ANNUAL SURVEY
OF
DOMESTIC OIL AND GAS RESERVES
FORM EIA-23

Field Survey Instructions
2003

U.S. Department of Energy
Energy Information Administration
Office of Oil and Gas

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ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES
FORM EIA-23
CALENDAR YEAR 2003

Field Survey Package

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For Information, Assistance, or Additional Forms, Contact the
EIA-23 Coordinator at
1-800-879-1470
8:30 a.m. – 5:00 p. m. CST
FAX (202) 586-1076

www.eia.doe.gov
Energy Information Administration

U.S. DEPARTMENT OF ENERGY
Energy Information Administration
Washington, DC 20585

Form Approved
OMB Number: 1905-0057
Expiration Date: 12/31/06

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES
FORM EIA-23
CALENDAR YEAR 2003

GENERAL INSTRUCTIONS

A. PURPOSE

The Energy Information Administration (EIA) of the Department of Energy (DOE) seeks, with Form EIA-23, to gather and summarize credible and timely data regarding proved reserves and production of crude oil, natural gas, lease condensate and other related matters. The Government will use the resulting information to develop national and regional estimates of proved reserves of domestic crude oil, natural gas and natural gas liquids and to facilitate national energy policy decisions.

B. WHO MUST SUBMIT FORM EIA-23

Each operator of domestic oil and/or gas wells as of December 31, 2003 that has been selected **must file** Form EIA-23. The definition of an operator as used in these instructions and forms is as follows:

> **Operator**: The person responsible for the management and day-to-day operation of one or more crude oil and/or natural gas wells on December 31, 2003. The operator is generally a working interest owner or a company under contract to the working interest owner(s). Wells included are those that 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 year are also to be considered "operated" on December 31.

Note that as defined, day-to-day physical operation of a well or wells does not alone qualify a person as the operator. Physical operation may occasionally be divorced from operatorship, such as in the instance of manipulation of swing wells by a gas pipeline company representative or the manipulation and maintenance of wells located on an offshore platform by the platform manager. While the operator's own personnel usually perform such duties, the key factor is that the operator is the person who makes management decisions regarding the well(s) in question on behalf of the owner(s). For example, such decisions might include deciding the following:

1) what flow rates can be sustained without reservoir damage;
2) whether well(s) should be shut-in, worked over or abandoned;
3) whether additional or replacement wells should be drilled into a reservoir;
4) whether a waterflood program should be initiated; or
5) whether additional or different production equipment should be installed.

Filing requirements are based on operator category or size, which is determined by the total or gross (8/8ths) annual operated production rate. Production refers to the total calendar year production from all domestic oil and/or gas wells you operated on December 31, 2003, including wells abandoned during the year.

Each operating affiliate of a parent company must file its own Form EIA-23. The parent company must file only if it is an operator itself. If no parent company exercises ultimate control over your company, please indicate that on the Cover Page

If you have received the Field Form (Schedule A), but your total gross operated production is below both 400 thousand barrels (400 MBarrels) of crude oil and 2 billion cubic feet (2,000 MMCF or 2 BCF) of natural gas, contact the EIA-23 Coordinator to obtain the appropriate form and instructions. Operators of wells in the federal offshore and/or of coalbed methane wells are requested to file using this Field Form regardless of their total production levels.

If in a particular instance you are **not** certain whether you are the operator, contact the EIA-23 Coordinator for assistance in making this determination. If you are **not** the operator of oil and/or gas wells on December 31, 2003 (perhaps a former operator or solely a working or royalty interest owner), you should:

1) complete and sign the Cover Page and return it to DOE along with
2) a letter stating when operations ceased and what became of the wells you previously operated.

C. WHAT MUST BE SUBMITTED

Production data and estimates of proven reserves of crude oil, natural gas and lease condensate are required of each operator selected. This survey segregates selected operators into three categories, according to the annual production of hydrocarbons from wells that they operated on December 31, 2003. The three size categories are as follows:

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**. Production and proven reserves estimates are required from all Category I operators.**

These operators must file:

- Cover Page
- Schedule A - Operated proved reserves, production and related data by fields
- Schedule B - Footnotes

Category II - Intermediate Operators: Operators that produced at least 400,000 barrels of crude oil or 2 billion cubic feet of natural gas but less than Category I operators. **Production data are required from all Category II operators.** Proved reserves estimates are required only if such data exists in company records. To the extent that these operators do not have proved reserves estimates associated with one or more specific properties, they must report their production data in "calendar year production". If production data includes properties for which reserves were not estimated, a footnote on Schedule B must be added.

These operators must file:

- Cover Page
- Schedule A - Operated proved reserves (if available), production and related data by fields
- Schedule B – Footnotes

Category III - Small Operators: Operators who produced less than Category II operators. These operators file an EIA-23 form with a different format. If, however, they operate either coalbed methane gas wells and/or federal offshore wells, then they should file the information shown above for a Category II operator.

D. WHEN AND WHERE TO SUBMIT

The completed 2003 forms must be submitted **on or before April 1, 2004.**

Completed forms may be submitted by mail, fax or e-mail.

Mail completed forms or RIGS diskettes to:

United States Department of Energy
Energy Information Administration
P O Box 8279
Silver Spring, MD 20907
Attention: Form EIA-23

Fax completed forms to: **(202) 586-1076**

E-mail completed forms to: OOG.SURVEYS@eia.doe.gov

RIGS (Reserves Information Gathering System) Electronic Reporting Packages (CD-ROM and RIGS Instruction Booklet) were sent to each Category I and II operator. To facilitate the processing of data, the use of EIA forms is requested (either hardcopies or these diskettes). Additional copies of the EIA-23 form and instructions are available in PDF format on the EIA Website at http://www.eia.doe.gov. (After logging on the EIA website, highlight the *By Fuel* category; select *Petroleum or Natural Gas*; then select *Survey Forms* on the sidebar at the left of the screen; then scroll to *Reserves Survey Forms)*.

In addition, filing electronically, when possible (i.e., using e-mail or by fax), is encouraged. When entering responses on hard copies, type or print in black ink using all capital letters. **Computer printouts on other than an exact duplicate of the forms provided are not acceptable.**

For information concerning requests for extension of time to file or for exception from filing Form EIA-23, contact the EIA-23 Coordinator toll-free at 1-800-879-1470 from 8:30 a.m. to 5:00 p.m. CST.

E. RECORD KEEPING REQUIREMENTS

All records necessary to reconstruct the data on this form must be kept at the reporting site or on file and available for a period of three (3) years from the filing due date.

EIA will follow this survey with efforts to perform Quality Assurance on the data, assessing the accuracy of the resulting information. Respondents may encounter two principal Quality Assurance activities:

1) government personnel will make or supervise independent reserve estimates on a sample basis or
2) a sample of operators will be visited to review the data submitted.

EIA recognizes that the judgment of geologists and petroleum engineers is required in the reserve estimation process, and that as a result, proved reserves are estimates rather than precise quantitative measurements.

F. SANCTIONS

The timely submission of Form EIA-23 by those required to report is mandatory under Section 13 (b) of the Energy Information Administration Act of 1974 (FEAA) (Public Law 93-275), as amended. Failure to respond may result in a civil penalty of not more than $2,750 a day for each violation, or a fine of not more than $5,000 a day for each willful violation. The government may bring a civil action to prohibit reporting violations that may result in a temporary restraining order or a preliminary or permanent injunction without bond. In such civil action, the court may also issue mandatory injunctions commanding any person to comply with these reporting requirements.

G. CONFIDENTIALITY

The calendar year production of crude oil and natural gas data reported on Form EIA-23 are not considered as confidential and may be publicly released in identifiable form. In addition to the use of the information by EIA for statistical purposes, the information may be used for any non-statistical purposes such as administrative, regulatory, law enforcement, or adjudicatory purposes.

All other information reported on Form EIA-23 will be kept confidential and not disclosed to the public to the extent that it satisfies the criteria for exemption under the Freedom of Information Act (FOIA), 5 U.S.C. §552, the DOE regulations, 10 C.F.R. §1004.11, implementing the FOIA, and the Trade Secrets Act, 18 U.S.C. §1905. The Energy Information Administration (EIA) will protect your information in accordance with its confidentiality and security policies and

procedures.
The Federal Energy Administration Act requires the EIA to provide company-specific data to other Federal agencies when requested for official use. The information reported on this form may also be made available, upon request, to another component of the Department of Energy (DOE); to any Committee of Congress, the General Accounting Office, or other Federal agencies authorized by law to receive such information. A court of competent jurisdiction may obtain this information in response to an order. The information may be used for any non-statistical purposes such as administrative, regulatory, law enforcement, or adjudicatory purposes.

Disclosure limitation procedures are applied to the statistical data published from EIA-23 survey information to ensure that the risk of disclosure of identifiable information is very small.

Confidential information collected on Form EIA-23 will be provided to United States Department of Interior offices (the Mineral Management Service and the United States Geological Survey) for statistical purposes only, in conducting their resource estimation activities. In addition, company-specific data considered as critical infrastructure information may be provided to other Federal agencies for emergency planning and response.

H. REPORTING STANDARDS

1. Proved Reserves

Proved reserves of oil and gas as of December 31, 2003 are the estimated quantities of oil and/or gas, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under current economic and operating conditions.

Oil and gas reservoirs are considered "proved" if economic producibility is supported by actual production or conclusive formation tests (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 reservoir considered "proved" includes:

1) that portion delineated by drilling and defined by gas-oil, gas-water 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 controls the lower proved limit of the reservoir.

Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when:

1) successfully tested by a pilot project, or
2) operation of an installed program in the reservoir provides support for the engineering analysis on which the project or program was based.

For natural gas reserves, wet after lease separation, an appropriate reduction in the reservoir gas volume shall be made to cover the removal of:

1) liquefiable portions of the gas in <u>lease and/or field separation facilities</u>, and
2) non-hydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable.

Estimates of proved reserves do not include the following:

1) oil that may become available from known reservoirs but is reported separately as "indicated additional reserves";
2) oil and/or gas, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics or economic factors;
3) oil and/or gas that may occur in undrilled prospects;
4) oil that may be recovered from oil shales, coal, gilsonite and other such sources; and
5) volumes placed in underground storage.

It is not necessary that production, gathering or transportation facilities are installed or operative for a reservoir to be considered proved.

2. Calendar Year Production

Production data are required from all operators. If the actual 2003 production data are not available at the time Form EIA-23 is prepared, estimate production. Note that amended schedules are not required to correct preliminary production data. Production data reported in the prior year survey may have been subsequently revised or corrected, thereby altering the end of the prior year reserves. Any change in the end of the prior year reserves due to this factor should be accounted for as part of the “Revision Increases” or “Revision Decreases” reported in the current survey.

If any properties were acquired during the Calendar Year, production data from the acquired properties should be reported from the date of purchase. If any properties were sold during the Calendar Year, production data should be reported until the date of sale.

3. Total Operated Basis

All data on Schedule A (reserves and related data by field) are to be reported on an 8/8ths or Total Operated Basis. When reporting on this basis, **production and reserves data for any properties on which operations were acquired during the Calendar Year should be reported from the date of transfer or purchase. If any properties were sold or transferred to a new operator during the Calendar Year, production and reserves data should be reported until the date of sale or transfer.**

EXAMPLES:

Of the total 8/8ths interest, respondent's share is 50 percent and the associated royalty share is 6.25 percent. Respondent operates property. Respondent reports 100 percent of proved reserves and production.

Of the total 8/8ths interest, respondent's share is zero but it operates the property (i.e., a contract operator). Respondent reports 100 percent of proved reserves and production.

4. States and Geographic Subdivisions

The determination of which state or geographic subdivision within which to report proved reserves and production data is based on the location of the field(s) containing the oil and/or gas. If a field overlaps two or more states or subdivisions, the proved reserves data must be subdivided into the

appropriate geographic components. Refer to the maps in the **Glossary** for the subdivision boundaries in the States of Alaska, California, Louisiana, New Mexico and Texas.

Offshore proved reserves data are required separately for the State and Federal domains. If an offshore field lies on or between disputed boundaries, include all data in the State offshore area.

5. Reporting Units

All volumes are to be reported in the appropriate reporting units as shown below.

a. Crude Oil

All crude oil volumes are to be reported in **thousands of barrels (MBarrels)** (42 U.S. gallons per barrel at atmospheric pressure corrected to 60° Fahrenheit) and excluding basic sediment and water.

b. Natural Gas

All natural gas volumes are to be reported in **millions of cubic feet (MMCF)** at **14.73 psia** and **60° Fahrenheit**, wet after lease separation.

It is recognized that the operator in many instances has no knowledge of the ultimate reduction of the gas stream produced from his properties, which may result from further downstream processing. The operator is requested to report volumes of natural gas, which remain after processing through lease and field separation facilities. Volumes of gas that are flared are also considered production.

