Entities with oil and gas producing activities with conforming changes as of May 1, 2008; Audit and accounting guide

American Institute of Certified Public Accountants. Oil and Gas Committee
This edition of the AICPA Audit and Accounting Guide
*Entities With Oil and Gas Producing Activities*, which was originally issued in 1986, has been modified by the AICPA staff to include certain changes necessary because of the issuance of authoritative pronouncements since the guide was originally issued and other changes necessary to keep the guide current on industry and regulatory matters. The changes made are identified in a schedule in appendix F of the guide. The changes do not include all those that might be considered necessary if the guide were subjected to a comprehensive review and revision.
Notice to Readers

This AICPA Audit and Accounting Guide has been prepared by the AICPA Oil and Gas Committee to assist preparers of financial statements in preparing financial statements in conformity with generally accepted accounting principles (GAAP) and to assist auditors in auditing and reporting on such financial statements in accordance with generally accepted auditing standards (GAAS). Descriptions of accounting principles and financial reporting practices in Audit and Accounting Guides are approved by the affirmative vote of at least two-thirds of the members of the Accounting Standards Executive Committee (AcSEC), which is the senior technical body of the AICPA authorized to speak for the AICPA in the areas of financial accounting and reporting. AU section 411, The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles (AICPA, Professional Standards, vol. 1), identifies AICPA Audit and Accounting Guides that have been cleared by the Financial Accounting Standards Board (FASB) as sources of accounting principles in category b of the hierarchy of GAAP that it establishes. This Audit and Accounting Guide has been cleared by the FASB.

This Audit and Accounting Guide presents recommendations of the AICPA Oil and Gas Guide Committee on the application of GAAS to audits of financial statements of entities with oil and gas producing activities. This guide also presents the committee’s recommendations on and descriptions of financial accounting and reporting principles and practice for entities with oil and gas producing activities. The AICPA AcSEC has found this guide to be consistent with existing standards and principles covered by Rule 202, Compliance With Standards (AICPA, Professional Standards, vol. 2, ET sec. 202), and Rule 203, Accounting Principles (AICPA, Professional Standards, vol. 2, ET sec. 203), of the AICPA Code of Professional Conduct. AICPA members should be prepared to justify departures from the accounting guidance in this guide, as discussed in paragraph .07 of AU section 411.*

* In May 2008, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 162, The Hierarchy of Generally Accepted Accounting Principles, which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States (the GAAP hierarchy). FASB concluded that the GAAP hierarchy should reside in the accounting literature established by FASB rather than in the auditing literature established by the AICPA (for non-Securities and Exchange Commission [SEC] registrants) or the Public Company Accounting Oversight Board (PCAOB) (for SEC registrants).

FASB Statement No. 162 carries forward the GAAP hierarchy as set forth in the AICPA’s Statements on Auditing Standards (SAS) No. 69, The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles (AICPA, Professional Standards, vol. 1, AU sec. 411), subject to certain modifications that FASB does not expect to result in changes to current practice. The modifications include, among other changes, the expansion of category (a) accounting principles to include, with one exception, all sources of accounting principles that are issued after being subject to FASB’s due process (including, but not limited to, FASB Staff Positions and FASB Statement 133 Implementation Issues, which are currently not addressed in SAS No. 69). Although certain consensus positions of the FASB Emerging Issues Task Force (EITF) have been issued after being subjected to the FASB’s due process, FASB decided to carry forward the categorization of EITF consensuses as presented in SAS No. 69, which is category (c).

FASB Statement No. 162 does not carry forward the exception permitted in Rule 203, Accounting Principles (AICPA, Professional Standards, vol. 2, ET sec. 203), of the AICPA’s Code of Professional Conduct, that allows departures from the GAAP hierarchy if the member can demonstrate that, due to unusual circumstances, the financial statements would otherwise have been misleading. Therefore, an entity cannot represent that its financial statements are presented in accordance with GAAP if its selection of accounting principles departs from the GAAP hierarchy set forth in FASB Statement No. 162, and that departure has a material effect on its financial statements.

(continued)

AAG-OGP
Auditing guidance included in an AICPA Audit and Accounting Guide is an interpretive publication pursuant to AU section 150, Generally Accepted Auditing Standards (AICPA, Professional Standards, vol. 1). Interpretive publications are recommendations on the application of Statements on Auditing Standards (SASs) in specific circumstances, including engagements for entities in specialized industries. An interpretive publication is issued under the authority of the Auditing Standards Board (ASB) after all ASB members have been provided an opportunity to consider and comment on whether the proposed interpretive publication is consistent with the SASs. The members of the ASB have found this guide to be consistent with existing SASs.

The auditor should be aware of and consider interpretive publications applicable to his or her audit. If an auditor does not apply the auditing guidance included in an applicable interpretive publication, the auditor should be prepared to explain how he or she complied with the SAS provisions addressed by such auditing guidance.

FASB Accounting Standards Codification™

On January 15, 2008, FASB launched the one-year verification phase of the FASB Accounting Standards Codification™ (codification). After the verification period, during which constituents are encouraged to provide feedback on whether the codification content accurately reflects existing U.S. GAAP for non-governmental entities, the FASB is expected to formally approve the codification as the single source of authoritative U.S. GAAP, other than guidance issued by the Securities and Exchange Commission (SEC). The codification includes all accounting standards issued by a standard-setter within levels A–D of the current U.S. GAAP hierarchy, including FASB, AICPA, Emerging Issues Task Force (EITF), and related literature. The codification does not change GAAP; instead it reorganizes the thousands of U.S. GAAP pronouncements into roughly 90 accounting topics, and displays all topics using a consistent structure. The SEC guidance will follow a similar topical structure in separate SEC sections.

This edition of the guide has not been conformed to the new codification. AICPA Audit and Accounting Guides, as well as other AICPA literature, will be conformed to reflect the codification after the verification phase and upon formal approval by the FASB.

Defining Professional Requirements

AU section 120, Defining Professional Requirements in Statements on Auditing Standards, and AT section 20, Defining Professional Requirements in

(footnote continued)

FASB Statement No. 162 is effective 60 days following the approval by the SEC of the conforming amendments included in PCAOB Auditing Standard No. 6, Evaluating Consistency of Financial Statements, and conforming amendments adopted by the PCAOB on January 29, 2008. Among other significant provisions, the conforming amendments remove the GAAP hierarchy from the PCAOB’s interim auditing standards.

In response to FASB’s release of the exposure draft of Statement No. 162 in April 2005, the AICPA issued an exposure draft of a proposed SAS, Amendment to Statement on Auditing Standards No. 69, The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles, for Nongovernmental Entities for Nongovernmental Entities, in May 2005 which deletes the GAAP hierarchy for nongovernmental entities from SAS No. 69. The effective dates of the AICPA, FASB, and PCAOB standards will coincide. For more information please visit the FASB Web site at www.fasb.org.

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Statements on Standards for Attestation Engagements (AICPA, Professional Standards, vol. 1), which were issued in December 2005, set forth the meaning of certain terms used in SASs and Statements on Standards for Attestation Engagements (SSAEs), respectively, issued by the ASB in describing the professional requirements imposed on auditors and practitioners. The specific terms used to define professional requirements in these sections are not intended to apply to interpretive publications issued under the authority of the ASB because interpretive publications are not auditing or attestation standards. It is the ASB’s intention to make conforming changes to the interpretive publications over the next several years to remove any language that would imply a professional requirement where none exists.

In December 2007, the Accounting and Review Services Committee (ARSC) issued AR section 20, Defining Professional Requirements in Statements on Standards for Accounting and Review Services (AICPA, Professional Standards, vol. 2), which sets forth the meaning of certain terms used in Statements on Standards for Accounting and Review Services (SSARS) issued by the ARSC in describing the professional requirements imposed on accountants performing a compilation or review of a nonissuer. The specific terms used to define professional requirements in this section are not intended to apply to interpretive publications issued under the authority of the ARSC because interpretive publications are not SSARSs. It is the ARSC’s intention to make conforming changes to the interpretive publications to remove any language that would imply a professional requirement where none exists.

AU section 120, AT section 20, and AR section 20, which were effective upon issuance, define the terminology that the ASB and ARSC will use going forward to describe the degree of responsibility that the requirements impose on the auditor, practitioner, or accountant in engagements performed for nonissuers. SASs, SSAEs, and SSARSs will use the words “must” or “is required” to indicate an unconditional requirement, with which the auditor, practitioner, or accountant is required to comply. SASs, SSAEs, and SSARSs will use the word “should” to indicate a presumptively mandatory requirement. The auditor, practitioner, or accountant is required to comply with a presumptively mandatory requirement in all cases in which the circumstances exist to which the presumptively mandatory requirement applies; however, in rare circumstances, the auditor, practitioner, or accountant may depart from a presumptively mandatory requirement provided he or she documents the justification for the departure and how the alternative procedures performed in the circumstances were sufficient to achieve the objectives of the presumptively mandatory requirement. If a SAS, SSAE, or SSARS provides that a procedure or action is one that the auditor, practitioner, and accountant “should consider,” the consideration of the procedure or action is presumptively required, whereas carrying out the procedure or action is not.

This guide has been updated as applicable for AU section 120, AT section 20, and AR section 20. Refer to the Schedule of Changes appendix for additional information.

Recognition

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The AICPA gratefully appreciates the invaluable assistance Thomas E. Smith, CPA, provided in updating and maintaining the guidance in this guide.

Guidance Considered in This Edition

This guide has been modified by the AICPA staff to include certain changes necessary due to the issuance of authoritative pronouncements since the guide was originally issued. Relevant guidance contained in official pronouncements issued through May 1, 2008, has been considered in the development of this edition of the guide. This includes relevant guidance issued up to and including the following:

- FASB Statement No. 161, Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133
- Revised FASB statements issued through May 1, 2008 including FASB Statement No. 141(R), Business Combinations
- FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109
- FASB EITF consensus positions adopted at meetings of the EITF held through May 1, 2008
- FASB Staff Positions issued through May 1, 2008
- FASB Derivatives Implementation Group Statement 133 Implementation Issues cleared by FASB through May 1, 2008
- Statement of Position (SOP) 07-1, Clarification of the Scope of the Audit and Accounting Guide Investment Companies and Accounting by Parent Companies and Equity Method Investors for Investments in Investment Companies (AICPA, Technical Practice Aids, ACC sec. 10,930)
- Practice Bulletin No. 15, Accounting by the Issuer of Surplus Notes (AICPA, Technical Practice Aids, PB sec. 12,150)
• Auditing Interpretation No. 1, "Communicating Deficiencies in Internal Control Over Compliance in an Office of Management and Budget (OMB) Circular A-133 Audit," of AU section 325, Communicating Internal Control Related Matters Identified in an Audit (AICPA, Professional Standards, vol. 1, AU sec. 9325 par. .01–.04)

• SOP 07-2, Attestation Engagements That Address Specified Compliance Control Objectives and Related Controls at Entities That Provide Services to Investment Companies, Investment Advisers, or Other Service Providers (AICPA, Technical Practice Aids, AUD sec. 14.430)


Users of this guide should consider pronouncements issued subsequent to those listed above to determine their effect on entities covered by this guide. In determining the applicability of a pronouncement, its effective date should also be considered.

The changes made to this edition of the guide are identified in the schedule of changes appendix. The changes do not include all those that might be considered necessary if the guide were subjected to a comprehensive review and revision.

Auditing Guidance Included in This Guide

Risk Assessment Standards

In March 2006, the ASB issued SAS Nos. 104–111 (the "risk assessment standards"). Collectively, the risk assessment standards establish standards and provide guidance concerning the auditor's assessment of the risks of material misstatement (whether caused by fraud or error) in a nonissuer financial statement audit; design and performance of tailored audit procedures to address assessed risks; audit risk and materiality; planning and supervision; and audit evidence. The most significant changes to existing practice that the auditor will be required to perform are as follows:

• Obtain a more in-depth understanding of the audited entity and its environment, including its internal control

• Perform a more rigorous assessment of the risks of where and how the financial statements could be materially misstated (defaulting to a maximum control risk is not acceptable)

• Provide a linkage between the auditor's assessed risks and the nature, timing, and extent of audit procedures performed in response to those risks

The statements are effective for audits of financial statements for periods beginning on or after December 15, 2006. Early adoption is permitted. See appendix E in this guide for a more detailed comparison between the risk assessment standards and the superseded standards. This guide has been conformed to the new risk assessment standards.
For additional guidance on the risk assessment standards, please refer to the AICPA Audit Guide Assessing and Responding to Risk in a Financial Statement Audit (product no. 012456kk), and the AICPA Audit Risk Alert Understanding the New Auditing Standards Related to Risk Assessment (product no. 022526kk).

**Defining Professional Requirements**

As previously stated, this guide has been conformed, as applicable, to the standards found in AU section 120, AT section 20, and AR section 20, which were effective upon issuance (December 2005, except for AR section 20, which was issued in December 2007). These new standards define the terminology that the ASB and ARSC will use going forward to describe the degree of responsibility that the requirements impose on the auditor, practitioner, or accountant in engagements performed for nonissuers. Refer to the schedule of changes appendix for additional information.
Preface

Purpose and Applicability

Scope

This guide describes relevant matters unique to the oil and gas producing industry in order to assist the independent auditor in auditing and reporting on financial statements of entities performing these activities.

Generally accepted auditing standards (GAAS) and generally accepted accounting principles (GAAP) are applicable in general to the oil and gas producing industry. The general application of those standards and principles is not discussed herein; rather, this guide focuses on the special problems inherent in auditing and reporting on the financial statements of an entity with oil and gas producing activities.

Limitations

This guide concentrates on the domestic exploration and production activities of oil and gas companies and generally does not address the special problems related to other activities of integrated oil and gas companies or foreign activities. This guide also does not differentiate between onshore and offshore activities, because their financial accounting considerations are similar.

This guide provides information regarding statutory rules and regulations applicable to the industry. Also included are illustrations of the form and content of financial statements for entities with oil and gas producing activities. Rules and regulations, as well as applicable authoritative accounting and auditing pronouncements, are subject to change and revision. Therefore, the auditor should keep abreast of developments affecting these items.

This guide contains certain suggested auditing procedures, but detailed internal control questionnaires and audit programs are not included. The nature, timing, and extent of auditing procedures are a matter of professional judgment and will vary depending on the size, organizational structure, existing internal control, and other factors in a particular engagement.

The accounting principles described in this guide are limited to the successful efforts method specified by Financial Accounting Standards Board (FASB) Statement No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, and the full cost method specified by the Securities and Exchange Commission (SEC) in Regulation S-X.

FASB Statement No. 25, Suspension of Certain Accounting Requirements for Oil and Gas Producing Companies—an amendment of FASB Statement No. 19, suspended the effective date specified by FASB Statement No. 19 for requiring the successful efforts method of accounting. However, the FASB statement maintains that for purposes of applying paragraph 13 of FASB Statement No. 154, Accounting Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3, the successful efforts method is preferable for accounting for oil and gas producing activities. As a consequence, no justification for a change to the successful efforts method is necessary nor is a preferability letter for such a change required by the SEC for its registrants. Any change to the full cost method must be justified as being preferable in the circumstances, and a preferability letter describing those circumstances must be filed with the SEC by registrants. This guide is intended only to provide an overview of the accounting principles and the current SEC regulations.
but the bibliography contains extensive references that include more in-depth discussions of accounting principles and SEC regulations. It should be recognized that hybrids of both of these methods are referred to by those names and are often considered to be within the framework of GAAP for nonissuers. This guide has not been expanded to include other practices followed by some nonissuers.

Effective Date

The provisions of this guide shall be effective for audits of financial statements for periods ending on or after December 31, 1986.

Public Accounting Firms Registered With the Public Company Accounting Oversight Board

Subject to the SEC oversight, Section 103 of the Sarbanes-Oxley Act of 2002 (act) authorizes the Public Company Accounting Oversight Board (PCAOB) to establish auditing and related attestation, quality control, ethics, and independence standards to be used by registered public accounting firms in the preparation and issuance of audit reports as required by the act or the rules of the SEC. Accordingly, public accounting firms registered with the PCAOB are required to adhere to all PCAOB standards in the audits of issuers, as defined by the act, and other entities when prescribed by the rules of the SEC.

References to Professional Standards

In citing the professional standards, references are made to the AICPA Professional Standards publication. In those sections of the guide where specific PCAOB Auditing Standards are referred to, references are made to the AICPA's PCAOB Standards and Related Rules publication. Please refer to appendix D of this guide for a summary of major existing differences between AICPA standards and PCAOB standards. Additionally, when referencing professional standards, this guide cites section numbers and not the original statement number, as appropriate. For example, SAS No. 54 is referred to as AU section 317.

Applicability of Requirements of the Sarbanes-Oxley Act of 2002

Publicly held companies and other issuers (definition to follow) are subject to the provisions of the act and related SEC regulations implementing the act. Their outside auditors are also subject to the provisions of the act and to the rules and standards issued by the PCAOB.

Presented is a summary of certain key areas addressed by the act, the SEC, and the PCAOB that are particularly relevant to the preparation and issuance of an issuer's financial statements and the preparation and issuance of an audit report on those financial statements. However, the provisions of the act, the regulations of the SEC, and the rules and standards of the PCAOB are numerous and are not all addressed in this section or in this guide.

Definition of an Issuer

The act states that the term issuer means an issuer (as defined in Section 3 of the Securities Exchange Act of 1934 (15 U.S.C. 78c)), the securities of which
are registered under Section 12 of that act (15 U.S.C. 78l), or that is required to file reports under Section 15(d) (15 U.S.C. 78o(d)), or that files or has filed a registration statement that has not yet become effective under the Securities Act of 1933 (15 U.S.C. 77a et seq.), and that it has not withdrawn.

Issuers, as defined by the act, and other entities when prescribed by the rules of the SEC (collectively referred to in this guide as issuers or issuer) and their public accounting firms (who must be registered with the PCAOB) are subject to the provisions of the act, implementing SEC regulations, and the rules and standards of the PCAOB, as appropriate.

Nonissuers are those entities not subject to the act or the rules of the SEC.

Guidance for Issuers

Management Assessment of Internal Control

As directed by Section 404 of the act, the SEC adopted final rules requiring companies subject to the reporting requirements of the Securities Exchange Act of 1934, other than registered investment companies and certain other entities, to include in their annual reports a report of management on the company’s internal control over financial reporting.

Companies that are large accelerated filers or accelerated filers, as defined in Exchange Act Rule 12b-2, are required to comply with these rules for fiscal years ending on or after November 15, 2004. Foreign private issuers that are large accelerated filers or accelerated filers and that file their annual reports on Form 20-F or 40-F must begin to comply with rules for the first fiscal year ending on or after July 15, 2006. Nonaccelerated filers including foreign private issuers that are not accelerated filers are required to comply with the rules for the first fiscal year ending on or after December 15, 2007. See the SEC Web site at www.sec.gov for further information.

The SEC rules clarify that management’s assessment and report is limited to internal control over financial reporting. The SEC’s definition of internal control encompasses the Committee of Sponsoring Organizations of the Treadway Commission (COSO) definition but the SEC does not mandate that the entity use COSO as its criteria for judging effectiveness.

The auditor’s attestation on the effectiveness of the internal control over financial reporting is currently required for large accelerated filers and accelerated filers. For nonaccelerated filers, the auditor’s attestation is required for annual reports for fiscal years ending on or after December 15, 2009.

Select SEC Developments

The SEC posted an interpretive release, Commission Guidance Regarding Management’s Report on Internal Control Over Financial Reporting Under Section 13(a) or 15(d) of the Securities Exchange Act of 1934, on June 20, 2007, to provide guidance for management regarding its evaluation and assessment of internal control over financial reporting. This guidance is organized around two broad principles. The first principle is that management should evaluate whether it has implemented controls that adequately address the risk that a material misstatement of the financial statements would not be prevented or detected in a timely manner. This guidance describes a top-down, risk-based approach to this principle. The second principle is that management’s evaluation of evidence about the operation of its controls should be based on its assessment
of risk. This guidance provides an approach for making risk-based judgments about the evidence needed for the evaluation.

The SEC also posted a final rule, Amendments to Rules Regarding Management's Report on Internal Control Over Financial Reporting, on June 20, 2007, that provides, among other significant provisions, that a company performing an evaluation in accordance with the aforementioned interpretive guidance also satisfies the annual evaluation required by Exchange Act Rules 13a-15 and 15d-15. Among other rule changes, the SEC defined the term material weakness and revised the requirements regarding the auditor’s attestation report on the effectiveness of internal control over financial reporting to require the auditor to express an opinion directly on the effectiveness of internal control over financial reporting and not on management’s evaluation process.

In a subsequent final rule, Definition of the Term Significant Deficiency, posted August 3, 2007, the SEC defined the term significant deficiency for the purpose of implementing Section 302 and Section 404 of the act. By including a definition of significant deficiency in SEC rules, in addition to the definition of material weakness, the SEC has enabled management to refer to its rules and guidance for information on the meaning of these terms rather than referring to the auditing standards. Readers should refer to the SEC Web site at www.sec.gov for more information.

Guidance for Auditors

The act mandates a number of requirements concerning auditors of issuers, including mandatory registration with the PCAOB, the setting of auditing standards, inspections, investigations, disciplinary proceedings, prohibited activities, partner rotation, and reports to audit committees, among others. The PCAOB continues to establish rules and standards implementing provisions of the act concerning the auditors of issuers.

Applicability of GAAS and PCAOB Standards

The act authorizes the PCAOB to establish auditing and related attestation, quality control, ethics, and independence standards to be used by registered public accounting firms in the preparation and issuance of audit reports for entities subject to the act or the rules of the SEC. Accordingly, public accounting firms registered with the PCAOB are required to adhere to all PCAOB standards in the audits of issuers, as defined by the act, and other entities when prescribed by the rules of the SEC.

For those entities not subject to the act or the rules of the SEC, the preparation and issuance of audit reports remain governed by GAAS as issued by the Auditing Standards Board.

Select PCAOB Developments

audits of internal control over financial reporting required by the act for fiscal years ending on or after November 15, 2007. Earlier adoption is permitted at any point after SEC approval.

Auditing Standard No. 5 is principles-based and is designed to increase the likelihood that material weaknesses in internal control will be found before they result in material misstatement of a company’s financial statements and, at the same time, eliminate procedures that are unnecessary. It focuses the auditor on the procedures necessary to perform a high quality audit and makes the audit scalable so it can change to fit the size and complexity of any company. Readers should refer to the PCAOB Web site at www.pcaob.org for more information.

**Major Existing Differences Between GAAS and PCAOB Standards**

The major differences between GAAS and PCAOB standards are described in both part I of volume one of the AICPA Professional Standards and in part I of the AICPA publication titled PCAOB Standards and Related Rules. Please refer to appendix D of this guide for a summary of major existing differences between AICPA standards and PCAOB standards.
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**Contents**
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Chapter 1

Overview of the Oil and Gas Industry

The Industry’s History

1.01 To gain an understanding of oil and gas producing activities, a brief review of the history of the industry and oil and gas accounting is helpful. The following discussion is intended to be basic in nature, but additional references are included in the bibliography section. (The interested reader is urged to refer to other available sources.)

1.02 The first commercial oil-drilling venture was in 1859 near Titusville, Pennsylvania. A steam-powered, cable-tool drilling rig was used to drill a 59 foot well, which yielded 5 barrels of oil per day. This well set off a boom of sorts, and the cable-tool rig—which at that time was revolutionary—was used to drill other wells in the area. Oil soon sold for about 10 cents a barrel because of the dramatic increase in supply.

1.03 In the 1850s and early 1860s, oil was chiefly used for lamp fuel. The Industrial Revolution and the Civil War greatly increased the uses of oil and therefore the demand—so much so that annual production in 1870 exceeded 25 million barrels. Early transportation of crude oil was cumbersome, however, requiring (1) wooden barrels (each with a capacity of 42 gallons—the present measurement of a barrel of crude oil), (2) horse-drawn wagons, (3) river barges, and (4) the railroads. The first pipeline, completed in the 1860s, was made of wood and was less than one thousand feet long.

1.04 One of the first to rise to power in this infant industry was John D. Rockefeller. In 1870, Rockefeller merged his firm with 4 others to form the Standard Oil Company. During the 1880s, Standard Oil controlled approximately 90 percent of the refining industry in the United States. Standard Oil’s market dominance eventually led to its forced dissolution in 1911–1915 because of federal and state antitrust legislation that had been enacted as a response to its size.

1.05 The growing number of automobiles steadily increased the demand for oil. Because a domestic shortage was feared by the U.S. government, the industry was encouraged to increase foreign exploration. In the 1920s, exploration in the Middle East, South America, Africa, and the Far East had begun. However, the east Texas oil field discovery of 1930 ultimately created an oil surplus that caused companies to cut back foreign operations. During and after World War II, however, demand again increased, and enormous capital investments developed the Persian Gulf area. This period also saw an increased use of natural gas, facilitated by improved transportation systems, and the growth of the petrochemical industry (which produced plastics and synthetics).

1.06 The oil and gas industry has gone through many changes in the past 20 years. The Arab oil embargo of 1973 focused public attention and criticism on the industry, partly because of the embargo’s effect on previously stable prices. (In 1973, before the embargo, the average barrel of crude oil sold for about 3 dollars.) Nearly half the oil used by the United States in 1977 was imported. In 1979, the government announced “phased decontrol” of oil prices on a schedule that would have freed all crude prices by October 1981; however, in...
January 1981, all price controls on crude oil were immediately lifted. Natural gas prices continued to be subject to controls, as required by the Natural Gas Policy Act of 1978, but initial deregulation began January 1, 1985, with complete deregulation occurring on January 1, 2003.

1.07 By the early 1980s, the price for a barrel of oil ranged from 30 to 40 dollars (and sometimes higher), representing an approximate 1000-percent increase in less than 10 years. In the mid-1980s, however, prices had declined in the face of a world oil surplus. The effects of these fluctuations were further complicated by U.S. government price controls that designated different grades of oil and created a complex pricing structure. As a result, producing companies grew increasingly reluctant to explore and drill. This reluctance may have stemmed from the fact that a barrel of domestically produced oil often had a sale price significantly less than the price of imported oil.

Types and Sizes of Companies in the Industry

1.08 Companies engaged in oil and gas exploration and production are characterized by a wide diversity in type and size; ultimately, most are primarily dependent on their success in exploring for and developing oil and gas reserves. Companies in the industry range from the largest corporations in the world to very small companies or proprietorships with limited sales and resources.

1.09 The organization of oil and gas companies varies depending on size and diversity of activities. Oil and gas producers are usually classified as independent or integrated companies. A fully integrated company produces oil and gas and also operates refineries, pipelines, and wholesale and retail outlets. Some companies are only partially integrated.

1.10 Independent exploration and production companies generally do not refine products or engage in marketing activities. They limit their activities to exploration, development, and production.

1.11 Discussions in this guide will concentrate on the oil gas exploration and production activities of both independent and integrated oil and gas operations. These activities include acquisition of mineral properties, exploration, drilling and development, and production.

Ownership Interests and Operations

1.12 The characteristics relatively unique to oil and gas operations are the normal existence of multiple ownerships of individual properties and the varying types of ownership interests. This variety of ownership interests has developed in response to the need to share risks, to take advantage of tax opportunities, and to raise the large amounts of capital necessary. The principal types of ownership or economic interests encountered in the industry will be discussed, but variations of these will be encountered because of the easily divisible nature of oil and gas operations.

Types of Interests

1.13 Mineral interest is the complete ownership of the minerals in place.

1.14 Royalty interest is the portion of the mineral interest retained by the lessor. This interest entitles the royalty interest owner to a fractional amount
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of the production from the property, in kind or in value, less the applicable severance taxes. Occasionally, the royalty interest may bear certain specific costs.

1.15 **Working interest (or operating interest)** is the interest in the oil and gas in place that bears most or all of the cost of development and operation of the property. Mineral interest revenues minus the royalty interest equals the working interest share of revenues.

1.16 **Overriding royalty** is a royalty interest that is created out of the working interest. Its term is coextensive with that of the working interest from which it was created.

1.17 **Net profits interest** is an interest in production created from the working interest and measured by a certain percentage of the net profits (as defined in the contract) from the operation of the property.

1.18 **Retained interest** is an interest that arises when the working interest owner transfers the basic rights and responsibilities for developing and operating the property to another party and retains a special nonoperating interest created by the conveyance contract.

1.19 **Carved-out interest** is an interest created when the working interest owner retains the basic working interest but grants to another entity special nonoperating rights and obligations.

**Joint Interest Operations**

1.20 **Operating agreements.** Joint interest (also referred to as joint venture) operations result from an agreement among two or more working interest owners whereby one party is designated as the operator for the development and operation of the jointly owned property included in the joint venture. In joint interest operations, each working interest owner retains an undivided interest in the jointly operated property. This direct ownership is usually included in the financial statements of the investor through direct inclusion of its proportional share of the expenses, revenues, and assets. Joint interest operations are designed to accomplish the objectives of sharing risk, obtaining capital, maximizing efficiency of development and operations, and enhancing the recovery of reserves.

1.21 Joint interest operations are governed by complex operating agreements that set forth the rights, duties, and obligations of each party. A significant part of the agreement is the accounting procedure section, which establishes the basis for charges and credits to the operator and the nonoperating parties and provides for billings, advance of funds, payment schedules, audits, and other general provisions of the arrangement. The accounting provisions in joint operating agreements usually follow a model provision devised by the Council of Petroleum Accountants Societies (COPAS). Although the lease is usually considered the accounting unit, many costs cannot be directly identified with a particular lease. Such costs are usually categorized as indirect expenses and are recovered by allocating overhead to leases on some reasonable basis. These costs include service unit costs and certain types of overhead.

