DOE/EIA-0216(94)
Distribution Category UC-950

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

1994 Annual Report

October 1995

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

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Reserves Data on Diskette

Historical oil and gas reserves data are available on 3.5 or 5.25 inch high-density diskettes. These data cover the years 1977 through 1994, as published in the Energy Information Administration's *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*. Eighteen separate annual ASCII files are stored on a single diskette and each contains the following data tables:

- **Crude Oil Proved Reserves, Reserves Changes, and Production**
- **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 - 1994, is available from the Energy Information Administration. Contact Bob King at 202/586-4787. (Fax: 202/586-1076 or E-mail: rking@eia.doe.gov)

Preface

The *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1994 Annual Report* is the 18th prepared by the Energy Information Administration (EIA) to fulfill its responsibility to gather and report annual proved reserves estimates. The EIA annual reserves report series is the only source of comprehensive domestic proved reserves estimates. This publication is used by the Congress, Federal and State agencies, industry, and other interested parties to obtain accurate 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.

This report presents estimates of proved reserves of crude oil, natural gas, and natural gas liquids as of December 31, 1994, as well as production volumes for the United States and selected States and State subdivisions for the year 1994. Estimates are presented for the following four categories of natural gas: total gas (wet after lease separation), nonassociated gas and associated-dissolved gas (which are the two major types of wet natural gas), and total dry gas (wet gas adjusted for the removal of liquids at natural gas processing plants). In addition, reserve estimates for two types of natural gas liquids, lease condensate and natural gas plant liquids, are presented. The 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 1994 is provided.

The appendices contain data by operator production size class for crude oil and natural gas reserves and production; the top 100 U.S. fields ranked within an oil or gas proved reserves group for 1993; report Table 1 converted to metric units; historical State data; 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. 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.

This annual reserves report was 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. General information regarding preparation of the report may be obtained from Diane W. Lique, Director of the Office of Oil and Gas; Craig H. Cranston, Chief of the Reserves and Production Branch (202/586-6023); or John H. Wood, Director of the Dallas Field Office (214/767-2200).

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The preparation of the report was supervised by John H. Wood. Significant contributions were made by Jack S. Sanders, David F. Morehouse, William L. Monroe, and John R. Tower. Editorial support was provided by Ann C. Whitfield.

Other EIA Oil and Gas Publications

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

***Natural Gas Productive Capacity for the Lower 48 States,* DOE/EIA-0542, December 1995**

This report describes an analysis of monthly natural gas wellhead productive capacity in the lower 48 States from 1980 through 1993, and projects this capacity through 1996. The impacts of drilling, oil and gas price assumptions, and demand on gas productive capacity are integrated into the capacity projections as low, base, and high cases.

***Natural Gas Annual 1994,* DOE/EIA-0131(94), September 1995**
***Petroleum Marketing Annual 1993,* DOE/EIA-0487(93), January 1995**
***Petroleum Supply Annual 1994,* DOE/EIA-0340(94), May 1995**

These annual reports provide comprehensive statistics on supply, disposition, and prices of natural gas and petroleum in the United States.

***Natural Gas 1995: Issues and Trends,* DOE/EIA-0560(95), October 1995**

This report addresses trends relating to natural gas supply, demand, prices, imports, contracting, transportation, storage, and Federal Energy Regulatory Commission (FERC) Order 636.

***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.

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U.S. proved reserves of natural gas were up 1 percent in 1994, the first gain in 4 years. Proved oil reserves declined by 2 percent, the smallest decline in 4 years. Large oil and gas discoveries in the Federal offshore, several in deep water, played a major role. Successful oil and gas exploratory well completions were up even though overall well completions were down, as were oil and gas prices.

As of December 31, proved reserves were:

Crude Oil (million barrels)	
1993	22,957
1994	22,457
Decrease	- 2.2%
Dry Natural Gas (billion cubic feet)	
1993	162,415
1994	163,837
Increase	+ 0.9%
Natural Gas Liquids (million barrels)	
1993	7,222
1994	7,170
Decrease	- 0.7%

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 are required in estimating proved reserves; therefore, the results are not precise measurements. This report of 1994 U.S. proved reserves of crude oil, natural gas, and natural gas liquids is the 18th in an annual series prepared by the Energy Information Administration.

Natural Gas

Total discoveries were up substantially as were *revisions and adjustments*. These combined to replace 108 percent of gas production, which also increased in 1994. The last gas reserves increase was in 1990, and the one prior to that was in 1981. While lower 48 States gas reserves have been generally declining since the late 1960s, they have declined less than 1 percent per year since natural gas prices peaked in 1983. This is a low reserves decline rate for a period in which rapid changes in price, demand, drilling, and the industry's regulatory environment occurred. These changes left gas prices and drilling at levels much lower in 1994 than in 1983.

In 1994, gas production reached the highest level since 1981. The United States is counting on more gas production increases in the future. This will require generally increasing levels of gas reserves. While improved technology has brought about the capability to add reserves with more effective exploratory and developmental drilling, it will take a strong and successful drilling effort to sustain a rising trend in gas reserves. There was a large increase in successful gas exploratory drilling in 1994.

Improved exploration and deepwater production technologies enhanced the ability to discover and develop offshore fields. For example, in the Gulf of Mexico, Shell Oil Company plans to develop the Ram/Powell platform in 3,220 feet of water. It will set a new U.S. depth record for a permanent platform. Shell also plans to develop a large natural gas discovery, its Mensa project, in 5,400 feet of water using subsea completions. This will set a world record for deepwater production.

The four leading gas producing areas, Texas, the Gulf of Mexico Federal Offshore, Oklahoma, and Louisiana had 1994 proved reserves increases that totaled 3,202 billion cubic feet.

Following several years of growth, coalbed methane reserves declined in 1994. However, coalbed methane production grew to nearly 5 percent of U.S. dry gas production. Coalbed methane reserves accounted for 6 percent of U.S. natural gas reserves in 1994. No federal tax incentives for new coalbed methane wells have been available for 2 years.

U.S. *total discoveries* of dry gas reserves were 12,315 billion cubic feet in 1994, an increase of 39 percent over 1993. These discoveries equal two-thirds of 1994 gas production. *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.

- *New field discoveries* were 1,894 billion cubic feet, up 111 percent over 1993.

- Field *extensions* were 6,941 billion cubic feet, up 14 percent over 1993.

- *New reservoir discoveries in old fields* were 3,480 billion cubic feet, up 86 percent over 1993 and the highest since 1979.
- *Total discoveries* per exploratory well were maintained at a high level in 1994. They were more than twice that of the early 1980s.
- Texas and the Gulf of Mexico Federal Offshore accounted for almost two-thirds of U.S. *total discoveries* of gas in 1994.

The net volume of *revisions and adjustments* to reserves also played a significant role in increasing U.S. natural gas proved reserves. It amounted to 7,429 billion cubic feet in 1994, an 18 percent increase over 1993. Texas had the largest increase in *revisions and adjustments* as its proved gas reserves increased in 1994. Successful infill drilling between existing wells played a major role in this increase.

Other 1994 notable events for natural gas were:

- Exploratory gas well completions increased by 48 percent to 720, the highest level since 1986.
- Total gas well completions substantially exceeded oil well completions.
- Natural gas prices at the wellhead decreased 10 percent to an average of $1.83 per thousand cubic feet.

Crude Oil

Proved reserves of crude oil have now declined for 7 consecutive years. Low oil prices and a continued string of new lows for oil drilling are the major factors. Operators replaced only 78 percent of their 1994 oil production. This resulted in the 2 percent decline in proved reserves of crude oil.

Total discoveries of crude oil were 572 million barrels in 1994. Just two areas, the Gulf of Mexico Federal Offshore and Texas, accounted for 60 percent of them.

New field discoveries were 64 million barrels, a sharp drop from the exceptionally high level of 1993. For the second year in a row, over 80 percent of them were in the Gulf of Mexico Federal Offshore. Deepwater discoveries made a large contribution both years.

Revisions and adjustments were 1,196 million barrels in 1994, up 56 percent. In particular, the large 482 million barrels of *revisions and adjustments* for Alaska replaced most of the State's production. These revisions were primarily due to the expansion of enhanced oil recovery projects in Alaskan North Slope fields. However, there were major downward revisions in many lower 48 States fields because of poor economics.

Other 1994 notable events for crude oil were:

- Oil prices declined to $13.19 per barrel, the lowest annual average in constant 1994 dollars since the 1973 Arab oil embargo.
- The lower oil prices caused lower oil drilling. Oil well completions dropped to 6,789, yet another 20-year low.
- *New reservoir discoveries in old fields* were 111 million barrels, about the same as 1993.
- Field *extensions* were up, at 397 million barrels, but still well below the prior 10-year average.

Indicated additional crude oil reserves were 3,151 million barrels in 1994, a 9-percent decrease from 1993. 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 declined 1 percent to 7,170 million barrels in 1994. Natural gas liquids reserves are the sum of natural gas plant liquids and lease condensate reserves.

Total proved reserves of liquid hydrocarbons (crude oil plus natural gas liquids) were 29,627 million barrels in 1994, a decline of 552 million barrels from the 1993 level. Natural gas liquids were 24 percent of total liquid hydrocarbon proved reserves in 1994, unchanged from 1993.

Data

These estimates are based upon analysis of data from Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," filed by 3,828 operators of oil and gas wells, and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production," filed by operators of 791 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 principal focus of this report is to provide the most accurate annual estimates of U.S. proved reserves of crude oil, natural gas, and natural gas liquids. These estimates are 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. However, the industry ceased publication of reserve estimates after its 1979 report.

In response to a recognized need for credible annual proved reserves estimates, Congress, in 1977, required the Department of Energy to prepare such estimates. To meet this requirement, the Energy Information Administration (EIA) developed a program that established a unified, verifiable, comprehensive, and continuing annual statistical series for proved reserves of crude oil and natural gas. It was expanded to include proved reserves of natural gas liquids for the 1979 and subsequent reports.

Survey Overview

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. Readers who are unfamiliar with the distinctions between types of reserves or with how reserves fit in the description of overall oil and gas resources should see Appendix G.

While the primary topic of this report is proved reserves, information is also presented on indicated additional crude oil 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.

This report provides proved reserves estimates for the calendar year 1994. It is based on data filed by a sample of operators of oil and gas wells on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and by operators of all natural gas processing plants on Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." The U.S. crude oil and natural gas proved reserves estimates are associated with sampling errors of less than 1 percent at a 95-percent confidence level.

Form EIA-23

On Form EIA-23, 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.

Operator size categories are based upon their annual production as indicated in various Federal, State, and commercial records. Large operators are 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. Intermediate operators produced less than large operators, but more than 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both. Small operators are those that produced less than did intermediate 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. 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 the 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 annual changes in the published reserve estimates that cannot be attributed to the estimates for other reserve change categories. They result from the survey and statistical estimation methods employed. For example, variations caused by changes in the operator frame, different random samples, changes in reserve estimates following ownership changes, incorrectly reported data, or imputations for missing or unreported reserve changes can contribute to adjustments.

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 and complete survey frame consisting of operators of oil and gas wells and of natural gas processing plants. The Form EIA-23 operator frame contained 22,854 probable active operators and the Form EIA-64A plant frame contained 783 probable active natural gas processing plants in the United States when the 1994 survey was initiated. Additional operators were added to the survey as it progressed, and many operators initially in the sample frame were found to be inactive in 1994.

For the report year 1994, the EIA mailed 4,074 EIA-23 forms to all known large and intermediate sized oil and gas well operators and to a sample of smaller operators that were expected to be active during 1994. Of these, 268 were found to be nonoperators in 1994. Data were received from 3,828 operators, an overall response rate of 99.8 percent of the active operators in the Form EIA-23 survey. The EIA mailed 825 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 791 unique active natural gas processing plants in the Form EIA-64A survey.

National estimates of the 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 the EIA, which are obtained from non-survey based State sources. For report year 1994, the Form EIA-23 National production estimates were 0.3 percent lower than the comparable *Petroleum Supply Annual 1994* volumes for crude oil and lease condensate combined, and were 2.8 percent lower than the comparable *Natural Gas Monthly July 1995* volume for 1994 dry natural gas. For report year 1994, the Form EIA-64A National estimates were 0.9 percent higher than the *Petroleum Supply Annual 1994* volume for natural gas plant liquids production.

2. Overview

The United States had the following proved reserves as of December 31, 1994:

- **Crude Oil** — 22,457 million barrels
- **Dry Natural Gas** — 163,837 billion cubic feet
- **Natural Gas Liquids** — 7,170 million barrels.

Table 1 lists the estimated annual reserve balances since 1983. In 1994, the proved reserves of dry natural gas increased by 1 percent. This was the first increase in 4 years. Crude oil proved reserves declined in 1994, which they have been doing since 1988. However, they declined by only 2 percent, the lowest decline rate in 4 years.

Major factors that caused natural gas reserves to go up and lessened the decline of oil reserves in 1994 were: large new discoveries of oil and gas in the Federal offshore waters of the Gulf of Mexico (several in deep water—more than 200 meters of water depth); Alaskan operators continued to expand the use of enhanced oil recovery; and Texas operators made several new discoveries of natural gas in the Lower Wilcox-Lobo trend of south Texas.

Crude Oil

Proved reserves of crude oil decreased by 500 million barrels during 1994. A decrease of only 8 million barrels occurred in Alaska, while the lower 48 States decreased by 492 million barrels. **Figure 1** shows the crude oil proved reserves levels by major area and **Figure 2** shows the components of the change in them from 1984 through 1994.

Consistent with the trend in **Figure 2**, production of crude oil exceeded the amount of crude oil proved reserves added to the U.S. total—resulting in a net decline of crude oil proved reserves in 1994. Operators replaced only about 78 percent of their 1994 oil production with reserve additions.

New field discoveries added 64 million barrels of proved reserves. This volume is down substantially compared to the high volume discovered in 1993 (319 million barrels), and is only 54 percent of the average volume discovered in the prior 10 years (118 million barrels).

New reservoir discoveries in old fields added 111 million barrels of proved reserves. This is 1 million barrels more than in 1993, and is 96 percent of the average volume discovered in the prior 10 years (116 million barrels).

Extensions added 397 million barrels of proved reserves. This is 112 percent of 1993's extensions (356 million barrels) and 83 percent of the average extensions in the prior 10 years (481 million barrels).

Total discoveries are those reserves attributable to field *extensions*, *new field discoveries*, and *new reservoir discoveries in old fields*. There were 572 million barrels of *total discoveries* in 1994.

Production deducted an estimated 2,268 million barrels of proved reserves from the National total. Production was down slightly from 1993's level (2,339 million barrels) and 84 percent of the prior 10-year average (2,713 million barrels).

Revisions and adjustments added 1,196 million barrels of proved reserves. This is 156 percent of 1993's volume (766 million barrels) and 79 percent of the average volume of the prior 10 years (1,521 million barrels).

Crude oil reserves have been primarily sustained by continuing upward *revisions and adjustments* to the reserves of older fields. Since 1983, *revisions and adjustments* accounted for 68 percent of reserve additions.

The overall 1994 United States reduction of 500 million barrels of crude oil proved reserves is less than in 1993 and slightly higher than the prior 10-year average (-478 million barrels).

Natural Gas

Proved reserves of dry natural gas increased by 1,422 billion cubic feet during 1994 (up 1 percent from 1993 levels). Dry natural gas reserves decreased by 174 billion cubic feet in Alaska, but dry natural gas reserves for the lower 48 States increased by 1,596 billion cubic feet. **Figure 3** shows the dry natural gas proved reserves levels by major area and **Figure 4** shows the components of the change in them from 1984 through 1994.

The last prior increase in dry natural gas proved reserves occurred in 1990 (**Figure 4**). The lower 48 States' dry gas reserves rose in 1994 due to the discovery of very large natural gas accumulations in

Table 1. U.S. Proved Reserves of Crude Oil, Dry Natural Gas, and Natural Gas Liquids, 1984-1994

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)										
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
1993	271	2,011	1,516	766	356	319	110	785	2,339	22,957	-788
1994	189	2,364	1,357	1,196	397	64	111	572	2,268	22,457	-500
	Dry Natural Gas (billion cubic feet, 14.73 psia, 60° Fahrenheit)										
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
1993	972	17,597	12,248	6,321	6,103	899	1,866	8,868	17,789	162,415	-2,600
1994	1,945	21,365	15,881	7,429	6,941	1,894	3,480	12,315	18,322	163,837	+1,422
	Natural Gas Liquids (million barrels of 42 U.S. gallons)										
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
1993	102	764	640	226	245	24	64	333	788	7,222	-229
1994	43	873	676	240	314	54	131	499	791	7,170	-52

[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 1994 contained in the *Petroleum Supply Annual 1994*, DOE/EIA-0340(94) and the *Natural Gas Annual 1994*, DOE/EIA-0131(94).

Sources: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1984 through 1994 annual reports, DOE/EIA-0216.{1-10}

Figure 1. U.S. Crude Oil Proved Reserves, 1984-1994

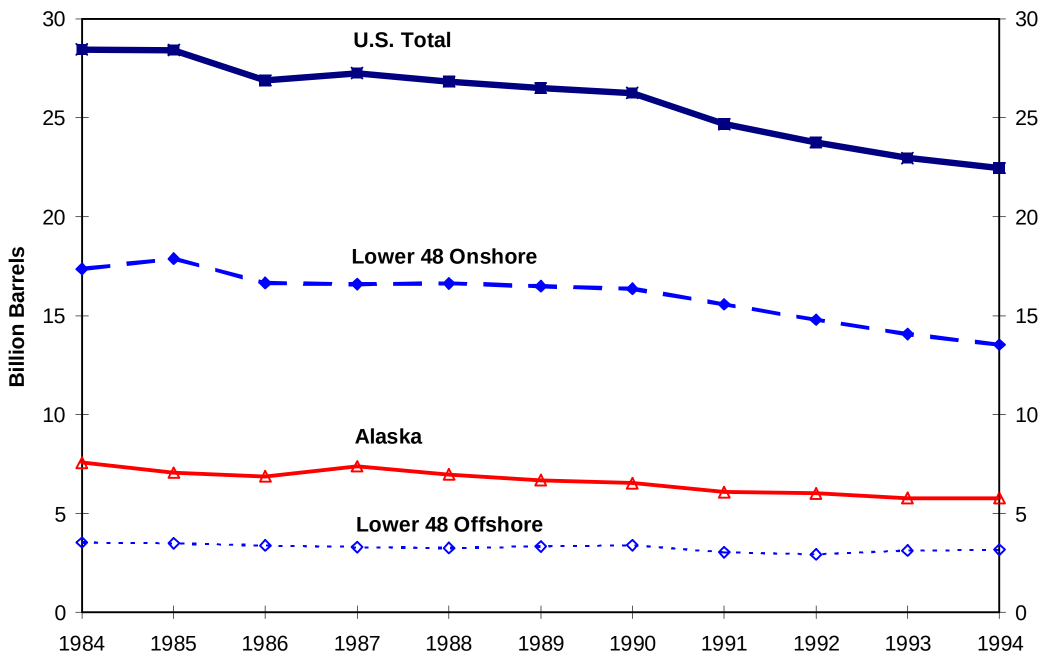
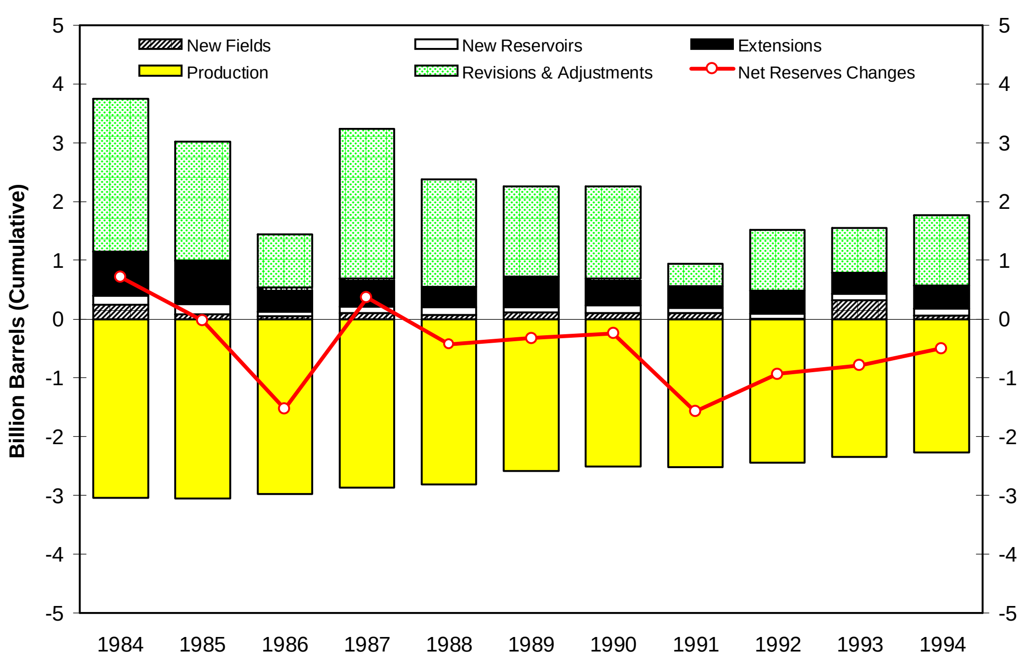


Figure 2. Components of Reserves Changes for Crude Oil, 1984-1994



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1984 through 1993 annual reports, DOE/EIA-0216.{1-10}

Figure 3. U.S. Dry Natural Gas Proved Reserves, 1984-1994

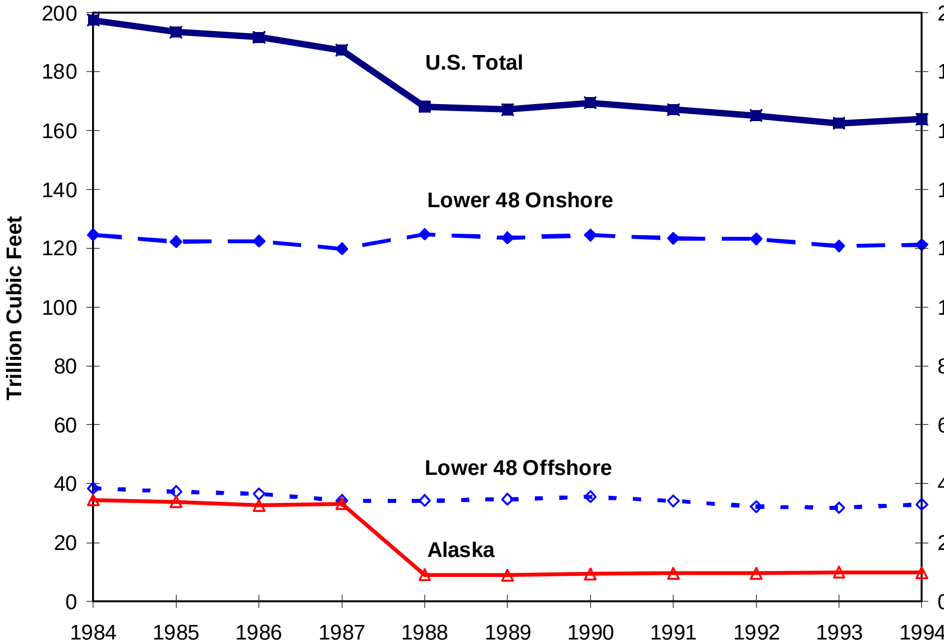
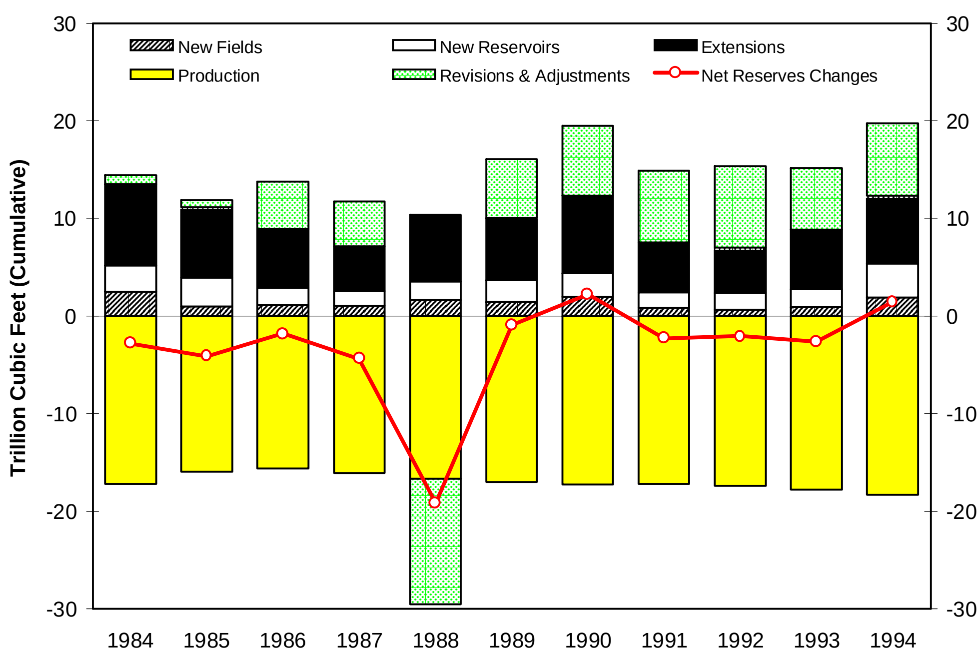


Figure 4. Components of Reserves Changes for Dry Natural Gas, 1984-1994



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1984 through 1993 annual reports, DOE/EIA-0216.{1-10}

deep water in the Gulf of Mexico, and substantial *total discoveries* in Texas and Louisiana. Operators replaced all of the United States' 1994 gas production (estimated to be about 18.322 trillion cubic feet of gas produced) with new reserves and added an additional 1,422 billion cubic feet to the U.S. total.

New field discoveries added 1,894 billion cubic feet of proved reserves. This is the third largest increase in *new field discoveries* since 1984 (larger volumes of new field discoveries were reported only in 1984 and 1990). Operators discovered over twice as much as in 1993, and 143 percent of the average volume discovered in the prior 10 years (1,321 billion cubic feet).

New reservoir discoveries in old fields added 3,480 billion cubic feet of proved reserves. Again, this is almost twice the volume discovered in 1993, and is 168 percent of the average volume discovered in the prior 10 years (2,067 billion cubic feet).

Extensions added 6,941 billion cubic feet of proved reserves. This is 114 percent of 1993's *extensions* and 110 percent of average extensions over the prior 10 years (6,308 billion cubic feet).

Production deducted an estimated 18,322 billion cubic feet of proved reserves as production increased compared to 1993. Gas production has been generally increasing since 1986.

Revisions and Adjustments added 7,429 billion cubic feet of proved reserves. This is 118 percent of 1993's revisions and adjustments.

Unlike crude oil reserves, natural gas reserves have historically been maintained by total discoveries, not revisions and adjustments. For 1994, *total discoveries* of gas rose 39 percent over those of 1993. Since 1983, *total discoveries* have accounted for 73 percent of all gas reserve additions.

Coalbed methane gas production and reserves are included in the 1994 totals. However, EIA maintains its separate tracking of these reserves in order to record the development and historical performance of this gas production source. Coalbed methane gas reserves declined in 1994 after several years of reserve growth. However, coalbed methane production rose to almost 5 percent of U.S. dry gas production. Federal tax incentives for new coalbed methane wells expired 2 years ago.

Natural Gas Liquids

Proved reserves of natural gas liquids decreased by 52 million barrels during 1994, less than 1 percent from 1993 levels. A decrease of 20 million barrels occurred in Alaska, while the lower 48 States' reserves decreased by 32 million barrels. **Figure 5** shows the natural gas liquids proved reserves levels by area and **Figure 6** shows the components of change in them from 1984 through 1994.

Operators replaced only 93 percent of their 1994 natural gas liquids production with new reserves. Since 1983, *total discoveries* have accounted for 56 percent of all natural gas liquids reserve additions, while *revisions and adjustments* accounted for the remaining 44 percent.

Total proved reserves of liquid hydrocarbons (crude oil plus natural gas liquids) were 29,627 million barrels in 1994—a decline of 552 million barrels from the 1993 level. Natural gas liquids represented 24 percent of total liquid hydrocarbon proved reserves in 1994, unchanged from 1993.

Reserves Changes Since 1977

EIA has collected oil and gas reserve estimates annually since 1977. **Table 2** lists the cumulative totals of the components of reserve changes for crude oil and dry natural gas from 1977 to 1994. It also allows separation of Alaska's contribution, so that one can separately observe the trend of the lower 48 States. Annual averages of each component of reserve changes are also listed in **Table 2**, along with the percentage of that particular component's impact on the U.S. total of proved reserves. In this section, we compare these averages to the 1994 proved reserves estimates as a means of gauging the past year against history.

Crude Oil: Since 1977 U.S. operators have:

- discovered an average of 775 million barrels per year of new reserves
- revised and adjusted their proved reserves upwards by an average 1,396 million barrels per year
- reduced reserves by an average 614 million barrels per year (difference between post-1976 average annual production and post-1976 average annual reserve additions) because production has outpaced reserve additions during this time period.

Crude oil reserves have been primarily sustained by continuing upward *revisions and adjustments* to the reserves of older fields, not discoveries. The bulk of

Figure 5. U.S. Natural Gas Liquids Proved Reserves, 1984-1994

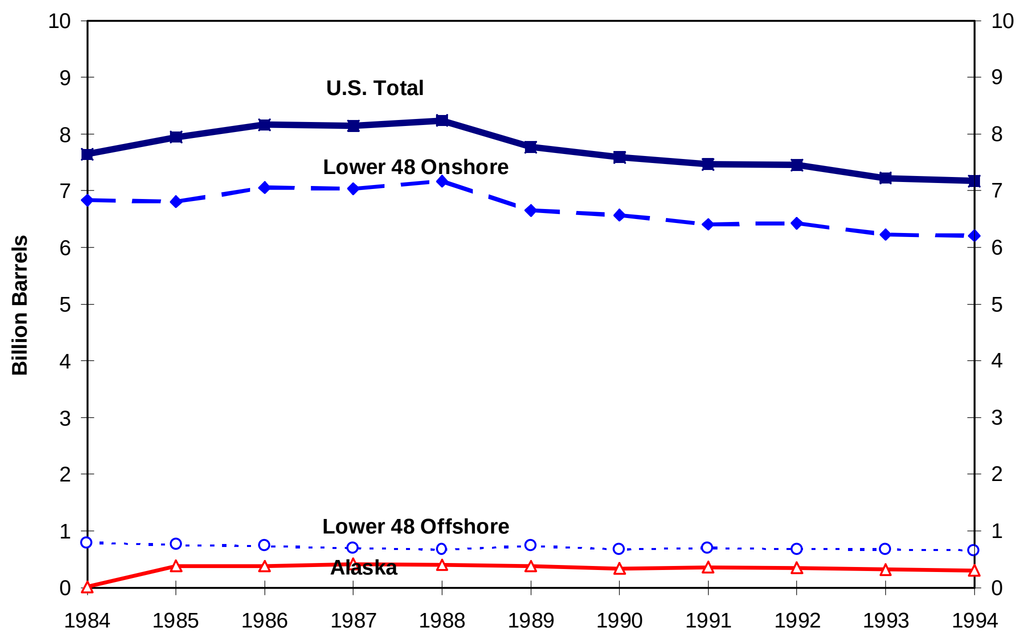
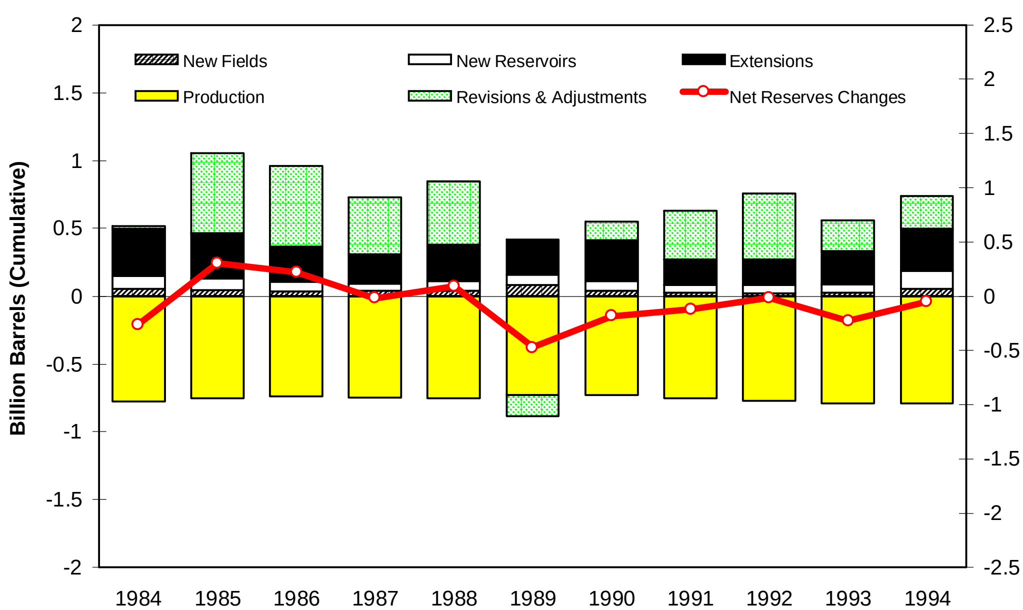


Figure 6. Components of Reserves Changes for Natural Gas Liquids, 1984-1994



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1984 through 1993 annual reports, DOE/EIA-0216.{1-10}

Table 2. Reserves Changes, 1977 - 1994

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	2,238	124	7.2	2,488	138	6.4
New Reservoir Discoveries in Old Fields	2,286	127	7.4	2,306	128	5.9
Extensions	8,185	455	26.3	9,158	509	23.4
Total Discoveries	**12,709**	**706**	**40.9**	**13,952**	**775**	**35.7**
Revisions and Adjustments	18,366	1,020	59.1	25,124	1,396	64.3
Total Reserve Additions	**31,075**	**1,726**	**100**	**39,076**	**2,171**	**100**
Production	**39,313**	**2,184**	**126.5**	**50,121**	**2,785**	**128.3**
Net Reserve Change	**-8,238**	**-458**	**-26.5**	**-11,045**	**-614**	**-28.3**
	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	35,830	1,991	12.7	35,857	1,992	13.5
New Reservoir Discoveries in Old Fields	46,194	2,566	16.4	46,559	2,587	17.6
Extensions	130,937	7,274	46.5	131,790	7,322	49.8
Total Discoveries	**212,961**	**11,831**	**75.6**	**214,206**	**11,900**	**80.9**
Revisions and Adjustments	68,800	3,822	24.4	50,512	2,806	19.1
Total Reserve Additions	**281,761**	**15,653**	**100**	**264,718**	**14,707**	**100**
Production	**308,495**	**17,139**	**109.5**	**314,159**	**17,453**	**118.7**
Net Reserve Change	**-26,734**	**-1,485**	**-9.5**	**-49,441**	**-2,747**	**-18.7**

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves* 1977 - 1993 annual reports, DOE/EIA-0216.{1-17}

post-1976 crude oil reserves additions were the 25,124 million barrels of *revisions and adjustments*. These accounted for 64 percent of all crude oil reserves additions since 1976.

In 1994, both *total discoveries* and *revisions and adjustments* were less than the post-1976 U.S. average. The 1994 crude oil reserve decline was not greater than the post-1976 U.S. average only because 1994 *production* was also down.