The EIA obtains data from gas processing plants separately. Gas volumes reported on Form EIA-23 should not be corrected for liquids removed by these plants. If you do not know if a field facility through which your gas is processed is currently reporting data to the EIA or not, contact the EIA-23 Coordinator to obtain information on those plants which report.

Operators should segregate natural gas data into **associated-dissolved and nonassociated gas** entries (see **natural gas, associated-dissolved and natural gas, nonassociated** in Glossary, Section J). For a given reservoir, the gas type should represent the State classification as of December 31, 2003. This gas type may differ from the classification reflected in the prior year's Form EIA-23 filing. Use identical "Revision Increases" of one gas type and "Revision Decreases" of the other gas type to record any changes in gas type classifications from previous EIA-23 filings.

c. Lease Condensate

All lease condensate volumes are to be reported in **thousands of barrels (MBarrels)** (42 U.S. gallons per barrel, at atmospheric pressure corrected to 60° Fahrenheit).

d. Rounding

When rounding liquid volumes, round 500 barrels and above up to "1" MBbls, and less than 500 barrels down to "0" MBbls. For gas volumes, round 500 MCF and above up to "1" MMCF, and less than 500 MCF down to "0" MMCF. **Blank entries <u>should not</u> be completed with "0".**

Volumes should be reported in whole numbers. Volumes containing decimals should be rounded to the nearest whole number.

e. Negative and Positive Volumes

All data are to be entered as whole number integers without plus (+) or minus (-) symbols. By definition, "Revision Decreases," "Sales," and "Production" all constitute reserve decreases and are entered without the minus symbol.

An unusual situation may occur when, for pressure maintenance, a field is injected with natural gas produced from another field. The resultant increase in proved gas reserves is considered a "Revision Increase" for those volumes that are reasonably expected to be recovered at some future date. A Schedule B footnote must indicate the total injected volume and the expected future recoveries.

6. Prior Year's Filing

Entries for "Reserves, December 31, 2002" in this year's Form EIA-23 filing should not differ from those quantities reported as end-of-year reserves in the prior year's filing. Special situations that can occur are listed below:

a. Properties Were Purchased or Acquired

If operations were transferred <u>from</u> another company to the respondent during the calendar year, then these reserves should be shown in "Acquisitions" (column (e) on Schedule A). Reserves and production for the acquired properties should be reported from the date of purchase. Additionally, a Schedule B footnote must be provided indicating the name of the previous operator and the month in which operations were acquired.

b. Properties Were Sold or Transferred

If operations were transferred <u>to</u> another company during the calendar year, then these reserves should be shown in "Sales" (column (d) on Schedule A). Reserves and production for these properties should be reported until the date of sale. Additionally, a Schedule B footnote must be provided indicating the name of the new operator and the month in which operations were transferred. In the event the respondent no longer operates any properties in this field, then the "Reserves, December 31, 2003" (column (j) on Schedule A) would be zero.

c. Gas Type Reclassified

In the case where the type of gas was improperly reported or reclassified from associated-dissolved (AD) to non-associated (NA), or vice-versa, report the "Reserves, December 31, 2002" from last year's Schedule A for the previous classification. Eliminate the reserves of the previous classification by a Revision Decrease {Schedule A, Column c} and create the reserves of the new classification by an equal Revision Increase {Schedule A, Column b}. Enter zero for December 31, 2002 reserves for the new classification. Note the reclassification of natural gas on Schedule B.

d. First Time Reserve Report

If a respondent reports reserves estimates in the current survey but not in the prior year's survey because such estimates were not available in the company records at that time, add column (i), "Calendar Year Production" and column (j), "Reserves December 31, 2003". Enter the sum in column (a), "Reserves December 31, 2002".

7. Schedule Preparation Standards

Prior to submission, completed forms must be assembled and paginated consecutively within each schedule in the following order:

1) Cover Page
2) Schedule A ... by state, then subdivision within state, in the same sequence as shown in the Location Code list of the Glossary. Field entries should be listed alphabetically by field name within each subdivision, or within each state not having subdivisions. The last Schedule A page is to contain the National Summary total for all reported fields
3) Schedule B (if needed) ... by state, then subdivision within state, in the same sequence as Schedule A.

SPECIFIC INSTRUCTIONS

I. OPERATOR IDENTIFICATION AND DETAILED REPORT

This information is to be reported on the Cover Page submitted. You are required to enter those items that are incorrect or missing from the preprinted form.

1. COVER PAGE - Operator Identification

Part I. Identification

EIA Identification Number: This item is for DOE use only.

Company Name, Address, City, State, ZIP Code. Enter the legal name and address of the operator. Use standard State abbreviations found in the Glossary on page 17. If a foreign address, enter city, local equivalent of State name (e.g., province), and country on the second address line.

EIN: Enter the operating firm's IRS Employer Identification Number (EIN), if it has one.

Item Instructions:

Item 1: Contact Information. Name, telephone number, fax number, and e-mail address of the person most knowledgeable about the reported data. This person should be familiar with the data provided, and will be the person to whom inquiries will be directed, if necessary.

Item 2: "Was your company an oil and gas field operator ...?" Check the appropriate box and follow the instructions for completing the rest of the form.

Item 3: Company Status, Name, and/or Address Change or Correction. If there was a change to the company name or address, or if the company was sold, merged with another company, or the company went out of business, check the appropriate box and complete Item 4.

Item 4: Change Company Name, Address, EIN, and/or Contact Information. If any box in Item 3 was checked, enter the new or correct company name, address, EIN, or contact person here.

Part II. Parent Company Identification

Item 5. Is there a parent company …?" Check the appropriate box. If Box 2 is checked, provide parent company information in Items 6 through 11.

Item 6. Company Name. Enter the legal name and address of the parent company, if any that exercises ultimate control over the respondent.

> **Example:** You are Company A, which takes direction from Company B, which in turn takes direction from Company C. Report Company C as the parent company, rather than Company B.

Item 7: Parent Company EIN - Enter the EIN of the parent company, if any.

Items 8-11: Address, City, State, and Zip Code. Enter the address, City, State, and Zip Code of the parent company.

Part III. Attestation

Items 12 thru 15: Attestation - Enter the name and title of the individual designated by the respondent company to sign the attestation, and the date of the signing. This report must be sworn to or affirmed by a responsible officer or the office responsible for regulatory filings.

2. SCHEDULE A – Operated Proved Reserves, Production and Related Data By Field

All proved reserves, production and reserve changes data on Schedule A are to be reported on a Total Operated Basis for each field in which the respondent operated oil and/or gas wells on December 31, 2003, including abandonments during the year. (See **Total Operated Basis** in Section H.3 and J) If a field overlaps two or more States or subdivisions, data pertaining to each must be separately reported.

SECTION 1.0: Operator and Report Identification Data

The information in this section is to be reported on each Schedule A submitted.

Item Instructions:

Item 1.1: Operator I.D. Code - If the operator ID from the preprinted form on the Cover Page is incorrect, enter the correct 10-digit number.

Item 1.2: Operator Name - If the name of the operator from the preprinted form on the Cover Page is incorrect, enter the first 35 characters of the operator name. If the name exceeds 35 characters, do not abbreviate, but simply truncate the extra characters from the right.

Item 1.3: Original - Enter an `X' if this is the first submission of this schedule for the report year. Otherwise, leave blank.

Item 1.4: Resubmission - Enter an `X' if this schedule amends a previously submitted schedule. Otherwise, leave blank.

Item 1.5: Page – Enter the current page number in this schedule series.

SECTION 2.0: Field Data (Operated Basis)

Production data and/or estimates of proved reserves of crude oil, natural gas, and lease condensate are required of each operator selected. This survey segregates selected operators into three categories, according to the annual production of hydrocarbons from wells that they operated on December 31, 2003. The three size categories are as follows:

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.

Production refers to the total report year production from all domestic oil and/or gas wells you operated on December 31, 2003, including wells abandoned during the year.

Production data and proved reserve estimates are required from all Category I operators. Production data are required from all Category II operators. Proved reserves estimates are required from Category II operators only if such data exist in company records. To the extent that Category II operators do not have proved reserves estimates associated with one or more specific properties, they must report total production for all properties. They need to provide a footnote that separates their production data according to production from properties for which proved reserves have been estimated and production from properties for which proved reserves have not been estimated.

Field data blocks, items 2.1 through 2.3, are to be utilized by both the Category I and Category II respondents to report their production and proved reserves at the field level. A Category II operator may elect to file as a Category I operator.

All Category II operators are required to complete Subitems 1, 2, 3, 4, and 6. Subitem 11 must also be completed if this information is available. Category II operators who have reserve estimates should complete Columns (a) through (i), Subitems 12 through 15 as appropriate. Category II operators who do not have proved reserve estimates should use Subitems 12 through 15, Column (i) only, as appropriate to report field production data. In the event the operator has partial reserve estimates for a given field, production for that portion for which no reserve estimates are available should be combined with the production for which reserves were estimated. Subitems 12 through 15 should be utilized to report available reserves and associated production data from the remaining part of the field.

If it would make your forms preparation easier, a new State or State subdivision may be started in the first field data block of a new Schedule A page. In all other cases, utilize all three-field data blocks on each Schedule A. When completing more than one page of Schedule A, do not renumber items 2.1 through 2.3 on successive pages. However, be certain to enter the correct, consecutive page numbers on each page in item 1.5.

Items 2.1 through 2.3:

Subitem 1: State Abbreviation - Enter the two-character alphabetic abbreviation of the State to which data reported for this field pertains. For offshore fields, use the abbreviation of the adjacent state. (See **Geographic Codes** in Section L)

Subitem 2: Subdivision Code - Enter the two-digit code of the appropriate geographic subdivision to which data reported for this field pertain; leave blank if not applicable. (See **Geographic Codes** in Section L)

Subitem 3: County Code - For onshore areas, enter the three-digit numeric code for the county or parish in which the field is located, as it appears on the EIA *2003 Annual Oil and Gas Field Code Master List*. The RIGS CD-ROM sent to all Category I and II operators contains the information from the *2003 Annual Oil and Gas Field Code Master List* publication. The List is also available on our website at http://www.eia.doe.gov. After logging on the EIA website, highlight the *By Fuel* category; select *Petroleum or Natural Gas*; then select *Publications* on the sidebar at the left of the screen; then scroll to *Oil and Gas Field Code Master List* under Annual. If the field is located in more than one county, enter the code for the county that contains the largest lease acreage, overlying proved reserves, which you operate. (See **County Codes** in Section L)

Subitem 4: Field Code - Enter the six-digit field identification code as it appears on the EIA *2003 Annual Oil and Gas Field Code Master List*. If you cannot locate the field name on the list or there is substantial doubt that a field identified on the list is the same field that you are reporting, insert UNK001 for the first such field, then UNK002 for the second such field, etc. for this Subitem. (See **Field Coding Conventions** in Section L)

Subitem 5: MMS Code – Enter the Minerals Management Service (MMS) Code, as shown in the EIA *2003 Annual Oil and Gas Field Code Master List*.

Subitem 6: Field Name - Enter the name of the field to which data entered in this data block item pertains. Do not include reservoir names unless they are part of the proper field name. (See **Field Naming Conventions** in Section K)

Subitem 7: Proved Non-producing Reserves. Enter the estimated volumes of proved reserves in the field, which were in non-producing status at the end of the calendar year. This includes proved developed non-producing and proved undeveloped reserves. (See **Non-producing Reserves** in Section J.)

Subitem 8: Footnote - Enter an "X" if further explanatory information pertaining to data for this field appears on Schedule B, Footnotes. Leave blank if there is no footnote information.

Subitem 9: Water Depth - For an offshore field, enter the average depth of water (from mean sea level to seabed) over the field, in feet. Leave blank if an onshore field.

Subitem 10: **Field Discovery Year** - Enter the calendar year in which the field was discovered. Field discovery years may be found in the *2003 Annual Oil and Gas Field Code Master List*. Footnote on Schedule B and check Subitem 8 if this represents a change from a previously reported discovery year for this field. Enter 'NA' if not known. (See **Field Discovery Year** in Section J)

Subitem 11: **Indicated Additional Reserves of Crude Oil** - Enter the estimated volumes of crude oil which may become available through the application of improved recovery techniques. (See **Indicated Additional Reserves of Crude Oil** in Section J)

Subitem 12: **Crude Oil** (MBarrels)

Subitem 13: **Associated-Dissolved Gas** (MMCF)

Subitem 14: **Non-associated Gas** (MMCF)

Subitem 15: **Lease Condensate** (MBarrels)

Column (a): **Total Proved Reserves, December 31, 2002** - Enter the volumes of total proved reserves as of December 31, 2002. (See **Proved Reserves of Crude Oil, Proved Reserves of Lease Condensate** and **Proved Reserves of Natural Gas, Wet After Lease Separation** in Section J) (See Section H, Item 6, page 4, for explanation of reserve changes from prior year's filing.)