1.22 The operator bills the nonoperators (usually at the end of each month) for their share of the month’s expenditures. The billing is referred to as a joint interest billing. The operator may also make a cash call at the beginning of each month for the nonoperator’s share of anticipated expenditures that will be incurred during the month. In some cases, the operator may also collect revenues
4

Entities With Oil and Gas Producing Activities

from production of crude oil and other liquids and distribute the proceeds to the various ownership interests, although in many cases the purchaser will pay the various interests directly based on the division order. Normally, purchasers of natural gas remit revenues directly to working interest owners in accordance with purchaser agreements negotiated with each working interest owner.

1.23 Most large oil and gas companies, as well as many smaller companies, act as operators on a number of the oil and gas properties in which they have an interest. It should be recognized, however, that nearly all companies will be nonoperators with respect to a significant portion of their properties. In addition, the extent to which nonoperators take an active role in the operation of properties varies widely in practice. In many instances, the nonoperator maintains full accountability for activities on the properties, including advance authorization of capital expenditures through the authorization for expenditure process and review and approval of revenue and expense transactions. In other instances, nonoperators may rely almost entirely on the operator for recording transactions and maintaining accountability and receive only a summary report of activity. The degree of actual involvement in practice may fall anywhere within this range.

1.24 Joint interest audits. The accounting procedure section of the operating agreement usually contains a provision that establishes the timing of the auditing of the operator’s records by the nonoperating parties. Under some of the accounting procedures, the nonoperators may audit the operator’s expenditures within two years after the end of the period to be audited. If such an option is not exercised, or if an exception is not granted in advance, the nonoperator would be precluded from conducting a subsequent audit and all transactions billed would be considered correct.

1.25 In some of the older agreements, provisions existed where the nonoperator was permitted much less time to conduct an audit (for example, a six-month constraint was not unusual).

1.26 Joint interest audits are normally conducted by the nonoperator’s internal auditors or by independent auditors hired by the nonoperator. The purpose—and therefore the scope—of joint interest audits is significantly different from an audit of financial statements in accordance with generally accepted auditing standards. Such audits are beyond the scope of this guide; however, it is important to note that there are no generally recognized joint interest audit standards in existence. The quality of joint interest audits may vary significantly. (See the bibliography for COPAS bulletins.)

1.27 Division orders. Contractual agreements among the parties determine ownership interests, and rarely are two contracts exactly the same. In almost every case there will be at least two recipients of production proceeds: the working interest owner and the royalty owner. Thus, a division-of-interest order (or simply division order) is prepared to indicate the proper distribution of production proceeds.

1.28 A regular division order is an agreement between the purchaser of production and all the various owners of interests in the property. This agreement includes the following: (1) the legal description of the property; (2) the owners of interests in the property; (3) the interest owned by each; and (4) the terms of purchase, including provisions dealing with passage of title, price, measurement, production taxes, and related items. The operator of the property circulates the division order to the various owners of interest. Each
owner, by signing the division order, does the following: represents ownership to be as stated; authorizes the purchaser to receive production from the property and to make payment to the owners in proportion to their respective interests; and agrees to all other provisions of the division order. Sometimes the operator receives the full payment from the purchaser and makes the distribution to the other owners.

1.29 In the event that an owner of interest is unknown or cannot be located and the signature cannot be secured on the division order, the revenue applicable to that interest is held in suspense. In a similar manner, revenue is held in suspense pending receipt of proof of title or title opinion, execution of the division order, or litigation to resolve a dispute over ownership of an interest.

Sources of Capital

1.30 Oil and gas producing companies require enormous amounts of capital, especially in their exploration and development activities. As in most industries, the traditional sources of capital are internal financing and equity and other forms of external financing. However, the various and sometimes unique adaptations in the oil and gas industry warrant discussion.

1.31 In the past, oil and gas companies, especially those that were large and financially strong, were able to fund a large amount of their exploration and development activities with internally generated funds. Increased competition among companies for exploration rights to undeveloped properties as well as rising acquisition and development costs have resulted in companies turning more frequently to other sources of funds.

Joint Interests

1.32 Companies often enter into arrangements with others as a means of raising or sharing capital. This can be done by creating joint ventures or partnerships, but is often accomplished by transferring a portion of the working interest to other parties, as discussed more thoroughly under "Conveyances" in paragraphs 2.136–148. Depending on the attractiveness of the property and the owner's willingness to dilute interest, a portion of the costs of a property may be financed in this manner. An example of a common deal at one time in the industry was a "third for a quarter," in which the purchaser agreed to assume a third of the costs in exchange for a fourth of the working interest in the property. Another example is a carried interest arrangement, in which one party agrees to develop and operate a property at its costs but maintains the right to recapture its costs or a defined greater amount from the proceeds of production.

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1 The Financial Accounting Standards Board (FASB) issued Emerging Issues Task Force (EITF) Issue No. 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights," which addresses the accounting for general partners of all new limited partnerships formed and for existing limited partnerships for which the partnership agreements are modified.

In addition, FASB published Staff Position (FSP) SOP 78-9-1, Interaction of AICPA Statement of Position 78-9 and EITF Issue No. 04-5, to amend AICPA Statement of Position (SOP) 78-9, Accounting for Investments in Real Estate Ventures (AICPA, Technical Practice Aids, ACC sec. 10,240), so that its guidance is consistent with the consensus reached by FASB’s EITF on EITF Issue No. 04-5.

FASB issued FASB Interpretation No. (FIN) 46(R), Consolidation of Variable Interest Entities (revised December 2003)—an interpretation of ARB No. 51, which addresses consolidation by business enterprises of variable interest entities or potential variable interest entities commonly referred to as special-purpose entities.
Limited Partnerships

1.33 It is common for oil and gas operators to organize limited partnerships. These partnerships are commonly called oil and gas funds or oil and gas programs. Limited partnerships are organized by a sponsor who sells interests in the partnership to private investors and then acts as the general partner when the partnership has been organized. In the past limited partnerships were usually structured to maximize the tax deductions passed through to the limited partners. The limited partners are usually liable only for the amount of their contribution to the partnership. The general partner normally has unlimited liability for the debts and obligations above the limited partners’ capital; however, the general partner has full control over the partnership’s operations.

1.34 The partnerships typically are either drilling funds or production funds. Drilling funds are organized to finance exploration of new prospects, while production funds are invested only in properties known to contain oil or gas.

1.35 The limited partnership is governed by the partnership agreement, which explains the rights and obligations of the partners. The partnership agreement specifies the method of allocating revenues and expenses between the general and limited partner interests. The basic allocation methods are functional allocation, reversionary interest, promoted interest, and carried interest. The limited partner analyzes the substance of the transaction to determine the proper accounting treatment. Methods for special allocation of profits and costs for tax purposes may be inappropriate for financial reporting purposes.

1.36 Functional allocation usually provides for the tax-deductible expenses to be paid with the limited partners’ contribution and allocated to them. Capital expenditures such as leasehold costs and equipment are paid with the general partners’ contribution. Revenue sharing is based on a predetermined percentage ratio between the general and limited partners. This method normally achieves the fastest deduction of costs for the limited partners.

1.37 Under a reversionary interest allocation, the limited partners’ contribution is used to pay the largest percentage of the partnership expenses, and the limited partners receive a high percentage of the revenues until they recover their initial capital contributions. After the limited partners recover their initial investment, the allocation reverts to another percentage ratio assigning a larger portion of revenues and expenses to the general partner interest.

1.38 In a promoted interest program, the general partner pays a specified percentage of all costs and receives a disproportionately larger percentage of net revenues.

1.39 In a carried interest program, the general partner pays a specified percentage of operating costs and receives a specified percentage (often larger) of revenues but does not bear any capital costs.

1.40 Aside from the differences in the equity section of the financial statements and the allocation of revenues and costs between the general and limited partners, which is dictated by the partnership agreement, the accounting for and the auditing of an oil and gas limited partnership are basically the same as for any other oil and gas producer. However, financial statements are often prepared on either the income tax or cash basis, except for those limited...
Overview of the Oil and Gas Industry

partnerships that are issuers, which are required to be prepared on the basis of generally accepted accounting principles (GAAP). This guide does not discuss the income tax or cash basis financial statements of limited partnerships—nor does it address financial accounting and auditing considerations that may be unique to limited partnerships.

Other Sources of Capital

1.41 Quite common are production payment transactions, whereby a lender advances funds to be repaid from future production. Short-term as well as long-term financing from banks often takes the form of production loans, secured by specific, producing mineral properties. The auditor may consider the potential implications of the different forms of financing.

Accounting for Oil and Gas Producing Activities

1.42 The two accounting methods followed by oil and gas producers are the successful efforts method and the full cost method. Successful efforts accounting essentially provides for capitalizing only those costs directly related to proved properties; it then amortizes those costs over the life of the properties.

1.43 Prior to the mid-1950s, most oil and gas companies used the successful efforts accounting method or some variation thereof. In the mid-1950s, a form of the full cost method of accounting was introduced.

1.44 The full cost concept became popular with small, newly formed companies. It allowed them to defer their early costs until successful exploration produced offsetting revenue. By 1970, almost half of the public oil and gas producing companies were using a form of the full cost method.

1.45 Full cost accounting generally provides for capitalizing (within a cost center) all costs incurred in exploring for, acquiring, and developing oil and gas reserves—regardless of whether or not the results of specific costs are successful. This method is based on the premise that the costs of unsuccessful exploration efforts are necessary for the discovery of reserves even though such expenditures are made with the knowledge that specific efforts may not actually locate any. Thus, all costs incurred in acquiring mineral rights, in drilling, and in exploration activities—along with all carrying costs of nonproducing properties in the cost center—are treated as the cost of reserves in that center. The costs capitalized in a cost center are then amortized and charged to expense while the mineral reserves in that cost center are produced.

1.46 Under the full cost method, the cost center is used to "pool" costs to be later matched with revenues generated from the cost center's operations. Under the broadest concept, the company's entire worldwide oil and gas operations would be treated as a single cost center. Most companies, however, consider the continent or the individual country a cost center, and the Securities and Exchange Commission (SEC) accounting rules specify the size of cost centers to be an individual country.

1.47 In 1969, the AICPA published Accounting Research Study No. 11, which called for the elimination of the full cost method and recommended that the successful efforts method be the only acceptable method. The Accounting

2 See the preface of this guide for the definitions of an issuer and nonissuer.
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Principles Board (APB) appointed a committee to develop an authoritative opinion on financial accounting and reporting for the oil and gas industry; however, the APB was terminated in 1973 before the committee completed its charge.

1.48 In December 1977, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*. The statement required a form of successful efforts accounting as the uniform method for all enterprises engaged in oil and gas producing activities.

1.49 In summary, successful efforts accounting as specified by FASB Statement No. 19 provides that

1. exploration costs, other than exploration drilling costs, including, geological and geophysical costs, costs of carrying and retaining undeveloped properties, and dry hole and bottom hole contributions should be charged to expense when incurred.

2. acquisition costs should be capitalized initially; however, losses should be recognized if the values of unproved properties are determined to be impaired on the basis of a required periodic assessment.

3. the costs of drilling exploratory wells and exploratory-type stratigraphic test wells should be capitalized pending determination of whether the well has found proved reserves. The costs of unsuccessful exploratory wells should be charged to expense.

4. the costs of drilling development wells, including unsuccessful development wells, should be capitalized.

5. production costs—together with the amortization of the capitalized acquisition, exploration, and development costs—should become the cost of oil and gas produced.

6. capitalized costs are accumulated by cost centers, which provide a means whereby costs can be collected and amortized against related revenues. For amortization purposes, the cost center is the individual property or an aggregation of properties in the same field or reservoir.

7. capitalized acquisition costs should be amortized on the unit-of-production method using total proved oil and gas reserves. Capitalized exploration and development costs should be amortized on the unit-of-production method using proved developed oil and gas reserves.

1.50 The SEC called for public hearings in August 1978 before adopting the statement as the authoritative standard of accounting and reporting for oil and gas producing companies filing reports with the SEC. Because of the strong opposition voiced at those hearings, the SEC issued Accounting Series Release (ASR) No. 253, section 406, *Adoption of Requirements for Financial Accounting and Reporting Practices for Oil and Gas Producing Activities*. This ASR

- adopted the form of successful efforts accounting and the disclosures prescribed by FASB Statement No. 19.
- indicated the SEC’s intention to develop a form of the full cost accounting method as an alternative acceptable for SEC reporting purposes (ASR No. 258, section 406).
- concluded that both the full cost and successful efforts methods of accounting, based on historical costs, fail to provide sufficient
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information on the financial position and operating results of oil and gas producing companies and, accordingly, that steps should be taken to develop an accounting method based on a valuation of proved oil and gas reserves. (The SEC later decided that the valuation accounting it proposed—reserve recognition accounting—was no longer considered to be a potential method of accounting in the primary financial statements of oil and gas producers. The SEC also announced its support of an undertaking by FASB to develop a comprehensive disclosure package for those engaged in oil and gas producing activities.)

• adopted rules that require financial statement disclosure of certain financial and operating data regardless of the method of accounting followed.

In ASR Nos. 257 and 258, section 406, the SEC released its final rules for successful efforts and full cost accounting. At that point, companies under SEC jurisdiction could follow either the full cost method prescribed in ASR No. 258, section 406.01.c., or the successful efforts method prescribed in ASR No. 253, section 406.01.b., as modified by ASR No. 257, section 406—a method identical to that contained in FASB Statement No. 19.

1.51 In response to the SEC’s issuance of ASR No. 253, section 406.01.b., FASB issued FASB Statement No. 25, Suspension of Certain Accounting Requirements for Oil and Gas Producing Companies—an amendment of FASB Statement No. 19. This statement suspended, for an indefinite period of time, most of the provisions of FASB Statement No. 19. However, some provisions of FASB Statement No. 19, including deferred income taxes and some aspects of property conveyances and disclosure requirements, were retained and became effective.3 Thus, companies that report to the SEC may follow either the full cost accounting method prescribed by ASR No. 258, section 406.01.c., or the successful efforts method prescribed by ASR No. 253, section 406.01.b., as modified by ASR No. 257, section 406—a method identical to that contained in FASB Statement No. 19. For nonpublic companies there is no prescribed method of accounting for costs incurred in oil and gas exploration or for amortization of those capitalized costs.

1.52 In November 1982, FASB issued FASB Statement No. 69, Disclosures about Oil and Gas Producing Activities—an amendment of FASB Statements 19, 25, 33, and 39. This statement amended FASB Statement No. 19 by establishing disclosures about oil and gas producing activities to be made for publicly traded enterprises4 when presenting a complete set of annual financial

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3 FASB Statement No. 25, Suspension of Certain Accounting Requirements for Oil and Gas Producing Companies—an amendment of FASB Statement No. 19, also states that for purposes of applying paragraphs 12–14 of FASB Statement No. 154, Accounting Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3, successful efforts is the preferable method of accounting for oil and gas producing activities; therefore, no justification for a change to the successful efforts method is necessary. The Securities and Exchange Commission (SEC) also does not require its registrants to obtain a preferability letter for such a change. Any change to the full cost method must be justified as being preferable in the circumstances, and a preferability letter describing those circumstances must be filed with the SEC for registrants. The SEC’s position on preferability letters for accounting changes to or from the successful efforts or full cost methods is described in ASR No. 300, section 406.01.d.

4 FSP FAS 126-1, Applicability of Certain Disclosure and Interim Reporting Requirements for Obligors for Conduit Debt Securities, clarifies the definition of a public entity in certain accounting standards to include entities that are conduit bond obligors for conduit debt securities that are traded (continued)
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It also requires all entities (issuers and nonissuers) engaged in oil and gas producing activities to disclose in their financial statements the method of accounting for costs incurred in these activities and the manner of disposing of capitalized costs relating to those activities. The SEC, in Financial Reporting Release No. 9, *Supplemental Disclosures in Oil and Gas Producing Activities*, section 406.02, generally adopted these disclosure standards. In summary, FASB Statement No. 69 provides for the following disclosures for issuers as supplementary information:

- Net quantities of proved reserves and proved developed reserves of oil (including condensate and natural gas liquids) and gas as of the beginning and end of the year, with details of changes in proved reserves during the year
- Capitalized costs relating to oil and gas producing activities and the related depreciation, depletion, amortization, and valuation allowances as of the end of the year
- Costs incurred in oil and gas property acquisition, exploration, and development activities during the year including asset retirement costs recorded as required by FASB Statement No. 143, *Accounting for Asset Retirement Obligations*.
- Details of the results of operations for oil and gas producing activities during the year
- Standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities as of the end of the year, with details of changes in the standardized measure during the year

FASB Statement No. 69 paragraph 30 provides that the standardized measure of discounted future net cash flows should be based on the year end prices of oil and gas. Future price changes should be considered only to the extent provided by contractual arrangements in existence at year-end. The SEC position is that the prices used must be the prices for the physical production and should not be adjusted for hedges.

For purposes of this guide, *successful efforts* refers to the accounting method specified in FASB Statement No. 19 and *full cost* refers to the accounting method specified in Regulation S-X of the SEC. It should be recognized that hybrids of both of these methods are commonly referred to by those names and often are considered to be within the framework of GAAP for nonissuers.

(footnote continued) in a public market. The FASB amends, among others, FASB Statement No. 69, *Disclosures about Oil and Gas Producing Activities—an amendment of FASB Statements 19, 25, 33, and 39*, footnote 2 to paragraph 1.

5 Paragraph .04 of AU section 550, *Other Information in Documents Containing Audited Financial Statements* (AICPA, *Professional Standards*, vol. 1), states that the auditor’s responsibility with respect to other information in a document does not extend beyond the financial information identified in the auditor’s report, and the auditor has no obligation to perform any procedures to corroborate other information contained in a document; however, the auditor should read the other information and consider whether such information, or the manner of its presentation, is materially inconsistent with information, or the manner of its presentation, appearing in the financial statements. AU section 558, *Required Supplementary Information* (AICPA, *Professional Standards*, vol. 1), establishes requirements and provides guidance on the auditor’s responsibility regarding required supplementary information. Auditing Interpretation No. 1, “Supplementary Oil and Gas Reserve Information,” of AU section 558 (AICPA, *Professional Standards*, vol. 1, AU sec. 5558 par. .01–.06), establishes requirements and provides guidance on the auditor’s responsibility regarding required supplementary oil and gas reserve information.

AAG-OGP 1.53
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1.54 In addition to accounting methods included within GAAP, income tax laws and regulations have a major effect on both the accounting and the economic decisions of oil and gas companies. There are many significant differences between the income tax and either of the principal accounting methods, including the ability to charge intangible drilling costs to expense for income tax purposes. The auditor should obtain an understanding of relevant regulatory and other external factors. An understanding of the more common differences are discussed in chapter 3.

Impairment or Disposal of Long-Lived Assets

1.55 FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, establishes accounting standards for financial accounting and reporting for the impairment or disposal of long-lived assets. The statement requires that a long-lived asset (asset group) to be held and used by an entity be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Long-lived assets also include intangible assets that are amortizable. An impairment loss should be recognized only if the carrying amount of a long-lived asset (asset group) is not recoverable and exceeds its fair value. FASB Statement No. 144 applies to the impairment of proved properties accounted for in accordance with FASB Statement No. 19. (Note: The impairment of unproved properties is addressed within FASB Statement No. 19.) The carrying amount of a long-lived asset (asset group) is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset (asset group). Typically the evaluation of oil and gas producing properties is on a field-by-field basis or by logical grouping of assets if there is a significant shared infrastructure (for example, platform). The undiscounted future cash flows are to be based on total proved and risk-adjusted probable and possible reserves. That assessment should be based on the carrying amount of the asset (asset group) at the date it is tested for recoverability. The impairment loss should be measured as the amount by which the carrying amount of a long-lived asset (asset group) exceeds its fair value.

1.56 When a long-lived asset (asset group) is tested for recoverability, it also may be necessary to review depreciation estimates and method as required by FASB Statement No. 154, Accounting Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3, or the amortization period as required by FASB Statement No. 142, Goodwill and Other

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6 SEC Staff Accounting Bulletin (SAB) No. 100, Restructuring and Impairment Charges, provides guidance regarding the accounting for and disclosure of certain expenses commonly reported in connection with exit activities and business combinations. SAB No. 103, Update of Codification of Staff Accounting Bulletins, among other matters has updated SAB No. 100 to reflect the provisions of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets.

7 The impairment provisions of FASB Statement No. 144 do not apply to unproved oil and gas properties that are being accounted for using the successful-efforts method of accounting. Also, companies using the full cost method should follow the accounting requirements prescribed by the SEC.

8 See paragraphs 1.76–.89 of this guide for discussion on the key provisions of FASB Statement No. 144, Fair Value Measurements.

9 Paragraph 10 of FASB Statement No. 144 provides that for purposes of recognition and measurement of an impairment loss a long-lived asset or assets shall be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Paragraph 11 provides that in limited circumstances, a long-lived asset may not have identifiable cash flows that are largely independent of the cash flows of other assets and liabilities and of other asset groups. In those circumstances, the asset group for the long-lived asset shall include all assets and liabilities of the entity.
Intangible Assets. Any revision to the remaining useful life of a long-lived asset resulting from that review also shall be considered in developing estimates of future cash flows used to test the asset (asset group) for recoverability. However, any change in the accounting method for the asset resulting from that review shall be made only after applying FASB Statement No. 144.

1.57 FASB Statement No. 144 did not change the rules for impairment of oil and gas properties by entities that apply the successful efforts method. In addition, the impairment provisions of FASB Statement No. 144 do not apply to oil and gas assets for entities that apply the full-cost method.

1.58 FASB Statement No. 144 (paragraph C25) amends FASB Statement No. 19 by adding a new paragraph dealing with impairment test for proved properties and capitalized exploration and development cost after paragraph 62. The paragraph reads as follows:

Impairment Test for Proved Properties and Capitalized Exploration and Development Cost

The provisions of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, are applicable to the costs of an enterprise’s wells and related equipment and facilities and the costs of the related proved properties. The impairment provisions relating to unproved properties referred to in paragraphs 12, 27–29, 31(b), 33, 40, 47(g), and 47(h) of this statement remain applicable to unproved properties.

1.59 FASB Statement No. 144 (paragraph 41) defines a component of an entity to encompass operations and cash flows that can be clearly distinguished, operationally and for financial reporting purposes, from the rest of the entity. The results of operations of a component of an entity that either has been disposed of or is classified as held for sale should be reported in discontinued operations in accordance with FASB Statement No. 144 paragraph 42 if both of the following conditions are met: (a) the operations and cash flows of the component entity have been (or will be) eliminated from the ongoing operations of the entity as a result of the disposal transaction and (b) the entity will not have any significant continuing involvement in the operations of the component after the disposal transaction.

1.60 According to FASB Statement No. 144 paragraph 43, in a period in which a component of an entity either has been disposed of or is classified as held for sale, the income statement of a business enterprise for current and prior periods should report the results of operations of the component, including any gain or loss recognized in accordance with paragraph 37 of FASB Statement No. 144, in discontinued operations. The results of operations of a component classified as held for sale should be reported in discontinued operations in the period(s) in which they occur. The results of discontinued operations, less applicable income taxes (benefit), should be reported as a separate component of income before extraordinary items (if applicable). A gain or loss recognized on

10 Paragraphs 19–22 of FASB Statement No. 154 addresses the accounting for changes in estimates, including changes in the method of depreciation, amortization, and depletion. Paragraph 11 of FASB Statement No. 142, Goodwill and Other Intangible Assets, addresses the determination of the useful life of an intangible asset.

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the disposal should be disclosed either on the face of the income statement or
in the notes to the financial statements.

1.61 For entities that follow the successful efforts method of accounting,
many sales of oil and gas properties may meet the criteria for reporting as
discontinued operations. Generally, entities should assess these criteria for any
sale comprising a complete cost center for measuring impairment under FASB
Statement No. 144. For many entities, this will be at the well, lease or field
level.12

1.62 FASB Statement No. 19 paragraph 4413 is amended by FASB State-
ment No. 144, FASB Statement No. 145, Rescission of FASB Statements No.
4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Correc-
tions, and FASB Statement No. 153, Exchanges of Nonmonetary Assets—an
amendment of APB Opinion No. 29, by replacing it with the following:

In a pooling of assets in a joint undertaking intended to find, develop,
or produce oil or gas from a particular property or group of properties,
gain or loss shall not be recognized at the time of conveyance.

1.63 FASB Statement No. 144 contains additional extensive requirements
about the recognition and measurement of an impairment loss, long-lived assets
to be disposed of by sale and other than by sale.

1.64 A long-lived asset is classified as held and used until (a) it ceases to
be used (abandoned), (b) it is exchanged,14 (c) it is to be distributed to owners
in a spin-off, or (d) it is held for sale. An asset (group) is classified as held
for sale in the period in which all of the criteria in paragraph 30 of FASB
Statement No. 144 are met. If at any time afterwards the criteria are no longer
met, the asset (group) is reclassified as held and used.14 Further, if the criteria
in paragraph 30 are met after the date of the statement of financial position,
but before the issuance of the financial statements, a long-lived asset (group)
is classified as held and used in the financial statements when issued. A long-
lived asset (group) that is held for sale is measured at the lower of its carrying
amount or fair value less cost to sell. The asset (group) should not be depreciated
(amortized) while it is classified as held for sale. (However, interest and other
expenses attributable to the liabilities of a group held for sale would continue

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12 EITF Issue No. 03-13, “Applying the Conditions in Paragraph 42 of FASB Statement No.
144 in Determining Whether to Report Discontinued Operations,” addresses the appropriate level of
reporting for discontinued operations for oil and gas properties. Readers may refer to exhibit 03-13B
example 4, of EITF Issue No. 03-13 for an industry specific example of the application of the EITF
consensus.

13 FASB issued FASB Statement No. 153, which amends Accounting Principles Board (APB)
Opinion No. 29, Accounting for Nonmonetary Transactions, to eliminate the exception for nonmonetary
exchanges of similar productive assets and replaces it with a general exception for exchanges of
nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial
substance if the future cash flows of the entity are expected to change significantly as a result of the
exchange. The statement requires that exchanges of productive assets be accounted for based on
the fair values of the assets involved, unless the exchange transaction does not have commercial
substance. The statement excludes from its scope transactions involving the exchange of a part of an
operating interest owned by one party for a part of an operating interest owned by another party that
are subject to paragraph 47(e) of FASB Statement No. 19, Financial Accounting and Reporting by Oil
and Gas Producing Companies.

14 A long-lived asset to be disposed of in an exchange measured based on the recorded amount
of the nonmonetary asset relinquished or to be distributed to owners in a spin-off is disposed of when
it is exchanged or distributed. In addition to any impairment losses required to be recognized while
the asset is classified as held or used, an impairment loss, if any, should also be recognized when the
asset is disposed of if the carrying amount of the asset (disposal group) exceeds its fair value.
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Paragraphs 41–48 of FASB Statement No. 144 prescribe the reporting and disclosure requirements for assets to be disposed of by sale or otherwise.

Goodwill and Other Intangible Assets

1.65 FASB Statement No. 142, as amended, addresses the financial accounting and reporting for acquired goodwill and other intangible assets (not including financial assets) and supersedes Accounting Principles Board APB Opinion No. 17, Intangible Assets. FASB Statement No. 142 does not change the accounting prescribed in FASB Statement No. 19. It addresses how intangible assets that are acquired individually or with a group of other assets (but not those acquired in a business combination) should be accounted for in financial statements upon their acquisition. The statement also addresses how goodwill and other intangible assets should be accounted for after they have been initially recognized in the financial statements.

1.66 Goodwill and all other intangible assets are not presumed to be wasting assets under FASB Statement No. 142. Instead, goodwill and intangible assets that have indefinite useful lives are not to be amortized but rather are to be tested at least annually for impairment. Intangible assets that have finite useful lives are to continue to be amortized over their useful lives, but without the constraint of an arbitrary ceiling.

1.67 Specific guidance for testing goodwill for impairment is provided in FASB Statement No. 142. Goodwill is to be tested for impairment at least annually using a 2-step process that begins with an estimation of the fair value of a reporting unit. The first step is a screen for potential impairment, and the second step measures the amount of impairment, if any. However, if certain criteria are met, the requirement to test goodwill for impairment annually can be satisfied without a remeasurement of the fair value of a reporting unit.

1.68 In addition, the statement provides specific guidance on testing intangible assets that will not be amortized for impairment and thus removes those intangible assets from the scope of other impairment guidance. Intangible assets that are not amortized are to be tested for impairment at least annually by comparing the fair values of those assets with their recorded amounts.

1.69 FASB Statement No. 142 requires disclosure of information about goodwill and other intangible assets in the years subsequent to their acquisition. Required disclosures include information about the changes in the carrying amount of goodwill from period to period (in the aggregate and by reportable segment), the carrying amount of intangible assets by major intangible asset class for those assets subject to amortization and for those not subject to amortization, and the estimated intangible asset amortization expense for the next 5 years.

1.70 FASB staff issued FASB Staff Position (FSP) FAS 142-2, Application of FASB Statement No. 142 to Oil- and Gas-Producing Entities. This FSP

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15 In April 2008, FASB issued FSP FAS 142-3, Determination of the Useful Life of Intangible Assets. FSP FAS 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under FASB Statement No. 142 with the intent to improve the consistency between the useful life of a recognized intangible asset under FASB Statement No. 142 and the period of expected cash flows used to measure the fair value of the asset under FASB Statement No. 141, Business Combinations. FSP FAS 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Early adoption is prohibited.
addresses whether oil and gas drilling rights (mineral interests) that are held under lease or other contractual arrangement are intangible assets subject to the disclosure and classification provisions of FASB Statement No. 142. FASB staff acknowledges that the accounting framework in FASB Statement No. 19 for oil- and gas-producing entities is based on the level of established reserves—not whether an asset is tangible or intangible. Accordingly, FASB staff believes that the scope exception in paragraph 8(b) of FASB Statement No. 142 extends to its disclosure provisions for drilling and mineral rights of oil- and gas-producing entities. However, an entity is not precluded from providing information about its drilling and mineral rights in addition to the information required by FASB Statement No. 69.

1.71 FASB issued FSP FAS No. 141-1 and FAS 142-1, Interaction of FASB Statements No. 141 and No. 142 and EITF Issue No. 04-2. The FSP clarifies some inconsistent language between FASB Statements Nos. 141 and 142 and states that mineral rights should be accounted for consistent with their substance.