Dry Natural Gas: Since 1976, U.S. operators:

- discovered an average of 11,900 billion cubic feet per year of new reserves
- revised and adjusted their proved reserves upwards by an average 2,806 billion cubic feet per year
- reduced reserves by an average 2,747 billion cubic feet per year.

Unlike crude oil, gas reserves have been sustained primarily by *total discoveries*. *Revisions and adjustments* account for only 19 percent of all reserve additions since 1977. However, since 1985, the contribution from *revisions and adjustments* has increased substantially.

The reserves results for 1994 are very positive for future gas supply. Compared to the post-1976 U.S. average, *discoveries* and *revisions* were both up.

Economics and Drilling

Economics: Table 3 lists the average annual domestic wellhead prices of crude oil and natural gas, and also the average number of active rotary drilling rigs, from 1970 to 1994. Oil prices declined 9 percent in 1994 to $13.19 per barrel, the lowest annual average in constant dollars since the 1973 Arab oil embargo.

Oil prices vary by region. In Texas the average price was $14.98 per barrel, while in California it was $12.12 per barrel, and only $9.77 per barrel on the Alaskan North Slope. Gas prices started out strong in 1994 due to record cold weather in the Northeast and remained somewhat stable until midyear, but declined rapidly during the last half of the year as industry storage facilities were generally full and expected colder fourth-quarter weather failed to materialize throughout most of the country. Natural gas prices at the wellhead in 1994 decreased 10 percent to an annual average of $1.83 per thousand cubic feet.

Drilling: From 1993 to 1994, the rig count increased from 754 to 775 active rigs (**Table 3**), but it remains well below the rig activity level of a decade ago (2,428 rigs in 1984).

Looking first at exploratory wells, there were 3,522 exploratory wells drilled in 1994 (**Table 4**). Of these wells, 17 percent were oil wells, 20 percent were gas wells, and 63 percent were dry holes. The total number (which includes dry holes) was roughly the same as in 1993. Although the number of exploratory wells drilled was almost the same, drilling was significantly more successful.

The success rate for exploratory drilling increased from 28 percent in 1993 to 35 percent in 1994. The higher success rate led to the completion of 48 percent more exploratory gas wells (see **Figure 7**) and 26 percent more exploratory oil wells (see **Figure 8**) than in 1993. The 720 gas wells represent the highest level of exploratory gas well completions since 1986. Operators are using improved drilling and seismic survey technology to increase their drilling success rate.

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 - 1994

Year	Crude Oil (dollars per barrel)		Natural Gas (dollars per thousand cubic feet)		
	Current	1994 Constant	Current	1994 Constant	Number of Rigs
1970	3.18	11.42	0.17	0.61	1,028
1971	3.39	11.52	0.18	0.61	976
1972	3.39	11.02	0.19	0.62	1,107
1973	3.89	11.88	0.22	0.67	1,194
1974	6.87	19.29	0.30	0.84	1,472
1975	7.67	19.66	0.44	1.13	1,660
1976	8.19	19.75	0.58	1.40	1,658
1977	8.57	19.33	0.79	1.78	2,001
1978	9.00	18.82	0.91	1.90	2,259
1979	12.64	24.33	1.18	2.27	2,177
1980	21.59	37.97	1.59	2.80	2,909
1981	31.77	50.78	1.98	3.16	3,970
1982	28.52	42.92	2.46	3.70	3,105
1983	26.19	37.87	2.59	3.75	2,232
1984	25.88	35.86	2.66	3.69	2,428
1985	24.09	32.18	2.51	3.35	1,980
1986	12.51	16.28	1.94	2.52	964
1987	15.40	19.42	1.67	2.11	936
1988	12.58	15.27	1.69	2.05	936
1989	15.86	18.43	1.69	1.96	869
1990	20.03	22.29	1.71	1.90	1,010
1991	16.54	17.74	1.64	1.76	860
1992	15.99	16.68	1.74	1.81	721
1993	R14.25	14.55	R2.03	2.07	754
1994	13.19	13.19	1.83	1.83	775

R=Revised data.

Sources: Current dollars and Number of rigs: *Annual Energy Review 1994*, DOE/EIA-0384(94). 1994 constant dollars: U.S. Department of Commerce, Bureau of Economic Anaylsis, Gross Domestic Product Implicit Price Deflators, January 1995.

Table 4. U.S. Exploratory and Development Well Completions,[a] 1970 - 1994

Year	Exploratory				Total Exploratory and Development			
	Oil	Gas	Dry	Total	Oil	Gas	Dry	Total
1970	763	478	6,193	7,434	13,043	4,031	11,099	28,173
1971	664	472	5,995	7,131	11,903	3,983	10,382	26,268
1972	690	659	6,202	7,551	11,437	5,484	11,013	27,934
1973	654	1,079	6,038	7,771	10,251	6,975	10,466	27,692
1974	870	1,205	6,894	8,969	13,664	7,170	12,205	33,039
1975	991	1,263	7,207	9,461	16,979	8,170	13,736	38,885
1976	1,100	1,362	6,854	9,316	17,697	9,438	13,805	40,940
1977	1,183	1,562	7,402	10,147	18,700	12,119	15,036	45,855
1978	1,191	1,792	8,054	11,037	19,065	14,405	16,591	50,061
1979	1,335	1,920	7,478	10,733	20,703	15,170	16,038	51,911
1980	1,781	2,094	9,035	12,910	32,278	17,223	20,337	69,838
1981	2,667	2,533	12,297	17,497	42,843	19,907	27,284	90,034
1982	2,470	2,168	11,346	15,984	39,142	18,944	26,382	84,468
1983	2,113	1,660	10,271	14,044	37,199	14,556	24,336	76,091
1984	2,335	1,599	11,482	15,416	42,585	17,012	25,797	85,394
1985	1,879	1,282	9,445	12,606	35,021	14,252	21,208	70,481
1986	988	733	5,511	7,232	18,701	8,135	12,766	39,602
1987	859	673	5,179	6,711	16,186	7,757	11,481	35,424
1988	792	663	4,766	6,221	13,322	8,238	10,242	31,802
1989	580	654	4,001	5,235	10,339	9,225	8,491	28,055
1990	R628	R641	R3,855	R5,124	12,150	R10,705	R8,612	R31,467
1991	R573	R533	R3,393	R4,499	11,908	R9,452	R7,914	R29,274
1992	R505	R407	R2,652	R3,564	R9,023	R8,073	R6,522	R23,618
1993	R479	R486	R2,513	R3,478	R8,742	R9,804	R6,720	R25,266
1994	602	720	2,200	3,522	6,789	8,913	5,293	20,995

[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 June 1994. Due to the method of estimation, data shown are frequently revised. Data are no longer rounded to nearest 10 wells.
Sources: Years 1970-1972: Energy Information Administration, Office of Oil and Gas. Years 1973-1994: *Monthly Energy Review*, DOE/EIA-0035(95/07), July 1995.

Figures 9 and 10 show the average volume of discoveries per exploratory well for natural gas and oil, respectively, since 1977. The average volume of new gas discoveries per exploratory well decreased only slightly from 1993's level, and is over twice the volume of gas discovered per well 10 years ago. However, the average volume of new oil discoveries per exploratory well is substantially less than last year's level. The volume of oil discoveries per exploratory well in 1994 performed closer to what was reported in 1991 and 1992.

For total drilling in 1994, there were an estimated 20,995 exploratory and development wells drilled. This is 17 percent fewer than in 1993 and is only 52 percent of the average number of wells drilled annually in the prior 10 years (40,038).

Operators drilled fewer development wells in 1994. As with the previous 4 years, low oil and gas prices are the primary cause for the decline in drilling. The total successful oil well completions of only 6,789 wells is the second lowest total recorded since 1895. Only once previously in the past 100 years did oil well completions drop below the 1994 level, it was in 1931 during the Great Depression, where 1 less well was reported.{18}

Looking at the types of wells drilled in 1994, the number of gas wells drilled in 1994 substantially

Figure 7. U.S. Exploratory Gas Well Completions, 1977-1994

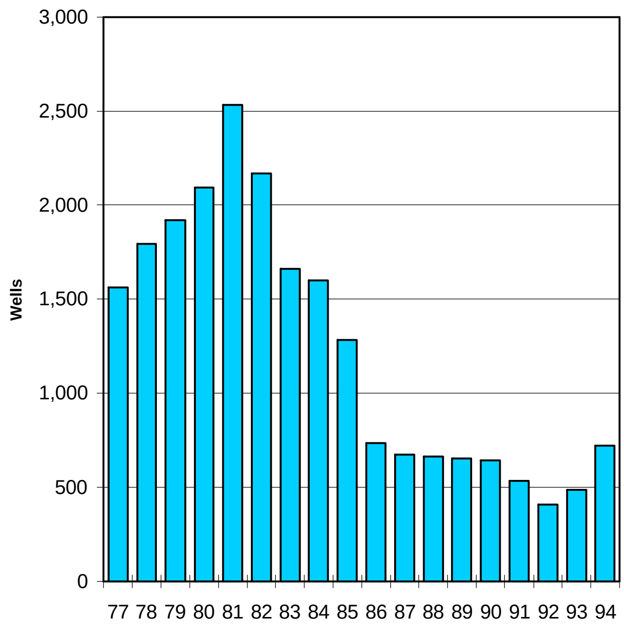


Figure 9. U.S. Total Discoveries of Dry Natural Gas per Exploratory Gas Well Completion, 1977-1994

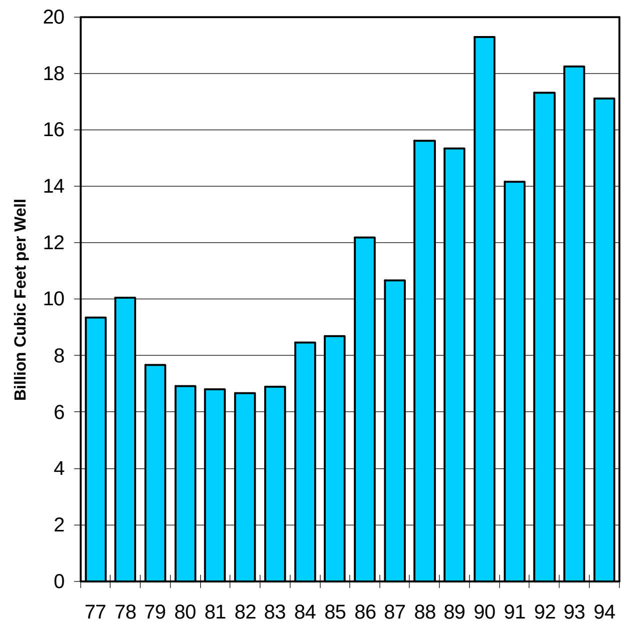


Figure 8. U.S. Exploratory Oil Well Completions, 1977-1994

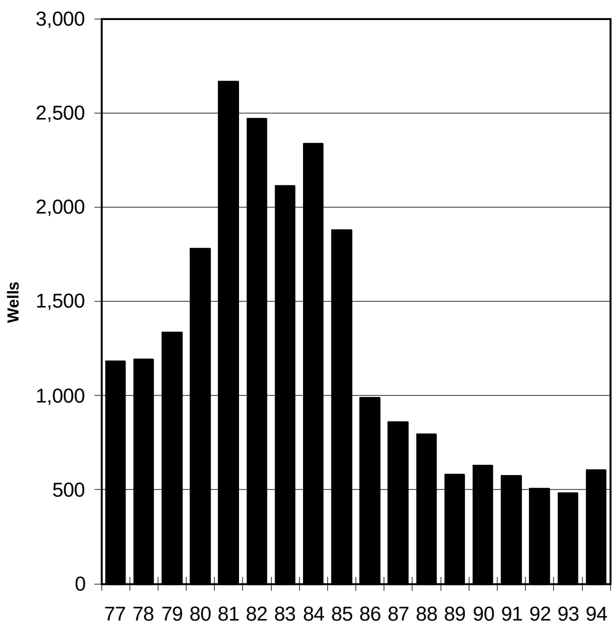
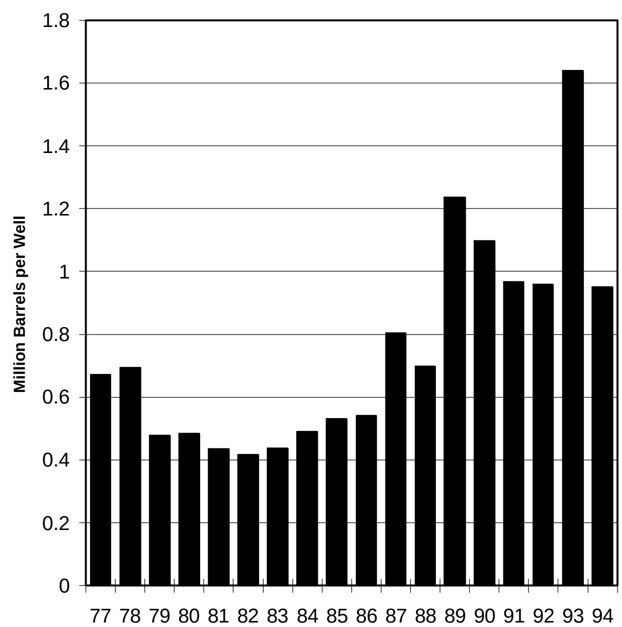


Figure 10. U.S. Total Discoveries of Crude Oil per Exploratory Oil Well Completion, 1977-1994



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

outweighed the number of crude oil wells in both the exploratory and development categories. 1994 was only the second year that gas well completions exceeded oil well completions (the only previous year was last year, 1993). The difference in the number of gas versus oil well completions grew significantly larger in 1994.

Reserve-to-Production Ratios and Ultimate Recovery

R/P Ratios

The relationship between reserves and production, expressed as the ratio of reserves to production (R/P ratio) is often used in analyses. 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 guide to the production level that can be maintained during the following year. Operators report data that yield R/P ratios that vary widely depending upon:

- the type of operators in a given area
- the geology and economics of an area
- the number and size of new discoveries in an area
- the amount of drilling that has occurred in that area.

R/P ratios are an indication of the state of development in an area and, over time, the ratios change. For example, when the Alaskan North Slope oil reserves were booked, the U.S. R/P ratio for crude oil 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 for crude oil went from 11.1-to-1 to 9.4-to-1 between 1977 and 1982, as Alaskan North Slope oil production reached high levels.

Figure 11 shows the U.S. R/P ratio trend for crude oil since 1945. After World War II, increased drilling and discoveries led to a greater R/P ratio. Later, when drilling found fewer reserves than were produced, the ratio became smaller. R/P Ratios also vary geographically. Less developed areas of the country, such as the Pacific offshore, have higher R/P ratios for crude oil than the 1994 National average of 9.9-to-1. Other areas with relatively high R/P ratios are the Permian Basin of Texas and New Mexico, and California, where EOR techniques such as carbon dioxide (CO_2) injection or steamflooding have enhanced recoverability in old, mature fields. Areas that have the lowest R/P ratios usually have many older fields, like the Mid-Continent area. There, even new technologies such as horizontal drilling (as practiced in Texas' Giddings oil field) could only add reserves equivalent to the annual production, keeping the regional reserves and R/P ratio for oil relatively stable.

Figure 12 shows the historical R/P ratio for wet natural gas since 1945. Prior to 1945, R/P ratios were very high, since the interstate pipeline infrastructure was not well developed. The market for and production of natural gas grew rapidly after World War II, lowering the R/P ratio.

Different marketing, transportation, and production characteristics for gas are seen when looking at regional average R/P ratios, compared to the 1994 average R/P ratio of about 9-to-1. The areas with the higher range of R/P ratios are less developed areas of the country, such as the Pacific offshore and the Rockies, and also include areas such as Alabama and Colorado, where considerable booking of coalbed methane reserves has recently occurred. Several major gas producing areas have R/P ratios below the National average—such as Texas, the Gulf of Mexico Federal Offshore, and Oklahoma. Since gas reserves increased more than production in 1994, the R/P ratio has increased in these areas, however, they remain below the 1994 average of 9-to-1. Even though U.S. gas reserves increased in 1994, production increased by a higher rate, resulting in a small decline in the U.S. gas R/P ratio.

Ultimate Recovery

Figures 13 and 14 show successive estimates of ultimate recovery and its components, proved reserves and cumulative production, for crude oil and wet natural gas from 1977 to 1994. They illustrate the continued growth of estimated ultimate recovery over time.

In 1976, U.S. crude oil proved reserves were 33,502 million barrels. Cumulative production for 1977 through 1994 was 50,121 million barrels. This cumulative oil production substantially exceeded the 1976 proved reserves, but at the end of 1994 there were still 22,457 million barrels of crude oil proved reserves. The estimated ultimate recovery of crude oil significantly increased during this period due to the continuing development of old fields and through *new field discoveries.*

Similarly, the 1976 dry natural gas proved reserves were 213,278 billion cubic feet. Cumulative gas production from 1977 through 1994 was 314,159 billion cubic feet. Cumulative gas production exceeded the 1976 reserves by 100,881 billion cubic feet, but at the end of 1994 there

Figure 11. Reserves-to-Production Ratios for Crude Oil, 1945-1994

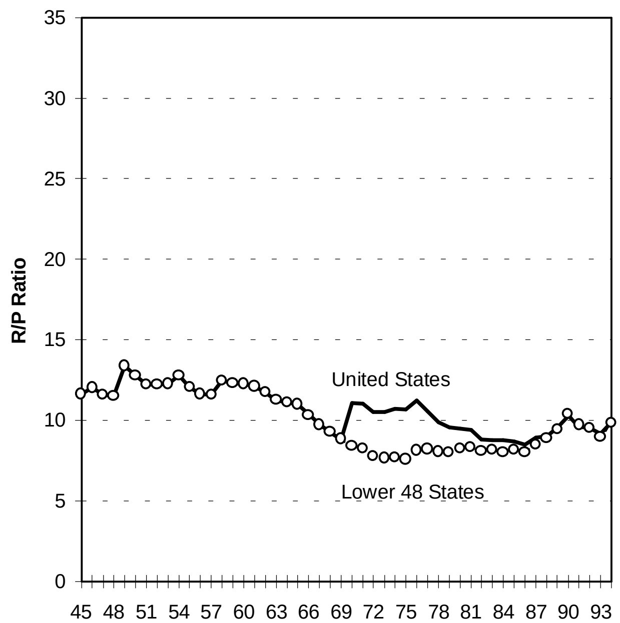


Figure 13. Components of Ultimate Recovery for Crude Oil and Lease Condensate, 1977-1994

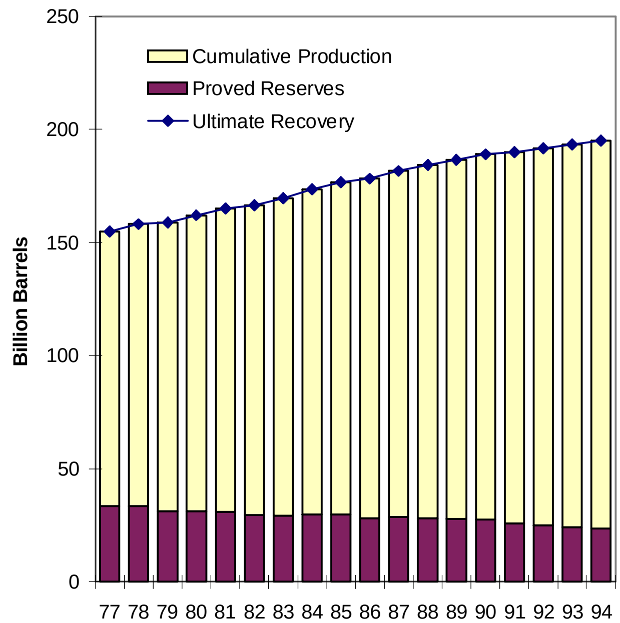


Figure 12. Reserves-to-Production Ratios for Wet Natural Gas, 1945-1994

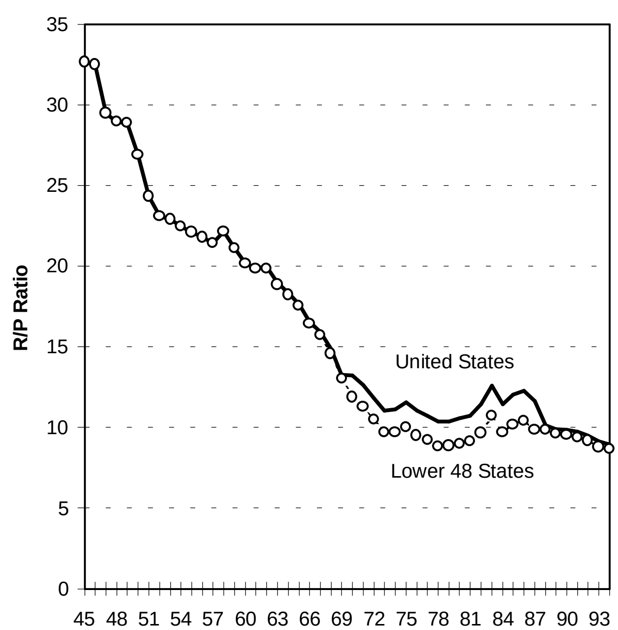
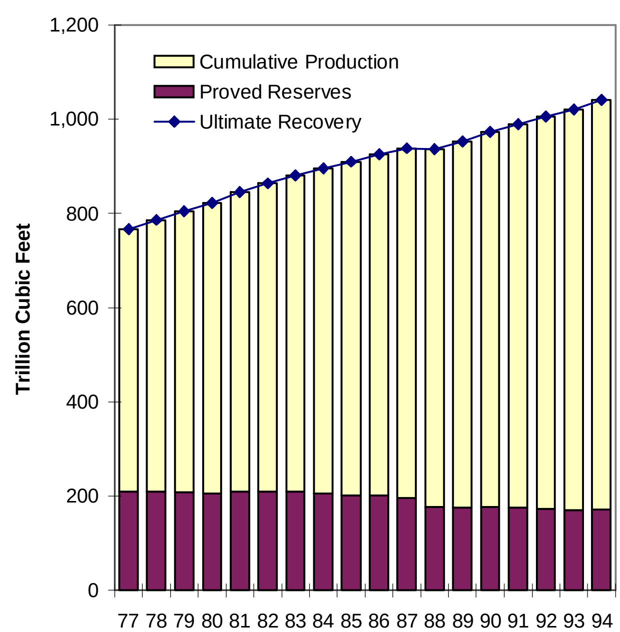


Figure 14. Components of Ultimate Recovery for Wet Natural Gas, 1977-1994



Sources: Annual reserves and production - American Petroleum Institute and American Gas Association (1945–1976){19} and Energy Information Administration, Office of Oil and Gas (1977–1993){1-17}. Cumulative production: *U.S. Oil and Gas Reserves by Year of Field Discovery* (1977–1988).{20} were still 163,837 billion cubic feet of dry natural gas proved reserves.

International Perspective

International Reserves

As shown in **Table 5**, international reserves are estimated in two widely circulated trade publications. The world's total reserves are estimated to be roughly 1 trillion barrels of oil and 5 quadrillion cubic feet of gas.

The United States ranks 11th in the world for proved reserves of crude oil and 6th for natural gas. A comparison of EIA's U.S. proved reserves estimates with worldwide estimates obtained from other sources shows that the United States had about 2 percent of the world's total crude oil proved reserves and about 3.5 percent of the world's total natural gas proved reserves at the end of 1994. There are sometimes substantial differences between estimates from these sources. Condensate is often included in foreign oil reserve estimates. The EIA estimates domestic oil and gas reserves but does not systematically estimate worldwide reserves.

The *Oil and Gas Journal*{21} and *World Oil*{22} estimates of world oil reserves both rose slightly in 1994. On world gas reserves, the *Oil and Gas Journal* reported a decline, while *World Oil* reported a slight increase.

Several foreign countries have oil reserves considerably larger than those of the United States. Saudi Arabian oil reserves are the largest in the world, dwarfing U.S. oil reserves. Iraqi oil reserves are more than 4 times U.S. reserves. Closer to home, Venezuela has almost 3 times and Mexico has just over twice the United States' oil reserves.

Oil reserve estimates for various countries differ widely. For example, *World Oil* reported oil reserves for the former Soviet Union (FSU) of about 191 billion barrels. This is more than 3 times the *Oil and Gas Journal's* estimate. However, *World Oil* has included more than proved reserves in its 1994 FSU estimate. EIA considers *World Oil's* FSU estimate comparable to proved reserves plus probable reserves classifications commonly used in the United States. The U.S. oil reserve estimates only include proved reserves.

Petroleum Consumption

The U.S. is the world's largest energy consumer. The EIA estimates energy consumption and publishes it in its *Monthly Energy Review* and *Annual Energy Review*.{23} In 1994:

- The U.S. consumed 85,572,000,000,000,000 Btu of energy in 1994 (85.572 quadrillion Btu).
- 65.5 percent of U.S. energy consumption is provided by petroleum—crude oil and natural gas liquids combined (40.6 percent), and natural gas (24.9 percent).
- U.S. petroleum consumption was about 17.7 million barrels of oil and natural gas liquids and 57 billion cubic feet of dry gas per day in 1994.

Dependence on Imports

The United States remains heavily dependent on imported oil to satisfy its ever-increasing appetite for energy. Domestic production provides about 50 billion cubic feet of dry gas per day and only 8.4 million barrels of oil and natural gas liquids per day. Imports have to fill the void between production and consumption. Price competitive Canadian gas exports continue to capture an increasing share of the U.S. market, and OPEC countries directly provided about 47 percent of crude oil imports.{23}

List Of Appendices

Appendix A: Reserves by Operator Production Size Class - How much of the National total of proved reserves are owned and operated by the large oil and gas corporations? Appendix A separates the large operators from the small and presents reserves data according to operator production size classes. The top 20 producing companies had 58 percent of U.S. natural gas proved reserves in 1994.

Appendix B: Top 100 Oil and Gas Fields - What fields had the most reserves and production in the United States in 1994? The top 100 fields for oil and natural gas out of the inventory of more than 45,000 oil and gas fields are listed in Appendix B. These fields held 66 percent of U.S. crude oil proved reserves in 1994.

Appendix C: Conversion to the Metric System - To simplify international comparisons, a summary of U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves expressed in metric units is included as Appendix C.

Appendix D: Historical Reserves Statistics - Appendix D contains selected historical reserves data presented at the State and National level. Readers interested in a historical look at one specific State or region can review these tables.

Appendix E: Summary of Data Collection Operations - This report is based on Form EIA-23 survey data collected annually from U.S. oil and gas well operators. Appendix E describes the survey design, its response statistics, its reporting requirements, and how its sampling frame is maintained.

Appendix F: Statistical Considerations - The EIA strives to maintain or improve the accuracy of its reports. Since complete coverage of all oil and gas operators is impractical, the EIA has adopted sound statistical methods to impute data for those operators not sampled and for those data elements that smaller operators are not required to file. These methods are described in Appendix F.

Appendix G: Discussion of Reserve Estimation Techniques - Reserves are not measured directly. Reserves are estimated on the basis of the best geological, engineering, and economic data available to the estimator. Appendix G describes reserve estimation techniques commonly used by oil and gas field operators and EIA personnel when in the field performing quality assurance checks. A discussion of the relationship of reserves to overall U.S. oil and gas resources is also included.

Appendix H: Maps of Selected State Subdivisions - Certain large producing States have been subdivided into smaller regions to allow more specific reporting of reserves data. Maps of these States identifying the smaller regions are provided in Appendix H.

Appendix I: Annual Survey Forms of Domestic Oil and Gas Reserves - Samples of Form EIA-23 and Form EIA-64A are presented in Appendix I.

Table 5. International Oil and Natural Gas Reserves as of December 31, 1994

Oil (million barrels)				Natural Gas (billion cubic feet)			
Rank[a]	Country	Oil & Gas Journal	World Oil	Rank[b]	Country	Oil & Gas Journal	World Oil
1	Saudi Arabia[c]	[d]261,203	[d]262,475	1	Former U.S.S.R.	1,977,000	1,936,971
2	Former U.S.S.R.	57,000	191,144	2	Iran[c]	741,609	620,000
3	Iraq[c]	100,000	99,427	3	Qatar[c]	250,000	164,000
4	Kuwait[c]	[d]96,500	[d]97,675	4	Abu Dhabi[c]	188,400	188,400
5	Abu Dhabi[c]	92,200	62,000	5	Saudi Arabia[c]	[d]185,900	[d]188,900
6	Iran[c]	89,250	58,650	**6**	**United States**	**[e]162,415**	**160,265**
7	Venezuela[c]	64,477	64,878	7	Venezuela[c]	130,400	140,009
8	Mexico	50,776	49,775	8	Nigeria[c]	120,000	120,800
9	Libya[c]	22,800	36,570	9	Algeria[c]	128,000	102,000
10	China	24,000	30,204	10	Iraq[c]	109,500	108,000
11	**United States**	**[e]22,957**	**22,132**	11	Norway	70,912	101,205
12	Nigeria[c]	17,900	17,210	12	Canada	79,231	80,126
13	Norway	9,416	16,998	13	Malaysia	68,000	80,760
14	United Kingdom	4,517	15,492	14	Mexico	69,675	68,413
15	Algeria[c]	9,200	10,157	15	Netherlands	66,215	70,494
16	Indonesia[c]	5,779	6,347	16	Indonesia[c]	64,388	64,915
17	India	5,776	5,807	17	China	59,000	45,500
18	Canada	5,038	5,848	18	Kuwait[c]	[d]52,900	[d]51,058
19	Oman	4,828	5,183	19	Libya[c]	45,800	45,167
20	Malaysia	4,300	5,090	20	United Kingdom	22,248	67,600
Top 20 Total for Oil		**947,917**	**1,063,063**	**Top 20 Total for Gas**		**4,591,593**	**4,404,583**
World Total for Oil		**999,761**	**1,111,598**	**World Total for Gas**		**4,980,278**	**4,761,251**

[a]Rank is based on an average of oil reserves reported by *Oil & Gas Journal* and *World Oil*.

[b]Rank is based on an average of natural gas reserves reported by *Oil & Gas Journal* and *World Oil*.

[c]Member of the Organization of Petroleum Exporting Countries.

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

[e]Energy Information Administration proved reserves as of December 31, 1993 were published by the *Oil & Gas Journal* as its estimates as of December 31, 1994.

Note: The Energy Information Administration does not certify these international reserves data, but reproduces the information as a matter of convenience for the reader.

Sources: *Oil & Gas Journal*, December 26, 1994, pp. 42-43. *World Oil*, August, 1995, p. 30.

3. Crude Oil Statistics

The United States had 22,457 million barrels of crude oil proved reserves as of December 31, 1994. This is 2 percent (500 million barrels) less than in 1993. The three largest oil producing States, Alaska, Texas, and California, all reported reductions in crude oil proved reserves in 1994. Alaska's oil reserves decreased only 8 million barrels, while the lower 48 States total decreased by 492 million barrels. The lower 48 States total was dominated by the declines in Texas and California.

Over the past decade, U.S. crude oil proved reserves have generally been declining (**Figure 1**, Chapter 2). Oil reserves have declined an average of 1.9 percent per year (478 million barrels). The 1994 decline is only slightly higher than the 10-year average, and is less than the declines of the last 3 years.

Alaska's revisions and extensions are the primary reason 1994 oil reserves did not decline as much as in 1993. Secondly, there were large discoveries and revisions for the Gulf of Mexico Federal Offshore. Alaska replaced almost all of its oil production with reserve additions. The decline was only 0.1 percent in 1994, whereas the 10-year average decline for this State was just over 2 percent. Expansion of enhanced oil recovery in Alaskan North Slope fields was primarily responsible for the large revisions. In the Gulf of Mexico Federal Offshore, operators overcame the technical challenges of deepwater exploration to discover large new oil fields. An overwhelming 83 percent (53 million barrels) of all new field crude oil proved reserves in the United States came from this area in 1994.

Texas and California's crude oil proved reserves declined more than 5 percent—about 2 percent more than the 10-year average in both States. This was primarily due to poor economics.

Proved Reserves

Table 6 presents the U.S. proved reserves of crude oil as of December 31, 1994, by selected States and State subdivisions.

Figure 15 maps the U.S. 1994 crude oil proved reserves by State. The following five areas account for 80 percent of U.S. crude oil proved reserves:

Area	Percent of U.S. Oil Reserves
Texas	26
Alaska	26
California	16
Gulf of Mexico Federal Offshore	9
New Mexico	3
Total	**80**

Of these five areas, the top three all reported a decline in crude oil proved reserves during 1994, while the Gulf of Mexico Federal Offshore and New Mexico reported increases.

Discussion of Reserves Changes

Figure 16 maps the change in crude oil proved reserves from 1993 to 1994 by State. Here's how the top five areas fared:

Area	Change in U.S. Oil Reserves (million barrels)
Texas	-324
Alaska	-8
California	-191
Gulf of Mexico Federal Offshore	+55
New Mexico	+11
Subtotal	**-457**
U.S. Total	**-500**

Figure 2 in Chapter 2 shows the components of the changes in crude oil proved reserves for 1994 and the preceding 10 years. These components are discussed below.

Total Discoveries

Total discoveries are those new reserves attributable to *extensions* of existing fields, *new field discoveries*, and *new reservoir discoveries in old fields.* They result from the drilling of exploratory wells.

In 1994, *total discoveries* of crude oil were 572 million barrels, down from 785 million barrels in 1993. Only three areas had *total discoveries* exceeding 35 million barrels:

- Gulf of Mexico Federal Offshore (200 million barrels)
- Texas (141 million barrels)
- Alaska (81 million barrels).

Table 6. Crude Oil Proved Reserves, Reserves Changes, and Production, 1994
(Million Barrels of 42 U.S. Gallons)

		Changes in Reserves During 1994							
State and Subdivision	Published Proved Reserves 12/31/93	Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	Proved Reserves 12/31/94
Alaska	5,775	2	491	11	81	0	0	571	5,767
Lower 48 States	**17,182**	**187**	**1,873**	**1,346**	**316**	**64**	**111**	**1,697**	**16,690**
Alabama	41	2	10	1	1	2	0	11	44
Arkansas	65	-4	10	12	0	0	0	8	51
California	3,764	-11	224	122	3	0	0	285	3,573
Coastal Region Onshore	528	-8	20	39	0	0	0	21	480
Los Angeles Basin Onshore	238	-8	39	27	0	0	0	21	221
San Joaquin Basin Onshore	2,772	5	142	53	3	0	0	222	2,647
State Offshore	226	0	23	3	0	0	0	21	225
Colorado	284	4	17	10	5	0	0	29	271
Florida	40	-2	39	0	0	0	0	6	71
Illinois	116	6	8	1	1	0	1	14	117
Indiana	15	1	1	0	0	0	0	2	15
Kansas	271	17	24	11	4	0	0	45	260
Kentucky	26	2	1	0	0	0	0	3	26
Louisiana	639	26	98	49	26	0	9	100	649
North	108	-1	24	8	2	0	0	17	108
South Onshore	382	26	50	34	21	0	5	59	391
State Offshore	149	1	24	7	3	0	4	24	150
Michigan	90	10	6	7	3	0	0	11	91
Mississippi	133	12	31	15	7	1	1	19	151
Montana	171	7	15	9	6	1	1	17	175
Nebraska	20	3	4	1	0	0	0	4	22
New Mexico	707	5	75	34	26	0	2	63	718
East	688	8	72	32	25	0	2	61	702
West	19	-3	3	2	1	0	0	2	16
North Dakota	226	1	39	24	8	1	2	27	226
Ohio	54	10	3	1	0	0	0	8	58
Oklahoma	680	35	87	50	17	0	0	80	689
Pennsylvania	14	0	3	1	0	0	0	1	15
Texas	6,171	73	471	458	114	6	21	551	5,847
RRC District 1	133	9	7	37	3	0	1	16	100
RRC District 2 Onshore	77	4	7	3	1	0	0	12	74
RRC District 3 Onshore	327	3	70	43	18	0	19	64	330
RRC District 4 Onshore	59	-4	8	15	1	0	0	8	41
RRC District 5	52	4	6	8	2	0	0	7	49
RRC District 6	406	-9	100	32	8	0	0	49	424
RRC District 7B	[a]171	-10	4	3	1	2	0	20	145
RRC District 7C	199	11	28	12	18	1	0	24	221
RRC District 8	2,057	35	98	72	39	1	1	157	2,002
RRC District 8A	2,435	16	119	211	20	0	0	156	2,223
RRC District 9	168	12	9	7	2	2	0	27	159
RRC District 10	83	1	14	14	1	0	0	10	75
State Offshore	4	1	1	1	0	0	0	1	4
Utah	228	6	13	7	4	0	3	16	231
West Virginia	24	-1	6	4	2	0	0	2	25
Wyoming	624	15	61	79	11	0	1	68	565
Federal Offshore	2,745	-34	627	434	77	53	70	324	2,780
Pacific (California)	673	-32	350	279	0	0	0	59	653
Gulf of Mexico (Louisiana)	1,880	-5	268	153	64	49	64	245	1,922
Gulf of Mexico (Texas)	192	3	9	2	13	4	6	20	205
Miscellaneous[b]	34	4	0	16	1	0	0	3	20
U.S. Total	**22,957**	**189**	**2,364**	**1,357**	**397**	**64**	**111**	**2,268**	**22,457**

[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 1994 contained in the *Petroleum Supply Annual 1994*, DOE/EIA-0340(94).

