	0	1,429	NA
1983	41	0	1,882	NA
1984	*40	0	1,575	NA
1985	*38	0	*1,617	NA
1986	*26	0	*1,560	1
1987	26	0	1,647	NA
1988	*27	0	2,072	NA
1989	26	0	1,642	NA
1990	22	0	1,720	NA
1991	15	0	1,629	NA
1992	16	0	1,528	NA

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - Total				
1977	9,751	637	56,422	NA
1978	8,911	533	55,583	NA
1979	8,284	471	53,021	2,482
1980	8,206	384	50,287	2,452
1981	8,093	459	50,469	2,646
1982	7,616	377	49,757	2,771
1983	7,539	421	50,052	3,038
1984	7,557	735	49,883	3,048
1985	[g]7,782	609	[g]41,775	[g]2,981
1986	[g]7,152	1,270	[g]40,574	[g]2,964
1987	[g]7,112	1,028	[g]38,711	[g]2,822
1988	[g]7,043	1,099	[g]38,167	[g]2,617
1989	[g]6,966	805	[g]38,381	[g]2,563
1990	[g]7,106	618	[g]38,192	[g]2,575
1991	[g]6,797	756	[g]36,174	[g]2,493
1992	[g]6,441	[g]612	[g]35,093	[g]2,402

[g]Excludes Federal Offshore; now included in Federal Offshore-Gulf of Mexico (Texas).

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 1				
1977	*174	0	1,319	NA
1978	111	2	986	NA
1979	110	0	919	23
1980	*150	0	829	24
1981	127	5	*1,022	26
1982	129	6	892	29
1983	165	6	1,087	43
1984	173	4	838	39
1985	177	8	967	40
1986	144	1	913	35
1987	143	1	812	27
1988	136	1	1,173	30
1989	139	1	1,267	25
1990	252	0	1,048	26
1991	227	0	1,030	28
1992	185	0	933	27

Texas - RRC District 2 Onshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	395	80	3,162	NA
1978	334	1	2,976	NA
1979	292	1	2,974	64
1980	252	1	2,502	64
1981	229	1	2,629	88
1982	206	0	2,493	75
1983	192	0	2,534	99
1984	192	<1	2,512	103
1985	168	0	2,358	100
1986	148	<1	2,180	89
1987	137	0	2,273	102
1988	117	0	2,037	92
1989	107	0	1,770	72
1990	91	0	1,737	80
1991	90	0	1,393	75
1992	86	0	1,389	80

Texas - RRC District 4 Onshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	145	7	9,621	NA
1978	123	3	9,031	NA
1979	113	4	8,326	248
1980	96	3	8,130	252
1981	97	6	8,004	260
1982	87	7	8,410	289
1983	96	3	8,316	292
1984	99	3	8,525	295
1985	08	2	8,250	269
1986	87	2	8,274	281
1987	80	2	7,490	277
1988	65	1	7,029	260
1989	77	<1	7,111	260
1990	67	<1	7,475	279
1991	52	<1	7,048	273
1992	50	<1	6,739	272

Texas - RRC District 3 Onshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	937	33	7,518	NA
1978	794	22	7,186	NA
1979	630	32	6,315	231
1980	581	11	5,531	216
1981	552	11	5,292	230
1982	509	22	4,756	265
1983	517	27	4,680	285
1984	522	25	4,708	270
1985	471	6	4,180	260
1986	420	3	3,753	237
1987	386	4	3,632	241
1988	360	16	3,422	208
1989	307	11	3,233	213
1990	275	13	2,894	181
1991	300	28	2,885	208
1992	304	27	2,684	211

Texas - RRC District 5

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	68	0	931	NA
1978	*68	0	*1,298	NA
1979	55	1	1,155	34
1980	52	0	1,147	44
1981	49	0	1,250	49
1982	45	0	1,308	53
1983	42	0	1,448	73
1984	36	<1	1,874	74
1985	*59	1	2,058	77
1986	*53	1	2,141	86
1987	54	0	2,119	88
1988	48	0	1,996	81
1989	46	0	1,845	80
1990	47	0	1,875	81
1991	46	0	1,863	71
1992	56	0	1,747	71

Texas - RRC District 6

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	1,568	12	3,214	NA
1978	1,444	3	3,240	NA
1979	1,177	6	3,258	272
1980	1,115	6	4,230	321
1981	1,040	7	4,177	308
1982	947	6	4,326	278
1983	918	5	4,857	342
1984	889	5	4,703	298
1985	851	4	4,822	293
1986	750	2	4,854	277
1987	733	3	4,682	264
1988	685	5	4,961	263
1989	631	4	5,614	266
1990	605	6	5,753	247
1991	504	7	5,233	243
1992	442	7	5,317	251

Texas - RRC District 7B

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	250	NA	699	NA
1978	190	NA	743	NA
1979	208	NA	*751	64
1980	196	NA	*745	85
1981	254	NA	804	102
1982	199	NA	805	105
1983	217	NA	1,027	133
1984	218	62	794	106
1985	239	63	708	104
1986	193	64	684	109
1987	200	46	697	92
1988	205	42	704	98
1989	204	11	459	73
1990	198	8	522	76
1991	184	8	423	82
1992	163	11	455	68

Texas - RRC District 7C

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	191	NA	2,831	NA
1978	202	NA	2,821	NA
1979	206	NA	2,842	182
1980	207	NA	2,378	135
1981	230	NA	2,503	186
1982	229	NA	2,659	199
1983	228	NA	2,568	219
1984	240	24	2,866	233
1985	243	21	2,914	256
1986	213	22	2,721	246
1987	220	25	2,708	243
1988	212	31	2,781	238
1989	247	16	3,180	238
1990	274	8	3,514	256
1991	253	9	3,291	241
1992	[illegible]	33	3,239	289

Texas - RRC District 8

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	2,915	127	11,728	NA
1978	2,795	102	11,093	NA
1979	2,686	88	10,077	505
1980	2,597	86	9,144	498
1981	2,503	105	8,546	537
1982	2,312	75	8,196	588
1983	2,350	99	8,156	681
1984	2,342	363	7,343	691
1985	2,333	325	7,330	665
1986	2,183	592	7,333	717
1987	2,108	399	6,999	640
1988	2,107	412	7,058	547
1989	2,151	366	6,753	554
1990	2,152	282	6,614	558
1991	2,114	328	6,133	477
1992	2,013	260	5,924	444

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 8A				
1977	2,626	291	1,630	NA
1978	2,439	330	1,473	NA
1979	2,371	270	1,055	351
1980	2,504	196	1,057	290
1981	2,538	247	1,071	335
1982	2,481	200	1,041	296
1983	2,366	203	966	262
1984	2,413	217	907	282
1985	2,711	147	958	283
1986	2,618	559	845	331
1987	2,735	525	876	307
1988	2,800	569	832	326
1989	2,754	377	1,074	332
1990	2,847	285	1,036	354
1991	2,763	363	1,073	333
1992	2,599	273	1,239	257

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 10				
1977	*120	4	7,744	NA
1978	90	0	7,406	NA
1979	97	2	6,784	375
1980	89	2	6,435	369
1981	107	2	6,229	364
1982	112	2	6,210	391
1983	105	6	5,919	413
1984	108	6	5,461	440
1985	*140	5	5,469	433
1986	*104	5	5,276	428
1987	102	2	4,962	417
1988	99	4	4,830	363
1989	97	3	4,767	342
1990	99	3	4,490	328
1991	95	2	4,589	356
1992	89	<1	4,409	336

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 9				
1977	260	28	724	NA
1978	190	27	*908	NA
1979	200	30	*700	79
1980	218	37	649	92
1981	225	34	953	86
1982	219	17	*1,103	119
1983	220	18	932	121
1984	214	25	900	119
1985	285	27	892	111
1986	237	19	868	119
1987	206	21	834	115
1988	202	18	783	106
1989	200	16	703	94
1990	193	12	776	104
1991	162	11	738	101
1992	176	1	670	92

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - State and Federal Offshore				
1977	102	0	5,301	NA
1978	131	1	6,422	NA
1979	139	0	7,865	54
1980	149	0	7,510	62
1981	142	0	7,989	75
1982	141	0	7,558	84
1983	123	0	7,562	75
1984	111	0	8,452	98
1985	119	0	8,129	90
1986	103	0	8,176	109
1987	96	0	7,846	98
1988	85	0	7,802	94
1989	75	0	7,573	84
1990	77	0	7,758	87
1991	67	0	7,150	84
1992	197	0	7,344	122

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - State Offshore				
1977	NA	NA	NA	NA
1978	NA	NA	NA	NA
1979	NA	NA	NA	NA
1980	NA	NA	NA	12
1981	NA	NA	NA	13
1982	NA	NA	NA	18
1983	NA	NA	NA	11
1984	NA	NA	NA	10
1985	7	0	869	10
1986	2	0	732	9
1987	8	0	627	9
1988	7	0	561	5
1989	6	0	605	6
1990	6	0	458	5
1991	7	0	475	5
1992	5	0	348	4

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Virginia				
1977	NA	NA	NA	NA
1978	NA	NA	NA	NA
1979	NA	NA	NA	NA
1980	NA	NA	NA	NA
1981	NA	NA	118	NA
1982	NA	NA	122	NA
1983	NA	NA	175	NA
1984	NA	NA	216	NA
1985	NA	NA	235	NA
1986	NA	NA	253	NA
1987	NA	NA	248	NA
1988	NA	NA	230	NA
1989	NA	NA	217	NA
1990	NA	NA	138	NA
1991	NA	NA	225	NA
1992	NA	NA	904	NA

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Utah				
1977	252	6	877	NA
1978	188	7	925	NA
1979	201	NA	948	59
1980	198	NA	1,201	127
1981	190	NA	1,912	277
1982	173	NA	2,161	(h)
1983	187	NA	2,333	(h)
1984	172	8	2,080	(h)
1985	276	13	1,999	(h)
1986	269	14	1,895	(h)
1987	284	22	1,947	(h)
1988	260	21	1,298	(h)
1989	246	50	1,507	(h)
1990	249	44	1,510	(h)
1991	233	66	1,702	(h)
1992	217	65	1,830	(h)

[h]Included with Wyoming.

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
West Virginia				
1977	21	0	1,567	NA
1978	*30	0	1,634	NA
1979	*48	0	1,558	74
1980	30	8	*2,422	97
1981	30	8	1,834	85
1982	48	8	2,148	79
1983	49	0	2,194	91
1984	*76	0	2,136	80
1985	40	0	2,058	85
1986	37	0	2,148	87
1987	34	0	2,242	87
1988	33	0	2,306	92
1989	30	0	2,201	100
1990	*31	0	2,207	86
1991	26	0	2,528	103
1992	27	0	2,356	97

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Wyoming				
1977	851	31	6,305	NA
1978	845	36	7,211	NA
1979	841	40	7,526	285
1980	928	28	9,100	341
1981	840	53	9,307	384
1982	856	58	9,758	[i]681
1983	957	61	10,227	[i]789
1984	954	71	10,482	[i]860
1985	951	18	10,617	[i]949
1986	849	126	9,756	[i]950
1987	854	27	10,023	[i]924
1988	815	35	10,308	[i]1,154
1989	825	46	10,744	[i]896
1990	794	42	9,944	[i]812
1991	757	24	9,941	[i]748
1992	689	18	10,826	[i]660

[i]Utah and Wyoming are combined.

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Miscellaneous				
1977	23	0	102	NA
1978	24	0	109	NA
1979	22	1	*153	2
1980	*38	0	176	3
1981	40	7	191	21
1982	33	0	69	4
1983	30	8	78	5
1984	23	0	75	5
1985	35	0	76	3
1986	33	0	133	2
1987	30	0	65	4
1988	34	0	83	5
1989	39	0	83	5
1990	43	1	*70	3
1991	42	5	75	8
1992	29	0	92	8

Note: States included may vary for different report years and hydrocarbon types.

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Federal Offshore - Total				
1985	2,862	11	[j]34,492	702
1986	2,715	16	[j]34,223	681
1987	2,639	21	[j]31,931	638
1988	2,629	21	[j]32,264	622
1989	2,747	32	[j]32,651	678
1990	2,805	49	31,433	619
1991	2,620	18	29,448	642
1992	2,569	31	27,767	610

[j]Includes State offshore Alabama.
Note: Data not tabulated for years 1977 through 1984.

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Federal Offshore - Gulf of Mexico (Louisiana)				
1985	1,759	11	[f]26,113	610
1986	1,640	14	[f]25,454	566
1987	1,514	19	[f]23,260	532
1988	1,527	21	[f]23,471	512
1989	1,691	32	[f]24,187	575
1990	1,772	49	[k]22,679	[k]519
1991	1,775	18	[k]21,611	[k]545
1992	1,643	31	[k]19,653	[k]472

[f]Includes State and Federal offshore Alabama.
[k]Includes Federal offshore Alabama.
Note: Data not tabulated for years 1977 through 1984.

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Federal Offshore - Pacific (California)				
1985	991	NA	1,119	12
1986	974	2	1,325	15
1987	1,037	2	1,452	17
1988	1,024	0	1,552	21
1989	987	0	1,496	25
1990	962	0	1,454	18
1991	785	0	1,162	18
1992	734	0	1,118	20

Note: Data not tabulated for years 1977 through 1984.

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Federal Offshore - Gulf of Mexico (Texas)				
1985	112	0	7,260	80
1986	101	0	7,444	100
1987	88	0	7,219	89
1988	78	0	7,241	89
1989	69	0	6,968	78
1990	71	0	7,300	82
1991	60	0	6,675	79
1992	192	0	6,996	118

Note: Data not tabulated for years 1977 through 1984.

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Lower 48 States				
1977	23,367	2,168	175,170	NA
1978	21,971	1,964	175,988	NA
1979	20,935	1,878	168,738	6,592
1980	21,054	1,622	165,639	6,717
1981	21,143	1,594	168,693	7,058
1982	20,452	1,478	166,522	7,212
1983	20,428	1,548	165,964	7,893
1984	20,883	1,956	162,987	7,624
1985	21,360	1,662	159,522	7,561
1986	20,014	2,597	158,922	7,784
1987	19,878	3,084	153,986	7,729
1988	19,866	3,169	158,946	7,837
1989	19,827	2,999	158,177	7,389
1990	19,730	2,514	160,046	7,246
1991	18,599	2,810	157,509	7,106
1992	17,723	2,451	155,377	7,104

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
U.S. Total				
1977	31,780	3,014	207,413	NA
1978	31,355	2,362	208,033	NA
1979	29,810	2,276	200,997	6,615
1980	29,805	1,622	199,021	6,728
1981	29,426	1,594	201,730	7,068
1982	27,858	1,478	201,512	7,221
1983	27,735	2,124	200,247	7,901
1984	28,446	2,325	197,463	7,643
1985	28,416	2,041	193,369	7,944
1986	26,889	3,499	191,586	8,165
1987	27,256	3,649	187,211	8,147
1988	26,825	3,600	168,024	8,238
1989	26,501	3,749	167,116	7,769
1990	26,254	3,483	169,346	7,586
1991	24,682	4,266	167,062	7,466
1992	23,745	3,782	165,015	7,451

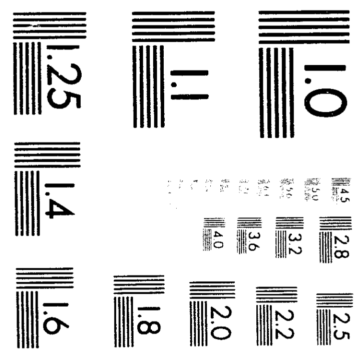
Table D1. Total U.S. Proved Reserves of Crude Oil, 1976 through 1992
(Million Barrels of 42 U.S. Gallons)

Year	Adjustments[a] (1)	Revision Increases (2)	Revision Decreases (3)	Revisions[b] and Adjustments (4)	Extensions (5)	New Field Discoveries (6)	New Reservoir Discoveries in Old Fields (7)	Total[c] Discoveries (8)	Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
						U.S. Total					
1976	–	–	–	–	–	–	–	–	–	[e]33,502	–
1977	[f]-40	1,503	1,117	346	496	168	130	794	2,862	31,780	-1,722
1978	366	2,799	1,409	1,756	444	267	116	827	3,008	31,355	-425
1979	337	2,438	2,001	774	424	108	104	636	2,955	29,810	-1,545
1980	219	2,883	994	2,108	572	143	147	862	2,975	29,805	-5
1981	138	2,151	880	1,409	750	254	157	1,161	2,949	29,426	-379
1982	-83	2,245	1,811	351	634	204	193	1,031	2,950	27,858	-1,568
1983	462	2,810	1,299	1,973	629	105	190	924	3,020	27,735	-123
1984	159	3,672	1,227	2,604	744	242	158	1,144	3,037	28,446	+711
1985	429	3,037	1,439	2,027	742	84	169	995	3,052	28,416	-30
1986	57	2,724	1,869	912	405	48	81	534	2,973	26,889	-1,527
1987	233	3,687	1,371	2,549	484	96	111	691	2,873	27,256	+367
1988	364	2,684	1,221	1,827	355	71	127	553	2,811	26,825	-431
1989	213	2,698	1,365	1,546	514	112	90	716	2,586	26,501	-324
1990	86	2,483	1,000	1,569	456	98	135	689	2,505	26,254	-247
1991	163	2,097	1,874	386	365	97	92	554	2,512	24,682	-1,572
1992	290	1,804	1,069	1,025	391	8	85	484	2,446	23,745	-937
						Lower 48 States					
1976	–	–	–	–	–	–	–	–	–	[e]24,928	–
1977	[f]-40	1,499	1,116	343	496	168	130	794	2,698	23,367	-1,561
1978	-48	1,909	1,400	461	444	142	116	702	2,559	21,971	-1,396
1979	342	2,404	1,975	771	424	108	104	636	2,443	20,935	-1,036
1980	210	2,505	981	1,734	479	143	147	769	2,384	21,054	+119
1981	276	1,887	878	1,285	750	254	157	1,161	2,357	21,143	+89
1982	-82	2,146	1,462	602	633	204	193	1,030	2,323	20,452	-691
1983	462	2,247	1,298	1,411	625	105	190	920	2,355	20,428	-24
1984	160	2,801	1,214	1,747	742	207	158	1,107	2,399	20,883	+455
1985	[illegible]	2,864	1,197	2,028	581	84	169	834	2,385	21,360	+477
1986	70	2,001	1,642	429	399	48	81	528	2,303	20,014	-1,346
1987	233	2,566	1,213	1,586	294	38	101	433	2,155	19,878	-136
1988	359	2,399	1,218	1,540	340	43	127	510	2,062	19,866	-12
1989	214	2,438	1,325	1,327	342	108	87	537	1,903	19,827	-39
1990	151	1,997	996	1,152	371	98	135	604	1,853	19,730	-97
1991	164	1,898	1,848	214	327	97	87	511	1,856	18,599	-1,131
1992	297	1,343	1,066	574	279	8	84	371	1,821	17,723	-876

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.
[b]Net of revisions and adjustments = Col. 1 + Col. 2 - Col. 3
[c]Total discoveries = Col. 5 + Col. 6 + Col. 7
[d]Proved reserves = Col. 10 from prior year + Col. 4 + Col. 8 - Col. 9
[e]Based on following year data only.
[f]Consists only of operator reported corrections and no other adjustments.
– = Not applicable.

Notes: •Old means discovered in a prior year. •New means discovered during the report year. •The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves." They may differ from the official Energy Information Administration production data for crude oil for 1992 contained in the *Petroleum Supply Annual 1992*, DOE/EIA-0340(92).