Business Combinations

1.72 FASB Statement No. 141, Business Combinations, addresses financial accounting and reporting for business combinations and supersedes APB Opinion No. 16, Business Combinations, and FASB Statement No. 38, Accounting for Preacquisition Contingencies of Purchased Enterprises—an amendment of APB Opinion No. 16. All business combinations in the scope of the statement are to be accounted for using one method, the purchase method.

1.73 The statement requires that intangible assets be recognized as assets apart from goodwill if they meet one of two criteria, the contractual-legal
criterion or the separability criterion. To assist in identifying acquired intangible assets, the statement also provides an illustrative list of intangible assets that meet either of those criteria.

1.74 FASB Statement No. 141 requires numerous disclosures including disclosure of the primary reasons for a business combination and the allocation of the purchase price paid to the assets acquired and liabilities assumed by major balance sheet caption. When the amounts of goodwill and intangible assets acquired are significant in relation to the purchase price paid, disclosure of other information about those assets is required, such as the amount of goodwill by reportable segment and the amount of the purchase price assigned to each major intangible asset class.

1.75 FASB Statement No. 141 contains extensive accounting guidance and requirements about business combinations including the application of the purchase method and accounting for goodwill and other intangible assets acquired.

Fair Value Measurements

1.76 FASB Statement No. 157, *Fair Value Measurements*, issued in September 2006, defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. FASB Statement No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including financial statements for an interim period within that fiscal year.

1.77 FASB issued 2 FSPs in February 2008 related to FASB Statement No. 157:

- FSP FAS 157-2, *Effective Date of FASB Statement No. 157*. This FSP delays the effective date of FASB Statement No. 157 for non-financial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value at least once a year, to fiscal years beginning after November 15, 2008. The FSP is effective upon issuance and also covers interim periods within the fiscal years for items within the scope of this FSP. The delay is intended to allow FASB and its constituents the time to consider the various implementation issues associated with SFAS No. 157.

- FSP FAS 157-1, *Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13*. This FSP amends FASB Statement No. 157 to exclude FASB Statement No. 13, *Accounting for Leases*, and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under FASB Statement No. 13. However, this scope exception does not apply to assets acquired and liabilities assumed in a business combination that are required to be measured at fair value under FASB Statement No. 141 or FASB Statement No. 141 (revised 2007), *Business Combinations*, regardless of whether those assets and liabilities are related to leases. This FSP shall be effective upon the initial adoption of FASB Statement No. 157.
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1.78 Paragraph 5 of FASB Statement No. 157 defines *fair value* as "the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date." That definition retains the exchange price notion in earlier definitions of fair value, but clarifies that the exchange price is the price in a hypothetical transaction at the measurement date in the market in which the reporting entity would transact for the asset or liability. A fair value measurement assumes that the transaction to sell the asset or transfer the liability occurs in the principal market for the asset or liability or, in the absence of a principal market, the most advantageous market for the asset or liability. Paragraph 8 of FASB Statement No. 157 defines the principal market as the market in which the reporting entity would sell the asset or transfer the liability with the greatest volume and level of activity for the asset or liability.

1.79 Paragraph 12 of FASB Statement No. 157 provides that a fair value measurement of an asset assumes the highest and best use of the asset by market participants, considering the use of the asset that is physically possible, legally permissible, and financially feasible at the measurement date. Highest and best use is determined based on the use of the asset by market participants that would maximize the value of the asset or the group of assets within which the asset would be used, even if the intended use of the asset by the reporting entity is different.

1.80 Paragraph 13 of FASB Statement No. 157 provides that the highest and best use for an asset is established by 1 of 2 valuation premises: value in-use or value in-exchange. The highest and best use of the asset is in-use if the asset would provide maximum value to market participants principally through its use in combination with other assets as a group (as installed or otherwise configured for use). For example, value in-use might be appropriate for certain nonfinancial assets. An asset’s value in-use should be based on the price that would be received in a current transaction to sell the asset assuming that the asset would be used with other assets as a group and that those other assets would be available to market participants. The highest and best use of the asset is in-exchange if the asset would provide maximum value to market participants principally on a standalone basis. For example, value in-exchange might be appropriate for a financial asset. An asset’s value in-exchange is determined based on the price that would be received in a current transaction to sell the asset standalone.

1.81 Paragraph 15 of FASB Statement No. 157 provides that a fair value measurement for a liability reflects its nonperformance risk (the risk that the obligation will not be fulfilled). Because nonperformance risk includes the reporting entity’s credit risk, the reporting entity should consider the effect of its credit risk (credit standing) on the fair value of the liability in all periods in which the liability is measured at fair value.

1.82 Paragraph 7 of FASB Statement No. 157 provides that the hypothetical transaction to sell the asset or transfer the liability is considered from the perspective of a market participant that holds the asset or owes the liability. Therefore, the definition of fair value focuses on the price that would be received to sell the asset or paid to transfer the liability (an exit price), not the price that would be paid to acquire the asset or received to assume the liability (an entry price). Conceptually, entry prices and exit prices are different. However, paragraph 17 of FASB Statement No. 157 explains that, in many cases,
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at initial recognition a transaction price (entry price) will equal the exit price and, therefore, will represent the fair value of the asset or liability.

1.83 Paragraph 9 of FASB Statement No. 157 provides that the price should not be adjusted for transaction costs. If location is an attribute of the asset or liability (as might be the case for a commodity), the price in the principal (or most advantageous) market used to measure the fair value of the asset or liability should be adjusted for the costs, if any, that would be incurred to transport the asset or liability to (or from) that market.

Valuation Techniques

1.84 Paragraphs 18–20 of FASB Statement No. 157 describe the valuation techniques that should be used to measure fair value. Valuation techniques consistent with the market approach, income approach, or cost approach should be used to measure fair value, as follows:

- The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. Valuation techniques consistent with the market approach include matrix pricing and often use market multiples derived from a set of comparables.

- The income approach uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts. Valuation techniques consistent with the income approach include present value techniques,\textsuperscript{16} option-pricing models, and the multi-period excess earnings method.

- The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (often referred to as current replacement cost). Fair value is determined based on the cost to a market participant (buyer) to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

1.85 Valuation techniques that are appropriate in the circumstances and for which sufficient data are available should be used to measure fair value. In some cases, a single valuation technique will be appropriate (for example, when valuing an asset or liability using quoted prices in an active market for identical assets or liabilities). In other cases, multiple valuation techniques will be appropriate and the respective indications of fair value should be evaluated and weighted, as appropriate, considering the reasonableness of the range indicated by those results. Examples 4–5 of appendix A of FASB Statement No. 157 illustrate the use of multiple valuation techniques. A fair value measurement is the point within that range that is most representative of fair value in the circumstances.

1.86 Valuation techniques used to measure fair value should be consistently applied. However, a change in a valuation technique or its application is appropriate if the change results in a measurement that is equally or more

\textsuperscript{16} See appendix B of FASB Statement No. 157 for additional guidance on using present value techniques to measure fair value. This appendix clarifies the concepts presented in FASB Concepts Statement No. 7, Using Cash Flow Information and Present Value in Accounting Measurements.
representative of fair value in the circumstances. Such a change would be accounted for as a change in accounting estimate in accordance with the provisions of FASB Statement No. 154.

The Fair Value Hierarchy

1.87 FASB Statement No. 157 emphasizes that fair value is a market-based measurement, not an entity-specific measurement. Therefore, a fair value measurement should be determined based on the assumptions that market participants would use in pricing the asset or liability (referred to in the statement as inputs). Paragraphs 21–31 establish a fair value hierarchy that distinguishes between (1) market participant assumptions developed based on market data obtained from sources independent of the reporting entity (observable inputs) and (2) the reporting entity’s own assumptions about market participant assumptions developed based on the best information available in the circumstances (unobservable inputs). Valuation techniques used to measure fair value should maximize the use of observable inputs and minimize the use of unobservable inputs.

1.88 The fair value hierarchy in FASB Statement No. 157 prioritizes the inputs to valuation techniques used to measure fair value into 3 broad levels. The 3 levels are described in the following list:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. An active market is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. A quoted price in an active market provides the most reliable evidence of fair value and should be used to measure fair value whenever available, except as discussed in paragraphs 25–26 of FASB Statement No. 157.

- Level 2 inputs are inputs other than quoted prices included within level 1 that are observable for the asset or liability, either directly or indirectly. Adjustments to level 2 inputs will vary depending on factors specific to the asset or liability. An adjustment that is significant to the fair value measurement in its entirety might render the measurement a level 3 measurement, depending on the level in the fair value hierarchy within which the inputs used to determine the adjustment fall. Level 2 inputs include

  — quoted prices for similar assets or liabilities in active markets.
  — quoted prices for identical or similar assets or liabilities in markets that are not active.
  — inputs other than quoted prices that are observable for the asset or liability (for example, interest rates and yield curves observable at commonly quoted intervals, volatilities, prepayment speeds, loss severities, credit risks, and default rates).
  — inputs that are derived principally from or corroborated by observable market data by correlation or other means (market-corroborated inputs).
Entities With Oil and Gas Producing Activities

- Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs should be used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. In developing unobservable inputs, the reporting entity need not undertake all possible efforts to obtain information about market participant assumptions. Unobservable inputs should reflect the reporting entity’s own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk). The reporting entity should not ignore information about market participant assumptions that is reasonably available without undue cost and effort.

In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The level in the fair value hierarchy within which the fair value measurement in its entirety falls should be determined based on the lowest level input that is significant to the fair value measurement in its entirety.

1.89 As discussed in paragraph 23 of FASB Statement No. 157, the availability of inputs relevant to the asset liability and the relative reliability of the inputs might affect the selection of appropriate valuation techniques. However, the fair value hierarchy prioritizes the inputs to valuation techniques, not the valuation techniques. For example, a fair value measurement using a present value technique might fall within level 2 or level 3, depending on the inputs that are significant to the measurement in its entirety and the level in the fair value hierarchy within which those inputs fall.

1.90 Market participant assumptions should include assumptions about the effect of a restriction on the sale or use of an asset if market participants would consider the effect of the restriction in pricing the asset. Examples 8–9 (paragraphs A29–A30) of FASB Statement No. 157 explain that restrictions that are an attribute of an asset, and therefore would transfer to a market participant, are the only restrictions reflected in fair value.

Fair Value Measurement Disclosures

1.91 Paragraphs 32–35 of FASB Statement No. 157 expand the disclosures required for assets and liabilities measured at fair value. For assets and liabilities that are measured at fair value on a recurring basis in periods subsequent to initial recognition or that are measured on a nonrecurring basis in periods subsequent to initial recognition, the statement requires the reporting entity to disclose certain information that enables users of its financial statements to assess the inputs used to develop those measurements. For recurring fair value measurements using significant unobservable inputs (level 3), the reporting entity is required to disclose certain information to help users assess the effect of the measurements on earnings (or changes in net assets) for the period.

Fair Value Option

1.92 FASB Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities—including an amendment of FASB Statement No. 115, creates a fair value option under which an organization may irrevocably elect fair value as the initial and subsequent measure for many financial instruments and certain other items, with changes in fair value recognized in
the statement of activities as those changes occur. FASB Statement No. 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Earlier adoption is permitted if certain conditions described in paragraph 30 of the statement are met. FASB Statement No. 155, *Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140*, similarly permits an elective fair value remeasurement for any hybrid financial instrument that contains an embedded derivative, if that embedded derivative would otherwise have to be separated from its debt host in conformity with FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*. An election is made on an instrument-by-instrument basis (with certain exceptions), generally when an instrument is initially recognized in the financial statements.

1.93 Most financial assets and financial liabilities are eligible to be recognized using the fair value option, as are firm commitments for financial instruments and certain nonfinancial contracts. Specifically excluded from eligibility are investments in other entities that are required to be consolidated, employer’s and plan’s obligations under postemployment, postretirement plans, and deferred compensation arrangements (or assets representing overfunded positions in those plans), financial assets and liabilities recognized under leases, deposit liabilities of depository institutions, and financial instruments that are, in whole or in part, classified by the issuer as a component of shareholder’s equity. Additionally, the election cannot be made for most nonfinancial assets and liabilities or for current or deferred income taxes.

1.94 FASB Statement No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. Organizations should report assets and liabilities that are measured using the fair value option in a manner that separates those reported fair values from the carrying amounts of similar assets and liabilities measured using another measurement attribute. To accomplish that, an organization should either (a) report the aggregate carrying amount for both fair value and non-fair-value items on a single line, with the fair value amount parenthetically disclosed or (b) present separate lines for the fair value carrying amounts and the non-fair-value carrying amounts.

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17 In March 2008, FASB issued FASB Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133*. In response to constituents’ concerns that FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*, does not provide adequate information about how derivatives and hedging activities affect an entity’s financial position, financial performance, and cash flows, FASB issued FASB Statement No. 161 to enhance disclosures about an entity’s derivative and hedging activities and to improve financial transparency. This statement has the same scope as FASB Statement No. 133 and, accordingly, applies to all entities. FASB Statement No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Early adoption is encouraged. FASB Statement No. 161 encourages, but does not require, comparative disclosures for earlier periods at initial adoption. Refer to FASB Web site at www.fasb.org for the full text of the statement.

† See paragraph 2.153 for additional discussion regarding FASB Statement No. 155.
Chapter 2

Business Activities of the Oil and Gas Producing Industry

Acquisition of Mineral Properties

2.01 In the oil and gas industry, rights to drill wells and produce minerals found are generally obtained through leasing transactions. Although the operator may acquire the fee interest in the property (outright ownership of both minerals and surface), this is not customary today. The operator usually obtains a lease from a landowner, either through an in-house landman or from an independent lease broker. The landman or broker researches the public records to verify the legal owner of the mineral interest in the property and may obtain legal title opinions, although in many instances the title work will not be performed until shortly before drilling commences. The landman or broker then negotiates the lease terms with the landowner. Leases on state-owned properties are normally awarded through a bidding process, with leases granted to the highest bidder. Leases on federally owned properties located offshore or on known geological structures, as well as certain other properties, are also awarded by bidding. Leases on most federally owned properties located onshore are awarded through lease application systems with a standard fee.

2.02 As discussed under "Exploration" in paragraphs 2.35–.50, exploration activities may take place prior to acquisition of the mineral rights.

The Lease

2.03 The most important and most commonly found provisions in oil and gas leases are outlined subsequently, but it is important that oil and gas leases be read carefully by the auditor to obtain an understanding of the principal provisions. A standard lease agreement, prepared by the American Association of Petroleum Landmen, is often adapted to fit particular circumstances. Although the basic provisions in leases are similar, each lease may contain unique provisions. These basic provisions are discussed in the following paragraphs.

2.04 Lease bonus. The lease bonus is the cash or other consideration paid to the lessor by the lessee in return for the lessor’s granting the lessee rights to explore for minerals, drill wells, and extract any minerals found. The bonus is computed on a per-acre basis and may range from a few dollars per acre in wildcat locations to thousands of dollars per acre for locations near producing properties. In negotiated leases, the full amount of the bonus may not be specified in the lease agreement.

2.05 Primary term. The maximum period of time allowed for the lessee to commence drilling a well is referred to as the primary term, which is normally three to ten years.

2.06 Drilling obligation. The lease generally stipulates that either drilling operations begin within a specified period (usually one year) or that the lessee make a specified payment (delay rental) to the lessor. In succeeding years, the same drilling obligation exists but can be deferred (and the lease retained) by
making the specified payment; however, no provision is made for the extension of the lease by payment of rent beyond the primary term.

2.07 Delay rentals. The payment made to defer drilling activities for an additional year is called a delay rental. The amount of the delay rental is normally much smaller than the lease bonus.

2.08 Royalty provisions. The lessor retains a royalty interest in the minerals. This interest entitles the lessor to receive free and clear of all costs a specified portion of the oil and gas produced, or a specified portion of the value of such production, except for (1) the related state severance or production taxes and (2) certain costs necessary to get the product into a salable condition.

2.09 Production holds lease. Once a successful well has been drilled and commercial production is begun, the lease usually remains in effect for as long as there is production without extended and indefinite interruption. If production ceases, the operator must act in good faith to resume the extraction of oil or gas within a reasonable time (specified in the lease contract).

2.10 Right to assign interest. The lease contract grants each party the right to assign, without approval of the other party, any part or all of its rights and obligations.

2.11 Fixed or mandatory rentals. The contract may provide for rental payments that cannot be avoided even though the property is abandoned or drilling has begun. In effect, these payments are deferred bonuses paid on an installment basis.

2.12 Shut-in royalties. Most lease contracts provide for shut-in royalties, which represent payments by the operator to the royalty owner if a successful well has been drilled but production has not begun within a specified time. Shut-ins frequently occur on properties containing gas and may be caused by the absence of a market, a lack of transportation, the necessity to obtain permission from a governmental unit, or for other reasons. Shut-in payments may or may not be recoverable by the operator out of future amounts accruing to the royalty owner.

2.13 Offset clause. A common provision called an offset clause requires an operator to drill such offset wells to prevent drainage of oil or gas to another tract that a prudent operator would drill under similar circumstances.

2.14 Compensatory royalties. Payments known as compensatory royalties are made by oil companies to royalty owners as compensation for the latter’s loss of income during periods when the company has not fulfilled its obligation to drill.

2.15 Guaranteed or minimum royalties. If leases are acquired on property having a high probability of being productive, the mineral owner may be able to negotiate a provision in the lease requiring the lessee to guarantee the mineral owner a specified minimum royalty payment each month or each year. If the royalty owner’s share of net proceeds from production is less than the specified amount, the lessee must pay the difference. Guaranteed payments may be non-recoverable or may be recoverable out of future royalties accruing to the royalty owner.

2.16 Surface damage. This provision is sometimes incorporated in a mineral lease to require a lessee to pay for any damages to the leasehold that occurs from drilling or operating the lease.


Business Activities of the Oil and Gas Producing Industry

**Contract Termination Costs**

2.17 Financial Accounting Standards Board (FASB) Statement No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*, as amended, addresses accounting for contract termination costs. Costs to terminate an operating lease (as defined by FASB Statement No. 13, *Accounting for Leases*) or other contract are (a) costs to terminate the contract before the end of its term or (b) costs that will continue to be incurred under the contract for its remaining term without economic benefit to the entity, as stated in paragraph 14 of FASB Statement No. 146.

2.18 A liability for costs to terminate a contract before the end of its term should be recognized and measured at its fair value when the entity terminates the contract in accordance with the contract terms. (For example, when the entity gives written notice to the counterparty within the notification period specified by the contract or if the entity has otherwise negotiated a termination with the counterparty.) The guidance in paragraph 6 of FASB Statement No. 146 should be applied in periods subsequent to that date. An example of this would be consolidation of operating locations where business activities are consolidated into a given location. The entity may incur employee relocation costs, operating lease terminations, sale of field location buildings, severance and employee related benefit costs.

2.19 A liability for costs that will continue to be incurred under a contract for its remaining term without economic benefit to the entity should be recognized and measured at its fair value when the entity ceases using the right conveyed by the contract. For example, the right to use a leased property or to receive future goods or services, referred to as the cease-use date. If the contract is an operating lease, the fair value of the liability at the cease-use date should be determined based on the remaining lease rentals, reduced by estimated sublease rentals that could be reasonably obtained for the property, even if the entity does not intend to enter into a sublease. Remaining lease rentals should not be reduced to an amount less than zero. The guidance in paragraph 6 of FASB Statement No. 146 should be applied for periods subsequent to the cease-use date. Example 4 of appendix A, FASB Statement No. 146, illustrates costs to terminate an operating lease.

2.20 **Disclosures.** In accordance with paragraph 20 of FASB Statement No. 146, an entity should disclose the following information in the financial statements that include the period in which an exit or disposal activity is initiated and any subsequent period until the activity is completed:

a. A description of the exit or disposal activity, including the facts and circumstances leading to the expected activity and the expected completion date.

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1 Financial Accounting Standards Board (FASB) Statement No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*, as amended, states that an exit or disposal activity is initiated when management, having the authority to approve the action, commits to an exit or disposal plan or otherwise disposed of a long-lived asset (disposal group) and, if the activity involves the termination of employees, the criteria for a plan of termination in paragraph 8 of FASB Statement No. 146 are met.


3 The remaining lease rentals should be adjusted for the effects of any prepaid or deferred items recognized under the lease.
Entities With Oil and Gas Producing Activities

b. For each major type of cost associated with the activity (for example, one-time termination benefits, contract termination costs, and other associated costs):

(1) The total amount expected to be incurred in connection with the activity, the amount incurred in the period, and the cumulative amount incurred to date.

(2) A reconciliation of the beginning and ending liability balances showing separately the changes during the period attributable to costs incurred and charged to expense, costs paid or otherwise settled, and any adjustments to the liability with an explanation of the reason(s) therefor.

c. The line item(s) in the income statement in which the costs in (b) are aggregated.

d. For each reportable segment, the total amount of costs expected to be incurred in connection with the activity, the amount incurred in the period, and the cumulative amount incurred to date, net of any adjustments to the liability with an explanation of the reason(s) therefor.

e. If a liability for a cost associated with the activity is not recognized because fair value cannot be reasonably estimated, that fact and the reasons therefor.

Other Considerations—Acquisition

2.21 Almost all transactions related to oil and gas activities have their foundations in the lease contract.

2.22 Oil and gas producers may also acquire interests in properties that have already been leased and perhaps drilled and developed by others. This is usually accomplished by assigning all the rights and obligations of the original lessee through a sale or by acquiring the operating interest subject to a nonoperating interest retained by the original lessee (sublease). Typically, the assignment contract specifies an agreed-on value of well and lease equipment, and the balance of purchase price is deemed to be applicable to the mineral rights obtained.

2.23 When a fee interest in property is acquired, the transaction is similar to a typical real estate transaction in that the acquirer may have all the interests in a property and not just mineral interests.

2.24 After mineral rights have been acquired through purchase or lease, several years may elapse before drilling begins. Economic or market conditions may delay development. During that period, the holder of the rights may be required to pay ad valorem taxes and pay other carrying costs in addition to possible delay rentals or minimum royalty payments.

2.25 The company will usually maintain a prospect file or a lease file, or both, for each property. These files generally include, as a minimum, a copy of the lease, the survey or other legal description of the property, and the title opinions. As the prospect develops, the lease file will include additional documents such as authorization for expenditures, division orders, purchase contracts (if applicable), operating agreements, and producer-status certifications.
2.26 The lessee should keep abreast of the timing of delay rental payments and reassignment obligations. If delay rental payments are not made when due, the lease contract expires. It is important that lease rentals be paid on properties that the lessee does not wish to surrender. Customarily, the lessee may avoid all obligations and give up all rights and responsibilities by simply failing to pay rentals when due, or the lessee may terminate the contract at any other time by executing a formal lease surrender or a quit claim deed. In cases where the original lease has been assigned and an overriding royalty or other type of interest is retained, a reassignment clause may be executed. If so, the assignee would be required to notify the assignor in advance of an intent to permit the lease to lapse.

2.27 If the lessee wishes to retain a property whose primary term is about to expire but on which drilling has not yet begun, an extension of the original lease may be agreed to by both parties upon an additional payment by the lessee, or a top lease (a new lease contract on the same property) may be executed, usually involving an additional bonus payment by the lessee. A top lease may also be taken by a third party, in expectation of the expiration of the existing lease.

Accounting for Acquisition Costs

2.28 **Successful efforts.** Under the successful efforts method, costs associated with the acquisition of leases are capitalized when incurred. These consist of costs incurred in obtaining a mineral interest in a property, such as the costs of lease bonuses and options to lease, brokers’ fees, recording fees, legal costs, and other similar costs in acquiring property interests.

2.29 Unproved properties are assessed periodically to determine whether they have been impaired under successful efforts accounting. A property may be considered impaired if, for example, a dry hole has been drilled on a portion of it or in close proximity, and the company has no intention of further drilling on the property. Also, as the expiration of the lease term approaches and the company has not begun drilling on the property or nearby properties, the possibility of partial or total impairment of the property may increase. Impairment on individually significant unproved properties is assessed on a property-by-property basis. If a property is found to be impaired, an impairment allowance is provided, and a loss is recognized in the income statement.

2.30 Unproved properties whose costs are individually insignificant may be amortized in the aggregate or by groups, on the basis of the experience of the company in similar situations and with the consideration of such factors as the primary lease terms, the average holding period of unproved properties, and the relative proportion of such properties on which proved reserves have been found in the past.

2.31 Properties are classified as unproved until proved reserves are discovered on the property. If a property being reclassified as proved has previously been impaired on an individual basis and a valuation allowance has been established, the net amount (acquisition cost minus valuation allowance) is reclassified. If a valuation allowance has been provided on the property on a group basis, the gross acquisition cost is reclassified as proved.

2.32 If an unproved property is surrendered or expires, the cost of the property is charged against the impairment allowance to the extent it has been provided. Any excess basis is charged to loss.
Entities With Oil and Gas Producing Activities

2.33 **Full cost.** Under the full cost method, all costs associated with the acquisition of properties are capitalized within the appropriate cost center. Prior to 1983, all capitalized costs were included in the full cost pool and became part of the amortizable base; however, in certain circumstances, the cost of unusually significant investments in unproved properties and major development projects could be excluded from costs to be amortized. Effective with the Securities and Exchange Commission’s (SEC) adoption of Financial Reporting Release (FRR) Release No. 14, Oil and Gas Producers—Full Cost Accounting Practices; Amendment of Rules,4 section 406.01.c.i., in 1983, all costs directly associated with the acquisition and evaluation of unproved properties may be excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties. The computation of depreciation, depletion, and amortization (DD&A) is further discussed under “Accounting for Production” in paragraphs 2.107–.124.

2.34 Full cost accounting requires that properties excluded from the amortization computation be assessed at least annually to ascertain whether impairment has occurred. Unevaluated properties whose costs are individually significant are assessed individually. When it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, such properties may be grouped for purposes of assessing impairment. The amount of impairment assessed is added to the costs to be amortized. Full cost accounting does not require the assessment of properties included in the amortization computation for impairment; rather, the cost pool in the aggregate is compared to the cost center ceiling. (The cost ceiling is further discussed under “Accounting for Production” in 2.107–.124.) Some companies not subject to SEC regulations follow other methods of computing the cost ceiling.

Exploration

2.35 The purpose of geological and geophysical exploration is to obtain information about subsurface geological conditions in an area that can be used in assessing the probability that oil or gas exists in commercial quantities. This involves first locating underground structures or stratigraphic variations that are conducive to the trapping of oil and gas, then carrying out detailed tests to see if drilling is justified.

Origin and Accumulation of Oil and Gas

2.36 Oil and gas are generally believed to have originated from organic matter in sedimentary rocks. Layer upon layer of sediment and animal and plant deposits were buried successively until the accumulation became thick, sometimes thousands of feet. Bacteria took oxygen from the trapped organic residues and gradually broke down the matter into substances rich in carbon and hydrogen. The weight of the overburden created high pressure and temperature, compacted and squeezed the sediment into hard shales, turned the organic material into oil and gas, and expelled the oil and gas from the shale into reservoir beds.

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4 Security and Exchange Commission (SEC) Financial Reporting Release (FRR) No. 14, Oil and Gas Producers—Full Cost Accounting Practices; Amendment of Rules, has been codified and included in the SEC Staff Accounting Bulletin (SAB): Codification of Staff Accounting Bulletins Topic 12(D)(2), Oil and Gas Producing Activities—Application of Full Cost Method of Accounting—Exclusion of costs from amortization.
2.37 Oil and gas are usually not found where they were formed. Source rocks, in which the organic material was originally trapped, are fine-grained and relatively impervious. They rarely hold oil and gas in significant quantities. The oil and gas normally move from the source rock into more porous rocks, then migrate upward through the porous rocks until they reach a structural closure or an impermeable barrier caused by stratigraphic variations. These closures and barriers are called traps and are the cause for accumulation of oil and gas into a pool or field.

2.38 An oil or gas reservoir is often erroneously viewed as a large pool of liquid or gas beneath the earth, like a subterranean pond. In reality, a petroleum reservoir is porous rock capable of containing gas, oil, or water. The petroleum is accumulated in the small pore spaces of the rock. For an oil and gas pool to be formed, the following features must be present:

- There must have been an original source bed of organic material, subjected to the proper temperature and pressure over sufficient time.
- There must be a reservoir rock—a rock filled with pores so the oil or gas can collect (porosity).
- The rock's pores must be interconnected so the oil or gas can move or migrate (permeability).
- There must be a trap that will cause the oil or gas to collect in a pool and prevent it from moving further upward.

Prosppecting for Oil and Gas

2.39 At one time, prospecting for oil and gas merely involved visible sightings of surface accumulations. The primary exploration technique used in many areas was surface geological mapping to define the structural features expressed in the rock outcrops that indicated an oil and gas trap would be present in the subsurface. However, these obvious drilling sites were rapidly developed and subsurface geological and geophysical studies were needed to locate petroleum reservoirs. Several scientific methods were developed, including the seismic method, the magnetic method, and the gravity method. Surface geological studies, however, are still used to locate areas structurally favorable for oil and gas accumulations in new exploration areas. In addition, there have been numerous advances in the use of seismic data such as 3D and 4D. These advanced techniques provide higher resolution which can significantly reduce the risk of drilling dry holes.

2.40 Geological exploration activities include the following: (1) studying the structural configuration of exposed formations on the surface in order to secure information about the structure of parallel subsurface beds; (2) examining the surface for oil or gas seepages, or paraffin residue that indicates past seepage of hydrocarbons; and (3) examining subsurface strata through the use of samples taken by core drilling as well as measurements of certain physical properties of the sample rocks, such as resistivity and radioactivity. In addition, geologists and other scientists make many different tests of cuttings brought to the surface in the process of drilling wells.

2.41 Some large companies maintain exploration departments or establish exploration subsidiaries that own or lease geological and geophysical equipment and employ exploration crews and scientists. Most companies, both large and
small, contract with exploration and oil industry service companies to carry out their exploration.