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

Figure 15. 1994 Crude Oil Proved Reserves by State

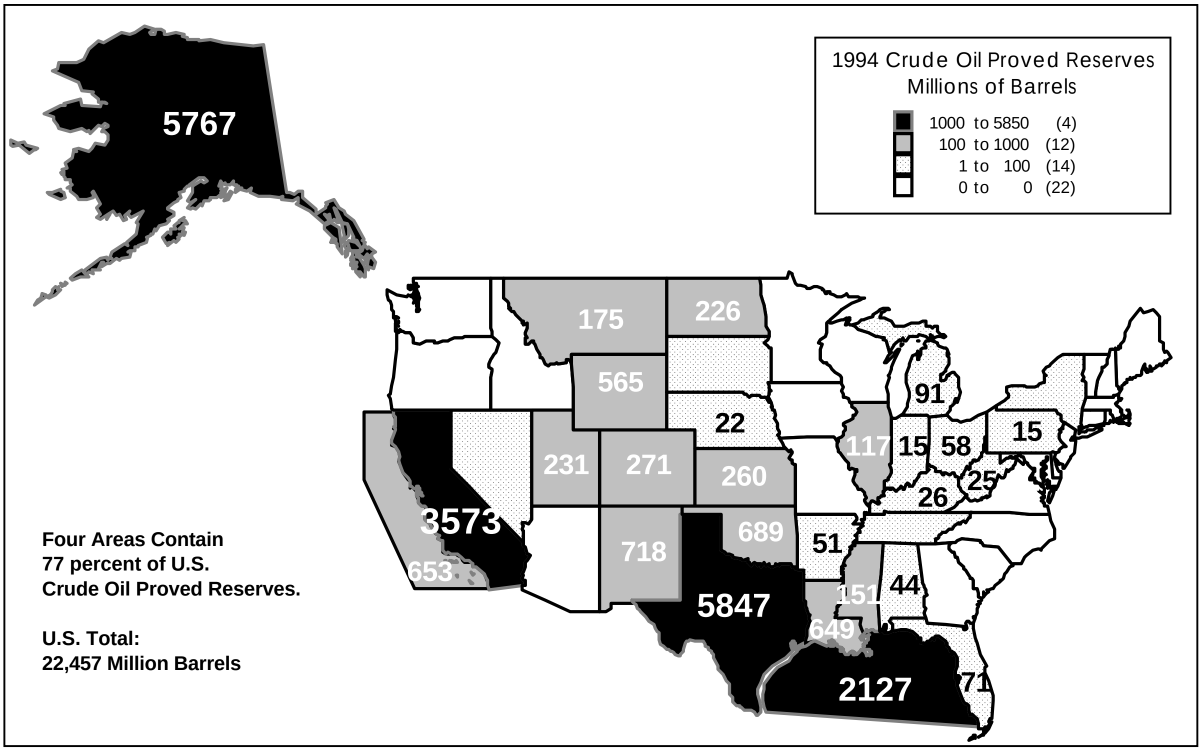
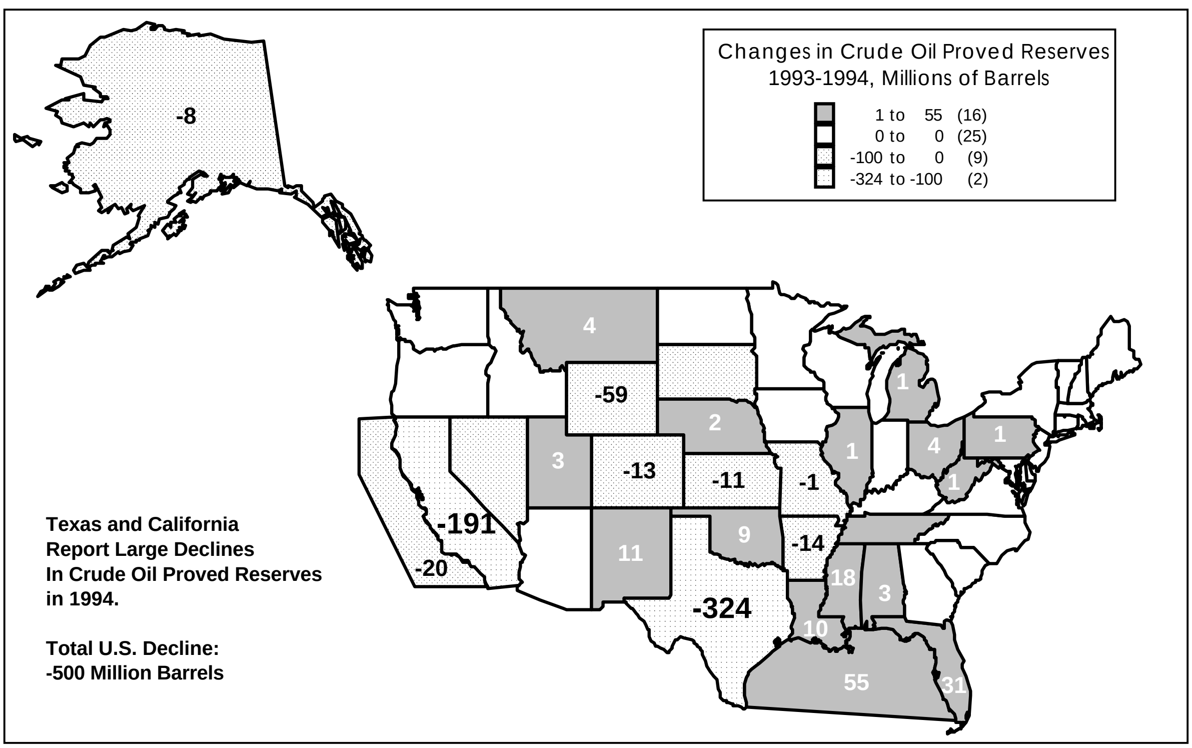


Figure 16. Changes in Crude Oil Proved Reserves by State, 1993 to 1994



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

The United States has discovered an average of 715 million barrels of new crude oil proved reserves per year in the prior 10 years (1984 through 1993). Discoveries in 1994 were 80 percent of the prior 10-year average of *total discoveries.*

Extensions: Operators reported 397 million barrels of *extensions* in 1994. The highest volumes of *extensions* were reported in Texas. Most of these (77 million barrels of 114 million barrels total) were in west Texas (Texas Railroad Commission (RRC) Districts 7C, 8, and 8A). Alaska was second to Texas, with 81 million barrels of *extensions,* followed by the Gulf of Mexico Federal Offshore with 77 million barrels. Despite its large share of U.S. oil reserves, almost no *extensions* were reported in California (where production is dominated by large, old fields), except for 3 million barrels reported in the San Joaquin Basin Onshore region. In the prior 10 years, U.S. operators have reported an average of 481 million barrels of *extensions* per year. The 1994 *extensions* were 83 percent of that average.

New Field Discoveries: There were 64 million barrels of *new field discoveries* reported in 1994. Only six areas in the United States reported any *new field discoveries.* Of these six, the only significant contributor was the Gulf of Mexico Federal Offshore. This region provided 83 percent (53 million barrels) of all *new field discoveries* in 1994. In the prior 10 years, U.S. operators reported an average of 118 million barrels of reserves from *new field discoveries* per year. Reserves from *new field discoveries* in 1994 were only 54 percent of that average.

New Reservoir Discoveries in Old Fields: Operators in the United States reported 111 million barrels of crude oil reserves from *new reservoir discoveries in old fields* in 1994. As with *new field discoveries,* the most significant portion of these reserves (70 million barrels) were from the Gulf of Mexico Federal Offshore. Texas reported 21 million barrels, and Louisiana reported 9 million barrels. In the prior 10 years, U.S. operators reported an average of 116 million barrels of reserves from *new reservoir discoveries in old fields* per year. Reserves from *new reservoir discoveries in old fields* in 1994 were 96 percent of that average.

Revisions and Adjustments

Thousands of positive and negative *revisions* to proved reserves occur each year as infill wells are drilled, well performance is analyzed, new technology is used, or economic conditions change. *Adjustments* are the annual changes in the published reserve estimates that cannot be directly attributed to the estimates for other reserve change categories because of the survey and statistical estimation methods employed.

There were 1,196 million barrels of positive net *revisions and adjustments* for crude oil in 1994. This is higher than the 1993 total of 766 million barrels. Average *revisions and adjustments* for the last 10 years were 1,521 million barrels—those for 1994 were only 79 percent of this average.

Production

U.S. *production* of crude oil in 1994 was 2,268 million barrels. This was lower than 1993's total of 2,339 million barrels. U.S. crude oil *production* has declined in 7 of the last 10 years.

Areas of Note: Large Discoveries and Reserves Additions

The following State and area discussions summarize notable activities during 1994 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.

In aggregate, the following areas added 108 million barrels of crude oil proved reserves additions to the National total, and are the major success stories of crude oil reserves and production of 1994.

Alaska

Alaska's proved oil reserves remained essentially the same, declining by only 8 million barrels. Alaska's 1994 performance is a relative success story because of the low level of crude oil reserves decline as compared to its large production. Events in the following fields had a major impact.

Prudhoe Bay (GHX-2 Project): Prudhoe Bay, the largest producing oil field in the United States, received its last sealift of additional production equipment planned by ARCO in April 1994. Using this equipment, the second phase of a large gas-handling expansion project (GHX-2) was completed in late 1994. GHX-2 was designed to expand gas conditioning and liquids production capacity for the Prudhoe Bay and Pt. McIntyre fields. ARCO estimates that the GHX-2 project would increase gas capacity to 7.5 billion cubic feet per day while providing an additional 100,000 barrels per day of liquids production. ARCO also predicts that the total recoverable oil reserves in Prudhoe Bay would increase by up to 435 million barrels as a result of the expansion.{24}

Kuparuk River: ARCO, the operator of the Kuparuk River Field, finalized its plans for a large-scale enhanced oil recovery project at this field. ARCO will expand its pilot miscible gas enhanced oil recovery program to encompass a large portion of the field.{24} ARCO has no plans to develop the Shallow West Sak and Ugnu reservoirs yet, due to high development costs.{25}

Milne Point: A first quarter 1993 discovery, called Cascade, is located just off the southeastern edge of the Milne Point Field. Operator BP Exploration expects it to come on-line in 1995 following rapid development. Due to its proximity to the Milne Point production facilities, Cascade appears to be a profitable discovery. BP Exploration (which owns 91 percent of Milne Point) estimates that nearby discoveries will boost production from Milne Point to 50,000 barrels per day by 1996.{26}

Gulf of Mexico Federal Offshore

Offshore in the Gulf of Mexico was a major focus of exploration during 1994. Most of the United States' crude oil reserve additions from *new field discoveries* (83 percent), and 63 percent of the additions from *new reservoir discoveries in old fields,* were from this area. The net increase of crude oil proved reserves in the region was 55 million barrels. The Gulf of Mexico produced about the same volume of crude oil in 1994 as it did in 1993.

Auger: In April 1994, Shell started oil and gas production from its Auger tension leg platform (TLP). The Auger Platform (see cover) is 214 miles southwest of New Orleans, Louisiana. The deepest producing platform in the Gulf of Mexico, it is set in 2,860 feet of water in Garden Banks Block 426. This is 1,100 feet deeper than the previous Gulf record. Ten wells were pre-drilled prior to the TLP installation. By October, Auger had reached its design flow maximum early. With only 8 wells onstream, and each well producing up to 13,000 barrels a day, the platform was producing 55,000 barrels per day of oil and 105 million cubic feet per day of gas.{27}

Ram/Powell: Shell Exploration and Production Company, with partners Exxon Company U.S.A. and Amoco Corporation, announced that they would begin development of the Ram / Powell Field, which has an estimated recovery of 250 million barrels of oil equivalent. The Ram / Powell prospect is 80 miles south of Mobile, Alabama, in Viosca Knoll Block 956. To bring this field on stream will require another record-breaking deep water platform.{28}

Subsalt: Subsalt exploration became active in the Gulf after Amoco's 1993 discovery of the large Mahogany Field on Ship Shoal South Addition blocks 349 / 359. Unfortunately, subsalt exploration turned out to be more complex, risky, expensive, and challenging than expected. Two additional wells drilled in 1994 in the Mahogany Field failed to discover commercial quantities of oil in deeper sands. Undaunted by this, operators began to go into deeper waters looking for more viable subsalt structures. The search tool of choice was three dimensional (3-D) seismic surveying. Advanced 3-D seismic interpretation techniques are now allowing companies to image prospects beneath 2,000 to 3,000-foot-thick salt layers.{29} Persistence paid off for the operators of the Mahogany Field. On April 17, 1995, Anadarko Petroleum Corporation, and partners Phillips Petroleum Company and Amoco Production Company, declared the Mahogany Field commercial. A fourth well is currently being drilled, and a platform is planned for installation in late 1996.{30}

Other Gain Areas

New Mexico: Proved oil reserves in New Mexico increased by 11 million barrels. Although there were no new fields reported, several operators increased their reserves due to application of waterflood or enhanced oil recovery methods.

Oklahoma: This State's proved oil reserves increased by 9 million barrels. There were no new fields of note—the boost was due to *revisions* and *extensions.*

Louisiana: Proved oil reserves increased by 10 million barrels. Nine of the 10 million barrels of new reserves in Louisiana were from *new reservoir discoveries in old fields.* Occidental had a new oil and gas discovery in the Austin Chalk in late 1994, and The Louisiana Land & Exploration Company was one of many operators that had successful drilling programs based on the data from 3-D seismic runs in South Louisiana.{31}

Florida: Proved oil reserves increased by 31 million barrels. At the Jay Field in Florida, a depletion enhancement program consisting of well workovers and debottlenecking projects led to increased production and additional recoverable reserves from this mature field. Current gross production averages 16,300 barrels per day.{31}

Areas of Note: Large Reserves Declines

The following areas had large declines in crude oil proved reserves, due to downward revisions or unreplaced production. These declines deducted 607 million barrels of crude oil proved reserves from the U.S. total.

Texas

Texas oil reserves declined by 324 million barrels—the greatest decline of any State in 1994. Texas' production also declined almost 5 percent from 1993 levels. The largest reserves decline (-212 million barrels) was in RRC District 8A. In this district, poor economics caused operators to shut in portions of existing fields. RRC District 8A's reserves decline alone was two-thirds of the Texas decline and greater than the decline of any other State. Other areas where oil reserves significantly decreased were RRC District 1 (-33 million barrels), RRC District 7B (-26 million barrels), and RRC District 4 Onshore (-18 million barrels).

The declines were counterbalanced somewhat by reserves increases in other RRC Districts. In southwest Texas' Permian Basin (RRC District 7C) a net of 22 million barrels of proved reserves were added. This was due to infill drilling and waterflood activities by numerous operators. As examples: Anadarko Petroleum Corporation drilled 75 wells and improved waterflood operations in its Permian Basin fields{32}, and Parker and Parsley Development Corp. continued its development of the Spraberry Trend area.{33} In east Texas in RRC District 6, Exxon boosted its reserves estimate for the Hawkins Field due to implementation of a large-scale enhanced oil recovery project.{34}

California

A major earthquake shook California on January 17, 1994. Although pipeline disruptions caused some transportation bottlenecks, the industry recovered quickly. What proved more difficult was late August's indefinite ban on all new oil and gas leasing in State offshore waters.

Combining the above factors with the poor economics of 1994, California oil reserves decreased by 191 million barrels. The largest decline was in the San Joaquin Basin Onshore, home of the California "heavy oil" fields. This region's reserves declined by 125 million barrels. The Coastal Region Onshore and the Los Angeles Basin Onshore also declined 48 and 17 million barrels of proved reserves, respectively.

California's production declined by about 2 percent from 1993's level.

Wyoming

Wyoming oil reserves decreased by 59 million barrels. Its reserve declines due to production were not replaced. Negative revisions exceeded positive revisions. Wyoming operators faced low oil prices and relatively high operating costs, leading to poor economics in many fields. As an example, Marathon shut in 400 barrels per day of heavy sour oil production in February, due to low oil prices.{35} Wyoming oil production dropped by 13 percent from the 1993 level.

Other Decline Areas

In the following areas of the United States, development of existing or new oil fields was outpaced by crude oil production, which remained at about the same level as the previous year.

Pacific Federal Offshore: This region's reserves decreased by 20 million barrels.

Colorado: Proved oil reserves decreased by 13 million barrels in Colorado.

Reserves in Nonproducing Reservoirs

Not all proved reserves of crude oil were contained in reservoirs that were producing. Operators reported 2,727 million barrels of proved reserves in nonproducing reservoirs. This is 12 percent less than reported in 1993 (3,017 million barrels).

The reasons for the nonproducing status of these proved reserves are not collected by the 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.

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 1994 volume, 3,151 million barrels, is about 9 percent less than was reported in 1993 (3,453 million barrels).

Table 7 lists the indicated additional reserves by selected States and State subdivisions. The presence of large indicated additional reserves in Alaska, California, and west Texas implies that significant upward revisions to proved crude oil reserves could occur in the future.

Table 7. Reported Indicated Additional Crude Oil Reserves,[a] 1994
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	Indicated Additional Reserves	State and Subdivision	Indicated Additional Reserves
Alaska	1,022	North Dakota	2
Lower 48 States	2,129	Ohio	0
Alabama	0	Oklahoma	47
Arkansas	0	Pennsylvania	0
California	835	Texas	491
Coastal Region Onshore	238	RRC District 1	1
Los Angeles Basin Onshore	4	RRC District 2 Onshore	0
San Joaquin Basin Onshore	593	RRC District 3 Onshore	61
State Offshore	0	RRC District 4 Onshore	<1
Colorado	22	RRC District 5	0
Florida	0	RRC District 6	<1
Illinois	0	RRC District 7B	5
Indiana	0	RRC District 7C	14
Kansas	0	RRC District 8	256
Kentucky	0	RRC District 8A	154
Louisiana	340	RRC District 9	<1
North	0	RRC District 10	<1
South Onshore	331	State Offshore	0
State Offshore	9	Utah	70
Michigan	1	West Virginia	0
Mississippi	40	Wyoming	13
Montana	0	Federal Offshore	53
Nebraska	0	Pacific (California)	0
New Mexico	215	Gulf of Mexico (Louisiana)	43
East	215	Gulf of Mexico (Texas)	10
West	0	Miscellaneous[b]	0
		U.S. Total	**3,151**

[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,” 1994.

4. Natural Gas Statistics

U.S. proved reserves of dry natural gas were up 1 percent in 1994. This was the first gain in 4 years. Large gas discoveries in the Federal offshore, several of them in deepwater, played a major role. Also, in 1994, gas production reached the highest level since 1981. *Total discoveries* were up substantially, as were *revisions and adjustments*. These combined to replace 108 percent of gas production, which also increased in 1994. The last gas reserves increase was in 1990, and the one before that was in 1981.

Lower 48 States gas reserves have been generally declining since natural gas prices peaked in 1983. U.S. *total discoveries* of dry gas reserves were 12,315 billion cubic feet in 1994, an increase of 39 percent more than 1993. *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 net volume of *revisions and adjustments* to reserves also played a significant role in increasing U.S. natural gas proved reserves. It amounted to 7,429 billion cubic feet in 1994, an 18 percent increase over 1993. Texas had the largest increase in *revisions and adjustments*. Its proved gas reserves increased in 1994. Successful infill drilling between existing field wells played a major role in this increase.

For the past 10 years proved reserves have dropped from 197,463 billion cubic feet at the end of 1984 to 163,837 billion cubic feet—a decrease of 33,636 billion cubic feet. While this is a large decline of 17 percent, most of it resulted from the 1988 negative revision in Alaskan reserves of 24.6 trillion cubic feet because no market existed for that gas. Proved dry gas reserves for the lower 48 States declined 5.4 percent over the past 10 years.

Dry Natural Gas

Proved Reserves

The Nation's proved reserves of dry natural gas were 163,837 billion cubic feet, 0.9 percent (1,422 billion cubic feet) more than in 1993 (**Table 8**). In the lower 48 States, reserves increased by 1 percent (1,596 billion cubic feet). Proved reserves by State are shown on the map in **Figure 17**. Five areas account for approximately 64 percent of the Nation's dry natural gas proved reserves.

Area	Percent of U.S. Gas Reserves
Texas	22
Gulf of Mexico Federal Offshore	17
New Mexico	10
Oklahoma	8
Wyoming	7
Total	**64**

The four leading gas producing areas, Texas, the Gulf of Mexico Federal Offshore, Oklahoma, and Louisiana had 1994 proved reserves net increases that totaled 3,202 billion cubic feet. Changes in the reserves in the States are seen in the map in **Figure 18**. Some prominent increases are those that occur in Texas (1,256), Gulf of Mexico Federal Offshore (1,174), Louisiana (574), and Virginia (511).

Discoveries

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. *Total discoveries* of dry natural gas reserves were 12,315 billion cubic feet, an increase of 39 percent (3,447 billion cubic feet) from that reported in 1993. These *total discoveries* are equivalent to two-thirds of the level of 1994 gas production. About one-half of the *total discoveries* were in the Gulf of Mexico Federal Offshore and south Texas (RRC District 4). Other areas with large amounts are the rest of Texas (16 percent), Louisiana (9 percent), Oklahoma (7 percent), New Mexico (6 percent) and Wyoming (5 percent). *New field discoveries* (1,894 billion cubic feet) were 111 percent higher than in 1993 as major new projects in the deep water of the Gulf of Mexico were announced. Those areas with the largest *new field discoveries* were the Gulf of Mexico Federal Offshore (with 83 percent of the total), Texas, and Oklahoma.

New reservoir discoveries in old fields were 3,480 billion cubic feet, 86 percent higher than 1993. Among the areas with the largest *new reservoir discoveries in old fields* were the Gulf of Mexico Federal Offshore, Texas, Louisiana, and Wyoming. The Louisiana portion of the Gulf of Mexico Federal Offshore accounted for 42 percent of the *new reservoir discoveries in old fields*. *Extensions* were 6,941 billion cubic feet, 14 percent higher than in 1993. Areas with the largest *extensions* were Texas, the Gulf of Mexico Federal Offshore, Oklahoma, New Mexico, and Wyoming. Texas accounted for 33 percent of the

Table 8. Dry Natural Gas Proved Reserves, Reserves Changes, and Production, 1994
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/93	Changes in Reserves During 1994: Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	Proved Reserves 12/31/94
Alaska	9,907	49	244	49	5	0	0	423	9,733
Lower 48 States	**152,508**	**1,896**	**21,121**	**15,832**	**6,936**	**1,894**	**3,480**	**17,899**	**154,104**
Alabama	5,140	27	2,101	2,128	80	1	0	391	4,830
Arkansas	1,552	95	147	95	92	1	1	186	1,607
California	2,682	-80	136	162	63	0	7	244	2,402
Coastal Region Onshore	189	4	33	17	1	0	0	16	194
Los Angeles Basin Onshore	102	-1	18	7	0	0	0	9	103
San Joaquin Basin Onshore	2,327	-82	76	133	62	0	7	213	2,044
State Offshore	64	-1	9	5	0	0	0	6	61
Colorado	6,722	-169	696	328	264	3	12	447	6,753
Florida	[a]50	-2	57	0	0	0	0	7	98
Kansas	9,348	175	524	342	102	13	7	671	9,156
Kentucky	1,003	40	49	101	35	0	7	64	969
Louisiana	9,174	557	1,586	1,239	510	25	588	1,453	9,748
North	2,325	100	421	166	170	0	15	328	2,537
South Onshore	5,932	419	924	930	333	25	529	981	6,251
State Offshore	917	38	241	143	7	0	44	144	960
Michigan	1,160	155	191	48	15	0	0	150	1,323
Mississippi	797	-1	55	133	2	4	8	82	650
Montana	673	142	26	76	1	0	0	49	717
New Mexico	18,619	-641	801	956	740	0	27	1,362	17,228
East	3,034	-30	385	218	289	0	27	466	3,021
West	15,585	-611	416	738	451	0	0	896	14,207
New York	[a]264	-3	14	13	0	0	1	21	242
North Dakota	525	-47	74	24	7	0	19	47	507
Ohio	1,104	87	27	16	8	0	3	119	1,094
Oklahoma	13,289	374	1,580	932	818	0	79	1,721	13,487
Pennsylvania	1,717	-19	315	117	16	0	29	141	1,800
Texas	34,718	878	5,800	3,883	2,318	257	661	4,775	35,974
RRC District 1	698	24	114	87	30	0	21	97	703
RRC District 2 Onshore	1,321	95	206	205	105	26	36	224	1,360
RRC District 3 Onshore	2,972	52	1,198	737	173	48	260	600	3,366
RRC District 4 Onshore	7,038	9	1,725	1,323	997	127	200	1,226	7,547
RRC District 5	1,867	103	170	116	142	16	14	185	2,011
RRC District 6	5,508	237	495	574	223	11	77	596	5,381
RRC District 7B	477	7	9	7	2	2	0	65	425
RRC District 7C	3,215	151	309	175	137	7	6	334	3,316
RRC District 8	5,516	73	639	311	181	9	23	688	5,442
RRC District 8A	1,043	66	256	63	4	0	0	87	1,219
RRC District 9	688	-23	58	17	121	0	1	100	728
RRC District 10	4,040	125	584	224	203	11	7	500	4,246
State Offshore	335	-41	37	44	0	0	16	73	230
Utah	2,040	-82	172	201	43	1	0	184	1,789
Virginia	1,322	-7	568	0	1	0	0	51	1,833
West Virginia	2,439	192	140	137	18	0	85	172	2,565
Wyoming	10,933	-31	1,146	1,026	371	17	249	780	10,879
Federal Offshore[b]	27,143	256	4,913	3,853	1,432	1,572	1,697	4,772	28,388
Pacific (California)	1,099	-17	569	438	0	0	4	47	1,170
Gulf of Mexico (Louisiana)[b]	19,383	230	2,919	2,334	1,245	1,373	1,459	3,440	20,835
Gulf of Mexico (Texas)	6,661	43	1,425	1,081	187	199	234	1,285	6,383
Miscellaneous[c]	94	0	3	22	0	0	0	10	65
U.S. Total	**162,415**	**1,945**	**21,365**	**15,881**	**6,941**	**1,894**	**3,480**	**18,322**	**163,837**

[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 1994 contained in the *Natural Gas Annual 1994*, DOE/EIA-0131(94).

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

Figure 17. 1994 Dry Natural Gas Proved Reserves by State

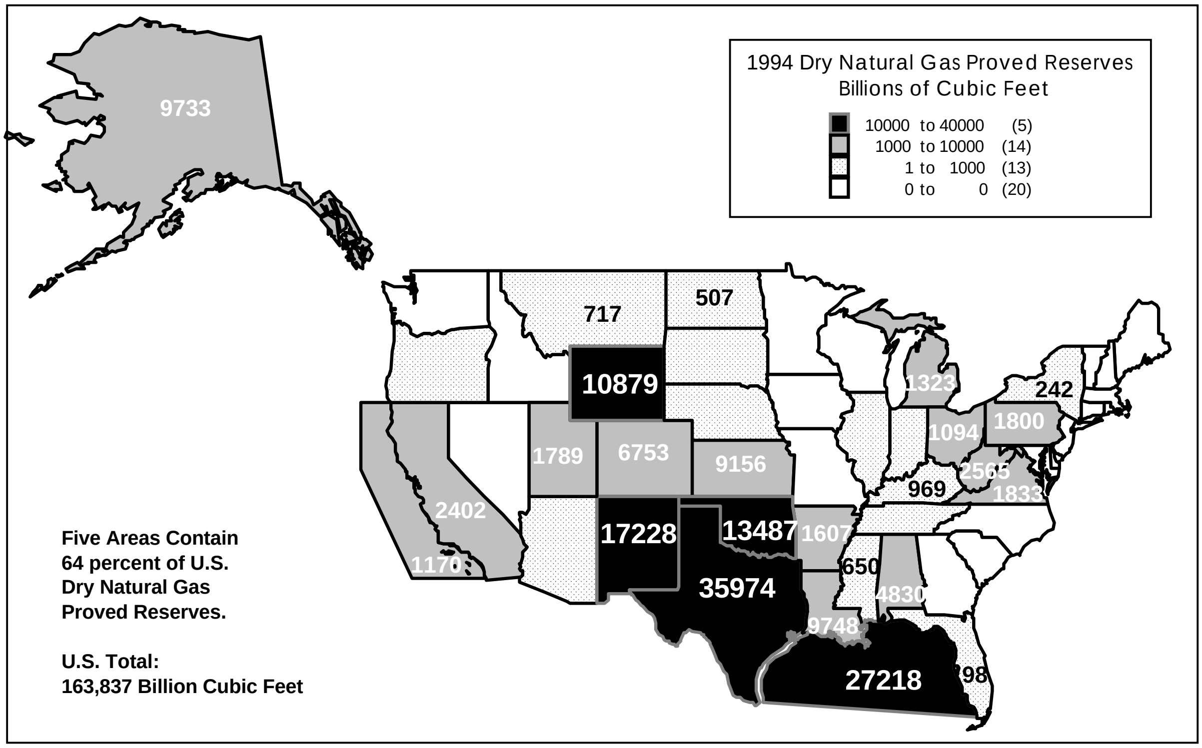
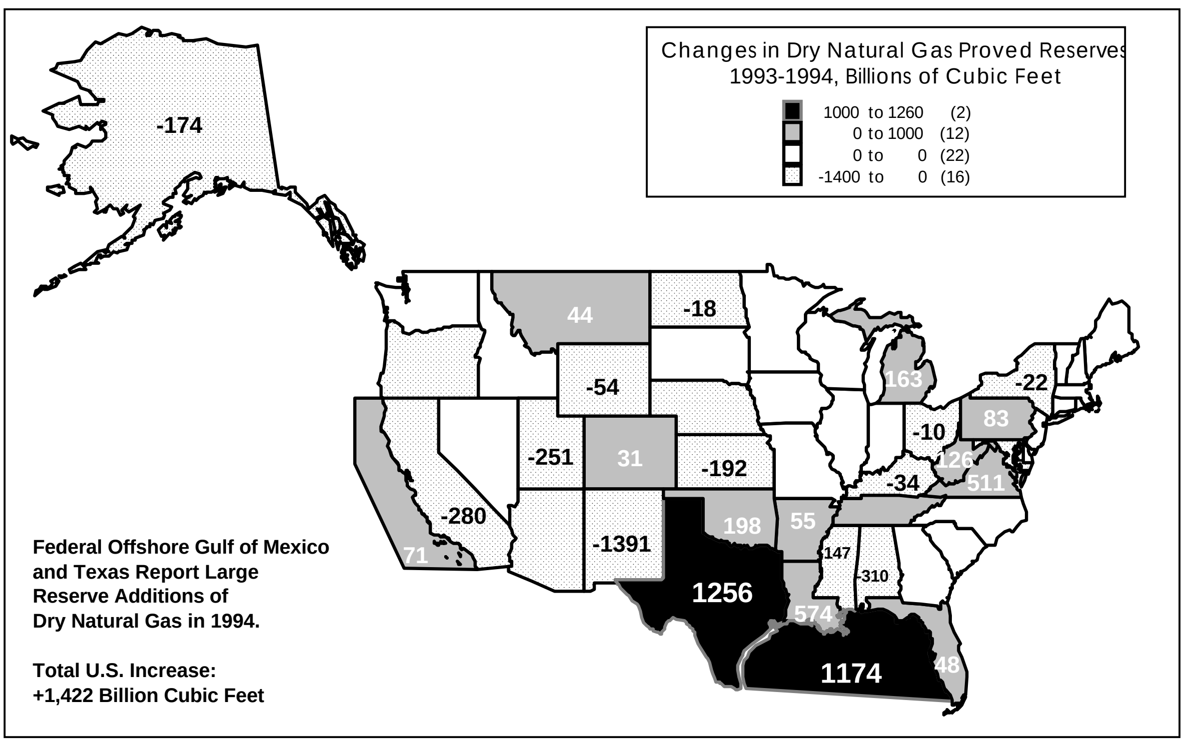


Figure 18. Changes in Dry Natural Gas Proved Reserves by State, 1993 to 1994



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

extensions in the United States, of these 43 percent were in south Texas (RRC District 4).

Production

Dry natural gas production increased 3 percent in 1994 (**Table 8**). This was the highest level of production of dry natural gas since 1981. The trend of increasing gas production is welcome news and in keeping with the various initiatives by the upstream industry, some State governments and the Department of Energy. These initiatives involve increasing the share of domestic natural gas in the Nation's energy supply. The Gulf of Mexico Federal Offshore and the State of Texas, each with over one-fourth of the U.S. total, were the leading producers of dry natural gas in 1994. The next three States combined, Oklahoma (9 percent), Louisiana (8 percent), and New Mexico (7 percent) added another one-fourth of the production.

Wet Natural Gas

U. S. proved reserves of wet natural gas, as of December 31, 1994, were 171,939 billion cubic feet, an increase of 0.8 percent, or 1,449 billion cubic feet, from that reported in 1993 (**Table 9**). At the end of year 1994 proved wet natural gas reserves for the lower 48 States were higher by 1 percent (1,622 billion cubic feet) than in 1993, while those of Alaska decreased by 173 billion cubic feet. The volumetric differences between the estimates reported in **Table 8** (dry) and **Table 9** (wet) results from the removal of natural gas liquids at natural gas processing plants. A discussion of the methodology used in this report is in found in Appendix F. All natural gas proved reserves data shown in this report exclude natural gas held in underground storage.