Column (b): **Revision Increases** - Enter the total of upward revisions made in the field during the calendar year. Explain any total revision increase in excess of 2,500 MBarrels of liquid or 15,000 MMCF of gas in a Schedule B footnote and check Subitem 8. To the extent that reserves are revised upward due to implementation of secondary or tertiary recovery techniques, such revisions should be indicated by volume and by recovery method in a Schedule B footnote. Also, indicate in a Schedule B footnote the volume of any upward revisions due to the transfer of reserves previously reported as `Indicated Additional Reserves of Crude Oil' to proved status. (See **Revisions** in Section J.)

Column (c): **Revision Decreases** - Enter the total of downward revisions made in the field during the calendar year. Do not enter a minus sign as entries in this column are assumed to be negative. Explain any total revision decrease in excess of 2,500 MBarrels of liquid or 15,000 MMCF of gas in a footnote on Schedule B and check subitem 8. (See **Revisions** in Section J.)

Column (d): **Sales** – If operations were transferred to another company during the calendar year, then these reserves should be reported as “Sales.” Enter the reserves for these properties until the date of sale. Additionally, a Schedule B footnote must be provided indicating the name of the new operator and the month in which operations were transferred. In the event the respondent no longer operates any properties in this field, then the “Reserves, December 31, 2003” (column (j)) will be zero.

Column (e): **Acquisitions** – If operations were transferred from another company to the respondent during the calendar year, then these reserves should be reported as “Acquisitions.” Enter the reserves for the acquired properties from the date of purchase or transfer. Additionally, a Schedule B footnote must be provided indicating the name of the previous operator and the month in which operations were acquired.

Column (f): **Extensions** – If this is an old field, enter the increases to the field’s reserves attributable to extensions, including increased density and recompleted wells, during the current calendar year. (See **Extensions** in Section J.)

Column (g): **New Field Discoveries** - If the field was discovered during the calendar year 2003, enter the estimated initial volumes of proved reserves attributable thereto (before reducing it by production during the calendar year, if any). See **New Field Discoveries** in Section J.)

Column (h): **New Reservoir Discoveries in Old Fields** - If this is an old field and any new reservoir discoveries were made in it during the calendar year, enter the estimated initial volumes attributable thereto, (before reducing by production during the calendar year, if any). (See **New Field** and **Old Field** in Section J.)

Column (i): **Calendar Year Production** - Enter the volumes produced from the field during the calendar year. (See **Production, Crude Oil, Production, Lease Condensate** and **Production, Natural Gas, Wet After Lease Separation** in Section J.)

Column (j): **Total Proved Reserves, December 31, 2003** - Enter the volumes of total proved reserves as of December 31, 2003. This item should be the algebraic sum of Columns (a) + (b) + (e) + (f) + (g) + (h), less Columns (c), (d), and (i). This value includes producing and non-producing reserves and therefore should always be equal to or greater than the values shown in Subitem 7.

NATIONAL TOTALS

National totals for each of the volumetric data elements reported on Schedule A are required. After all fields in which you operate have been reported on Schedule A, sum each data element included in subitem 7, 11, and 12 through 15. Enter these national totals in corresponding subitem locations of the first unused field data block, items 2.1 through 2.4. Enter "ZZ" in Subitems 1 through 4 and "NATIONAL TOTALS" or “COMPANY TOTALS” in Subitem 6 to identify these data as national summary totals.

3. SCHEDULE B - Footnotes

At a minimum, submit footnotes in clarification of reported data items when required to do so by the instructions for the

applicable schedule. This includes sales or acquisitions of properties during the calendar year 2003. Additionally, you may footnote any other reported item if this will enhance its clarity.

SECTION 1.0: Operator and Report Identification Data

This information is to be reported for each Schedule B submitted.

Item Instructions:

Item 1.1: Operator I.D. Code - If the operator ID from the preprinted form on the Cover Page is incorrect, enter into this space the correct 10-digit operator code. If no code has been assigned to you, leave this space blank.

Item 1.2: Operator Name - If the operator name from the preprinted form on the Cover Page is incorrect, enter the first 35 characters of the operator name. If the name exceeds 35 characters, do not abbreviate, but simply truncate the extra characters from the right.

Item 1.3: Original - Enter an “X” if this is the first submission of this schedule for the calendar year. Otherwise, leave blank.

Item 1.4: Resubmission - Enter an 'X' if this schedule amends a previously submitted schedule. Otherwise leave blank.

Item 1.5: Page - Enter the current page number in this schedule series.

SECTION 2.0: Footnote Data

Use all lines on each Schedule B page before using additional pages. Columns (a) thru (d) must be filled in only for the first line of each footnote.

Column (a): Page Number - Enter the page number that is referenced by this footnote.

Column (b): Field Designation – Enter the corresponding field data section number from Schedule A (e.g., 2.1, 2.2, or 2.3).

Column (c): Item Number - Enter the item number (1 through 15) that is referenced by this footnote 9.

Column (d): Column Designation - Enter the column designation (alphabetic character, a to j), if applicable, that is referenced by the footnote. Otherwise leave blank.

Column (e): Footnote - Enter the text of the footnote, using as many lines as necessary.

GLOSSARY AND CODES

J. DEFINITIONS

The definitions contained herein have been formulated with reference to the particular purposes to be served by Form EIA-23. They are not necessarily synonymous with the same or similar terms as used in DOE regulations and are not to be constructed as definitions applicable for any purposes other than the collection and reporting of data on Form EIA-23.

Acquisitions: The volumes of proved reserves of crude oil, natural gas and/or lease condensate associated with properties that were purchased and/or transferred from another company to the respondent's operatorship during the calendar year.

Affiliated (Associated) Company: An entity that is directly or indirectly owned, operated or controlled by another entity. (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 (excluding Lease Condensate): A mixture of hydrocarbons that exists primarily in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Such hydrocarbons as lease condensate and natural gasoline recovered as liquids from natural gas wells in lease or field separation facilities and later mixed into the crude stream are excluded. Depending upon the characteristics of the crude stream, it may also include:

1) small amounts of hydrocarbons that exist in gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators and are subsequently commingled with the crude stream without being separately measured and/or
2) small amounts of non-hydrocarbons produced with the oil, such as sulfur and various metals.

When a State regulatory agency specifies a definition of crude oil, which differs from that set forth above, the State definition is followed.

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. This would also include increased density wells and recompletions that extend the drainage area of the field beyond the existing wells.

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, which are separated vertically by intervening impervious strata or laterally by local geologic barriers or by both.

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

Field Discovery Year: The calendar year in which a field was first recognized as containing economically recoverable accumulations of oil and/or gas. The official dates may be found in the *Oil and Gas Field Code Master List.*

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

Gas Processing Plant: Facilities designed to recover natural gas liquids from a stream of natural gas that may or may not have passed through lease separators and/or field separation facilities. These facilities also control the quality of the natural gas stream to be marketed. Cycling plants are classified as natural gas processing plants.

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

These recovery techniques may:

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

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

Lease Condensate: A mixture consisting primarily of pentanes and heavier hydrocarbons which is recovered as a liquid from natural gas in lease or field separation facilities. This category excludes natural gas plant liquids, such as butane and propane, which are recovered at downstream natural gas processing plants or facilities. The output of natural gas processing plants is reported on Form EIA-64A, "*Annual Report of the Origin of Natural Gas Liquids Production*," and Form EIA-816, "*Monthly Natural Gas Liquids Report*."

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

Natural Gas: A gaseous mixture of hydrocarbon compounds, the primary one being methane. Note: The Energy Information Administration measures ***wet natural gas*** and its sources of production, ***associated/dissolved natural gas*** and ***non-associated natural gas***, and ***dry natural gas***, which are produced from ***wet natural gas***. This EIA survey does not include landfill gas (biomass gas), synthetic natural gas, coke oven gas or manufactured gas.

Wet natural gas: A mixture of hydrocarbon compounds and small quantities of various non-hydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane and pentane. Typical non-hydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, hydrogen sulfide, nitrogen and trace amounts of helium. Under reservoir conditions, natural gas and its associated 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. Note: The Securities and Exchange Commission and The Financial Accounting Standards Board refer to this product as ***natural gas***.

Associated-dissolved natural gas: Natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (casinghead gas). See ***natural gas***.

Non-associated natural gas: Natural gas that is not in contact with significant quantities of crude oil in the reservoir. See ***natural gas***.

Dry natural gas: Natural gas that remains after:
1) the liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field and/or plant separation); and
2) any volumes of non-hydrocarbon gases have been removed where they occur in sufficient quantity to reduce the gas quality below minimum pipeline specifications (rendering it unmarketable).

Note: Dry natural gas is also known as consumer-grade natural gas. The parameters for measurement are cubic feet at 60 degrees Fahrenheit and 14.73 pounds per square inch absolute (psia). See ***natural gas***.

New Field: A field discovered during the calendar year.

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

New Reservoir: A reservoir discovered during the calendar 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 calendar year in new reservoir(s) located in old fields.

Non-producing Reserves: Quantities of proved liquid or gaseous hydrocarbon reserves that have been identified, but which did not produce during the last calendar year regardless of the availability and/or operation of production, gathering or transportation facilities. This includes both proved undeveloped and proved developed non-producing reserves.

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

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

Operator: 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, 2003. 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 2003 are also to be considered "operated" as of December 31, 2003. (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: A firm that directly or indirectly controls another entity. (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 general, a reservoir. In certain situations a pool may consist of more than one reservoir. (See **Field Area**)

Production, Crude Oil: The volumes of crude oil that was extracted from oil reservoirs during 2003. These volumes are determined through measurement of the volumes delivered from lease storage tanks or at the point of custody transfer, with adjustment for:
1) net differences between opening and closing lease inventories, and
2) basic sediment and water.

Crude oil used on the lease is considered production.

Production, Lease Condensate: The volume of lease condensate produced during 2003. Lease condensate volumes include only those volumes recovered from lease or field separation facilities. (See **Lease Condensate**)

Production, Natural Gas: The volume of natural gas withdrawn from reservoirs during the calendar year less:
1) the volume returned to such reservoirs in cycling, repressuring of oil reservoirs and conservation operations;
2) the shrinkage resulting from the removal of lease condensate; and
3) non-hydrocarbon 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. Flared and vented gas is also considered production and should be included in the volumes reported.

Proved Reserves of Crude Oil: Proved reserves of crude oil as of December 31, 2003 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 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 are installed or operative for a reservoir to be considered proved.

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

Proved Reserves of Natural Gas: The estimated quantities which analysis of geologic 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 considered proved reserves.

For natural gas reserves, wet after lease separation, an appropriate reduction in the reservoir gas volume must be 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.

It is not necessary that production, gathering or transportation facilities are 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.

Report Year: The calendar year to which data reported on this form pertains.

Reserves: (See **Proved Reserves**)

Reserves Changes: Positive and negative revisions, sales, acquisitions, extensions, new field discoveries and new reservoir discoveries in old fields which occurred during the calendar 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) or acquisition or sales of properties. Revisions include increases of proved reserves associated with the installation of improved recovery techniques or equipment. They also include correction of prior calendar year arithmetical or clerical errors **and** adjustments to prior year-end production volumes to the extent that these alter previous reserves estimates.

Royalty (Including Overriding Royalty) Interests: Rights that entitle their owner(s) to a share of the mineral production from a property or to a share of the proceeds from a property. 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.

Sales: The volumes of proved reserves of crude oil, natural gas and/or lease condensate associated with properties that were sold and/or transferred during the calendar year from the respondent's operatorship to that of another company.

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 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: Rights that 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. In return for these investments, the owner(s) is (are) entitled to a share of the mineral production from the property or to a share of the proceeds from the property.

K. FIELD NAMING AND CODING CONVENTIONS

Information from the EIA *2003 Annual Oil and Gas Field Code Master List* were included on the RIGS CD-ROM enclosed for all Category I and Category II operators. This List is also available on our website at http://www.eia.doe.gov. After logging on the EIA website, highlight the *By Fuel* category; select *Petroleum or Natural Gas*; then select *Publications* on the sidebar at the left of the screen; then scroll to *Oil and Gas Field Code Master List* under Annual. Please consult this publication for the appropriate State, county and field codes and spelling conventions for field names.

1. Field Naming Conventions

Field naming conventions are used to provide a standard nomenclature for each geologic field that is recognizable to both the personnel working with the EIA-23 form and the computer system and fits into 26 characters. In most instances, field names should reflect the conventions imposed by State oil and gas regulatory agencies. (See *2003 Annual Oil and Gas Field Code Master List*, Table 1. List of Authorities for Naming Oil and Gas Fields.) Field names that have come into general acceptance in an area may be used, unless they have been specifically altered or replaced by the appropriate naming authority. Also, field names used strictly by one company must give precedence to the State recognized name.