2.42 If an outside contractor is used, the contract normally contains detailed provisions about the following: (1) the area to be covered; (2) the nature of work to be performed; (3) the time period in which the exploration is to be carried out; (4) the nature of reports to be made; and (5) rules for insuring security of data, as well as other provisions.

2.43 When the operating company maintains its own exploration department, it is customary for costs of that department to be accumulated and allocated to exploration activities and projects. The allocation is based on standardized charges, such as cost per day for a crew, costs per shot-point for seismic work, hourly basis for engineers, and the like. Frequently, employment contracts with geologists or geophysicists call for the employee to receive ownership interests in leases acquired as the result of exploration.

2.44 For control purposes, exploration is undertaken on a project basis. A project area is usually the maximum size that can be efficiently explored under a coordinated exploration program. A preliminary reconnaissance of the project area using magnetometers, gravitometers, aerial photography, and surface geology seeks to define areas of interest for oil and gas accumulations that justify more intensive exploration through seismic shooting or core drilling. The detailed exploration is conducted to determine more specific prospective areas for evaluation with drilling and may be conducted either before or after acquiring the lease.

2.45 Once the seismic data have been analyzed and the leases acquired, the company determines the exact spot for drilling. Wells drilled in an unproved area are referred to as exploratory wells. The more risky exploratory wells are referred to as wildcat wells and are often drilled in areas that have not previously yielded commercial production.

Other Considerations—Exploration

2.46 Some exploration can be conducted without direct access to privately owned land surface; for example, photography and gravimetric and magnetic measurements can be conducted from planes or satellites, and studies of surface strata can be made from creek beds or river beds and from public roads and railroads cut through hills. However, to gain access to private land the operator secures permission from landowners. This transaction may involve a “rights to explore only” contract, which permits the operator to conduct exploration on the property but does not provide for subsequently leasing acreage. Permission may also be granted through a “rights to explore with option to acquire acreage” contract. This agreement calls for the operator to make a payment at the time the contract is signed, and it gives the operator not only the right to explore but also the right to lease all or part of the acreage by paying a specified bonus per acre within the option period (often six months).

2.47 Holders of mineral properties may make cash contributions to other operators who are drilling wells on nearby properties in exchange for which the operator conducting drilling provides the contributor with geological data, including samples from the well being drilled. Sometimes the transaction involves a bottom hole contribution, calling for cash to be paid when the well has been drilled to a specific geological formation or to a specified depth. In other cases, the transaction involves a dry hole contribution, which provides that
the contribution is to be made only if the well being drilled does not produce commercial reserves. If the well is a producer, no contribution is made.

Accounting for Exploration Costs

2.48 Exploration costs incurred in the geological and geophysical activities are commonly referred to as G&G costs. G&G costs include the following: costs of topographical, geological, and geophysical studies; rights of access to properties to conduct those studies; and salaries and other expenses of geologists, geophysical crews, or others conducting those studies. Also included in exploration costs are expenses of carrying and retaining undeveloped properties, dry hole and bottom hole contributions, costs of drilling and equipping exploratory wells, and costs of drilling exploratory-type stratigraphic test wells.

2.49 Successful efforts. Under the successful efforts method, G&G costs, costs of carrying and retaining undeveloped properties such as delayed rentals, ad valorem taxes on properties, legal costs for title defense, maintenance of land and lease records, and dry hole and bottom hole contributions are charged to expense as incurred. The costs of drilling exploratory and exploratory-type stratigraphic test wells are capitalized, pending determination of whether the well can produce proved reserves. If it is determined the well will not produce proved reserves, the capitalized costs, net of any salvage value, are charged to expense. See "Accounting for Drilling and Development Costs" in paragraphs 2.64–.71.

2.50 Full cost. Under the full cost method, all costs associated with the exploration of properties are capitalized within an appropriate cost center. These cost centers are established on a country-by-country basis. The costs become part of the full cost pool.

Drilling and Development

2.51 Although most wells drilled by oil and gas operators are intended to find oil and gas and to extract minerals, some wells are drilled solely to obtain geological information (stratigraphic test wells) or to facilitate production (gas or water injection wells). Wells drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive are classified as development wells; other wells drilled to find oil and gas are called exploratory wells.

2.52 Various drilling methods exist. Rotary drilling is by far the most prevalent method. Rotary drilling, as the name implies, involves the application of a rotating motion to a drill bit to bore a hole into the earth. A drilling fluid (mud) is continually circulated in the drilled hole to flush the cuttings from the hole as it is drilled.

2.53 Although well bores are normally planned to be drilled vertically, it is sometimes necessary or advantageous to drill at an angle, especially in offshore operations. Directional drilling makes it possible to drill a number of wells using the same rig from the same surface location. Directional drilling has other applications. Wells may be drilled from the shoreline and deflected to reach a reservoir offshore. It is also used, among other things, for exploratory drilling to locate the fault plane of a structure. Horizontal drilling is a type of directional drilling used where the departure of the wellbore from vertical exceeds about 80 degrees. Because a horizontal well typically penetrates a greater length of
the reservoir, it can offer significant production improvement over a vertical well.

The Drilling Contract

2.54 Operators may carry out drilling activities using their own rigs, or they may hire independent drilling contractors to drill wells. The terms of drilling contracts vary widely, but most involve footage-rate contracts, day-rate contracts, turnkey contracts, or a combination of the three.

2.55 Under footage-rate contracts, the drilling contractor is paid a fixed amount per foot drilled to a specified depth or a number of feet below a geological formation. The drilling contractor provides the rig, the drilling crew, and certain materials and supplies. The operator may provide drilling mud and normally provides all well equipment. In a footage-rate contract, some of the risk of drilling is shifted from the operator to the drilling contractor. If the rig is idle through no fault of the driller, a daily or hourly charge generally is specified. If the rig can only drill a few feet per day because of hard rock or other problems, the drilling contractor bears the economic adversity.

2.56 Under day-rate contracts, the operator is charged a specified sum per day for the use of a drilling rig and drilling crew, which may vary depending on whether the rig is drilling or idle, the extent of equipment furnished, or other factors. The cost of a well bore hole is a function of the speed of the rig, the depth to be drilled, the geological formation encountered, and other drilling factors. Typically, under day-rate contracts, the drilling contractor furnishes the rig and crew, but the operator provides supplies, mud, and services.

2.57 Under a turnkey contract, the contractor guarantees to the operator a hole drilled to a specified depth. The drilling contractor bears most of the risk of adversity associated with drilling costs. Turnkey contracts usually specify completing a well to a certain point—such as to casing point, to completion, to tanks, or the like. The drilling contract specifies the point or points at which payment is to be made by the operator.

2.58 Frequently, an operator will assign an economic interest in the leasehold to another party in return for the latter’s assumption of the cost of drilling a well. These drilling arrangements are discussed under “Conveyances” in paragraphs 2.136–148.

Completing or Plugging and Abandoning the Well

2.59 Once the well has been drilled to total depth, the operator evaluates the evidence to determine whether the costs of completion can be justified. This is often referred to as casing point. Completion of the well does not necessarily mean the well will be profitable. Generally, the well will be completed if the expected revenues exceed the incremental completion costs and the expected operating expenses. Therefore, even though total costs, including drilling costs, may not be recovered, completion may be economically justified. It is common in the industry—particularly in promoted ventures—for costs to be shared in different percentages depending on whether they are incurred before casing point or after casing point. The determination of this cut-off point can be very important in the allocation.

2.60 In completing the well, casing is set and cemented into the hole, which seals off the producing formation. The most widely used method of completion is to perforate the casing with explosive charges that puncture through the
casing and cement into the formation so the oil and gas can enter the well bore. Depending on the permeability of the formation, it may also be necessary to fracture or acidize the formation to obtain the desired flow of oil and gas. These are specialized services, generally performed by independent well service companies.

2.61 Completion of the well also involves the installation of equipment. The specific equipment required will depend on the nature of the well, whether oil or gas or both are produced, the availability of pipelines, and other factors.

Developing the Reservoir

2.62 Normally, a single well is not sufficient to complete the development of a reservoir. Additional wells usually increase the ultimate quantity of oil or gas to be extracted from the reservoir. They also affect the timing of the extraction and thus the present value of the income stream. While the presence of an oil and gas reservoir was established through the drilling of the discovery well, the property may or may not have sufficient potential reserves to warrant the further expenditures required for the complete development. Core samples, along with pressure tests, flow tests and rates, fluid analyses, and other geological data, are used in deciding whether to continue with development. Assuming that a successful discovery well has been drilled, drilling and development will continue until the boundaries of the reservoir are delineated.

The Regulatory Environment

2.63 Various state agencies issue regulations concerning well spacing limitations, rules regarding unitization of reservoirs, and allowable maximum production limits. Normally, the operator obtains permits before exploration or drilling commences. Reports on well depths and results of drilling activities generally should be filed with the applicable agency. For example, if a well is determined to be dry or commercially unproductive, a plugging report is filed with the state agency. If a well is completed, various types of information, including production, generally should be filed on a regular basis with the appropriate state and federal agencies, including the Department of Energy, the Federal Energy Regulatory Commission, and the Minerals Management Service.

Accounting for Drilling and Development Costs

2.64 Successful efforts. Under the successful efforts method, all costs incurred while drilling an exploratory well are capitalized pending determination of whether the well has found proved reserves. If the well has not found proved reserves, the capitalized costs of drilling the well, net of any salvage value, are charged to expense.5 If an exploratory well or exploratory-type stratigraphic test well is in progress at the end of a period and the well is determined not to have found proved reserves before the financial statements for that period are issued, the costs incurred through the end of the period, net of any salvage value, are charged to expense for that period (FASB Interpretation No. [FIN] 36, Accounting for Exploratory Wells in Progress at the End of a Period— an interpretation of FASB Statement No. 19).

5 FASB Staff Position (FSP) FAS 19-1, Accounting for Suspended Well Costs, provides guidance on the accounting and disclosure for exploratory well costs and amends paragraphs 31–34 of FASB Statement No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies. The guidance in the FSP applies to entities that use the successful efforts method of accounting. Readers should refer to the entire FSP at www.fasb.org for additional guidance.

AAG-OGP 2.64
Entities With Oil and Gas Producing Activities

2.65 All drilling and completion costs that directly lead to the extraction and production of oil and gas reserves and all development dry holes are capitalized. Capitalized costs are accumulated by cost centers, which provide a means whereby costs can be collected and amortized against the revenues therefrom. For amortization purposes, the cost center is the individual property or an aggregation of properties in the same field or reservoir.

2.66 Because development dry holes are capitalized and exploratory dry holes are expensed, the distinction between them is extremely important and should be made by the company prior to drilling.

2.67 Full cost. A company that employs the full cost method of accounting capitalizes all costs associated with the drilling and completion of a well, regardless of whether or not it results in the discovery of oil and gas reserves.

2.68 Interest capitalization. Interest capitalization may be accounted for quite differently under the full cost and successful efforts methods. A significant difference may occur between these two methods when a company following the full cost method does not elect to exclude costs of unevaluated properties from costs to be amortized.

2.69 FIN 33, Applying FASB Statement No. 34 to Oil and Gas Producing Operations Accounted for by the Full Cost Method—an interpretation of FASB Statement No. 34, states that assets whose costs are being currently depreciated, depleted, or amortized are assets in use in the earnings activities of the enterprise and are not assets qualifying for capitalization of interest.

2.70 Under the successful efforts method, capitalized costs of each property represent the company’s assets. When a property is ready for production to commence, the capitalized costs of that property are considered “in the earnings activities of the enterprise,” and are no longer qualifying assets. Costs of successful and unsuccessful exploratory efforts, including related leasehold costs, incurred on a property are qualifying assets until the property is ready for production to commence.

2.71 Under both methods, capitalized interest is attached to the qualifying costs on which the interest was computed and amortized in the same manner as those costs.

Oil and Gas Reserves

2.72 The discovery of oil and gas reserves is the primary objective of exploration and development activities. In order to assure its long-term existence, an oil and gas producing company continues to replace the reserves produced with newly discovered reserves.

2.73 Reserve determinations have a significant effect on a company’s results of operations and financial position. For a company following the successful efforts method of accounting, exploratory wells discovering proved oil and gas reserves will be capitalized instead of being expensed. Additionally, for both the successful efforts and full cost methods of accounting, amortization of capitalized costs is computed by means of the unit-of-production method, based on proved reserves. Further, under the full cost method, there is a limitation on capitalized costs in each cost center based primarily on a calculation of future net revenues from estimated production of proved oil and gas reserves. See “Full Cost Ceiling” in paragraph 2.119.

AAG-OGP 2.65
Reserves are classified as either proved or potential (potential reserves can be further categorized as probable and possible). Only proved reserves are used for accounting purposes.

Proved Reserves

Proved oil and gas reserves (as defined by FASB and the SEC) are the estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (prices and costs as of the date the estimate is made). Prices include consideration of fixed and determinable changes in existing prices provided only by contractual arrangements, but not on escalations based on future conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or a conclusive formation test. The area of a reservoir considered proved includes (1) that portion delineated by drilling and defined by gas-oil or oil-water contacts or both, 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 successful testing by a pilot project, or the operation of an installed program in the reservoir, provide support for the engineering analysis on which the project or program was based.

Proved developed reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery ordinarily should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed, through production response, that increased recovery will be achieved.

Proved undeveloped reserves. Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undeveloped acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undeveloped acreage are limited to those drilling units that offset productive units and that are reasonably certain of production when drilled. Proved reserves for other undeveloped units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances are estimates for proved undeveloped reserves to be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.
Entities With Oil and Gas Producing Activities

2.80 Subdivisions. Although variations in terminology occur depending on the engineer responsible for the study, it is quite common to find reserve classifications further divided as follows:

- **Producing reserves**—Those reserves estimated to be recoverable from zones currently open and producing.
- **Shut-in reserves**—Those reserves estimated to be recovered from zones in which completions have been made in wells ready to produce and awaiting connection to delivery facilities.
- **Behind-pipe reserves**—Those reserves behind casing in producing wells.

Potential Reserves

2.81 Proved reserves have industry and regulatory definitions, but there are no such standards for potential reserves, which are often referred to as probable and possible. These reserve classifications are not subject to SEC disclosure. However, since potential reserves are commonly used terms in the industry, these definitions are offered as examples.

2.82 **Probable reserves.** Probable reserves are those that are supported by favorable engineering and geological data but are subject to some element of risk, which prevents classification as proved reserves.

2.83 **Possible reserves.** Possible reserves include speculative reserves where risk is relatively high. Usually, reserves to be included as possible are those that depend on some favorable development or event (such as creation of a unit to conduct fluid-injection operations or remedial work to correct a mechanical defect) that is not predictable with sufficient accuracy.

Definitional Problems

2.84 As indicated by the foregoing definitions, the classification of reserves is highly complex. Although the definition of proved reserves cited is from SEC regulations, it was derived directly from similar definitions developed by the Society of Petroleum Engineers of the American Institute of Mining, Metallurgical, and Petroleum Engineers. The definition of probable and possible reserves can vary significantly from one engineer to another.

Determination of Reserves

2.85 Reserve estimates are prepared by persons such as petroleum reservoir engineers and geologists with the specialized knowledge and experience required to estimate oil and gas reserves. The engineers may be either employees of the company or independent reservoir engineers. Reserve studies may also be prepared using various assumptions, each for different purposes.

2.86 Reserve estimates or studies are used for a variety of purposes, including

- a basis for financing or investment decisions.
- a basis for management’s estimates of internally generated cash flow and as input for better operational decisions.
- a basis for computing the depreciation, depletion, and amortization rates used in the systematic allocation of capitalized costs to the production function.
Business Activities of the Oil and Gas Producing Industry

- disclosure information about a producing company’s resources, which is used in financial reporting to lenders, investors, analysts, and the SEC.
- a basis for determining cost ceiling limitations.

2.87 The initial evaluation of a well or wells is made to determine whether sufficient reserves have been discovered to justify developing the property. This evaluation is usually prepared by employees of the company based on log and core data, drill stem tests, and other available information.

2.88 Oil and gas companies should revise reserve estimates whenever there is an indication of the need for revision, at least annually. The reserve estimates prepared for this purpose are usually made as of the company’s year-end. In many cases the estimate is prepared by independent reservoir engineers.

2.89 Preparation of estimates. The Society of Petroleum Engineers has adopted standards pertaining to the estimating and auditing of oil and gas reserve information by qualified engineers and geologists. A general understanding of the methods of, and limitations on, estimating proved reserves is helpful to the auditor.

2.90 The following information may be used to develop reserve quantity information:
- Area and thickness of the productive zone
- Porosity of the reservoir rock
- Permeability of the reservoir rock to fluids
- Oil, gas, and water saturation
- Physical characteristics of oil and gas
- Depth to the producing formation
- Reservoir pressure and temperature
- Production history of the reservoir
- Ownership of the oil and gas property

2.91 Estimates of the reserve quantities that are economically recoverable also include consideration of estimated selling prices as well as development and production costs. The methods used to estimate recoverable reserves vary with the amount and nature of the previously listed information that is available. After a discovery, volumetric calculations are frequently used to estimate the volume of oil and gas in-place. The in-place volume is then converted into recoverable reserves by use of an estimated recovery factor. This factor is initially based on experience in the area and the type of reservoir drive. As production data become available, it is possible to estimate reserves from reservoir performance as well as from volumetric calculations. The methods used for these combination-type procedures include material-balance calculations, decline curves, and rate cumulative curves.

2.92 Precision of estimates. According to the Society of Petroleum Engineers, the reliability of reserve information is considerably affected by several

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6 Society of Petroleum Engineers of American Institute of Mining Engineers, Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information (Dallas: Society of Petroleum Engineers of AIME, 2007.) See appendix B.
factors. Reserve information is imprecise because of the inherent uncertainties in, and the limited nature of, the data base upon which the estimating of reserve information is predicated. Moreover, the methods and data used in estimating reserve information are necessarily often indirect or analogical in character rather than direct or deductive. Furthermore, the persons estimating reserve information are required, in applying generally accepted petroleum engineering and evaluation principles, to make numerous judgments based solely on their educational background, their professional training, and their professional experience. The extent and significance of the judgments to be made are, in themselves, sufficient to render reserve information inherently imprecise.

2.93 Reports. The reserve estimation process culminates in the preparation of a reserve report or reserve study. The cover letter to a reserve report should indicate the level of responsibility assumed by the estimator. For example, some reports are based solely on information obtained from the client, without corroboration. Others are prepared based on an independent review of relevant data. The degree of responsibility assumed by the estimator may affect the extent to which the auditor can rely on the report. Generally, the study will contain a page for each reserve classification of each well. Summary pages are included for each reserve classification of each lease or field, and there usually is a summary page for the company total by each reserve classification. Each well page normally identifies the location, the operator, and the revenue and working interest attributable to the estimated interest. Exhibits 2-1–2-3 are illustrations of a summary reserve report and a reserve report for an individual well.

2.94 The reserve study may present both net unrecovered reserve volume amounts and associated cash flow from production by year. Dollar values are generally attributed only to the subject producer’s interest in projected annual production. Amounts presented for each remaining year of a property’s economic life are

- Production of gas and oil, unit prices, and gross revenues. Production prices are based on current prices, which include consideration of changes in existing prices provided by law, regulatory agencies, or contractual arrangements.
- Production expenses, including production taxes, operating expenses, windfall profit taxes, and equipment and development costs. Production expenses generally do not include provisions for depletion, depreciation, or amortization. Further, reserve studies assume consumption of equipment during a property’s producing life and do not ordinarily consider residual values of equipment or reclamation costs.
- Future net income (revenues less production expenses) or cash flow.
- Discounted (present) value of cash flow, generally computed at various rates.

Production

2.95 After the well is completed, the production phase begins. In the case of gas wells, the pressure in the reservoir is usually sufficient so that the gas expands into the well bore when the well is opened and flows to the surface. Oil
wells, however, may be flowing wells, or they may require mechanical equipment that provides artificial lift to raise the oil to the surface.

2.96 However the product is lifted from the well, fluids produced are directed to a central gathering point, often a tank battery. Some fields may be equipped with lease automatic custody transfer units that automatically perform the following tasks: (1) measure the oil’s temperature, gravity, and volume; (2) drain off basic sediment and water (BS&W); and (3) run the oil from the tank into the pipeline. The well area normally has all the equipment necessary to field-separate oil, gas, and water, as well as having adequate storage for the oil from the time it is produced until it is sold. Oil generally contains a certain amount of gas in solution, and usually some provision should be made to separate the gas from the oil before placing the oil in the storage tanks. The well fluids enter the oil and gas separator near the center, and the gas is removed from the top while the liquid (oil or water) is removed from the bottom.

2.97 At this point, the liquid is likely to contain a certain amount of water, which is removed before the oil can be sold. For this purpose, it may be necessary to heat the liquid by passing it through a continuous type of heater. Generally, this is done in a heater-treater, which heats the oil and water mixture, separating the water from the oil in a single operation.

2.98 The tanks in the tank battery that are used to store the oil vary in number and size, depending on the production of the lease and the frequency of the oil runs. Each tank has a strapping table that converts the feet and inches measurement of oil in the tank to barrels of oil. There is a drain at the bottom of the tank for draining the BS&W.

2.99 When the tank is full or at another predetermined time, the oil is run, or delivered to a pipeline, tank car, or tank truck. The pipeline outlet valve on the tank is sealed with a metal seal while the tank is being filled from the well and is locked open when the tank is being emptied. This assures the pipeline company and the producer that only oil in a particular tank is entering the pipeline company’s lines.
### Entities With Oil and Gas Producing Activities

#### Exhibit 2-1

Oil Investors, Inc.
**Estimated Future Reserves and Income Attributable to Certain Interests as of January 1, 2003**

**Grand Summary**

<table>
<thead>
<tr>
<th>Category</th>
<th>Revenue Interest</th>
<th>Product Prices</th>
<th>Discounted Future Net Income–M$</th>
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**Estimated 88 THS Production**

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<tr>
<th>Year</th>
<th>Number of Wells</th>
<th>Oil/Cond. (Barrels)</th>
<th>Plant Products (Barrels)</th>
<th>Gas (MMCF)</th>
<th>Oil/Cond. (Barrels)</th>
<th>Plant Products (Barrels)</th>
<th>Gas (MMCF)</th>
<th>Oil/Cond. ($/bbl)</th>
<th>Plant Products ($/bbl)</th>
<th>Gas ($/MCF)</th>
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</thead>
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<td>7,399</td>
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<tr>
<td>2016</td>
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<td>0.628</td>
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<td>2017</td>
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<td>14,089</td>
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<tr>
<td>Sub-Total</td>
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<td>Remainder</td>
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<td>Total</td>
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<td>Cumulative</td>
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### COMPANY FUTURE GROSS REVENUE (FGR-M$)

<table>
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Remainder 345.350 0.000 1.624 0.000 346.974 13.814 0.000 0.065 333.095
Total Future 6,044.675 0.000 4,871.676 0.000 10,916.351 242.973 0.000 364.413 10,308.964

### DEDUCTIONS-M$

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<th>Other/M$</th>
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Remainder 51.039 17.349 0.000 0.000 68.387 264.707 9,271.481 53.187
Total Future 617.711 419.772 0.000 0.000 1,037.483 9,271.481 6,327.548

### AAG-OGP 2.99

Life of evaluation is: 17.37 years
## Exhibit 2-2

### Oil Investors, Inc.

**Estimated Future Reserves and Income Attributable to Certain Interests as of January 1, 2003**

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<th>PRODUCED-OPERATOR EXAMPLE GAS WELL (FRIO)</th>
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<th><strong>PRODUCT PRICES</strong></th>
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### ESTIMATED 8/8 T/HS PRODUCTION

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<th>Plant (Barrels)</th>
<th>Gas (MMCF)</th>
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<th>Plant (Barrels)</th>
<th>Sales Gas (MMCF)</th>
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AAG-OGP 2.99
### Business Activities of the Oil and Gas Producing Industry

#### COMPANY FUTURE GROSS REVENUE (FGR) – M$

| Year | From Oil/Cond. | From Plant Products | From Gas | Other | Total | From Plant Prod./ Other | From Gas | Total | FGR AFTER PRODUCTION TAXES – M$
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Sub-Total | 197.643 | 0.000 | 4,844.182 | 0.000 | 5,041.825 | 9.092 | 0.000 | 363.314 | 4,669.419 |

Remainder | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |

Total Future | 197.643 | 0.000 | 4,844.182 | 0.000 | 5,041.825 | 9.092 | 0.000 | 363.314 | 4,669.419 |

#### DEDUCTIONS – M$

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<th>Ad Valorem Taxes</th>
<th>Development Costs</th>
<th>Other</th>
<th>Total</th>
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<td>6.086</td>
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<td>31.886</td>
<td>193.586</td>
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<td>4.582</td>
<td>0.000</td>
<td>0.000</td>
<td>30.382</td>
<td>139.366</td>
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<td>25.800</td>
<td>3.450</td>
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<td>0.000</td>
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<td>1.143</td>
<td>0.000</td>
<td>0.000</td>
<td>11.615</td>
<td>30.719</td>
<td>4,300.701</td>
<td>12.284</td>
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</table>

Sub-Total | 242.673 | 126.046 | 0.000 | 0.000 | 368.718 | 4,300.701 | 4,300.701 | 3,357.423 |

Remainder | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |

Total Future | 242.673 | 126.046 | 0.000 | 0.000 | 368.718 | 4,300.701 | 4,300.701 | 3,357.423 |

Life of evaluation is: 9.41 years

Final Production rate: 3.042 mmcf/month
44

Entities With Oil and Gas Producing Activities

Exhibit 2-3

Oil Investors, Inc.
Estimated Future Reserves and Income Attributable to Certain Interests as of January 1, 2003

ROADRUNNER FIELD, SAN JUAN COUNTY, UT COYOTE OIL COMPANY–OPERATOR EXAMPLE GAS WELL (9,500' SAND)

<table>
<thead>
<tr>
<th>REVENUE INTEREST</th>
<th>PRODUCT PRICES</th>
<th>DISCOUNTED FUTURE NET INCOME</th>
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<td></td>
<td>Oil/Cond.</td>
<td>Plant</td>
</tr>
<tr>
<td>Expense Interest</td>
<td>Oil/Cond.</td>
<td>Products</td>
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<td>0.43750000</td>
</tr>
<tr>
<td>FINAL</td>
<td>0.50000000</td>
<td>0.43750000</td>
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<tr>
<td>REMARKS</td>
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<tr>
<td></td>
<td>12.00%</td>
<td>2,733.502</td>
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<tr>
<td></td>
<td>15.00%</td>
<td>2,437.527</td>
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ESTIMATED 8/8 THS PRODUCTION

<table>
<thead>
<tr>
<th>COMPANY NET PRODUCTION</th>
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</thead>
<tbody>
<tr>
<td></td>
</tr>
</tbody>
</table>

AVERAGE PRICES

<table>
<thead>
<tr>
<th>Year</th>
<th>Number of Wells</th>
<th>Oil/Cond. Products Gas (MMCF)</th>
<th>Plant Products MCF</th>
<th>Oil/Cond. Products MCF</th>
<th>Sales Oil/Cond. MCF</th>
<th>Prod. Oil/Cond. MCF</th>
<th>Gas MCF</th>
<th>$/bbl</th>
<th>$/bbl</th>
<th>$/MCF</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003</td>
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<td>2.305</td>
<td>24,834</td>
<td>0.000</td>
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<td>3.20</td>
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<td>0.000</td>
<td>0.906</td>
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<td>0.811</td>
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<td>41,076</td>
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<td>1.668</td>
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Sub-Total 455,131 0 18.478 199,120 0 8.984 27.63 0.00 3.20
Remainder 28,569 0 1.160 12,499 0 0.507 27.63 0.00 3.20
Total 483,701 0 19.638 211,619 0 8.592 27.63 0.00 3.20

AAG-OGP 2.99
## Business Activities of the Oil and Gas Producing Industry

### COMPANY FUTURE GROSS REVENUE (FGR–M$)

<table>
<thead>
<tr>
<th>Year</th>
<th>From Oil/Cond.</th>
<th>From Plant Products</th>
<th>From Gas</th>
<th>Other</th>
<th>Total Oil/Cond.</th>
<th>Production Taxes–M$</th>
<th>FGR After Production Taxes–M$</th>
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**Sub-Total** 5,501.683 0.000 25.870 0.000 5,527.552 220.067 0.000 1.035 5,306.450

**Remainder** 345.350 0.000 1.624 0.000 346.974 13.814 0.000 0.065 333.095

**Total Future** 5,847.032 0.000 27.494 0.000 5,874.526 233.881 0.000 1.100 5,639.545

### DEDUCTIONS–M$

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<th>Year</th>
<th>Operating Costs</th>
<th>Ad Valorem Taxes</th>
<th>Development Costs</th>
<th>Other</th>
<th>Total Costs</th>
<th>Total Annual</th>
<th>Total Undiscounted</th>
<th>Total Discounted @ 10.00%</th>
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<td>30.156</td>
<td>134.115</td>
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**Sub-Total** 324.000 276.378 0.000 0.000 600.378 4,706.073 2,916.938

**Remainder** 51.039 17.349 0.000 0.000 68.387 264.707 4,970.780 53.187

**Total Future** 375.039 293.726 0.000 0.000 668.765 4,970.780 2,970.125

- Life of evaluation is: 17.37 years
- Final Production rate: 913 bbl/month

## AAG-OGP 2.99
Entities With Oil and Gas Producing Activities

2.100 The oil delivered is measured by gauging the height of oil in the tank before and after delivery. The oil is also tested at this time to determine its gravity or density, its temperature, and its BS&W content. Crude oil prices are posted at a standard base temperature of 60 degrees Fahrenheit, and the value of the crude oil varies with its density. Therefore, these measurements, which are made when measuring the tank's contents, are recorded on the run ticket and are used in converting to net barrels delivered. It is the responsibility of the lease operator to watch the gauging and testing of the oil done by the gauger and to be sure that the measurements are correct.