Nonassociated Natural Gas

Proved Reserves

Proved reserves of nonassociated (NA) natural gas, wet after lease separation, in the United States increased by 1,094 billion cubic feet (0.8 percent) in 1994 to 141,539 billion cubic feet (**Table 10**). This increase arrested 4 years of decreases in these proved reserves. The lower 48 States NA wet natural gas proved reserves increased by 1,260 billion cubic feet, or 0.9 percent. Those areas with the largest increases in NA wet natural gas reserves were Texas, Federal Offshore Louisiana in the Gulf of Mexico, Louisiana, Virginia, and Oklahoma. There were large decreases in NA wet natural gas reserves in New Mexico where major operators in the San Juan basin reassessed their reserves. In addition, there were decreases in NA wet natural gas reserves in Federal Offshore Texas Gulf of Mexico, Alabama, Utah, and Alaska.

Discoveries

NA wet natural gas *total discoveries* of 11,264 billion cubic feet increased 42 percent (3,306 billion cubic feet) in 1994. The Gulf of Mexico Federal Offshore, Texas, Louisiana, Oklahoma, and Wyoming, accounted for 9,771 billion cubic feet or 87 percent of U.S. NA wet natural gas *total discoveries* in 1994.

Production

U.S. production of NA wet natural gas increased by 3 percent (530 billion cubic feet) in 1994 (**Table 10**). While most areas showed some production increases, the areas that showed the largest increases were Texas, Alabama, Federal Offshore, Colorado, and Wyoming. These accounted for 61 percent of total U.S. NA wet natural gas production. Increases in Alabama were due to production from the State offshore area that now accounts for one-half of the Alabama total production.

Associated-Dissolved Natural Gas

Proved Reserves

Proved reserves of associated-dissolved (AD) natural gas, wet after lease separation, in the United States increased by 1 percent to 30,400 billion cubic feet in 1994 (**Table 11**). Proved reserves of AD wet natural gas in the lower 48 States increased by 362 billion cubic feet to 23,913 billion cubic feet.

Production

U.S. production of AD wet natural gas increased by 1 percent in 1994 (**Table 11**). On the other hand, production of AD wet natural gas in the lower 48 States remained essentially the same, decreasing by 2 billion cubic feet to 2,654 billion cubic feet. Those areas of the country with the largest AD wet natural gas reserves were Texas, Alaska, the Gulf of Mexico Federal Offshore, Colorado, California, New Mexico, and Oklahoma. These areas logically correspond to the areas of the country with the largest volumes of crude oil reserves and production.

Table 9. Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation, 1994 (Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/93	Changes in Reserves During 1994: Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	Proved Reserves 12/31/94: Total Gas	Non-associated Gas	Associated Dissolved Gas
Alaska	9,986	53	274	51	5	0	0	454	9,813	3,326	6,487
Lower 48 States	**160,504**	**1,924**	**22,071**	**16,458**	**7,294**	**1,941**	**3,606**	**18,756**	**162,126**	**138,213**	**23,913**
Alabama	5,212	28	2,105	2,132	80	2	0	397	4,898	4,842	56
Arkansas	1,555	95	147	96	93	1	1	186	1,610	1,525	85
California	2,799	-83	141	169	65	0	8	255	2,506	808	1,698
Coastal Region Onshore	201	5	34	19	1	0	0	17	205	60	145
Los Angeles Basin Onshore	108	-3	19	7	0	0	0	9	108	0	108
San Joaquin Basin Onshore	2,425	-85	79	138	64	0	8	223	2,130	744	1,386
State Offshore	65	0	9	5	0	0	0	6	63	4	59
Colorado	6,979	-159	738	351	279	3	13	466	7,036	5,948	1,088
Florida	[a]59	-1	67	0	0	0	0	8	117	0	117
Kansas	9,872	219	556	363	109	14	8	710	9,705	9,630	75
Kentucky	1,036	67	52	107	37	0	7	67	1,025	978	47
Louisiana	9,541	591	1,648	1,294	530	26	615	1,512	10,145	9,165	980
North	2,376	109	431	171	174	0	15	335	2,599	2,465	134
South Onshore	6,219	446	969	976	349	26	555	1,030	6,558	5,880	678
State Offshore	946	36	248	147	7	0	45	147	988	820	168
Michigan	1,218	152	199	50	16	0	0	156	1,379	1,022	357
Mississippi	800	2	55	135	2	4	8	83	653	610	43
Montana	684	143	26	77	1	0	0	50	727	672	55
New Mexico	19,939	-583	858	1,004	796	0	31	1,449	18,588	16,947	1,641
East	3,338	-22	425	241	319	0	31	515	3,335	1,791	1,544
West	16,601	-561	433	763	477	0	0	934	15,253	15,156	97
New York	[a]264	-3	14	13	0	0	1	21	242	240	2
North Dakota	585	-49	82	26	8	0	21	53	568	293	275
Ohio	1,106	86	27	16	8	0	3	119	1,095	780	315
Oklahoma	14,099	410	1,678	989	868	0	84	1,827	14,323	12,981	1,342
Pennsylvania	1,722	-18	316	117	16	0	29	142	1,806	1,797	9
Texas	37,847	747	6,281	4,157	2,477	274	705	5,154	39,020	31,071	7,949
RRC District 1	731	27	119	91	31	0	22	102	737	586	151
RRC District 2 Onshore	1,425	101	224	222	114	29	39	242	1,468	1,169	299
RRC District 3 Onshore	3,251	32	1,300	800	187	52	282	651	3,653	2,590	1,063
RRC District 4 Onshore	7,351	0	1,798	1,381	1,039	132	209	1,278	7,870	7,679	191
RRC District 5	1,931	101	175	119	147	16	14	191	2,074	1,926	148
RRC District 6	5,777	283	523	605	236	12	82	630	5,678	5,131	547
RRC District 7B	580	1	12	8	2	3	0	77	513	332	181
RRC District 7C	3,578	137	341	193	151	8	6	368	3,660	3,029	631
RRC District 8	6,131	49	707	344	200	9	26	760	6,018	3,267	2,751
RRC District 8A	1,463	-21	334	82	4	0	1	112	1,587	15	1,572
RRC District 9	814	-25	69	21	143	1	1	119	863	715	148
RRC District 10	4,478	104	642	247	223	12	7	550	4,669	4,405	264
State Offshore	337	-42	37	44	0	0	16	74	230	227	3
Utah	2,198	-100	184	216	46	1	2	198	1,917	1,631	286
Virginia	1,322	-7	568	0	1	0	0	51	1,833	1,833	0
West Virginia	2,598	174	148	144	19	0	89	182	2,702	2,569	133
Wyoming	11,387	-13	1,196	1,070	387	18	260	814	11,351	10,740	611
Federal Offshore[b]	27,586	225	4,982	3,910	1,456	1,598	1,721	4,845	28,813	22,075	6,738
Pacific (California)	1,123	-24	577	445	0	0	4	48	1,187	110	1,077
Gulf of Mexico (Louisiana)[b]	19,751	222	2,972	2,379	1,268	1,398	1,481	3,505	21,208	16,226	4,982
Gulf of Mexico (Texas)	6,712	27	1,433	1,086	188	200	236	1,292	6,418	5,739	679
Miscellaneous[c]	96	1	3	22	0	0	0	11	67	56	11
U.S. Total	**170,490**	**1,977**	**22,345**	**16,509**	**7,299**	**1,941**	**3,606**	**19,210**	**171,939**	**141,539**	**30,400**

[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 1994 contained in the *Natural Gas Annual 1994*, DOE/EIA-0131(94).
Source: Energy Information Administration, Office of Oil and Gas.

Table 10. Nonassociated Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation, 1994

(Billion Cubic Feet at 14.73 psia and 60^{o} Fahrenheit)

		Changes in Reserves During 1994							
State and Subdivision	Published Proved Reserves 12/31/93	Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	Proved Reserves 12/31/94
Alaska	3,492	28	34	32	5	0	0	201	3,326
Lower 48 States	**136,953**	**1,786**	**17,792**	**13,475**	**6,444**	**1,411**	**3,404**	**16,102**	**138,213**
Alabama	5,166	22	2,091	2,130	78	0	0	385	4,842
Arkansas	1,462	84	142	91	93	1	1	167	1,525
California	817	51	56	84	58	0	8	98	808
Coastal Region Onshore	66	1	9	11	0	0	0	5	60
Los Angeles Basin Onshore	0	0	0	0	0	0	0	0	0
San Joaquin Basin Onshore	749	50	44	73	58	0	8	92	744
State Offshore	2	0	3	0	0	0	0	1	4
Colorado	5,817	-167	663	230	231	2	10	378	5,948
Florida	0	0	0	0	0	0	0	0	0
Kansas	9,779	254	528	357	101	14	8	697	9,630
Kentucky	1,030	43	52	106	17	0	7	65	978
Louisiana	8,615	491	1,475	1,171	488	26	604	1,363	9,165
North	2,256	93	407	151	160	0	15	315	2,465
South Onshore	5,570	375	869	900	322	26	547	929	5,880
State Offshore	789	23	199	120	6	0	42	119	820
Michigan	890	101	167	29	8	0	0	115	1,022
Mississippi	747	-17	45	104	1	3	8	73	610
Montana	631	137	18	71	0	0	0	43	672
New Mexico	18,354	-530	622	891	604	0	8	1,220	16,947
East	1,860	29	209	148	128	0	8	295	1,791
West	16,494	-559	413	743	476	0	0	925	15,156
New York	[a]264	-5	14	13	0	0	1	21	240
North Dakota	311	-18	6	4	0	0	20	22	293
Ohio	763	93	13	13	1	0	2	79	780
Oklahoma	12,549	501	1,414	788	858	0	83	1,636	12,981
Pennsylvania	1,714	-19	315	117	16	0	29	141	1,797
Texas	29,967	641	4,677	3,065	2,197	267	683	4,296	31,071
RRC District 1	540	26	92	41	29	0	22	82	586
RRC District 2 Onshore	1,137	60	178	174	111	29	38	210	1,169
RRC District 3 Onshore	2,092	21	763	291	163	52	278	488	2,590
RRC District 4 Onshore	7,136	10	1,724	1,322	1,038	132	209	1,248	7,679
RRC District 5	1,790	84	168	112	146	16	14	180	1,926
RRC District 6	5,170	309	490	560	212	12	82	584	5,131
RRC District 7B	393	-14	8	6	2	1	0	52	332
RRC District 7C	2,945	141	261	157	115	7	4	287	3,029
RRC District 8	3,569	-51	322	128	25	6	11	487	3,267
RRC District 8A	12	-3	5	0	1	0	1	1	15
RRC District 9	636	-9	51	10	140	0	1	94	715
RRC District 10	4,214	110	580	222	215	12	7	511	4,405
State Offshore	333	-43	35	42	0	0	16	72	227
Utah	1,909	-123	163	203	43	1	1	160	1,631
Virginia	1,322	-7	568	0	1	0	0	51	1,833
West Virginia	2,408	220	142	140	19	0	89	169	2,569
Wyoming	10,885	-151	1,149	1,025	361	18	250	747	10,740
Federal Offshore[b]	21,466	189	3,469	2,821	1,269	1,079	1,592	4,168	22,075
Pacific (California)	147	0	0	31	0	0	4	10	110
Gulf of Mexico (Louisiana)[b]	15,181	167	2,220	1,721	1,089	883	1,376	2,969	16,226
Gulf of Mexico (Texas)	6,138	22	1,249	1,069	180	196	212	1,189	5,739
Miscellaneous[c]	87	-4	3	22	0	0	0	8	56
U.S. Total	**140,445**	**1,814**	**17,826**	**13,507**	**6,449**	**1,411**	**3,404**	**16,303**	**141,539**

[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." They may differ from the official Energy Information Administration production data for natural gas for 1994 contained in the *Natural Gas Annual 1994*, DOE/EIA-0131(94).

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, 1994
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/93	Changes in Reserves During 1994						Production (-)	Proved Reserves 12/31/94
		Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)		
Alaska	6,494	25	240	19	0	0	0	253	6,487
Lower 48 States	**23,551**	**138**	**4,279**	**2,983**	**850**	**530**	**202**	**2,654**	**23,913**
Alabama	46	6	14	2	2	2	0	12	56
Arkansas	93	11	5	5	0	0	0	19	85
California	1,982	-134	85	85	7	0	0	157	1,698
Coastal Region Onshore	135	4	25	8	1	0	0	12	145
Los Angeles Basin Onshore	108	-3	19	7	0	0	0	9	108
San Joaquin Basin Onshore	1,676	-135	35	65	6	0	0	131	1,386
State Offshore	63	0	6	5	0	0	0	5	59
Colorado	1,162	8	75	121	48	1	3	88	1,088
Florida	[a]59	-1	67	0	0	0	0	8	117
Kansas	93	-35	28	6	8	0	0	13	75
Kentucky	6	24	0	1	20	0	0	2	47
Louisiana	926	100	173	123	42	0	11	149	980
North	120	16	24	20	14	0	0	20	134
South Onshore	649	71	100	76	27	0	8	101	678
State Offshore	157	13	49	27	1	0	3	28	168
Michigan	328	51	32	21	8	0	0	41	357
Mississippi	53	19	10	31	1	1	0	10	43
Montana	53	6	8	6	1	0	0	7	55
New Mexico	1,585	-53	236	113	192	0	23	229	1,641
East	1,478	-51	216	93	191	0	23	220	1,544
West	107	-2	20	20	1	0	0	9	97
New York	0	2	0	0	0	0	0	0	2
North Dakota	274	-31	76	22	8	0	1	31	275
Ohio	343	-7	14	3	7	0	1	40	315
Oklahoma	1,550	-91	264	201	10	0	1	191	1,342
Pennsylvania	8	1	1	0	0	0	0	1	9
Texas	7,880	106	1,604	1,092	280	7	22	858	7,949
RRC District 1	191	1	27	50	2	0	0	20	151
RRC District 2 Onshore	288	41	46	48	3	0	1	32	299
RRC District 3 Onshore	1,159	11	537	509	24	0	4	163	1,063
RRC District 4 Onshore	215	-10	74	59	1	0	0	30	191
RRC District 5	141	17	7	7	1	0	0	11	148
RRC District 6	607	-26	33	45	24	0	0	46	547
RRC District 7B	187	15	4	2	0	2	0	25	181
RRC District 7C	633	-4	80	36	36	1	2	81	631
RRC District 8	2,562	100	385	216	175	3	15	273	2,751
RRC District 8A	1,451	-18	329	82	3	0	0	111	1,572
RRC District 9	178	-16	18	11	3	1	0	25	148
RRC District 10	264	-6	62	25	8	0	0	39	264
State Offshore	4	1	2	2	0	0	0	2	3
Utah	289	23	21	13	3	0	1	38	286
Virginia	0	0	0	0	0	0	0	0	0
West Virginia	190	-46	6	4	0	0	0	13	133
Wyoming	502	138	47	45	26	0	10	67	611
Federal Offshore[b]	6,120	36	1,513	1,089	187	519	129	677	6,738
Pacific (California)	976	-24	577	414	0	0	0	38	1,077
Gulf of Mexico (Louisiana)[b]	4,570	55	752	658	179	515	105	536	4,982
Gulf of Mexico (Texas)	574	5	184	17	8	4	24	103	679
Miscellaneous[c]	9	5	0	0	0	0	0	3	11
U.S. Total	**30,045**	**163**	**4,519**	**3,002**	**850**	**530**	**202**	**2,907**	**30,400**

[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." They may differ from the official Energy Information Administration production data for natural gas for 1994 contained in the *Natural Gas Annual 1994*, DOE/EIA-0131(94).

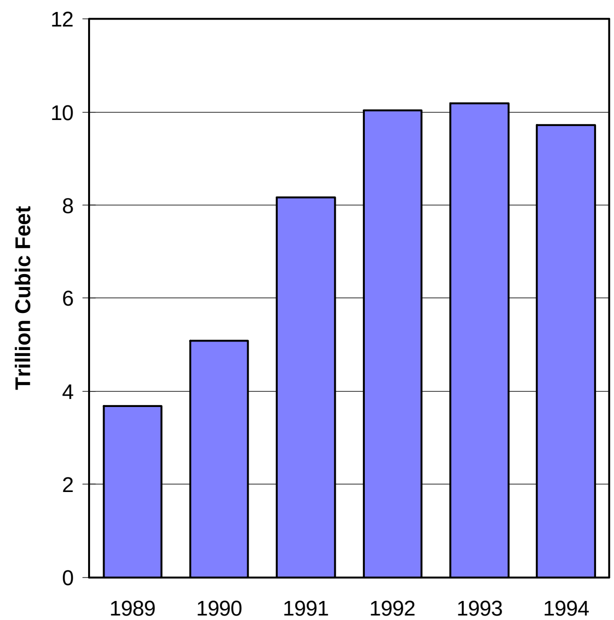
Source: Energy Information Administration, Office of Oil and Gas.

Coalbed Methane

Proved Reserves

Following several years of growth, coalbed methane reserves declined in 1994 for the first time since the data was first collected in 1988 (**Figure 19**). Federal tax incentives for new coalbed methane wells expired at the end of 1992. However, coalbed methane production grew to nearly 5 percent of U.S. dry gas production. Coalbed methane reserves accounted for 6 percent of U.S. natural gas reserves in 1994. Reserves in coalbed methane fields decreased to 9,712 billion cubic feet, 5 percent less than in 1993. The EIA estimates that the 1994 proved gas reserves of fields identified as having coalbed methane were still 19 percent more than the 8,163 billion cubic feet reported only 3 years ago (**Table 12**). Coalbed methane proved reserves are principally in New Mexico, Colorado, Alabama, and Virginia. Estimates of proved coalbed methane reserves in Alabama, Colorado, and New Mexico were lower. In the other States, primarily Virginia had substantial increases in proved reserves in 1994.

Figure 19. Coalbed Methane Proved Reserves 1989 - 1994



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

Production

Coalbed methane production grew by more than 16 percent in 1994. Most of the 119 billion cubic feet production increase occurred in the San Juan basin of Colorado and New Mexico. Coalbed methane production in 1991 represented 2 percent of the Nation's total dry gas production, by 1994, this proportion grew to 5 percent.

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 extracted from various trade publications and company reports. The citations do not necessarily reflect EIA's concurrence, but are considered important enough to be brought to the reader's attention.

Gulf of Mexico

Probably the biggest production news from the Gulf was the start-up of oil and gas production from several

Table 12. U.S. Coalbed Methane Proved Reserves and Production, 1991 - 1994
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State	1991 Reserves	1991 Production	1992 Reserves	1992 Production	1993 Reserves	1993 Production	1994 Reserves	1994 Production
Alabama	1,714	68	1,968	89	1,237	103	976	108
Colorado	2,076	48	2,716	82	3,107	125	2,913	179
New Mexico	4,206	229	4,724	358	4,775	486	4,137	530
Others[a]	167	3	626	10	1,065	18	1,686	34
Total	**8,163**	**348**	**10,034**	**539**	**10,184**	**732**	**9,712**	**851**

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

deepwater projects. The deepwater Gulf region is off the Continental Shelf, in waters generally greater than 200 meters (about 600 feet) deep.

Auger: In April 1994, Shell Oil began production from its Auger Field tension leg platform (TLP). The field is in Garden Banks Block 426, 214 miles southwest of New Orleans, in 2,860 feet of water in the Gulf of Mexico, The first production well is one of 14 planned at the TLP. Ten wells were predrilled prior to the TLP installation, and most were expected to be producing before year-end. Auger is expected to have estimated gross ultimate recovery of 220 million barrels of crude oil equivalents. Initial production rates have surpassed expectations, reaching as high as 55,000 barrels per day and 110 million cubic feet per day.{36}

Ewing Bank Block 873: The discovery well was drilled in early 1991. Installation of the platform is complete and production began in August 1994 and is expected to peak at 45,000 barrels per day of crude oil and 30 million cubic feet per day of gas. The development is expected to ultimately produce an estimated 66 million gross barrels of oil and 45 billion cubic feet of gas.{37}

Tahoe Project: Shell began production in 1994 from Tahoe, Viosca Knoll 783, in 1,500 feet of water. Tahoe is important because it involves Shell's first use of modern sub-sea production technology in deepwater.{38}

Again, the deepwater region of the Gulf of Mexico shows significant potential for the development of natural gas. Many major projects are underway, or in advanced planning stages, to move out into the deepwater off the Continental Shelf. Most companies plan to use state of the art subsea producing technology. Subsea technology allows the commercial development of deepwater prospects that lack the size to support the cost of surface structures. Some of these major projects are:

Mensa Project: Shell Exploration and Production Company announced plans to develop a large natural gas discovery in waters more than a mile deep in the Gulf of Mexico. The project in 5,400 feet of water will exceed the existing world record for deepwater production by almost 2,000 feet. Production will begin in 1997 and is expected to yield about 300 million cubic feet per day of gas. Mensa will be a subsea development project with up to four wells located on the seafloor and connected by flowlines to a platform in shallower water 68 miles away. The 68-mile connection will be the world's longest and will represent an important technological advancement in linking deepwater fields to existing production infrastructures on the Gulf of Mexico shelf. Shell discovered Mensa in 1987, about 140 miles southeast of New Orleans in the Mississippi Canyon Block 731 area. Ultimate recovery from the field is estimated at 720 billion cubic feet of natural gas. Mensa's deepwater production will surpass the existing world record water depth of approximately 3,400 feet established by Petrobras, offshore Brazil. The current Gulf of Mexico water depth record is 2,860 feet held by Shell's Auger TLP. Shell will install its Mars TLP, in 1996 in 2,933 feet of water, and its Ram / Powell TLP in 1997, in 3,218 feet of water.{39}

Ram/Powell Project: Shell and partners Exxon Company USA and Amoco Corporation approved development plans in late 1994. Production is expected to begin in late 1997 from a TLP, reaching a peak rate of 60,000 barrels per day of oil and 200 million cubic feet per day of gas. Ultimate gross recovery is expected to be about the same as Auger. The Ram / Powell prospect is located in water depth of 3,220 feet in the Viosca Knoll Block 912, 955, 956, and 957 Area, 80 miles south of Mobile. The Ram / Powell project will establish a new water depth record for oil and gas production, surpassing the Mars project, which will itself surpass Auger.{38}

Mahogany Project: Production platform construction for the industry's first commercial sub-salt oil and gas development is underway on Ship Shoal South Addition blocks 349 / 359 (Mahogany). This discovery was declared commercial by the operator in April 1995. The platform will be capable of handling 45,000 barrels per day of oil and 100 million cubic feet per day of gas. Initial production is expected in 1996. The project is a break through for the industry, proving both new seismic technology and a new play.{40}

Neptune Project: Oryx Energy began development of the company's Gulf of Mexico reserve acquisition, Viosca Knoll 826, 80 miles off the coast of Alabama. The project is in water depths of 1,500 to 2,500 feet. Production is projected to be at 25,000 barrels per day and 30 million cubic feet per day of gas in 1997. A 700-foot long production platform called a "spar" will be floated into place, partially flooded so it turns on end, and then moored to the Gulf bottom, some 2,000 feet below the surface. It will be the first spar to be used in the Gulf of Mexico. The field will be developed in multiple phases with the spar being moved from location to location.{41}

Cooper Project: Enserch Corporation is continuing with record setting activity in its Garden Banks 388 development named Cooper. A 1,300-ton drilling and production template was installed in Garden Banks Block 388, the largest yet installed deeper than 2,000 feet. Plans for further development continue, and the massive production template and floating facility were scheduled for completion in preparation for a 1995 production start date.{42}

Popeye Project: Popeye, Green Canyon Block 116, in 2,100 feet of water, is currently being developed with subsea technology. Initial production is anticipated in 1995.{38}

Texas

South Texas: A number of operators were active in the Lobo Trend in the lower Rio Grande Valley of south Texas (RRC District 4). This district now accounts for 21 percent of all of the reserves of dry natural gas in the State. The Lobo Trend occurs primarily in Webb and Zapata counties and contains the four producing horizons, Wilcox, Expanded Wilcox, Frio, and Lobo. A number of operators had fields with large extensions, new reservoirs or new fields in this area. The principal fields where these increases occurred were Bob West, Bob West North, Juraschek, La Grulla, La Perle Ranch, McAllen Ranch, and Tordilla. Unlike some other parts of the country, not one or two fields dominate the area. However, the reported top 10 producing fields in south Texas (RRC District 4) account for more than one-fourth of the production and reserves in the District.

Panhandle: Two fields (Panhandle West and Texas Hugoton) reported about one-third of the production and about one-half the reserves of the total NA gas in the Panhandle (RRC District 10) of Texas.

East Texas: The top five fields based on reserves (Carthage, Oak Hill, Willow Springs, Whelan, and Blocker) account for about one-half of the production and for over one-half of the reserves of total NA gas reported in RRC District 6.

West Texas: The top five fields based on production (Coyanosa, Gomez, Headlee, Puckett, and Block 16) reported over one-half of the production and over one-half of the reserves of the total NA gas in West Texas (RRC District 8). The top five fields based on production (Spraberry Trend Area, Conger, Sugg Ranch, Sand Hills, and Goldsmith) reported over one-third of the production and reserves of the total AD gas in West Texas (RRC District 8).

Mid Continent

Kansas: Significant reserve additions through revisions are still happening in old fields like the Kansas Hugoton discovered in 1922. Nevertheless, these gas reserve additions were less than production as the Hugoton field proved reserves declined in 1994. The reported Hugoton reserves account for about three-fourths of Kansas reserves, which also declined in 1994.

The Kansas Corporation Commission (KCC) is the State regulatory agency that regulates oil and gas production in Kansas. One of KCC's most important responsibilities is the determination of market demand (allowables) for the Hugoton Field and the allocation of allowables among the more than 6,200 wells in the field. Twice each year, the KCC sets the fieldwide allowable production at a level estimated to be necessary to meet the Hugoton market demand for the summer and winter production periods. The fieldwide allowable is then allocated among individual wells by a series of calculations that are principally based on each well's pressure, deliverability, and acreage. The allowables assigned to individual wells are affected by the relative production, testing, and drilling practices of all producers in the field, as well as the relative pressure and deliverability of each well. Generally, fieldwide allowables are influenced by overall gas market supply and demand in the United States as well as specific nominations for gas from the parties who produce or purchase gas from the filed. Since 1987, fieldwide allowables have increased each year except 1991. The total field allowable in 1994 was 613 billion cubic feet of wellhead gas.

On February 2, 1994, the KCC issued an order, effective April 1, 1994, establishing new field rules which modified the formulae used to allocate allowables among wells in the field. The standard pressure used in each well's calculated deliverability was reduced by 35 percent. Also, the new rules assign a 30 percent greater allowable to 640 acre units with infill wells than to similar units without infill wells. The new field rules also allow Hugoton producers to make up pre-1994 canceled underages over a 10-year period.{43}

Oklahoma: The top ten fields based on reserves accounted for about one-third of the production and about one-half the reserves of the total NA gas in Oklahoma. A number of Oklahoma fields (Strong City District, Golden Trend, Elk City, Moorewood NE, and Okeene NW) reported increases in reserves as adjustments, net revisions, and extensions that exceeded production. Oklahoma production from currently inactive and recompleted wells and deep production can receive tax incentives because of action passed in late 1994. Various combinations of active versus inactive wells and well depth qualify for tax credit. Inactive wells from January 7, 1993 to June 30, 1994 or longer brought back on-line receive a tax credit that applies to 100 percent of production. In-service wells that are reworked or recompleted receive tax credits for all incremental production. Wells drilled to 1,500 feet or greater receive tax credits on 100 percent of production up to payout.{44}

Rockies

Colorado: Reserve additions in Ignacio-Blanco and Wattenburg fields exceeded production levels. Reported reserves in these two fields account for about one-half of the total for the State of Colorado.

New Mexico: The net of revisions and adjustments were large and negative for the Basin and Blanco fields, and the fields proved gas reserves declined in 1994. Reported reserves in these two fields account for about two-thirds of the total for the State of New Mexico. When the tax incentive to spud coalbed methane wells expired at year-end 1992, companies that had positioned themselves to take advantage of the credit began concentrating on building production from qualified wells. As a result, much of the San Juan Basin's upstream activity in 1993-1994 involved operators consolidating coal seam portfolios, completing wells spudded in previous years, installing surface production equipment, and laying gathering systems. Most basin operators had chosen to drill mainly prospects that would be economic without the incentive. Part of the higher production in the region stems from growing output of coalbed wells during dewatering early in the production cycle. Since 1990, San Juan basin recompletions have accounted for nearly one of five completion procedures in the basin. Due mainly to its coal seam drilling program, Meridian's net San Juan gas production in 1994 averaged 660 million cubic feet per day compared with only 354 million cubic feet per day in 1990. Also in the San Juan basin, Amoco is experimenting with enhanced methane recovery by injecting CO_2, nitrogen, or gases with high concentrations of one or the other into coal seams. Injecting CO_2 or nitrogen appears to speed methane recovery, increasing a coal seam well's economically recoverable reserves in the process.{45}

Wyoming: Production exceeded reserve additions in Fogarty Creek, Madden, Lake Ridge, and Tip Top fields. Reserve additions in the Whitney Canyon-Carter Creek Field exceeded production. The reserves reported in these five fields account for about one-third of the total for the State of Wyoming. Coalbed methane production was reported for the first time in Wyoming. In early June 1994, Union Pacific Resources Company, began operating its sour-gas Wahsatch gathering system in southwestern Wyoming and northeastern Utah. The project currently ties in 40 miles of pipeline among six wells delivering design capacity of 65 million cubic feet per day at 1,600 pounds per square inch. The gathering system was constructed as declining production in other fields opened up long term processing capacity in Whitney Canyon.{46}

Michigan

Devonian Antrim shale gas, the Michigan basin's dominant hydrocarbon play in terms of number of wells drilled for several years, shows every sign of continuing at a busy pace. About 3,500 Antrim shale well completions now yield 350 million cubic feet per day of gas, more than 60 percent of Michigan's gas production. Antrim production averaged about 23 million cubic feet per day of gas statewide during 1985 to 1986, according to the Michigan Geological Survey. The outlook is for Antrim shale gas production to climb in the next 2 to 3 years to 500 to 600 million cubic feet per day, or about 1 percent of the U.S. gas output. Well completion and production technology advances are improving well performance and trimming costs. Several hundred wells a year are likely to be drilled during the next few years. The play, centered in Otsego County and becoming well developed in four neighboring counties, is expanding to the east, south and southwest in Michigan's Lower Peninsula. Even without the Section 29 Federal tax credits, which expired at year-end 1992, Antrim drilling is still deemed viable in many areas. Wells generally tap the Antrim shale at 1,200 to 1,800 feet, but the range has been 600 to 2,200 feet depending on location in the basin. A consistent Antrim shale gas in-place estimate is 16 billion cubic feet per square mile, but estimates for some areas have ranged to more than double that figure.{47}

Alabama

The offshore waters of Alabama have produced some of the most exciting exploration news in the lower 48 States for the past 3 years. In 1994, much of that exploration became full-blown production as Exxon fully implemented its Mobile Bay gas project in March. The project, which includes three production platforms, 11 initial development wells, and an onshore gas treatment plant. It involves three offshore fields: Northwest Gulf, North Central Gulf, and Bon Secour Bay. Exxon calls the development the world's largest sour gas project with reserves estimated at 1 trillion cubic feet and flow rates ranging as high as 50 million cubic feet per day per well.{48}

The project began handling its capacity of sour gas from State and Federal leases some six months ahead of schedule, almost from its start-up. The complex, third in the area for handling the high-sulfur gas, began taking the full 300 million cubic feet per day of gas in October 1993 when the overall project started up. In addition to the new processing plant, Mobil operates the Mary Ann plant, processing 80-90 million cubic feet per day, with expansion to be completed by year end. And Shell's Yellowhammer plant now processes as much as 200 million cubic feet per day of sour gas from five producing wells in the Fairway Field. Exxon obtained an air-emissions permit that recognizes fluctuations in inlet streams and sulfur production.{49}

Virginia

In Virginia, applications for 357 wells were received in 1994. Of these, 175 were coalbed methane wells. The majority of the activity has occurred in Buchanan, Dickson and Wise Counties. The Oakwood coalbed methane field is the primary field in Virginia in 1994. Both Consol and Conoco are partners and are operating projects in that field. It is a new field and both projects are mine related projects. Gradually the recovery factors have been improving as they gain more experience with the mining operations. These companies have both mining operations and conventional gas wells. Two-thirds of the total comes from the mining operation. The operation enables the exploitation of good coal seams from the actual mine and above the mine.{50}

Reserves in Nonproducing Reservoirs

Proved natural gas reserves, wet after lease separation, of 30,718 billion cubic feet were reported in nonproducing reservoirs in 1994 (**Table 13**). This was 0.4 percent lower than in 1993. About 41 percent are located in the Gulf of Mexico Federal Offshore area. Much of the new deepwater reserves are in the nonproducing category. Proved reserves in nonproducing reservoirs were reported by Category I and II operators, who collectively account for about 93 percent of the estimated total wet natural gas production in the United States. The reasons for the nonproducing status of these proved reserves were not collected by EIA in 1994. However, past 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.

Table 13. Reported Reserves of Natural Gas, Wet After Lease Separation, in Nonproducing Reservoirs, 1994[a]
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Nonassociated Gas	Associated-Dissolved Gas	Total
Alaska	31	59	90
Lower 48 States	**26,013**	**4,615**	**30,628**
Alabama	331	1	332
Arkansas	132	10	142
California	194	106	300
Coastal Region Onshore	11	36	47
Los Angeles Basin Onshore	0	17	17
San Joaquin Basin Onshore	183	53	236
State Offshore	0	0	0
Colorado	510	327	837
Florida	0	0	0
Kansas	221	10	231
Kentucky	22	0	22
Louisiana	2,681	251	2,932
North	630	11	641
South Onshore	1,749	204	1,953
South State Offshore	302	36	338
Michigan	107	17	124
Mississippi	56	4	60
Montana	50	2	52
New Mexico	2,064	117	2,181
East	199	99	298
West	1,865	18	1,883
New York	5	0	5
North Dakota	126	23	149
Ohio	50	3	53
Oklahoma	1,049	83	1,132
Pennsylvania	84	1	85
Texas	6,394	704	7,098
District 1	59	41	100
District 2 Onshore	222	53	275
District 3 Onshore	362	111	473
District 4 Onshore	2,646	40	2,686
District 5	732	21	753
District 6	1,312	16	1,328
District 7B	3	3	6
District 7C	370	49	419
District 8	273	251	524
District 8A	6	89	95
District 9	12	1	13
District 10	326	29	355
State Offshore	71	1	71
Utah	160	83	243
Virginia	3	0	3
West Virginia	141	4	145
Wyoming	1,754	41	1,795
Federal Offshore[b]	9,878	2,828	12,706
Pacific (California)	49	17	66
Gulf of Mexico (Texas)	2,056	259	2,315
Gulf of Mexico (Louisiana)[b]	7,773	2,552	10,325
Miscellaneous[c]	1	0	1
U.S. Total	**26,044**	**4,674**	**30,718**

[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," 1994.

5. Natural Gas Liquids Statistics

Natural Gas Liquids

Proved Reserves

U.S. natural gas liquids proved reserves declined 1 percent to 7,170 million barrels in 1994 (**Table 14**). This was the lowest reserves level since 1982. The 52 million barrel decrease was predominantly in the lower 48 States, which declined to 6,869 million barrels in 1994, the lowest level since 1980. The reserves of five areas account for about three-fourths of the Nation's natural gas liquids proved reserves. Of these, Texas had 34 percent, New Mexico had 14 percent, Oklahoma had 9 percent, and the Gulf of Mexico Federal Offshore and Utah-Wyoming had about 8 percent each. The volumes of natural gas liquids 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**.