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1977 through 1992 annual reports, DOE/EIA-0216.(8-22)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2 of 2

Table D2. Total U.S. Proved Reserves of Dry Natural Gas, 1976 through 1992
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Year	Adjustments[a] (1)	Revision Increases (2)	Revision Decreases (3)	Revisions[b] and Adjustments (4)	Extensions (5)	New Field Discoveries (6)	New Reservoir Discoveries in Old Fields (7)	Total[c] Discoveries (8)	Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
						U.S. Total					
1976	–	–	–	–	–	–	–	–	–	[e]213,278	–
1977	[f]-20	13,691	15,296	-1,625	8,129	3,173	3,301	14,603	18,843	207,413	-5,865
1978	2,429	14,969	15,994	1,404	9,582	3,860	4,579	18,021	18,805	208,033	+620
1979	-2,264	16,410	16,629	-2,483	8,950	3,188	2,566	14,704	19,257	200,997	-7,036
1980	1,201	16,972	15,923	2,250	9,357	2,539	2,577	14,473	18,699	199,021	-1,976
1981	1,627	16,412	13,813	4,226	10,491	3,731	2,998	17,220	18,737	201,730	+2,709
1982	2,378	19,795	19,340	2,833	8,349	2,687	3,419	14,455	17,506	201,512	-218
1983	3,090	17,602	17,617	3,075	6,909	1,574	2,965	11,448	15,788	200,247	-1,265
1984	-2,241	17,841	14,712	888	8,299	2,536	2,686	13,521	17,193	197,463	-2,784
1985	-1,708	18,775	16,304	763	7,169	999	2,960	11,128	15,985	193,369	-4,094
1986	1,320	21,269	17,697	4,892	6,065	1,099	1,771	8,935	15,610	191,586	-1,783
1987	1,268	17,527	14,231	4,564	4,587	1,089	1,499	7,175	16,114	187,211	-4,375
1988	2,193	23,367	38,427	-12,867	6,803	1,638	1,909	10,350	16,670	[g]168,024	-19,187
1989	3,013	26,673	23,643	6,043	6,339	1,450	2,243	10,032	16,983	167,116	-908
1990	1,557	18,981	13,443	7,095	7,952	2,004	2,412	12,368	17,233	169,346	+2,230
1991	2,960	19,890	15,474	7,376	5,090	848	1,604	7,542	17,202	167,062	-2,284
1992	2,235	18,055	11,962	8,328	4,675	649	1,724	7,048	17,423	165,015	-2,047
						Lower 48 States					
1976	–	–	–	–	–	–	–	–	–	[e]180,838	–
1977	[f]-21	13,689	15,229	-1,561	8,056	3,173	3,301	14,530	18,637	175,170	-5,668
1978	2,446	13,912	14,670	1,688	9,582	3,860	4,277	17,719	18,589	175,988	818
1979	-2,202	15,691	16,398	-2,909	8,949	3,173	2,566	14,688	19,029	168,738	-7,250
1980	1,163	15,881	15,819	1,225	9,046	2,539	2,577	14,162	18,486	165,639	-3,099
1981	1,840	16,258	13,752	4,346	10,485	3,731	2,994	17,210	18,502	168,693	3,054
1982	2,367	17,570	19,318	619	8,349	2,687	3,419	14,455	17,245	166,522	-2,171
1983	3,089	17,296	16,875	3,510	6,908	1,574	2,965	11,447	15,515	165,964	-558
1984	-2,245	16,934	14,317	372	8,298	2,536	2,686	13,520	16,869	162,987	-2,977
1985	-1,349	18,252	15,752	1,151	7,098	999	2,960	11,057	15,673	159,522	-3,465
1986	1,618	21,084	16,940	5,762	6,064	1,099	1,761	8,924	15,286	158,922	-600
1987	1,066	16,809	14,164	3,711	4,542	1,077	1,499	7,118	15,765	153,986	-4,936
1988	2,017	22,571	13,676	10,912	6,771	1,638	1,909	10,318	16,270	158,946	4,960
1989	2,997	26,446	23,507	5,936	6,184	1,450	2,243	9,877	16,582	158,177	-769
1990	1,877	17,916	13,344	6,449	7,898	2,004	2,412	12,314	16,894	160,046	+1,869
1991	2,967	19,095	15,235	6,827	5,074	848	1,563	7,485	16,849	157,509	-2,537
1992	1,946	17,878	11,941	7,883	4,621	649	1,724	6,994	17,009	155,377	-2,132

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.
[b]Net of revisions and adjustments = Col. 1 + Col. 2 - Col. 3.
[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[d]Proved reserves = Col. 10 from prior year + Col. 4 + Col. 8 - Col. 9.
[e]Based on following year data only.
[f]Consists only of operator reported corrections and no other adjustments.
[g]An unusually large revision decrease to North Slope dry natural gas reserves was made in 1988. It recognizes some 24.6 trillion cubic feet of downward revisions reported during the last few years by operators because of economic and market conditions. EIA in previous years carried these reserves in the proved category.
– = Not applicable.

Notes: •Old means discovered in a prior year. •New means discovered during the report year. •The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production,". They may differ from the official Energy Information Administration production data for crude oil, natural gas, and natural gas liquids for 1992 contained in the *Petroleum Supply Annual 1992,* DOE/EIA-0340(92) and the *Natural Gas Annual 1992,* DOE/EIA-0131(92).
Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1977 through 1992 annual reports, DOE/EIA-0216.{8-22}

Table D3. Total U.S. Proved Reserves of Wet Natural Gas, After Lease Separation, 1978 through 1992
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Year	Adjustments[a] (1)	Revision Increases (2)	Revision Decreases (3)	Revisions[b] and Adjustments (4)	Extensions (5)	New Field Discoveries (6)	New Reservoir Discoveries in Old Fields (7)	Total[c] Discoveries (8)	Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
						U.S. Total					
1978	–	–	–	–	–	–	–	–	–	[e]208,033	–
1979	5,356	17,077	17,300	5,133	9,332	3,279	2,637	15,248	20,079	208,335	+302
1980	1,253	17,668	16,531	2,390	9,757	2,629	2,648	15,034	19,500	206,259	-2,076
1981	2,057	17,156	14,413	4,800	10,979	3,870	3,080	17,929	19,554	209,434	+3,175
1982	2,598	20,596	20,141	3,053	8,754	2,785	3,520	15,059	18,292	209,254	-180
1983	4,363	18,442	18,385	4,420	7,263	1,628	3,071	11,962	16,590	209,046	-208
1984	-2,413	18,751	15,418	920	8,688	2,584	2,778	14,050	18,032	205,984	-3,062
1985	-1,299	19,732	17,045	1,388	7,535	1,040	3,053	11,628	16,798	202,202	-3,782
1986	2,137	22,392	18,557	5,972	6,359	1,122	1,855	9,336	16,401	201,109	-1,093
1987	1,199	18,455	14,933	4,721	4,818	1,128	1,556	7,502	16,904	196,428	-4,681
1988	2,180	24,638	[f]39,569	-12,751	7,132	1,677	1,979	10,788	17,466	[f]176,999	-19,429
1989	2,537	27,844	24,624	5,757	6,623	1,488	2,313	10,424	17,752	175,428	-1,571
1990	1,494	19,861	14,024	7,331	8,287	2,041	2,492	12,820	18,003	177,576	+2,148
1991	3,368	20,758	16,189	7,937	5,298	871	1,655	7,824	18,012	175,325	-2,251
1992	2,543	18,906	12,532	8,917	4,895	668	1,773	7,336	18,269	173,309	-2,016
						Lower 48 States					
1978	–	–	–	–	–	–	–	–	–	[e]175,988	–
1979	5,402	16,358	17,069	4,691	9,331	3,264	2,637	15,232	19,851	176,060	+72
1980	1,218	16,577	16,427	1,368	9,446	2,629	2,648	14,723	19,287	172,864	-3,196
1981	2,270	17,002	14,352	4,920	10,973	3,870	3,076	17,919	19,318	176,385	+3,521
1982	2,586	18,371	20,119	838	8,754	2,785	3,520	15,059	18,030	174,252	-2,133
1983	4,366	18,136	17,643	4,859	7,262	1,628	3,071	11,961	16,317	174,755	+503
1984	-2,409	17,844	15,023	412	8,687	2,584	2,778	14,049	17,708	171,508	-3,247
1985	-1,313	19,203	16,490	1,400	7,463	1,040	3,053	11,556	16,485	167,979	-3,529
1986	2,114	22,207	17,797	6,524	6,357	1,122	1,845	9,324	16,073	167,754	-225
1987	1,200	17,733	14,865	4,068	4,772	1,116	1,556	7,444	16,553	162,713	-5,041
1988	2,025	23,829	[f]14,439	11,415	7,099	1,677	1,979	10,755	17,063	167,820	+5,107
1989	2,545	27,616	24,488	5,673	6,467	1,485	2,313	10,265	17,349	166,409	-1,411
1990	1,811	18,784	13,925	6,670	8,232	2,041	2,492	12,765	17,661	168,183	+1,774
1991	3,367	19,961	15,948	7,380	5,281	871	1,614	7,766	17,657	165,672	-2,511
1992	2,265	18,728	12,511	8,482	4,840	668	1,773	7,281	17,851	163,584	-2,088

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.
[b]Net of revisions and adjustments = Col. 1 + Col 2 - Col. 3.
[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[d]Proved reserves = Col. 10 from prior year + Col. 4 + Col. 8 - Col. 9.
[e]Based on following year data only.
[f]An unusually large revision decrease to North Slope wet natural gas reserves was made in 1988. It recognizes some 25 trillion cubic feet of downward revisions reported during the last few years by operators because of economic and market conditions. EIA in previous years carried these reserves in the proved category.
– = Not applicable.

Notes: •Old means discovered in a prior year. •New means discovered during the report year. •The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production,". They may differ from the official Energy Information Administration production data for crude oil, natural gas, and natural gas liquids for 1992 contained in the *Petroleum Supply Annual 1992*, DOE/EIA-0340(92) and the *Natural Gas Annual 1992*, DOE/EIA-0131(92).
Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1977 through 1992 annual reports, DOE/EIA-0216.(8-22)

Table D4. Total U.S. Proved Reserves of Natural Gas Liquids, 1978 through 1992
(Million Barrels of 42 U.S. Gallons)

Year	Adjustments[a] (1)	Revision Increases (2)	Revision Decreases (3)	Revisions[b] and Adjustments (4)	Extensions (5)	New Field Discoveries (6)	New Reservoir Discoveries in Old Fields (7)	Total[c] Discoveries (8)	Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
					U.S. Total						
1978	–	–	–	–	–	–	–	–	–	[e]6,772	–
1979	[f]64	677	726	15	364	94	97	555	727	6,615	-157
1980	153	743	639	257	418	90	79	587	731	6,728	+113
1981	231	729	643	317	542	131	91	764	741	7,068	+340
1982	299	811	832	278	375	112	109	596	721	7,221	+153
1983	849	847	781	915	321	70	99	490	725	7,901	+680
1984	-123	866	724	19	348	55	96	499	776	7,643	-258
1985	426	906	744	588	337	44	85	466	753	7,944	+301
1986	367	1,030	807	590	263	34	72	369	738	8,165	+221
1987	231	847	656	422	213	39	55	307	747	8,147	-18
1988	11	1,168	715	464	268	41	72	381	754	8,238	+91
1989	-277	1,143	1,020	-154	259	83	74	416	731	7,769	-469
1990	-83	827	606	138	299	39	73	411	732	7,586	-183
1991	233	825	695	363	189	25	55	269	754	7,464	-122
1992	225	806	545	486	190	20	64	274	773	7,451	-13
					Lower 48 States						
1978	–	–	–	–	–	–	–	–	–	[e]6,749	–
1979	[f]63	677	726	14	364	94	97	555	726	6,592	-157
1980	165	743	639	269	418	90	79	587	731	6,717	+125
1981	233	728	643	318	542	131	91	764	741	7,058	+341
1982	300	811	832	279	375	112	109	596	721	7,212	+154
1983	850	847	781	916	321	70	99	490	725	7,893	+681
1984	-115	847	724	8	348	55	96	499	776	7,624	-269
1985	70	883	731	222	334	44	85	463	748	7,561	-63
1986	363	1,030	804	589	263	34	72	369	735	7,784	+223
1987	179	846	655	370	212	39	55	306	731	7,729	-55
1988	10	1,167	715	462	267	41	72	380	734	7,837	+108
1989	-273	1,141	1,018	-150	259	83	74	416	714	7,389	-448
1990	-60	827	606	161	298	39	73	410	714	7,246	-143
1991	183	815	677	321	187	25	55	267	730	7,104	-142
1992	225	796	542	479	183	20	64	267	746	7,104	0

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.
[b]Net of revisions and adjustments = Col. 1 + Col. 2 - Col. 3.
[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[d]Proved reserves = Col. 10 from prior year + Col. 4 + Col. 8 - Col. 9.
[e]Based on following year data only.
[f]Consists only of operator reported corrections and no other adjustments.
– = Not applicable.

Notes: •Old means discovered in a prior year. •New means discovered during the report year. •The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production,". They may differ from the official Energy Information Administration production data for crude oil, natural gas, and natural gas liquids for 1992 contained in the *Petroleum Supply Annual 1992,* DOE/EIA-0340(92) and the *Natural Gas Annual 1992,* DOE/EIA-0131(92).

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1979 through 1992 annual reports, DOE/EIA-0216.{10-22}

Appendix E

Summary of Data Collection Operations

Summary of Data Collection Operations

Form EIA-23 Survey Design

The data collected on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," were used to produce this report. This section provides information concerning the survey design, response statistics, reporting requirements, and frame maintenance of this report.

Form EIA-23 is mailed annually to all known large and intermediate sized operators, and a scientifically selected sample of small operators. Operator size categories were based upon their annual production as indicated in various Federal, State, and commercial records. The term **State/subdivision** refers to an individual subdivision within a State or an individual State that is not subdivided. Operators were divided into the three size categories shown below.

- **Category I** - ***Large Operators:*** Operators who produced 1.5 million barrels or more of crude oil, or 15 billion cubic feet or more of natural gas, or both.

- **Category II** - ***Intermediate Operators:*** Operators who produced at least 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both, but less than Category I operators.

- **Category III** - ***Small Operators:*** Operators who produced less than the Category II operators.

Small Category III operators were further subdivided into groups of operators sampled with certainty and those that were randomly sampled (noncertainty) as shown below.

- **Certainties** - Small operators who produced less than the Category II operators but satisfied any of the following four criteria based upon their production as shown in the operator frame master file:

  1. Operators with annual crude oil production of 200 thousand barrels or more, or reserves of 4 million barrels or more; or annual natural gas production of 1 billion cubic feet or more, or reserves of 20 billion cubic feet or more.

  2. All other operators with production or reserves in a State/subdivision that exceed selected cutoff levels for that State/subdivision.

  3. The largest operator in each State/subdivision regardless of level of production or reserves.

  4. Operators with production or reserves of oil or gas shown for six or more State/subdivisions.

- **Noncertainties** - Small operators not in the certainty stratum were classified in a noncertainty stratum sampled at an overall rate of 8 percent.

Data were filed for calendar year 1992 by crude oil or natural gas well operators who were active as of December 31, 1992. EIA defines an operator as an organization or person responsible for the management and day-to-day operation of crude oil or natural gas wells. The purpose of this definition is to eliminate responses from royalty owners, working interest owners (unless they are also operators), and others not directly responsible for operations. An operator need not be a separately incorporated entity. To minimize reporting burden corporations are permitted to report on the basis of operating units of the company convenient for them. A large corporation may be represented by a single form or by several forms.

Table E1 shows a comparison of the EIA-23 sample and sampling frame between 1985 and 1992, and depicts the number of active operators, 1989 showing the largest in the series. The 1992 sampling frame of 4,257 operators consisted of 157 Category I, 480 Category II, 1,896 Category III certainties, and 21,573 operators in the noncertainty stratum for a total of 24,106 active operators. The survey sample consisted of 2,533 operators selected with certainty that included all of the Category I and II certainty operators, the 1,896 smaller operators that were selected with certainty because of their size in relation to the area or areas in which they operated, and 1,724 noncertainty operators selected as random samples from the remaining operators.

Form EIA-23 Response Statistics

Each company and its parent company or subsidiaries were required to file Form EIA-23 if they met the survey specifications. Response to the 1992 survey is summarized in Table E2. EIA makes a considerable effort to gain responses from all operators. About 8 percent of those selected turned out to be nonoperators (those that reported being nonoperators during the report year and operators that could not be located). Of the 338 nonoperators, 82 had successor operators that had taken over the production of the nonoperator. These successor operators were sub-

Table E1. Comparison of the EIA-23 Sample and Sampling Frame, 1985 through 1992

Operator Category	Number of Operators							
	1985	1986	1987	1988	1989	1990	1991	1992
Certainty								
Category I	145	155	152	149	134	144	144	157
Category II	486	548	541	500	500	468	484	480
Category III	1,586	2,451	3,116	3,289	2,936	2,316	2,074	1,896
Total in Frame	2,217	3,154	3,809	3,938	3,570	2,929	2,702	2,533
Sampled	2,217	3,154	3,809	3,938	3,570	2,929	2,702	2,533
Percent Sampled	100	100	100	100	100	100	100	100
Noncertainty								
Total in Frame	22,837	23,019	23,570	22,797	24,062	24,628	21,972	21,573
Sampled	1,827	1,423	1,265	1,282	1,325	1,431	1,760	1,724
Percent Sampled	8	8	6	5	6	6	8	8
Total								
Active Operators	25,054	26,173	27,379	26,735	27,632	27,556	24,674	24,106
Not Sampled	21,010	21,596	22,305	21,515	22,737	23,196	20,212	19,849
Sampled	4,044	4,577	5,074	5,220	4,895	4,360	4,462	4,257
Percent Sampled	16	17	19	20	18	16	18	18

Source: Energy Information Administration, Office of Oil and Gas.

Table E2. Form EIA-23 Survey Response Statistics, 1992

Operator Category	Sample Selected	Successor[a] Operators	Net[b] Category Changes	Non-[c] operators	Total Operators	Responding Operators		Nonresponding Operators	
						Number	Percent	Number	Percent
Certainty									
Category I	157	1	7	-5	160	160	100.0	0	0.0
Category II	480	3	5	-17	471	471	100.0	0	0.0
Category III	1,896	38	-12	-82	1,840	1,827	99.3	13	0.7
Subtotal	2,533	42	0	-104	2,471	2,458	99.5	13	0.5
Noncertainty	1,724	40	0	-234	1,530	1,506	98.4	24	1.6
Total	4,257	82	0	-338	4,001	3,964	99.1	37	0.9

[a]Successor operators are those, not initially sampled, that have taken over the production of a sampled operator.
[b]Net of recategorized operators in the sample (excluding nonoperators).
[c]Includes former operators reporting that they were not operators during the report year and operators that could not be located who are treated as nonoperators.
Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves" 1992.

sequently sampled. The overall response rate for the 1992 survey was 99.1 percent. This compares with a 98.4 percent overall response rate for all operators in 1991. The response rates for Category I and Category II operators in 1992 was 100 percent.

Nonresponse was not a problem among Category I and Category II operators. However, imputations at a State/subdivision level were made for the missing data of 13 Category III and 24 noncertainty operators who were delinquent in filing. These imputations were included in the published estimates and accounted for approximately 0.04 percent of the total estimated production for crude oil and approximately 0.08 percent of the total estimated production for natural gas.

Form EIA-23 Reporting Requirements

The collection format for Form EIA-23 actually consists of two forms. The form that the respondent is required to file is dependent upon the annual production levels of crude oil, natural gas, and lease condensate. Category I and Category II operators file a more detailed field level data form. Category III operators file a summary report which is aggregated at a State/subdivision level.

The cover page required of all respondents identifies each operator by name and address and is shown as Figure I1. The oil and gas producing industry includes a large number of small enterprises. To minimize reporting burden, only a sample of small operators were required to file a summary report of Form EIA-23. The summary report schedules are shown in Figures 12 and 13. Report year production data were required by State/subdivision areas for crude oil, natural gas, and lease condensate. Proved reserves data for operators were required only for those properties where estimates existed in the respondent's records.

All Category I and Category II operators were required to file field level data on Schedule A, "Operated Proved Reserves, Production, and Related Data by Field," for each oil and/or gas field in which the respondent operated properties. An example of Schedule A is shown in Figure 14. All Category I and those Category II operators who had reserve estimates were required to file on a total operated basis for crude oil, nonassociated natural gas, associated-dissolved natural gas, and lease condensate. The following data items were required to be filed: proved reserves at the beginning and the end of the report year, revision increases and revision decreases, extensions, new field discoveries, new reservoirs in old fields, production, indicated additional reserves of crude oil, nonproducing reserves, field discovery year, water depth, and field location information.