Exceptions occur for names of fields located in Texas and New Mexico, in which States the regulatory agencies consider geologic reservoirs to be "fields." For example, in Texas, Parker (Pennsylvanian) and Parker (Wolfcamp) are considered separate fields by the State. In actuality, Parker is the name of the geologic field and Pennsylvanian and Wolfcamp are reservoir names of the geologic reservoirs in the field (by Texas Railroad Commission convention, the geologic reservoir name appears in parentheses after the geologic field name). For the purpose of reporting names on Schedule A of form EIA-23, only the geologic field name should be used. In the example above, "PARKER" would be entered as the field name, subitem 6, in the field data block of Schedule A. Some specific conventions include the following:

1) Offshore field names usually (but not always) consist of a basic offshore area name and block number specified by the U.S. Minerals Management Service. Example: East Cameron South addition Block 265. If offshore area names must be abbreviated to fit within 26 characters allowed, the following standard abbreviations should be used:

Name	Code	Name	Code
NORTH	N	NORTH ADDITION	NA
SOUTH	S	SOUTH ADDITION	SA
EAST	E	EAST ADDITION	EA
WEST	W	WEST ADDITION	WA
BLOCK	BLK	SOUTH EXTENSION	SX
ISLAND	IS	EAST EXTENSION	EX

For example, High Island East Addition South Extension Block A-375 should be abbreviated as follows:

HIGH IS EA SX BLK A-375.

2) Such abbreviations should not be applied to names of onshore fields (except for non-cardinal compass points such as NW for northwest or SE for southeast). If an onshore field name is too long to fit in the allotted space, truncate it on the right and provide the full name on Schedule B.

3) Compass point words used in field names are to be placed at the end of the field name (i.e. Three Mile Creek North). Exceptions are made for geographic places, such as East Texas field of East Texas or East Branch, a field named for East Branch, Pennsylvania.

4) Special attention should be given to reporting field names in Michigan. Most fields have the section, township and range after the field name. For example: Kalkaska 12-27N-7W. Operators should report field name as indicated.

5) If a field that has been reported in the previous year is changed or aliased to another field according to the field code publication, report the data under the new field name. For example, Mud Spring is an alias of Four Mile Creek. All data that was previously reported under Mud Spring should now be reported under and combined with any previous Four Mile Creek data.

6) Lease names are not acceptable in lieu of geologic field names. To determine the field name for a particular lease, contact the EIA-23 Field Coordinator at 1-800-879-1470, the state geologic survey or conservation commission. If a field name cannot be determined, report the field name as "unknown."

Any names other than official EIA field names will be researched during routine editing of Form EIA-23 data.

2. Field Coding Conventions

Field codes are to be entered on Schedule A for all fields reported by Category I and Category II respondents. The field names and corresponding six-digit code are contained in the EIA *2003 Annual Oil and Gas Field Code Master List*. If a field for which you are reporting does not appear on the Master List, enter UNK001 or UNK002 for

the field code and enter the field name and location information. Please use Schedule B - Footnotes for such clarifying data as may allow us to properly identify fields not on the Master List.

L. LOCATION CODES

Wherever applicable, the following codes are those specified as in the EIA *2003 Annual Oil and Gas Field Code Master List*.

1. Geographic Codes

The following State abbreviations and geographic subdivision codes should be used in Schedule A, Subitems 1 and 2 of Items 2.1 through 2.3.

State and geographic codes are to be entered on Schedule A for all fields reported by Category I and Category II respondents. The State and geographic subdivision names and corresponding codes are contained in the EIA *2003 Annual Oil and Gas Field Code Master List*. If a field for which you are reporting does not appear on the Master List, enter UNK001 or UNK002, etc. for the field code and enter the state location, county code and field name information in Schedule A. Please use Schedule B - Footnotes for such clarifying data as may allow us to properly identify fields not on the Field Code Master List.

2. County Codes

The county codes should be used in Schedule A, Subitem 3 of Items 2.1 through 2.3. County codes are to be entered on Schedule A for all fields reported by Category I and Category II respondents. The county names and corresponding three-digit code are contained in the EIA *2003 Annual Oil and Gas Field Code Master List* publication. If a field for which you are reporting does not appear on the Master List, enter UNK001 or UNK002, etc. for the field code and enter the field name, county name and state location information in Schedule B. Please use Schedule B - Footnotes for such clarifying data as may allow us to properly identify fields not on the Master List.

There are no counties in Alaska. Census Divisions have been used to locate oil and gas fields in the past. However, these Divisions are subject to change every 10 years. Therefore, pseudo-county codes as defined by the American Petroleum Institute (API) are to be used for Form EIA-23 reporting. The API pseudo-county codes are used by the State of Alaska and are generally accepted within the industry. They correspond to Universal Transverse Mercator 1 degree by 3-degree quadrangles. Each quadrangle is assigned a 3-digit code that should be entered in the county code blank. See the map of Alaska for the location of the quadrangles.

The EIA-23 Coordinator can be contacted at 1-800-879-1470 for assistance with both county codes and the Alaska codes.

State Abbreviation and Geographic Subdivision Codes

State Name and Geographic Subdivisions[1]	State Abbreviation	Subdivision Code
Alaska - South State Offshore[2]	AK	05
Alaska - South Onshore	AK	10
Alaska - North Onshore and Offshore[3]	AK	50
Alabama - Onshore	AL	Blank
Alabama - State Offshore[2]	AL	05
Arkansas	AR	Blank
Arizona	AZ	Blank
California - State Offshore[2]	CA	05
California - San Joaquin Basin Onshore	CA	10
California - Coastal Region Onshore	CA	50
California - Los Angeles Basin Onshore	CA	90
Colorado	CO	Blank
Connecticut	CT	Blank
District of Columbia	DC	Blank
Delaware	DE	Blank
Federal Offshore - Atlantic	AC	00
Federal Offshore - Gulf of Mexico (Alabama)	AL	00
Federal Offshore - Gulf of Mexico (Florida)	FL	00
Federal Offshore - Gulf of Mexico (Louisiana)	LA	00
Federal Offshore - Gulf of Mexico (Mississippi)	MS	00
Federal Offshore - Gulf of Mexico (Other Gulf)	OG	00
Federal Offshore - Gulf of Mexico (Texas)	TX	00
Federal Offshore - Pacific (Alaska)	AK	00
Federal Offshore - Pacific (California)	CA	00
Federal Offshore - Pacific (Oregon)	OR	00
Federal Offshore - Pacific (Washington)	WA	00
Florida - Onshore	FL	Blank
Florida - State Offshore[2]	FL	05
Georgia	GA	Blank
Hawaii	HI	Blank
Iowa	IA	Blank
Idaho	ID	Blank
Illinois	IL	Blank
Indiana	IN	Blank
Kansas	KS	Blank
Kentucky	KY	Blank
Louisiana - South State Offshore[2]	LA	05
Louisiana - South Onshore	LA	10
Louisiana - North	LA	50
Massachusetts	MA	Blank
Maryland	MD	Blank
Maine	ME	Blank
Michigan	MI	Blank
Minnesota	MN	Blank
Missouri	MO	Blank
Mississippi - Onshore	MS	Blank
Mississippi - State Offshore[2]	MS	05
Montana	MT	Blank
North Carolina	NC	Blank
North Dakota	ND	Blank
Nebraska	NE	Blank
New Hampshire	NH	Blank
New Jersey	NJ	Blank
New Mexico - East	NM	10
New Mexico - West	NM	50
Nevada	NV	Blank
New York	NY	Blank
Ohio	OH	Blank
Oklahoma	OK	Blank
Oregon	OR	Blank
Pennsylvania	PA	Blank
Rhode Island	RI	Blank
South Carolina	SC	Blank
South Dakota	SD	Blank
Tennessee	TN	Blank
Texas - State Offshore[2]	TX	05
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
Utah	UT	Blank
Virginia	VA	Blank
Vermont	VT	Blank
Washington	WA	Blank
Wisconsin	WI	Blank
West Virginia	WV	Blank
Wyoming	WY	Blank
National Totals	**ZZ**	**ZZ**

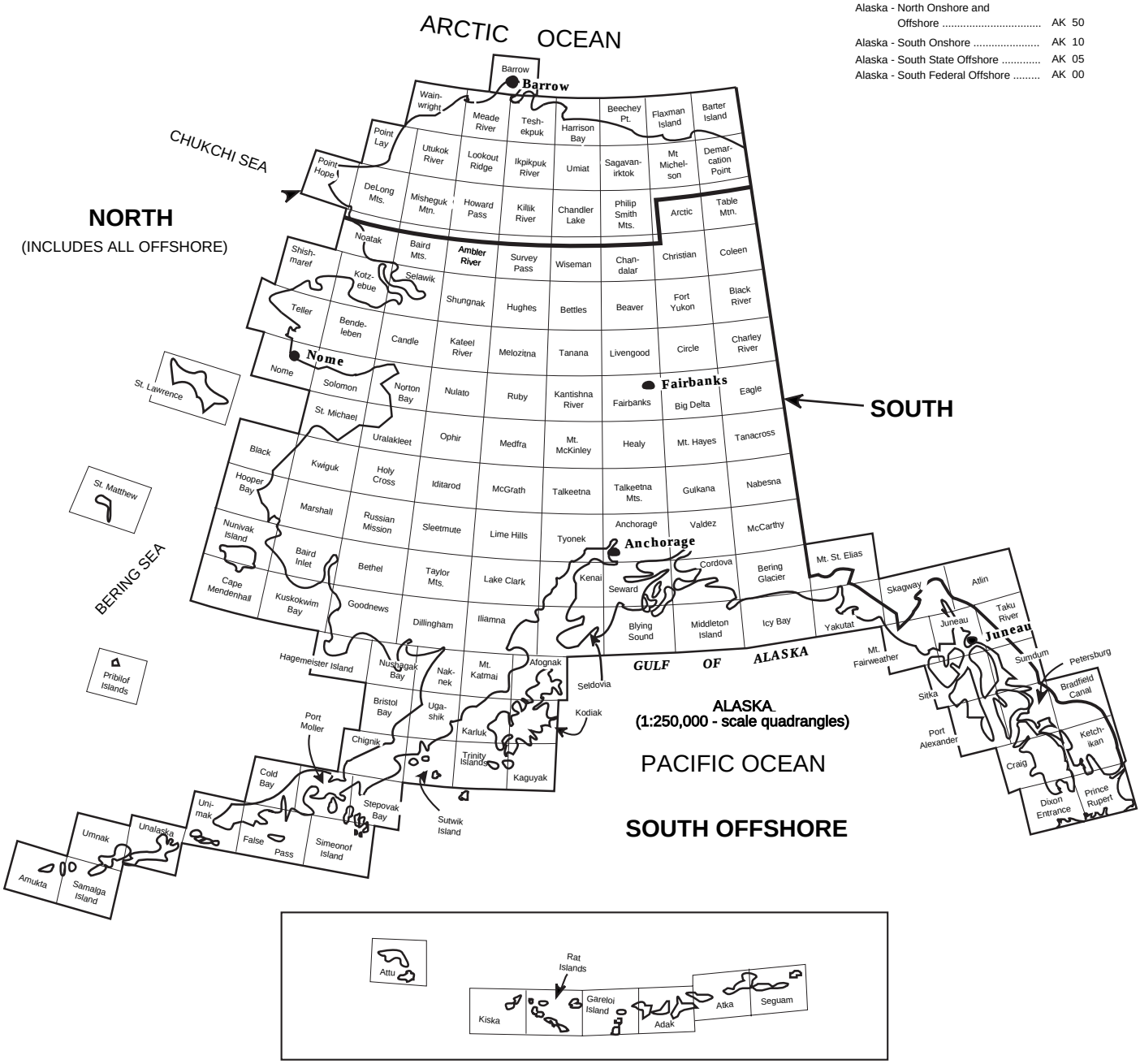
[1] Refer to maps for subdivision boundaries in the States of Alaska, California, Louisiana, New Mexico and Texas.

[2] If you are not certain whether an offshore field lies in the Federal or the State domain, assume that it lies in the State domain and indicate this in a footnote in Schedule B.

[3] Alaska - North Onshore and Offshore includes both State and Federal domain.