Discoveries

Total discoveries of natural gas liquids reserves increased by 50 percent in 1994 to 499 million barrels, the highest level since 1984. Areas with the largest *total discoveries* were Texas, the Gulf of Mexico Federal Offshore, Louisiana, New Mexico, and Oklahoma. *New field discoveries,* at 54 million barrels, were 30 million barrels greater than in 1993. Areas with the largest *new field discoveries* were the Gulf of Mexico Federal Offshore and Texas, with 91 percent of the total. *New reservoir discoveries in old fields,* at 131 million barrels, were twice what they were in 1993. Areas with the largest *new reservoir discoveries in old fields* were the Gulf of Mexico Federal Offshore, Texas, and Louisiana. *Extensions* were 314 million barrels, an increase of 28 percent over 1993. Areas with the largest *extensions* were Texas, the Gulf of Mexico Federal Offshore, Louisiana, New Mexico, Oklahoma, and Utah-Wyoming.

Production

Natural gas liquids production increased 0.4 percent to 791 million barrels in 1994. Five areas accounted for about 79 percent of the Nation's natural gas liquids production. Of these, Texas had 39 percent, the Gulf of Mexico Federal Offshore had 12 percent, Oklahoma had 11 percent, Louisiana had 9 percent, and New Mexico had 8 percent.

Natural Gas Plant Liquids

Proved Reserves

Natural gas plant liquids proved reserves were steady decreasing in 1994 by only 0.1 percent to 6,023 million barrels (**Table 15**). Five areas accounted for approximately 76 percent of the Nation's natural gas plant liquids proved reserves: Texas (36 percent), New Mexico (16 percent), Oklahoma (10 percent), Utah-Wyoming, and Kansas about 7 percent each.

Production

Natural gas plant liquids production remained essentially the same, decreasing 0.2 percent to 634 million barrels in 1994 (**Table 15**). Five areas accounted for approximately 79 percent of the Nation's natural gas plant liquids production: Texas (42 percent), Oklahoma (12 percent), New Mexico (10 percent), the Gulf of Mexico Federal Offshore (8 percent), and Louisiana (7 percent). Natural gas processing plants are usually located in the same general area where the natural gas is produced. Of the 16.4 trillion cubic feet of natural gas processed in plants, about 15.8 trillion cubic feet are both produced and processed in the same State (**Table E4**, Appendix E).

According to the State of Alaska, production of natural gas from the Prudhoe Bay Field increased in 1994 to 2.3 trillion cubic feet, 4.8 percent over 1993.{51} However, the output of natural gas liquids at the Prudhoe Bay Unit decreased in 1994. Natural gas at Prudhoe Bay (a byproduct of the oil production) is processed and reinjected into the reservoir in order to slow the field's natural decline and enable incremental oil production. With installation of the final Gas Handling Expansion No. 2 (GHX-2) facilities, in September 1994, Prudhoe Bay's average gas handling capacity was increased to 7.5 billion cubic feet per day. The GHX-2 project should increase total liquids production from the field by an additional 100,000 barrels per day. Overall total recoverable reserves in Prudhoe Bay are expected to increase by 453 million barrels as a result of the GHX-2 project.{24} In Kansas, 1994 was the first full year of MESA's Satanta plant operation. The Satanta plant has capacity to process 250 million cubic feet per day of natural gas from MESA's Hugoton Field properties.{43}

Table 14. Natural Gas Liquids Proved Reserves, Reserves Changes, and Production, 1994
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	Published Proved Reserves 12/31/93	Changes in Reserves During 1994 Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	Proved Reserves 12/31/94
Alaska	321	5	1	0	0	0	0	26	301
Lower 48 States	**6,901**	**38**	**872**	**676**	**314**	**54**	**131**	**765**	**6,869**
Alabama	158	1	4	9	0	0	0	12	142
Arkansas	4	2	0	0	0	0	0	0	6
California	104	-6	6	6	2	0	0	8	92
Coastal Region Onshore	12	-1	2	1	0	0	0	1	11
Los Angeles Basin Onshore	6	-2	1	0	0	0	0	0	5
San Joaquin Basin Onshore	85	-3	3	5	2	0	0	7	75
State Offshore	1	0	0	0	0	0	0	0	1
Colorado	214	18	44	23	12	0	1	18	248
Florida	9	-1	11	0	0	0	0	1	18
Kansas	380	35	23	16	4	1	0	29	398
Kentucky	26	17	2	4	1	0	0	3	39
Louisiana	421	25	70	66	21	3	29	69	434
North	57	9	13	6	5	0	1	10	69
South Onshore	334	19	49	55	16	3	26	55	337
State Offshore	30	-3	8	5	0	0	2	4	28
Michigan	57	-1	7	3	0	0	0	6	54
Mississippi	11	0	1	2	0	0	0	1	9
Montana	8	2	0	1	0	0	0	1	8
New Mexico	996	33	44	41	41	0	2	64	1,011
East	233	5	31	23	22	0	2	36	234
West	763	28	13	18	19	0	0	28	777
North Dakota	55	-4	7	2	1	0	2	4	55
Oklahoma	643	21	81	52	40	0	3	84	652
Texas	2,469	-84	389	239	134	16	41	312	2,414
RRC District 1	26	1	4	3	1	0	1	4	26
RRC District 2 Onshore	86	4	13	13	7	1	3	15	86
RRC District 3 Onshore	253	-23	83	54	15	6	23	49	254
RRC District 4 Onshore	278	-1	73	58	35	4	7	48	290
RRC District 5	64	-2	6	7	4	0	0	6	59
RRC District 6	248	29	27	28	15	0	4	30	265
RRC District 7B	79	-8	1	1	0	0	0	9	62
RRC District 7C	273	-3	24	15	11	1	0	26	265
RRC District 8	439	-15	49	25	13	3	2	52	414
RRC District 8A	298	-55	56	14	1	0	0	19	267
RRC District 9	92	-2	9	3	16	0	0	14	98
RRC District 10	329	-9	44	17	16	1	1	39	326
State Offshore	4	0	0	1	0	0	0	1	2
Utah and Wyoming	600	7	70	94	17	1	11	48	564
West Virginia	108	-13	5	5	1	0	3	6	93
Federal Offshore[a]	630	-13	107	113	40	33	39	99	624
Pacific (California)	25	-3	8	8	0	0	0	1	21
Gulf of Mexico (Louisiana)[a]	490	0	80	88	38	27	36	83	500
Gulf of Mexico (Texas)	115	-10	19	17	2	6	3	15	103
Miscellaneous[b]	8	-1	1	0	0	0	0	0	8
U.S. Total	**7,222**	**43**	**873**	**676**	**314**	**54**	**131**	**791**	**7,170**

[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 1994 contained in the publications *Petroleum Supply Annual 1994*, DOE/EIA-0340(94) and *Natural Gas Annual 1994* DOE/EIA-0131(94).

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

Table 15. Natural Gas Plant Liquids Proved Reserves and Production, 1994
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	1994 Reserves	1994 Production
Alaska	301	26
Lower 48 States	**5,722**	**608**
Alabama	51	4
Arkansas	3	0
California	86	8
Coastal Region Onshore	9	1
Los Angeles Basin Onshore	5	0
San Joaquin Basin Onshore	71	7
State Offshore	1	0
Colorado	210	15
Florida	18	1
Kansas	396	29
Kentucky	39	3
Louisiana	281	43
North	48	6
South Onshore	214	34
State Offshore	19	3
Michigan	43	5
Mississippi	3	0
Montana	8	1
New Mexico	946	60
East	222	34
West	724	26
North Dakota	46	4
Oklahoma	592	76
Texas	2,151	267
RRC District 1	23	3
RRC District 2 Onshore	74	12
RRC District 3 Onshore	200	36
RRC District 4 Onshore	220	36
RRC District 5	50	5
RRC District 6	218	24
RRC District 7B	61	9
RRC District 7C	241	24
RRC District 8	398	50
RRC District 8A	267	19
RRC District 9	94	13
RRC District 10	305	36
State Offshore	0	0
Utah and Wyoming	440	34
West Virginia	93	6
Federal Offshore[a]	309	52
Pacific (California)	17	1
Gulf of Mexico (Louisiana)[a]	267	46
Gulf of Mexico (Texas)	25	5
Miscellaneous[b]	7	0
U.S. Total	**6,023**	**634**

[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 1994 contained in the publications *Petroleum Supply Annual 1994,* DOE/EIA-0340(94) and *Natural Gas Annual 1994*, DOE/EIA-0131(94).

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

Lease Condensate

Proved Reserves

Proved reserves of lease condensate in the United States were 1,147 million barrels in 1994 (**Table 16**). This was 45 million barrels or 4 percent lower than reported in 1993. The reserves of four areas account for about three-fourths of the Nation’s lease condensate proved reserves. Of these, the Gulf of Mexico Federal Offshore had 27 percent, Texas had 23 percent, Louisiana had 13 percent, and Utah-Wyoming had 11 percent.

Production

Production of lease condensate was 157 million barrels, an increase of 4 million barrels, or 3 percent, in 1994. The production of four areas account for about five-sixths of the Nation’s lease condensate production. Of these, the Gulf of Mexico Federal Offshore had 30 percent, Texas had 29 percent, Louisiana had 17 percent, and Utah-Wyoming had 9 percent.

Reserves in Nonproducing Reservoirs

Like crude oil and natural gas, not all lease condensate proved reserves were contained in reservoirs that were producing during 1994. Proved reserves of 331 million barrels of lease condensate, a decrease of 16 percent from 1993, were reported in nonproducing reservoirs in 1994. These reserves were reported by Category I and Category II operators who collectively accounted for more than 97 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, 1994
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	1994 Reserves	1994 Production
Alaska	0	0
Lower 48 States	**1,147**	**157**
Alabama	91	8
Arkansas	3	0
California	6	0
Coastal Region Onshore	2	0
Los Angeles Basin Onshore	0	0
San Joaquin Basin Onshore	4	0
State Offshore	0	0
Colorado	38	3
Florida	0	0
Kansas	2	0
Kentucky	0	0
Louisiana	153	26
North	21	4
South Onshore	123	21
State Offshore	9	1
Michigan	11	1
Mississippi	6	1
Montana	0	0
New Mexico	65	4
East	12	2
West	53	2
North Dakota	9	0
Oklahoma	60	8
Texas	263	45
RRC District 1	3	1
RRC District 2 Onshore	12	3
RRC District 3 Onshore	54	13
RRC District 4 Onshore	70	12
RRC District 5	9	1
RRC District 6	47	6
RRC District 7B	1	0
RRC District 7C	24	2
RRC District 8	16	2
RRC District 8A	0	0
RRC District 9	[a]4	1
RRC District 10	21	3
State Offshore	2	1
Utah and Wyoming	124	14
West Virginia	0	0
Federal Offshore[b]	315	47
Pacific (California)	4	0
Gulf of Mexico (Louisiana)[b]	233	37
Gulf of Mexico (Texas)	78	10
Miscellaneous[c]	1	0
U.S. Total	**1,147**	**157**

[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, 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" 1994.
Source: Energy Information Administration, Office of Oil and Gas.

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Operator Data by Size Class

To remain competitive in the domestic industry, companies have to reduce costs and look for areas of profitable growth. Over the past few years, we have seen companies restructure to focus on their core areas of profit. This restructuring has taken many forms, for example, laying off employees, early retirements and buyouts, flattening management structure, selective sales of marginally profitable properties, and acquisitions. It is important to document some of these changes. Appendix A contains tables of the proved reserves and production of the top 2,500 oil and gas well operators by production size class for the years 1989 through 1994. The tables show the volumetric change and percent change from the previous year and from 1989. In addition the 1994 average per operator in each class is shown. All companies operating in the United States that reported production or reserves to EIA were ranked by production size for each year of the six years. Company production size classes were computed as the sum of the barrel oil equivalent of the crude oil production, lease condensate production, and wet gas production for each operator. The companies were then placed in the following production size classes: 1-10, 11-20, 21-100, 101-500, 501-2,500, and all "other" oil and gas operators. The "other" category contains 20,354 small operators. Production and reserves of small operators are estimated each year from a sample of approximately 8 percent of these operators.

Class 1-10 contains the 10 highest producing companies each year on a barrel oil equivalent basis. These companies are not necessarily the same 10 companies each year. For example in 1993 an operator moved from the 11-20 production size class to the 1-10 class, displacing an operator from the group that had been there since 1991. Most of the apparent changes in these two size classes resulted from the movement of operators from size class to size class.

Statistics for operator *Category* sizes are also included at the bottom portion of tables in this appendix. These are the categories used by EIA in processing and assessing reserves surveys and are presented here as additional perspective. For further explanation of categories sizes see definitions and descriptions in Appendix E.

Natural Gas

Proved Reserves

The wet natural gas proved reserves reported for 1989 through 1994 have decreased from 175.4 trillion cubic feet to 171.9 trillion cubic feet (**Table A1**). These proved reserves are highly concentrated in the larger companies. Although not as highly concentrated as oil reserves, in 1994, the top 20 producing companies had 58 percent of the proved reserves of natural gas. The next two size classes contain 80 companies and 400 companies and account for 24 and 12 percent of the U.S. natural gas proved reserves, respectively. On average, a company in the top 20 production size class has more than 25,000 times the wet natural gas reserves as the average operator in the "other" class of small operators. The top 20 operators had a decline of 5 percent in their natural gas proved reserves from 1989 to 1994. The rest of the U.S. operators had an increase of 2 percent. In 1994, the top 20 operators' natural gas reserves decreased 0.7 percent. On the other hand, the rest of the operators had an increase of 3 percent.

Production

Wet natural gas production reported from 1989 through 1994 has steadily increased from 17.8 trillion cubic feet to 19.2 trillion cubic feet (**Table A2**). In 1994, the top 20 producing companies had 54 percent of the production of natural gas, while having 58 percent of the proved reserves. The next two size classes contain 80 companies and 400 companies, and have 25 and 13 percent of the gas production, respectively. The average top 20 company has more than 18,000 times the wet gas production as the average operator in the "other" class of small operators. The top 20 operators also had an increase of 8 percent in their natural gas production from 1989 to 1994. The rest of the U.S. operators had an increase of 9 percent from 1989 to 1994. The top 20 operators' wet natural gas production increased 7 percent in 1994, while the rest of the U.S. operators had a decrease of 0.8 percent, in 1994.

Crude Oil

Proved Reserves

Proved reserves of crude oil are more highly operator concentrated than those of natural gas. The 20 largest oil and gas producing companies in 1994 had 74 percent of U.S. proved reserves of crude oil (**Table A3**), in contrast to wet natural gas where only 58 percent of the total proved reserves were operated by these same companies. These largest companies have tended to concentrate their domestic operations in fewer fields and focus more of their resources on their foreign operations in the past few years.

U.S. proved reserves of crude oil declined 2 percent in 1994. The top 20 producing companies had a decline of 4 percent in their domestic proved reserves of crude oil during 1994. The average top 20 company had more than 22,000 times the oil reserves as the average operator in the “other” category. The top 20 class had a decline of 23 percent in their crude oil proved reserves from 1989 to 1994. Without the top 20, the rest of the U.S. operators had a 16 percent increase from 1989 to 1994. The large independents, the 80 companies in production size class 21-100, accounted for most of the increase in crude oil proved reserves. The companies in the 21-100 class had 12 percent of U.S. proved reserves of crude oil. These companies had a 50 percent increase in their oil reserves during the 1989-1994 period. A substantial portion of this increase came from property acquisitions. During the 1989-1994 period, many of these operators were actively buying, selling, and restructuring their oil property positions.

Production

Crude oil production reported for 1989 through 1994 has decreased from 2.6 billion barrels to 2.3 billion barrels (**Table A4**). The 20 largest oil and gas producing companies had 68 percent of U.S. production of crude oil, or 1.5 billion barrels, in 1994, while in 1989 they accounted for 74 percent of production. This is in contrast to wet natural gas where only 54 percent of the total was produced by these same companies. The average “top 20" operator had more than 14,000 times the oil production of the average operator in the “other” class.

U.S. production of crude oil declined by 12 percent from 1989 to 1994. The top 20 operators had a decline of 20 percent in their oil production during the same period. U.S. production of crude oil declined by declined 3 percent from 1993 to 1994, while the top 20 operators production also declined 3 percent. The large independents, the 80 companies in production size class 21-100, had a 26 percent increase in their oil production during the 1989-1994 period. A substantial portion of this increase is because of oil property acquisitions.

Fields

The number of fields in which large operators were active dropped significantly during the 1989-1994 period. From 1989 through 1994, fields in which these large operators were active dropped by 4,463 or 14 percent (**Table A5**). The trend continued in 1994 with a 2 percent decline. Most of the changes in operator field counts resulted from the top 20 operators class concentrating their effort in a diminishing number of fields. From 1989 through 1994, the number of fields in which the top 20 operators were active in dropped by 3,802 or 39 percent, while in 1994 the number dropped 8 percent.

Table A1. Natural Gas Proved Reserves, Wet After Lease Separation, by Operator Production Size Class, 1989-1994
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Size Class	1989	1990	1991	1992	1993	1994	1993-1994 Volume and Percent Change	1989-1994 Volume and Percent Change	1994 Average Reserves per Operator
Class 1-10	80,608	82,356	79,028	74,350	77,552	76,665	-887	-3,943	7,666.501
Percent of Total	45.9%	46.4%	45.1%	42.9%	45.5%	44.6%	-1.1%	-4.9%	
Class 11-20	23,883	24,765	25,763	28,442	22,467	22,691	224	-1,192	2,269.147
Percent of Total	13.6%	13.9%	14.7%	16.4%	13.2%	13.2%	1.0%	-5.0%	
Class 21-100	37,809	36,696	38,362	38,388	39,135	40,566	1,431	2,757	507.076
Percent of Total	21.6%	20.7%	21.9%	22.2%	23.0%	23.6%	3.7%	7.3%	
Class 101-500	20,784	20,995	19,330	19,728	19,870	20,608	738	-176	51.520
Percent of Total	11.8%	11.8%	11.0%	11.4%	11.7%	12.0%	3.7%	-0.8%	
Class 501-2,500	8,085	8,328	8,414	7,922	7,278	7,468	190	-617	3.734
Percent of Total	4.6%	4.7%	4.8%	4.6%	4.3%	4.3%	2.6%	-7.6%	
Class Other	4,259	4,436	4,428	4,479	4,188	3,941	-247	-318	0.194
Percent of Total	2.4%	2.5%	2.5%	2.6%	2.5%	2.3%	-5.9%	-7.5%	
Category I	145,458	145,483	145,595	144,351	142,892	143,703	811	-1,755	927.117
Percent of Total	82.9%	81.9%	83.0%	83.3%	83.8%	83.6%	0.6%	-1.2%	
Category II	17,307	19,684	17,604	17,682	17,305	18,158	853	851	38.551
Percent of Total	9.9%	11.1%	10.0%	10.2%	10.2%	10.6%	4.9%	4.9%	
Category III	12,663	12,409	12,126	11,276	10,292	10,078	-214	-2,585	0.453
Percent of Total	7.2%	7.0%	6.9%	6.5%	6.0%	5.9%	-2.1%	-20.4%	
Total Published	**175,428**	**177,576**	**175,325**	**173,309**	**170,490**	**171,939**	**1,449**	**-3,489**	**7.523**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**0.8%**	**-2.0%**	

Note: There were 22,854 operators in 1994 including 155 Category I, 471 Category II, and 22,228 Category III. The "other" size class had 20,354 operators in 1994.
Source: Energy Information Administration, Office of Oil and Gas.

Table A2. Natural Gas Production, Wet After Lease Separation, by Operator Production Size Class, 1989-1994
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Size Class	1989	1990	1991	1992	1993	1994	1993-1994 Volume and Percent Change	1989-1994 Volume and Percent Change	1994 Average Production per Operator
Class 1-10	7,030	6,955	6,857	6,625	6,801	7,216	415	186	721.597
Percent of Total	39.6%	38.6%	38.1%	36.3%	36.5%	37.6%	6.1%	2.6%	
Class 11-20	2,545	2,723	2,864	3,036	2,861	3,083	222	538	308.326
Percent of Total	14.3%	15.1%	15.9%	16.6%	15.3%	16.0%	7.8%	21.1%	
Class 21-100	4,287	4,366	4,367	4,592	4,894	4,878	-16	591	60.971
Percent of Total	24.1%	24.3%	24.2%	25.1%	26.3%	25.4%	-0.3%	13.8%	
Class 101-500	2,369	2,421	2,348	2,411	2,597	2,552	-45	183	6.379
Percent of Total	13.3%	13.4%	13.0%	13.2%	13.9%	13.3%	-1.7%	7.7%	
Class 501-2,500	971	916	956	974	904	904	0	-67	0.452
Percent of Total	5.5%	5.1%	5.3%	5.3%	4.8%	4.7%	0.0%	-6.9%	
Class Other	550	622	620	631	584	577	-7	27	0.028
Percent of Total	3.1%	3.5%	3.4%	3.5%	3.1%	3.0%	-1.2%	4.9%	
Category I	14,084	14,235	14,464	14,767	15,122	15,656	534	1,572	101.009
Percent of Total	79.3%	79.1%	80.3%	80.8%	81.1%	81.5%	3.5%	11.2%	
Category II	2,081	2,226	2,086	2,036	2,159	2,221	62	140	4.716
Percent of Total	11.7%	12.4%	11.6%	11.1%	11.6%	11.6%	2.9%	6.7%	
Category III	1,587	1,541	1,462	1,467	1,360	1,333	-27	-254	0.060
Percent of Total	8.9%	8.6%	8.1%	8.0%	7.3%	6.9%	-2.0%	-16.0%	
Total Published	**17,752**	**18,003**	**18,012**	**18,269**	**18,641**	**19,210**	**569**	**1,458**	**0.841**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**3.1%**	**8.2%**	

Note: There were 22,854 operators in 1994 including 155 Category I, 471 Category II, and 22,228 Category III. The “other” size class had 20,354 operators in 1994.
Source: Energy Information Administration, Office of Oil and Gas.

Table A3. Crude Oil Proved Reserves by Operator Production Size Class, 1989-1994
(Million Barrels of 42 U.S. Gallons)

Size Class	1989	1990	1991	1992	1993	1994	1993-1994 Volume and Percent Change	1989-1994 Volume and Percent Change	1994 Average Reserves per Operator
Class 1-10	19,085	18,639	16,825	15,733	14,894	14,351	-543	-4,734	1,435.076
Percent of Total	72.0%	71.0%	68.2%	66.3%	64.9%	63.9%	-3.6%	-24.8%	
Class 11-20	2,398	1,892	2,247	2,250	2,389	2,276	-113	-122	227.570
Percent of Total	9.0%	7.2%	9.1%	9.5%	10.4%	10.1%	-4.7%	-5.1%	
Class 21-100	1,735	2,310	2,270	2,370	2,401	2,607	206	872	32.588
Percent of Total	6.5%	8.8%	9.2%	10.0%	10.5%	11.6%	8.6%	50.3%	
Class 101-500	1,295	1,410	1,415	1,463	1,440	1,512	72	217	3.781
Percent of Total	4.9%	5.4%	5.7%	6.2%	6.3%	6.7%	5.0%	16.8%	
Class 501-2,500	1,096	1,214	1,121	1,107	1,000	965	-35	-131	0.483
Percent of Total	4.1%	4.6%	4.5%	4.7%	4.4%	4.3%	-3.5%	-12.0%	
Class Other	892	789	804	822	833	746	-87	-146	0.037
Percent of Total	3.4%	3.0%	3.3%	3.5%	3.6%	3.3%	-10.4%	-16.4%	
Category I	23,365	23,209	21,714	20,767	20,090	19,648	-442	-3,718	126.758
Percent of Total	88.2%	88.4%	88.0%	87.5%	87.5%	87.5%	-2.2%	-15.9%	
Category II	1,056	1,066	1,088	1,150	1,131	1,142	11	85	2.424
Percent of Total	4.0%	4.1%	4.4%	4.8%	4.9%	5.1%	1.0%	8.1%	
Category III	2,079	1,979	1,880	1,828	1,737	1,668	-69	-411	0.075
Percent of Total	7.8%	7.5%	7.6%	7.7%	7.6%	7.4%	-4.0%	-19.8%	
Total Published	**26,501**	**26,254**	**24,682**	**23,745**	**22,957**	**22,457**	**-500**	**-4,044**	**0.983**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**-2.2%**	**-15.3%**	

Note: There were 22,854 operators in 1994 including 155 Category I, 471 Category II, and 22,228 Category III. The “other” size class had 20,354 operators in 1994.
Source: Energy Information Administration, Office of Oil and Gas.

Table A4. Crude Oil Production by Operator Production Size Class, 1989-1994
(Million Barrels of 42 U.S. Gallons)

Size Class	1989	1990	1991	1992	1993	1994	1993-1994 Volume and Percent Change	1989-1994 Volume and Percent Change	1994 Average Production per Operator
Class 1-10	1,683	1,574	1,544	1,458	1,346	1,310	-36	-373	131.024
Percent of Total	65.1%	62.8%	61.5%	59.6%	57.5%	57.8%	-2.7%	-22.2%	
Class 11-20	235	215	218	231	236	224	-12	-11	22.376
Percent of Total	9.1%	8.6%	8.7%	9.4%	10.1%	9.9%	-5.1%	-4.7%	
Class 21-100	227	241	259	272	276	287	11	60	3.593
Percent of Total	8.8%	9.6%	10.3%	11.1%	11.8%	12.7%	4.0%	26.4%	
Class 101-500	175	193	208	213	202	200	-2	25	0.500
Percent of Total	6.8%	7.7%	8.3%	8.7%	8.6%	8.8%	-1.0%	14.3%	
Class 501-2,500	159	165	167	153	148	137	-11	-22	0.068
Percent of Total	6.1%	6.6%	6.6%	6.3%	6.3%	6.0%	-7.4%	-13.8%	
Class Other	107	117	116	119	131	110	-21	3	0.005
Percent of Total	4.1%	4.7%	4.6%	4.9%	5.6%	4.9%	-16.0%	2.8%	
Category I	2,159	2,075	2,068	2,022	1,922	1,879	-43	-280	12.125
Percent of Total	83.5%	82.8%	82.3%	82.7%	82.2%	82.8%	-2.2%	-13.0%	
Category II	150	147	167	163	153	150	-3	0	0.318
Percent of Total	5.8%	5.9%	6.6%	6.7%	6.5%	6.6%	-2.0%	0.0%	
Category III	277	283	277	261	264	239	-25	-38	0.011
Percent of Total	10.7%	11.3%	11.0%	10.7%	11.3%	10.5%	-9.5%	-13.7%	
Total Published	**2,586**	**2,505**	**2,512**	**2,446**	**2,339**	**2,268**	**-71**	**-318**	**0.099**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**-3.0%**	**-12.3%**	

Note: There were 22,854 operators in 1994 including 155 Category I, 471 Category II, and 22,228 Category III. The “other” size class had 20,354 operators in 1994.
Source: Energy Information Administration, Office of Oil and Gas.

Table A5. Operator Field Count by Operator Production Size Class, 1989-1994

Size Class	1989	1990	1991	1992	1993	1994	1993-1994 Number and Percent Change	1989-1994 Number and Percent Change	1994 Average Number of Fields per Operator
1-10	6,661	6,045	4,947	4,189	3,591	3,258	-333	-3,403	326
Percent of Total	21.4%	20.0%	16.7%	14.7%	13.2%	12.2%	-9.3%	-51.1%	
11-20	3,194	3,282	3,466	3,432	2,998	2,795	-203	-399	280
Percent of Total	10.3%	10.8%	11.7%	12.1%	11.1%	10.5%	-6.8%	-12.5%	
21-100	8,736	7,907	8,156	8,003	7,600	7,752	152	-984	97
Percent of Total	28.1%	26.1%	27.6%	28.2%	28.0%	29.1%	2.0%	-11.3%	
101-500	12,345	12,620	11,824	11,896	11,881	11,878	-3	-467	30
Percent of Total	39.7%	41.7%	40.0%	41.9%	43.8%	44.6%	0.0%	-3.8%	
Rest	1,314	1,660	1,760	2,059	1,715	1,897	182	583	15
Percent of Total	4.2%	5.5%	6.0%	7.2%	6.3%	7.1%	10.6%	44.4%	
Category I	19,493	18,806	18,189	17,620	16,603	16,161	-442	-3,332	108
Percent of Total	62.7%	62.1%	61.5%	62.0%	61.2%	60.7%	-2.7%	-17.1%	
Category II	11,583	11,478	11,370	10,799	10,516	10,452	-64	-1,131	22
Percent of Total	37.3%	37.9%	38.5%	38.0%	38.8%	39.3%	-0.6%	-9.8%	
Total Published	**31,076**	**30,284**	**29,559**	**28,419**	**27,119**	**26,613**	**-506**	**-4,463**	**43**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**-1.9%**	**-14.4%**	

Note: Includes only data from Category I and Category II operators. In 1994, there were 155 Category I operators and 471 Category II operators. The “rest” size class had 126 operators in 1994.

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

Top 100 Oil and Gas Fields for 1993

Estimates of the proved reserves, cumulative production, and ultimate recovery of the top 100 oil and gas fields are contained in **Tables B1 and B2** of this Appendix. The oil field production and reserves data include both crude oil and lease condensate. The gas field production and reserves data is wet gas, after lease separation.

The top 100 oil fields in the United States as of December 31, 1993, had 15,914.9 million barrels of proved reserves accounting for 66 percent of the total United States (**Table B1**). For the top 100 oil fields, this is a decrease of 2.8 percent from 1992. Although there is considerable grouping of field-level statistics within the tables, rough orders of magnitude can be estimated for the proved reserves, cumulative production, and ultimate recovery of most fields. Many fields in the top 100 groups are operated by only one or two operators, therefore, the totals for proved reserves are grouped as top 10, top 20, top 50, and top 100 to avoid revealing company proprietary data. In the top 20 oil fields for 1993 there is only one newcomer, Mississippi Canyon Block 807, the Mars prospect, in the Gulf of Mexico Federal Offshore. This field displaced the Rangely field in Colorado from the top 20 fields in terms of reserves. The top 100 oil fields in the United States as of December 31, 1993, had 1,340.5 million barrels of production or 54 percent of the total (**Table B1**). For the top 100 oil fields, this is a decrease of 5 percent from 1992. These are approximately the same percentages of reserves and production as in the 1993 annual report.

The top 100 gas fields in the United States as of December 31, 1993, had 80,769.9 billion cubic feet of proved reserves or 47 percent of the total (**Table B2**). For the top 100 gas fields, this is only a decrease of 0.9 percent from 1992. Unlike the oil fields, the top 100 gas fields show a lesser degree of concentration. Many, but not all, of the same fields are in both tables. As an example, the top three gas fields, Basin, Hugoton Gas Area, and Blanco, are not found in the oil table. Unlike the top 20 in the oil table there was shifting in the rank of the gas fields, most notable was the addition of the Mobile Bay of Alabama to the top 10 which dropped the Elk Hills field in California into the next ranking group. The Mobile Bay field is a combination of the North Central Gulf and Northwest Gulf fields which were reported separately in the previous report. In the 11-20 group there were three new fields added, Oakwood in Virginia, Whitney Canyon-Carter Creek in Wyoming, and Cook Inlet North in Alaska. Dropping out of the top 20 was Big Sandy in Kentucky and McArthur River in Alaska. The top 100 gas fields in the United States as of December 31, 1993, had 5,944.7 billion cubic feet of production or 31 percent of the total (**Table B2**). For the top 100 gas fields, this is only a decrease of 1.3 percent from 1992.