Category II operators who did not have reserves estimates were required to file the field location information and report year production for the four hydrocarbon types from properties where reserves were not estimated.

These respondents used Schedule B, "Footnotes," to provide clarification of reported data items when required in the instructions, or electively to provide narrative or detail to explain any data item filed. An example of Schedule B is shown in Figure 15.

Crude oil and lease condensate volumes were reported rounded to thousands of barrels of 42 U.S. gallons at 60° Fahrenheit, and natural gas volumes were reported rounded to millions of cubic feet. All natural gas volumes were requested to be reported at 60° Fahrenheit and a pressure base of 14.73 pounds per square inch absolute. Other minor report preparation standards were specified to assure that the filed data could be readily processed.

Oil and Gas Field Coding

A major effort to create standardized codes for all identified oil or gas fields throughout the United States was implemented during the 1982 survey year. Information from previous lists was reviewed and reconciled with State lists and a consolidated list was created. The publication of the *Oil and Gas Field Code Master List 1992*, in December of 1992, was the 11th annual report and reflected data collected through October 1992. This publication was mailed to operators to assist in identifying the field code data necessary for the preparation of Form EIA-23. A copy of this publication may be purchased from the National Energy Information Center. A machine-readable tape version of the publication is available from the National Technical Information Service.

Form EIA-23 Comparison with Other Data Series

Estimated crude oil, lease condensate, and natural gas production volumes from Form EIA-23 were compared with official EIA production data supplied by Federal and State oil and natural gas regulatory agencies and published in EIA's monthly and annual reports. Reports published by the Federal and State oil and natural gas regulatory agencies were used to compare specific operator production responses to these agencies with Form EIA-23 responses. When significant differences were found, responses were researched to detect and reconcile possible reporting errors.

For 1992, Form EIA-23 national estimates of production were 2,593 million barrels for crude oil and lease condensate or 32 million barrels (1.2 percent) lower than that reported in the *Petroleum Supply Annual 1992* for crude oil and lease condensate. Form EIA-23 national estimates of production for dry natural gas were 17,423 billion cubic feet or 354 billion cubic feet (2 percent) lower than the *Natural Gas Monthly August 1993* for 1992 dry natural gas production.

Form EIA-23 Frame Maintenance

Operator frame maintenance is a major data quality control effort. It is necessary to update and maintain the frame regularly in order to ensure an accurate basis for each annual survey. Extensive effort is expended to keep the frame as current as possible. The Form EIA-23 frame contains a listing of all crude oil and natural gas well operators in the United States and must be maintained and updated regularly in order to ensure an accurate frame from which to draw the sample for the annual crude oil and natural gas reserves survey. The original frame, created in 1977, has been revised annually. In addition, outside sources, such as State publications and computer tapes, and commercial information data bases such as Dwight's Energydata and Petroleum Information, are used to obtain information on operator status and to update addresses for the frame each year.

A maintenance procedure is utilized, using a postcard form with prepaid return postage, to contact possible active crude oil and natural gas well operators presently listed on EIA's master frame, but for whom the listing had not been updated for 2 years. This procedure identifies active operators and nonoperators which improves the frame for future sample selections for the survey. Table A3 provides a summary of changes made to the Form EIA-23 frame of crude oil and natural gas well operators for the 1992 survey mailing. These changes resulted from all frame maintenance activities.

The Form EIA-23 operator frame contained a total of 57,628 entries as of January 10, 1993. Of these, 24,079 were confirmed operators. These are operators who have filed in the past or for whom the EIA has recent production data from an outside source. The remaining operators (including both definite and probable nonoperators) exist as a pool of names and addresses that may be added to the active list if review indicates activity.

Table E3. Summary of the 1992 Operator Frame Activity, Form EIA-23

Total 1991 Operator Frame	57,628
Changes to 1991 Operator Status	
From Operator to Nonoperator	2,329
From Nonoperator to Operator	87
Subtotal	2,416
No Changes to 1991 Operator Status	
Operators	22,303
Nonoperators	32,909
Subtotal	55,212
Additions to Operator Frame	
Operator	1,689
Nonoperator	38
Subtotal	1,727
Total 1992 Operator Frame	**59,355**

Note Includes operator frame activity through January 10, 1993.
Source Energy Information Administration, Office of Oil and Gas.

Form EIA-64A Survey Design

The data for this report are also collected on Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." This section provides information concerning the survey design, response statistics, reporting requirements, and frame maintenance for Form EIA-64A.

Form EIA-23 for report years 1977 and 1978 required natural gas well operators to report their natural gas data on a fully dry basis. It was discovered in the course of those surveys that many operators had little or no knowledge of the extraction of liquids from their produced natural gas streams once custody transfer had taken place. Therefore, these operators reverted to reporting the only natural gas volume data they had in their possession. These volume data were for dryer natural gas than that which had passed through the wellhead, but wetter than fully dry natural gas. With reference to Figure E1, they reported their volumes either at point A, the wellhead, or point C, after removal of lease condensate in their lease or field separation facilities.

Some of the larger operators, however, also owned or operated natural gas processing plants. They reported their volumes at point E, after removal of both lease condensate and plant liquids, as required by Form EIA-23. The aggregate volumes resulting from the 1977 and 1978 surveys, therefore, were neither fully dry (as was intended) nor fully wet. They do appear to have been more dry than wet simply because the operators who reported fully dry volumes also operated properties that contained the bulk of proved natural gas reserves.

The EIA recognized that its estimates of proved reserves of natural gas liquids (NGL) had to reflect not only those volumes extractable in the future under current economic and operating conditions at the lease or field (lease condensate), but also volumes (plant liquids) extractable downstream at existing natural gas processing plants. Form EIA-64, which already canvassed these processing plants, did not request that the plants' production volumes be attributed to source areas. Beginning with the 1979 survey, a new form to collect plant liquids production according to the area or areas where their input natural gas stream had been produced was mailed to all of the operating plants. The instructions for filing the Form EIA-23 were altered to collect data from natural gas well operators that reflected those volumes of natural gas dried only through the lease or field separation facilities. The reporting basis of these volumes are referred to as "wet after lease separation." The methodology used to estimate NGL reserves by State and State subdivision is provided in Appendix B.

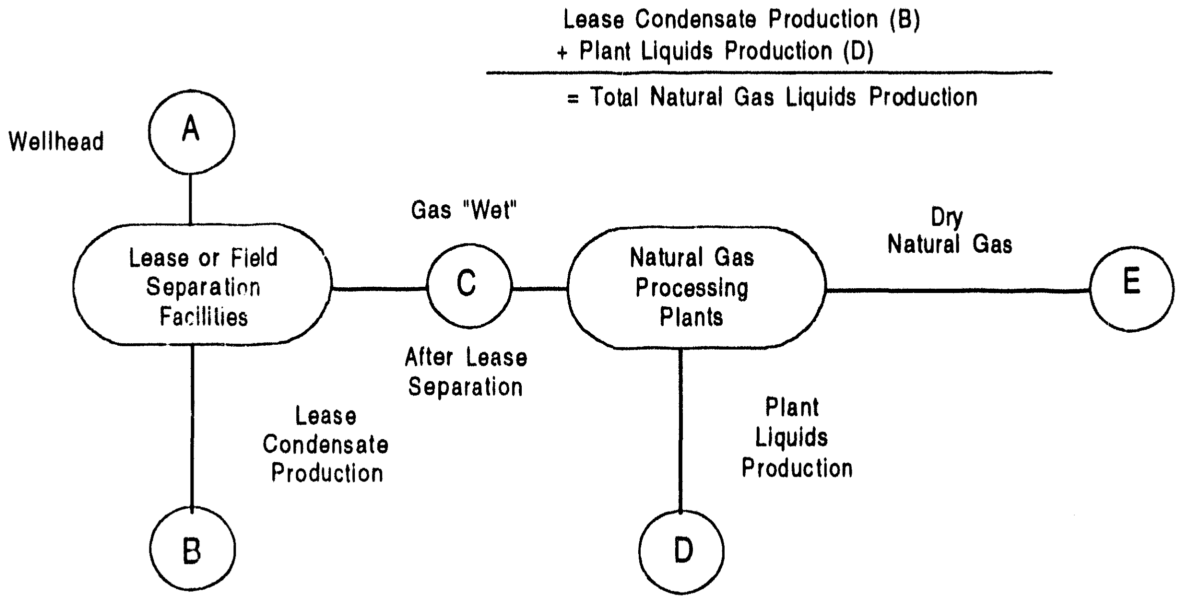
Form EIA-64A Response Statistics

EIA mailed EIA-64A forms to all known natural gas processing plant operators as of December 31, 1992. In addition, plant operators whose plants were shut down or dismantled during 1992 were required to complete forms for the portion of 1992 when the plants were in operation.

Natural gas processing plant operators were requested to file a Form EIA-64A for each of their plants. A total of 315 operators of 867 plants were sent forms. This number included 6 new plants and 35 successor plants identified after the initial 1992 survey mailing. A total of 56 plants were reported as nonoperating according to the Form EIA-64A definition. The response rate was again 100 percent.

Form EIA-64A respondents were requested to report natural gas liquids production data by area of origin. Table E4 summarizes the responses by plant operators of the

Figure E1. Natural Gas Liquids Extraction Flows



Source: Energy Information Administration, Office of Oil and Gas.

volume and origin of natural gas delivered to the processing plants and the volume of the natural gas liquids extracted by the plants by State. The majority of the plant operators reported only one area of origin for the natural gas that was processed by a plant. The State or area of origin reported is generally also the plant's location.

Form EIA-64A Reporting Requirements

Form EIA-64A consisted of the reporting schedule shown in Figure 16. The form identifies the plant, its geographic location, the plant operator's name and address, and the parent company name. The certification was signed by a responsible official of the operating entity. The form pertains to the volume of natural gas received and of natural gas liquids produced at the plant, allocated to each area of origin. Operators also filed the data pertaining to the amount of natural gas shrinkage that resulted from extraction of natural gas liquids at the plant, and the amount of fuel used in processing.

Natural gas liquids volumes were reported rounded to thousands of barrels of 42 U.S. gallons at 60° Fahrenheit, and natural gas volumes were reported rounded to millions of cubic feet. All natural gas volumes were requested to be reported at 60° Fahrenheit and a pressure base of 14.73 pounds per square inch absolute. Other minor report preparation standards were specified to assure that the filed data could be readily processed.

Form EIA-64A Comparison with Other Data Series

Form EIA-64A plant liquids production data were compared with data collected on Form EIA-816, "Monthly Natural Gas Liquids Report." Aggregated production from Form EIA-816 represents the net volume of natural gas processing plant liquid output less input for the report year. These data are published in EIA's *Petroleum Supply Annual* reports. The Form EIA-64A annual responses reflect all corrections and revisions to EIA's monthly estimates. Differences, when found, were reconciled in both sources. For 1992, the Form EIA-64A national estimates were 0.8 percent (5 million barrels) higher than the *Petroleum Supply Annual 1992* volume for natural gas plant liquids production.

Table E4. Processed Natural Gas and Liquids Extracted at Natural Gas Processing Plants, 1992

Plant Location	Volume of Natural Gas Delivered to Processing Plants: State Production	Out of State Production	Natural Gas Processed	Total Liquids Extracted
	(millions of cubic feet)			(thousand barrels)
Alaska	1,873,279	0	1,873,279	24,019
Lower 48 States	**13,669,850**	**686,555**	**14,356,405**	**578,715**
Alabama	76,739	0	76,739	3,650
Arkansas	224,625	0	224,625	259
California	246,335	0	246,335	9,389
Colorado	234,021	830	234,851	11,747
Florida	5,990	216,903	222,893	1,695
Kansas	774,871	180,169	955,040	30,328
Kentucky	40,682	284	40,966	1,655
Louisiana	4,182,669	157,862	4,340,531	91,128
Michigan	170,574	0	170,574	6,307
Mississippi	7,605	44	7,649	408
Montana	14,509	335	14,864	789
North Dakota	59,228	0	59,228	4,852
New Mexico	633,514	12,602	646,116	49,151
Oklahoma	1,096,784	4,028	1,100,812	72,824
Texas	4,781,445	93,273	4,874,718	253,476
Utah and Wyoming	1,000,971	13,886	1,014,857	33,729
West Virginia	111,635	0	111,635	6,858
Miscellaneous[a]	7,653	6,319	13,972	470
Total	**15,543,129**	**686,555**	**16,229,684**	**602,734**

[a]Includes Illinois, Nebraska, Ohio, Pennsylvania, and Tennessee.
Source: Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production," 1992

Form EIA-64A Frame Maintenance

The Form EIA-64A plant frame contains data on all known active and inactive natural gas processing plants in the United States. The 1992 plant frame was compared to listings of natural gas processing plants from Form EIA-816, "Monthly Natural Gas Liquids Report"; the *LPG Almanac*; and the *Oil and Gas Journal*. A list of possible additions to the plant frame was compiled. Table E5 summarizes the Form EIA-64A plant frame changes made as a result of the comparisons as of December 31, 1992.

Table E5. Summary of the 1992 Plant Frame Activity, Form EIA-64A

Frame as of 1991 survey mailing	876
Additions	222
Deletions	–230
Frame as of 1992 survey mailing	868

Note: Includes operator frame activity through December 31, 1992.
Source: Energy Information Administration, Office of Oil and Gas.

Appendix F

Statistical Considerations

Statistical Considerations

Survey Methodology

The Form EIA-23 survey is designed to provide reliable estimates for reserves and production of crude oil, natural gas, and lease condensate for the United States. Operators of crude oil and natural gas wells were selected as the appropriate respondent population because they have access to the most current and detailed information, and therefore, presumably have better reserve estimates than do other possible classes of respondents, such as working interest or royalty owners.

While large operators are quite well known, they comprise only a small portion of all operators. The small operators are not well known and are difficult to identify because they go into and out of business, alter their corporate identities, and change addresses frequently. As a result, EIA conducts extensive frame maintenance activities each year to identify all current operators of crude oil and natural gas wells in the country.

Sampling Strategy

EIA publishes data on reserves and production for crude oil, natural gas, and lease condensate by State for most States, and by State subdivision for the States of California, Louisiana, New Mexico, and Texas. To meet the survey objectives, while minimizing respondent burden, a random sampling strategy has been used since 1977. Each operator reporting on the survey is asked to report production for crude oil, natural gas, and lease condensate for each State/subdivision in which he operates. The term **State/subdivision** refers to an individual subdivision within a State or an individual State that is not subdivided.

The total volume of production varies among the State/subdivisions. To meet the survey objectives while controlling total respondent burden, EIA selected the following target sampling error for the 1992 survey for each product class.

- 1.0 percent for National estimates.
- 1.0 percent for each of the 5 States having subdivisions: Alaska, California, Louisiana, New Mexico, and Texas. For selected subdivisions within these States, targets of 1.0 percent or 1.5 percent as required to meet the State target.
- 2.5 percent for each State/subdivision having 1 percent or more of estimated U.S. reserves or production in 1991 (Lower 48 States) for any product class.
- 4 percent for each State/subdivision having less than 1 percent of estimated U.S. reserves or production in 1991 (Lower 48 States) for all 3 product classes.
- 8 percent for States not published separately. The combined production from these States was less than 0.2 percent of the U.S. total in 1991 for crude oil and for natural gas.

The volume of production defining the certainty stratum, referred to as the **cutoff**, varies by product or State/subdivision. The cutoff criteria and sampling rates are shown in Table B1. The certainty stratum, therefore, has three components.

- **Category I** - *Large Operators:* Operators who produced a total of 1.5 million barrels or more of crude, or 15 billion cubic feet or more of natural gas, or both in 1991.
- **Category II** - *Intermediate Operators:* Operators who produced a total of at least 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both, but less than Category I operators in 1991.
- **Category III** - *Small Operators:* Operators who produced less than the Category II operators in 1991, but which were selected with certainty because they operate in six or more States/subdivisions, or because their production volumes exceeded the State/subdivision cutoff.

In each State/subdivision the balance between the number of small certainty operators and the sample size was determined in an iterative procedure designed to minimize the number of total respondents. The iteration for each State/subdivision began with only the Category I and Category II operators in the certainty stratum. The size of the sample of small operators required to meet the target variance was calculated based on the variance of the volumes of those operators. For a number of State/subdivisions with high correlations between frame values across pairs of consecutive years, an adjusted target variance was calculated, that utilized the information about the correlations. This allowed the selection of a smaller sample that still met the target sampling error criteria. At each iteration a small operator, beginning with the largest of the Category III operators, was added to the certainty group and the required sample size was again calculated. The procedure of

Table F1. 1992 EIA-23 Survey Initial Sample Criteria

State and Subdivision	Production Cutoffs: Crude Oil (mbbls)	Production Cutoffs: Cutoff (mmcf)	Certainty Sample Number	Noncertainty Sample: Single State Operator Number	Noncertainty Sample: Multi-State Operator Number
Alabama Onshore	117	886	73	2	0
Alaska	0	0	9	0	0
Arkansas	31	1,000	148	19	4
California Unspecified	4	16	10	5	0
California-Coastal Region Onshore	200	768	33	7	3
California-Los Angeles Basin Onshore	200	25	50	11	2
California-San Joaquin Basin Onshore	200	545	77	26	1
Colorado	200	900	206	28	11
Florida Onshore	0	0	11	0	0
Illinois	38	25	164	38	3
Indiana	5	12	115	11	1
Kansas	61	542	373	159	14
Kentucky	6	240	171	16	2
Louisiana Unspecified	3	61	17	8	0
Louisiana North	14	1,000	272	49	10
Louisiana South Onshore	200	1,000	251	18	5
Michigan	110	1,000	62	9	0
Mississippi Onshore	200	1,000	144	9	4
Montana	200	337	122	10	2
Nebraska	30	4	83	5	1
New Mexico Unspecified	2	44	6	2	0
New Mexico East	200	1,000	226	16	8
New Mexico West	32	1,000	86	7	3
New York	5	84	66	50	1
North Dakota	200	1,000	136	6	1
Ohio	14	249	217	147	1
Oklahoma	86	1,000	527	290	37
Pennsylvania	6	694	140	25	2
Texas Unspecified	9	89	78	48	1
Texas-RRC District 1	139	1,000	246	69	30
Texas-RRC District 2 Onshore	200	1,000	219	13	18
Texas-RRC District 3 Onshore	200	1,000	320	37	23
Texas-RRC District 4 Onshore	200	1,000	236	16	18
Texas-RRC District 5	200	1,000	125	13	7
Texas-RRC District 6	200	1,000	240	24	17
Texas-RRC District 7B	54	148	329	88	43
Texas-RRC District 7C	200	1,000	276	22	28
Texas-RRC District 8	200	1,000	306	32	28
Texas-RRC District 8A	200	1,000	272	17	19
Texas-RRC District 9	45	684	278	91	29
Texas-RRC District 10	110	716	239	37	10
Utah	200	671	74	6	4
Virginia	0	0	24	0	0
West Virginia	6	492	131	46	3
Wyoming	200	1,000	226	14	9
Offshore Areas	0	0	269	0	0
Other States[a]	139	95	56	14	1
Total	--	--	[b]2,439	1,560	[b]171

[a]Includes Arizona, Connecticut, Delaware, Georgia, Idaho, Iowa, Massachusetts, Maryland, Minnesota, Missouri, North Carolina, New Hampshire, Nevada, New Jersey, Oregon, Rhode Island, South Carolina, South Dakota, Tennessee, Washington, and Wisconsin.

[b]Non-duplicative count of operators by States.

Note: Sampling rate was 8 percent except in Alaska, Florida Onshore, Virginia, and Offshore areas where sampling rate was 100 percent.

-- = Not applicable.

Source: Energy Information Administration, Office of Oil and Gas.

adding one operator at a time stopped when the proportion of operators to be sampled at random dropped below 8 percent. Independent samples of single location operators (operators who, according to the sampling frame, operate in only one State/subdivision, were selected from each State/subdivision using simple random sampling.