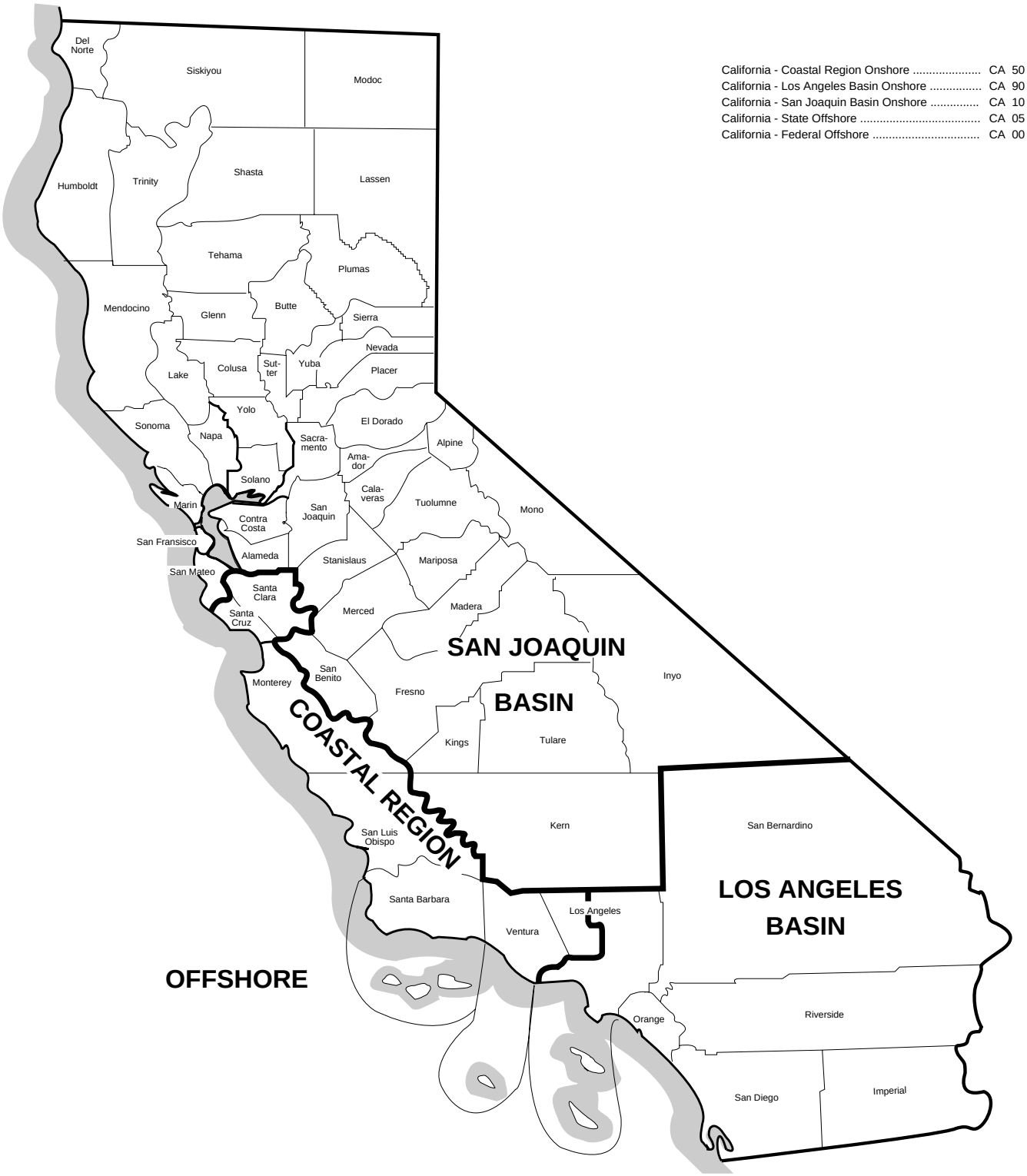
MAPS OF SELECTED STATE SUBDIVISIONS

Alaska - North Onshore and Offshore	AK 50
Alaska - South Onshore	AK 10
Alaska - South State Offshore	AK 05
Alaska - South Federal Offshore	AK 00



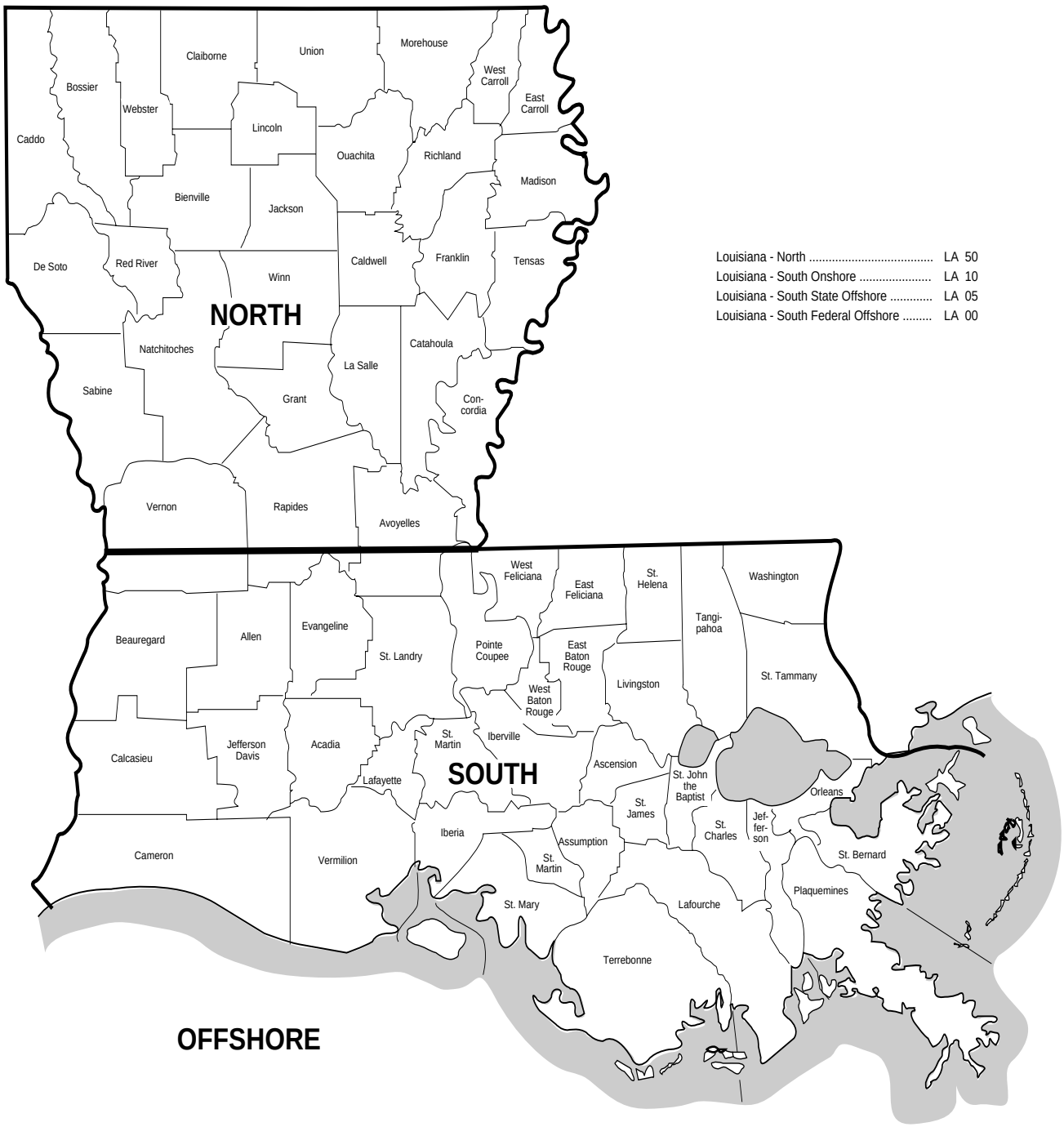
Source: After U.S. Geological Survey

Alaska Subdivisions and U.S. Geological Survey Quadrangles



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

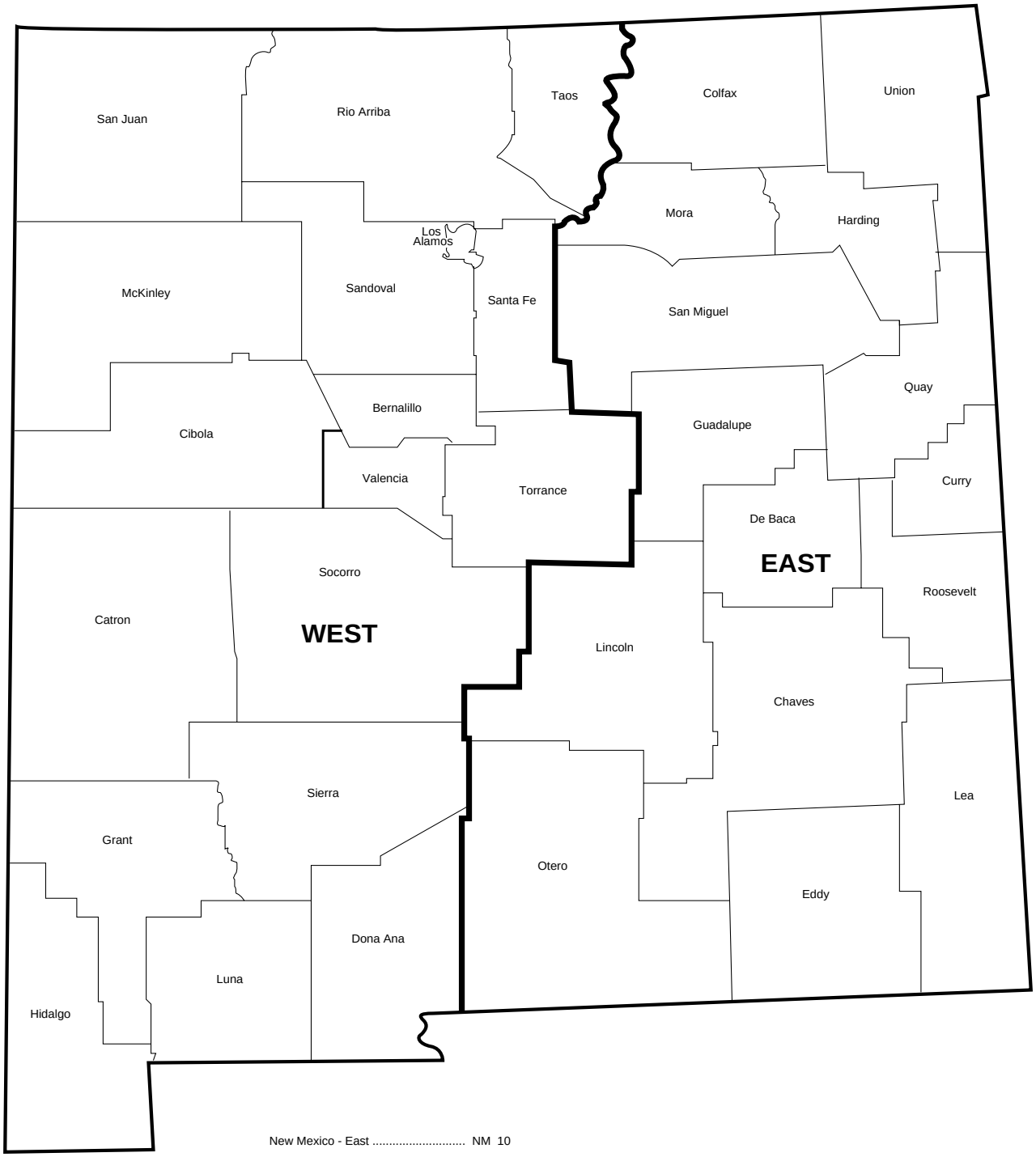
Subdivisions of California



Louisiana - North	LA 50
Louisiana - South Onshore	LA 10
Louisiana - South State Offshore	LA 05
Louisiana - South Federal Offshore	LA 00