The field name, location, years of discovery, and an estimate of 1993 annual production are also a part of the information found in the tables. Where two or more States are listed, the name of the field shown is that name recognized by the State listed first. The additional States listed may recognize an alternative field name for the area. 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 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 gotten 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 OGIFF data base system contained information on more than 45,000 fields in 1993. 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 reserve's report. Three reports have already been published: *U.S. Oil and Gas Reserves by Year of Field Discovery*{20}, *Geologic Distributions of U.S. Oil and Gas*{52}, and *Largest U.S. Oil and Gas Fields.*{53}

Table B1. Top 100 U.S. Fields Ranked by Oil[a] Production within Proved Reserves Group, 1993
(Million Barrels of 42 U.S. Gallons)

Field Name	Location	Discovery Year	Proved Reserves 12/31/93 Rank Group	Annual Production Rank	Annual Production Volume	Cumulative Production Rank	Ultimate Recovery Rank Group
Prudhoe Bay	AK	1967	1-10	1	395.4	1	1-10
Kuparuk River	AK	1969	1-10	2	115.2	13	1-10
Midway-Sunset	CA	1901	1-10	3	60.9	4	1-10
Belridge South	CA	1911	1-10	4	46.6	15	11-20
Kern River	CA	1899	1-10	5	45.2	7	1-10
Endicott	AK	1978	1-10	6	39.2	108	21-50
Wasson	TX	1937	1-10	10	24.6	5	1-10
Elk Hills	CA	1919	1-10	11	23.5	14	11-20
Yates	TX	1926	1-10	15	17.6	9	1-10
Point McIntyre	AK	1988	1-10	32	7.5	> 1,000	51-100
Top 10 Volume Subtotal			**8,955.0**		**775.8**	**18,323.1**	**27,278.1**
Top 10 Percentage of U.S. Total			**37.1%**		**31.0%**	**10.9%**	**14.2%**
East Texas	TX	1930	11-20	8	30.1	2	1-10
Wilmington	CA	1932	11-20	12	22.2	3	1-10
Spraberry Trend Area	TX	1950	11-20	13	19.7	25	11-20
Slaughter	TX	1937	11-20	16	16.3	11	11-20
Levelland	TX	1945	11-20	18	15.0	34	21-50
Cowden North	TX	1930	11-20	21	12.9	40	21-50
Hondo	PF	1969	11-20	33	7.4	215	51-100
San Ardo	CA	1947	11-20	55	4.7	52	21-50
Pescado	PF	1970	11-20	> 1,000	0.0	> 1,000	101-200
Mississippi Canyon Blk 807	GF	1989	11-20	-	0.0	-	51-100
Top 20 Volume Subtotal			**11,163.1**		**904.1**	**29,494.5**	**40,657.6**
Top 20 Percentage of U.S. Total			**46.2%**		**36.2%**	**17.6%**	**21.2%**
Giddings	TX	1960	21-50	7	37.2	78	51-100
Point Arguello	PF	1981	21-50	9	25.9	553	101-200
Sho-Vel-Tum	OK	1905	21-50	17	15.3	8	1-10
Seminole	TX	1936	21-50	19	14.7	42	21-50
Bay Marchand Blk 2	GF & LA	1949	21-50	20	14.2	21	21-50
Rangely	CO	1902	21-50	22	10.5	22	11-20
Coalinga	CA	1887	21-50	23	10.3	20	11-20
Lost Hills	CA	1910	21-50	24	10.2	142	51-100
Cymric	CA	1916	21-50	25	9.7	105	51-100
McElroy	TX	1926	21-50	26	9.6	33	21-50
Main Pass SA Blk 299	GF	1967	21-50	27	9.3	337	201-300
Vacuum	NM	1929	21-50	30	7.9	48	21-50
South Pass SA Blk 89	GF	1969	21-50	31	7.8	217	101-200
Salt Creek	TX	1942	21-50	34	7.2	82	51-100
Fullerton	TX	1942	21-50	36	7.0	66	51-100
Milne Point	AK	1982	21-50	37	6.8	696	201-300
Wattenberg	CO	1970	21-50	42	6.1	709	201-300
Greater Aneth	UT	1956	21-50	47	5.5	64	51-100
Ventura	CA	1916	21-50	49	5.3	17	11-20
Robertson North	TX	1956	21-50	52	5.2	282	101-200
Beta	PF	1976	21-50	70	3.8	432	201-300
Huntington Beach	CA	1920	21-50	71	3.8	12	11-20
Wasson 72	TX	1940	21-50	73	3.7	245	101-200
Dollarhide	TX & NM	1945	21-50	75	3.7	112	51-100
Elk Basin	WY & MT	1915	21-50	106	2.8	43	21-50
Eunice Monument	NM	1929	21-50	120	2.5	65	51-100
Cat Canyon	CA	1909	21-50	264	1.2	83	51-100
Arroyo Grande	CA	1906	21-50	461	0.6	> 1,000	401-500
Garden Banks Blk 426	GF	1987	21-50	-	0.0	-	201-300
Viosca Knoll Blk 990	GF	1981	21-50	-	0.0	-	201-300
Top 50 Volume Subtotal			**14,001.6**		**1,151.9**	**40,772.6**	**54,774.2**
Top 50 Percentage of U.S. Total			**58.0%**		**46.1%**	**24.3%**	**28.6%**

Table B1. Top 100 U.S. Fields Ranked by Oil[a] Production within Proved Reserves Group, 1993 (Continued) (Million Barrels of 42 U.S. Gallons)

Field Name	Location	Discovery Year	Proved Reserves 12/31/93 Rank Group	Annual Production Rank	Annual Production Volume	Cumulative Production Rank	Ultimate Recovery Rank Group
Green Canyon Blk 65	GF	1983	51-100	14	18.4	526	301-400
Pearsall	TX	1924	51-100	28	8.8	196	101-200
Eugene Island SA Blk 330	GF	1971	51-100	29	8.5	76	51-100
Mississippi Canyon Blk 109	GF	1984	51-100	35	7.0	> 1,000	701-800
McArthur River	AK	1965	51-100	38	6.6	39	21-50
West Delta Blk 73	GF	1962	51-100	39	6.6	126	101-200
Mississippi Canyon Blk 194	GF	1975	51-100	41	6.1	201	101-200
Green Canyon Blk 19	GF	1980	51-100	43	5.9	698	401-500
Oregon Basin	WY	1912	51-100	44	5.9	54	51-100
Panhandle	TX	1910	51-100	45	5.8	6	1-10
West Delta Blk 30	GF	1949	51-100	46	5.7	46	21-50
Means	TX	1934	51-100	48	5.4	111	101-200
Jay	FL & AL	1970	51-100	51	5.3	51	51-100
Howard-Glasscock	TX	1925	51-100	53	5.0	53	51-100
Hawkins	TX	1940	51-100	56	4.7	19	21-50
Hobbs	NM	1928	51-100	57	4.6	72	51-100
Prentice	TX	1950	51-100	58	4.5	157	101-200
Goldsmith	TX	1935	51-100	59	4.5	27	21-50
Stephens County Regular	TX	1915	51-100	62	4.3	99	51-100
Point Pedernales	PF	1983	51-100	64	4.2	689	401-500
Sooner Trend	OK	1938	51-100	65	4.1	80	51-100
Anschutz Ranch East	UT & WY	1980	51-100	66	4.1	253	201-300
Bluebell	UT	1949	51-100	69	3.8	221	101-200
Hatters Pond	AL	1974	51-100	88	3.4	506	301-400
Painter Reservoir East	WY	1979	51-100	93	3.2	684	401-500
Hartzog Draw	WY	1976	51-100	97	3.0	333	201-300
Salt Creek	WY	1889	51-100	100	2.9	30	21-50
Main Pass Blk 69	LA & GF	1948	51-100	101	2.9	101	101-200
Foster	TX	1932	51-100	109	2.7	91	51-100
Granite Point	AK	1965	51-100	116	2.5	228	101-200
Pennel	MT	1955	51-100	118	2.5	338	201-300
Welch	TX	1942	51-100	122	2.4	186	101-200
Kern Front	CA	1925	51-100	130	2.3	156	101-200
Mabee	TX	1944	51-100	134	2.2	291	201-300
Belridge North	CA	1912	51-100	140	2.2	294	201-300
Middle Ground Shoal	AK	1962	51-100	142	2.2	169	101-200
Sand Hills	TX	1930	51-100	143	2.2	104	101-200
Chunchula	AL	1974	51-100	144	2.2	496	301-400
Brea-Olinda	CA	1897	51-100	205	1.5	58	51-100
South Pass Blk 61	GF & LA	1955	51-100	224	1.4	134	101-200
T X L	TX	1944	51-100	241	1.3	94	51-100
Pegasus	TX	1949	51-100	246	1.3	190	101-200
Placerita	CA	1920	51-100	265	1.2	528	301-400
Shafter Lake	TX	1938	51-100	270	1.2	290	201-300
McKittrick	CA	1887	51-100	276	1.1	90	51-100
Sespe	CA	1869	51-100	348	0.8	613	401-500
Monument	NM	1935	51-100	>1,000	0.1	132	101-200
Niakuk	AK	1984	51-100	-	0.0	-	501-600
Ewing Bank Blk 873	GF	1991	51-100	-	0.0	-	501-600
Viosca Knoll Blk 825	GF	1988	51-100	-	0.0	-	901-1,000
Top 100 Volume Subtotal			**15,914.9**		**1,340.5**	**52,876.8**	**68,791.7**
Top 100 Percentage of U.S. Total			**65.9%**		**53.6%**	**31.5%**	**35.9%**

[a]Includes lease condensate.

– = Not Applicable.

Note: Fields are grouped in “proved reserves rank groups” and then listed within that group in descending order by National 1993 annual production rank. The U.S. total production estimate, 2,499.033 million barrels, used to calculate the percentages in this table, is from the official Energy Information Administration production data for crude oil and lease condensate for 1993 contained in the *Petroleum Supply Annual 1994*, DOE/EIA-0340(94), p. 6. They differ from the U.S. total data reported in this publication. Column totals may not add due to independent rounding.

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

Table B2. Top 100 U.S. Fields Ranked by Gas[a] Production within Proved Reserves Group, 1993
(Billion Cubic Feet)

Field Name	Location	Discovery Year	Proved Reserves 12/31/93 Rank Group	Annual Production Rank	Annual Production Volume	Cumulative Production Rank	Ultimate Recovery Rank Group
Basin	NM	1947	1-10	1	589.2	7	1-10
Hugoton Gas Area	KS & OK & TX	1922	1-10	2	526.3	1	1-10
Blanco	NM & CO	1927	1-10	3	372.8	4	1-10
Prudhoe Bay	AK	1967	1-10	5	205.2	53	1-10
Carthage	TX	1936	1-10	6	196.6	5	1-10
Panhandle West	TX	1918	1-10	7	157.5	2	1-10
Wattenberg	CO	1970	1-10	8	117.3	128	21-50
Panoma Gas Area	KS	1956	1-10	9	116.3	49	11-20
Red Oak-Norris	OK	1910	1-10	11	89.8	81	21-50
Mobile Bay	AL	1983	1-10	207	16.1	> 1,000	21-50
Top 10 Volume Subtotal			**42,168.1**		**2,387.0**	**91,513.8**	**133,681.9**
Top 10 Percentage of U.S. Total			**24.7%**		**12.3%**	**10.7%**	**13.0%**
Mocane-Laverne Gas Area	OK & KS & TX	1946	11-20	10	114.2	8	1-10
Whitney Canyon-Carter Crk	WY	1978	11-20	13	83.5	123	51-100
Gomez	TX	1963	11-20	16	77.6	11	1-10
Cook Inlet North	AK	1962	11-20	44	45.5	113	21-50
Elk Hills	CA	1919	11-20	61	36.4	100	51-100
Beluga River	AK	1962	11-20	78	31.7	315	51-100
Fogarty Creek	WY	1975	11-20	92	28.7	135	51-100
Madden	WY	1968	11-20	115	23.8	371	101-200
Lake Ridge	WY	1981	11-20	245	13.9	> 1,000	101-200
Oakwood	VA	1990	11-20	264	13.0	> 1,000	101-200
Top 20 Volume Subtotal			**51,319.8**		**2,855.4**	**107,179.4**	**158,499.3**
Top 20 Percentage of U.S. Total			**30.1%**		**14.7%**	**12.5%**	**15.5%**
Giddings	TX	1960	21-50	4	207.4	63	51-100
McAllen Ranch	TX	1960	21-50	12	85.4	94	51-100
Watonga-Chickasha Trend	OK	1948	21-50	14	80.6	13	11-20
Kinta	OK	1914	21-50	18	75.4	35	21-50
Lake Arthur South	LA	1955	21-50	20	72.0	214	101-200
Strong City District	OK	1966	21-50	21	69.7	271	101-200
Bruff	WY	1969	21-50	22	67.9	500	101-200
Matagorda Island Blk 623	GF	1980	21-50	23	66.8	385	101-200
Natural Buttes	UT	1940	21-50	24	66.1	325	101-200
Fairway	AL	1986	21-50	25	65.6	> 1,000	301-400
Spraberry Trend Area	TX	1950	21-50	26	64.6	66	51-100
Mobile Blk 823	GF & AL	1983	21-50	27	62.8	> 1,000	301-400
McArthur River	AK	1965	21-50	29	62.5	210	101-200
Golden Trend	OK	1945	21-50	32	59.7	10	11-20
Oak Hill	TX	1958	21-50	33	59.5	235	101-200
Ozona	TX	1953	21-50	38	49.7	169	101-200
Elk City	OK	1947	21-50	40	46.6	95	51-100
Sawyer	TX	1960	21-50	47	42.6	160	101-200
Big Sandy	KY	1881	21-50	49	41.7	68	51-100
Anschutz Ranch East	UT & WY	1980	21-50	51	40.5	> 1,000	101-200
Bob West	TX	1990	21-50	68	34.5	> 1,000	301-400
Lower Mobile Bay-Mary Ann	AL	1979	21-50	71	34.0	> 1,000	201-300
South Pass SA Blk 89	GF	1969	21-50	112	24.9	608	201-300
Tip Top	WY	1928	21-50	163	19.0	443	101-200
Wasson	TX	1937	21-50	167	18.7	92	51-100
Blanco South	NM	1951	21-50	210	16.0	111	51-100
Lisbon	UT	1960	21-50	297	11.9	288	101-200
Hondo	PF	1969	21-50	345	10.5	> 1,000	201-300
Garden Banks Blk 426	GF	1987	21-50	-	0.0	-	401-500
Green Canyon Blk 116	GF	1983	21-50	-	0.0	-	401-500
Top 50 Volume Subtotal			**67,122.8**		**4,411.8**	**134,801.9**	**201,924.7**
Top 50 Percentage of U.S. Total			**39.4%**		**22.7%**	**15.8%**	**19.7%**

Table B2. Top 100 U.S. Fields Ranked by Gas[a] Production within Proved Reserves Group, 1993 (Continued) (Billion Cubic Feet)

Field Name	Location	Discovery Year	Proved Reserves 12/31/93 Rank Group	Annual Production Rank	Annual Production Volume	Cumulative Production Rank	Ultimate Recovery Rank Group
Chalkley	LA	1938	51-100	15	78.4	257	101-200
Coyanosa	TX	1959	51-100	17	76.6	46	21-50
Wilburton	OK	1941	51-100	19	73.4	75	51-100
Headlee	TX	1953	51-100	30	61.7	52	51-100
South Timbalier Blk 172	GF	1965	51-100	31	60.8	71	51-100
Tiger Shoal	GF	1958	51-100	34	55.1	21	21-50
Sooner Trend	OK	1938	51-100	35	52.8	9	11-20
Boonsville	TX	1945	51-100	36	51.5	28	21-50
High Island SA Blk A573	GF	1973	51-100	37	50.7	280	201-300
Moorewood NE	OK	1979	51-100	39	48.8	343	201-300
Indian Basin	NM	1963	51-100	42	46.0	78	51-100
Vermilion Blk 14	GF & LA	1956	51-100	46	43.9	18	11-20
Brown-Bassett	TX	1953	51-100	50	41.5	56	51-100
Main Pass Blk 41	GF	1956	51-100	53	39.4	110	101-200
Eumont	NM	1929	51-100	54	39.2	47	21-50
Willow Springs	TX	1938	51-100	56	37.9	158	101-200
Puckett	TX	1952	51-100	58	37.3	14	11-20
Waskom	TX & LA	1916	51-100	64	35.2	64	51-100
Mississippi Canyon Blk 397	GF	1984	51-100	70	34.0	> 1,000	601-700
Sho-Vel-Tum	OK	1905	51-100	73	33.1	27	21-50
Garden Banks Blk 236	GF	1977	51-100	74	32.6	907	401-500
Sugg Ranch	TX	1985	51-100	81	30.2	> 1,000	501-600
Reydon	OK	1962	51-100	87	29.1	203	101-200
Painter Reservoir East	WY	1979	51-100	88	28.9	846	301-400
Panhandle	TX	1910	51-100	94	28.3	51	51-100
Eugene Island SA Blk 330	GF	1971	51-100	95	28.1	72	51-100
Carpenter	OK	1951	51-100	96	28.0	378	201-300
Kuparuk River	AK	1969	51-100	104	26.3	567	201-300
Sand Hills	TX	1930	51-100	106	25.8	57	51-100
Mississippi Canyon Blk 194	GF	1975	51-100	108	25.5	444	201-300
Cecil	AR	1950	51-100	111	25.2	260	201-300
Cedar Cove Coal Degas	AL	1983	51-100	123	22.6	> 1,000	301-400
Church Buttes	WY	1946	51-100	135	21.0	264	201-300
Opelika	TX	1937	51-100	143	20.3	96	51-100
Endicott	AK	1978	51-100	149	20.0	> 1,000	601-700
Big Piney	WY	1964	51-100	158	19.3	660	301-400
Nora	VA	1949	51-100	185	17.7	> 1,000	401-500
Sonora	TX	1954	51-100	247	13.9	619	301-400
Keystone	TX	1935	51-100	254	13.4	166	101-200
Beaver Lodge	ND	1951	51-100	293	12.0	401	201-300
Hogsback	WY	1955	51-100	340	10.6	426	201-300
Hay Reservoir	WY	1976	51-100	347	10.4	> 1,000	501-600
Robinsons Bend Coal Degas	AL	1985	51-100	372	9.8	> 1,000	501-600
Pegasus	TX	1949	51-100	467	8.2	391	201-300
Hawkins	TX	1940	51-100	519	7.4	261	201-300
Whelan	TX	1937	51-100	606	6.5	486	301-400
Anahuac	TX	1935	51-100	732	5.3	197	101-200
Mississippi Canyon Blk 354	GF	1977	51-100	823	4.7	> 1,000	701-800
Swanson River	AK	1957	51-100	830	4.6	> 1,000	501-600
Mississippi Canyon Blk 807	GF	1989	51-100	-	0.0	-	701-800
Top 100 Volume Subtotal			**80,769.9**		**5944.7**	**186,813.4**	**267,583.4**
Top 100 Percentage of U.S. Total			**47.4%**		**30.6%**	**21.8%**	**26.1%**

[a]Wet after lease separation.

– = Not Applicable.

Note: Fields are grouped in “proved reserves rank groups” and then listed within that group in descending order by National 1993 annual production rank. The U.S. total production estimate, 19,422.097 billion cubic feet, used to calculate the percentages in this table, is from the official Energy Information Administration production data for natural gas for 1993 contained in the *Natural Gas Annual 1993*, DOE/EIA-0131 (93). They differ from the U.S. total data reported in this publication.Column totals may not add due to independent rounding.

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

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."{54}

Table C1 is in keeping with the spirit of this law. The petroleum industry in the United States is slowly moving in the direction prescribed by this law and the data collected by EIA are collected in the units that are still common to the U.S. petroleum industry, namely barrels and cubic feet. Standard metric conversion factors were used to convert the National level volumes in **Table 1** to the metric equivalents in **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. U.S. Proved Reserves of Crude Oil, Dry Natural Gas, and Natural Gas Liquids, in Metric Units, 1984 - 1994

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 cubic meters)						
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	46.2	286.8	170.0	163.0	62.2	1.3	13.5	77.0	388.9	3,775.2	-148.9
1993	43.1	319.7	241.0	121.8	56.6	50.7	17.5	124.8	371.9	3,649.9	-125.3
1994	30.1	375.8	215.7	190.2	63.1	10.2	17.6	90.9	360.6	3,570.4	-79.5
					Dry Natural Gas (billion cubic meters)						
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	[d]1,088.13	-364.36	192.64	46.38	54.06	293.08	472.04	[d]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
1993	27.51	498.29	346.82	178.98	172.82	25.46	52.84	251.12	503.73	4,599.08	-73.63
1994	55.08	604.99	449.70	210.37	196.55	53.63	98.54	348.72	518.82	4,639.35	40.27
					Natural Gas Liquids (million cubic meters)						
1984	-19.6	137.7	115.1	3.0	55.3	8.7	15.3	79.3	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	35.7	128.1	86.6	77.2	30.2	3.2	10.2	43.6	122.9	1,184.6	-2.1
1993	16.2	121.5	101.8	35.9	39.0	3.8	10.2	53.0	125.3	1,148.2	-36.4
1994	6.9	138.8	107.5	38.2	49.9	8.6	20.8	79.3	125.8	1,139.9	-8.3

[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 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.” The following conversion factors were used to convert data in Columns 2, 3, 5, 6, 7, 9, and 10: barrels = 0.1589873 per cublic meter, cubic feet = 0.02831685 per cublc meter. Number of decimal digits varies in order to accurately reproduce corresponding equivalents shown on Table 1 in Chapter 2.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1984-1993 annual reports, DOE/EIA-0216.{1-10}

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 1993 of the EIA publication *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE EIA-0216.{1-17}

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
1993	41	0	[c]5,140	158
1994	44	0	[c]4,830	142

[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; 3,364 Bcf in 1993; 3,297 Bcf in 1994.

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
1993	5,775	1,161	9,907	321
1994	5,767	1,022	9,733	301

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

Arkansas

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	65	0	1,552	4
1994	51	0	1,607	6

California - Coastal Region Onshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	528	313	189	12
1994	480	238	194	11

California - Total

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	5,005	1,047	4,737	NA
1978	4,974	968	4,947	NA
1979	5,265	960	5,022	111
1980	5,470	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
1993	[d]3,764	[d]965	[d]2,682	[d]104
1994	[d]3,573	[d]835	[d]2,402	[d]92

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

California - Los Angeles Basin Onshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	238	4	102	6
1994	221	4	103	5

California - San Joaquin Basin Onshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	2,772	648	2,327	85
1994	2,647	593	2,044	75

California - State Offshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	226	0	64	1
1994	225	0	61	1

California-State and Federal Offshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	899	0	1,163	26
1994	878	0	1,231	22

California - Federal Offshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	673	0	1,099	25
1994	653	0	1,170	21

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
1993	284	22	6,722	214
1994	271	22	6,753	248

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
1993	116	0	NA	NA
1994	117	0	NA	NA

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	40	0	50	9
1994	71	0	98	18

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	15	0	NA	NA
1994	15	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
1993	271	0	9,348	380
1994	260	0	9,156	398

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	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
1993	[f]639	[f]338	[f]9,174	[f]421
1994	[f]649	[f]340	[f]9,748	[f]434

[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
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
1993	26	0	1,003	26
1994	26	0	969	39

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
1993	108	0	2,325	57
1994	108	0	2,537	69

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
1993	382	329	5,932	334
1994	391	331	6,251	337

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
1993	90	0	1,160	57
1994	91	1	1,323	54

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
1993	[f]149	[f]9	[f]917	[f]30
1994	[f]150	[f]9	[f]960	[f]28

[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
1993	133	44	797	11
1994	151	40	650	9

Montana

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	171	0	673	8
1994	175	0	717	8

New Mexico - Total

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	707	211	18,619	996
1994	718	215	17,228	1,011

Nebraska

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	20	0	NA	NA
1994	22	0	NA	NA

New Mexico - East

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	688	211	3,034	233
1994	702	215	3,021	234

New Mexico - West

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	19	0	15,585	763
1994	16	0	14,207	777

North Dakota

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	226	7	525	55
1994	226	2	507	55

New York

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	NA	NA	*264	NA
1994	NA	NA	242	NA

Ohio

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1993	54	0	1,104	NA
1994	58	0	1,094	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
1993	680	40	13,289	643
1994	689	47	13,487	652

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
1993	14	0	1,717	NA
1994	15	0	1,800	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
1993	[g]6,171	[g]581	[g]34,718	[g]2,469
1994	[g]5,847	[g]491	[g]35,974	[g]2,414

[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
1993	133	0	698	26
1994	100	1	703	26

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 2 Onshore				
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
1993	77	0	1,321	86
1994	74	0	1,360	86

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 3 Onshore				
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
1993	327	31	2,972	253
1994	330	61	3,366	254

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 4 Onshore				
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	98	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
1993	59	<1	7,038	278
1994	41	<1	7,547	290

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 5				
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
1993	52	0	1,867	64
1994	49	0	2,011	59

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
1993	406	<1	5,508	248
1994	424	<1	5,381	265

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	255	33	3,239	289
1993	199	15	3,215	273
1994	221	14	3,316	265

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
1993	*171	7	477	79
1994	145	5	425	62

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
1993	2,057	262	5,516	439
1994	2,002	256	5,442	414

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
1993	2,435	264	1,043	298
1994	2,223	154	1,219	267

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
1993	83	<1	4,040	329
1994	75	<1	4,246	326

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
1993	168	2	688	92
1994	159	<1	728	98

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
1993	196	0	6,996	119
1994	209	10	6,613	105

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
1993	4	0	335	4
1994	4	0	230	2
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)
1993	228	54	2,040	(h)
1994	231	70	1,789	(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
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
1993	NA	NA	1,322	NA
1994	NA	NA	1,833	NA
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
1993	24	0	2,439	108
1994	25	0	2,565	93

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
1993	624	12	10,933	[i]600
1994	565	13	10,879	[i]564

[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
1993	34	0	94	8
1994	20	0	65	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
1993	2,745	18	27,143	630
1994	2,780	53	28,388	624

[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
1993	1,880	18	[k]19,383	[k]490
1994	1,922	43	[k]20,835	[k]500

[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
1993	673	0	1,099	25
1994	653	0	1,170	21

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
1993	192	0	6,661	115
1994	205	10	6,383	103

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
1993	17,182	2,292	152,508	6,901
1994	16,690	2,129	154,104	6,869

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
1993	22,957	3,453	162,415	7,222
1994	22,457	3,151	163,837	7,170

Table D1. U.S. Proved Reserves of Crude Oil, 1976 – 1994
(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)
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
1993	271	2,011	1,516	766	356	319	110	785	2,339	22,957	-788
1994	189	2,364	1,357	1,196	397	64	111	572	2,268	22,457	-500

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.

[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]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 contained in the *Petroleum Supply Annual*, DOE/EIA-0340.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1977 through 1993 annual reports, DOE/EIA-0216.{1-17}

Table D2. U.S. Lower 48 Proved Reserves of Crude Oil, 1976 – 1994
(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)
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	361	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
1993	250	1,712	1,514	448	343	319	109	771	1,760	17,182	-541
1994	187	1,873	1,346	714	316	64	111	491	1,697	16,690	-492

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.

[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]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 contained in the *Petroleum Supply Annual*, DOE/EIA-0340.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1977 through 1993 annual reports, DOE/EIA-0216.{1-17}

Table D3. U.S. Proved Reserves of Dry Natural Gas, 1976 – 1994
(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)
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
1993	972	17,597	12,248	6,321	6,103	899	1,866	8,868	17,789	162,415	-2,600
1994	1,945	21,365	15,881	7,429	6,941	1,894	3,480	12,315	18,322	163,837	+1,422

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.

[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]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 natural gas contained in the *Natural Gas Annual,* DOE/EIA-0131.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1977 through 1993 annual reports, DOE/EIA-0216.{1-17}

Table D4. U.S. Lower 48 Proved Reserves of Dry Natural Gas, 1976 – 1994
(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)
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
1993	915	16,918	12,139	5,694	6,076	899	1,858	8,833	17,396	152,508	-2,869
1994	1,896	21,121	15,832	7,185	6,936	1,894	3,480	12,310	17,899	154,104	+1596

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.

[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]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 natural gas contained in the *Natural Gas Annual,* DOE/EIA-0131.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1977 through 1993 annual reports, DOE/EIA-0216.{1-17}

Table D5. U.S. Proved Reserves of Wet Natural Gas, After Lease Separation, 1978 – 1994
(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)
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
1993	1,048	18,394	12,853	6,589	6,376	927	1,930	9,233	18,641	170,490	-2,819
1994	1,977	22,345	16,509	7,813	7,299	1,941	3,606	12,846	19,210	171,939	+1,449

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.

[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]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”. They may differ from the official Energy Information Administration production data for natural gas contained in the *Natural Gas Annual,* DOE/EIA-013.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1979 through 1993 annual reports, DOE/EIA-0216.{3-17}

Table D6. U.S. Lower 48 Proved Reserves of Wet Natural Gas, After Lease Separation, 1978 – 1994
(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)
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
1993	996	17,714	12,743	5,967	6,349	927	1,922	9,198	18,245	160,504	-3,080
1994	1,924	22,071	16,458	7,537	7,294	1,941	3,606	12,841	18,756	162,126	+1,622

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.

[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]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”. They may differ from the official Energy Information Administration production data for natural gas contained in the *Natural Gas Annual,* DOE/EIA-0131.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1979 through 1993 annual reports, DOE/EIA-0216.{3-17}

Table D7. U.S. Proved Reserves of Natural Gas Liquids, 1978 – 1994
(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)
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
1993	102	764	640	226	245	24	64	333	788	7,222	-229
1994	43	873	676	240	314	54	131	499	791	7,170	-52

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.

[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]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 natural gas liquids contained in the *Natural Gas Annual,* DOE/EIA-0131.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1979 through 1993 annual reports, DOE/EIA-0216.{3-17}

Table D8. U.S. Lower 48 Proved Reserves of Natural Gas Liquids, 1978 – 1994
(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)
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
1993	101	755	631	225	245	24	64	333	761	6,901	-203
1994	38	872	676	234	314	54	131	499	765	6,869	-32

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.

[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]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 natural gas liquids contained in the *Natural Gas Annual,* DOE/EIA-0131.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1979 through 1993 annual reports, DOE/EIA-0216.{3-17}

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.

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.

Category III operators were further subdivided into operators sampled with certainty (certainties) and operators that were randomly sampled (noncertainty).

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

  - 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.

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

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

  - 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 1994 by crude oil or natural gas well operators who were active as of December 31, 1994. 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 1987 and 1994, and depicts the number of active operators, 1989 showing the largest in the series. The 1994 sampling frame of 4,074 operators consisted of 161 Category I, 482 Category II, 1,694 Category III certainties, and 20,517 operators in the noncertainty stratum for a total of 22,854 active operators. The survey sample consisted of 2,337 operators selected with certainty that included all of the Category I and II certainty operators, the 1,694 smaller operators that were selected with certainty because of their size in relation to the area or areas in which they operated, and 1,737 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 1994 survey is summarized in **Table E2**. EIA makes a considerable effort to gain responses from all operators. About 7

Table E1. Comparison of the EIA-23 Sample and Sampling Frame, 1987 through 1994

Operator Category	1987	1988	1989	1990	1991	1992	1993	1994
	Number of Operators							
Certainty								
Category I	152	149	134	144	144	157	160	161
Category II	541	500	500	468	484	480	500	482
Category III	3,116	3,289	2,936	2,316	2,074	1,896	1,723	1,694
Total in Frame	3,809	3,938	3,570	2,929	2,702	2,533	2,383	2,337
Sampled	3,809	3,938	3,570	2,929	2,702	2,533	2,383	2,337
Percent Sampled	100	100	100	100	100	100	100	100
Noncertainty								
Total in Frame	23,570	22,797	24,062	24,628	21,972	21,573	21,193	20,517
Sampled	1,265	1,282	1,325	1,431	1,760	1,724	1,691	1,737
Percent Sampled	6	5	6	6	8	8	8	8
Total								
Active Operators	27,379	26,735	27,632	27,556	24,674	24,106	23,576	22,854
Not Sampled	22,305	21,515	22,737	23,196	20,212	19,849	19,502	18,780
Sampled	5,074	5,220	4,895	4,360	4,462	4,257	4,074	4,074
Percent Sampled	19	20	18	16	18	18	17	18

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

Table E2. Form EIA-23 Survey Response Statistics, 1994

Operator Category	Sample Selected	Successor[a] Operators	Net[b] Category Changes	Non-[c] operators	Total Operators	Responding Operators Number	Responding Operators Percent	Nonresponding Operators Number	Nonresponding Operators Percent
Certainty									
Category I	161	0	1	-7	155	155	100.0	0	0.0
Category II	482	1	1	-13	471	471	100.0	0	0.0
Category III	1,694	21	-2	-57	1,656	1,656	100.0	0	0.0
Subtotal	2,337	22	0	-77	2,282	2,282	100.0	0	0.0
Noncertainty	1,737	7	0	-191	1,553	1,546	99.5	7	0.5
Total	4,074	29	0	-268	3,835	3,828	99.8	7	0.2

[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" 1994.

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 268 nonoperators, 29 had successor operators that had taken over the production of the nonoperator. These successor operators were subsequently sampled. The overall response rate for the 1994 survey was 99.8 percent. This compares with a 99.6 percent overall response rate for all operators in 1993. The response rates for Certainty operators in 1994 was 100 percent.

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 (**Figure I1**, Appendix I). 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 (**Figures I2 and I3**, Appendix I). 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 (**Figure I4**, Appendix I). 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(**Figure I5**, Appendix I).

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 1994,* in January of 1995, was the 13th annual report and reflected data collected through October 1994. 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 1994, Form EIA-23 national estimates of production were 2,425 million barrels for crude oil and lease condensate or 6 million barrels (0.2 percent) lower than that reported in the *Petroleum Supply Annual 1994* for crude oil and lease condensate. Form EIA-23 national estimates of production for dry natural gas were 18,322 billion cubic feet or 523 billion cubic feet (2.8 percent) lower than the *Natural Gas Monthly July 1995* for 1994 dry natural gas production.

Form EIA-23 Frame Maintenance

Operator frame maintenance is a major data quality control effort. 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 E3** provides a summary of changes made to the Form EIA-23 frame of crude oil and natural gas well operators for the 1994 survey mailing. These changes resulted from all frame maintenance activities.

The Form EIA-23 operator frame contained a total of 60,892 entries as of December 14, 1994. Of these, 24,139 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 1994 Operator Frame Activity, Form EIA-23

Total 1993 Operator Frame	60,892
Changes to 1993 Operator Status	
From Operator to Nonoperator	1,846
From Nonoperator to Operator	441
Subtotal	2,287
No Changes to 1993 Operator Status	
Operators	21,712
Nonoperators	36,893
Subtotal	58,605
Additions to Operator Frame	
Operator	1,986
Nonoperator	29
Subtotal	2,015
Total 1994 Operator Frame	**62,907**

Note: Includes operator frame activity through December 14, 1994.
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 the wellhead or 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 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.

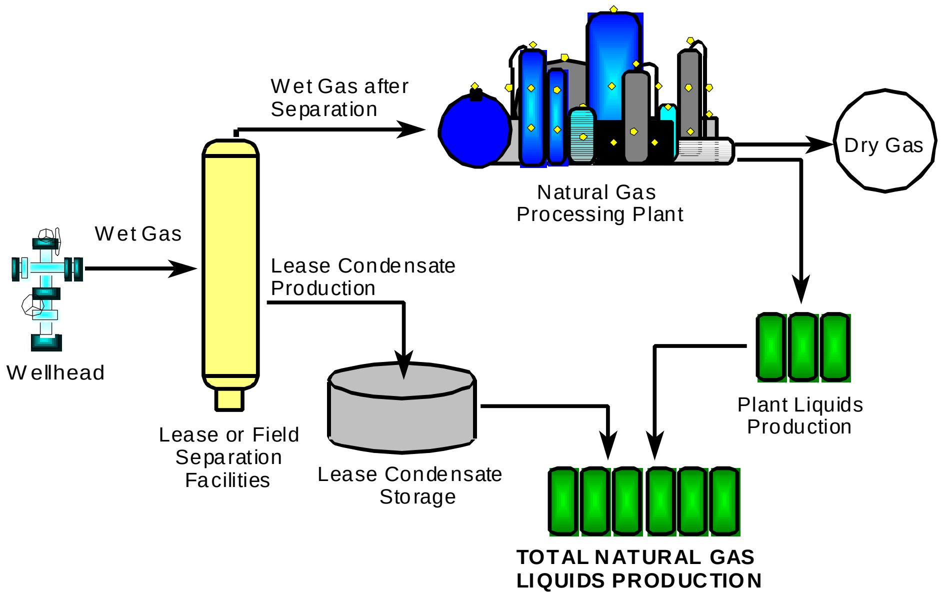
The EIA recognized that its estimates of proved reserves of natural gas liquids (NGL) had to reflect not only those volumes extractable in the future under current economic and operating conditions at the lease or field (lease condensate), but also volumes (plant liquids) extractable downstream at existing 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 F.

Form EIA-64A Response Statistics

EIA mailed EIA-64A forms to all known natural gas processing plant operators as of December 31, 1994. In addition, plant operators whose plants were shut down or dismantled during 1994 were required to complete forms for the portion of 1994 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 307 operators of 791 plants were sent forms. This number included 7 new plants and 29 successor plants identified after the initial 1994 survey mailing. A total of 47 plants were reported as nonoperating according to

Figure E1. Natural Gas Liquids Extraction Flows



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

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 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 I6**, Appendix I. 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 1994, the Form EIA-64A national estimates were 0.9 percent (6

Table E4. Natural Gas Processed and Liquids Extracted at Natural Gas Processing Plants, 1994

Plant Location	Volume of Natural Gas Delivered to Processing Plants: State Production	Out of State Production	Natural Gas Processed	Total Liquids Extracted
	(million cubic feet)			(thousand barrels)
Alaska	2,667,254	0	2,667,254	26,071
Lower 48 States	**13,397,313**	**394,949**	**13,792,262**	**609,912**
Alabama	134,635	1,560	136,195	4,167
Arkansas	216,024	2,686	218,710	458
California	228,346	0	228,346	9,425
Colorado	353,547	308	353,855	14,546
Florida	7,311	2,954	10,265	1,768
Kansas	819,544	146,130	965,674	33,762
Kentucky	41,637	1,240	42,877	1,453
Louisiana	4,071,043	129,083	4,200,126	91,569
Michigan	196,000	0	196,000	4,900
Mississippi	5,052	0	5,052	337
Montana	10,388	30	10,418	474
New Mexico	799,285	1,551	800,836	60,740
North Dakota	55,150	0	55,150	4,278
Oklahoma	1,072,307	20,427	1,092,734	71,936
Texas	4,123,600	36,951	4,160,551	267,602
Utah	349,631	18,954	368,585	9,763
West Virginia	84,801	29,064	113,865	7,369
Wyoming	820,504	1,185	821,689	24,818
Miscellaneous[a]	8,508	2,826	11,334	547
Total	**16,064,567**	**394,949**	**16,459,516**	**635,983**

[a]Includes Illinois, Nebraska, Ohio, Pennsylvania, and Tennessee.
Source: Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production," 1994.

million barrels) higher than the *Petroleum Supply Annual 1994* volume for natural gas plant liquids production.

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 1994 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, 1994.

Table E5. Summary of the 1994 Plant Frame Activity, Form EIA-64A

Frame as of 1993 survey mailing	855
Additions	125
Deletions	–191
Frame as of 1994 survey mailing	789

Note: Includes operator frame activity through December 31,1994.
Source: Energy Information Administration, Office of Oil and Gas.