An additional complexity is introduced by the fact that some small operators selected for the sample in another region or regions, sometimes report production volumes in a region in which EIA has no previous record of production.

State/subdivision estimates are calculated as the sum of the certainty strata and all of the estimates for the sampling strata in that region. The sampling variance of the estimated total is the sum of the sampling variances for the sampling strata. There is no sampling error associated with the certainty stratum. The square root of the sampling variance is the standard error. It can be used to provide confidence intervals for the State/subdivision totals.

For the States in which subdivision estimates are published, the State total is the sum of the individual estimates for the subdivisions. The sampling variance is the sum of the corresponding sampling variances for the subdivisions. The U.S. total is estimated as the sum of the State estimates.

Total U.S. Reserve Estimates

Conceptually, the estimates of U.S. reserves and production can be thought of as the sum of the estimates for the individual States. Correspondingly, the estimates for the four States for which estimates are published separately by subdivision (California, Louisiana, New Mexico, and Texas) can be thought of as the sum of the estimates by subdivision. The remaining States are not subdivided and may be considered as a single subdivision.

The estimates of year-end proved reserves and annual production for any State/subdivision is the sum of the volumes in the State/subdivision reported by the certainty stratum operators and an estimate of the total volume in the State/subdivision by the noncertainty stratum operators. Mathematically, this may be stated as the following sum:

$$\hat{V}_s = V_{sc} + \hat{V}_{sr}$$

where

$\hat{V}_s$ = estimated total volume in the State/subdivision

V_{sc} = total volume in the State/subdivision reported by certainty operators

$\hat{V}_{sr}$ = estimated total volume in the State/subdivision of noncertainty operators.

The total volume of certainty operators in the State/subdivision is simply the sum of individual operator's volumes:

$$V_{sc} = \sum_{m=1}^{n_{sc}} V_{scm}$$

where

n_{sc} = number of certainty operators reporting production in the State/subdivision

V_{scm} = volume reported by the m-th certainty stratum operator in the State/subdivision.

The estimated total volume of noncertainty operators in the State/subdivision is the weighted sum of the reports of the noncertainty sample operators:

$$\hat{V}_{sr} = \sum_{m=1}^{n_{sr}} W_{srm} V_{srm}$$

where

n_{sr} = number of noncertainty operators reporting production in the State/subdivision

V_{srm} = volume reported by the m-th noncertainty sample operator in the State/subdivision

W_{srm} = weight for the report by the m-th noncertainty sample operator in the State/subdivision.

In selecting the noncertainty sample, the number of sample operators with production in a given State/subdivision is not controlled to the number expected based on the sampling rate, but is subject to some variation. The weight used is the reciprocal of the actual sampling rate that resulted for the stratum from which the sample operator was selected, rather than the reciprocal of the expected sampling rate. The sample estimate with either set of weights is an unbiased estimator of the noncertainty stratum total. However, use of the actual sampling rates is expected to lead to smaller sampling errors for the estimates. In making estimates for a State/subdivision, separate weights are applied as appropriate for noncertainty operators shown in the frame as having had production in only the State/subdivision, for those shown as having had production in that State/subdivision and up to four other States/subdivisions, and for operators with no previous record of production in the State/subdivision. National totals were then obtained by summation of the component totals.

The weights used for making the survey estimates were based on the sampling strata. However, in a few cases the sampling strata were combined for purposes of estimation and the sampling weights were adjusted by a post-stratification technique intended to minimize the sampling variance of survey estimates. The sampling strata affecting the States included in the miscellaneous line in the published tables were combined for this purpose. In a few cases, sampling strata affecting a State/subdivision for which separate estimates are shown in the tables were combined.

Imputation for Operator Nonresponse

Table A2 shows that nonresponse was not a problem for Category I operators (100 percent response rate). The nonresponse rate among Category II and Category III operators has been relatively low in past surveys and was (2.2 percent) in 1992. EIA chose to impute for the nonresponding operators in order to improve production estimates. The resulting estimate of production data from nonresponding operators represented less than 0.1 percent of either the total National estimate of crude oil or natural gas production.

Imputations for Category III certainty operators and Category III random operators were calculated separately, using adjusted average production. The average production per responding sampled operator, adjusted to reflect the proportion of net nonoperators among responding operators, was used to impute for the nonresponding operators.

- Category change operators were excluded since they are not expected to have an effect on current nonresponding operators.
- Successors are included in calculating average production figures but nonoperators are excluded.

The approach utilizes the definitional categories found in Table A2. The imputed production by State/subdivision is calculated separately for certainty operators and random operators. For each, the imputed production is calculated by product, by State/subdivision, in three steps.

1. The average production reported on the EIA-23 survey, per responding operator by State/subdivision and product is calculated.

2. A net nonoperator adjustment factor is then calculated to account for the potential effect of nonoperators. For this purpose, it is assumed that the proportion of net operators and nonoperators among the nonrespondents is the same as among respondents. The average production is then adjusted by this factor.

3. The imputed production volume, IV_{sp}, for each product and State/subdivision is then calculated as:

$$IV_{sp} = F_{sp} * (AV_{sp} * NR_{sp})$$

where

F_{sp} = The net nonoperator adjustment factor for certainties in State/subdivision s and for product p

AV_{sp} = The average production volume per responding operator in State/subdivision s and for product p

NR_{sp} = The number of nonrespondents expected to report in State/subdivision s for product p.

For each nonrespondent, data are imputed only for each product and State/subdivision in which they were expected to report, based on the sampling criteria and data. The data used to select the operator for the sample were used to predict which product p and State/subdivision s each nonrespondent was expected to report. The resulting imputed values are provided by State/subdivision, by product (oil and gas only), and for production only.

The calculations for certainty and random nonrespondents follow the same methodology with the exception that the random nonrespondents data was weighted data rather than the reported data.

Estimation and Imputation for Reserve Data

In order to estimate reserve balances for National and State/subdivision levels, a series of estimation and imputation steps at the operator level must be carried out. Year-end reserves for operators who provided production data only were imputed on the basis of their production volumes. Imputation was also applied to the small and intermediate operators as necessary to provide data on each of the reserve balance categories (i.e., revisions, extensions, or new discoveries). Finally, an imputation was required for the natural gas data of the small operators to estimate their volumes of associated-dissolved and nonassociated natural gas. The final manipulation of the data accounts for the differences caused by different sample frames from year to year. Each of these imputations generated only a small percentage of the total estimates. The methods used are discussed in the following paragraphs.

The actual data reported on an operated basis by Form EIA-23 respondents for the report year 1992 are summarized in Tables F2, F3, F4, and F5. The differences between these sums and the total estimates shown in Tables 6, 9, 10, and 16 in the main text represent the aggregate result of statistical estimation and imputation performed by EIA. The reported data shown in Table F2 indicate that those responding operators accounted for 93.1 percent of published crude oil production and 95.4 percent of the reserves shown in Table 6. The reported data in Table F3 also show that those responding operators accounted for 96.7 percent of the published production for natural gas shown in Table 9 and 93.4 percent of the reserves. Data shown in Table F4 indicate that those responding operators accounted for 92.9 percent of the nonassociated natural gas production and 91.9 percent of the reserves published in Table 10. Additionally, Table F5 indicates that those responding operators accounted for 100 percent of the published production and 96.2 percent of the published proved reserves for lease condensate shown in Table 16.

Imputation of Year-End Proved Reserves

Category I operators were required to submit year-end estimates of proved reserves. Category II and Category III operators were required to provide year-end estimates of proved reserves only if such estimates existed in their records. Some of these respondents provided estimates for all of their operated properties, others provided estimates for only a portion of their properties, and still others provided no estimates for any of their properties. All respondents did, however, provide annual production data. The production reported by noncertainty sample operators and the corresponding reserves imputed were weighted to estimate the full noncertainty stratum when calculating reserves and production as described in the section "Total U.S. Reserves Estimates."

A year-end proved reserves estimate was imputed in each case where an estimate was not provided by the respondent. Reserves were imputed from reported production data for all random operators. The reported annual production was multiplied by a reserves-to-production (R/P) ratio (shown in Table B6) characteristic of operators of similar size in the region where the properties were located. The regional R/P ratios in this report are averages calculated by dividing the mean of reported reserves by the mean of reported production for selected respondents of similar size who did report estimated reserves. Operators that had R/P ratios that exceeded 25 to 1 and Category I operators were excluded from the respondents selected to calculate the characteristic regional R/P ratio. All other Category III respondents who reported both production and reserves were used to calculate the regional R/P ratio characteristic.

The R/P ratio varied significantly from region to region. This variation was presumably in response to variation in geologic conditions and the degree of development of crude oil and natural gas resources in each area. The average R/P ratio was computed for regional areas similar to the National Petroleum Council regional units (Figure B1). These units generally follow the boundaries of geologic provinces wherein the stage of resource development tends to be similar. Table B6 lists the R/P ratio calculated for each region that required such imputations and the number of observations on which it was based.

The regional R/P ratio is determined primarily to provide a factor that can be applied to the production reported by operators without reserve estimates to provide an estimate of the reserves of these operators when aggregated to the regional level. The average R/P ratio, when multiplied by each individual production in the distribution of R,P pairs used to calculate it, will exactly reproduce the sum of the reported reserves in the distribution.

Imputation of Annual Changes to Proved Reserves by Component of Change

Category II and Category III operators that do not keep reserves data were not asked to provide estimates of beginning-of-year reserves or annual changes to proved reserves by component of change, i.e., revisions, extensions, and discoveries. When they did not provide estimates, these volumes were estimated by applying an algebraic allocation scheme which preserved the relative relationships between these items within each State/subdivision, as reported by Category I and Category II operators, and also preserved an exact annual reserves balance of the following form:

Table F2. Summary of Reported Crude Oil Used in Estimation Process, Form EIA-23
(Thousand Barrels of 42 U.S. Gallons)

Level of Reporting	Operator Category I	Operator Category II	Operator Category Noncertainty[a] III	Operator Category Certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/91	21,682,086	900,448	--	93,939	22,676,473
(+) Revision Increases	1,525,059	111,004	--	3,608	1,639,671
(–) Revision Decreases	851,915	69,268	--	3,241	924,424
(+) Extensions	327,724	25,583	--	1,173	354,480
(+) New Field Discoveries	7,524	1,277	--	0	8,801
(+) New Reservoir Discoveries in Old Fields	66,335	11,672	--	600	78,607
(–) Production in 1992	2,017,478	118,910	--	10,986	2,147,374
Proved Reserves as of 12/31/92	20,739,342	861,778	--	85,090	21,686,210
State Level Summary Report					
Production in 1992	0	3,6852	2,159	45,508	51,519
Proved Reserves as of 12/31/92	0	33,865	17,030	372,638	423,533
Production without Proved Reserves Reported in 1992	4,510	40,697	7,810	80,497	133,514
Total Production in 1992	**2,021,988**	**163,459**	**9,969**	**136,991**	**2,332,407**
Total Proved Reserves as of 12/31/92	**20,739,342**	**895,643**	**17,030**	**457,728**	**22,109,743**

[a]Unweighted reported data.
-- = Not applicable.
Note: Field level data are reported volumes and may not balance due to submission of incomplete records.
Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1992.

Table F3. Summary of Reported Total Natural Gas, Wet After Lease Separation, Data Used in Estimation Process, Form EIA-23
(Million Cubic Feet at 14.73 psia and 60° Fahrenheit)

Level of Reporting	Operator Category I	Operator Category II	Operator Category Noncertainty[a] III	Operator Category Certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/91	146,957,884	14,936,432	--	677,201	162,571,517
(+) Revision Increases	15,644,804	1,699,470	--	30,577	17,374,851
(–) Revision Decreases	10,003,316	1,405,175	--	11,053	11,419,544
(+) Extensions	4,025,101	452,324	--	5,643	4,438,068
(+) New Field Discoveries	554,161	65,614	--	15,287	635,062
(+) New Reservoir Discoveries in Old Fields	1,506,550	191,026	--	2,287	1,699,863
(–) Production in 1992	14,711,197	1,545,424	--	78,707	16,335,328
Proved Reserves as of 12/31/92	143,974,839	14,393,823	--	641,235	159,009,897
State Level Summary Report					
Production in 1992	0	23,864	12,707	256,205	292,776
Proved Reserves as of 12/31/92	0	158,293	89,413	2,674,192	2,921,898
Production without Proved Reserves Reported in 1992	55,391	466,568	40,024	466,944	1,028,927
Total Production in 1992	**14,766,588**	**2,035,856**	**52,731**	**801,856**	**17,657,031**
Total Proved Reserves as of 12/31/92	**143,974,839**	**14,552,116**	**89,413**	**3,315,427**	**161,931,795**

[a]Unweighted reported data.
-- = Not applicable.
Note: Field level data are reported volumes and may not balance due to submission of incomplete records.
Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1992.

Table F4. Summary of Reported Nonassociated Natural Gas, Wet After Lease Separation, Data Used in Estimation Process, Form EIA-23

(Million Cubic Feet at 14.73 psia and 60° Fahrenheit)

Level of Reporting	Operator Category I	II	Noncertainty[a] III	Certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/91	119,8038895	12,953,226	– –	467,294	133,224,409
(+) Revision Increases	13,339,016	1,448,147	– –	25,391	14,812,554
(–) Revision Decreases	8,530,233	1,237,261	– –	6,934	9,774,428
(+) Extensions	3,464,754	337,168	– –	1,525	3,803,447
(+) New Field Discoveries	545,409	64,515	– –	15,287	625,211
(+) New Reservoir Discoveries in Old Fields	1,255,205	161,185	– –	2,000	1,418,390
(–) Production in 1992	12,354,110	1,302,817	– –	50,330	13,707,257
Proved Reserves as of 12/31/92	117,523,938	12,424,173	– –	454,233	130,402,344
State Level Summary Report					
Production in 1992	NA	NA	NA	NA	NA
Proved Reserves as of 12/31/92	NA	NA	NA	NA	NA
Production without Proved Reserves Reported in 1992	32,472	344,561	– –	71,965	446,998
Total Production in 1992	**12,386,582**	**1,647,378**	**– –**	**122,295**	**14,156,255**
Total Proved Reserves as of 12/31/92	**117,523,938**	**12,424,173**	**– –**	**454,233**	**130,402,344**

[a]Unweighted reported data.
– – = Not applicable.
NA = Not available.
Note: Field level data are reported volumes and may not balance due to submission of incomplete records.
Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1992.

Table F5. Summary of Reported Lease Condensate Data Used in Estimation Process, Form EIA-23

(Thousand Barrels of 42 U.S. Gallons)

Level of Reporting	Operator Category I	II	Noncertainty[a] III	Certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/91	1,089,097	101,313	– –	4,191	1,194,601
(+) Revision Increases	153,498	29,396	– –	268	183,162
(–) Revision Decreases	111,666	21,005	– –	280	132,951
(+) Extensions	26,047	1,814	– –	6	27,867
(+) New Field Discoveries	8,484	77	– –	1,625	10,186
(+) New Reservoir Discoveries in Old Fields	28,164	1,580	– –	50	29,794
(–) Production in 1992	127,340	12,648	– –	661	140,649
Proved Reserves as of 12/31/92	1,066,306	100,627	– –	5,203	1,172,136
State Level Summary Report					
Production in 1992	0	50	0	68	1,012
Proved Reserves as of 12/31/92	0	475	5	1	7,527
Production without Proved Reserves Reported in 1992	415	3,465	0	643	5,897
Total Production in 1992	**127,755**	**16,163**	**0**	**1,372**	**147,558**
Total Proved Reserves as of 12/31/92	**1,066,306**	**101,102**	**5**	**5,204**	**1,179,663**

[a]Unweighted reported data.
– – = Not applicable.
Note: Field level data are reported volumes and may not balance due to submission of incomplete records.
Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1992.

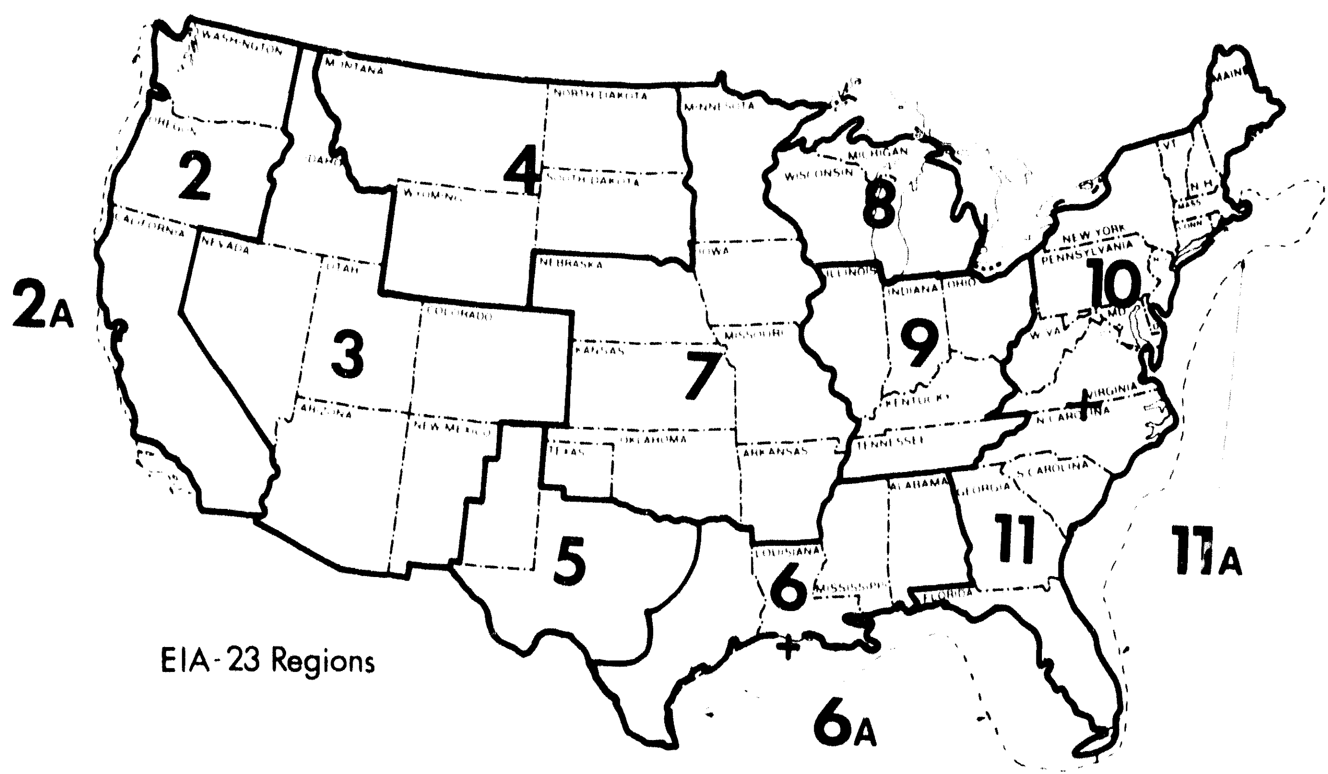
Table F6. Statistical Parameters of Reserve Estimation Equation by Region for 1992

Region Number	Region	Number of Nonzero R/P Pairs: Oil	Gas	Lease Condensate	Characteristic Multipliers: Oil	Gas	Lease Condensate
2	Pacific Coastal States	41	34	3	8.4	[a]6.8	[a]5.4
3	Western Rocky Mountains	90	111	20	8.0	11.2	[a]5.4
4	Northern Rocky Mountains	156	117	15	6.9	7.6	[a]5.4
5	West Texas and East New Mexico	579	502	79	6.9	6.1	5.8
6 + 6A	Western Gulf Basin and Gulf of Mexico	551	640	343	5.2	5.5	5.3
7	Mid-Continent	416	416	123	6.3	6.9	5.3
8 + 9	Michigan Basin and Eastern Interior	163	83	12	6.9	9.5	[a]5.4
10 + 11	Appalachians	40	82	3	8.1	10.6	[a]5.4
	United States	2,036	1,985	598	6.2	6.8	5.4

[a]Multiplier of the U.S. national average is assumed. Effect of multiplier on related natural gas or lease condensate reserves estimate negligible in these regions.