Source: Energy Information Administration, Office of Oil and Gas

Subdivisions of Louisiana

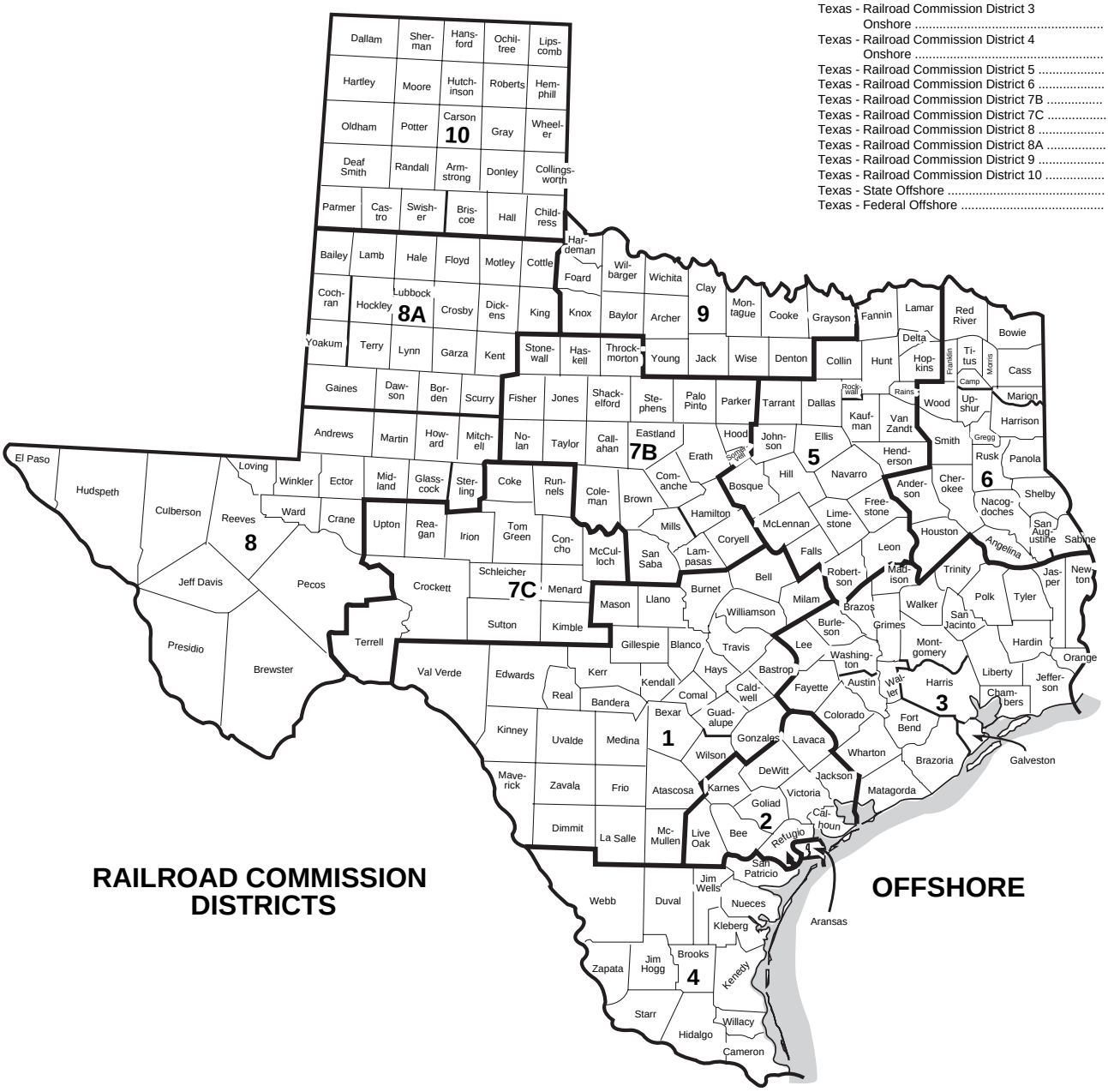


New Mexico - East ..... NM 10
New Mexico - West ..... NM 50

Source: Energy Information Administration, Office of Oil and Gas

Subdivisions of New Mexico

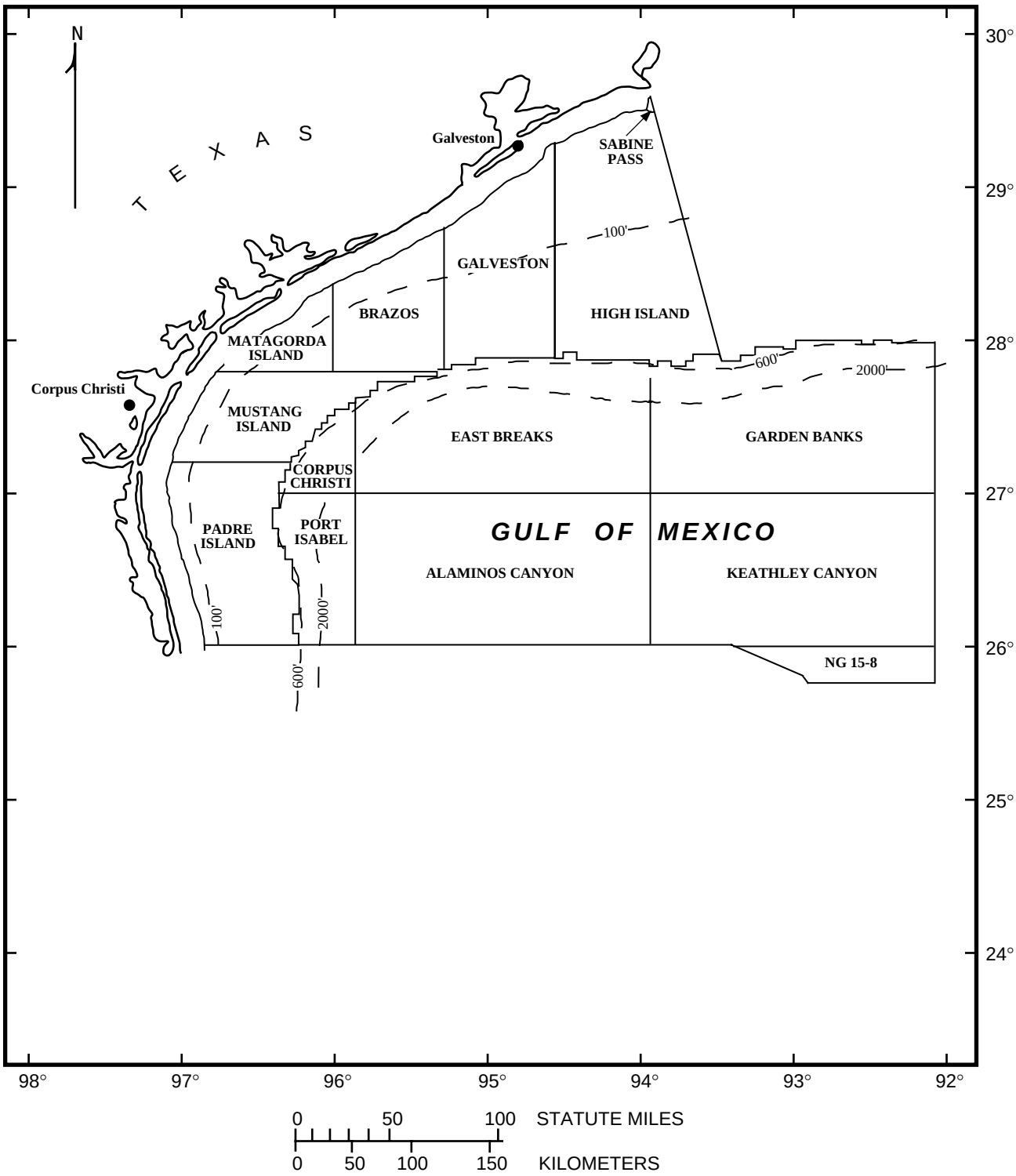
Texas - Railroad Commission District 1	TX 10
Texas - Railroad Commission District 2 Onshore	TX 20
Texas - Railroad Commission District 3 Onshore	TX 30
Texas - Railroad Commission District 4 Onshore	TX 40
Texas - Railroad Commission District 5	TX 50
Texas - Railroad Commission District 6	TX 60
Texas - 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.

Subdivisions of Texas

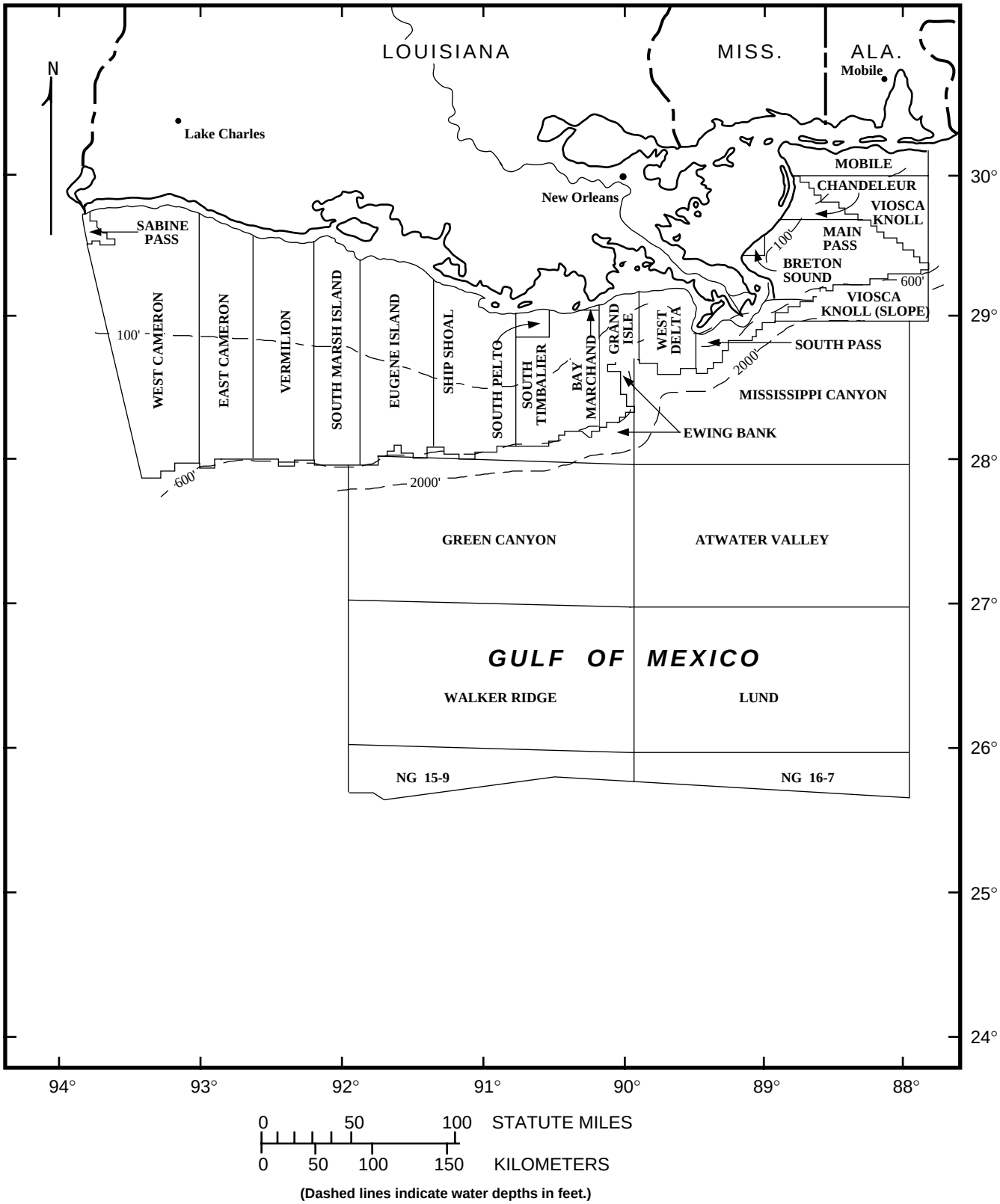
Western Planning Area, Gulf of Mexico Outer Continental Shelf Region



(Dashed lines indicate water depths in feet.)