Appendix F

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 1994 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 1993 (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 1993 (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 1993 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 F1**. 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 1993.
- **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 1993.
- **Category III -** *Small Operators:* Operators who produced less than the Category II operators in 1993, 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

Table F1. 1994 EIA-23 Survey Initial Sample Criteria

State and Subdivision	Production Cutoffs: Crude Oil (mbbls)	Production Cutoffs: Gas (mmcf)	Number of Certainty Operators	Noncertainty Sample: Number of Single State Operators	Noncertainty Sample: Number of Multi-State Operators
Alabama Onshore	200	1,000	62	2	0
Alaska	0	0	9	0	0
Arkansas	43	1,000	133	20	9
CaliforniaUnspecified	7	2	8	4	0
California Coastal Region Onshore	200	1,000	34	7	0
California Los Angeles Basin Onshore	188	21	47	12	0
California San Joaquin Basin Onshore	200	379	76	27	0
Colorado	131	1,000	167	23	14
Florida Onshore	0	0	11	0	0
Illinois	39	14	134	32	4
Indiana	8	6	162	7	1
Kansas	84	937	280	181	16
Kentucky	9	295	96	18	2
Louisiana Unspecified	2	14	3	6	0
Louisiana North	14	837	246	50	15
Louisiana South Onshore	82	1,000	264	22	5
Michigan	49	1,000	76	10	1
Mississippi Onshore	105	1,000	141	9	4
Montana	108	1,000	102	11	4
Nebraska	23	1,000	74	7	2
New Mexico Unspecified	2	7	3	2	0
New Mexico East	200	1,000	201	16	8
New Mexico West	26	1,000	83	6	2
New York	7	102	53	54	1
North Dakota	200	1,000	112	5	5
Ohio	15	231	161	196	5
Oklahoma	104	1,000	440	261	43
Pennsylvania	5	616	100	25	2
Texas Unspecified	49	231	9	61	0
Texas RRC District 1	34	1,000	229	59	26
Texas RRC District 10	199	1,000	214	36	11
Texas RRC District 2 Onshore	200	1,000	203	9	18
Texas RRC District 3 Onshore	200	1,000	299	36	27
Texas RRC District 4 Onshore	82	1,000	219	17	17
Texas RRC District 5	84	459	118	12	9
Texas RRC District 6	200	1,000	230	21	19
Texas RRC District 7B	37	115	321	76	51
Texas RRC District 7C	200	1,000	239	23	28
Texas RRC District 8	200	1,000	280	34	35
Texas RRC District 8A	200	1,000	244	14	21
Texas RRC District 9	50	1,000	254	82	32
Utah	200	1,000	73	6	2
Virginia	0	0	27	0	0
West Virginia	8	249	159	33	2
Wyoming	200	1,000	189	14	9
Offshore Areas	0	0	296	0	0
Other States[a]	102	124	49	11	2
Total	**—**	**—**	**[b]2,244**	**1,557**	**[b]190**

[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]Nonduplicative 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.

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 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 because 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 volume 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 volume estimates are published, the State total is the sum of the individual volume estimates for the subdivisions. The U.S. total is the sum of the State estimates. A sampling variance is calculated for each State subdivision, State, and for the U.S. total.

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 reporting production in the State/subdivision.

In many State/subdivisions, the accuracy of the oil and gas estimates was improved by using a difference estimator for many of the noncertainty operator reports. This difference estimator took advantage of the stability of production reports from year-to-year in those State/subdivisions. The difference estimator was only applied to operators who had known production greater than one in the previous year. For those State/subdivisions and operators the above formula was modified with V_{srm} replaced by V'_{srm}:

$$V'_{srm} = V_{srm} + k\ (\overline{X}_{sr} - X_{srm})$$

where

k = 1 when estimating production volumes

k = regional R/P ratio (**Table F6**) when estimating reserve volumes

$\overline{X}_{sr}$ = average production volume reported in the State/subdivision for the preceding year by all noncertainty operators who reported greater than 1 in that preceding year

X_{srm} = production volume reported 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.

Imputation for Operator Nonresponse

The response rate for Certainty operators for the 1994 survey was 100 percent. The nonresponse rate among noncertainty operators has been relatively low in past surveys and was 0.5 percent in 1994. Due to the 100 percent response rate of Certainly operators, imputing for the nonresponding Certainty operators was not necessary. No imputation is done for nonresponding noncertainty operators.

Estimation and Imputation for Reserves 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 1994 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 in **Table F2** shows that those responding operators accounted for 97.0 percent of the published production for natural gas shown in **Table 9** and 93.1 percent of the reserves. Data shown in **Table F3** indicate that those responding operators accounted for 93.6 percent of the nonassociated natural gas production and 91.6 percent of the reserves published in **Table 10**. The reported data shown in **Table F4** indicate that those responding operators accounted for 95.2 percent of published crude oil production and 94.0 percent of the reserves shown in **Table 6**. Additionally, **Table F5** indicates that those responding operators accounted for 98.9 percent of the published production and 96.3 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 previously described in the section "Total U.S. Reserves Estimates" in this appendix.

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 (**Table F6**) 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 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 F1**). These units generally follow the boundaries of geologic provinces wherein the stage of resource development tends to be somewhat similar. **Table F6** 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:

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

Table F2. Summary of Reported Total Natural Gas, Wet After Lease Separation, Used in Estimation Process, Form EIA-23
(Million Cubic Feet at 14.73 psia and 60° Fahrenheit)

Level of Reporting	Operator Category I	II	Certainty III	Non-certainty[a] III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/93	144,408,098	12,441,114	818,348	–	157,667,560
(+) Revision Increases	18,399,783	2,074,030	120,716	–	20,594,529
(–) Revision Decreases	14,328,938	1,012,663	25,914	–	15,367,515
(+) Extensions	6,115,994	553,720	23,374	–	6,693,088
(+) New Field Discoveries	1,683,406	206,905	5,985	–	1,896,296
(+) New Reservoirs in Old Fields	3,060,952	300,518	7,302	–	3,368,772
(–) Production in 1994	15,653,782	1,550,289	98,785	–	17,302,856
Proved Reserves as of 12/31/94	143,685,521	13,013,325	851,029	–	157,549,875
State Level Summary Report					
Production in 1994	0	33,935	211,673	12,434	258,042
Proved Reserves as of 12/31/94	0	388,348	61,246	136,482	2,586,076
Production Without Proved Reserves in 1994	**2,610**	**636,833**	**398,012**	**38,085**	**1,075,540**
Total Production in 1994	**15,656,392**	**2,221,057**	**708,470**	**50,519**	**18,636,438**
Total Proved Reserves as of 12/31/94	**143,685,521**	**13,401,673**	**2,912,275**	**136,482**	**160,135,951**

[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," 1994.

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

Level of Reporting	Operator Category I	II	Certainty III	Non-certainty[a] III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/93	118,810,369	10,611,595	657,930	–	130,079,894
(+) Revision Increases	14,575,126	1,755,228	108,273	–	16,438,627
(–) Revision Decreases	11,816,769	809,214	21,508	–	12,647,491
(+) Extensions	5,434,438	475,866	5,487	–	5,915,791
(+) New Field Discoveries	1,172,947	190,090	5,982	–	1,369,019
(+) New Reservoirs in Old Fields	2,878,190	287,957	6,660	–	3,172,807
(–) Production in 1994	13,320,228	1,325,247	79,849	–	14,725,324
Proved Reserves as of 12/31/94	117,734,080	11,186,270	682,975	–	129,603,325
State Level Summary Report					
Production in 1994	NA	NA	NA	NA	NA
Proved Reserves as of 12/31/94	NA	NA	NA	NA	NA
Production Without Proved Reserves in 1994	**1,881**	**504,997**	**31,883**	**NA**	**538,761**
Total Production in 1994	**13,322,109**	**1,830,244**	**111,732**	**NA**	**15,264,085**
Total Proved Reserves as of 12/31/94	**117,734,080**	**11,186,270**	**682,975**	**NA**	**129,603,325**

[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," 1994.

Table F4. 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	II	Certainty III	Non-certainty[a] III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/93	20,153,049	860,964	95,979	–	21,109,992
(+) Revision Increases	2,044,916	138,286	10,496	–	2,193,698
(–) Revision Decreases	1,154,720	72,168	1,936	–	1,228,824
(+) Extensions	336,413	18,523	2,981	–	357,917
(+) New Field Discoveries	48,639	15,633	114	–	64,386
(+) New Reservoirs in Old Fields	97,485	8,329	479	–	106,293
(–) Production in 1994	1,879,196	107,184	10,361	–	1,996,741
Proved Reserves as of 12/31/94	19,646,596	862,388	97,752	–	20,606,736
State Level Summary Report					
Production in 1994	0	4,599	36,468	1,916	42,983
Proved Reserves as of 12/31/94	0	34,129	384,487	81,459	500,075
Production Without Proved Reserves in 1994	**140**	**37,920**	**74,511**	**7,756**	**120,327**
Total Production in 1994	**1,879,336**	**149,703**	**121,340**	**9,672**	**2,160,051**
Total Proved Reserves as of 12/31/94	**19,646,596**	**896,517**	**482,239**	**81,459**	**21,106,811**

[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," 1994.

Table F5. Summary of Reported Lease Condensate Used in Estimation Process, Form EIA-23
(Thousand Barrels of 42 U.S. Gallons)

Level of Reporting	Operator Category I	II	Certainty III	Non-certainty[a] III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/93	1,044,547	80,009	3,792	–	1,128,348
(+) Revision Increases	154,683	18,117	848	–	173,648
(–) Revision Decreases	203,993	13,279	389	–	217,661
(+) Extensions	53,216	2,643	0	–	55,859
(+) New Field Discoveries	16,773	2,993	1,522	–	21,288
(+) New Reservoirs in Old Fields	39,113	2,607	84	–	41,804
(–) Production in 1994	130,735	11,570	571	–	142,876
Proved Reserves as of 12/31/94	973,629	81,518	5,287	–	1,060,434
State Level Summary Report					
Production in 1994	0	254	817	27	1,098
Proved Reserves as of 12/31/94	0	4,462	28,332	10,833	43,627
Production Without Proved Reserves in 1994	**38**	**9,163**	**1,987**	**144**	**11,332**
Total Production in 1994	**130,773**	**20,987**	**3,375**	**171**	**155,306**
Total Proved Reserves as of 12/31/94	**973,629**	**85,980**	**33,619**	**10,833**	**1,104,061**

[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," 1994.

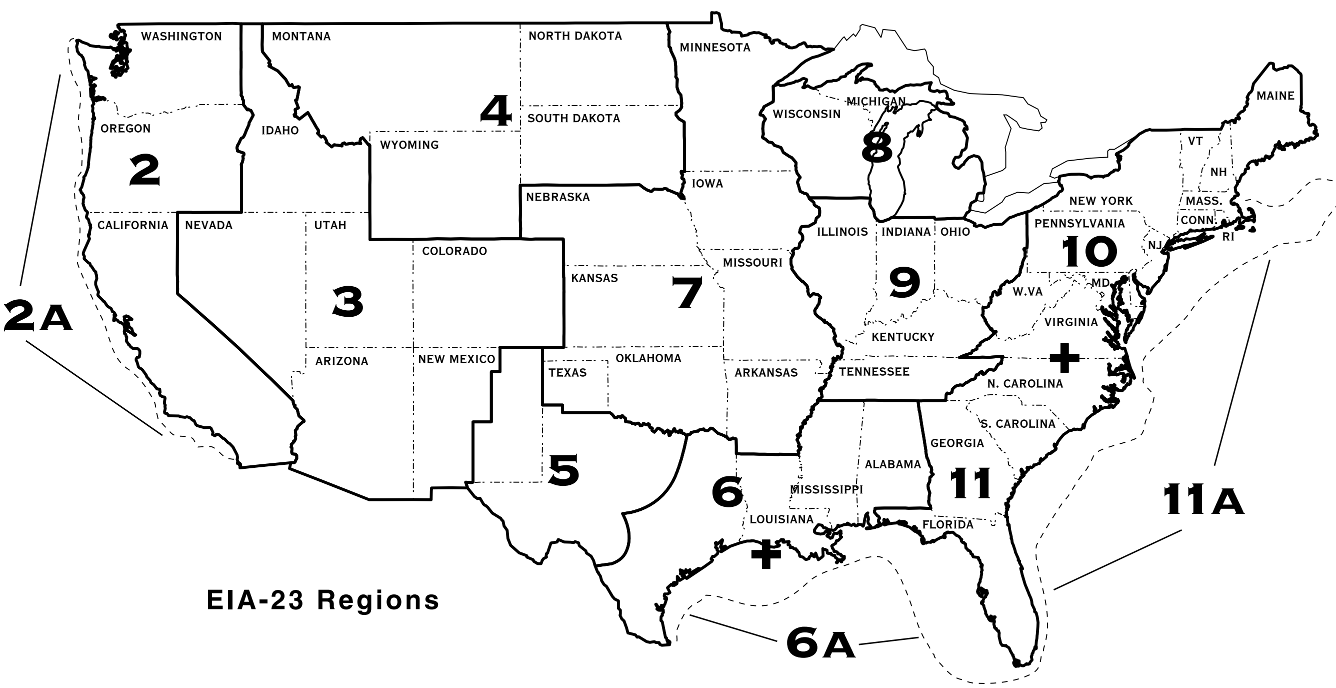
Table F6. Statistical Parameters of Reserve Estimation Equation by Region for 1994

Region Number	Region	Number of Nonzero R/P Pairs			Characteristic Multipliers		
		Oil	Gas	Lease Condensate	Oil	Gas	Lease Condensate
2	Pacific Coast States	31	31	6	[a]6.9	[a]7.2	[a]6.0
3	Western Rocky Mountains	67	71	25	6.3	11.0	[a]6.0
4	Northern Rocky Mountains	83	62	17	7.4	7.7	[a]6.0
5	West Texas and East New Mexico	205	208	49	6.8	6.8	6.4
6 + 6A	Western Gulf Basin and Gulf of Mexico . .	249	274	172	6.3	6.7	5.7
7	Mid-Continent	237	231	94	6.0	6.4	6.3
8 + 9	Michigan Basin and Eastern Interior . . .	80	64	10	7.1	8.5	[a]6.0
10 + 11	Appalachians	34	54	0	[a]6.9	11.6	[a]6.0
	United States	986	995	373	6.9	7.2	6.0

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

Source: Based on data filed on Form EIA-23,"Annual Survey of Domestic Oil and Gas Reserves, 1994".

Figure F1. Form EIA-23 Regional Boundaries



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

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 8 percent of the random stratum operators sampled in 1993 were sampled again in 1994, 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 fewer certainty operators were included in 1994 than in 1993.
- 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 1993 or 1994, but not both, and the error was not detected by edit processing.
- Operation of properties was transferred during 1994 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 1994 to an operator with a different evaluation of the proved reserves associated with the properties than that of the 1993 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 F7, F8, F9, and F10** 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 $\hat{V}_s$ 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 two 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 two types of operator, and $Var(\hat{V}_{srj})$ 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:

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

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 and Type 2 components where the classification of operators by type is with regard to the State as a whole; e.g., Type 2 operators at the State level are those that were not shown in the sample frame as having production anywhere in the State.

Since there are no operators in the frame who would be classified as Type 2 at the U.S. level, there would be no Type 2 components at the U.S. level. Therefore, at the U.S. level, there was only one sample variance component calculated for Type 1 operators.

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

Table F7. Factors for Confidence Intervals (2S.E.) for Dry Natural Gas Proved Reserves and Production, 1994 (Billion Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

State and Subdivision	1994 Reserves	1994 Production
United States	787	79
Alabama	28	4
Alaska	0	0
Arkansas	126	9
California	29	4
Coastal Region Onshore	11	2
Los Angeles Basin Onshore	0	0
San Joaquin Basin Onshore	27	3
State Offshore	0	0
Colorado	130	11
Florida	0	0
Kansas	485	25
Kentucky	45	5
Louisiana	198	30
North	95	14
South Onshore	163	24
State Offshore	0	0
Michigan	80	22
Mississippi	17	3
Montana	25	3
New Mexico	79	8
East	44	5
West	57	5
New York	17	1
North Dakota	2	0
Ohio	57	7
Oklahoma	252	38
Pennsylvania	96	8
Texas	302	39
RRC District 1	18	3
RRC District 2 Onshore	86	13
RRC District 3 Onshore	150	19
RRC District 4 Onshore	66	8
RRC District 5	34	5
RRC District 6	110	8
RRC District 7B	20	3
RRC District 7C	42	6
RRC District 8	70	7
RRC District 8A	12	2
RRC District 9	30	4
RRC District 10	65	10
State Offshore	0	0
Utah	34	5
Virginia	0	0
West Virginia	59	5
Wyoming	32	4
Federal Offshore[a]	0	0
Pacific (California)	0	0
Gulf of Mexico (Louisiana)[a]	0	0
Gulf of Mexico (Texas)	0	0
Miscellaneous[b]	10	1

[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 the United States 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," 1994 and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production," 1994.

Table F8. Factors for Confidence Intervals (2S.E.) for Natural Gas Proved Reserves and Production, Wet After Lease Separation, 1994 (Billion Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

State and Subdivision	1994 Reserves	1994 Production
United States	826	87
Alabama	31	5
Alaska	0	0
Arkansas	126	9
California	30	4
Coastal Region Onshore	11	2
Los Angeles Basin Onshore	0	0
San Joaquin Basin Onshore	28	3
State Offshore	0	0
Colorado	140	11
Florida	0	0
Kansas	514	26
Kentucky	48	6
Louisiana	207	31
North	35	6
South Onshore	171	26
State Offshore	0	0
Michigan	84	23
Mississippi	17	3
Montana	25	3
New Mexico	88	9
East	49	6
West	63	6
New York	17	1
North Dakota	2	0
Ohio	57	7
Oklahoma	267	41
Pennsylvania	96	8
Texas	325	43
RRC District 1	19	3
RRC District 2 Onshore	93	14
RRC District 3 Onshore	163	20
RRC District 4 Onshore	69	8
RRC District 5	35	5
RRC District 6	116	9
RRC District 7B	24	3
RRC District 7C	47	6
RRC District 8	77	8
RRC District 8A	15	2
RRC District 9	35	5
RRC District 10	71	11
State Offshore	0	0
Utah	37	5
Virginia	0	0
West Virginia	62	5
Wyoming	34	4
Federal Offshore[a]	0	0
Pacific (California)	0	0
Gulf of Mexico (Louisiana)[a]	0	0
Gulf of Mexico (Texas)	0	0
Miscellaneous[b]	10	1

[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 the United States 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," 1994.

Table F9. Factors for Confidence Intervals (2S.E.) for Crude Oil Proved Reserves and Production, 1994
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	1994 Reserves	1994 Production
United States	86	10
Alabama	10	2
Alaska	0	0
Arkansas	4	1
California	18	2
Coastal Region Onshore	15	1
Los Angeles Basin Onshore	4	1
San Joaquin Basin Onshore	9	1
State Offshore	0	0
Colorado	8	1
Florida	0	0
Illinois	9	1
Indiana	1	0
Kansas	21	3
Kentucky	2	0
Louisiana	9	1
North	3	0
South Onshore	7	1
State Offshore	0	0
Michigan	5	1
Mississippi	6	1
Montana	4	1
Nebraska	2	0
New Mexico	11	2
East	9	1
West	1	0
North Dakota	8	1
Ohio	5	1
Oklahoma	43	5
Pennsylvania	0	0
Texas	59	6
RRC District 1	4	1
RRC District 2 Onshore	6	1
RRC District 3 Onshore	43	2
RRC District 4 Onshore	7	1
RRC District 5	3	0
RRC District 6	7	1
RRC District 7B	6	1
RRC District 7C	10	1
RRC District 8	12	2
RRC District 8A	14	1
RRC District 9	9	1
RRC District 10	8	1
State Offshore	0	0
Utah	18	1
West Virginia	1	0
Wyoming	14	2
Federal Offshore	0	0
Pacific (California)	0	0
Gulf of Mexico (Louisiana)	0	0
Gulf of Mexico (Texas)	0	0
Miscellaneous[a]	2	0

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

Note: Factors for confidence intervals for each State subdivision, State, and the United States 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," 1994.

Table F10. Factors for Confidence Intervals (2S.E.) for Lease Condensate Proved Reserves and Production, 1994 (Million Barrels of 42 U.S. Gallons)

State and Subdivision	1994 Reserves	1994 Production
United States	6	1
Alabama	0	0
Alaska	0	0
Arkansas	0	0
California	0	0
Coastal Region Onshore	0	0
Los Angeles Basin Onshore	0	0
San Joaquin Basin Onshore	0	0
State Offshore	0	0
Colorado	1	0
Florida	0	0
Kansas	0	0
Kentucky	0	0
Louisiana	2	0
North	1	0
South Onshore	2	0
State Offshore	0	0
Michigan	1	0
Mississippi	0	0
Montana	0	0
New Mexico	0	0
East	0	0
West	0	0
North Dakota	0	0
Oklahoma	1	0
Texas	6	1
RRC District 1	0	0
RRC District 2 Onshore	0	0
RRC District 3 Onshore	5	1
RRC District 4 Onshore	0	0
RRC District 5	0	0
RRC District 6	2	0
RRC District 7B	0	0
RRC District 7C	1	0
RRC District 8	1	0
RRC District 8A	0	0
RRC District 9	1	0
RRC District 10	0	0
State Offshore	0	0
Utah and Wyoming	0	0
West Virginia	0	0
Federal Offshore[a]	0	0
Pacific (California)	0	0
Gulf of Mexico (Louisiana)[a]	0	0
Gulf of Mexico (Texas)	0	0
Miscellaneous[b]	0	0

[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 the United States 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," 1994.

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 G.

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 percent of the crude oil proved reserve estimates, 6.9 percent of the natural gas proved reserve estimates, and 3.7 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 1994 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 1994 Form EIA-64A survey, the national weighted average gas equivalents ratio was computed to be 1,398 cubic feet of natural gas shrinkage per barrel of NGL recovered. This is 1 cubic feet per barrel more than in the 1993 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 F7** provides estimates for 2 times the $S.E.(\hat{V}_s)$ for dry natural gas.

Estimation of Reserves and Resources

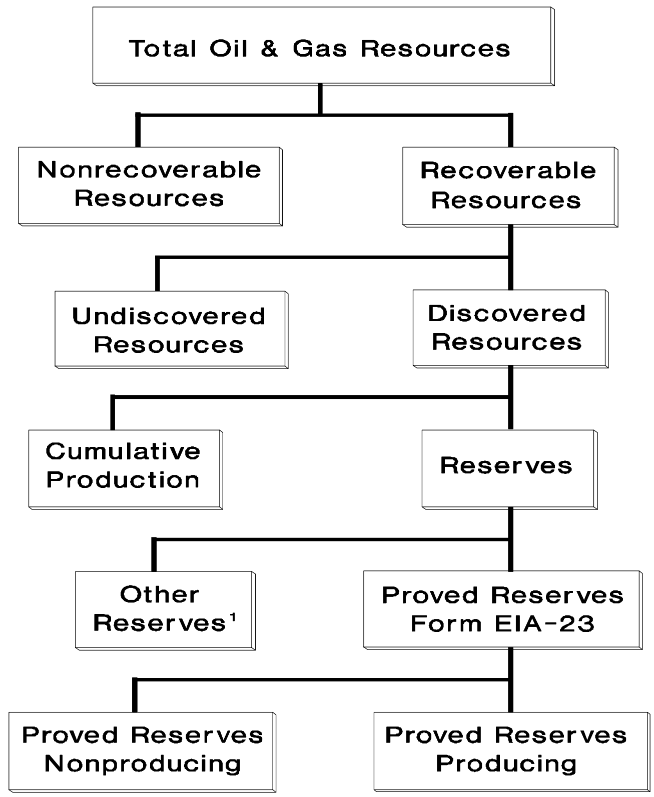
Oil and Gas Resource Base

Universally accepted definitions have not been developed for the many terms used by geologists, engineers, accountants and others to denote various components of overall oil and gas resources. In part, this is because most of these terms describe estimated and therefore uncertain, rather than measured, quantities. The lack of standardized terminology sometimes leads to inaccurate understanding of the meaning and/or import of estimates. Particularly common is an apparently widespread lack of understanding of the substantial difference between the terms "reserves" and "resources", as indicated by the frequent misuse of either term in place of the other.

The total resource base of oil and gas is the entire volume formed and trapped in-place within the Earth before any production. The largest portion of this total resource base is nonrecoverable by current or foreseeable technology. Most of the nonrecoverable volume occurs at very low concentrations throughout the earth's crust and 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 currently available production techniques cannot extract all of the in-place oil and gas even when present in commercial concentrations. The inability to recover all of the in-place oil and gas from a producible deposit occurs because of unfavorable economics, intractable physical forces, or a combination of both. Recoverable resources, the subset of the total resource base that is of societal and economic interest, are defined so as to exclude these nonrecoverable portions of the total resource base.

The structure presented in **Figure G1** outlines the total resource base and its components. The total resource base first consists of the recoverable and nonrecoverable portions discussed above. The next level down divides recoverable resources into discovered and undiscovered segments. Discovered resources are further separated into cumulative (i.e., all past) production, and reserves. Reserves are additionally subdivided into proved reserves and "other reserves".

Figure G1. Components of the Oil and Gas Resource Base



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

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

Recoverable Resources

Discovered recoverable resources are those economically recoverable quantities of oil and gas for which specific locations are known. While the specific locations of estimated undiscovered recoverable resources are not yet known, they are believed to exist in geologically favorable settings.

Current estimates of undiscovered recoverable resources merit discussion in order to provide a useful sense of scale relative to proved reserves. The sources of official estimates of domestic undiscovered recoverable resources are two agencies of the Department of the

Interior (DOI), the United States Geological Survey (USGS) for onshore areas and those offshore waters subject to State jurisdiction, and the Minerals Management Service (MMS) for those offshore waters under Federal jurisdiction.

The USGS defines undiscovered recoverable conventional resources as those expected to be resident in accumulations of sufficient size and quality that they could be produced using conventional recovery technologies, without regard to present economic viability. Therefore, only part of the USGS undiscovered recoverable conventional resource is economically recoverable now. The USGS also defines a class of resources that occur in "continuous-type" accumulations. Unlike conventional oil and gas accumulations, continuous-type accumulations do not occur in discrete reservoirs of limited areal extent. They include accumulations in low-permeability (tight) sandstones, shales, and chalks, and those in coal beds. Again, only part of the continuous-type technically recoverable resource is economically recoverable now. In fact, only a small portion of the in-place continuous-type resource accumulations are estimated to be technically recoverable now. **Table G1** presents the latest available USGS and MMS estimates, along with the EIA 1994 proved reserves estimates. New MMS estimates for Federal offshore resources are expected to be available in late 1995.

Subtracting EIA's estimate of proved reserves from the **Table G1** recoverable resource total for wet natural gas yields an unproven technically recoverable gas resource target of 1,094 trillion cubic feet. This is about 57 times the 1994 gas production level.

Other organizations have also estimated unproven technically recoverable gas resources. For example, the Potential Gas Committee (PGC), an industry sponsored group, provides detailed geology-based gas resource estimates every 2 years. In 1994 the PGC mean estimate of potential gas resources was 1,028 trillion cubic feet, only 66 trillion cubic feet less than the DOI estimates in **Table G1**. Another recent estimate was made by the National Petroleum Council (NPC), an industry-based group that serves in an advisory capacity to the U.S. Secretary of Energy. The NPC's estimate, based on data available at year-end 1990, was 1,135 trillion cubic feet, 41 trillion cubic feet more than the DOI estimates summarized in **Table G1**. The differences among these estimates are usually due to the differences in coverage or resource category definitions and to legitimate but differing data interpretations.

While the estimation of undiscovered resources is certainly a more imprecise endeavor than is the estimation of proved reserves, it is clear that substantial volumes of technically recoverable oil and gas resources remain to be found and produced domestically. Current estimates indicate that as much domestic gas remains to be found and then produced as has been to date. Of course, much effort, investment and time will be required to bring this gas to market.

The oil resource base has been more intensively developed than the gas resource base. More oil has been produced in the United States than is estimated as remaining recoverable. Nevertheless, the ratio of 1994 oil production to unproven technically recoverable oil resources (**Table G1**) was about 48 to 1.

Discovered Resources

In addition to cumulative production, which is the sum of current year production and the production in all prior years, estimates of discovered recoverable resources include estimates of reserves. Broadly, reserves are those volumes that are believed to be recoverable in the future from known deposits through the eventual application of present or anticipated technology.

Reserves

Reserves include both **proved reserves** and **other reserves**. Several different reserve classification systems are in use by different organizations, as preferred for operational reasons. These systems utilize and incorporate various definitions of terms such as *measured reserves, indicated reserves, inferred reserves, probable reserves*, and *possible reserves*. As used by the different organizations, the definitions that attach to these terms sometimes overlap, or the terms may require a slightly different interpretation from one organization to the next. Nevertheless, all kinds of "other reserves" are generally less well known and therefore less precisely quantifiable than proved reserves, and their eventual recovery is less assured.

Measured reserves are defined by the USGS as that part of the identified (i.e., discovered) economically recoverable resource that is estimated from geologic evidence and supported directly by engineering data.{55} They are similarly defined by the MMS, although its system also subdivides them by degree of development and producing status.{56} Measured reserves are demonstrated with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, and are essentially equivalent to proved reserves as defined by the EIA. Effectively, estimates of proved reserves

Table G1. Estimated Oil and Gas Reserves and Mean Estimates of Technically Recoverable Oil and Gas Resources

Categories	Crude Oil (billion barrels)	Natural Gas (Wet) (trillion cubic feet)	Natural Gas Liquids (billion barrels)
Lower 48 States			
Discovered			
Proved Reserves (EIA, end 1994)	16.690	[a]162.126	6.869
Reserve Growth (USGS, end 1991 - conventional)	[b]47.000	290.000	12.900
Other Reserves (e.g., Probable, Possible)	NE	NE	NE
Undiscovered, Technically Recoverable			
Conventional (USGS, end 1993)	21.810	190.280	6.080
Continuous-type (USGS, end 1993 - ss, sh, chalk)	2.066	308.080	2.119
Continuous-type (USGS, end 1993 - coal beds)	NA	49.910	NA
Federal Offshore (MMS, end 1986 - conventional)	12.700	128.300	[c]<1.8
Subtotal	**100.266**	**1,128.696**	**NA**
Alaska			
Discovered			
Proved Reserves (EIA, end 1994)	5.767	9.813	0.301
Reserve Growth (USGS, end 1991 - conventional)	[d]13.000	32.000	0.500
Other Reserves (e.g., Probable, Possible)	NE	NE	NE
Undiscovered, Technically Recoverable			
Conventional (USGS, end 1993)	8.440	68.410	1.120
Continuous-type (USGS, end 1993 - ss, sh, chalk)	NE	NE	NE
Continuous-type (USGS, end 1993 - coal beds)	NA	NE	NA
Federal Offshore (MMS, end 1986 - conventional)	3.400	16.800	[c]<1.8
Subtotal	**30.607**	**127.023**	**NA**
U.S. Total (categories have different end years)	**130.873**	**1,255.719**	**31.689**

[a] Includes 9.712 trillion cubic feet of coalbed methane (EIA, end 1994).
[b] By USGS definition, includes 2.129 billion barrels of indicated additional oil reserves in the lower 48 States (EIA, end 1994).
[c] Total undiscovered natural gas liquids for Federal offshore are 1.8 billion barrels; source did not separate lower 48 and Alaska.
[d] By USGS definition, includes 1.022 billion barrels of indicated additional oil reserves in Alaska (EIA, end 1994).
NE = not estimated.
NA = not applicable.

Notes: ss = sandstone and sh = shale. End years indicate the latest data used. Energy Information Administration (EIA), onshore and offshore estimated reserves. U.S. Geological Survey (USGS): 1995 National Assessment mean estimates as of the end of 1993 (onshore and State offshore). Minerals Management Service (MMS): 1989 National Assessment mean estimates as of the end of 1986. The MMS also has end 1989 estimates, but those are for economically recoverable resources. Other discovered resource categories, such as probable and possible reserves, were not estimated, but by USGS definition are considered to be part of Reserve Growth. Excluded from the estimates are undiscovered oil resources in tar deposits and oil shales, and undiscovered gas resources in geopressured brines and gas hydrates.

Sources: Energy Information Administration, Office of Oil and Gas; USGS and MMS - *Estimates of Undiscovered Conventional Oil and Gas Resources in the United States—A Part of the Nation's Energy Endowment* (1989), U.S. Department of the Interior, and *1995 National Assessment of United States Oil and Gas Resources*, USGS Circular 1118, U.S. Department of the Interior.

may be thought of as reasonable estimates (as opposed to exact measures) of "on-the-shelf inventory."

Inferred reserves and indicated reserves, due to their more uncertain economic or technical recoverability, are included in the "other reserves" category. The USGS defines inferred reserves as that part of the identified economically recoverable resource, over and above both measured and indicated (see below) reserves, that will be added to proved reserves in the future through extensions, revisions, and the discovery of new pay zones in already discovered fields.{55} Inferred reserves are considered equivalent to "probable reserves" by many analysts, for example, those of the PGC.

Indicated additional reserves, a separate category, are defined by both the DOI and the 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 as-yet uninstalled recovery technology. At such time as the technology is successfully applied, indicated additional reserves are reclassified to the proved reserves category. Of all the various "other reserves" categories, only indicated additional reserves are estimated by the EIA and reported herein.

Proved Reserves

The EIA defines proved reserves 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. Proved reserves are either proved producing or proved nonproducing (i.e., resident in reservoirs that did not produce during the report year). The latter may represent a substantial fraction of total proved reserves.

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 their 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 the engineering and geological data for reservoir rock and its fluid content. These data are obtained from direct and indirect 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 the *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 G2** summarizes the various methods.

Table G2. 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.

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.

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 follows.

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.