2.101 When gas is produced, it may be run directly into the gas pipeline after being measured by an orifice meter. If the gas contains liquid condensates, it may be run through a processing facility to remove the liquids, which are similar to crude oil, before the gas is turned into the pipeline.

2.102 When an outsider purchases oil or gas, settlement is usually made monthly. The purchaser customarily withholds and remits to the state the production or severance taxes on all production. Production taxes or severance taxes may be based on the quantity of production, on the value of production, or on a combination of quantity and value.

Work-Overs

2.103 Occasionally, it is necessary to work over a well. Work-overs are remedial operations sometimes required to maintain maximum oil producing rates. For example, when a well begins to produce an excessive amount of salt water, a work-over rig—very similar to a drilling rig but somewhat smaller—is moved onto the well, and remedial operations are conducted.

2.104 As another example, where there is more than one producing interval in the well bore and a lower zone has been depleted, a plug-back to a higher zone is in order. The plug-back can be accomplished with a cement plug in the casing or with a bridge plug—a mechanical device that can be set in the casing to effectively seal off the casing below the point at which it is set.

Improved Recovery Methods

2.105 More than half of the oil originally in place in a reservoir may remain in the reservoir after the cessation of primary operations. To plan operations for maximum economic recovery, usually all wells are tested at regular intervals. Oil wells are tested for the oil producing rate, the gas/oil ratio, the gravity, the saltwater production, and the BS&W. Gas wells are tested to determine their gas producing rates (open-flow potential), the gas/liquid ratios, and the BTU (energy) content. When production rates from primary recovery methods are no longer satisfactory, secondary and enhanced oil recovery, or tertiary, techniques may be used to attain maximum production of the reserves.

Abandonment of Wells and Facilities

2.106 When oil and gas reserves are depleted or when production drops to the point that it is no longer economically feasible to produce, equipment is removed and operations are abandoned. Federal and state regulations and contractual obligations require that wells be plugged, all facilities and equipment removed, and the terrain restored to specified conditions.
Accounting for Production

2.107 Revenues, production costs and expenses, and income taxes are treated in the same manner under full cost and successful efforts accounting, except for DD&A and impairment costs.

2.108 Revenue. Most companies recognize revenue from oil produced at the point of sale—that is, when the oil is run from the tanks. Gas is not stored on the lease; thus, revenue is recognized at the point of production and sale because they are the same. However, some companies record revenue on a cash basis throughout the year, which requires an accrual adjustment at the end of the period under generally accepted accounting principles.

2.109 The company may record the revenue based on the remittance advice received from the purchaser. Generally, proceeds from production are received one to three months after the actual production has occurred. Thus, it may be necessary to estimate revenue, based on prior months’ production and current lease operations (for example, whether the well has been shut in for a work-over or maintenance), in order to prepare financial statements on a timely basis.

2.110 Inventory. Oil in the lease tanks at the end of the accounting period is usually ignored for financial reporting purposes and inventory is not recorded because the amount of such oil normally is immaterial to the financial statements.

2.111 When inventory of oil in lease tanks is recorded, valuation methods vary in practice.

2.112 Operating expenses. Lease operating expenses are charged to expense; examples are pumpers’ wages, fuel or electricity for operating pumping equipment, subsurface maintenance, surface maintenance (such as lease roads and cutting of grass), insurance, ad valorem taxes, producing-well overhead, salt water disposal, fracturing, acidizing, and work-overs to maintain production. One exception to this occurs when a completion is made to a new zone, in which case that portion of the charges allocable to the completion may be accounted for as development or exploratory costs.

2.113 DD&A—successful efforts. DD&A of capitalized costs is recorded as the reservoir is produced and depleted. Under successful efforts accounting,
DD&A is based on the unit-of-production method for the following: (1) acquisition costs of proved properties on the basis of total estimated units of proved (both developed and undeveloped) reserves and (2) all other costs on the basis of total estimated units of proved developed reserves. DD&A is computed using current-period production divided by beginning reserves (that is, reserves at the end of the period plus current-period production) either on a property-by-property basis or on the basis of some reasonable aggregation of properties with a common geological structure or stratigraphic condition, such as a reservoir or field.

2.114 If significant development costs (such as an off-shore production platform) are incurred in connection with a planned group of development wells before all of the planned wells have been drilled, it is appropriate to exclude a portion of those development costs in determining the DD&A rate until the additional development wells have been drilled. Similarly, the proved developed reserves that will be produced only after significant additional development costs are incurred (as in improved recovery) are excluded in computing the DD&A rate. Future development costs are not considered when computing the DD&A rate under successful efforts accounting. FASB Statement No. 143, Accounting for Asset Retirement Obligations, amends FASB Statement No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies. FASB Statement No. 143 requires that obligations for dismantlement, restoration, and abandonment costs shall be accounted for in accordance with the provisions of FASB Statement No. 143. Estimated residual salvage values shall be taken into account in determining amortization and depreciation rates. A detailed discussion of the requirements of FASB Statement No. 143 is provided in paragraphs 2.125–135.

2.115 When a property contains both oil and gas reserves, the units of oil and gas used to compute amortization are converted to a common unit of measure on the basis of their relative energy content (see “DD&A—Full Cost” in paragraph 2.119) unless (1) the relative proportion of gas to oil is expected to continue throughout the life of the property, in which case DD&A may be computed on the basis of one of the two minerals only or unless (2) oil or gas clearly dominates both the reserves and current production, the DD&A rate may be computed on the basis of the dominant mineral only.

2.116 Impairment of proved properties is based on the guidance contained in FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. See impairment or disposal of long-lived assets at paragraphs 1.55–64.

2.117 DD&A—full cost. Full cost companies compute their DD&A of the full cost pool on a cost center basis using the depletion rate calculated on the unit-of-production method. The DD&A rate is computed on the basis of physical units, unless economic circumstances (related to the effects of regulated prices) indicate that use of the units-of-revenue method is a more appropriate basis of computing DD&A. If physical units are used in the computation, the oil and gas must be converted to a common unit of measure on the basis of

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9 FASB Interpretation No. (FIN) 47, Accounting for Conditional Asset Retirement Obligations—an interpretation of FASB Statement No. 143, clarifies that the term conditional asset retirement obligation as used in FASB Statement No. 143, Accounting for Asset Retirement Obligations, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity.
their approximate relative energy content (generally, a ratio of six thousand cubic feet (mcf, or thousand cubic feet) of gas to one barrel of oil is used); also, the current-period production is divided by reserves at the beginning of the period (that is, reserves at the end of the period plus current-period production). If the units-of-revenue method is used, the DD&A rate is computed on the basis of current gross revenues divided by the sum of the following: (1) future gross revenues based on current prices (unless fixed and determinable changes in existing prices are provided by contract) from proved reserves and (2) current-period gross revenues. This DD&A rate is multiplied by the sum of (1) unamortized costs in the pool plus (2) estimated future expenditures based on current costs to be incurred in developing proved reserves (specified in the reserve report) plus (3) estimated dismantlement and abandonment costs net of salvage value. In 2004, the SEC issued Staff Accounting Bulletin (SAB) No. 106. SAB No. 106 provides guidance regarding the interaction of FASB Statement No. 143, with the full cost accounting rules in Article 4-10 of Regulation S-X. FASB Statement No. 143 requires that upon initial recognition of an asset retirement obligation (ARO), the associated asset retirement costs be included in the capitalized costs of the company. Future development expenditures will create an additional ARO when those activities are performed in the future, resulting in the capitalization of additional asset retirement costs once those future development costs are incurred. Upon adoption of FASB Statement No. 143, it remained unclear whether full cost companies should include in their costs to be amortized an amount for future asset retirement costs that are expected to result from future development activities. SAB No. 106 clarifies that companies should estimate the amount of dismantlement and abandonment costs that will be incurred as a result of future development activities of proved reserves and includes those amounts in the costs to be amortized.

2.118 Under certain circumstances prior to 1983, the cost of unusually significant investments in unproved properties and major development projects could be excluded from capitalized costs to be amortized. In September 1983, the SEC adopted Release No. FRR 14, section 406.01.c.i., which provided that the cost of all investments in unproved properties and major development projects expected to entail significant costs could be excluded from capitalized costs to be amortized, subject to the following conditions:

- The properties are to be assessed at least annually for impairment.
- Dry hole costs are included in the amortization base immediately.
- G&G costs that cannot be directly associated with specific unevaluated properties are to be included in the amortization base as incurred.

2.119 Full cost ceiling. A full cost company also determines if the value of proved reserves and other mineral assets in the cost center are adequate to recover the unamortized costs in the full cost pool. This test, referred to as the full cost ceiling test, is to be computed for each full cost center. Specifically, under SEC requirements as discussed in Rule 4-10(c)(4) of Regulation S-X, the net unamortized costs less related deferred income taxes should not exceed the sum of the following: (a) the present value of estimated future net revenues computed by applying current prices of oil and gas reserves (with consideration of price changes only to the extent provided by contractual arrangements and

\[ \text{Present Value} = \sum_{t=1}^{T} \left( \frac{R_t}{(1 + r)^t} \right) \]

Where:
- \( R_t \) is the estimated net revenue in period \( t \)
- \( r \) is the discount rate
- \( T \) is the number of periods

SEC FRR No. 14 has been codified and included in the SEC SAB: Codification of Staff Accounting Bulletins Topic 12(D)(2).

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hedge adjusted prices\textsuperscript{11} to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves computed using a discount factor of 10 percent and assuming continuation of existing economic conditions plus (b) the cost of unproved properties and major development projects not being amortized plus (c) the lower of cost or estimated fair value of unproved properties included in costs being amortized less (d) the income tax effects on the differences between the amount computed previously and the tax basis of the properties involved. Any excess is charged to expense and separately disclosed during the year in which the excess occurs. Even if the cost ceiling subsequently increases, the write-off is not reinstated. However, events occurring subsequent to year-end can be considered in determining a write-down. For example, if additional reserves become proved on properties owned at year-end or price increases become known that were not fixed and determinable as of year-end, the resulting increases in present value can be considered in computing the cost ceiling.

2.120 SAB No. 106 provides guidance regarding the interaction of FASB Statement No. 143, which states that a company shall recognize a liability for an ARO at fair value in the period in which the obligation is incurred, if a reasonable estimate of fair value can be made. The company also initially capitalizes the associated asset retirement costs by increasing the carrying amount of the related long-lived oil and gas asset by the same amount as the liability. Any asset retirement costs capitalized pursuant to FASB Statement No. 143 are subject to the full cost ceiling limitation under Rule 4-10(c)(4) of Regulation S-X. If after adoption of FASB Statement No. 143, a company were to continue calculating the full cost ceiling by reducing expected future net revenues by the cash flows required to settle the ARO, then the effect would be to double-count such costs in the ceiling test. This would result as the assets that must be recovered would be increased while the future net revenues available to recover the assets would continue to be reduced by the amount of the ARO settlement cash flows. SAB No. 106 clarified that the estimated cash outflows associated with AROs that have been accrued on the balance sheet should be excluded from the computation of the present value of estimated future net revenues that are used in the ceiling test.

2.121 SAB No. 106 also requires the company to provide certain disclosures in order to inform financial statement users on the interaction of FASB

\textsuperscript{11} SEC SAB No. 103, Update of Codification of Staff Accounting Bulletins, requires the computation of the limitation of capitalized costs to include the impact of cash flow hedges. The price used in the calculation should only include the hedge adjustment if the hedge instrument is qualified as a hedging instrument under FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. The use of hedge-adjusted prices should be consistently applied in all reporting periods, including periods in which the hedge-adjusted price is less than the current spot market price. Oil and gas producers whose computation of the ceiling limitation includes hedge-adjusted prices because of the use of cash flow hedges also should consider the disclosure requirements under AICPA Statement of Position 94-6, Disclosure of Certain Significant Risks and Uncertainties (AICPA, Technical Practice Aids, ACC sec. 10,640). Paragraph 14 of SOP 94-6 calls for disclosure when it is at least reasonably possible that the effects of cash flow hedges on capitalized costs on the reported balance sheet date will change in the near term due to one or more confirming events, such as potential future changes in commodity prices. In addition, the use of cash flow hedges in calculating the ceiling limitation may represent a type of critical accounting policy that oil and gas producers should consider disclosing consistent with cautionary advice provided in FR-60. Through this release, the SEC has encouraged companies to include, within their management discussion and analysis disclosures, full explanations, in plain English, of the judgments and uncertainties affecting the application of critical accounting policies, and the likelihood that materially different amounts would be reported under different conditions or using different assumptions.

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Statement No. 143 and the full cost rules. The disclosures in the financial statement notes and Management’s Discussion and Analysis should explain in detail how the adoption of FASB Statement No. 143 impacts its accounting for oil and gas operations. This disclosure is expected to address each area of accounting that is impacted or expected to be impacted and should specifically address each way that the company’s application of full cost accounting has changed as a result of adoption of FASB Statement No. 143. These disclosures and discussions should include, but are not limited to, how the company’s calculation of the ceiling test and depreciation, depletion, and amortization are affected by the adoption of FASB Statement No. 143.

2.122 Some companies not subject to SEC requirements follow other methods of computing the cost ceiling.

2.123 Abandonments. Under the successful efforts method, no gain or loss is recognized normally if only an individual well or a single item of equipment is abandoned as long as the well is part of a group of proved properties constituting an amortization base and the remaining properties continue to produce. The asset abandoned or retired is presumed to be fully amortized, and its cost is charged against the accumulated DD&A. Only when the last well or property ceases to produce and the entire property is abandoned does gain or loss become recognized. However, if a catastrophic event or other major abnormality results in partial abandonment or retirement of a proved property or wells or related facilities, a loss is recognized at the time of abandonment or retirement. FASB Statement No. 144 amends FASB Statement No. 19; see paragraph 1.62 for the changes related to proved and unproved properties.

2.124 Under full cost accounting, abandonment or retirement of proved properties, wells, and related facilities does not result in any gain or loss being recognized.

Asset Retirement Obligations

2.125 FASB Statement No. 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs such as plug and abandonment and platform dismantlement. It applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and (or) the normal operation of a long-lived asset, except for certain obligations of lessees. As used in FASB Statement No. 143, a legal obligation is an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of a promissory estoppel.

2.126 FASB Statement No. 143 replaces paragraph 37 of FASB Statement No. 19 with the following:

Obligations for dismantlement, restoration, and abandonment costs should be accounted for in accordance with the provisions of FASB Statement No. 143. Estimated residual values should be taken into account in determining amortization and depreciation rates.

 FIN 47 clarifies that the term conditional asset retirement obligation as used in FASB Statement No. 143 refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity.
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2.127 FASB Statement No. 143 requires that the fair value\textsuperscript{13} of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of fair value can be made.

2.128 As stated in paragraph 11 of FASB Statement No. 143, upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. An entity shall subsequently allocate that asset retirement cost to expense using a systematic and rational method over its useful life.

2.129 As stated in paragraph 13 of FASB Statement No. 143, in periods subsequent to initial measurement, an entity shall recognize period-to-period changes in the liability for an asset retirement obligation resulting from (a) the passage of time and (b) revisions to either the timing or the amount of the original estimate of undiscounted cash flows. An entity shall measure and incorporate changes due to the passage of time into the carrying amount of the liability before measuring changes resulting from a revision to either the timing or the amount of estimated cash flows.

2.130 An entity shall measure changes in the liability for an asset retirement obligation due to passage of time by applying an interest method of allocation to the amount of the liability at the beginning of the period, as stated in paragraph 14 of FASB Statement No. 143. The interest rate used to measure that change shall be the credit-adjusted risk-free rate that existed when the liability, or portion thereof, was initially measured. That amount, referred to as accretion expense, shall be recognized as an increase in the carrying amount of the liability and as an expense classified as an operating item in the statement of income.

2.131 Paragraph 15 of FASB Statement No. 143 requires changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows shall be recognized as an increase or a decrease in (a) the carrying amount of the liability for an asset retirement obligation and (b) the related asset retirement cost capitalized as part of the carrying amount of the related long-lived asset.

2.132 Disclosures. In accordance with paragraph 22 of FASB Statement No. 143, an entity shall disclose the following information about its asset retirement obligations:

\begin{enumerate}
\item A general description of the asset retirement obligations and the associated long-lived assets.
\item The fair value of assets that are legally restricted for purposes of settling asset retirement obligations.
\item A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations showing separately the changes attributable to (1) liabilities incurred in the current period, (2) liabilities settled in the current period, (3) accretion expense, and (4) revisions in estimated cash flows, whenever there is
\end{enumerate}

\textsuperscript{13} See paragraphs 1.76–.94 in chapter 1 of this guide for additional discussion on FASB Statement Nos. 157 and 159.
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a significant change in one or more of those four components during the reporting period.

If the fair value of an asset retirement obligation cannot be reasonably estimated, that fact and the reasons therefore shall be disclosed.

2.133 Dismantlement and restoration costs were taken into account in determining amortization and depreciation rates under FASB Statement No. 19. Consequently, many entities recognized asset retirement obligations as a contra-asset. Under FASB Statement No. 143, those obligations are recognized as a liability. Also, under FASB Statement No. 19 the obligation was recognized over the useful life of the related asset. FASB Statement No. 143 requires the obligation to be recognized when the liability is incurred.

2.134 Upon initial application of FASB Statement No. 143, the computed amounts of depletion and accretion expenses should be measured from the inception of each obligation; net of any retirement expense accrued under the previous method, and should be recognized as a change in accounting principle as described in FASB Statement No. 154, Accounting Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3.

2.135 As a result of adopting FASB Statement No. 143 there has been an increase in the amounts of assets and liabilities reported by oil and gas producers. In addition, the combination of depletion and accretion expenses recognized under FASB Statement No. 143 may result in a greater portion of the total retirement expense being recognized in the later years of an oil or gas property’s life, a period in which operating cash flows often decline rapidly.

Conveyances

2.136 The oil and gas industry is capital-intensive and usually associated with considerable risks. These characteristics, along with the wasting, nonre-generative nature of its most significant asset, require companies to continually expand their exploration efforts and capital commitments. Oil and gas companies desiring to spread the risks and to generate the funds necessary to explore and develop properties will often convey an economic interest in a property to another party in return for financing or other considerations. A conveyance is the assignment or transfer of mineral rights, usually a portion of the working interest, to another entity. A conveyance may involve a transfer of all or part of the rights and responsibilities of developing and operating a property.

Forms of Conveyances

2.137 Several types of economic interests are commonly associated with oil and gas properties. The mineral interest is the ownership of the right to explore for and produce the minerals underlying the surface of a property. An owner of the mineral interest would not necessarily own the surface rights. Most leasing transactions involve the lease of operating rights of the mineral interest to an oil company with the lessor retaining a royalty interest.

2.138 The working interest normally operates the property, paying most of the costs of exploration, development, and production. The working interest is also normally entitled to all the revenues generated by the property, net of any royalties or overriding royalties. The working interest can also assign a portion of its interest, thereby creating a joint working interest. This allows the original working interest to spread its risk and share the costs incurred.

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Often, the working interest owner will carve out and convey to another entity a nonoperating interest. This interest may be an **overriding royalty interest**, which is similar to a royalty interest except that it is created out of a working interest rather than out of the original mineral interest or a net operating interest.

Another interest created out of the working interest is the **production payment**. Production payments are generally used to finance development of a property. The owner of a production payment is entitled to a specified share of the production of a property until a designated amount of money or product is generated from the property. After the terms of the production payment are satisfied, the interest reverts to the working interest from which it was created.

In addition to the sale of royalty or working interests and production payments, common forms of conveyances include free-well agreements, carried interests, farm-outs, and unitizations.

Under a free-well agreement, the working interest owner assigns a share of the working interest or some type of nonoperating interest to another party in return for the drilling of one or more wells on the property by the other party. If oil or gas is found, the parties immediately begin sharing revenues and expenses in the proportions called for in the contract, but neither party recovers any part of costs before sharing begins.

In cases where the working interest owner transfers all or part of the operating rights to an assignee in return for the latter's assumption of all or part of the development, the transaction is referred to as a farm-out. The assignor usually retains an overriding royalty but may retain any type of interest.

Carried-interest arrangements can be categorized into two types:

1. **Carried interest for production property life**. In this arrangement, one party (the carried party) assigns an individual portion of a lease to another party (the carrying party) to develop and operate until all costs—perhaps plus an additional percentage of such costs—have been recovered out of production from the property. At pay-out, the carried party begins to receive its share of the proceeds in excess of its share of the costs.

2. **Carried interest for period of initial development**. In this arrangement, the carried party begins to share in the revenues and expenses as soon as the carrying party recovers all costs incurred in connection with the drilling of the first well.

Another form of joint interest is a unitization. In unitization transactions owners of all interests in a geological structure agree to give up their shares in the individual properties, receiving in exchange a fractional share in the unitized properties. The interest received by each is usually in proportion to the estimated reserves contributed to the unit by that party. Properties may not be at the same stage of development, however. It may be necessary for some parties to contribute cash and others to receive cash to equalize the values given and received for equipment and drilling costs.

**Accounting for Conveyances**

Mineral property conveyances and related transactions may be classified according to their natures as sales, borrowings, exchanges of nonmonetary assets, poolings of interests in joint undertakings, or some combination thereof.
2.147 Because the forms of conveyances will vary widely, are generally complex, and often will not fit exactly within the accounting literature, a thorough understanding of the form is necessary to reach a proper conclusion. In addition, the auditor should be aware that the form of the conveyance may have significant tax consequences. Guidance on accounting for conveyances can be found in paragraphs 42–47 of FASB Statement No. 19, as amended by FASB Statement No. 144, for the successful efforts method and Regulation S-X, 4-10(c)(6) for the full cost method.

2.148 FASB’s Derivatives Implementation Group (DIG) issued guidance in Statement 133 Implementation Issue B11, Embedded Derivatives: Volumetric Production Payments. That implementation issue provides guidance on volumetric production payments for which the quantity of the commodity that will be delivered is reliably determinable. FASB Statement No. 153, Exchanges of Nonmonetary Assets—an amendment of APB Opinion No. 29, amends Accounting Principles Board (APB) Opinion No. 29, Accounting for Nonmonetary Transactions, to eliminate the exception from fair value measurement for nonmonetary exchanges of similar productive assets and replace it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The FASB statement requires that exchanges of productive assets be accounted for based on the fair values of the assets involved, unless the exchange transaction does not have commercial substance. FASB Statement No. 153 also amends paragraph 4 of APB Opinion No. 29 to exclude, among other items, the following transactions from being accounted for under the provisions of APB Opinion No. 29 as amended by FASB Statement No. 153: (1) a pooling of assets in a joint undertaking intended to find, develop, or produce oil or gas from a particular property or group of properties, as described in paragraph 44 of FASB Statement No. 19, as amended, and (2) the exchange of a part of an operating interest owned for a part of an operating interest owned by another party that is subject to paragraph 47(e) of FASB Statement No. 19.

Commodity Derivative Activities

2.149 Oil and gas producers may be involved in commodity derivative activities. Commodity derivative activities including swaps and option contracts linked to oil or natural gas as well as similar forward, future, and option positions, fall within the scope of FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. With the adoption of FASB Statement No. 133, as amended, oil and gas producers are significantly

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14 Statement 133 Implementation Issue B11, Embedded Derivatives: Volumetric Production Payments, was revised to reflect the issuance of FASB Statement No. 155, Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140. Further, the following statement was included in the body of the Implementation Issue: "Note that Statement 155 was issued in February 2006 and allows for a fair value election for hybrid financial instruments that otherwise would require bifurcation. However, Statement 155 does not apply to hybrid instruments that are not financial instruments, such as nonfinancial instruments that require volumetric production payments. Hybrid financial instruments that are elected to be accounted for in their entirety at fair value cannot be used as a hedging instrument in a Statement 133 hedging relationship."

15 In March 2008, FASB issued FASB Statement No. 161, Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133. In response to constituents’ concerns that FASB Statement No. 133 does not provide adequate information about how derivatives and hedging activities affect an entity’s financial position, financial performance, and cash (continued)
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impacted by the expanded scope of these standards. Physical contractual agreements put in place on a day-to-day basis are now within the scope of these new rules. The “normal purchase or normal sales” criteria have a great amount of subjectivity involved and potentially opens up such contracts to derivative accounting applications. The adoption of FASB Statement No. 133, as amended, requires a broader application of mark-to-market accounting based on changes in fair value. The decision to qualify for hedge accounting or not to designate the use of derivative instruments as either fair value hedges or cash flow hedges is an elective process. For greater detail, refer to the respective DIG issues for implementation guidance.

2.150 FASB Statement No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in host contracts, (collectively referred to as embedded derivatives) and for hedging activities. It requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position and measure those investments at fair value. If certain conditions are met, a derivative may be specifically designated as (a) a hedge of the exposure to changes in the fair value of a recognized asset or liability or an unrecognized firm commitment, (b) a hedge of the exposure to variable cash flows of a forecasted transaction, or (c) a hedge of the foreign currency exposure of a net investment in a foreign operation, an unrecognized firm commitment, an available-for-sale security, or a foreign-currency-denominated forecasted transaction. The accounting for changes in the fair value of a derivative (that is, gains and losses) depends on the intended use of the derivative and the resulting designation. FASB Statement No. 133 (paragraphs 44–47) also contains extensive disclosure requirements. Refer to the full text of the statement when considering accounting and reporting issues related to derivative instruments and hedging activities. The FASB has established the DIG to assist the Board and its staff in providing implementation guidance regarding FASB Statement No. 133. Issues addressed by the DIG and the status of related guidance can be found at the FASB’s Web site www.fasb.org. Certain decisions arising from the DIG process that required specific amendments to FASB Statement No. 133 were incorporated into FASB Statement No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities—an amendment of FASB Statement No. 133.

2.151 In April 2003, the Financial Accounting Standards Board issued FASB Statement No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities, to amend and clarify financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under FASB Statement No. 133. The changes in FASB Statement No. 149 improve financial reporting by requiring that contracts with comparable characteristics be accounted for similarly. In particular, the FASB flows, FASB issued FASB Statement No. 161 to enhance disclosures about an entity’s derivative and hedging activities and to improve financial transparency. This statement has the same scope as FASB Statement No. 133 and, accordingly, applies to all entities. FASB Statement No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Early adoption is encouraged. FASB Statement No. 161 encourages, but does not require, comparative disclosures for earlier periods at initial adoption. Refer to the FASB Web site at www.fasb.org for the full text of the statement.

16 Refer to paragraphs 5.134–.143 for guidance on auditing fair value measurements.
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Statement (1) clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative discussed in paragraph 6(b) of FASB Statement No. 133, (2) clarifies when a derivative contains a financing component, (3) amends the definition of an underlying to conform it to language used in FIN 45, Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others—an interpretation of FASB Statements No. 5, 57, and 107 and rescission of FASB Interpretation No. 34, and (4) amends certain other existing pronouncements.

2.152 FASB Statement No. 149 amends FASB Statement No. 133 for certain decisions made by the board as part of the DIG process. For those amendments that relate to FASB Statement No. 133 implementation guidance, the specific FASB Statement No. 133 Implementation Issue necessitating the amendment is identified. If the amendment relates to a cleared issue, the clearance date also is noted.

2.153 FASB Statement No. 155, Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140, amends FASB Statement No. 133 and FASB Statement No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities—a replacement of FASB Statement No. 125. A hybrid instrument is a financial instrument that contains an embedded derivative. Among other things, FASB Statement No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation in conformity with paragraph 12 of FASB Statement No. 133. A hybrid instrument for which the election is permitted could be an asset or a liability and it could be acquired or issued by the entity, but it may not be designated as a hedging item. Additionally, the election cannot be made for the financial instruments described in paragraph 8 of FASB Statement No. 107, Disclosures about Fair Value of Financial Instruments. FASB Statement No. 155 allows an entity to irrevocably elect to initially and subsequently measure the hybrid instrument at fair value. The election may be made on an instrument-by-instrument basis and should be supported by concurrent documentation or a preexisting documented policy for automatic election. An entity should report hybrid financial instruments measured at fair value under the election and under the practicability exception in paragraph 16 of FASB Statement No. 133 separately on the face of the statement of financial position from the carrying amounts of assets and liabilities subsequently measured using another measurement attribute.

2.154 AU section 332, Auditing Derivative Instruments, Hedging Activities, and Investments in Securities (AICPA, Professional Standards, vol. 1), provides guidance to auditors in planning and performing auditing procedures for assertions about derivative instruments, hedging activities, and investments in securities. In addition, the AICPA Audit Guide Auditing Derivative Investments, Hedging Activities, and Investments in Securities is a companion guide to AU section 332.

2.155 Auditing Interpretation No. 1, “Auditing Investments in Securities Where a Readily Determinable Fair Value Does Not Exist,” of AU section 332, Auditing Derivative Instruments, Hedging Activities, and Investments in Securities (AICPA, Professional Standards, vol. 1, AU sec. 9332 par. 01–04), provides additional guidance for auditing securities, such as investments in hedge funds, for which a readily determinable fair value does not exist. The interpretation states that in circumstances in which the auditor determines that the nature
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and extent of auditing procedures should include verifying the existence and testing the measurement of investments in securities, simply receiving a confirmation from a third party, either in aggregate or on a security-by-security basis, does not in and of itself constitute adequate audit evidence with respect to the valuation assertion in AU section 332. In addition, receiving confirmation from a third party for investments in aggregate does not constitute adequate audit evidence with respect to the existence assertion under AU section 332. Receiving confirmation from a third party on a security-by-security basis, however, typically would constitute adequate audit evidence with respect to the existence assertion under AU section 332. In circumstances in which the auditor is unable to audit the existence or measurement of interests in investments in securities at the financial statement date, the auditor should consider whether that scope limitation requires the auditor to either qualify his or her opinion or to disclaim an opinion, as discussed in paragraphs .22–.26 of AU section 508, *Reports on Audited Financial Statements* (AICPA, *Professional Standards*, vol. 1).
Chapter 3

Tax Considerations*

3.01 Taxes represent one of the major costs affecting oil and gas producing companies. A general understanding of the principal types of taxes and their impact on the industry is essential to planning and performing an audit of an oil and gas company’s financial statements.