Source: After Minerals Management Service, U.S. Department of the Interior

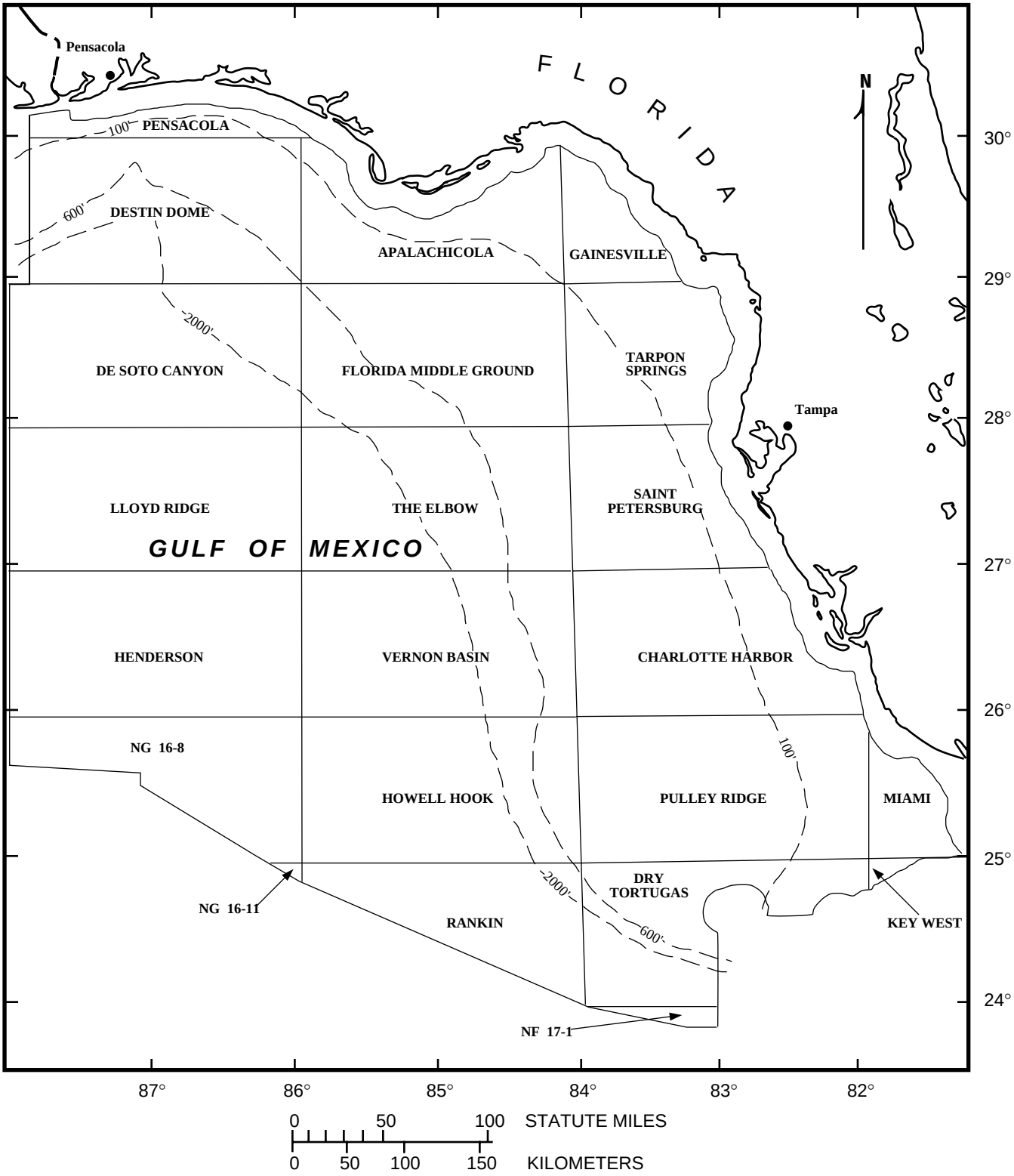
Central Planning Area, Gulf of Mexico Outer Continental Shelf Region



(Dashed lines indicate water depths in feet.)

Source: After Minerals Management Service, U.S. Department of the Interior

Eastern Planning Area, Gulf of Mexico Outer Continental Shelf Region



(Dashed lines indicate water depths in feet.)

Source: After Minerals Management Service, U.S. Department of the Interior.

www.eia.doe.gov Energy Information Administration

U.S. DEPARTMENT OF ENERGY
ENERGY INFORMATION ADMINISTRATION
Washington, DC 20585

Form Approved
OMB No. 1905-0057
Expiration Date: 12/31/06
(Revised 2003)

FORM EIA-23
ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES
REPORT YEAR 2 0 0 3

This report is mandatory under the Federal Energy Administration Act of 1974 (Public Law 93-275). For the provisions concerning the confidentiality of information and sanction statements, see Section VII and VIII of the instructions.

Resubmission? ☐

PART I. IDENTIFICATION

Complete and return by April 1, 2004 to:

Energy Information Administration
U.S. Department of Energy
P O Box 8279
Silver Spring, MD 20907
Attn: Form EIA-23
OR
Fax to: (202) 586-1076/ATTN: FORM EIA-23

Questions? Call 1-800-879-1470

Affix mailing label or enter mailing address

EIA Identification Number: | | | | | | | 0 | 0 | 0 | 0 |

Company Name:

Street or P.O Box:

City, State, Zip Code:

EIN:

1. Contact Information ***(person most knowledgeable about the reported data)***

Contact Person (*Please Print*): Billy Joe Smith

Phone Number: (777) 555-5555 Ext. 189

Fax Number: (777) 555-5000

E-mail Address: bjsmith@office.com

2. Was your company an oil and gas field operator at any time during calendar year 2003? ***(See definition of an operator, page 1)***

(1) ☐ No... *Complete only items 3 through15 below and return this page.*

(2) ☒ Yes... *Complete rest of form.*

Contact person should be familiar with reserves and production information.

3. Company Status, Name, and/or Address Change or Correction. (Check appropriate box.)

☐ Name and address on mailing label are correct.

☒ Change company name, contact person, and/or mailing address as indicated below.

☐ Company was sold to or merged with company entered below.

☐ Company went out of business. Operations transferred to company entered below..

4. Change Company Name, Address, Employer Identification Number (EIN), and/or Contact Information to:

Make any corrections from the mailing label here.

Company Name: Star Spangled Oil Industries

Street or P. O. Box: 50 Banner Way

City, State, Zip Code:

EIN: 12-3456780

Add Employer Identification Number (EIN) if not present, incorrect or changed.

Contact Person (*Please Print*):

Phone Number: ( ) - Ext. | Fax Number: ( ) - | E-Mail Address:

Comments:

PART II. PARENT COMPANY IDENTIFICATION

5. Is there a parent company that exercises ultimate control over your company?

(1) ☒ No… Answer 12 through 15.

(2) ☐ Yes... Answer 6 through 15.

6. Company Name

7. Parent Company EIN

8. Address

9. City

10. State

11. Zip Code

PART III. ATTESTATION **(I hereby swear or affirm that I have reviewed this Form EIA-23 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.)**

12. Attestor (*Please Print*) Jane Doe

13. Title: Petroleum Engineer

14. Signature Jane Doe

15. Date: April 1, 2004

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

2003

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

SCHEDULE A - OPERATED PROVED RESERVES, PRODUCTION, AND RELATED DATA BY FIELD

Report All Liquid Volumes in Thousands of Barrels [MBbls] at 60°F;
Report All Volumes of Natural Gas in Millions of Cubic Feet [MMCF] at 60°F and 14.73 psia

Form Approved
OMB No. 1905-0057
Expiration Date: 12/31/06
(Revised 2003)

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
		12 31 03			_____ OF _____

2.0 FIELD DATA (OPERATED BASIS)

2.1	1. STATE ABBR.	2. SUBDIV. CODE	3. COUNTY CODE	4. FIELD CODE	5. MMS CODE	6. FIELD NAME	7. PROVED NONPRODUCING RESERVES – December 31, 2003				8. FOOTNOTE
							(a) CRUDE OIL (MBbls)	(b) ASSOC-DISSOLVED GAS (MMCF)	(c) NONASSOCIATED GAS (MMCF)	(d) LEASE CON-DENSATE (MBbls)	
	AL		125	012124	CB	BLUE CREEK COAL DEGAS					X

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

TYPE OF HYDROCARBON	TOTAL PROVED RESERVES DECEMBER 31, 2002 (A)	REVISION INCREASES (B)	REVISION DECREASES (C)	SALES (D)	ACQUISITIONS (E)	EXTENSIONS (F)	NEW FIELD DISCOVERIES (G)	NEW RESERVOIRS IN OLD FIELDS (H)	CALENDAR YEAR PRODUCTION (I)	TOTAL PROVED RESERVES DECEMBER 31, 2003 (J)
12. CRUDE OIL (MBbls)										
13. ASSOCIATED-DISSOLVED GAS (MMCF)										
14. NONASSOCIATED GAS (MMCF)									10	
15. LEASE CONDENSATE (MBbls)										

Coalbed Methane Designation

10 MMCF Production

Item 2.1 contains the suggested reporting for a field that contains only coalbed methane gas. The operated properties in this field have no reserves estimate available and annual 2003 production of 10 MMCF is reported in Column (I). Inclusion of a footnote is shown on Item 8 that identifies this production as coalbed methane gas.

Items 2.2 and 2.3 reflect the suggested reporting method for a field that contains both coalbed methane and non-coalbed methane gas. The operated properties in this field have total gas reserves of 650 MMCF (250 MMCF of coalbed methane gas reserves and 75 MMCF of production and 400 MMCF of conventional gas reserves and 100 MMCF of production) as of December 31, 2003.

2.2	1. STATE ABBR.	2. SUBDIV. CODE	3. COUNTY CODE	4. FIELD CODE	5. MMS CODE	6. FIELD NAME	7. PROVED NONPRODUCING RESERVES – December 31, 2003				8. FOOTNOTE
							(a) CRUDE OIL (MBbls)	(b) ASSOC-DISSOLVED GAS (MMCF)	(c) NONASSOCIATED GAS (MMCF)	(d) LEASE CON-DENSATE (MBbls)	
	NM	50	045	042233	CB	BASIN					X

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

TYPE OF HYDROCARBON	TOTAL PROVED RESERVES DECEMBER 31, 2002 (A)	REVISION INCREASES (B)	REVISION DECREASES (C)	SALES (D)	ACQUISITIONS (E)	EXTENSIONS (F)	NEW FIELD DISCOVERIES (G)	NEW RESERVOIRS IN OLD FIELDS (H)	CALENDAR YEAR PRODUCTION (I)	TOTAL PROVED RESERVES DECEMBER 31, 2003 (J)
12. CRUDE OIL (MBbls)										
13. ASSOCIATED-DISSOLVED GAS (MMCF)										
14. NONASSOCIATED GAS (MMCF)	325								75	250
15. LEASE CONDENSATE (MBbls)										

2.3	1. STATE ABBR.	2. SUBDIV. CODE	3. COUNTY CODE	4. FIELD CODE	5. MMS CODE	6. FIELD NAME	7. PROVED NONPRODUCING RESERVES – December 31, 2003				8. FOOTNOTE
							(a) CRUDE OIL (MBbls)	(b) ASSOC-DISSOLVED GAS (MMCF)	(c) NONASSOCIATED GAS (MMCF)	(d) LEASE CON-DENSATE (MBbls)	
	NM	50	045	042233		BASIN					

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

TYPE OF HYDROCARBON	TOTAL PROVED RESERVES DECEMBER 31, 2002 (A)	REVISION INCREASES (B)	REVISION DECREASES (C)	SALES (D)	ACQUISITIONS (E)	EXTENSIONS (F)	NEW FIELD DISCOVERIES (G)	NEW RESERVOIRS IN OLD FIELDS (H)	CALENDAR YEAR PRODUCTION (I)	TOTAL PROVED RESERVES DECEMBER 31, 2003 (J)
12. CRUDE OIL (MBbls)										
13. ASSOCIATED-DISSOLVED GAS (MMCF)										
14. NONASSOCIATED GAS (MMCF)	500								100	400
15. LEASE CONDENSATE (MBbls)										

Coalbed Methane Designation

Special Points for Consideration on Field Level Form EIA-23

- If you became an operator of a property during calendar year 2003, report all elements. **December 31, 2002 Reserves** {Columns (A)} for these new properties should be zero. The December 31, 2002 reserves for these properties should be included in Acquisitions {Columns (E)}. Note the previous operator and date of operatorship change on Schedule B.

- If you ceased being an operator of a property during calendar year 2003, report all elements. **December 31, 2002 Reserves** {Columns (A)} for these previously operated properties should be reported. The reserves for these properties at the time of sale or transfer of operations should be included in Sales {Columns (D)}. Note the new operator and date of operatorship change on Schedule B.

- Category 3 operators of federal offshore and/or coal bed methane gas wells should report production and available proved reserve volumes by field.

- For **natural gas reclassified** during 2003, report the **December 31, 2002 Reserves** {Column (J)} of last year in {Column (A)} for the previous classification. Eliminate the reserves of the previous classification by a Revision Decrease {Column (C)} and create the reserves of the new classification by an equal Revision Increase {Column (B)}. Enter zero for December 31, 2003 reserves for the new classification. Note the reclassification of natural gas on Schedule B.

- **Nonproducing Reserves** {Item 7} are those reserves from which there was no production during calendar year 2003. **December 31, 2003 Reserves** {Column (J)} includes both producing and nonproducing reserves. **Operators often overlook this category.**

- All volumes of gases are to be reported at the Federal standard reporting base of 14.73 psia and 60° Fahrenheit. Filings made at any other pressure base are incorrect. Any such errors in your prior year filings should be corrected and any differences reported as **Revision Increases or Revision Decreases**. Note the differences on Schedule B.

- Production volumes from properties for which reserves have not been estimated should be reported in Items 12 thru 15, {Column (I)}, Calendar Year Production. All reserve values should be left blank.