Source: Estimated based on data filed on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves, 1992.

Figure F1. Form EIA-23 Regional Boundaries



Source: Energy Information Administration, Office of Oil and Gas

Published Proved Reserves at End of Previous Report Year
+ Adjustments
+ Revision Increases
− Revision Decreases
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
− Report Year Production
= Published Proved Reserves at End of Report Year

A ratio was calculated as the sum of the annual production and year-end proved reserves of those respondents who did not provide the reserves balance components, divided by the sum of year-end proved reserves and annual production of those respondents who did provide these quantities. This ratio was then multiplied by each of the reserves balance components reported by Category I and some Category II operators, to obtain imputed volumes for the reserves balances of the other Category II operators and certainty and noncertainty operators. These were then added to the State/subdivision totals.

Imputation of Natural Gas Type Volumes

Operators in the State/subdivision certainty and noncertainty strata were not asked to segregate their natural gas volumes by type of natural gas, i.e., nonassociated natural gas (NA) and associated-dissolved natural gas (AD). The total estimated year-end proved reserves of natural gas and the total annual production of natural gas reported by, or imputed to, operators in the State/subdivision certainty and noncertainty strata were, therefore, subdivided into the NA and AD categories, by State/subdivision, in the same proportion as was reported by Category I and Category II operators in the same area.

Adjustments

The instructions for Schedule A of Form EIA-23 specify that, when reporting reserves balance data, the following arithmetic equation must hold:

Proved Reserves at End of Previous Year
+ Revision Increases
Revision Decreases
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
- Report Year Production
= Proved Reserves at End of Report Year

Any remaining difference in the State/subdivision annual reserves balance between the published previous year-end proved reserves and current year-end proved reserves not accounted for by the imputed reserves changes was included in the adjustments for the area. One of the primary reasons that adjustments are necessary is that very few of the same random operators are sampled each year. Less than 4 percent of the random stratum operators sampled in 1991 were sampled again in 1992, and there is no guarantee that in the smaller producing States/subdivision the same number of small operators will be selected each year, or that the operators selected will be of comparable sizes when paired with operators selected in a prior year. Thus, some instability of this stratum from year to year is unavoidable, resulting in minor adjustments.

Some of the adjustments are, however, more substantial, and could be required for any one or more of the following reasons:

- The frame coverage may or may not have improved between survey years, such that more or less certainty operators were included in 1992 than in 1991.
- The random sample for either year may have been an unusual one loaded by chance with either larger or smaller random operators.
- One or more operators may have reported data incorrectly on Schedule A in 1991 or 1992, but not both, and the error was not detected by edit processing.
- Operation of properties was transferred during 1992 from operators not in the frame or random operators not selected for the sample to certainty operators or random operators selected for the sample.
- Operations of properties was transferred during 1992 to an operator with a different evaluation of the proved reserves associated with the properties than that of the 1991 operator.
- Respondent changed classification of natural gas from NA to AD or vice versa.
- The trend in reserve changes imputed for the small operators, that was based on the trend reported by the large operators, did not reflect the actual trend for the small operators.
- Random operators, who have grown substantially in size since they were added to the frame, occasionally cause a larger standard error than expected.

The causes of adjustments are known for some but not all areas. The only problems whose effects cannot be expected to balance over a period of several years are those associated with an inadequate frame or those associated with any actual trend in reserve changes for small operators not being the same as those for large operators. EIA continues to attempt to improve sources of operator data to resolve problems in frame completeness.

Sampling Reliability of the Estimates

The sample of noncertainty operators selected is only one of the large number of possible samples that could have been selected and each would have resulted in different estimates. The standard error or sampling error of the estimates provides a measure of this variability. When probability sampling methods are used, as in the EIA-23 survey, the sampling error of estimates can also be estimated from the survey data.

The estimated sampling error can be used to compute a confidence interval around the survey estimate, with a prescribed degree of confidence that the interval covers the value that would have been obtained if all operators in the frame had been surveyed. If the estimated volume is denoted by $\hat{V}_s$ and its sampling error by S.E. ($\hat{V}_s$), the confidence interval can be expressed as:

$$\hat{V}_s \pm \; k \; S.E. \; (\hat{V}_s)$$

where k is a multiple selected to provide the desired level of confidence. For this survey, k was taken equal to 2. Then there is approximately 95 percent confidence that the interval:

$$\hat{V}_s \pm \; 2S.E. \; (\hat{V}_s)$$

includes the universe value, for both the estimates of reserves and production volumes. Correspondingly, for approximately 95 percent of the estimates in this report, the difference between the published estimate and the value that would be found from a complete survey of all operators is expected to be less than twice the sampling error of the estimate. Tables B7, B8, B9, and B10 provide estimates for 2S.E.($\hat{V}_s$) by product. These estimates are directly applicable for constructing approximate 95 percent confidence intervals. EIA estimates should be viewed as the value of the estimate plus or minus twice the associated sampling error. The sampling error of V_s is equal to the sampling error of the noncertainty estimate $\hat{V}_{sr}$, because the certainty total is not subject to sampling error. The estimated sampling error of a noncertainty estimate is the square root of its estimated sampling variance.

The noncertainty estimate for a given State/subdivision had two separately weighted components based on reports of:

- **Type 1 Operators** shown in the frame as having had crude oil or natural gas production in the State/ subdivision.
- **Type 2 Operators** shown in the frame as having had no crude oil or natural gas production in the State/subdivision.

Correspondingly, the sampling variance had two components associated with the estimated production from each component:

$$Var(\hat{V}_{sr}) = Var(\hat{V}_{sr1}) + Var(\hat{V}_{sr2})$$

The $Var(V_{sr})$ was estimated as the sum of the estimated variances of the three component estimates. The variance for any component, say component j, was estimated from the formula:

$$Var(\hat{V}_{srj}) \; = \; n_{srj} \left(\frac{W_{srj} - 1}{W_{srj}} \right) S^2_{srj}$$

In general, $\hat{V}_{srj}$ denotes the production estimate from component j for each of the three types of operator, and $Var(V_{srj})$ denotes its variance where

n_{srj} = number of operators in sample in component j

w_{srj} = weight for operator reports in component j

$S^2{}_{srj}$ = variance between operator reports in component j.

If the subscripts sr are dropped, $S^2{}_{srj}$ can be expressed as:

$$S_j^2 = \frac{\sum_i^{n_j} V''^2_{ji} - \left(\sum_i^{n_j} V''_{ji} \right)^2 \Big/ n_j}{n_j - 1}$$

where

V''_{ji} = weighted production or reserves volume for the i-th sample operator in the component j.

The variance of the estimated total volume for a State having subdivisions is the sum of corresponding Type 1, Type 2, and Type 3 components where the classification of operators by type is with regard to the State as a whole; e.g., Type 3 operators at the State level are those that were not shown in the sample frame as having production anywhere in the State.

Similar summations resulted in the variance of the estimated volume for the U.S. total. However, since there are no operators in the frame who would be classified as Type 3 at the U.S. level, there would be no Type 3 components at the U.S. level. Therefore, at the U.S. level there were only two separate sample variance components calculated, one for Type 1 operators and one for Type 2 operators.

Table F7. Factors for Confidence Intervals (2S.E.) for Crude Oil Proved Reserves and Production, 1992
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	1992 Reserves	1992 Production	State and Subdivision	1992 Reserves	1992 Production
Alabama	0	0	Ohio	4	1
Alaska	0	0	Oklahoma	28	4
Arkansas	4	1	Pennsylvania	0	0
California	21	2	Texas	90	13
Coastal Region Onshore	4	0	RRC District 1	15	3
Los Angeles Basin Onshore	8	1	RRC District 2 Onshore	15	2
San Joaquin Basin Onshore	12	1	RRC District 3 Onshore	20	4
State Offshore	0	0	RRC District 4 Onshore	6	1
Colorado	14	2	RRC District 5	3	0
Florida	0	0	RRC District 6	20	4
Illinois	15	1	RRC District 7B	14	2
Indiana	0	0	RRC District 7C	41	4
Kansas	22	3	RRC District 8	35	5
Kentucky	1	0	RRC District 8A	27	3
Louisiana	28	2	RRC District 9	14	2
North	4	1	RRC District 10	9	2
South Onshore	28	2	State Offshore	0	0
State Offshore	0	0	Utah	6	1
Michigan	18	3	West Virginia	1	0
Mississippi	13	3	Wyoming	26	4
Montana	12	2	Federal Offshore	0	0
Nebraska	1	0	Pacific (California)	0	0
New Mexico	13	2	Gulf of Mexico (Louisiana)	0	0
East	13	2	Gulf of Mexico (Texas)	0	0
West	2	0	Miscellaneous[a]	2	0
North Dakota	12	2	**U.S. Total**	**111**	**16**

[a]Includes Arizona, Missouri, Nevada, New York, South Dakota, Tennessee, and Virginia.
Note: Factors for confidence intervals for each State subdivision, State, and U.S. total are independently estimated and do not add.
Source: Factor estimates based on data filed on Form EI-23, "Annual Survey of Domestic Oil and Gas Reserves," 1992.

Table F8. Factors for Confidence Intervals (2S.E.) for Natural Gas Proved Reserves and Production, Wet After Lease Separation, 1992 (Billion Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

State and Subdivision	1992 Reserves	1992 Production	State and Subdivision	1992 Reserves	1992 Production
Alabama	56	10	Pennsylvania	78	7
Alaska	0	0	Texas	381	65
Arkansas	25	4	RRC District 1	148	28
California	45	7	RRC District 2 Onshore	106	19
Coastal Region Onshore	3	0	RRC District 3 Onshore	83	14
Los Angeles Basin Onshore	1	0	RRC District 4 Onshore	99	16
San Joaquin Basin Onshore	11	2	RRC District 5	75	16
State Offshore	0	0	RRC District 6	35	7
Colorado	136	13	RRC District 7B	63	6
Florida	0	0	RRC District 7C	91	15
Kansas	103	9	RRC District 8	89	14
Kentucky	0	0	RRC District 8A	68	11
Louisiana	56	13	RRC District 9	75	12
North	38	10	RRC District 10	153	22
South Onshore	43	8	State Offshore	0	0
State Offshore	0	0	Utah	27	2
Michigan	49	10	Virginia	0	0
Mississippi	41	7	West Virginia	128	12
Montana	99	6	Wyoming	352	13
New Mexico	89	16	Federal Offshore[a]	0	0
East	80	15	Pacific (California)	0	0
West	39	5	Gulf of Mexico (Louisiana)[a]	0	0
New York	55	5	Gulf of Mexico (Texas)	0	0
North Dakota	0	0	Miscellaneous[b]	3	0
Ohio	34	4			
Oklahoma	410	60	**U.S. Total**	**771**	**103**

[a]Includes Federal offshore Alabama.
[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.
Note: Factors for confidence intervals for each State subdivision, State, and U.S. total are independently estimated and do not add.
Source: Factor estimates based on data filed on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1992.

Table F9. Factors for Confidence Intervals (2S.E.) for Lease Condensate Proved Reserves and Production, 1992 (Million Barrels of 42 U.S. Gallons)

State and Subdivision	1992 Reserves	1992 Production	State and Subdivision	1992 Reserves	1992 Production
Alabama	0	0	Oklahoma	1	0
Alaska	0	0	Texas	3	0
Arkansas	0	0	RRC District 1	0	0
California	0	0	RRC District 2 Onshore	1	0
Coastal Region Onshore	0	0	RRC District 3 Onshore	2	0
Los Angeles Basin Onshore	0	0	RRC District 4 Onshore	2	0
San Joaquin Basin Onshore	0	0	RRC District 5	0	0
State Offshore	0	0	RRC District 6	1	0
Colorado	1	0	RRC District 7B	0	0
Florida	0	0	RRC District 7C	1	0
Kansas	0	0	RRC District 8	0	0
Kentucky	0	0	RRC District 8A	0	0
Louisiana	1	0	RRC District 9	0	0
North	0	0	RRC District 10	0	0
South Onshore	1	0	State Offshore	0	0
State Offshore	0	0	Utah and Wyoming	3	0
Michigan	4	1	West Virginia	0	0
Mississippi	0	0	Federal Offshore[a]	0	0
Montana	0	0	Pacific (California)	0	0
New Mexico	0	0	Gulf of Mexico (Louisiana)[a]	0	0
East	0	0	Gulf of Mexico (Texas)	0	0
West	0	0	Miscellaneous[b]	0	0
North Dakota	0	0	**U.S. Total**	**6**	**1**

[a]Includes Federal offshore Alabama.
[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, and Virginia.
Note: Factors for confidence intervals for each State subdivision, State, and U.S. total are independently estimated and do not add.
Source: Factor estimates based on data filed on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1992.

Table F10. Factors for Confidence Intervals (2S.E.) for Dry Natural Gas Proved Reserves and Production, 1992 (Billion Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

State and Subdivision	1992 Reserves	1992 Production	State and Subdivision	1992 Reserves	1992 Production
Alabama	54	10	Pennsylvania	78	7
Alaska	0	0	Texas	351	60
Arkansas	25	4	RRC District 1	143	27
California	43	6	RRC District 2 Onshore	99	18
Coastal Region Onshore	3	0	RRC District 3 Onshore	76	13
Los Angeles Basin Onshore	1	0	RRC District 4 Onshore	95	16
San Joaquin Basin Onshore	11	2	RRC District 5	72	15
State Offshore	0	0	RRC District 6	33	6
Colorado	129	13	RRC District 7B	52	5
Florida	0	0	RRC District 7C	81	13
Kansas	97	8	RRC District 8	81	13
Kentucky	0	0	RRC District 8A	53	9
Louisiana	54	12	RRC District 9	63	10
North	38	10	RRC District 10	139	20
South Onshore	41	8	State Offshore	0	0
State Offshore	0	0	Utah	24	2
Michigan	46	9	Virginia	0	0
Mississippi	40	7	West Virginia	121	11
Montana	97	6	Wyoming	337	12
New Mexico	82	15	Federal Offshore[a]	0	0
East	73	14	Pacific (California)	0	0
West	37	5	Gulf of Mexico (Louisiana)[a]	0	0
New York	55	5	Gulf of Mexico (Texas)	0	0
North Dakota	0	0	Miscellaneous[b]	3	0
Ohio	34	4			
Oklahoma	388	57	**U.S. Total**	**733**	**97**

[a]Includes Federal offshore Alabama.
[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.
Note: Factors for confidence intervals for each State subdivision, State, and U.S. total are independently estimated and do not add.
Source: Factor estimates based on data filed on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1992 and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production," 1992.

Discussion of Nonsampling Errors

Several sources of possible error, apart from sampling error, are associated with the Form EIA-23 survey. These include bias due to nonresponse of operators in the sample, proved reserve estimation errors, and reporting errors on the part of the respondents to the survey. On the part of EIA, possible errors include inadequate frame coverage, data processing error, and errors associated with statistical estimates. Each of these sources is discussed below. An estimate of the bias from nonresponse is presented in the section on adjustment for operator nonresponse.

Assessing the Accuracy of the Reserve Data

The EIA maintains an evaluation program to assess the accuracy and quality of proved reserve estimates gathered on Form EIA-23. Field teams consisting of petroleum engineers from EIA's Dallas Field Office conduct technical reviews of reserve estimates and independently estimate the proved reserves of a statistically selected sample of operator properties. The results of these reviews are used to evaluate the accuracy of reported reserve estimates. Operators are apprised of the team's findings to assist them in completing future filings. The magnitude of errors due to differences between reserve volumes submitted by operators on the Form EIA-23 and those estimated by EIA petroleum engineers on their field trips were generally within accepted professional engineering standards.

Respondent Estimation Errors

The principal data elements of the Form EIA-23 survey consist of respondent estimates of proved reserves of crude oil, natural gas, and lease condensate. Unavoidably, the respondents are bound to make some estimation errors, i.e., until a particular reservoir has been fully produced to its economic limit and abandoned, its reserves are not subject to direct measurement but must be inferred from limited, imperfect, or indirect evidence. A more complete discussion of the several techniques of estimating proved reserves, and the many problems inherent in the task, appears in Appendix C.

Reporting Errors and Data Processing Errors

Reporting errors on the part of respondents are of definite concern in a survey of the magnitude and complexity of the Form EIA-23 program. Several steps were taken by EIA to minimize and detect such problems. The survey instrument itself was carefully developed, and included a detailed set of instructions for filing data, subject to a common set of definitions similar to those already used by the industry. Editing software is continually developed to detect different kinds of probable reporting errors and flag them for resolution by analysts, either through confirmation of the data by the respondent or through submission of amendments to the filed data. Data processing errors, consisting primarily of random keypunch errors, are detected by the same software.

Imputation Errors

Some error, generally expected to be small, is an inevitable result of the various estimations outlined. These imputation errors have not yet been completely addressed by EIA and it is possible that estimation methods may be altered in future surveys. Nationally, about 6.9 percent of the crude oil proved reserve estimates, 6.6 percent of the natural gas proved reserve estimates, and 3.8 percent of the lease condensate proved reserve estimates resulted from the imputation and estimation of reserves for those certainty and noncertainty operators who did not provide estimates for all of their properties, in combination with the expansion of the sample of noncertainty operators to the full population. Errors for the latter were quantitatively calculated, as discussed in the previous section. Standard errors, for the former, would tend to cancel each other from operator to operator, and are, therefore, expected to be negligible, especially at the National level of aggregation. In States where a large share of total reserves is accounted for by Category III and smaller Category II operators, the errors are expected to be somewhat larger than in States where a large share of total reserves is accounted for by Category I and larger Category II operators.

Frame Coverage Errors

Of all the sources of controllable error connected with the Form EIA-23 survey, errors in the operator frame were expected to be the most important. If the frame does not list all operators in a given State, the sample selected from the frame for the State will not represent the entire operator population, a condition called undercoverage. Undercoverage is a problem with certain States, but it does not appear to be a problem with respect to the National proved reserve estimates for either crude oil or natural gas. While it is relatively straightforward to use existing sources to identify large operators and find addresses for them, such is not the case for small operators. A frame such as that used in the 1992 survey is particularly likely to be deficient in States where a large portion of total reserves and production is accounted for by small operators. These States are not likely to allocate sufficient resources to keep track of all operators on a current basis. Some undercoverage of this type seems to exist, particularly, with reference to natural gas operators. EIA is continuing to work to remedy the undercoverage problem in those States where it occurred.

Calculation of Reserves of Natural Gas Liquids and Dry Natural Gas

Natural Gas Liquids Reserve Balance

The published reserves, production, and reserves change statistics for crude oil, lease condensate, and natural gas, wet after lease separation, were derived from the data reported on Form EIA-23 and the application of the imputation methods discussed previously. The information collected on Form EIA-64A was then utilized in converting the estimates of the wet natural gas reserves into two components: plant liquids reserve data and dry natural gas reserve data. The total natural gas liquids reserve estimates presented in Table 14 were computed as the sum of plant liquids estimates (Table 15) and lease condensate (Table 16) estimates.

To generate estimates for each element in the reserves balance for plant liquids in a given producing area, the first step was to group all natural gas processing plants that reported this area as an area-of-origin on their Form EIA-64A, and then sum the liquids production attributed to this area over all respondents. Next, the ratio of the liquids production to the total wet natural gas production for the area was determined. This ratio represented the percentage of the wet natural gas that was recovered as natural gas liquids. Finally, it was assumed that this ratio was applicable to the reserves and each component of reserve changes (except adjustments), as well as production. Therefore, each element in the wet natural gas reserves balance was multiplied by this recovery factor to yield the corresponding estimate for plant liquids. Adjustments of natural gas liquids were set equal to the difference between the end of previous year reserve estimates, based upon the current report year Form EIA-23 and Form EIA-64A surveys, and the end of current year reserve estimates published in the preceding year's annual reserves report.

Natural Gas Reserve Balance

This procedure involved downward adjustments of the natural gas data, wet after lease separation, in estimating the volumes of natural gas on a fully dry basis. These reductions were based on estimates of the gaseous equivalents of the liquids removed (in the case of production), or expected to be removed (in the case of reserves), from the natural gas stream at natural gas processing plants. Form EIA-64A collected the volumetric reduction, or **shrinkage**, of the input natural gas stream that resulted from the removal of the NGL at each natural gas processing plant.