3.02 The discussion in this chapter is intended to be only an overview of specific oil and gas tax considerations. Tax laws are subject to continuous change as a result of legislation, regulatory action, and judicial interpretation.

Income Taxes

3.03 In general, income taxes affect oil and gas operations in the same manner as they do other companies. However, the income tax provisions related to oil and gas are among the most complicated. Tax considerations affect the economics of many transactions in the industry to such an extent that they may become one of the determining factors in making decisions. This economic effect and the impact on financial reporting means that the auditor should have an understanding of some of the principal income tax considerations.

Intangible Drilling and Development Costs

3.04 Intangible drilling and development costs (IDC) represent costs that in themselves have no salvage value and are incurred incident to, and are necessary for, the drilling of wells and the preparation of wells for the production of oil and gas (for example, items such as a drilling contractor’s footage or daily rate charges, mud and chemicals, perforating, electric logging, and cementing qualify for treatment as IDC). Items such as casing and tubing do not qualify; however, the related cost of installation does. Costs applicable to line pipe, storage tanks, and comparable costs, including installation costs, are not considered IDC (not related to the drilling and preparation of wells for production), but these costs are treated as part of the cost of tangible property.

3.05 A taxpayer may elect to deduct domestic IDC by claiming a deduction for such costs on the tax return for the first taxable year during which the taxpayer incurred or paid such costs. A failure to deduct such costs is deemed an election to capitalize and deplete IDC. Such election is binding on the taxpayer for subsequent years. Only 70 percent of domestic IDC expenditures of an integrated oil company may be deducted in the year paid or incurred. The remaining 30 percent must be deducted ratably over 60 months beginning with the month such costs were paid or incurred. Generally, any IDC incurred outside of the United States must be capitalized and amortized ratably over a 10 year period or capitalized to the depletable base of the property and then depleted.

3.06 An individual owning a working interest (other than through a limited business interest) in a property may elect to capitalize IDC and amortize it over a 60-month period. If an individual is allocated IDC deductions through a limited partnership, such costs are also subject to an election to be amortized ratably over a 60-month period. These elections are in addition to that applicable to deducting IDC. An individual may be inclined to make such

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* Readers should refer to currently enacted provisions of the Internal Revenue Code for changes that have been made subsequent to the publication of this guide.
entities for various reasons (for example, to avoid alternative minimum tax payments).

Depletion

3.07 Producers of oil and gas are entitled to a deduction for depletion to recover capitalized leasehold costs. The costs to be recovered through depletion represent those (a) that must be capitalized in connection with acquisition of the taxpayer’s interest in the property and (b) that are not recoverable through depreciation (including capitalized IDC). Such costs may represent bonuses paid to a lessor, amounts paid for a royalty interest, geological and geophysical (G&G) costs previously required to be capitalized, and other types of expenditures related to acquisition of the interest.

3.08 The auditor may consider the importance attached, for tax purposes, to associating the producer with the holding of an economic interest. The holder of the economic interest in the property is the party who may be entitled to the deduction for depletion. An economic interest in the property can be held by a taxpayer as the result of a direct interest held in the minerals through a fee title resulting from a lease, through an assignment from the original lessee (or previous assignees of the original lessee), or through another contractual arrangement (such as certain net profits interest arrangements). Under IRS rules, the holder of the interest must have the right to share in proceeds from the sale of the reserves rather than a right to receive compensation for services rendered.

3.09 Depletion deductions methodologies include cost and percentage depletion. All taxpayers are entitled to cost depletion deductions. Deductions for percentage depletion are covered by specific exceptions to a general rule that such deductions are normally not allowable with respect to oil and gas production. The allowable deduction for depletion is the higher of percentage or cost depletion, determined on an individual property basis. Percentage depletion in excess of the tax-cost basis in a property is a permanent difference in determining the provision for income taxes.

3.10 Percentage depletion is available to certain taxpayers under an exemption applicable to specified domestic gas wells and another exemption applicable to independent producers and royalty owners. Generally, integrated oil companies that refine 75,000 or more barrels of oil on any one day during the taxable year do not qualify for the percentage depletion methodology. An independent producer is defined as one who does not directly, or through a related party, engage in certain specified retailing or refining activities involving oil and gas or products derived therefrom. An independent producer’s eligibility for percentage depletion deductions is generally limited to 1,000 barrels per day of production. Independent producer status can result in significant benefits with respect to income taxes from the ability to fully deduct IDCs and from eligibility for deducting percentage depletion.

Conveyances

3.11 As discussed in chapter 2, conveyances in the oil and gas industry take a wide variety of forms. In many of these transactions, the income tax treatment varies significantly from the accounting treatment. Because of the effect on the financial statements and the economic impact, conveyances should be carefully reviewed and the terms and provisions analyzed to determine the appropriate tax treatment.

AAG-OGP 3.07
Tax Considerations

### Common Temporary Differences

#### 3.12 In addition to temporary differences related to IDC deductions and depletion provisions, other common temporary differences may be encountered, depending on the method of accounting used for financial statement purposes. Exhibit 3-1 summarizes the most common temporary differences.

**Exhibit 3-1**

<table>
<thead>
<tr>
<th>Temporary Difference</th>
<th>Successful Efforts</th>
<th>Full Cost</th>
<th>Income Tax</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Prospecting Costs</strong> (Pre acquisition exploration costs)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>G&amp;G costs</td>
<td>Expense</td>
<td>Capitalize</td>
<td></td>
</tr>
<tr>
<td><strong>Exploration Costs</strong> (Postacquisition)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carrying costs of undeveloped properties</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Delay rentals</td>
<td>Expense</td>
<td>Capitalize</td>
<td></td>
</tr>
<tr>
<td>Ad valorem taxes</td>
<td>Expense</td>
<td>Capitalize</td>
<td></td>
</tr>
<tr>
<td>Legal costs of title defense</td>
<td>Expense</td>
<td>Capitalize</td>
<td>Capitalize</td>
</tr>
<tr>
<td>Direct costs of maintaining land and lease records</td>
<td>Expense</td>
<td>Capitalize</td>
<td>Expense</td>
</tr>
<tr>
<td>Costs to prepare well location for drilling exploratory wells and intangible drilling costs</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proved reserves are found</td>
<td>Capitalize</td>
<td>Capitalize</td>
<td>Expense</td>
</tr>
<tr>
<td>No proved reserves are found</td>
<td>Expense</td>
<td>Capitalize</td>
<td>Expense</td>
</tr>
<tr>
<td>Dry hole contribution</td>
<td>Expense</td>
<td>Capitalize</td>
<td></td>
</tr>
<tr>
<td>Bottom hole contribution</td>
<td>Expense</td>
<td>Capitalize</td>
<td>Capitalize</td>
</tr>
<tr>
<td><strong>IDC (Development Wells)</strong></td>
<td>Capitalize</td>
<td>Capitalize</td>
<td>Optional (usually expense)</td>
</tr>
<tr>
<td><strong>Disposition of Capitalized Costs</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depletion</td>
<td>Expense</td>
<td>Expense</td>
<td>Expense</td>
</tr>
</tbody>
</table>

AAG-OGP 3.12
### Entities With Oil and Gas Producing Activities

#### Common Temporary Differences—continued

<table>
<thead>
<tr>
<th>Temporary Difference</th>
<th>Successful Efforts</th>
<th>Full Cost</th>
<th>Income Tax</th>
</tr>
</thead>
<tbody>
<tr>
<td>Abandonments</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A property that is a portion of an amortization base becomes worthless</td>
<td>No loss recognized</td>
<td>No loss recognized</td>
<td>Loss recognized(^6)</td>
</tr>
<tr>
<td>Book provision for abandonments</td>
<td>Expense</td>
<td>N/A</td>
<td>Nondeductible</td>
</tr>
<tr>
<td>Amortization base becomes worthless</td>
<td>Loss recognized</td>
<td>Loss</td>
<td>Loss recognized(^6)</td>
</tr>
<tr>
<td>Impairment valuation allowances for unproved properties</td>
<td>Expense</td>
<td>N/A</td>
<td>Nondeductible</td>
</tr>
</tbody>
</table>

#### Conveyances and Related Transactions

**(7)**

#### Sale of Part of an Interest Owned

<table>
<thead>
<tr>
<th>Temporary Difference</th>
<th>Successful Efforts</th>
<th>Full Cost</th>
<th>Income Tax</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substantial uncertainty exists concerning recovery of costs applicable to retained interest or seller has substantial obligation for future performance</td>
<td>No gain recognized, No gain or loss recognized</td>
<td>No gain or loss recognized</td>
<td>Gain or loss recognized(^8)</td>
</tr>
</tbody>
</table>

#### NOTES

1. G&G costs incurred in tax years beginning after August 8, 2005, are generally capitalized and recovered over 24 months unless the taxpayer is a "major integrated oil company." Previously, such G&G was generally capitalized if such costs would be associated with the acquisition of a property; otherwise they were deducted.
2. Delay rentals and ad valorem taxes on undeveloped properties that the taxpayer does not intend to develop may be able to be deducted; otherwise, they are capitalized.
3. Income tax treatment is unsettled. IRS position is that dry hole and bottom hole contributions should be capitalized (Rev. Rul. 80-153). Many taxpayers continue to contend that all dry hole contributions should be expensed, as should bottom hole contributions if dry.
4. Must make a one time election to deduct IDCs in order to deduct. Thereafter, independents can deduct 100 percent of IDCs and integrateds can deduct 70 percent and amortize the remaining over 60 months. An annual election is available to all taxpayers to capitalize a portion of deductible IDCs and recover them over 60 months.
5. The difference between tax depletion and book depletion may be a temporary difference. "Tax preference" depletion (depletion in excess of basis) is a permanent difference.
6. Loss is recognized only if total property is abandoned; no deduction is taken for partial abandonments.

**AAG-OGP 3.12**
Conveyances and related transactions may cause temporary differences. Such transactions should be investigated on an individual basis to determine any differences between book and tax accounting. Consider special tax treatment of carried interests, earned acreage, (Rev. Rul. 77-176), farmouts, tax partnerships, and the like.

Conveyances of an interest where conveyer retains an overriding royalty, net profits interest, or other interest should be separately identified because tax treatment is different than when an outright sale occurs.

Ad Valorem and Severance Taxes

3.13 Ad valorem and severance taxes are assessed by state and local taxing authorities. Again, a detailed coverage of ad valorem and severance taxes is not within the scope of the guide. However, the following points are worth mentioning.

- Severance and ad valorem taxes are deductible for income tax purposes. Both must be allocated to the appropriate property when calculating net income from the property applicable to determining limitations for percentage depletion and windfall profit taxes.
- Severance and ad valorem taxes are normally applicable at the revenue-interest level (as opposed to lease operating expenses applicable at the working-interest level).

3.14 Tax reporting requirements for severance and ad valorem taxes will vary depending on the applicable state or local statutes and regulations.

Enhanced Oil Recovery Credit (Internal Revenue Code Section 43)

3.15 For tax years after December 31, 1990, a credit is available for qualifying costs paid or incurred as part of an enhanced oil recovery (EOR) project. The base for the credit is qualified enhanced oil recovery costs. Qualified costs must be related to a certified qualified EOR project. Only domestic costs qualify. To qualify the project must involve the application of various gases, liquids or other matters specified by Department of Energy regulations. To claim the credit the taxpayer must own an operating mineral interest in the property. Three types of cost qualify for this credit: IDC, tangible and tertiary injectant costs. Generally, the credit is 15 percent of the qualified costs multiplied by a factor that is based on price of oil and inflation. The basis of the assets that qualify for the credit must be reduced by the amount of the credit claimed on such assets. The EOR credit is subject to a phase out based on the inflation-adjusted price of crude oil such that the credit was not applicable for calendar year taxpayers in 2006.

Credit for Production of Oil and Gas From Marginal Wells (Jobs Creation Act of 2004)

3.16 For tax years beginning after December 31, 2004, a credit for production of crude oil or qualified natural gas from marginal wells is allowed as part of the general business credit. The credit is the sum of (1) $3.00 per barrel for the production of crude oil and (2) $.50 per 1,000 cubic feet of qualified natural
gas production. The maximum amount of production on which credit can be claimed is 1,095 barrels or barrel equivalents. Unused credits can be carried back five years. This credit is subject to a phase out based on the inflation-adjusted price of crude oil such that the credit was not applicable for calendar year taxpayers in 2006.

**Deduction for Income Attributable to Domestic Production Activities**

3.17 For tax years beginning after December 31, 2004, a deduction related to domestic production activities is allowed for qualified production activities income, including that generated from the extraction of crude oil or natural gas within the United States. The deduction is equal to 9 percent of the lesser of qualified production activities income or taxable income for the year when fully phased in for tax years beginning after 2009. In addition, the deduction allowed generally cannot exceed 50 percent of the amount of W-2 wages paid by the taxpayer during the year. This deduction is treated as a permanent difference in the generally accepted accounting principles calculation of income taxes.
Chapter 4

**Internal Control Considerations**

4.01 Internal control of a company engaged in oil and gas exploration and production activities may be simple or it may be very complex. The nature of a particular company’s internal control is influenced by the size of the company, the degree of geographic dispersion of its operations, its types of operations (for example, operator versus nonoperator), governmental requirements, and management’s information needs.

4.02 In general, internal control for oil and gas producing activities is not different from that of other types of enterprises. AU section 314, *Understanding the Entity and Its Environment and Assessing the Risks of Material Misstatement* (AICPA, *Professional Standards*, vol. 1), establishes standards and provides guidance on the independent auditor’s consideration of an entity’s internal control in an audit of financial statements. It defines internal control, describes the objectives and components of internal control and explains how an auditor must obtain an understanding of internal control to assess the risks of material misstatement and to design the nature, timing, and extent of further audit procedures. In order for the auditor to obtain a sufficient understanding of an entity’s internal control, the auditor should perform risk assessment procedures to evaluate the design of controls relevant to an audit of financial statements and determine whether they have been implemented. Auditors of issuers are also required to attest to and report on management’s assessment of the effectiveness of the company’s internal control over financial reporting in conjunction with their audit of the company’s financial statements. Public Company Accounting Oversight Board (PCAOB) Auditing Standard No. 5, *An Audit of Internal Control Over Financial Reporting That Is Integrated with An Audit of Financial Statements* (AICPA, *PCAOB Standards and Related Rules*, Rules of the Board, “Standards”), establishes requirements and provides directions that apply when an auditor is engaged to audit both a company’s financial statements and management’s assessment of the effectiveness of internal control over financial reporting. Most of the business functions of companies engaged in oil and gas exploration and production activities are similar to the corresponding functions found in other types of businesses. However, certain business functions of the exploration, development, and production activities are unique. Internal control considerations for some examples of these types of functions are discussed subsequently. Controls discussed are not always present, nor are they required for the auditor to perform the audit of financial statements.

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1 Refer to the preface of this guide for important information about the applicability of the professional standards to audits of issuers and nonissuers (see definitions in the preface).

2 AU section 325A, *Communicating Internal Control Related Matters Identified in an Audit* (AICPA, *Professional Standards*, vol. 1), establishes standards and provides guidance on the auditor’s responsibilities for identifying, evaluating, and communicating matters related to an entity’s internal control over financial reporting identified in an audit of financial statements.

AU section 380, *The Auditor’s Communication With Those Charged With Governance* (AICPA, *Professional Standards*, vol. 1), uses the term *those charged with governance* to refer to those with responsibility for overseeing the strategic direction of the entity and obligations related to the accountability of the entity, including overseeing the entity’s financial reporting process and internal control over financial reporting.

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AAG-OGP 4.02
Entities With Oil and Gas Producing Activities

4.03 Management of an issuer is required by Section 404(a) of the Sarbanes-Oxley Act of 2002 to assess the effectiveness of the company’s internal control over financial reporting and to include in the company’s annual report to shareholders management’s conclusion as a result of that assessment about whether the company’s internal control is effective. This chapter is not intended to provide guidance to management of public oil and gas producing entities on how to comply with the requirements of the Sarbanes-Oxley Act. Nor is this chapter intended to help auditors perform an audit of internal control over financial reporting in accordance with PCAOB Auditing Standard No. 5. The “SEC Requirements for Management’s Report on Internal Control Over Financial Reporting” section in this chapter provides some general information on internal control reporting requirements established by the Sarbanes-Oxley Act.

4.04 When performing an integrated audit of financial statements and internal control over financial reporting, refer to appendix B, “Special Topics,” of PCAOB Auditing Standard No. 5 for discussion of considerations when a company has multiple locations or business units.

Lease Records

4.05 Accurate records of nonproducing and producing properties and the related financial obligations should be maintained. For example, failure to pay delay rental payments on time can result in the loss of a valuable asset. Also, ownership interests in oil and gas properties are often complex and may change on the occurrence of certain events. Generally, a company maintains master files of lease records that contain all essential ownership and financial obligation information. Controls for this function would normally cover authorization of updates of those master files, integrity of processing master file transactions, periodic substantiation of master file contents, and prevention of unauthorized access to or alteration of data.

Division-of-Interest File Maintenance

4.06 The revenue from oil and gas producing properties is generally divided among multiple royalty and working interest owners. The operator with responsibility for remitting the revenues to the various interest owners should have reasonable assurance that all remittances are accurately computed. Typically, information about the ownership of revenue interests will be maintained in division-of-interest master files. The controls should provide for accurate and timely updating of the information, as well as prevention of unauthorized access to or alteration of the data. Division orders should be reviewed or adequately tested by individuals who do not have control over the properties.

Joint Interest Billing

4.07 Many oil and gas exploration activities are conducted jointly by two or more participants. Generally, accounting responsibility for a project is contractually defined. The operations and allocations are governed by an operating agreement. A company conducting joint operations should have controls giving reasonable assurance that all costs attributable to joint operations are identified and recorded, that the proper participant accounts are charged, that amounts due from participants are collected, and that accurate and timely
statements of account are provided to the co-owners. The importance and difficulty of administering joint interest operations are increased because such operations often involve special cost allocations, carried interest arrangements, and other complexities. Most joint interest agreements also provide the non-operating party with the right to perform (or to have performed) joint interest audits of the operator.

**Revenue and Revenue Payables**

4.08 A company may receive oil and gas revenues from properties for which it is the operator as well as from properties operated by others. Controls should provide reasonable assurance that the company receives all production revenues to which it is entitled. Such controls may involve the following: periodic calibration and inspection of meters, manually gauging or witnessing the gauging of production tanks, and period-to-period comparison of production volumes. In addition, settlement reports should be reconciled to the production data regularly. Prices should be monitored to ensure that maximum allowable prices are received. For revenues received on behalf of other co-owners, the amounts to be remitted must be accurately computed based on division-of-interest file information. Provisions for royalties payable should be consistent with the basic lease or royalty agreements and any questionable areas related to the computation of royalties due may be referred to legal counsel for interpretation. Detailed trial balances of royalties in suspense should be reviewed on a regular basis, and investigations of significant balances and fluctuations should be made by an employee with no conflicting duties.

**Property Accounting**

4.09 The tax and financial reporting requirements of accounting for oil and gas properties are unique and complex. Generally, the cost, expense, and revenue information is accumulated at the individual lease or well level regardless of the accounting method used. Subsidiary property records should be routinely reconciled to the general ledger. Controls should provide for (1) the proper capitalization or expensing of exploration costs, (2) computation of depletion for both tax and financial reporting purposes, and (3) identification of amounts recorded for oil and gas properties that are not realizable. In addition, property records should have sufficient detail of ownership, status (abandonments, leases held for sale, operations), assigned equipment, and so on. This generally requires coordinating the land department, the legal department, and the accounting department. Controls should be established (1) for review of joint interest billings and comparison against the appropriate authorization for expenditures (AFE), (2) for review of AFEs for credits due when a project is completed, and (3) for consideration of joint interest audits on a timely basis. There should be a proper segregation of duties between those responsible for preparing an economic assessment of the value of proved or unproved properties and those who have the authority to acquire or dispose of the properties. Controls should also provide for a routine review of potential impairment.

4.10 Controls should be established to determine that property transactions are properly authorized—including the selection of properties, the amount of expenditures, the location and types of resources to explore and develop, and the levels and timing of production and inventory maintained. The timing
and terms of sales or other dispositions of property should also be properly authorized.

Physical Security

4.11 The substantial investment in physical assets and the ready marketability of equipment and inventory require appropriate controls over access. Also, many sites are in rather remote areas and may be unattended for long periods of time. The construction of physical barriers and restricting access should be considered, along with detection and prevention devices. In addition, there should be specific responsibility for physical custody of assets and signature access (requisition authority).

Authorization for Expenditure

4.12 An AFE, which is a procedure for documenting authorization of large expenditures, usually contains a description of the project, a listing of budgeted expenditures, and appropriate approvals. An AFE should be obtained for each major fixed asset acquisition. They are normally obtained for all costs incurred in acquiring leases, drilling and equipping oil and gas properties, purchasing drilling equipment and service units, constructing buildings, and other major projects. The company should have established controls to follow up on variances between actual expenditures and the amounts in the AFEs.

Cost Accruals

4.13 Operators should have controls to provide reasonable assurance that accruals are made for exploration and development costs incurred. Normally, such accruals are based on field reports (such as daily drilling reports) of estimated completion percentages of AFEs in progress. Controls should also be established to assure that estimated production expenses are accrued if significant. Nonoperating interest owners should similarly accrue payables to operators for their share of expenditures incurred. This may necessitate controls for confirmation with the operator on properties where activities are in progress.

Government Requirements

4.14 Oil and gas producing activities are subject to numerous federal and state regulations. Noncompliance with these regulations can result in legal actions—fines, assessments, and other potential liabilities. In addition, there are certain tax regulations, such as the ad valorem taxes, and statutory depletion allowances, at both the federal and state levels. Controls should be established and competent personnel should be employed to monitor and comply with the various governmental requirements.

Related Parties

4.15 The industry’s unique financing arrangements, royalty relationships, management fees, and tax partnerships—among other arrangements—tend to be conducive to related party transactions. Controls should be established to accumulate the necessary information for disclosure requirements of Financial Accounting Standards Board Statement No. 57, Related Party Disclosures.
Nonoperated Interests

4.16 Internal control for nonoperated interests should include many of the functions described in the earlier sections of this chapter. Certain other controls may also be necessary because of limited access to the operations:

- Controls should be established to provide reasonable assurance that reports of drilling activity, production, capital projects, lease renewals, and so forth, are received in a timely fashion and are reviewed by responsible employees.
- Production revenues should be reviewed against historical records and compared with estimates. Any unusual fluctuations ordinarily should be investigated and appropriately resolved.
- Consideration should be given to periodically obtaining independent evaluations of significant nonoperated properties.
- Controls should be established to assure that the need for joint interest audits is given appropriate consideration within the necessary time limits.

SEC Requirements for Management’s Report on Internal Control Over Financial Reporting

4.17 As directed by Section 404 of the Sarbanes-Oxley Act of 2002, the Securities and Exchange Commission (SEC) adopted final rules requiring companies subject to the reporting requirements of the Securities Exchange Act of 1934, other than registered investment companies, to include in their annual reports a report of management on the company’s internal control over financial reporting. See the SEC Web site for more information.

4.18 The SEC rules clarify that management’s assessment and report is limited to internal control over financial reporting. Management is not required to consider other aspects of control, such as controls pertaining to operating efficiency. The SEC’s definition of internal control encompasses the Committee of Sponsoring Organizations of the Treadway Commission (COSO) definition but the SEC does not mandate that the entity use COSO as its criteria for assessing effectiveness.

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3 See the preface of this guide for additional Securities and Exchange Commission developments.
Chapter 5

Auditing Overview

5.01 In accordance with AU section 150, Generally Accepted Auditing Standards (AICPA, Professional Standards, vol. 1), an independent auditor plans, conducts, and reports the results of an audit in accordance with generally accepted auditing standards (GAAS). Auditing standards provide a measure of audit quality and the objectives to be achieved in an audit. This chapter provides guidance, primarily on the application of the standards of fieldwork. Specifically, this chapter provides guidance on the risk assessment process (which includes, among other things, obtaining an understanding of the entity and its environment, including its internal control) and general auditing considerations for auditing financial statements of companies with oil and gas producing activities.

5.02 Financial accounting for oil and gas producing activities is unique in many areas and consequently presents problems for the auditor, when determining whether the financial statements are presented in conformity with generally accepted accounting principles (GAAP). This chapter is intended to identify these special accounting areas and provide general guidance on the most effective way of auditing them. Auditors should use professional judgment in applying this guidance to develop the specific audit procedures that will meet their particular needs.

Planning and Other Auditing Considerations

5.03 The objective of an audit of the financial statements of a company with oil and gas producing activities is to express an opinion on whether its financial statements are presented fairly, in all material respects, in conformity with GAAP or an other comprehensive basis of accounting. To accomplish that objective, the independent auditor’s responsibility is to plan and perform the audit to obtain reasonable assurance (a high, but not absolute, level of assurance) about whether the financial statements are free of material misstatements, whether caused by errors or fraud. This section addresses general planning considerations and other auditing considerations relevant to entities with oil and gas producing activities.

Audit Focus

5.04 In audits of the financial statements of most oil and gas producing activities the primary focus is generally on the company’s properties. Evaluating the accumulation and recovery of costs associated with the properties is central to the audit process and to determining whether the financial statements are presented in conformity with GAAP.

Audit Planning

5.05 The first standard of field work states, “The auditor must adequately plan the work and must properly supervise any assistants.” AU section 311, Planning and Supervision (AICPA, Professional Standards, vol. 1), establishes
standards and guidance on the considerations and activities applicable to planning and supervision of an audit conducted in accordance with GAAS, including appointment of the independent auditor; preliminary engagement activities; establishing an understanding with the client; preparing a detailed, written audit plan; determining the extent of involvement of professionals with specialized skills; and communicating with those charged with governance and management. Audit planning also involves developing an overall audit strategy for the expected conduct, organization, and staffing of the audit. The nature, timing, and extent of planning vary with the size and complexity of the entity, and with the auditor’s experience with the entity and understanding of the entity and its environment, including its internal control.

5.06 AU section 311 paragraph .03 states that the auditor must plan the audit so that it is responsive to the assessment of the risks of material misstatement based on the auditor’s understanding of the entity and its environment, including its internal control. Planning is not a discrete phase of the audit, but rather an iterative process that begins with engagement acceptance and continues throughout the audit as the auditor performs audit procedures and accumulates sufficient appropriate audit evidence to support the audit opinion.

Considerations for Audits Performed in Accordance with Public Company Accounting Oversight Board (PCAOB) Standards

Paragraph .01 of AU section 311, Planning and Supervision (AICPA, PCAOB Standards and Related Rules, PCAOB Standards, As Amended), states that when performing an integrated audit of financial statements and internal control over financial reporting, refer to paragraph 9 of PCAOB Auditing Standard No. 5, An Audit of Internal Control Over Financial Reporting That Is Integrated with An Audit of Financial Statements (AICPA, PCAOB Standards and Related Rules, Rules of the Board, “Standards”), regarding planning considerations, in addition to the planning considerations set forth in AU section 311 (AICPA, PCAOB Standards and Related Rules, PCAOB Standards, As Amended).

Audit Risk

5.07 AU section 312 paragraph .12, Audit Risk and Materiality in Conducting an Audit (AICPA, Professional Standards, vol. 1), states that audit risk is a function of the risk that the financial statements prepared by management are materially misstated and the risk that the auditor will not detect such material misstatement. The auditor should consider audit risk in relation to the relevant assertions related to individual account balances, classes of transactions, and disclosures and at the overall financial statement level.

5.08 At the account balance, class of transactions, relevant assertion, or disclosure level, audit risk consists of (a) the risks of material misstatement (consisting of inherent risk and control risk) and (b) detection risk. AU section 312 paragraph .23 states that auditors should assess the risk of material misstatement at the relevant assertion level as a basis to design and perform further audit procedures (tests of controls or substantive procedures). It is not acceptable to simply deem risk to be “at the maximum.” This assessment may be in qualitative terms such as high, medium, and low or in quantitative terms such as percentages.
5.09 In considering audit risk at the overall financial statement level, the auditor should consider risks of material misstatement that relate pervasively to the financial statements taken as a whole and potentially affect many relevant assertions. Risks of this nature often relate to the entity’s control environment and are not necessarily identifiable with specific relevant assertions at the class of transactions, account balance, or disclosure level. Such risks may be especially relevant to the auditor’s consideration of the risks of material misstatement arising from fraud, for example, through management override of internal control.

Planning Materiality

5.10 The auditor’s consideration of materiality is a matter of professional judgment and is influenced by the auditor’s perception of the needs of users of financial statements. Materiality judgments are made in light of surrounding circumstances and necessarily involve both quantitative and qualitative considerations.

5.11 In accordance with AU section 312 paragraph .27, the auditor should determine a materiality level for the financial statements taken as a whole when establishing the overall audit strategy for the audit. The auditor often may apply a percentage to net income as a step in determining materiality for the financial statements taken as a whole.

Considerations for Audits Performed in Accordance with PCAOB Standards

Paragraph .03 of AU section 312, Audit Risk and Materiality in Conducting an Audit (AICPA, PCAOB Standards and Related Rules, PCAOB Standards, As Amended), states that when performing an integrated audit of financial statements and internal control over financial reporting, refer to paragraph 20 of PCAOB Auditing Standard No. 5 regarding materiality considerations.

Tolerable Misstatement

5.12 The initial determination of materiality is made for the financial statement taken as a whole. However, depending on the circumstances, the auditor also may determine materiality levels for particular items that are lesser than the materiality level determined for the financial statements taken as a whole, as described in paragraph .31 of AU section 312. The auditor should allow for the possibility that some misstatements of lesser amounts than the materiality levels could, in the aggregate, result in a material misstatement of the financial statements. To do so, the auditor should determine one or more levels of tolerable misstatement. AU section 312 paragraph .34 defines tolerable misstatement (or tolerable error) as the maximum error in a population (for example, the class of transactions or account balance) that the auditor is willing to accept. Such levels of tolerable misstatement are normally lower than the materiality levels.