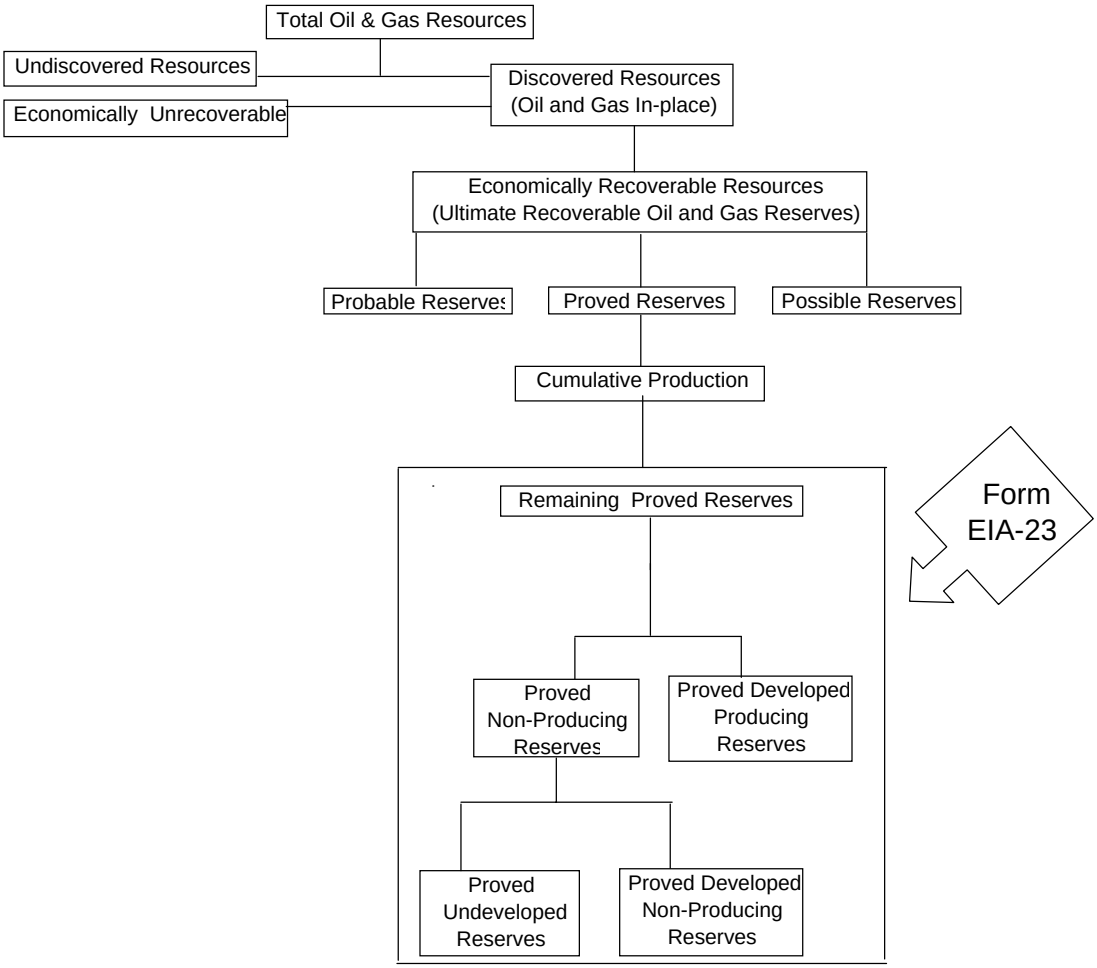
- All volumes of any crude oil, natural gas or condensate used on the lease or vented are to be included in the volumes reported as Production {Column (I)}.

- When a field name differs from that reported on the previous year's submission, report only under the new field name on Item 6 and supply a footnote on Schedule B to indicate the name reported from the previous year.

- Wildcat, new or unnamed fields should be designated as "Unknown" in **Field Name** (Item 6) and reported as "UNK001" for the first such field, then UNK002 for the second such field, etc in **Field Code** (Item 4). **Be certain to include the appropriate county code.**

- Report **Field Discovery Year** (Item 10) as the year of field discovery, as recognized by the State in which it is located, not as the year during which the operator started operations in that field. This date is included in the 2003 *Oil and Gas Field Code Master List.*

Overview of Domestic Oil and Gas Reserves Types Within Total U.S. Oil and Gas Resources



PETROLEUM RESERVES DEFINITIONS

SOCIETY OF PETROLEUM ENGINEERS (SPE) AND WORLD PETROLEUM CONGRESSES (WPC)

PREAMBLE

Petroleum is the world's major source of energy and is a key factor in the continued development of world economies. It is essential for future planning that governments and industry have a clear assessment of the quantities of petroleum available for production and quantities which are anticipated to become available within a practical time frame through additional field development, technological advances, or exploration. To achieve such an assessment, it is imperative that the industry adopt a consistent nomenclature for assessing the current and future quantities of petroleum expected to be recovered from naturally occurring underground accumulations. Such quantities are defined as reserves, and their assessment is of considerable importance to governments, international agencies, economists, bankers, and the international energy industry.

The terminology used in classifying petroleum substances and the various categories of reserves have been the subject of much study and discussion for many years. Attempts to standardize reserves terminology began in the mid 1930's when the American Petroleum Institute considered classification for petroleum and definitions of various reserves categories. Since then, the evolution of technology has yielded more precise engineering methods to determine reserves and has intensified the need for an improved nomenclature to achieve consistency among professionals working with reserves terminology. Working entirely separately, the Society of Petroleum Engineers (SPE) and the World Petroleum Congresses (WPC) produced strikingly similar sets of petroleum reserve definitions for known accumulations which were introduced in early 1987. These have become the preferred standards for reserves classification across the industry. Soon after, it became apparent to both organizations that these could be combined into a single set of definitions which could be used by the industry worldwide. Contacts between representatives of the two organizations started in 1987, shortly after the publication of the initial sets of definitions. During the World Petroleum Congress in June 1994, it was recognized that while any revisions to the current definitions would require the approval of the respective Boards of Directors, the effort to establish a worldwide nomenclature should be increased. A common nomenclature would present an enhanced opportunity for acceptance and would signify a common and unique stance on an essential technical and professional issue facing the international petroleum industry.

As a first step in the process, the organizations issued a joint statement which presented a broad set of principles on which reserves estimations and definitions should be based. A task force was established by the Boards of SPE and WPC to develop a common set of definitions based on this statement of principles. The following joint statement of principles was published in the January 1996 issue of the SPE *Journal of Petroleum Technology* and in the June 1996 issue of the *WPC Newsletter:*

> *There is a growing awareness worldwide of the need for a consistent set of reserves definitions for use by governments and industry in the classification of petroleum reserves. Since their introduction in 1987, the Society of Petroleum Engineers and the World Petroleum Congresses reserves definitions have been standards for reserves classification and evaluation worldwide.*
>
> *SPE and WPC have begun efforts toward achieving consistency in the classification of reserves. As a first step in this process, SPE and WPC issue the following joint statement of principles.*
>
> *The SPE and the WPC recognize that both organizations have developed a widely accepted and simple nomenclature of petroleum reserves.*

The SPE and the WPC emphasize that the definitions are intended as standard, general guidelines for petroleum reserves classification which should allow for the proper comparison of quantities on a worldwide basis.

The SPE and the WPC emphasize that, although the definition of petroleum reserves should not in any manner be construed to be compulsory or obligatory, countries and organizations should be encouraged to use the core definitions as defined in these principles and also to expand on these definitions according to special local conditions and circumstances.

The SPE and the WPC recognize that suitable mathematical techniques can be used as required and that it is left to the country to fix the exact criteria for reasonable certainty of existence of petroleum reserves. No methods of calculation are excluded, however, if probabilistic methods are used, the chosen percentages should be unequivocally stated.

The SPE and the WPC agree that the petroleum nomenclature as proposed applies only to known discovered hydrocarbon accumulations and their associated potential deposits.

The SPE and the WPC stress that petroleum proved reserves should be based on current economic conditions, including all factors affecting the viability of the projects. The SPE and the WPC recognize that the term is general and not restricted to costs and price only. Probable and possible reserves could be based on anticipated developments and/or the extrapolation of current economic conditions.

The SPE and the WPC accept that petroleum reserves definitions are not static and will evolve.

A conscious effort was made to keep the recommended terminology as close to current common usage as possible in order to minimize the impact of previously reported quantities and changes required to bring about wide acceptance. The proposed terminology is not intended as a precise system of definitions and evaluation procedures to satisfy all situations. Due to the many forms of occurrence of petroleum, the wide range of characteristics, the uncertainty associated with the geological environment, and the constant evolution of evaluation technologies, a precise classification system is not practical. Furthermore, the complexity required for a precise system would detract from its understanding by those involved in petroleum matters. As a result, the recommended definitions do not represent a major change from the current SPE and WPC definitions which have become the standards across the industry. It is hoped that the recommended terminology will integrate the two sets of definitions and achieve better consistency in reserves data across the international industry.

Reserves derived under these definitions rely on the integrity, skill, and judgment of the evaluator and are affected by the geological complexity, stage of development, degree of depletion of the reservoirs, and amount of available data. Use of these definitions should sharpen the distinction between the various classifications and provide more consistent reserves reporting.

DEFINITIONS

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

The intent of the SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of reserves classified as unproved. Public disclosure of

the quantities classified as unproved reserves is left to the discretion of the countries or companies involved.

Estimation of reserves is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves is made based on known geological, engineering, and economic data. The method of estimation is called probabilistic when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. Identifying reserves as proved, probable, and possible has been the most frequent classification method and gives an indication of the probability of recovery. Because of potential differences in uncertainty, caution should be exercised when aggregating reserves of different classifications.

Reserves estimates will generally be revised as additional geologic or engineering data becomes available or as economic conditions change. Reserves do not include quantities of petroleum being held in inventory, and may be reduced for usage or processing losses if required for financial reporting.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

PROVED RESERVES

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve an averaging period that is consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves.

In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production or formation tests. In this context, the term proved refers to the actual quantities of petroleum reserves and not just the productivity of the well or reservoir. In certain cases, proved reserves may be assigned on the basis of well logs and/or core analysis that indicate the subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

The area of the reservoir considered as proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonably be judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering or performance data.

Reserves may be classified as proved if facilities to process and transport those reserves to market are operational at the time of the estimate or there is a reasonable expectation that such facilities will be installed. Reserves in undeveloped locations may be classified as proved undeveloped provided (1) the locations are direct offsets to wells that have indicated commercial production in the objective formation, (2) it is reasonably certain such locations are within the known proved productive limits of the objective

formation, (3) the locations conform to existing well spacing regulations where applicable, and (4) it is reasonably certain the locations will be developed. Reserves from other locations are categorized as proved undeveloped only where interpretations of geological and engineering data from wells indicate with reasonable certainty that the objective formation is laterally continuous and contains commercially recoverable petroleum at locations beyond direct offsets.

Reserves which are to be produced through the application of established improved recovery methods are included in the proved classification when (1) successful testing by a pilot project or favorable response of an installed program in the same or an analogous reservoir with similar rock and fluid properties provides support for the analysis on which the project was based, and, (2) it is reasonably certain that the project will proceed. Reserves to be recovered by improved recovery methods that have yet to be established through commercially successful applications are included in the proved classification only (1) after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program where the response provides support for the analysis on which the project is based and (2) it is reasonably certain the project will proceed.

UNPROVED RESERVES

Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

Unproved reserves may be estimated assuming future economic conditions different from those prevailing at the time of the estimate. The effect of possible future improvements in economic conditions and technological developments can be expressed by allocating appropriate quantities of reserves to the probable and possible classifications.

PROBABLE RESERVES

Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

In general, probable reserves may include (1) reserves anticipated to be proved by normal step-out drilling where sub-surface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time of the estimate, (4) reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear favorable for commercial application, (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area, (6) reserves attributable to a future workover, treatment, re-treatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behavior in analogous reservoirs, and (7) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.

POSSIBLE RESERVES

Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic

methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

In general, possible reserves may include (1) reserves which, based on geological interpretations, could possibly exist beyond areas classified as probable, (2) reserves in formations that appear to be petroleum bearing based on log and core analysis but may not be productive at commercial rates, (3) incremental reserves attributed to infill drilling that are subject to technical uncertainty, (4) reserves attributed to improved recovery methods when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics are such that a reasonable doubt exists that the project will be commercial, and (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and geological interpretation indicates the subject area is structurally lower than the proved area.

RESERVE STATUS CATEGORIES

Reserve status categories define the development and producing status of wells and reservoirs.

Developed: Developed reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be sub-categorized as producing or non-producing.

> **Producing:** Reserves subcategorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.
>
> **Non-producing:** Reserves subcategorized as non-producing include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

Undeveloped Reserves: Undeveloped reserves are expected to be recovered: (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different reservoir, or (3) where a relatively large expenditure is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Approved by the Board of Directors, Society of Petroleum Engineers (SPE), Inc. March 7, 1997