The shrinkage volume was then allocated to the plant's reported area or areas of origin. Because shrinkage is, by definition, roughly in proportion to the NGL recovered, i.e. the NGL produced, the allocation was in proportion to the reported NGL volumes for each area of origin. However, these derived shrinkage volumes were rejected if the ratio between the shrinkage and the NGL production (gas equivalents ratio) fell outside certain limits of physical accuracy. The ratio was expected to range between 1,558 cubic feet per barrel (where NGL consists primarily of ethane) and 900 cubic feet per barrel (where NGL consists primarily of natural gasolines). When the computed gas equivalents ratio fell outside these limits, an imputed ratio was utilized to estimate the plant's natural gas shrinkage allocation to each reported area of origin.

This imputed ratio was that calculated for the aggregate of all other plants reporting production and shrinkage, and having a gas equivalent ratio within the aforesaid limits, from the area in question. The imputed area ratio was applied only if there were at least five plants to base its computation on. If there were less than five plants, the imputed ratio was calculated based on all plants in the survey whose individual gas equivalents ratio was within the acceptable limits. Less than one percent of the liquids production was associated with shrinkage volumes imputed in this manner. Based on the 1992 Form EIA-64A survey, the national weighted average gas equivalents ratio was computed to be 1,392 cubic feet of natural gas shrinkage per barrel of NGL recovered. This is 7 cubic feet per barrel more than in the 1991 survey. The total shrinkage volume (reported plus imputed) for all plants reporting a given area of origin was then subtracted from the estimated value of natural gas production, wet after lease separation, yielding dry natural gas production for the area. The amount of the reduction in the wet natural gas production was then expressed as a percentage of the wet natural gas production. Dry natural gas reserves and reserve changes were determined by reducing the wet natural gas reserves and reserve changes by the same percentage reduction factor.

A further refinement of the estimation process was added this year. This refinement was a change in methodology to generate an estimate of the natural gas liquid reserves in those States with large amounts of coalbed methane. The first step in the process was to identify all Form EIA-23 reported coalbed methane fields. The second step was to estimate the amount of the undercoverage in the nonreported coalbed methane fields on Form EIA-23. Production of coalbed methane in reported fields was compared to the State reported production of coalbed methane, to calculate a factor to increase reported coalbed methane production to the reported State production of coalbed methane. This factor was applied to each reported element in the reserve balance for a State. The assumption was made that coalbed methane fields contained little or no extractable natural gas liquids. Therefore, when the normal shrinkage procedure was applied to the wet gas volume elements, the estimate of State coalbed methane volumes were excluded and were not reduced for liquid extraction. Following the computation for shrinkage, each coalbed field gas volume was added back to each of the dry gas volume elements in a State. The effect of this is that the large increases in reserves in some States from coalbed methane fields did not cause corresponding increases in the State natural gas liquids proved reserves. The States where this procedure was applied were Alabama, Colorado, and New Mexico.

Adjustments of dry natural gas were set equal to the difference between the end of previous year reserves estimates, based upon the current report year Form EIA-23 and Form EIA-64A surveys, and the end of current year reserve estimates published in the preceding year's annual reserves report.

Each estimate of end of year reserves and report year production has associated with it an estimated sampling error. The standard errors for dry natural gas were computed by multiplying the wet natural gas standard errors by these same percentage reduction factors. Table B10 provides estimates for 2 times the $S.E.(V_S)$ for dry natural gas.

Appendix G

Discussion of Reserve Estimation Methodologies

Appendix G

Discussion of Reserve Estimation Methodologies

The adoption of a standard definition of proved reserves for each type of hydrocarbon surveyed by the Form EIA-23 program provided a far more consistent response from operators than if each operator had used his own definition. Such standards, however, do not guarantee that the resulting estimates themselves are determinate. Regardless of the definition selected, proved reserves cannot be measured directly. They are estimated quantities that are inferred on the basis of the best geological, engineering, and economic data available to the estimator, who generally uses considerable judgment in the analysis and interpretation of the data. Consequently, the accuracy of a given estimate varies with and depends on the quality and quantity of raw data available, the estimation method used, and the training and experience of the estimator. The element of judgment commonly accounts for the differences among independent estimates for the same reservoir or field.

Data Used in Making Reserve Estimates

The raw data used in estimating proved reserves include data on engineering and geological properties of the reservoir rock and its hydrocarbon fluids. These data are obtained from direct measurements. The data available for a given reservoir vary in kind, quality, and quantity. When a reservoir is first discovered only data from a single well are available, and prior to flow testing or actual production, proved reserves can only be inferred. As development of the reservoir proceeds, and flow tests are made or actual production commences, more and more data become available, enabling proved reserves estimates to become more accurate.

Many different kinds of data are useful in making reserves estimates. They may include: data on porosity, permeability, and fluid saturations of the reservoir rocks (obtained directly from core analysis or from various types of electrical measurements taken in a well or several wells); data on the production of fluids from a well or several wells; geologic maps of the areal extent, thickness, and continuity of the reservoir rocks (inferred from well logs, geophysical, and geological data); and reservoir pressure and temperature data. Also involved are economic data including the current price of crude oil and natural gas, and various developmental and operating costs.

Reserve Estimation Techniques

Depending on the kinds and amounts of data available, and a judgment on the reliability of those data, the estimator will select one of several methods of making a proved reserves estimate. Methods based on production performance data are generally more accurate than those based strictly on inference from geological and engineering data. Such methods include the *Production Decline* method (for crude oil or natural gas reservoirs), the *Material Balance* method (for crude oil reservoirs), the *Pressure Decline* method (which is actually a material balance, for natural gas reservoirs), and *Reservoir Simulation* method (for crude oil or natural gas reservoirs). The reservoir type and production mechanisms and the types and amounts of reliable data available determine which of these methods is more appropriate for a given reservoir. These methods are of comparable accuracy.

Methods not based upon production data include the *Volumetric* method (for crude oil or natural gas reservoirs) and the *Nominal* method. Of these, the *Volumetric* method is the more accurate. Both methods, however, are less accurate than those based on production data. Table G1 summarizes the various methods.

Judgmental Factors in Reserve Estimation

The determination of rock and hydrocarbon fluid properties involves judgment and is subject to some uncertainty; however, the construction of the geologic maps and cross sections and the determination of the size of the reservoir are the major judgmental steps in the *Volumetric* method, and are subject to the greatest uncertainty. Estimates made using the *Material Balance* method, the *Reservoir Simulation* method, or the *Pressure Decline* method are based on the estimator's judgment that the type of reservoir drive mechanism has been identified and on the specification of abandonment conditions. Estimates based on the *Production Decline* method are subject to judgment in constructing the trend line, and are based on the estimator's assumption of reservoir performance through abandonment.

Table G1. Reserve Estimation Techniques

Method	Comments
Volumetric	Applies to crude oil and natural gas reservoirs. Based on raw engineering and geologic data
Material Balance	Applies to crude oil and natural gas reservoirs. Is used in estimating reserves. Usually of more value in predicting reserves, and reservoir performance.
Pressure Decline	Applies to nonassociated and associated gas reservoirs. The method is a special case of material balance equation in the absence of water influx.
Production Decline	Applies to crude oil and natural gas reservoirs during production decline (usually in the later stages of reservoir life)
Reservoir Simulation	Applies to crude oil and natural gas reservoirs. Is used in estimating reserves. Usually of more value in predicting reservoir performance. Accuracy increases when matched with past pressure and production data.
Nominal	Applied to crude oil and natural gas reservoirs. Based on rule of thumb or analogy with another reservoir or reservoirs believed to be similar, least accurate of methods used.

Source: Energy Information Administration, Office of Oil and Gas

Contributing to the degree of uncertainty inherent in the above methods for estimating reserves are other factors associated with economic considerations and the perceived reservoir limits, which together influence the final reserves estimate. A brief discussion of these other factors is provided in succeeding paragraphs.

Economic Considerations. There has been continuing debate about the effects of prices on proved reserves. Although no all-inclusive statement can be made on the impact of price, the points at issue can be discussed and some general remarks can be made about some circumstances where price may be a factor.

Developed gas fields. In a gas reservoir, price affects the economic limit (i.e., the production rate required to meet operating costs) and, therefore, the abandonment pressure. Thus, price change has some effect on the conversion of noneconomic hydrocarbon resources to the category of proved reserves. In both nearly depleted reservoirs and newly developed reservoirs, the actual increase in the quantity of proved reserves resulting from price rises is generally limited in terms of national volumes (even though the percentage increase for a given reservoir may be great).

- ***Developed oil fields.*** In developed crude oil reservoirs many of the same comments apply; however, there is an additional consideration. If the price is raised to a level sufficient to justify initiation of an improved recovery project, and if the improved recovery technique is effective, then the addition to ultimate recovery from the reservoir can be significant. Because of the speculative nature of predicting prices and costs many years into the future, proved reserves are estimated on the basis of current prices, costs, and operating practices in effect as of the date the estimation was made.

- ***Successful exploration efforts.*** Price can have a major impact on whether a new discovery is produced or abandoned. For example, the decision to set casing in a new onshore discovery, or to install a platform as the result of an offshore discovery, are both price-sensitive. If the decision is made to set pipe or to install a platform, the discoveries in both cases will add to the proved reserves total. If such projects are abandoned, they will make no contribution to the proved reserves total.

Effect of operating conditions. Operating conditions are subject to change caused by changes in economic conditions, unforeseen production problems, new production practices or methods, and the operator's financial position. As with economic conditions, operating conditions to be expected at the time of abandonment are speculative. Thus, current operating conditions are used in estimating proved reserves. In considering the effect of operating conditions, a distinction must be made between processes and techniques that would normally be applied by a prudent operator in producing his oil and gas, and initiation of changes in operating conditions that would require substantial new investment.

- **Compression.** Compression facilities are normally installed when the productive capacity or deliverability of a natural gas reservoir or its individual wells declines. In other cases compression is used in producing shallow, low-pressure reservoirs or reservoirs in which the pressure has declined to a level too low for the gas to flow into a higher pressure pipeline. The application of compression increases the pressure and, when economical, is used to make production into the higher pressure pipeline possible. Compression facilities normally require a significant investment and result in a change in operating conditions. It increases the proved reserves of a reservoir, and reasonably accurate estimates of the increase can be made.

- **Well stimulation.** Procedures that increase productive capacity (workovers, such as acidizing or fracturing, and other types of production practices) are routine field operations. The procedures accelerate the rate of production from the reservoir, or extend its life, and they have only small effect on proved reserves. Reasonable estimates of their effectiveness can be made.

- **Improved recovery techniques.** These techniques involve the injection of a fluid or fluids into a reservoir to augment natural reservoir energy. Because the response of a given reservoir to the application of an improved recovery technique cannot be accurately predicted, crude oil production that may ultimately result from the application of these techniques is classified as "indicated additional reserves of crude oil" rather than as proved reserves until response of the reservoir to the technique has been demonstrated. In addition, improved recovery methods are not applicable to all crude oil reservoirs. Initiation of improved recovery techniques may require significant investment.

- **Infill drilling.** Infill drilling (drilling of additional wells within a field/reservoir) may result in a higher recovery factor, and, therefore, be economically justified. Predictions of whether infill drilling will be justified under current economic conditions are generally based on the expected production behavior of the infill wells.

Reservoir Limits. The initial proved reserves estimate made from the discovery well is subject to significant uncertainty because one well provides little information on the size of the reservoir. The area proved by a discovery well is frequently estimated on the basis of experience in a given producing region. Where there is continuity of the producing formation over wide geographic areas, a relatively large proved area may be assigned. In some cases where reliable geophysical and geological data are available, a reasonable estimate of the extent of the reservoir can be made by drilling a relatively small number of delineation wells. Conversely, a relatively small proved area may be assigned when the producing formation is of limited continuity, owing to either structural or lithological factors.

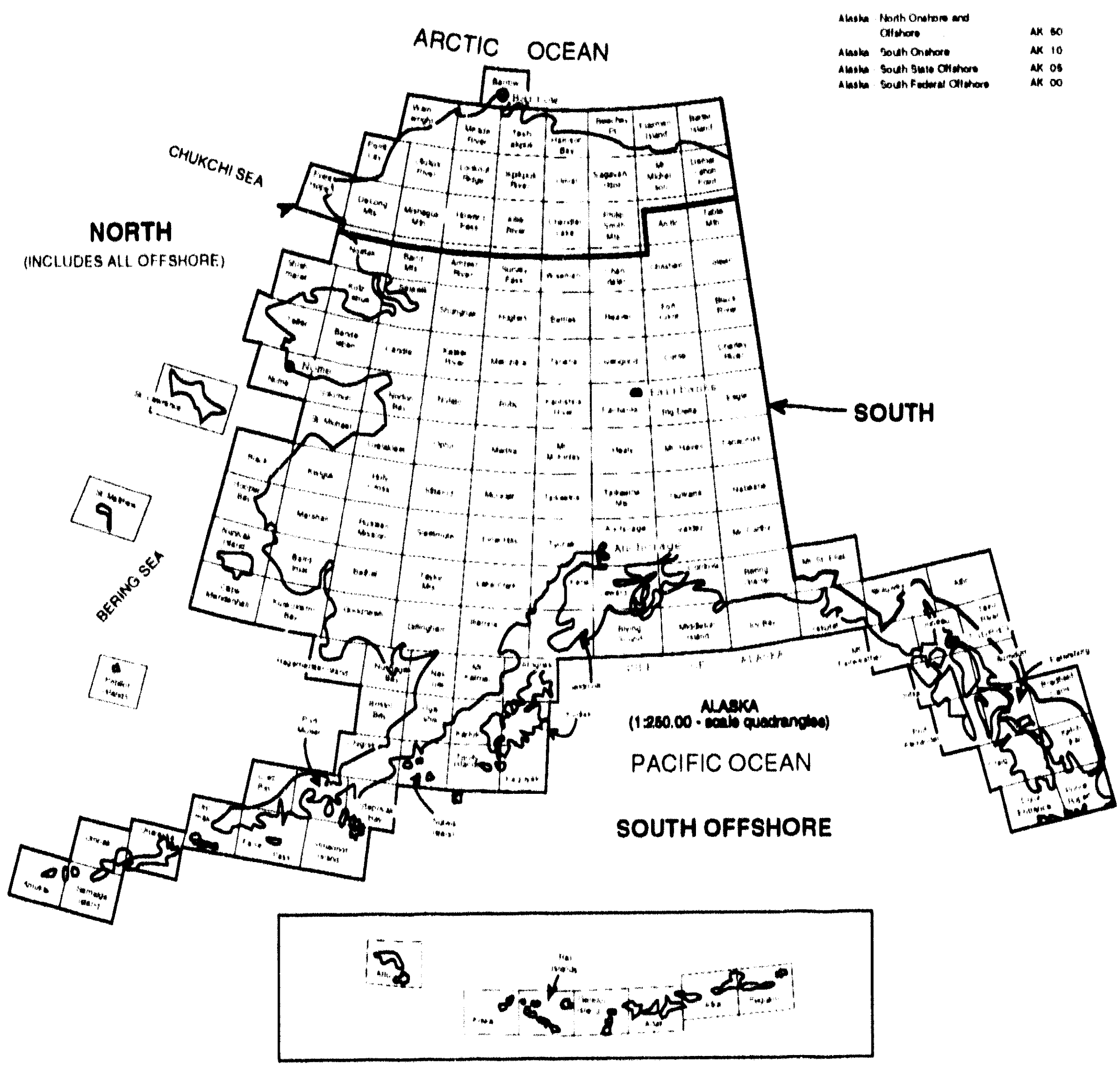
Additional wells provide more information and reduce the uncertainty of the reserves estimate. As additional wells are drilled, the geometry of the reservoir and, consequently, its bulk volume, become more clearly defined. This process accounts for the large extensions to proved reserves typical of the early stages of most reservoir development.