Qualitative Aspects of Materiality

5.13 As indicated previously, judgments about materiality include both quantitative and qualitative information. As a result of the interaction of quantitative and qualitative considerations in materiality judgments, misstatements of relatively small amounts that come to the auditor’s attention could have a material effect on the financial statements. For example, an illegal
payment of an otherwise immaterial amount could be material if there is a reasonable possibility that it could lead to a material contingent liability or a material loss of revenue.

5.14 Qualitative considerations also influence the auditor in reaching a conclusion about whether misstatements are material. Paragraph .60 of AU section 312 provides qualitative factors that the auditor may consider relevant in determining whether misstatements are material.

Use of Specialists

5.15 Specialists such as reservoir engineers and geologists are often used due to the nature of the oil and gas industry. Such specialists may be employees of the company or they may be independent consultants or contractors. AU section 336, Using the Work of a Specialist (AICPA, Professional Standards, vol. 1), provides guidance to the auditor who does use the work of a specialist in performing an audit. In addition, Auditing Interpretation No. 1, “Supplementary Oil and Gas Reserve Information,” of AU section 558, Required Supplementary Information (AICPA, Professional Standards, vol. 1, AU sec. 9558 par. .01–.06), describes standards prepared by the Society of Petroleum Engineers for qualifications of a reserve estimator.

5.16 The auditor may make an early assessment of the extent of use of specialists and the timing considerations thereof, including the need for involving independent consultants. The auditor may consider outlining those needs in an audit engagement letter.

5.17 The extent to which an independent outside specialist is used may depend on whether a cost ceiling limitation problem is considered likely to exist. (See discussion under “Accounting for Production” in paragraphs 2.107–124.) This is a judgmental area; however, auditors may consider the advisability of requesting the involvement of an independent outside specialist when it appears the costs are approaching or may exceed the cost ceiling limitation.

Scope of the Engagement

5.18 AU section 311 states that the auditor should establish an understanding with the entity regarding the services to be performed for each engagement. This understanding should be documented through a written communication with the entity in the form of an engagement letter. The understanding should include the objectives of the engagement, the responsibilities of management and the auditor, and any limitations of the engagement. Paragraph .09 of AU section 311 indicates that this understanding with the client generally includes, among other things, management’s responsibility for determining the appropriate disposition of financial statement misstatements aggregated by the auditor. AU section 311 also identifies specific matters and other contractual matters that may be included in the understanding with the client. Paragraph .10 of AT section 201, Agreed-Upon Procedures Engagements (AICPA, Professional Standards, vol. 1), identifies matters that might be included in such an understanding for attestation engagements.

Use of Assertions in Obtaining Audit Evidence

5.19 Paragraphs .14–19 of AU section 326, Audit Evidence (AICPA, Professional Standards, vol. 1), discuss the use of assertions in obtaining audit
Auditing evidence. In representing that the financial statements are fairly presented in accordance with GAAP, management implicitly or explicitly makes assertions regarding the recognition, measurement, and disclosure of information in the financial statements and related disclosures. Assertions used by the auditor fall into the following categories.

<table>
<thead>
<tr>
<th>Categories of Assertions</th>
<th>Description of Assertions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Classes of Transactions and Events During the Period</td>
<td>Account Balances at the End of the Period</td>
</tr>
<tr>
<td>Occurrence/Existence</td>
<td>Transactions and events that have been recorded and pertain to the entity.</td>
</tr>
<tr>
<td>Rights and Obligations</td>
<td>—</td>
</tr>
<tr>
<td>Completeness</td>
<td>All transactions and events that should have been recorded have been recorded.</td>
</tr>
<tr>
<td>Accuracy/Valuation and Allocation</td>
<td>Amounts and other data relating to recorded transactions and events have been recorded appropriately.</td>
</tr>
</tbody>
</table>

(continued)
Categories of Assertions—continued

| Cut-off | Transactions and events have been recorded in the correct accounting period. | — | — |
| Classification and Understandability | Transactions and events have been recorded in the proper accounts. | — | Financial information is appropriately presented and described and information in disclosures is expressed clearly. |

5.20 The auditor should use relevant assertions for classes of transactions, account balances, and presentation and disclosures in sufficient detail to form a basis for the assessment of risks of material misstatement and the design and performance of further audit procedures. The auditor should use relevant assertions in assessing risks by considering the different types of potential misstatements that may occur, and then designing further audit procedures that are responsive to the assessed risks.

Understanding the Entity, Its Environment, and Its Internal Control

5.21 AU section 314, Understanding the Entity and Its Environment and Assessing the Risks of Material Misstatement (AICPA, Professional Standards, vol. 1), establishes standards and provides guidance about implementing the second standard of field work, as follows:

The auditor must obtain a sufficient understanding of the entity and its environment, including its internal control, to assess the risks of material misstatement of the financial statements whether due to error or fraud, and to design the nature, timing, and extent of further audit procedures.

5.22 Obtaining an understanding of the entity and its environment, including its internal control, is a continuous, dynamic process of gathering, updating, and analyzing information throughout the audit. Throughout this process, the auditor should also follow the guidance in AU section 316, Consideration of Fraud in a Financial Statement Audit (AICPA, Professional Standards, vol. 1).
This section addresses the unique aspects of entities with oil and gas producing activities that may be helpful in developing the required understanding of the entity, its environment, and its internal control.

Risk Assessment Procedures

As described in AU section 326, audit procedures performed to obtain an understanding of the entity and its environment, including its internal control, to assess the risks of material misstatement at the financial statement and relevant assertion levels are referred to as risk assessment procedures. AU section 326 paragraph .21 states that the auditor must perform risk assessment procedures to provide a satisfactory basis for the assessment of risks at the financial statement and relevant assertion levels. Risk assessment procedures by themselves do not provide sufficient appropriate audit evidence on which to base the audit opinion and must be supplemented by further audit procedures in the form of tests of controls, when relevant or necessary, and substantive procedures.

In accordance with AU section 314 paragraph .06, the auditor should perform the following risk assessment procedures to obtain an understanding of the entity and its environment, including its internal control:

a. Inquiries of management and others within the entity
b. Analytical procedures
c. Observation and inspection

See paragraphs .06–.13 of AU section 314 for additional guidance on risk assessment procedures.

Discussion Among the Audit Team

In obtaining an understanding of the entity and its environment, including its internal control, AU section 314 states that there should be discussion among the audit team. In accordance with paragraph .14 of AU section 314, the members of the audit team, including the auditor with final responsibility for the audit, should discuss the susceptibility of the entity’s financial statements to material misstatements. This discussion could be held concurrently with the discussion among the audit team that is specified by AU section 316 to discuss the susceptibility of the entity’s financial statements to fraud.

Understanding of the Entity and Its Environment

AU section 314 states that the auditor must obtain an understanding of the entity and its environment, including its internal control. In accordance with AU section 314 paragraph .04, the auditor should use professional judgment to determine the extent of the understanding required of the entity and its environment, including its internal control. The auditor’s primary consideration is whether the understanding that has been obtained is sufficient (1) to assess risks of material misstatement of the financial statements and (2) to design and perform further audit procedures (tests of controls and substantive tests).
The auditor's understanding of the entity and its environment consists of an understanding of the following aspects:

a. Industry, regulatory, and other external factors
b. Nature of the entity
c. Objectives and strategies and the related business risks that may result in a material misstatement of the financial statements
d. Measurement and review of the entity's financial performance
e. Internal control, which includes the selection and application of accounting policies (see the following section for further discussion)

Refer to appendix A of AU section 314 for examples of matters that the auditor may consider in obtaining an understanding of the entity and its environment relating to categories (a)–(d). Examples of matters an auditor may consider when obtaining an understanding of the nature of an entity with oil and gas producing activities are discussed subsequently.* Chapters 1–4 of this guide provide additional information about the oil and gas industry that may be helpful in obtaining an understanding of the entity and environment.

**Nature of Operations**

5.29 It is important for the auditor to consider the company's method of operation when obtaining an understanding of the entity and its environment. Responsibilities associated with property operation will vary widely. Among matters the auditor may consider are the extent of operating responsibilities, the use of partnerships or joint ventures, and related party transactions.

5.30 **Operator or nonoperator.** A distinction can be drawn between audit procedures designed to be used in the audit of the financial statements of a producer acting as an operator of properties and the audit procedures used in the audit of the financial statements of a company acting solely as a nonoperator to joint operating agreements. Some of the factors an auditor may consider are

- the terms of the operating agreement concerning the duties and responsibilities of the operator and the rights and obligations of the nonoperators.
- whether the operator's controls provide reasonable assurance of compliance with the provisions of the operating agreement, provide proper and prompt billing of costs and expenses to nonoperators, and provide distribution of revenues to royalty interest owners and nonoperator working interest holders.
- whether the nonoperator's controls provide reasonable assurance of proper accounting for costs and expenses. Another factor to consider is that billings received from the operator are properly supported and in compliance with the terms of the operating agreement.
- whether or not joint interest audits are periodically performed.

* In addition to the nature of the entity, the auditor's understanding of the entity and its environment also consists of industry, regulatory, and other external factors; objectives and strategies and related business risks; and measurement and review of the entity's financial performance. Examples of these aspects as they relate to oil and gas entities will be incorporated in a future edition of this guide.
5.31 Nonoperators generally utilize significantly less accounting and operations personnel than would an operator. The operator will have the responsibility for paying all costs of the development and the operation of the property, properly billing such costs to the nonoperators, and often collecting and distributing revenues. On the other hand, the nonoperator pays and collects only its share of the costs and revenues (generally no more often than once a month).

5.32 *Use of partnerships.* The use of partnerships for financing purposes usually adds significant complications to the accounting and auditing of an oil and gas company. Many companies create limited partnerships by selling limited partner interests in public or private offerings. Often, the limited partnership agreements require audits of the partnership. The auditor should be mindful that a lower materiality factor may be more appropriate for testing partnership transactions than for testing transactions of the sponsoring company, which may also be audited.

5.33 In addition, the terms of the partnership agreement would dictate the allocation of costs and revenues to the limited and general partners and often would require a determination of the status of individual properties or groups of properties within the partnership. Therefore, the auditor should be familiar with the significant provisions of the partnership agreement and, where applicable, the audit procedures should reflect these considerations.

5.34 *Related party transactions.* The nature of oil and gas operations tends to result in a greater frequency and significance of related party transactions than would occur in many other industries. This is largely because of the readily divisible nature of property ownership, but these transactions also occur from dealings with limited partnerships, joint ventures, and the like. Commonly encountered related-party transactions include

- employee interest in properties, particularly through incentive plans that enable key employees to earn an interest in successful prospects.
- participation in properties with directors. Particularly in smaller companies, a frequent source of prospects may be directors who are themselves independent operators in the industry.
- transactions with limited partnerships, including handling property transactions and allocating costs. Limited partnerships often involve conflicts of interest, in which decisions may benefit or adversely affect either the company or the limited partners.

5.35 In planning the audit, consideration should be given to determining that information necessary for related party disclosures is available and procedures for testing the related accounts should be designed to comply with AU section 334, *Related Parties* (AICPA, *Professional Standards*, vol. 1).

5.36 *Other considerations.* Other items related to property operations that the auditor may consider in the planning of specific audit procedures include the following:

- Long-term sales contracts
- Drilling contracts
- Take-or-pay contracts
- Production payments
- Farm-outs and carried interests
Entities With Oil and Gas Producing Activities

- Leases, particularly expiration provisions
- Timing of drilling activities and evaluation of unproved properties
- Production-balancing contracts
- Division orders
- Regulatory agreements

5.37 The procedures used by the auditor during an audit of an oil and gas producing company's financial statements may be greatly affected by the geographical areas in which the company operates. For example, if offshore operations and operations in foreign countries are applicable, then the auditor may consider

- different types of property costs associated with offshore as opposed to onshore operations.
- regional pricing differences and the availability of markets.
- various environmental and other regulatory implications.
- production-sharing contracts with foreign governments.
- tax implications of foreign operations.
- disclosure requirements of foreign operations.

5.38 Identifying specified personnel, and their geographic location, having the responsibility for specific functions related to accounting, internal control, and financial reporting is an integral part of planning the audit.

5.39 Field operation accounting personnel. Field operations may be conducted in a manner whereby the accounting data for investments in, and operations of, oil and gas properties are processed in the company’s home office. On the other hand, certain functions may be performed in district or field offices. The auditor identifies the personnel, and their location, responsible for specific items, such as

- preparing and approving authorization for expenditures (AFEs) and subsequently reconciling actual costs with estimates.
- measuring and reporting units of production.
- pricing production.
- approving expenses and allocations to specific properties.
- joint interest billing (JIB) and revenue sharing.
- handling warehouse receipts and issuing materials.
- complying with regulations.

5.40 Geological, geophysical, and engineering personnel. Financial statements and reports to management for companies with oil and gas producing activities may request that certain data be provided that calls for the input of personnel other than accounting department personnel. This information may include

- status of wells and well classification (that is, exploratory versus developmental).
- reserve data about units, production curves, future development and operating costs, and the like.
- production data analyses of pricing, number of units, conversion factors, and so on.

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- AFE data—for example, identification of capital versus expense workovers.
- Value information and exploration plans for measuring impairment and cost ceiling.

5.41 Land department personnel. These personnel may assist in providing information regarding property identification, ownership data, transfers from undeveloped properties to producing leaseholds or abandonments, or current status of contractual obligations that are applicable to leasehold rights (such as delay rental payments, drilling obligations, and payout status). When making the inquiries referred to previously, the auditor may also plan to identify the procedures used by the company’s personnel in accumulating, processing, and validating the data involved.

Understanding of Internal Control

5.42 AU section 314 states that the auditor should obtain an understanding of the five components of internal control sufficient to assess the risks of material misstatement of the financial statements whether due to error or fraud, and to design the nature, timing, and extent of further audit procedures. The auditor should obtain a sufficient understanding by performing risk assessment procedures to

a. evaluate the design of controls relevant to an audit of financial statements.

b. determine whether they have been implemented.

5.43 The auditor should use the understanding to

- identify types of potential misstatements.
- consider factors that affect the risks of material misstatement.
- design tests of controls, when applicable, and substantive procedures.

5.44 Obtaining an understanding of the entity and its environment, including internal control, is a continuous, dynamic process of gathering, updating, and analyzing information throughout the audit. The objective of obtaining an understanding of controls is to evaluate the design of controls and determine whether they have been implemented for the purpose of assessing the risks of material misstatement. In contrast, the objective of testing the operating effectiveness of controls is to determine whether the controls, as designed, prevent or detect a material misstatement.

5.45 AU section 314 paragraph .41 defines internal control as “a process—effected by those charged with governance, management, and other personnel—designed to provide reasonable assurance about the achievement of the entity’s objectives with regard to reliability of financial reporting, effectiveness and efficiency of operations, and compliance with applicable laws and regulations.” Internal control consists of 5 interrelated components:

a. The control environment

b. Risk assessment

c. Information and communication systems

d. Control activities

e. Monitoring
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Refer to paragraphs .67–.101 of AU section 314 for a detailed discussion of the internal control components.

5.46 Refer to chapter 4, "Internal Control Considerations," for additional discussion of internal controls.

Assessment of Risks of Material Misstatement and the Design of Further Audit Procedures

5.47 As discussed previously, risk assessment procedures allow the auditor to gather the information necessary to obtain an understanding of the entity and its environment, including its internal control. This knowledge provides a basis for assessing the risks of material misstatement of the financial statements. These risk assessments are then used to design further audit procedures, such as tests of controls, substantive tests, or both. This section provides guidance on assessing the risks of material misstatement and how to design further audit procedures that effectively respond to those risks.

Assessing the Risks of Material Misstatement

5.48 AU section 314 paragraph .102 states that the auditor should identify and assess the risks of material misstatement at the financial statement level and at the relevant assertion level related to classes of transactions, account balances, and disclosures. For this purpose, the auditor should

a. identify risks throughout the process of obtaining an understanding of the entity and its environment, including relevant controls that relate to the risks, and considering the classes of transactions, account balances, and disclosures in the financial statements.

b. relate the identified risks to what can go wrong at the relevant assertion level.

c. consider whether the risks are of a magnitude that could result in a material misstatement of the financial statements.

d. consider the likelihood that the risks could result in a material misstatement of the financial statements.

5.49 The auditor should use information gathered by performing risk assessment procedures, including the audit evidence obtained in evaluating the design of controls and determining whether they have been implemented, as audit evidence to support the risk assessment. The auditor should use the assessment of the risks of material misstatement at the relevant assertion level as the basis to determine the nature, timing, and extent of further audit procedures to be performed.

Identification of Significant Risks

5.50 As part of the assessment of the risks of material misstatement, the auditor should determine which of the risks identified are, in the auditor’s judgment, risks that require special audit consideration (such risks are defined as significant risks). One or more significant risks normally arise on most audits. In exercising this judgment, the auditor should consider inherent risk to determine whether the nature of the risk, the likely magnitude of the potential misstatement including the possibility that the risk may give rise to multiple misstatements, and the likelihood of the risk occurring are such that they require special audit consideration. Refer to paragraphs .45 and .53 of AU section
Performing Audit Procedures in Response to Assessed Risks and Evaluating the Audit Evidence Obtained (AICPA, Professional Standards, vol. 1), for further audit procedures pertaining to significant risks.

Designing and Performing Further Audit Procedures

5.51 AU section 318 establishes requirements and provides guidance about implementing the third standard of field work, as follows:

The auditor must obtain sufficient appropriate audit evidence by performing audit procedures to afford a reasonable basis for an opinion regarding the financial statements under audit.

5.52 To reduce audit risk to an acceptably low level, the auditor (1) should determine overall responses to address the assessed risks of material misstatement at the financial statement level and (2) should design and perform further audit procedures whose nature, timing, and extent are responsive to the assessed risks of material misstatement at the relevant assertion level. The purpose is to provide a clear linkage between the nature, timing, and extent of the auditor’s further audit procedures and the assessed risks. The overall responses and the nature, timing, and extent of the further audit procedures to be performed are matters for the professional judgment of the auditor and should be based on the auditor’s assessment of the risks of material misstatement.

Overall Responses

5.53 The auditor’s overall responses to address the assessed risks of material misstatement at the financial statement level may include emphasizing to the audit team to maintain professional skepticism in gathering and evaluating audit evidence, assigning more experienced staff or those with specialized skills or using specialists, providing more supervision, or incorporating additional elements of unpredictability in the selection of further audit procedures to be performed. Additionally, the auditor may make general changes to the nature, timing, or extent of further audit procedures as an overall response, for example, performing substantive procedures at period end instead of at an interim date.

Further Audit Procedures

5.54 Further audit procedures provide important audit evidence to support an audit opinion. These procedures consist of tests of controls and substantive tests. The nature, timing, and extent of the further audit procedures to be performed by the auditor should be based on the auditor’s assessment of risks of material misstatement at the relevant assertion level.

5.55 In some cases, an auditor may determine that performing only substantive procedures is appropriate. However, the auditor often may determine that a combined audit approach using both tests of the operating effectiveness of controls and substantive procedures is an effective audit approach.

5.56 The auditor should perform tests of controls when the auditor’s risk assessment includes an expectation of the operating effectiveness of controls or when substantive procedures alone do not provide sufficient appropriate audit evidence at the relevant assertion level.

5.57 Regardless of the audit approach selected, the auditor should design and perform substantive procedures for all relevant assertions related to each material class of transactions, account balance, and disclosure.
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5.58 The auditor’s substantive procedures should include the following audit procedures related to the financial statement reporting process:

- Agreeing the financial statements, including their accompanying notes, to the underlying accounting records
- Examining material journal entries and other adjustments made during the course of preparing the financial statements

The nature and extent of the auditor’s examination of journal entries and other adjustments depends on the nature and complexity of the entity’s financial reporting system and the associated risks of material misstatement.

5.59 The section titled “Unique Audit Procedures for Oil and Gas Producing Entities” in the later part of this chapter provides specific guidance on the more significant auditing procedures that the independent auditor may consider in the audits of companies with oil and gas producing activities.

Evaluating Misstatements

5.60 Based on the results of substantive procedures, the auditor may identify misstatements in accounts or notes to the financial statements. AU section 312 paragraph .42 states that auditors must accumulate all known and likely misstatements identified during the audit, other than those that the auditor believes are trivial and communicate them to the appropriate level of management. AU section 312 further states that auditors must consider the effects, both individually and in the aggregate, of misstatements (known and likely) that are not corrected by the entity. This consideration should include, among other things, the effect of misstatements related to prior periods.

5.61 For detailed guidance on evaluating audit findings and audit evidence, refer to AU section 312 and AU section 326, respectively.

Consideration of Fraud in a Financial Statement Audit

5.62 AU section 316 is the primary source of authoritative guidance about an auditor’s responsibilities concerning the consideration of fraud in a financial statement audit. AU section 316 establishes standards and provides guidance to auditors in fulfilling their responsibility to plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether caused by error or fraud as stated in paragraph .02 of AU section 110, Responsibilities and Functions of the Independent Auditor (AICPA, Professional Standards, vol. 1).

Considerations for Audits Performed in Accordance with PCAOB Standards

Paragraph .01 of AU section 316, Consideration of Fraud in a Financial Statement Audit (AICPA, PCAOB Standards and Related Rules, PCAOB Standards, As Amended), states that when performing an integrated audit of financial statements and internal control over financial reporting, refer to paragraphs 14–15 of PCAOB Auditing Standard No. 5 regarding fraud considerations, in addition to the fraud considerations set forth in AU section 316 (AICPA, PCAOB Standards and Related Rules, PCAOB Standards, As Amended).
5.63 There are two types of misstatements relevant to the auditor’s consideration of fraud in a financial statement audit:

- Misstatements arising from fraudulent financial reporting
- Misstatements arising from misappropriation of assets

5.64 Three conditions generally are present when fraud occurs. First, management or other employees have an incentive or are under pressure, which provides a reason to commit fraud. Second, circumstances exist—for example, the absence of controls, ineffective controls, or the ability of management to override controls—that provide an opportunity for a fraud to be perpetrated. Third, those involved are able to rationalize committing a fraudulent act.

The Importance of Exercising Professional Skepticism

5.65 Because of the characteristics of fraud, the auditor’s exercise of professional skepticism is important when considering the risk of material misstatement due to fraud. Professional skepticism is an attitude that includes a questioning mind and a critical assessment of audit evidence. The auditor should conduct the engagement with a mindset that recognizes the possibility that a material misstatement due to fraud could be present, regardless of any past experience with the entity and regardless of the auditor’s belief about management’s honesty and integrity. Furthermore, professional skepticism requires an ongoing questioning of whether the information and evidence obtained suggests that a material misstatement due to fraud has occurred.

Discussion Among Engagement Personnel Regarding the Risks of Material Misstatement Due to Fraud

5.66 Members of the audit team should discuss the potential for material misstatement due to fraud in accordance with the requirements of AU section 316 paragraphs .14–.18. The discussion among the audit team members about the susceptibility of the entity’s financial statements to material misstatement due to fraud should include a consideration of the known external and internal factors affecting the entity that might (a) create incentives or pressures for management and others to commit fraud, (b) provide the opportunity for fraud to be perpetrated, and (c) indicate a culture or environment that enables management to rationalize committing fraud. Communication among the audit team members about the risks of material misstatement due to fraud also should continue throughout the audit.

5.67 Listed subsequently are some examples of possible fraud risk factors that may exist in the oil and gas producing activities industry: Please note that this list is not inclusive of all potential fraud risk factors. Other examples of such risk factors can be found in appendix A of AU section 316.

Part 1: Fraudulent Financial Reporting

A. Incentives or Pressures

1. External company performance pressures including analysts expectations on earnings, oil and gas reserve
Entities With Oil and Gas Producing Activities

1. Individual incentives including promotions, advancement and compensation contingent on performance related to financial targets such as cash flow, profitability, reserve replacement, production increases
2. Debt or equity financing needed to complete a major acquisition, exploratory or development project
3. Recurring increases in production costs unrelated to revenue increases
4. Marginal ability to meet debt covenants
5. Personal guarantees of debt by key management, those charged with governance, or other similar parties

B. Opportunities

1. Manipulation or bias of significant estimates to manage earnings
   - Oil and gas revenue and expense accruals
   - Carrying value of assets and estimated recoverable oil and gas reserve quantities
   - Collectibility of receivables
   - For full cost companies, capitalization of internal costs directly identified with acquisition, exploration, and development activities
   - Contingent liabilities
2. Intentional misapplication of GAAP
3. Lack of transparency or intentional omission of material disclosures
4. Significant related-party transactions not in the ordinary course of business or with related entities not audited or audited by another firm
5. Significant operations located or conducted across international borders
6. Domination of management by a single person or small group without compensating controls
7. Those charged with governance or committee oversight over financial reporting process and internal controls are ineffective
8. Overly complex joint operating agreement or other arrangements

C. Attitudes or Rationalizations

1. Management displaying a significant disregard for regulatory authorities
   a. Environmental crime, and violating occupational health and safety laws
2. Recurring attempts by management to justify inappropriate accounting on the basis of materiality
Part 2: Misappropriations of Assets

A. Incentives or Pressures

1. Adverse relationships between the entity and employees with access to cash or other assets susceptible to theft may motivate those employees to misappropriate those assets. For example, adverse relationships may be created by the following:
   a. Sabotage and espionage by employees, competitors, or others
   b. Nepotism and other related party transactions

2. Compensation or bonus structures tied to financial performance within an organization may result in an incentive to misappropriate assets.

B. Opportunities

1. Inadequate internal control over assets may increase the susceptibility of misappropriation of those assets. For example, misappropriation of assets may occur because there is the following:
   a. Inadequate segregation of duties or independent checks
      (1) Accounts payable and payroll fraud, such as phony suppliers or ghost employees
      (2) Revenue settlement process and the division of interest files resulting in improper revenue recognition and payout
      (3) Secret commissions, bid rigging, kickbacks, and the like
   b. Inadequate physical safeguards over assets including:
      (1) Materials, supplies and drilling equipment in inventory
      (2) Proprietary seismic data
   c. Inadequate system of approval and authorization of transactions
      (1) Outsider fraud, such as inflated supplier invoices or product substitution, con schemes, copyright piracy, patent infringement, and the like

C. Attitudes or Rationalizations

1. Employees may have individual financial problems that pressure them to misappropriate assets for personal gain
2. Employees may rationalize an action if they believe they are not compensated appropriately or have been treated unfairly
3. Compensation plans may be structured in a manner that implies certain actions are appropriate or justified
4. The tone set by senior management may inappropriately convey that personal use of assets or other actions are acceptable.

**Obtaining the Information Needed to Identify the Risks of Material Misstatement Due to Fraud**

5.68 AU section 314 establishes requirements and provides guidance about how the auditor obtains an understanding of the entity and its environment, including its internal control for the purpose of assessing the risk of material misstatement. In performing that work, information may come to the auditor’s attention that should be considered in identifying risks of material misstatement due to fraud. As part of this work, the auditor should perform the following procedures to obtain information that is used (as described in AU section 316 paragraphs .35–.42) to identify the risks of material misstatement due to fraud:

   a. Make inquiries of management and others within the entity to obtain their views about the risks of fraud and how they are addressed. (See AU section 316 paragraphs .20–.27.)

   b. Consider any unusual or unexpected relationships that have been identified in performing analytical procedures in planning the audit. (See AU section 316 paragraphs .28–.30.)

   c. Consider whether one or more fraud risk factors exist. (See AU section 316 paragraphs .31–.33, the appendix to AU section 316, and paragraph 5.67 in this guide.)

   d. Consider other information that may be helpful in the identification of risks of material misstatement due to fraud. (See AU section 316 paragraph .34.)

5.69 In planning the audit, the auditor also should perform analytical procedures relating to revenue with the objective of identifying unusual or unexpected relationships involving revenue accounts that may indicate a material misstatement due to fraudulent financial reporting. For example, in the oil and gas producing activities industry, the following unusual or unexpected relationships may indicate a material misstatement due to fraud:

   1. Relationship of taxes withheld to oil sales and lease operating expenses, prior year refund experience, changes in the company’s status or types of wells, and fluctuations in production volumes.

   2. Reasonableness of prices and volumes underlying recorded revenues relative to actual market prices and historical production and current well performance.

   3. Unusual ownership or cost or risk sharing arrangements.


5.70 **Considering fraud risk factors.** As indicated in paragraph 5.68 item c, the auditor may identify events or conditions that indicate incentives or pressures to perpetrate fraud, opportunities to carry out the fraud, or attitudes or rationalizations to justify a fraudulent action. Such events or conditions are referred to as fraud risk factors. Fraud risk factors do not necessarily indicate the existence of fraud; however, they often are present in circumstances where fraud exists.

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5.71 AU section 316 provides fraud risk factor examples that have been written to apply to most enterprises. Paragraph 5.67 of this chapter contains a list of fraud risk factors specific to the oil and gas producing industry. Remember that fraud risk factors are only one of several sources of information an auditor considers when identifying and assessing risk of material misstatement due to fraud.