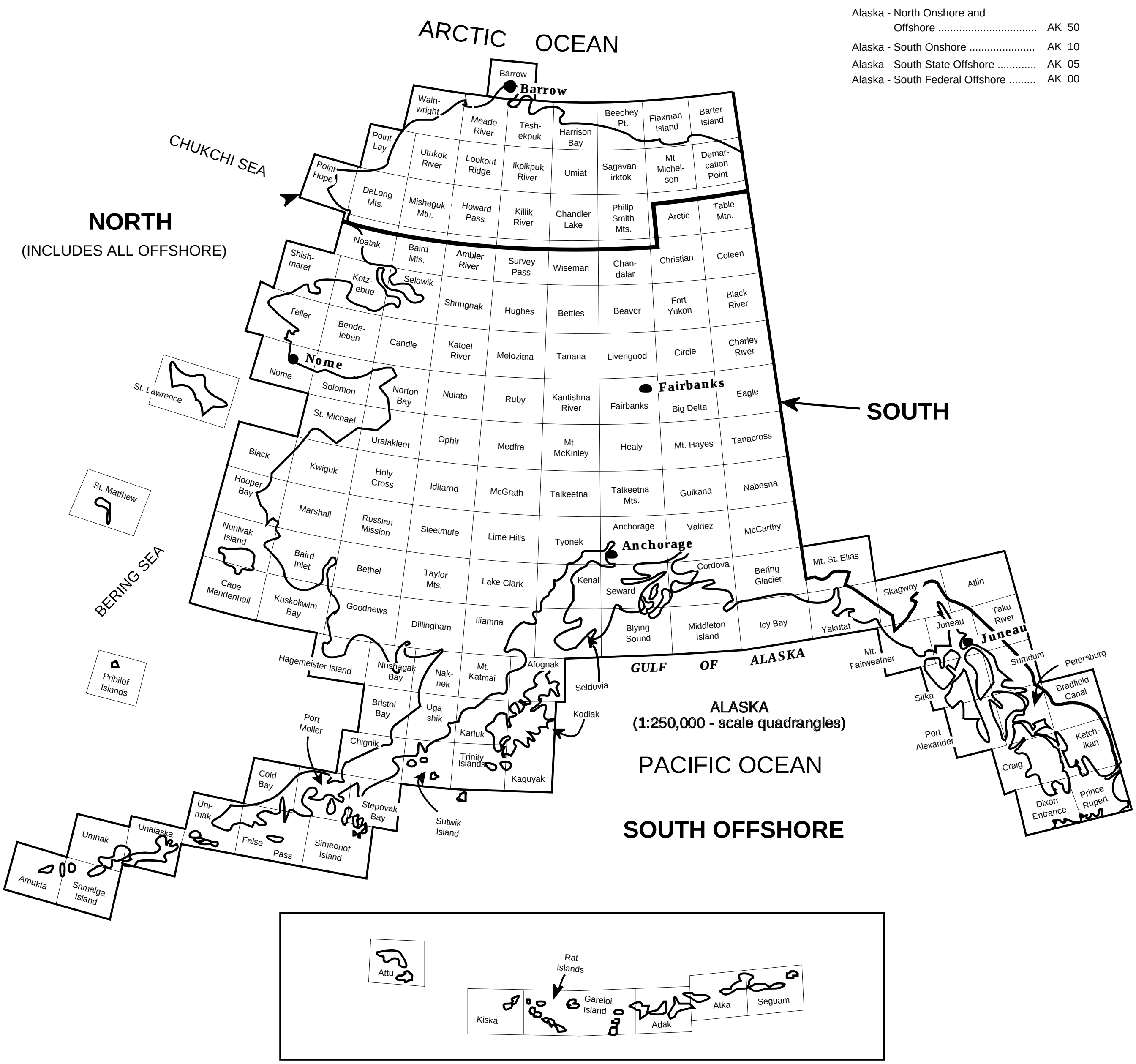
Reservoir limits: The initial proved reserves estimate made from the discovery well is subject to significant uncertainty because one well provides little information on the size of the reservoir. The area proved by a discovery well is frequently estimated on the basis of experience in a given producing 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

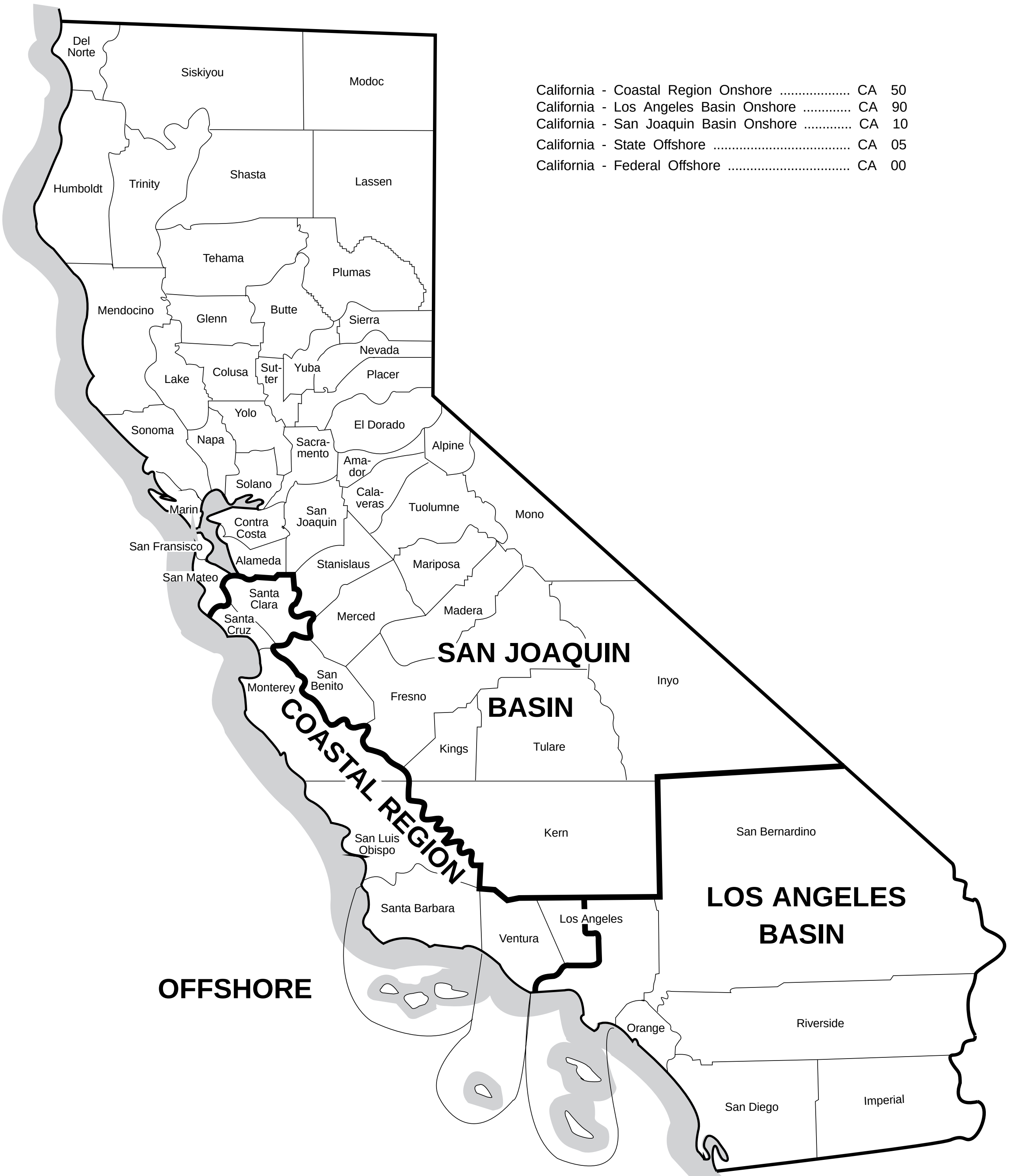
Maps of Selected State Subdivisions

Figure H1. Subdivisions of Alaska



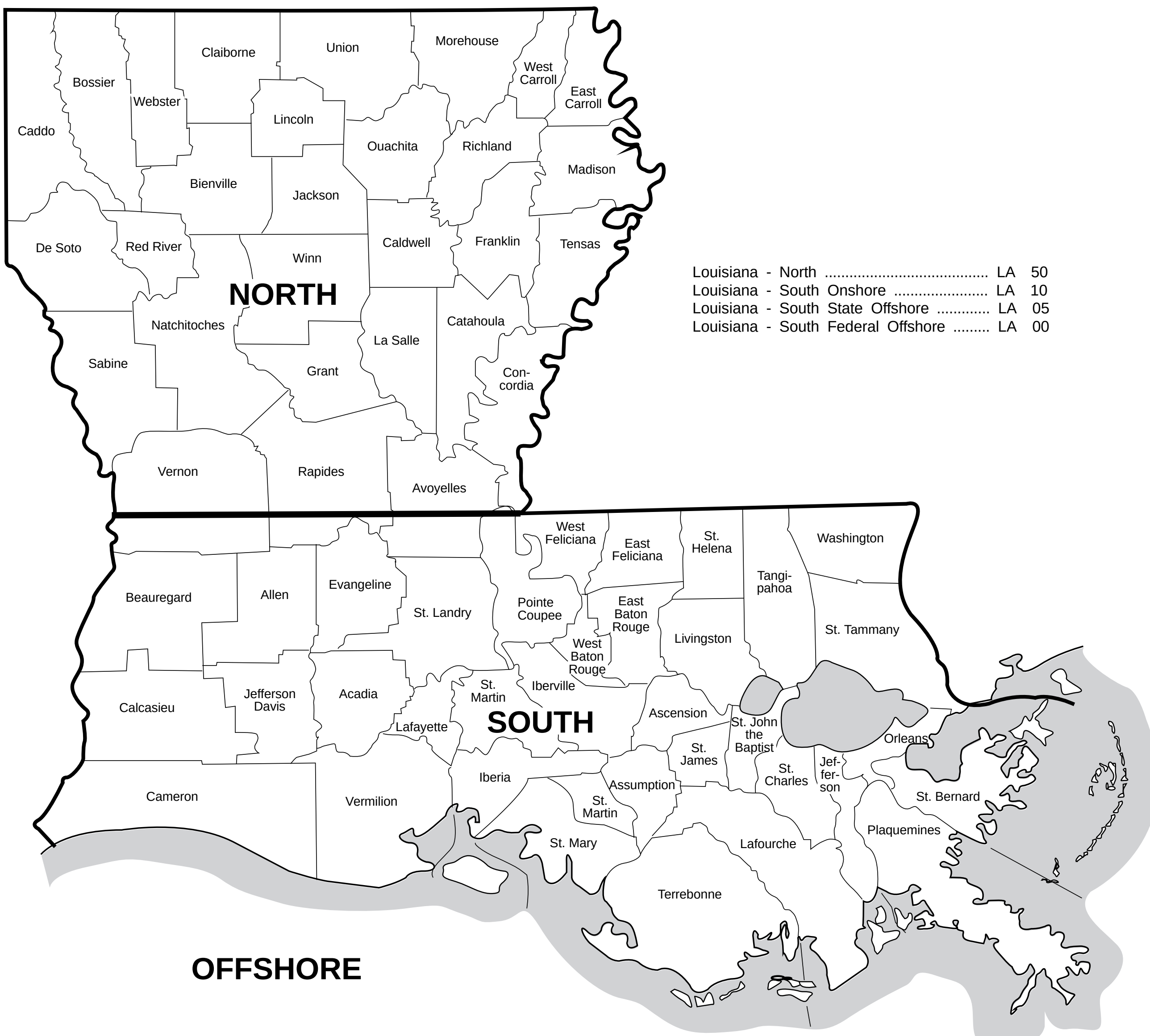
Source: After U.S. Geological Survey.

Figure H2. Subdivisions of California



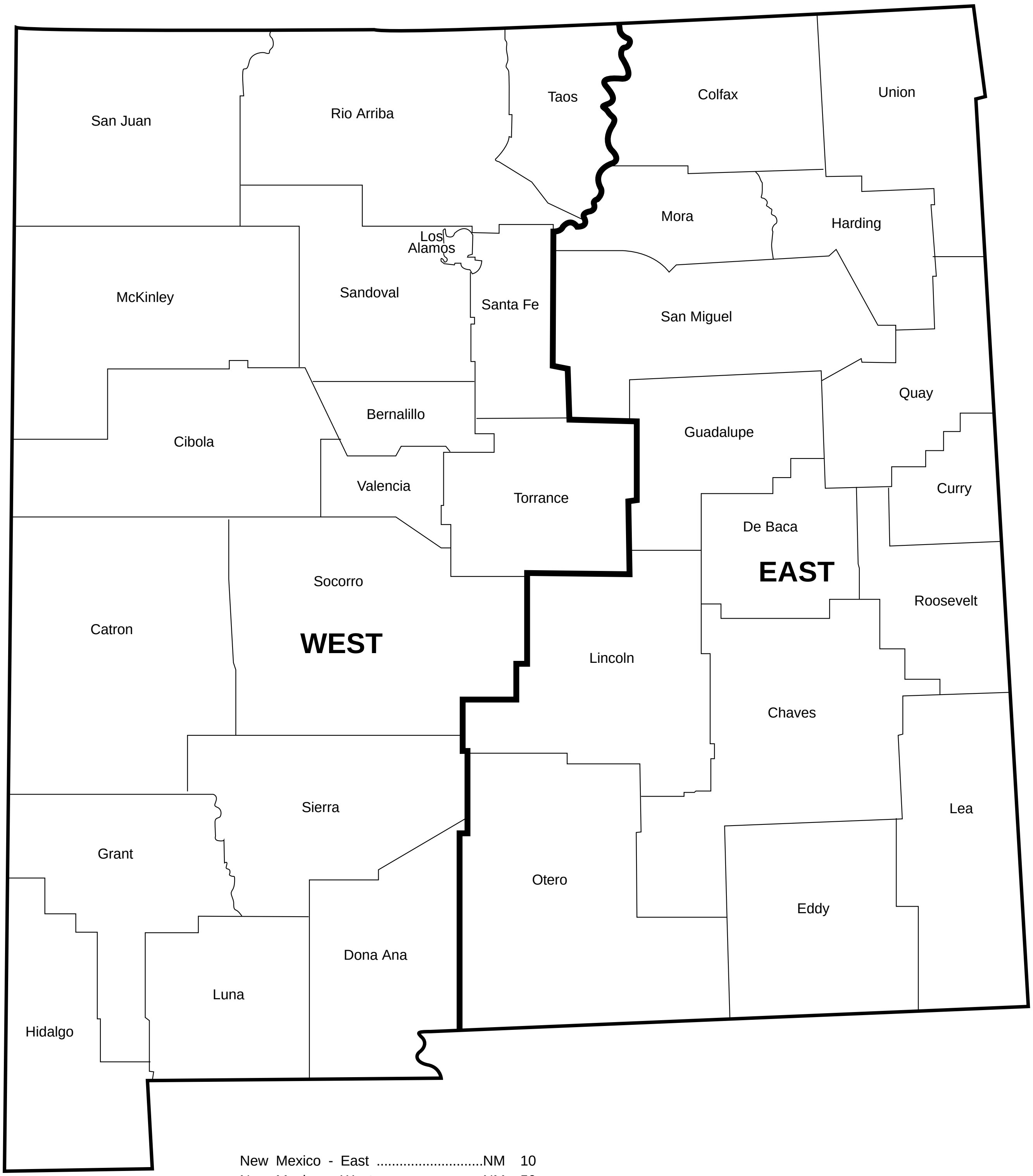
Source: Energy Information Administration, Office of Oil and Gas.

Figure H3. Subdivisions of Louisiana



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

Figure H4. Subdivisions of New Mexico

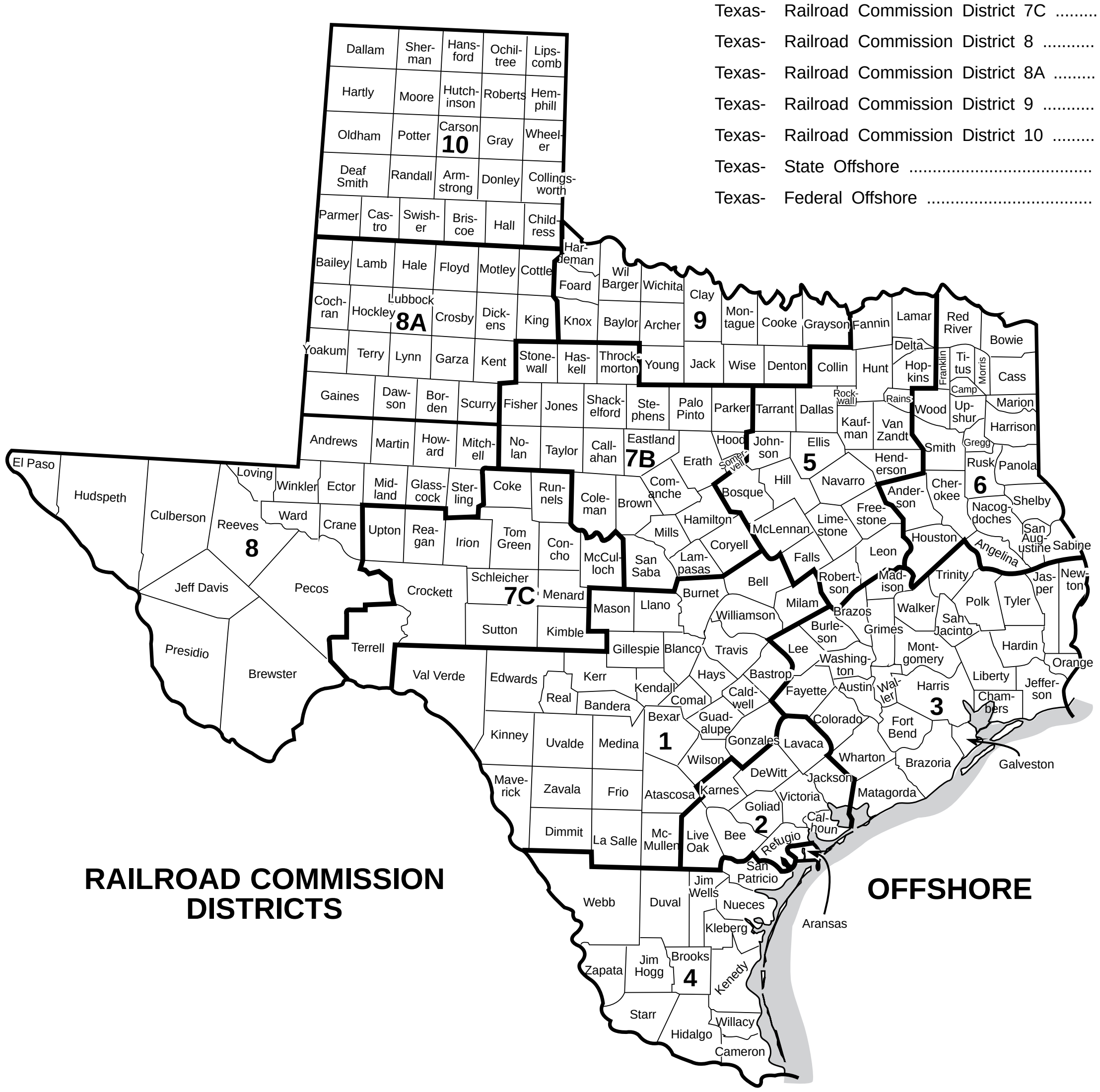


New Mexico - East ....NM 10
New Mexico - West ....NM 50

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

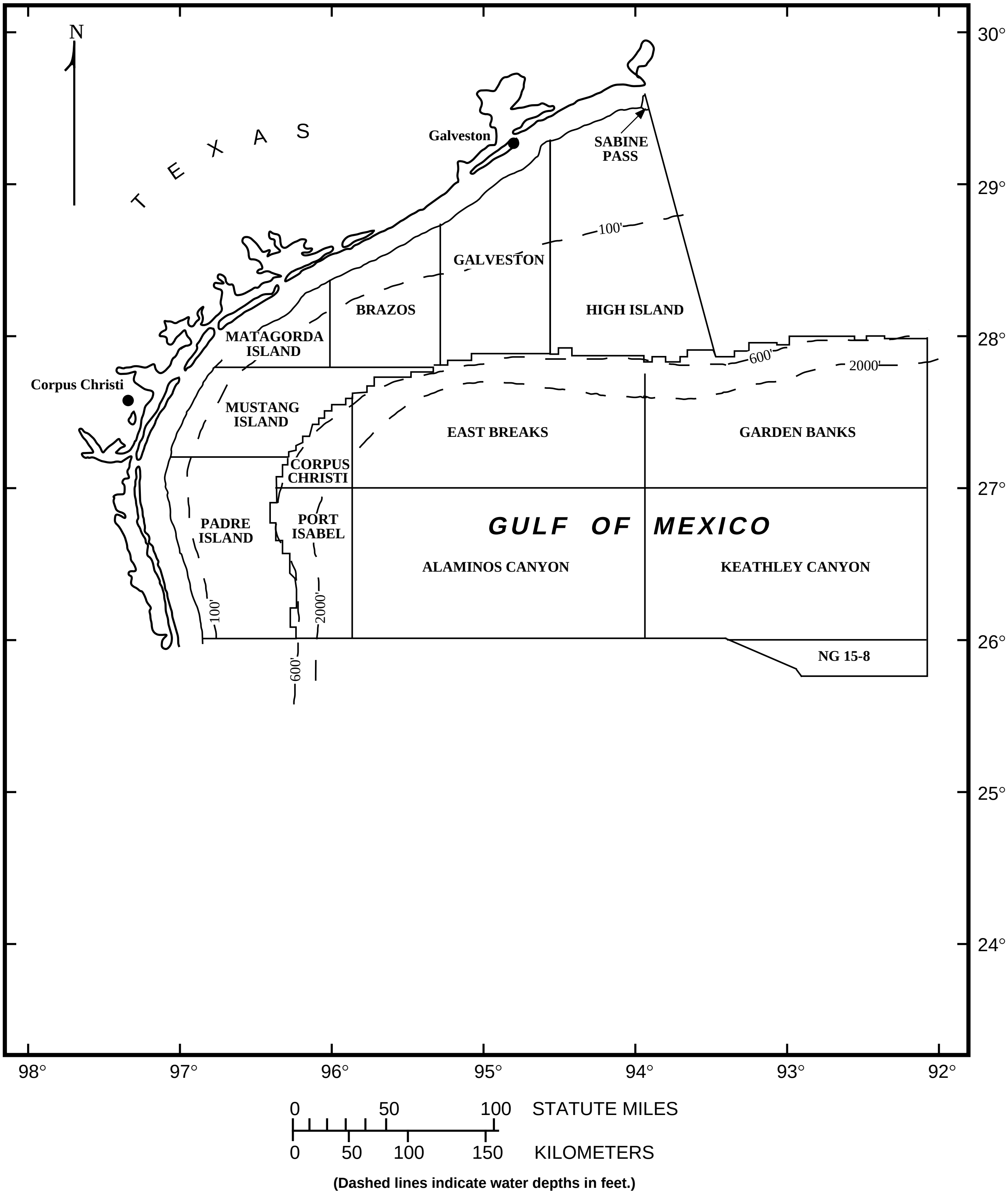
Figure H5. Subdivisions of Texas

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



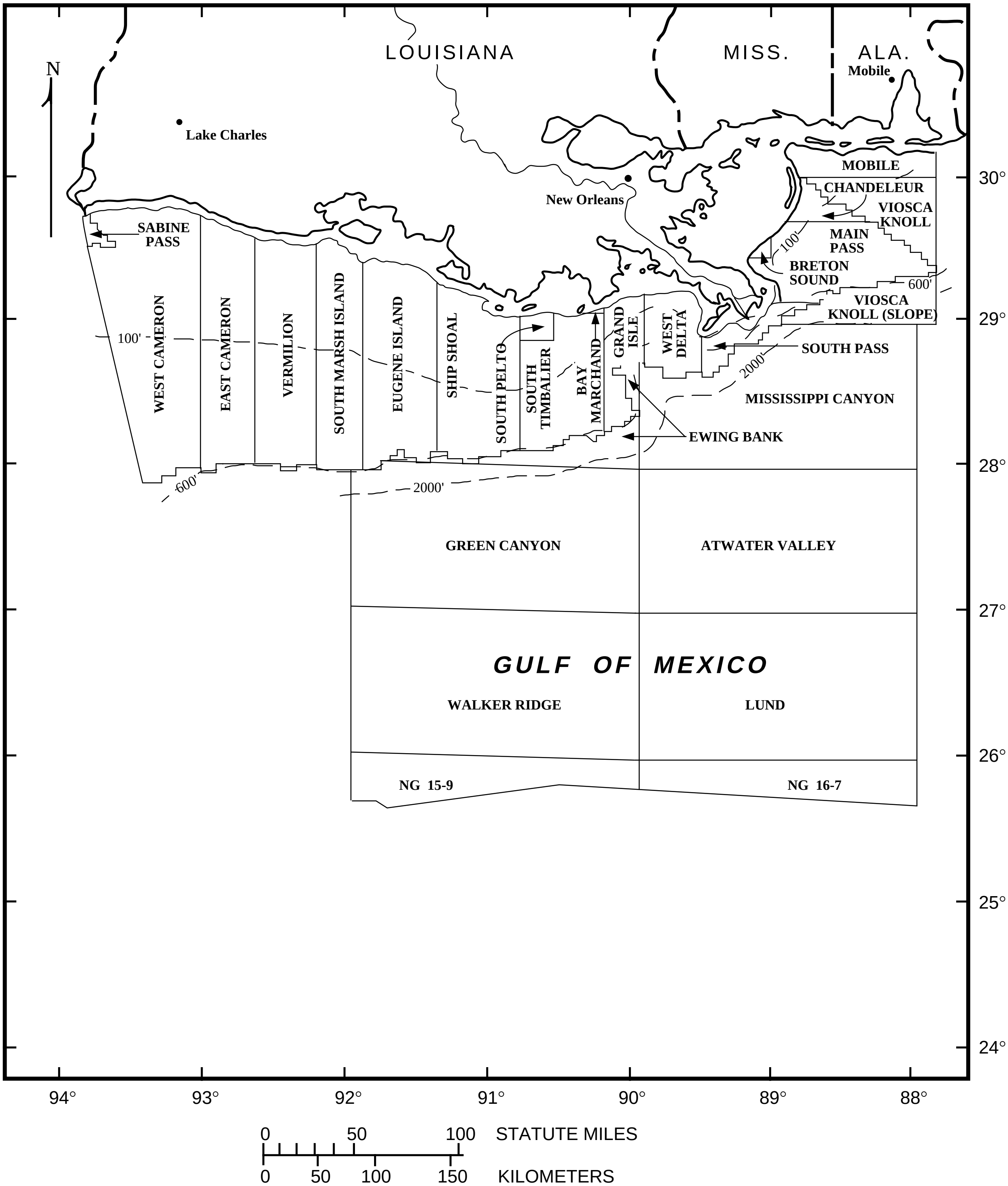
Source: Energy Information Administration, Office of Oil and Gas.

Figure H6. Western Planning Area, Gulf of Mexico Outer Continental Shelf Region



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

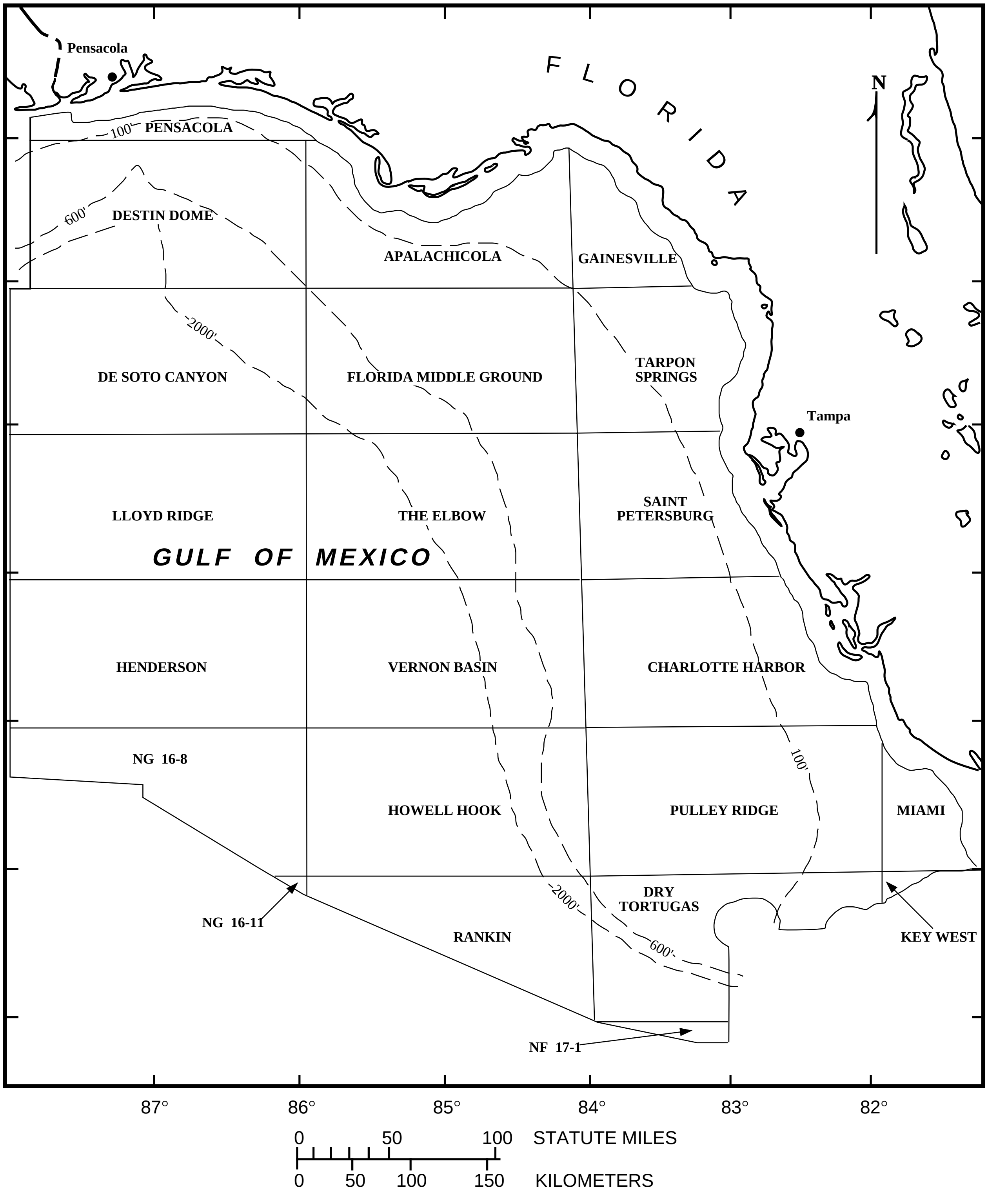
Figure H7. Central Planning Area, Gulf of Mexico Outer Continental Shelf Region



(Dashed lines indicate water depths in feet.)

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

Figure H8. Eastern Planning Area, Gulf of Mexico Outer Continental Shelf Region



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

Appendix I

Annual Survey Forms for Domestic Oil and Gas Reserves

EIA-23 (Revised 12/93)

OFFICIAL USE ONLY

1994

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES
U.S. DEPARTMENT OF ENERGY
CALENDAR YEAR 1994

Form Approved
OMB No. 1905-0057
Expires 12/97

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, 1994?**

(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.

SAMPLE

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 (   ) _____-__________

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)* | 21. Signature

20. Title | 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

OFFICIAL USE ONLY

1994

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

Form Approved
OMB No. 1905-0057
Expires 12/97

SUMMARY REPORT
PAGE 1 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^{o}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 94		

2.0 PRODUCTION AND RESERVES DATA

STATE OR GEOGRAPHIC SUBDIVISION		CRUDE OIL RESERVES	CRUDE OIL 1994 PRODUCTION		NATURAL GAS RESERVES	NATURAL GAS 1994 PRODUCTION		LEASE CONDENSATE RESERVES	LEASE CONDENSATE 1994 PRODUCTION	
		Proved Reserves Dec. 31, 1994 (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, 1994 (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, 1994 (Mbbl) (G)	(From properties for which reserves were Estimated) (Mbbl) (H)	(From properties for which reserves were Not Estimated) (Mbbl) (I)
ALABAMA-ONSHORE	AL									
ALABAMA-STATE OFFSHORE	AL05									
ALASKA-NORTH ONSHORE AND OFFSHORE	AK50									
ALASKA-SOUTH ONSHORE	AK10									
ALASKA-SOUTH STATE OFFSHORE	AK05									
ARIZONA	AZ									
ARKANSAS	AR									
CALIFORNIA-COASTAL REGION ONSHORE	CA50									
CALIFORNIA-LOS ANGELES BASIN ONSHORE	CA90									
CALIFORNIA-SAN JOAQUIN BASIN ONSHORE	CA10									
CALIFORNIA-STATE OFFSHORE	CA05									
COLORADO	CO									
FLORIDA-ONSHORE	FL									
FLORIDA-STATE OFFSHORE	FL05									
ILLINOIS	IL									
INDIANA	IN									
KANSAS	KS									
KENTUCKY	KY									
LOUISIANA-NORTH	LA50									
LOUISIANA-SOUTH ONSHORE	LA10									
LOUISIANA-SOUTH STATE ONSHORE	LA05									
MARYLAND	MD									
MICHIGAN	MI									
MISSISSIPPI-ONSHORE	MS									
MISSISSIPPI-STATE OFFSHORE	MS05									
MISSOURI	MO									
MONTANA	MT									
NEBRASKA	NE									
NEVADA	NV									
NEW MEXICO-EAST	NM10									
NEW MEXICO-WEST	NM50									
NEW YORK	NY									
NORTH DAKOTA	ND									
OHIO	OH									

SAMPLE

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1994

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

Form Approved
OMB No. 1905-0057
Expires 12/97

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 94		

2.0 PRODUCTION AND RESERVES DATA

STATE OR GEOGRAPHIC SUBDIVISION		CRUDE OIL			NATURAL GAS			LEASE CONDENSATE		
		RESERVES	1994 PRODUCTION		RESERVES	1994 PRODUCTION		RESERVES	1994 PRODUCTION	
		Proved Reserves Dec. 31, 1994 (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, 1994 (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, 1994 (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									

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1994

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

Form Approved
OMB No. 1905-0057
Expires 12/97

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)

SAMPLE

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	94				

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				8. FOOTNOTE
						(a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CON-DENSATE (Mbbl)	

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

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1993	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, 1994	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				8. FOOTNOTE
						(a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CON-DENSATE (Mbbl)	

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

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1993	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, 1994	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				8. FOOTNOTE
						(a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CON-DENSATE (Mbbl)	

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

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1993	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, 1994	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				8. FOOTNOTE
						(a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CON-DENSATE (Mbbl)	

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

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1993	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, 1994	NONPRODUCING (i) RESERVES
12. CRUDE OIL (Mbbl)									
13. ASSOCIATED-DISSOLVED GAS(MMcf)									
14. NONASSOCIATED GAS (MMcf)									
15. LEASE CONDENSATE (Mbbl)									

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1994

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

SCHEDULE B - FOOTNOTES

Form Approved
OMB No. 1905-0057
Expires 12/97

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 94				

2.0 FOOTNOTE DATA

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

SAMPLE

Figure I6. Form EIA-64A

EIA-64A (Revised 9/91)

OFFICIAL USE ONLY **1994**

Energy Information Administration
U.S. DEPARTMENT OF ENERGY
Calendar Year 1994

Form Approved
OMB No. 1905-0057
Expires 12/97

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

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 5.9 hours per respondent, 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.

PLEASE COMPLETE THIS FORM AND RETURN TO

DOMESTIC OIL AND GAS RESERVES PROGRAM
PO BOX 1470
ROCKVILLE, MD 20849-1470

PLANT AND PRODUCTION REPORT IDENTIFICATION

1.0 Does this report reflect active natural gas processing at the facility for the entire year? ☐ Yes ☐ No
Months covered by this report___________ through ___________ (Include Explanatory Notes in Section **8.0**)

2.0 *If label is incorrect or information is missing or no label is given, enter correct information to the right*

2.1 Plant Operator's Name
2.2 Contact Person's Name
2.3 Plant Name
2.4 Geographic Location (Use Area of Origin Codes, Page 6) ☐☐☐☐
2.5 Mailing Address
2.6 City State Zip Code
2.7 Telephone Number ( )

3.0 Parent Company's Name

4.0 Submission Status ☐ Original ☐ Amended

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)
5.1			
5.2			
5.3			
5.4			
5.5			
5.6			
5.7			
5.8			
5.9			
5.10			
5.11			
5.12			
5.13			
5.14			
5.15			
5.16	**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: I certify that the information provided herein and appended hereto is true and accurate to the best of my knowledge.

Name (Please Print) Date

Signature Title

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, Offfice of Oil and Gas.

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 1993.

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
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 primiaily 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
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)
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.