Appendix H

Maps of Selected State Subdivisions

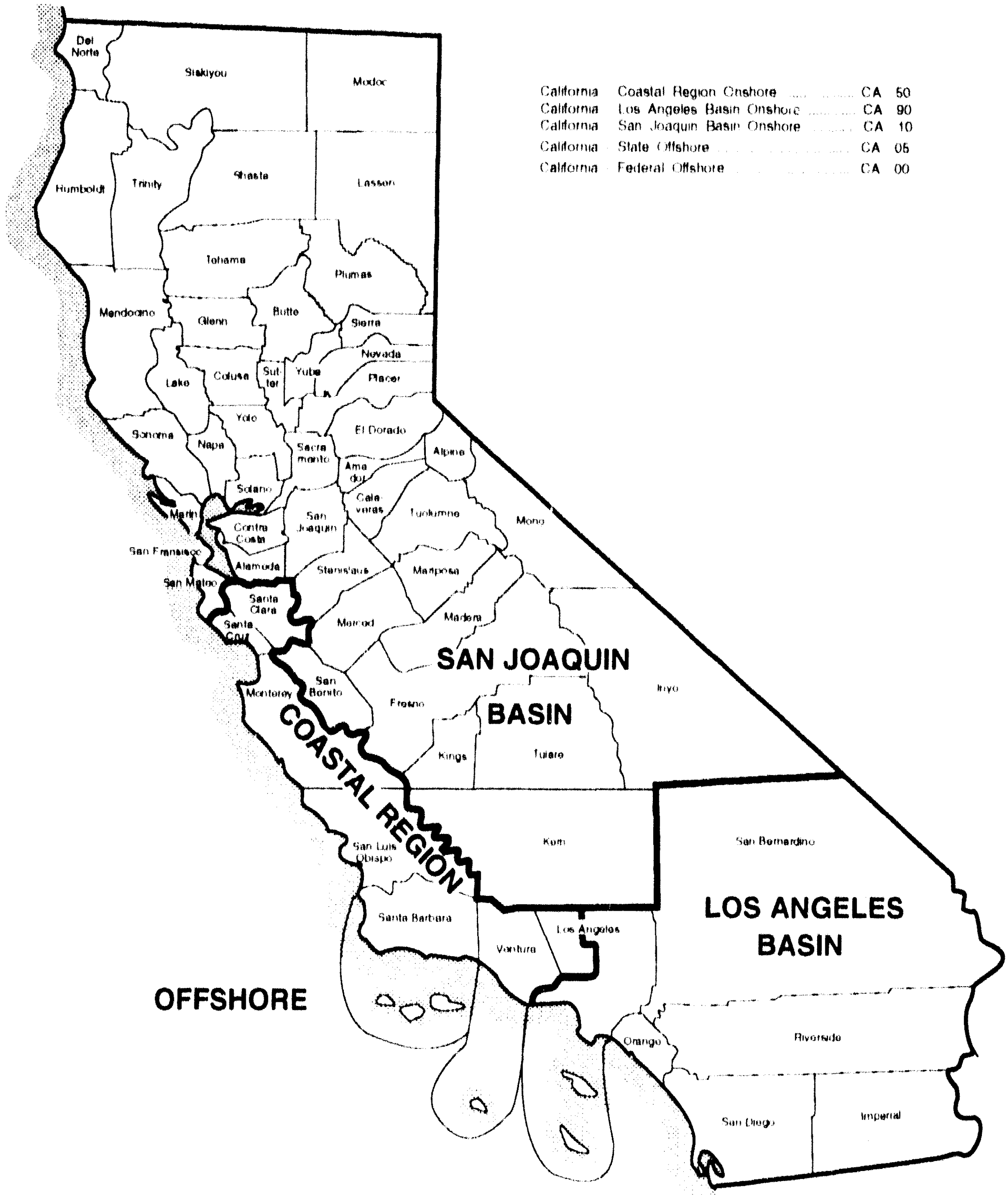
Maps of Selected State Subdivisions

Figure H1. Subdivisions of Alaska



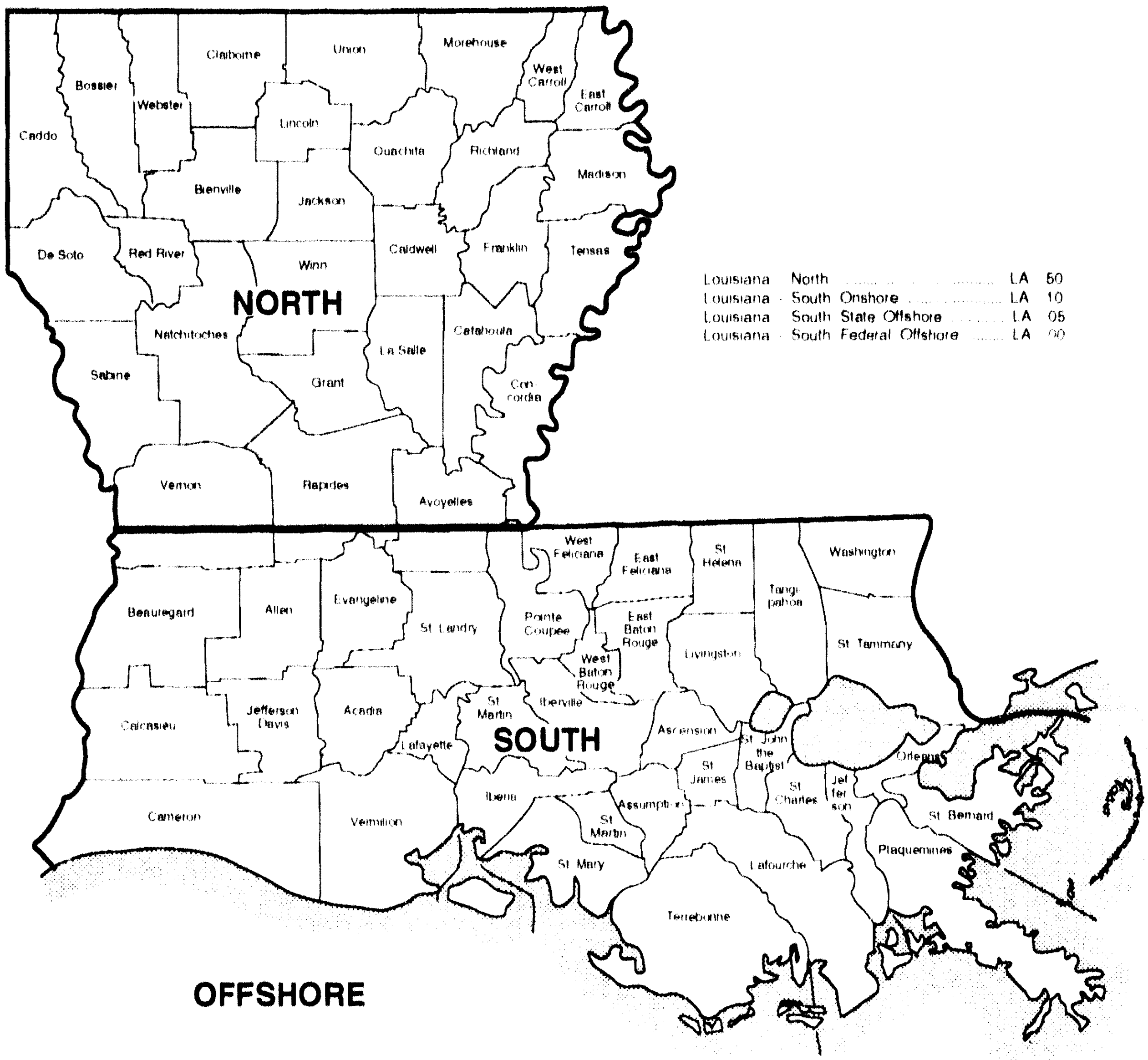
Source: After U.S. Geological Survey

Figure H2. Subdivisions of California



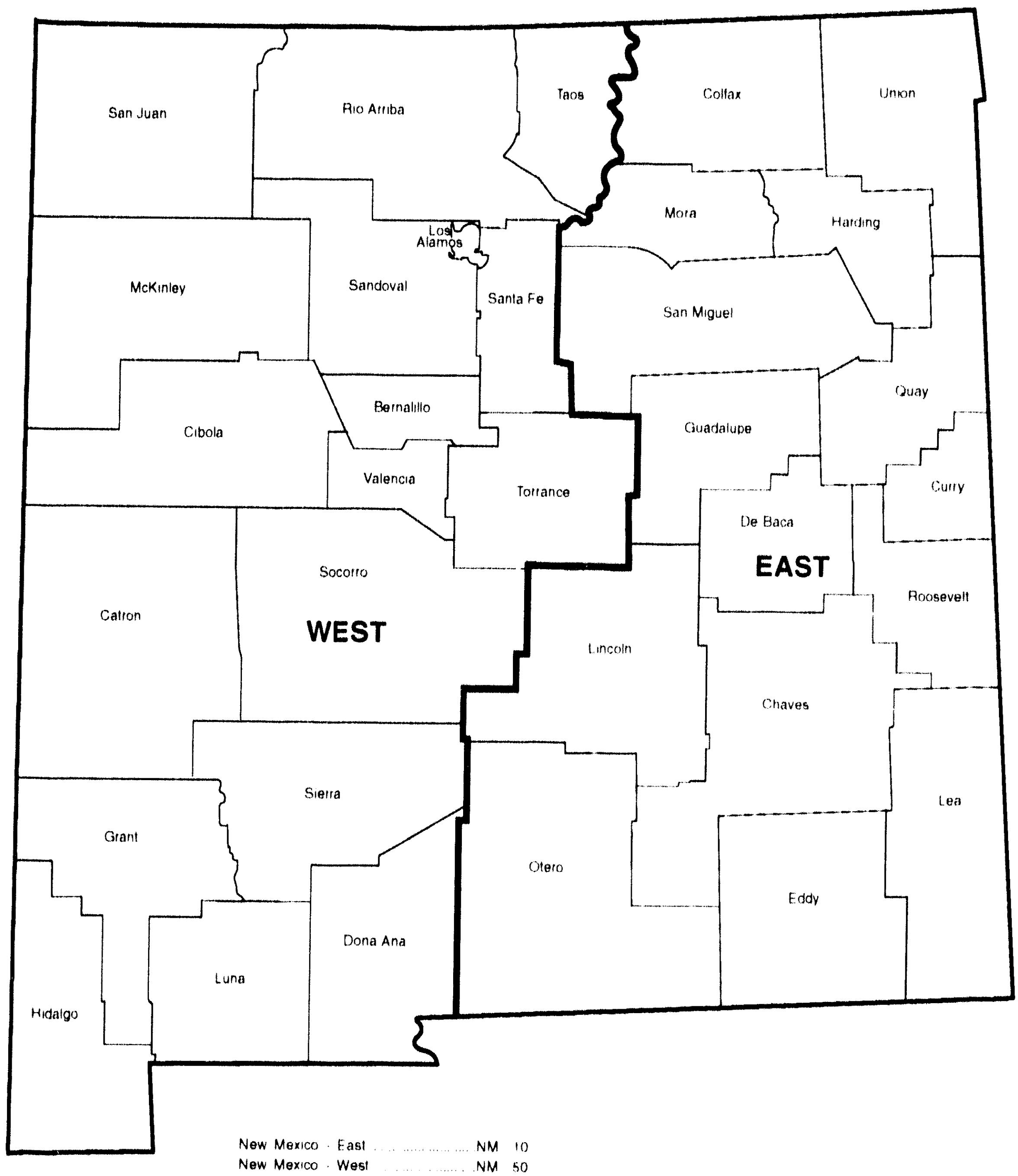
Source: Energy Information Administration, Office of Oil and Gas.

Figure H3. Subdivisions of Louisiana



Source: Energy Information Administration, Office of Oil and Gas.

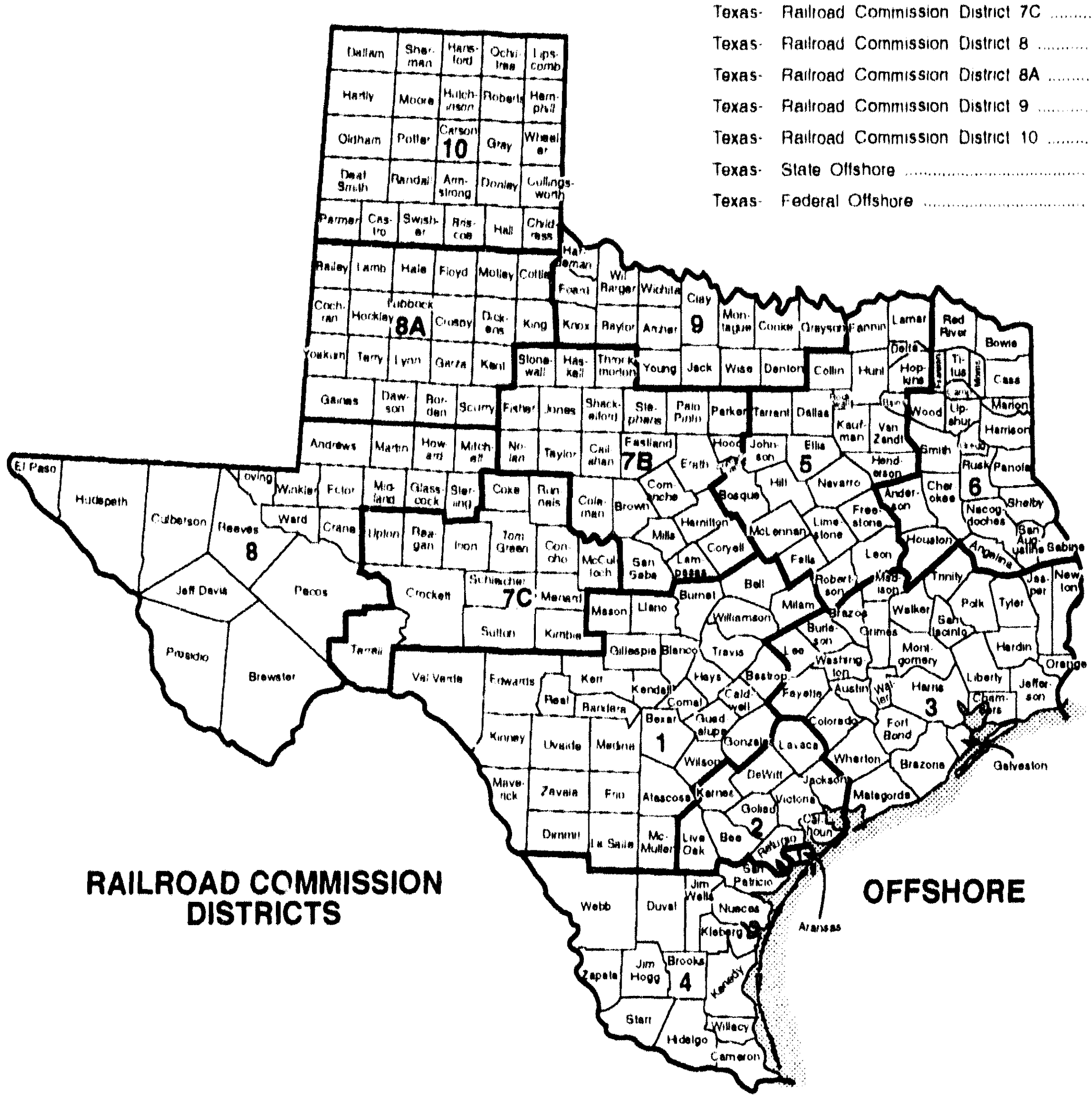
Figure H4. Subdivisions of New Mexico



Source: Energy Information Administration, Office of Oil and Gas.

Figure H5. Subdivisions of Texas

Texas- Railroad Commission District 1 .... TX 10
Texas- Railroad Commission District 2 Onshore .... TX 20
Texas- Railroad Commission District 3 Onshore .... TX 30
Texas- Railroad Commission District 4 Onshore .... TX 40
Texas- Railroad Commission District 5 .... TX 50
Texas- Railroad Commission District 6 .... TX 60
Texas- Railroad Commission District 7B .... TX 70
Texas- Railroad Commission District 7C .... TX 75
Texas- Railroad Commission District 8 .... TX 80
Texas- Railroad Commission District 8A .... TX 85
Texas- Railroad Commission District 9 .... TX 90
Texas- Railroad Commission District 10 .... TX 95
Texas- State Offshore .... TX 05
Texas- Federal Offshore .... TX 00



Source: Energy Information Administration, Office of Oil and Gas.

Appendix I

Annual Survey Forms of Domestic Oil and Gas Reserves

Figure I1. Form EIA-23, Cover Page

OFFICIAL USE ONLY

1992

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES
U.S. DEPARTMENT OF ENERGY
CALENDAR YEAR 1992

Form Approved
OMB No. 1905-0057
Expires 12/94

This report is mandatory under Public Law 93-275. Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. For the sanctions and the provisions concerning the confidentiality of information submitted on this form, see page 2 of the instructions. Public reporting burden for this collection of information is estimated to average from 62 to 333 hours per response, including the time of reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the Energy Information Administration, Office of Statistical Standards EI-73, Washington, DC 20585, and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503.

COVER PAGE

IDENTIFICATION

1. **Were you an operator** *(see definition of an operator, p. 1)* **of one or more oil or gas wells on December 31, 1992?**
   - (1) ☐ No — *Complete only items 3 through 22 below and return this page with a letter stating when operations ceased and what became of the wells you operated to* **P.O. Box 1470 Rockville, MD 20849-1470**
   - (2) ☐ Yes — *Complete the attached forms and return them to* **P.O. Box 1470 Rockville, MD 20849-1470**

2. I.D. Code FOR DOE USE ONLY: 0 0 0 0

If information to the left is incorrect or is missing, enter correct information below

3. Name
4. Address
5. City
6. State
7. Zip Code
8. EIN — Check if Attestor's Social Security Number ☐
9. Name of Contact Person
10. Telephone Number of Contact Person — Area Code ( ) ____-______

SAMPLE

PARENT COMPANY IDENTIFICATION

11. Is there a parent company which exercises ultimate control over your company?
    - (1) ☐ No — Answer 18 thru 22
    - (2) ☐ Yes — Answer 12 thru 22

12. Name
13. Address
14. City
15. State
16. Zip Code
17. Parent Company EIN
18. What is the total number of pages (including this page) submitted in this filing?

ATTESTATION

(This report must be attested to by a responsible official of the company.)
I hereby swear or affirm that I have read the report and am familiar with its contents, and that to the best of my knowledge, information, and belief, the information provided and appended is true and complete.

19. Name of Attestor *(Please print)*
20. Title
21. Signature
22. Date

Title 18 USC 1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

FOR ASSISTANCE CALL 1-800-879-1470

Source: Energy Information Administration, Office of Oil and Gas

Figure I2. Form EIA-23, Summary Report — Page 1

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

1992

SUMMARY REPORT
PAGE 1 OF 2

SAMPLE

STATE OR GEOGRAPHIC SUBDIVISION		CRUDE OIL RESERVE	CRUDE OIL 1992 PRODUCTION		NATURAL GAS RESERVE	NATURAL GAS 1992 PRODUCTION		LEASE CONDENSATE RESERVE	LEASE CONDENSATE 1992 PRODUCTION	
ALABAMA ONSHORE										
[illegible]										
ALASKA NORTH ONSHORE AND OFFSHORE										
[illegible]										
ALASKA SOUTH STATE OFFSHORE										
[illegible]										
ARKANSAS	AR									
[illegible]										
CALIFORNIA LOS ANGELES BASIN ONSHORE										
[illegible]										
CALIFORNIA STATE OFFSHORE										
[illegible]										
FLORIDA ONSHORE	FL									
[illegible]										
ILLINOIS	IL									
INDIANA	IN									
KANSAS	KS									
[illegible]										
LOUISIANA NORTH										
[illegible]										
LOUISIANA SOUTH STATE ONSHORE										
[illegible]										
MICHIGAN	MI									
[illegible]										
MISSISSIPPI STATE OFFSHORE										
[illegible]										
MONTANA	MT									
NEBRASKA	NE									
NEVADA	NV									
[illegible]										
NEW MEXICO-WEST										
[illegible]										
NORTH DAKOTA	ND									
[illegible]										

Source: Energy Information Administration, Office of Oil and Gas.

Figure I3. Form EIA-23, Summary Report — Page 2

OFFICIAL USE ONLY

1992

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

Form Approved
OMB No. 1905-0057
Expires 12/94

SUMMARY REPORT
PAGE 2 OF 2

(Report All Volumes of Crude Oil and Lease Condensate in Thousands of Barrels [Mbbl])
Report All Volumes of Natural Gas in Millions of Cubic Feet [MMcf] at 14.73 psia and 60° F

1.0 OPERATOR AND REPORT IDENTIFICATION DATA

1.1 OPERATOR I.D. CODE		1.2 OPERATOR NAME		REPORT DATE	1.3 ORIGINAL		1.4 AMENDED	
				12 / 31 / 92				

2.0 PRODUCTION AND RESERVES DATA

SAMPLE

STATE OR GEOGRAPHIC SUBDIVISION		CRUDE OIL			NATURAL GAS			LEASE CONDENSATE		
		RESERVE	1992 PRODUCTION		RESERVE	1992 PRODUCTION		RESERVE	1992 PRODUCTION	
		Proved Reserves Dec. 31, 1992 (Mbbl) (A)	(From properties for which reserves were Estimated) (Mbbl) (B)	(From properties for which reserves were Not Estimated) (Mbbl) (C)	Proved Reserves Dec. 31, 1992 (MMcf) (D)	(From properties for which reserves were Estimated) (MMcf) (E)	(From properties for which reserves were Not Estimated) (MMcf) (F)	Proved Reserves Dec. 31, 1992 (Mbbl) (G)	(From properties for which reserves were Estimated) (Mbbl) (H)	(From properties for which reserves were Not Estimated) (Mbbl) (I)
OKLAHOMA	OK									
PENNSYLVANIA	PA									
SOUTH DAKOTA	SD									
TENNESSEE	TN									
TEXAS-RRC DISTRICT 1	TX10									
TEXAS-RRC DISTRICT 2 ONSHORE	TX20									
TEXAS-RRC DISTRICT 3 ONSHORE	TX30									
TEXAS-RRC DISTRICT 4 ONSHORE	TX40									
TEXAS-RRC DISTRICT 5	TX50									
TEXAS-RRC DISTRICT 6	TX60									
TEXAS-RRC DISTRICT 7B	TX70									
TEXAS-RRC DISTRICT 7C	TX75									
TEXAS-RRC DISTRICT 8	TX80									
TEXAS-RRC DISTRICT 8A	TX85									
TEXAS-RRC DISTRICT 9	TX90									
TEXAS-RRC DISTRICT 10	TX95									
TEXAS-STATE OFFSHORE	TX05									
UTAH	UT									
VIRGINIA	VA									
WEST VIRGINIA	WV									
WYOMING	WY									
FEDERAL OFFSHORE-GULF OF MEXICO (ALABAMA)	AL00									
FEDERAL OFFSHORE-GULF OF MEXICO (FLORIDA)	FL00									
FEDERAL OFFSHORE-GULF OF MEXICO (LOUISIANA)	LA00									
FEDERAL OFFSHORE-GULF OF MEXICO (MISSISSIPPI)	MS00									
FEDERAL OFFSHORE-GULF OF MEXICO (TEXAS)	TX00									
FEDERAL OFFSHORE-PACIFIC (ALASKA)	AK00									
FEDERAL OFFSHORE-PACIFIC (CALIFORNIA)	CA00									
FEDERAL OFFSHORE-PACIFIC (OREGON)	OR00									
OTHER STATE (SPECIFY)										
TOTAL (SUM EACH COLUMN)	US									

Source: Energy Information Administration, Office of Oil and Gas.

Figure 14. Form EIA-23, Detail Report — Schedule A

OFFICIAL USE ONLY

1992

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

Form Approved
OMB No. 1905-0057
Expires 12/94

SCHEDULE A - OPERATED PROVED RESERVES, PRODUCTION, AND RELATED DATA BY FIELD
(Report All Liquid Volumes in Thousands of Barrels [Mbbl] at 60°F;
Report All Volumes of Natural Gas in Millions of Cubic Feet [MMcf] at 60°F and 14.73 psia)

1.0 OPERATOR AND REPORT IDENTIFICATION DATA

1.1 OPERATOR I.D. CODE	1.2 OPERATOR NAME	REPORT DATE	1.3 ORIGINAL	1.4 AMENDED	1.5 PAGE	FOR DOE USE ONLY
		12 31 92				

2.0 FIELD DATA (OPERATED BASIS)

2.1

1 STATE ABBR	2 SUBDIV CODE	3 COUNTY CODE	4 FIELD CODE	5 OCS BLOCK NUMBER	6 FIELD NAME	7 Calendar Year PRODUCTION From Properties For which RESERVES Were NOT ESTIMATED: (a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CONDENSATE (Mbbl)	8 FOOTNOTE

9 WATER DEPTH | 10 FIELD DISCOVERY YEAR | 11 INDICATED ADDITIONAL RESERVES OF CRUDE OIL (Mbbl)

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1991	REVISION (b) INCREASES	REVISION (c) DECREASES	EXTENSIONS (d)	NEW FIELD (e) DISCOVERIES	NEW RESERVOIRS (f) IN OLD FIELDS	CALENDAR YEAR (g) PRODUCTION	RESERVES (h) DECEMBER 31, 1992	NONPRODUCING (i) RESERVES
12 CRUDE OIL (Mbbl)									
13 ASSOCIATED-DISSOLVED GAS (MMcf)									
14 NONASSOCIATED GAS (MMcf)									
15 LEASE CONDENSATE (Mbbl)									

2.2

1 STATE ABBR	2 SUBDIV CODE	3 COUNTY CODE	4 FIELD CODE	5 OCS BLOCK NUMBER	6 FIELD NAME	7 Calendar Year PRODUCTION From Properties For which RESERVES Were NOT ESTIMATED: (a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CONDENSATE (Mbbl)	8 FOOTNOTE

9 WATER DEPTH | 10 FIELD DISCOVERY YEAR | 11 INDICATED ADDITIONAL RESERVES OF CRUDE OIL (Mbbl)

SAMPLE

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1991	REVISION (b) INCREASES	REVISION (c) DECREASES	EXTENSIONS (d)	NEW FIELD (e) DISCOVERIES	NEW RESERVOIRS (f) IN OLD FIELDS	CALENDAR YEAR (g) PRODUCTION	RESERVES (h) DECEMBER 31, 1992	NONPRODUCING (i) RESERVES
12 CRUDE OIL (Mbbl)									
13 ASSOCIATED-DISSOLVED GAS (MMcf)									
14 NONASSOCIATED GAS (MMcf)									
15 LEASE CONDENSATE (Mbbl)									

2.3

1 STATE ABBR	2 SUBDIV CODE	3 COUNTY CODE	4 FIELD CODE	5 OCS BLOCK NUMBER	6 FIELD NAME	7 Calendar Year PRODUCTION From Properties For which RESERVES Were NOT ESTIMATED: (a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CONDENSATE (Mbbl)	8 FOOTNOTE

9 WATER DEPTH | 10 FIELD DISCOVERY YEAR | 11 INDICATED ADDITIONAL RESERVES OF CRUDE OIL (Mbbl)

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1991	REVISION (b) INCREASES	REVISION (c) DECREASES	EXTENSIONS (d)	NEW FIELD (e) DISCOVERIES	NEW RESERVOIRS (f) IN OLD FIELDS	CALENDAR YEAR (g) PRODUCTION	RESERVES (h) DECEMBER 31, 1992	NONPRODUCING (i) RESERVES
12 CRUDE OIL (Mbbl)									
13 ASSOCIATED-DISSOLVED GAS (MMcf)									
14 NONASSOCIATED GAS (MMcf)									
15 LEASE CONDENSATE (Mbbl)									

2.4

1 STATE ABBR	2 SUBDIV CODE	3 COUNTY CODE	4 FIELD CODE	5 OCS BLOCK NUMBER	6 FIELD NAME	7 Calendar Year PRODUCTION From Properties For which RESERVES Were NOT ESTIMATED: (a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CONDENSATE (Mbbl)	8 FOOTNOTE

9 WATER DEPTH | 10 FIELD DISCOVERY YEAR | 11 INDICATED ADDITIONAL RESERVES OF CRUDE OIL (Mbbl)

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1991	REVISION (b) INCREASES	REVISION (c) DECREASES	EXTENSIONS (d)	NEW FIELD (e) DISCOVERIES	NEW RESERVOIRS (f) IN OLD FIELDS	CALENDAR YEAR (g) PRODUCTION	RESERVES (h) DECEMBER 31, 1992	NONPRODUCING (i) RESERVES
12 CRUDE OIL (Mbbl)									
13 ASSOCIATED-DISSOLVED GAS (MMcf)									
14 NONASSOCIATED GAS (MMcf)									
15 LEASE CONDENSATE (Mbbl)									

Source: Energy Information Administration, Office of Oil and Gas

Figure I5. Form EIA-23, Detail Report — Schedule B

OFFICIAL USE ONLY **1992**

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES
SCHEDULE B - FOOTNOTES

Form Approved
OMB No 1905-0057
Expires 12/94

1 0 OPERATOR AND REPORT IDENTIFICATION DATA						
1 1 OPERATOR I D CODE	1 2 OPERATOR NAME	REPORT DATE	1 3 ORIGINAL	1 4 AMENDED	1 5 PAGE	FOR DOE USE ONLY
		12 31 92				

2 0 FOOTNOTE DATA

Page Number (a)	Item Number (b)	Subitem Number (c)	Column Designation (d)	Sequence Number (e)	Notation (f)	FOR DOE USE ONLY

SAMPLE

Source: Energy Information Administration, Office of Oil and Gas.

Figure 16. Form EIA-64A

EIA-64A (Revised 9/91)

1992

U.S. DEPARTMENT OF ENERGY

Form Approved
OMB No. 1905-0057
Expires 12/94

ANNUAL REPORT OF THE ORIGIN OF NATURAL GAS LIQUIDS PRODUCTION
FORM EIA-64A

PLEASE COMPLETE THIS FORM AND RETURN TO

PLANT AND PRODUCTION REPORT IDENTIFICATION

1.0

2.0

3.0 Parent Company's Name

4.0 Submission Status

5.0 Origin of Natural Gas Received and Natural Gas Liquids Produced

Line	Area of Origin Code (A)	Natural Gas Received (MMcf) (B)	Natural Gas Liquids Production (Mbbl) (C)
	TOTAL		

SAMPLE

6.0 Gas Shrinkage Resulting from Natural Gas Liquids Extracted (MMcf)

7.0 Natural Gas Used as Fuel in Processing (MMcf)

8.0 Explanatory Notes

9.0 Certification

FOR ASSISTANCE CALL 1-800-879-1470

Glossary

Glossary

This glossary contains definitions of the technical terms used in this report and employed by respondents in completing Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," or Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production," for the report year 1992.

Adjustments: The quantity which preserves an exact annual reserves balance within each State or State subdivision of the following form:

Published Proved Reserves at End of Previous Report Year
+ Adjustments
+ Revision Increases
− Revision Decreases
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
+ Report Year Production
= Published Proved Reserves at End of Report Year

These adjustments are the yearly changes in the published reserve estimates that cannot be attributed to the estimates for other reserve change categories because of the survey and statistical estimation methods employed. For example, variations as a result of changes in the operator frame, different random samples or imputations for missing or unreported reserve changes, could contribute to adjustments.

Affiliated (Associated) Company: An "affiliate" of, or a person "affiliated" with, a specific person is a person that directly, or indirectly through one or more intermediaries: controls; or is controlled by; or is under common control with, the person specified. (See **Person and Control**)

Control: The term "control" (including the terms "controlling," "controlled by," and "under common control with") means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting shares, by contract, or otherwise. (See **Person**)

Corrections: (See **Revisions**)

Crude Oil: A mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Crude oil may also include:

1. small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators, and that subsequently are comingled with the crude stream without being separately measured, and
2. small amounts of nonhydrocarbons produced with the oil.

When a State regulatory agency specifies a definition of crude oil which differs from that set forth above, the State definition is to be followed and its use footnoted on Schedule B of Form EIA-23.

Extensions: The reserves credited to a reservoir because of enlargement of its proved area. Normally the ultimate size of newly discovered fields, or newly discovered reservoirs in old fields, is determined by wells drilled in years subsequent to discovery. When such wells add to the proved area of a previously discovered reservoir, the increase in proved reserves is classified as an extension.

Field: An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.

Field Area: A geographic area encompassing two or more pools that have a common gathering and metering system, the reserves of which are reported as a single unit. This concept applies primarily to the Appalachian region. (See **Pool**)

Field Discovery Year: The calendar year in which a field was first recognized as containing economically recoverable accumulations of oil and/or gas.

Field Separation Facility: A surface installation designed to recover lease condensate from a produced natural gas stream frequently originating from more than one lease, and managed by the operator of one or more of these leases. (See **Lease Condensate**)

Gross Working Interest Ownership Basis: Gross working interest ownership is the respondent's working interest in a given property plus the proportionate share of any royalty interest, including overriding royalty interest, associated with the working interest. (See **Working Interest** and **Royalty** (including **Overriding Royalty**) **Interest**)

Indicated Additional Reserves of Crude Oil: Quantities of crude oil (other than proved reserves) which may become economically recoverable from existing productive reservoirs through the application of improved recovery techniques using current technology. These recovery techniques may:

1. already be installed in the reservoir, but their effects are not yet known to the degree necessary to classify the additional reserves as proved, or
2. be installed in another similar reservoir, where the results of that installation can be used to estimate the indicated additional reserves.

Indicated additional reserves are not included in proved reserves due to their uncertain economic recoverability. When economic recoverability is demonstrated, the indicated additional reserves must be transferred to proved reserves as positive revisions.

Lease Condensate: A mixture consisting primarily of pentanes and heavier hydrocarbons which is recovered as a liquid from natural gas in lease or field separation facilities, exclusive of products recovered at natural gas processing plants or facilities.

Lease Separator: A lease separator is a facility installed at the surface for the purpose of (a) separating gases from produced crude oil and water at the temperature and pressure conditions of the separator, and/or (b) separating gases from that portion of the produced natural gas stream which liquefies at the temperature and pressure conditions of the separator.

Natural Gas: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in natural underground reservoirs at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentanes. Typical nonhydrocarbon gases which may be present in reservoir natural gas are water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions occur either in a single gaseous phase in the reservoir or in solution with crude oil, and are not distinguishable at the time as separate substances. (See **Natural Gas, Associated-Dissolved** and **Natural Gas, Nonassociated**.)

Natural Gas, Associated-Dissolved: The combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

Natural Gas, "Dry": The actual or calculated volumes of natural gas which remain after:

1. the liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or plant separation), and
2. any volumes of nonhydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable.

Natural Gas, Nonassociated: Natural gas not in contact with significant quantities of crude oil in a reservoir.

Natural Gas Liquids: Those hydrocarbons in natural gas which are separated from the gas through the processes of absorption, condensation, adsorption, or other methods in gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as condensate, natural gasoline, or liquefied petroleum gases. Where hydrocarbon components lighter than propane are recovered as liquids, these components are included with natural gas liquids.

Natural Gas Processing Plant: A facility designed to recover natural gas liquids from a stream of natural gas which may or may not have passed through lease separators and/or field separation facilities. Another function of the facility is to control the quality of the processed natural gas stream. Cycling plants are considered natural gas processing plants.

Natural Gas, Wet After Lease Separation: The volume of natural gas remaining after removal of lease condensate in lease and/or field separation facilities, if any, and after exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Natural gas liquids may be recovered from volumes of natural gas, wet after lease separation, at natural gas processing plants. (See **Lease Condensate, Lease Separator,** and **Field Separation Facility**.)

Net Revisions: (See **Revisions**.)

New Field: A field discovered during the report year.

New Field Discoveries: The volumes of proved reserves of crude oil, natural gas and/or natural gas liquids discovered in new fields during the report year.

New Reservoir: A reservoir discovered during the report year.

New Reservoir Discoveries in Old Fields: The volumes of proved reserves of crude oil, natural gas, and/or natural gas liquids discovered during the report year in new reservoir(s) located in old fields.

Nonproducing Reservoirs: Reservoirs in which proved liquid or gaseous hydrocarbon reserves have been identified, but which did not produce during the last calandar year regardless of the availability and/or operation of production, gathering, or transportation facilities.

Old Field: A field discovered prior to the report year.

Old Reservoir: A reservoir discovered prior to the report year.

Operator, Gas Plant: The person responsible for the management and day-to-day operation of one or more natural gas processing plants as of December 31 of the report year. The operator is generally a working interest owner or a company under contract to the working interest owner(s). Plants shut down during the report year are also to be considered "operated" as of December 31. (See **Person**)

Operator, Oil and/or Gas Well: The person responsible for the management and day-to-day operation of one or more crude oil and/or natural gas wells as of December 31 of the report year. The operator is generally a working interest owner or a company under contract to the working interest owner(s). Wells included are those which have proved reserves of crude oil, natural gas, and/or lease condensate in the reservoirs associated with them, whether or not they are producing. Wells abandoned during the report year are also to be considered "operated" as of December 31. (See **Person**, **Proved Reserves of Crude Oil**, **Proved Reserves of Natural Gas**, **Proved Reserves of Lease Condensate**, **Report Year**, and **Reservoir**)

Ownership: (See **Gross Working Interest Ownership Basis**)

Parent Company: The parent company of a business entity is an affiliated company which exercises ultimate control over that entity, either directly or indirectly through one or more intermediaries. (See **Affiliated (Associated) Company and Control**)

Person: An individual, a corporation, a partnership, an association, a joint-stock company, a business trust, or an unincorporated organization.

Pool: In geenral, a reservoir. In certain situations a pool may consist of more than one reservoir. (See **Field Area**)

Plant Liquids: Those volumes of natural gas liquids recovered in natural gas processing plants.

Production, Crude Oil: The volumes of crude oil which are extracted from oil reservoirs during the report year. These volumes are determined through measurement of the volumes delivered from lease storage tanks, (i.e., at the point of custody transfer) with adjustment for (1) net differences between opening and closing lease inventories, and for (2) basic sediment and water. Oil used on the lease is considered production.

Production, Lease Condensate: The volume of lease condensate produced during the report year. Lease condensate volumes include only those volumes recovered from lease or field separation facilities. (See **Lease Condensate**)

Production, Natural Gas, Dry: The volume of natural gas withdrawn from reservoirs during the report year less (1) the volume returned to such reservoirs in cycling, repressuring of oil reservoirs and conservation operations; less (2) shrinkage resulting from the removal of lease condensate and plant liquids; and less (3) nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Volumes of gas withdrawn from gas storage reservoirs and native gas, which has been transferred to the storage category, are not considered production. This is not the same as marketed production, since the latter also excludes vented and flared gas, but contains plant liquids.

Production, Natural Gas, Wet after Lease Separation: The volume of natural gas withdrawn from reservoirs during the report year less (1) the volume returned to such reservoirs in cycling, repressuring of oil reservoirs and conservation operations; less (2) shrinkage resulting from the removal of lease condensate; and less (3) nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Volumes of gas withdrawn from gas storage reservoirs and native gas, which has been transferred to the storage category, are not considered production. This is not the same as marketed production, since the latter excludes vented and flared gas.

Production, Natural Gas Liquids: The volume of natural gas liquids removed from natural gas in lease separators, field facilities, gas processing plants or cycling plants during the report year.

Production, Plant Liquids: The volume of liquids removed from natural gas in natural gas processing plants or cycling plants during the report year.

Proved Reserves of Crude Oil: Proved reserves of crude oil as of December 31 of the report year are the estimated quantities of all liquids defined as crude oil, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reservoirs are considered proved if economic producibility is supported by actual production or conclusive formation test (drill stem or wire line), or if economic producibility is supported by core analyses and/or electric or other log interpretations. The area of an oil reservoir considered proved includes (1) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons is considered to be the lower proved limit of the reservoir.

Volumes of crude oil placed in underground storage are not to be considered proved reserves.

Reserves of crude oil which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved crude oil reserves do not include the following: (1) oil that may become available from known reservoirs but is reported separately as "indicated additional reserves"; (2) natural gas liquids (including lease condensate); (3) oil, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (4) oil that may occur in undrilled prospects; and (5) oil that may be recovered from oil shales, coal, gilsonite, and other such sources. It is not necessary that production, gathering or transportation facilities be installed or operative for a reservoir to be considered proved.

Proved Reserves of Lease Condensate: Proved reserves of lease condensate as of December 31 of the report year are the volumes of lease condensate expected to be recovered in future years in conjunction with the production of proved reserves of natural gas as of December 31 of the report year, based on the recovery efficiency of lease and/or field separation facilities installed as of December 31 of the report year. (See **Lease Condensate** and **Proved Reserves of Natural Gas**)

Proved Reserves of Natural Gas: Proved reserves of natural gas as of December 31 of the report year are the estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reservoirs are considered proved if economic producibility is supported by actual production or conclusive formation test (drill stem or wire line), or if economic producibility is supported by core analyses and/or electric or other log interpretations.

The area of a gas reservoir considered proved includes: (1) that portion delineated by drilling and defined by gas-oil and/or gas-water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons is considered to be the lower proved limit of the reservoir.

Volumes of natural gas placed in underground storage are not to be considered proved reserves.

For natural gas, wet after lease separation, an appropriate reduction in the reservoir gas volume has been made to cover the removal of the liquefiable portions of the gas in lease and/or field separation facilities and the exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable.

For dry natural gas, an appropriate reduction in the gas volume has been made to cover the removal of the liquefiable portions of the gas in lease and/or field separation facilities, and in natural gas processing plants, and the exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable.

It is not necessary that production, gathering, or transportation facilities be installed or operative for a reservoir to be considered proved. It is to be assumed that compression will be initiated if and when economically justified.

Proved Reserves of Natural Gas Liquids: Proved reserves of natural gas liquids as of December 31 of the report year are those volumes of natural gas liquids (including lease condensate) demonstrated with reasonable certainty to be separable in the future from proved natural gas reserves, under existing economic and operating conditions.

Report Year: The calendar year to which data reported in this publication pertain.

Reserves: (See **Proved Reserves**)

Reserve Additions: Consist of adjustments, net revisions, extensions to old reservoirs, new reservoir discoveries in old fields, and new field discoveries.

Reserves Changes: Positive and negative revisions, extensions, new reservoir discoveries in old fields, and new field discoveries, which occurred during the report year.

Reservoir: A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

Revisions: Changes to prior year-end proved reserves estimates, either positive or negative, resulting from new information other than an increase in proved acreage (extension). Revisions include increases of proved reserves associated with the installation of improved recovery techniques or equipment. They also include correction of prior report year arithmetical or clerical errors and adjustments to prior year-end production volumes to the extent that these alter reported prior year reserves estimates.

Royalty (Including Overriding Royalty) Interests: These interests entitle their owner(s) to a share of the mineral production from a property or to a share of the proceeds therefrom. They do not contain the rights and obligations of operating the property, and normally do not bear any of the costs of exploration, development, and operation of the property.

Subdivision: A prescribed portion of a given State or other geographical region defined in this publication for statistical reporting purposes.

Subsidiary Company: A company which is controlled through the ownership of voting stock, or a corporate joint venture in which a corporation is owned by a small group of businesses as a separate and specific business or project for the mutual benefit of the members of the group. (See **Control**)

Total Discoveries: The sum of extensions, new reservoir discoveries in old fields, and new field discoveries, which occurred during the report year.

Total Liquid Hydrocarbon Reserves: The sum of crude oil and natural gas liquids reserves volumes.

Total Operated Basis: The total reserves or production associated with the wells operated by an individual operator. This is also commonly known as the "gross operated" or "8/8ths" basis.

Working Interest: A working interest permits the owner(s) to explore, develop and operate a property. The working interest owner(s) bear(s) the costs of exploration, development and operation of the property, and in return is (are) entitled to a share of the mineral production from the property or to a share of the proceeds therefrom.

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