Identifying Risks That May Result in a Material Misstatement Due to Fraud

5.72 In identifying risks of material misstatement due to fraud, it is helpful for the auditor to consider the information that has been gathered in accordance with the requirements established in AU section 316 paragraphs .19–.34. The auditor’s identification of fraud risks may be influenced by characteristics such as the size, complexity, and ownership attributes of the entity. In addition, the auditor should evaluate whether identified risks of material misstatement due to fraud can be related to specific financial-statement account balances or classes of transactions and related assertions, or whether they relate more pervasively to the financial statements as a whole. Certain accounts, classes of transactions, and assertions that have high inherent risk because they involve a high degree of management judgment and subjectivity also may present risks of material misstatement due to fraud because they are susceptible to manipulation by management. Such items in the oil and gas industry may include:

- property costs (proven and unproven),
- costs withheld from amortization (full cost),
- interest capitalization,
- internal capitalization of direct costs (full cost),
- conveyances,
- abandonment costs,
- dry hole costs,
- wells in progress,
- depletion, depreciation, and amortization,
- capital cost limitations,
- joint interest payables,
- revenue distribution,
- borrowings from production purchasers,
- unapplied advances,
- production taxes payable,

A Presumption That Improper Revenue Recognition Is a Fraud Risk

5.73 Material misstatements due to fraudulent financial reporting often result from an overstatement of revenues (for example, through premature revenue recognition or recording fictitious revenues) or an understatement of revenues (for example, through improperly shifting revenues to a later period). Therefore, the auditor should ordinarily presume that there is a risk of material

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2 AU section 314 paragraph .102 states that the auditor should identify and assess the risk of material misstatement at the financial statement level and at the relevant assertion level related to classes of transactions, account balances, and disclosures.
misstatement due to fraud relating to revenue recognition (see AU section 316 paragraph .41).

A Consideration of the Risk of Management Override of Controls

5.74 Even if specific risks of material misstatement due to fraud are not identified by the auditor, there is a possibility that management override of controls could occur, and accordingly, the auditor should address that risk (see AU section 316 paragraph .57) apart from any conclusions regarding the existence of more specifically identifiable risks. Specifically, the procedures described in AU section 316 paragraphs .58–.67 should be performed to further address the risk of management override of controls. These procedures include (1) examining journal entries and other adjustments for evidence of possible material misstatement due to fraud, (2) reviewing accounting estimates for biases that could result in material misstatement due to fraud, and (3) evaluating the business rationale for significant unusual transactions.

Key Estimates

1. Estimates impacted by oil and gas reserve determinations:
   a. Depreciation, depletion and amortization
   b. Future development costs
   c. Future abandonment costs
   d. Properties withheld from amortization (full cost)
   e. Impairment or full cost ceiling limitation
2. Capital accruals
3. Lease operating expense accruals
4. Oil and gas revenue accruals
5. Unreceived production revenues and related production taxes

Assessing the Identified Risks After Taking Into Account an Evaluation of the Entity’s Programs and Controls That Address the Risks

5.75 Auditors should comply with the requirements established in AU section 316 paragraphs .43–.45 concerning an entity’s programs and controls that address identified risks of material misstatement due to fraud. Some examples of programs and controls in the oil and gas industry include the following:

1. A corporate mission statement and strong code of ethics with strict sanctions for any breach (for example, dismissal and prosecution for fraud)
2. Good employee relations (for example, fair compensation, counseling) and fair performance appraisal and review system
3. Employee screening and testing before hiring
4. Management acting as a good role model
5. Strong physical controls, particularly with respect to the company’s precious inventory or proprietary seismic or drilling information (for example, physical access restrictions (such as locks, alarms, security), surveillance, periodic and surprise counts)
6. Job descriptions, segregation-duplication of duties, and the like

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7. Mandatory annual vacations
8. Accounting reconciliations, especially inventory
9. Customer account statements, or confirmations, or both
10. No management override of controls
11. Supervisor awareness of fraud and the possibility of fraud
12. Supervisory review and approval
13. Supervisory performance, or independent checks, or both
15. A strong internal audit function, and periodic external audits.

5.76 The auditor should consider whether such programs and controls mitigate the identified risks of material misstatement due to fraud or whether specific control deficiencies exacerbate the risks. After the auditor has evaluated whether the entity’s programs and controls have been suitably designed and placed in operation, the auditor should assess these risks taking into account that evaluation. This assessment should be considered when developing the auditor’s response to the identified risks of material misstatement due to fraud.

Responding to the Results of the Assessment

5.77 AU section 316 paragraphs .46–.67 provide requirements and guidance about an auditor’s response to the results of the assessment of the risks of material misstatement due to fraud. The auditor responds to risks of material misstatement due to fraud in the following 3 ways:

   a. A response that has an overall effect on how the audit is conducted—that is, a response involving more general considerations apart from the specific procedures otherwise planned (see AU section 316 paragraph .50).
   
   b. A response to identified risks involving the nature, timing, and extent of the auditing procedures to be performed (see AU section 316 paragraphs .51–.56).
   
   c. A response involving the performance of certain procedures to further address the risk of material misstatement due to fraud involving management override of controls, given the unpredictable ways in which such override could occur (see AU section 316 paragraphs .57–.67 and paragraph 5.74.)

Evaluating Audit Evidence

5.78 AU section 316 paragraphs .68–.78 provide requirements and guidance for evaluating audit evidence. The auditor should evaluate whether analytical procedures that were performed as substantive tests or in the overall review stage of the audit indicate a previously unrecognized risk of material misstatement due to fraud. The auditor also should consider whether responses to inquiries throughout the audit about analytical relationships have been vague or implausible, or have produced evidence that is inconsistent with other audit evidence accumulated during the audit.

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3 AU section 318, Performing Audit Procedures in Response to Assessed Risks and Evaluating the Audit Evidence Obtained (AICPA, Professional Standards, vol. 1), states that the auditor should determine overall responses and design and perform further audit procedures to respond to the assessed risks of material misstatement at the financial statement and relevant assertion levels in a financial statement audit. See paragraphs .04 and .07 of AU section 318.
At or near the completion of fieldwork, the auditor should evaluate whether the accumulated results of auditing procedures and other observations affect the assessment of the risks of material misstatement due to fraud made earlier in the audit. As part of this evaluation, the auditor with final responsibility for the audit should ascertain that there has been appropriate communication with the other audit team members throughout the audit regarding information or conditions indicative of risks of material misstatement due to fraud.

Responding to Misstatements That May Be the Result of Fraud

When audit test results identify misstatements in the financial statements, the auditor should consider whether such misstatements may be indicative of fraud. See AU section 316 paragraphs .75–.78 for requirements and guidance about an auditor’s response to misstatements that may be the result of fraud. If the auditor believes that misstatements are or may be the result of fraud, but the effect of the misstatements is not material to the financial statements, the auditor nevertheless should evaluate the implications, especially those dealing with the organizational position of the person(s) involved.

If the auditor believes that the misstatement is or may be the result of fraud, and either has determined that the effect could be material to the financial statements or has been unable to evaluate whether the effect is material, the auditor should:

a. Attempt to obtain additional audit evidence to determine whether material fraud has occurred or is likely to have occurred and, if so, its effect on the financial statements and the auditor’s report thereon.4

b. Consider the implications for other aspects of the audit (see AU section 316 paragraph .76).

c. Discuss the matter and the approach for further investigation with an appropriate level of management that is at least one level above those involved, and with senior management and the audit committee.5

d. If appropriate, suggest that the client consult with legal counsel.

The auditor’s consideration of the risks of material misstatement and the results of audit tests may indicate such a significant risk of material misstatement due to fraud that the auditor should consider withdrawing from the engagement and communicating the reasons for withdrawal to the audit committee or others with equivalent authority and responsibility. The auditor may wish to consult with legal counsel when considering withdrawal from an engagement.

Communicating About Possible Fraud to Management, Those Charged With Governance, and Others

Whenever the auditor has determined that there is evidence that fraud may exist, that matter should be brought to the attention of an

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5 If the auditor believes senior management may be involved, discussion of the matter directly with those charged with governance may be appropriate.
appropriate level of management. See AU section 316 paragraphs .79–.82, for further requirements and guidance about communications with management, those charged with governance, and others.

**Documenting the Auditor’s Consideration of Fraud**

5.84 AU section 316 paragraph .83 establishes guidance regarding certain items and events that the auditor should document.

**Practical Guidance**

5.85 The AICPA Practice Aid *Fraud Detection in a GAAS Audit—Revised Edition* provides a wealth of information and help on complying with the provisions of AU section 316. This Practice Aid is an *other auditing publication* as defined in AU section 150. Other auditing publications have no authoritative status; however, they may help the auditor understand and apply other sections of the AICPA *Professional Standards*.

**Additional Audit Considerations**

5.86 As stated in paragraph .03 of AU section 339, *Audit Documentation* (AICPA, *Professional Standards*, vol. 1), the auditor must prepare audit documentation in connection with each engagement in sufficient detail to provide a clear understanding of the work performed (including the nature, timing, extent, and results of audit procedures performed), the audit evidence obtained and its source, and the conclusion reached. Audit documentation

a. provides the principal support for the representation in the auditor’s report that the auditor performed the audit in accordance with GAAS.

b. provides the principal support for the opinion expressed regarding the financial information or the assertion to the effect that an opinion cannot be expressed.

5.87 Audit documentation is an essential element of audit quality. Although documentation alone does not guarantee audit quality, the process of preparing sufficient and appropriate documentation contributes to the quality of an audit.

5.88 Audit documentation is the record of audit procedures performed, relevant audit evidence obtained, and conclusions the auditor reached. Audit documentation, also known as working papers or workpapers, may be recorded on paper or on electronic or other media. When transferring or copying paper documentation to another media, the auditor should apply procedures to generate a copy that is faithful in form and content to the original paper document.

5.89 Audit documentation includes, for example audit programs, analyses, issues memoranda, summaries of significant findings or issues, letters of confirmation and representation, checklists, abstracts or copies of important documents, correspondence (including email) concerning significant findings or issues, and schedules of the work the auditor performed. Abstracts or copies of the entity’s records (for example, significant and specific contracts and agreements) should be included as part of the audit documentation if they are needed.

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6 There may be legal, regulatory, or other reasons to retain the original paper document.

7 Paragraph .05 of AU section 311, *Planning and Supervision* (AICPA, *Professional Standards*, vol. 1), provides guidance regarding preparation of audit programs.
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to enable an experienced auditor to understand the work performed and conclusions reached. The audit documentation for a specific engagement is assembled in an audit file.

5.90 AU section 339 establishes requirements and provides guidance on the form, content, and extent of audit documentation. It also discusses how to document significant findings or issues. This section states that the auditor should record the preparer and reviewer of the audit work and the date such work was prepared and reviewed. In addition, it provides guidance on audit documentation of specific items tested, documentation when there is a departure from Statements on Auditing Standards, revisions to audit documentation made after the date of the auditor’s report, and the ownership and confidentiality of audit documentation. See AU section 339 for specific guidance.

Considerations for Audits Performed in Accordance with PCAOB Standards

PCAOB Auditing Standard No. 3, Audit Documentation (AICPA, PCAOB Standards and Related Rules, Rules of the Board, "Standards"), establishes the requirements for documentation required for audits performed in accordance with PCAOB standards.

Tax and Other Regulatory Matters

5.91 Various tax and other regulatory matters can have a significant impact on an oil and gas company’s financial statements. The auditor should make inquiries about the status of federal and state income tax matters and severance and property-tax reporting matters. The auditor should also review the determination of the producer’s status as an independent producer because of the substantial impact such a determination can have on income tax liabilities. (See discussion under “Depletion” in paragraphs 3.07–.10.) In addition, the auditor may consider certain inquiries concerning taxes. These include

- status of depository or withholding requirements and compliance with applicable reporting requirements.
- procedures used to test the accuracy of amounts withheld or deposited and to compute amounts refundable.
- the company’s reporting responsibility because of its role as general or managing partner in existing partnerships.

Other regulatory matters include

- pricing procedures used in, and personnel responsible for, compliance with applicable statutes and regulations.
- reporting to state regulatory authorities (which states are involved, what reports are filed, what procedures are used to accumulate applicable data, and so on).

Unique Audit Procedures for Oil and Gas Producing Entities

5.92 This section identifies and discusses certain audit considerations of some of the business functions and accounts unique to oil and gas producing
The procedures selected to achieve the particular audit objectives may be adapted to the specific circumstances of the company. In accordance with AU section 318 paragraph .07, the nature, timing, and extent of these procedures should be based on the auditor’s assessment of the risks of material misstatements at the assertion level. The areas discussed include property, receivables, payables, expenses, revenues, and other considerations.

**Property**

5.93 Property generally represents the largest item in the balance sheet and is often the most difficult to test. Reliance is often placed on estimates by the company’s operations department and management assertions. AU section 342, *Auditing Accounting Estimates* (AICPA, *Professional Standards*, vol. 1), provides additional guidance on auditing accounting estimates. The following are several areas that may deserve special attention in the tests of oil and gas property accounts:

- Property costs
- Interest capitalization
- Materials and supplies
- Timing of drilling activities and evaluation of unproved properties
- Conveyances
- Abandonment costs
- Dry hole costs
- Wells in progress
- Depletion, depreciation, and amortization
- Capital cost limitations

5.94 Property costs. Joint interest owners share in acquisition, exploration, development, and production costs in accordance with the cost-sharing provisions of the joint operating agreement. Carried and reversionary interest provisions (among many other similar arrangements) often cause the sharing of costs to be different from the permanent lease ownership. The auditor should obtain an understanding of the cost-sharing provisions of each property selected for testing in order to effectively audit property costs.

5.95 For cost-control purposes, an AFE is prepared for most exploratory and development drilling activities and major projects undertaken by joint interests. The AFE gives the operator approval to incur specified dollar amounts in accomplishing agreed-upon tasks. The auditor may compare actual costs incurred by the operator with AFE amounts for evidence of unauthorized or excessive expenditures. Indications of potential charges or credits from joint interest audits impeding or in progress should be evaluated in accordance with Financial Accounting Standards Board (FASB) Statement No. 5, *Accounting for Contingencies*.

5.96 Depreciation of support equipment and facilities used in oil and gas producing activities is properly accounted for as exploration, development, or production costs, depending on the activity with which the support equipment or facilities are involved. The auditor should consider appropriate audit procedures to determine that depreciation of support equipment is properly allocated based on the nature of the activity.
A standard procedure in auditing property accounts of any commercial enterprise is testing physical existence. Physical examination of many types of oil and gas property is sometimes impractical and often alternative procedures are performed. For instance, producing wells are frequently too widely dispersed and too numerous to be examined. Alternately, the auditor may examine production records maintained by the operations department to determine that production proceeds were being received on the property as of the end of the period. Likewise, leasehold rights are intangible, and ownership is evidenced only through a lease or assignment document. Absolute verification of the company’s ownership in a lease would require a title search—a time-consuming and expensive process. For this reason, the auditor may test ownership by examining a lease agreement and lease file. Additionally, examination of a delay rental payment is further evidence of the company’s retention of its interest in the lease. The auditor may also obtain signed representations that the subject lease was not sold, assigned, or otherwise disposed of during the period.

Interest capitalization. In determining whether capitalized interest is properly accounted for, the auditor should check that the qualifying assets have not previously entered the earnings activities of the company and determine that interest capitalized is properly computed.

Materials and supplies. Operators of oil and gas properties often hold or have materials and supplies (production equipment inventory) stored by independent storage yards for use in future drilling activities and operations. Frequently, equipment will be transferred to a property in which the operator has an interest. The operator charges the joint account for the equipment and bills nonoperating interest owners for their share of the equipment pursuant to the joint operating agreement. Likewise, equipment is often transferred back to a storage yard upon the abandonment of a well. The operator issues credit to the nonoperating interest owners for their share of the condition value attached to the equipment as dictated by the accounting procedures supplement to the joint operating agreement. The auditor may consider procedures to identify equipment movements and test the propriety of the accounting treatment for such movements. Depending on the extent of controls in effect, the auditor may confirm the existence of equipment with independent yards or may consider it necessary to observe the taking of a physical inventory. The auditor should determine that materials and supplies are not carried at amounts in excess of the amounts recoverable in the normal course of business through use by the operator or recovery through operating agreements; the auditor should also review for obsolescence. When materials and supplies are held for sale, the usual lower-of-cost-or-market testing should be applied.

Conveyances. Oil and gas property conveyances can take a variety of forms, each of which may be unique. The auditor should evaluate the accounting treatment of conveyance transactions in accordance with the conveyance provisions of FASB Statement No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, and Regulation S-X. The auditor should also be aware of the considerable differences between the financial accounting and income tax treatments of conveyances in the review of the company’s income tax accrual.

Abandonment costs. Accounting for abandoned wells and leases is discussed under “Production” in paragraphs 2.95–135. For abandoned, unproved leases that are not expiring under their own terms, the auditor may
obtain representations\(^8\) from the company (1) that it does not intend to promote, develop, or sell the lease, or to pay future delay rentals when they come due and (2) that it has all necessary approvals. For leases that expire under their own terms or because of failure to perform drilling obligations, the auditor should consider appropriate procedures to determine that the company no longer has an interest in the lease and that the company has properly approved and recorded the abandonment. When wells are abandoned, the operator is required to file a plugging report with the appropriate state governmental agency. The auditor may examine the plugging report to substantiate the abandonment of the well and, where applicable, determine that proper credit was granted to joint owners for salvageable lease and well equipment.

5.102 **Dry hole costs.** Under the successful efforts method of accounting, dry hole costs of an exploratory well are expensed when a determination is made that the well has no proved reserves. The auditor may substantiate the success or failure of a drilling effort by examining drilling reports from the drilling company (or operator for nonoperating interest owners). If drilling reports are unavailable, the auditor may examine a plugging report filed by the operator as support of the unsuccessful outcome of a well.

5.103 **Wells in progress.**\(^9\) The accounting treatment for costs associated with exploratory wells in progress at the end of a reporting period is unique only under the successful efforts method. Costs of an exploratory well that has not found proved reserves should be expensed. The auditor uses all information available in evaluating the status of an exploratory well as of the report date. Occasionally, a well is drilled and it cannot be immediately determined whether the property has proved reserves. This often happens because the property appears marginally economical or a major capital expenditure is required before production can begin. Usually, if a decision about the economic viability of a well cannot be made within one year, the well would be considered impaired and the costs charged to expense. A well requiring a major capital expenditure is carried as an asset only if the well has a sufficient quantity of reserves to justify its completion. If the drilling of additional wells is necessary to determine if reserves are sufficient, the company decides whether it is warranted to incur the additional capital expenditures. In addition, the drilling of the wells must have commenced or be firmly planned in the future in order to be carried as an asset.

\(^8\) AU section 333, *Management Representations* (AICPA, *Professional Standards*, vol. 1), establishes a requirement that an auditor, performing an audit in accordance with generally accepted auditing standards, obtain written representations from management for all financial statements and periods covered by the auditor’s report. AU section 333 also provides guidance concerning the representations to be obtained, along with an illustrative management representation letter.

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The auditor evaluates all available information to determine if capitalization of costs is proper under the previous criteria.

5.104 Depletion, depreciation, and amortization (DD&A). The methods used in computing DD&A under the full cost and successful efforts methods are discussed under “Production” in paragraphs 2.95–135. The key to auditing DD&A is to substantiate the DD&A rate and the DD&A cost base to which the rate is applied. In testing the DD&A rate, the auditor may inquire about the methods and bases used in the reserve study and their consistency with other available information. Current-year production quantities may be tested in conjunction with the testing of oil and gas production revenues. The cost base to which the DD&A rate is applied pertains to each cost center under the full cost method and on a property-by-property or an aggregation-of-properties basis under the successful efforts method. The auditor should test the cost base used in the computation and determine if all costs excluded from the cost base are properly excludable. The full cost method requires including estimated future development costs in the company’s cost base. The auditor should review the company’s estimated future development costs; determine if they are reasonable, given estimated future development activity; and compare them to the reserve report. The auditor should also determine whether these costs are based on current costs.

5.105 Unproved properties are periodically assessed to determine if they have been impaired. (Accounting for impairment of unproved property costs is discussed under “Acquisition of Mineral Properties” in paragraphs 2.01–34.) The auditor should review the company’s procedures in providing for impairment and evaluate the adequacy of the provision. In evaluating the adequacy of the impairment provision, the auditor may use such information as the company’s drilling plans, dry holes drilled in areas near the company’s leases, and lease expiration dates, because it is more likely that impairment exists on leases whose expiration dates are approaching. Top leases may be impaired by drilling activities of the original lessee, whether successful or not.

5.106 Capital cost limitations. The full cost method prescribes a ceiling test for capitalized costs. The auditor should review the components of the cost ceiling computation to determine that they are computed in accordance with the prescribed guidelines. The rationale behind the ceiling test is that oil and gas property costs should be recoverable from the underlying assets. Therefore, any capitalized costs—net of accumulated DD&A and related deferred income taxes—in excess of the ceiling are written off to expense. In those situations where costs approach or exceed the ceiling, it may be advisable to consider consultation with independent outside specialists.

5.107 Impairment of proved properties for a successful efforts company is based on the provisions of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. (See paragraph 1.55 of this guide for further information.) The auditor should consider audit procedures to be applied for testing impairment of long-lived assets.

10 Securities and Exchange Commission Staff Accounting Bulletin (SAB) No. 100, Restructuring and Impairment Charges, provides guidance regarding the accounting for and disclosure of certain expenses commonly reported in connection with exit activities and business combinations. SAB No. 103, Update of Codification of Staff Accounting Bulletins, among other matters, has updated SAB No. 100 to reflect the provisions of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets.

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Receivables

5.108 The general approach in auditing receivables from oil and gas producing activities is in many respects similar to that followed in auditing receivables of commercial enterprises. The confirmation of accounts receivable is a useful procedure for most accounts; however, special consideration may be given to the performance of additional or alternative audit procedures in the following areas:

- JIBs
- Joint interest credits
- Oil and gas sales
- Production imbalances
- Cash calls
- Collectibility

5.109 Joint interest billings. The operator can normally confirm from nonoperating interest owners the JIB balance as of the audit date; however, the validity of joint interest receivables is often dependent solely on the operator’s accuracy in preparing the underlying JIBs. Accordingly, the auditor of the operator may perform procedures to test (a) the validity and accuracy of the charges supporting the JIB statements and (b) the percentages charged to nonoperating interest owners. At the audit date the property operator may have incurred obligations on behalf of the joint owners that have not been billed. These unbilled obligations also represent JIB receivables that, if not confirmed, may be tested by the auditor.

5.110 Joint interest credits. Nonoperating parties normally have the right to audit the accounts and records of the operator relating to the joint account. These audits often result in credits being granted to nonoperating parties. The nonoperator’s auditor should determine whether the nonoperator has recorded accounts receivable for credits granted and evaluate possible credits from audits in progress or impending in accordance with the gain-contingency provisions of FASB Statement No. 5. These procedures also apply to the audit of accounts payable of an operating company where the operator is subject to issuance of potential joint interest credits.

5.111 Oil and gas sales. Oil and gas production sales are generally recorded from run tickets or remittance advices received from purchasers of the production. Remittance advices are usually received from one to three months after the purchaser takes control of the production. Oil and gas revenue transactions may be recorded on a cash basis; however, the company should accrue estimated unreceived production revenues and related production taxes at the financial statement date. Such estimates consider production volumes, revenue interests, sales price histories, and appropriate deductions. The auditor should test the accrual through appropriate means. For example, the auditor may verify production quantities used in the estimate to independent production records (or run tickets, if available), compare revenue interest or royalty interest percentages with appropriate division orders, and substantiate the reasonableness of sales prices and tax withholdings used in the accrual.

5.112 Production imbalances. Oil and gas production from a property is usually sold to purchasers for the benefit of all joint owners of that property.
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The purchasers then usually remit the sales proceeds to joint owners in accordance with the distribution provisions of the division order covering the property. Most standard joint operating agreements allow joint owners the option of taking their share of production in kind rather than having it sold to purchasers on their behalf. Where revenue interest owners take their share of production in kind, it is likely that the owners have taken more (overlift) or less (underlift) production than they are entitled to as of the audit date. The auditor should review the company's entitlement computation and may use confirmation procedures to substantiate any production imbalance receivables or payables recorded at the audit date.

5.113 Cash calls. Under the provisions of most joint operating agreements the operator of a property generally requires nonoperating interest owners to advance their share of the estimated cash outlay for the succeeding month's drilling activities and producing-property operations of the joint account. In these cases, the operator is entitled to these advances upon proper notification to the nonoperating interest owners. Where applicable, the auditor may confirm cash calls receivable with nonoperating interest owners. The auditor may also review the operator's computations supporting the cash call to determine if the amounts requested approximate anticipated expenditures for operations in the following month.

5.114 Collectibility. Collectibility of joint interest accounts receivable in the oil and gas industry traditionally has not been a problem because of the remedies available to operators in the event of nonpayment or default. Operators have a preferred lien on the ownership interest of nonoperating parties. Under the provisions of the standard operating agreement, the operator can collect from oil and gas purchasers the proceeds accruing to the interest of the delinquent party up to the amount owed. Where it appears that an operator will have to collect amounts due in this manner, the auditor should determine that the delinquent party's share of future proceeds will cover the uncollected balance and the appropriate balance sheet classification. Disputes can arise over joint interest ownership percentages in oil and gas production and requested natural gas pricing classifications can be disallowed by the Federal Energy Regulatory Committee. The auditor should inquire of company management whether such disputes or potential disallowances exist and perform appropriate audit procedures to determine that the effect of any such disputes is properly reflected or disclosed in the financial statements. Collectibility is a more serious problem when wells are plugged and abandoned or are only marginally economical, particularly if one or more of the nonoperators has financial difficulties. The operator may have the right under the operating agreement to rebill all operating interest owners for their proportionate share of the unpaid costs.

Payables

5.115 Liabilities related to oil and gas producing activities are in many ways similar to those of a typical commercial enterprise. Accordingly, procedures in these areas are not necessarily unique; however, certain liabilities deserve special attention because of their peculiarity to the oil and gas industry. Many of these liabilities arise from the various everyday activities and transactions between operators and nonoperators of joint properties. The following are some of the more unusual areas:

- Joint interest payables
- Revenue distribution
Auditing

- Borrowings from production purchasers
- Unapplied advances
- Production taxes payable

5.116 Joint interest payables. JIBs sent to nonoperating interest owners from operators generally provide very little detail about the timing of exploration, development, and production expenditures incurred by the operator. Therefore, these JIBs may not be useful when nonoperating parties accrue accounts payable as of the audit date. Nonoperating interest owners accrue these expenditures based on the best available information from the company’s operations department (or from the operator if more accessible). Usually, such information can be adequately estimated from a schedule of AFEs, which details all open AFEs, AFE costs, the company’s working interest in the related properties, and the completion percentage of each AFE. The auditor should consider appropriate audit procedures to substantiate the completeness of the schedule of open AFEs and review the AFE data contained in the schedule with operations personnel for reasonableness.

5.117 Revenue distribution. Production revenues generated from a property are distributed by purchasers in accordance with the provisions of the division order executed by the joint owners of the property. Joint owners often collect production proceeds on behalf of other joint or royalty owners and make appropriate disbursements to them on a periodic basis. At the audit date, a proper cutoff is important. The party designated to collect such proceeds accrues accounts receivable (revenues net of tax withholdings) with an offset to a payable-to-royalty-owner’s account. Depending on taxing jurisdiction regulations or contractual agreements, the responsibility for payment of severance or production taxes may lie with the purchaser, the operator, or the working interest owners individually. Occasionally, proceeds collected are in dispute and are recorded in a suspense account. This type of liability is not relieved until the dispute is resolved. The auditor should consider appropriate audit procedures to identify those properties on which the company collects revenues on behalf of royalty and other joint owners. Special attention may be given to suspense payables, as they may accumulate over extended periods of time before the underlying disputes are resolved.

5.118 Under the terms of many lease agreements, lessors are entitled to shut-in well payments, mandatory or minimum royalty payments, and payments of a similar nature. As of the balance sheet date, lessees accrue such mandatory payments to lessors. The auditor may identify potential obligations and determine their proper treatment in the financial statements by interviewing operations personnel and performing audit procedures.

5.119 Borrowings from production purchasers. Enterprises seeking sources of oil and gas supplies sometimes advance cash to property owners to finance exploration or development. The auditor may confirm borrowings and thus be satisfied that the terms of the borrowing arrangement have been complied with. The auditor may consider tests to determine the substance of the transactions involving advances from purchasers because they sometimes take the form of mineral sales whose treatment is addressed under “Conveyances” in paragraphs 2.136–.148.

5.120 Unapplied advances. As discussed previously, property operators may call nonoperating parties for cash advances to cover the estimated expenditures to be incurred in the following month’s operations. As the operator...
incurs expenditures on behalf of nonoperating interest owners, their share of the expenditures is applied against advances received. Unapplied advances as of the financial statement date are liabilities to nonoperating interest owners and may be confirmed by the auditor. Joint interest owners will usually be able to confirm only the advances made to the operator, less reductions for their share of expenditures incurred as represented on JIBs received from the operator. The validity of JIBs depends on the operator’s accuracy in preparing them. The nonoperator’s auditor may consider procedures to test the reasonableness of the JIB statements.

5.121 Production taxes payable. Production taxes are payable to state or other governmental agencies by either the purchaser or producer as determined by state or other governmental agencies. Where the producer is liable for the taxes, the operator usually pays production taxes on behalf of all joint interest owners. The auditor should determine that the operator has properly recorded the liability for state taxes and test the propriety of recorded production taxes payable.

Expenses

5.122 This section deals with expenditures and other charges (a) that are classified as expenses under both the successful efforts and full cost methods and (b) that are unique to the oil and gas industry. This section does not deal with expenses arising from the amortization or write-off of assets such as abandonment expenses, depletion and depreciation expense, amortization expense, and the like. (These expenses are dealt with under “Property” in paragraphs 5.93–107.) Two types of related expenses are (a) work-over expense, and (b) district and warehousing expenses and administrative overhead.

5.123 Work-over expense. AFEs may be prepared for well work-overs where charges are expected to exceed a minimum amount. In determining the nature of well work-overs and testing the propriety of the company’s classification of the work-over charges as capital or expense items, the auditor may compare actual charges with the AFE (where an AFE has been prepared), and make a determination and evaluation of any apparent excessive or unauthorized charges.

5.124 Overhead. The operator of a property is usually entitled to be paid by the joint venture for certain overhead charges as compensation for administrative, supervisory, office service, and warehousing costs. The accounting procedures supplement to the joint operating agreement specifies the types and often the amount of charges that can be allocated to the joint account for such overhead. The nonoperator’s auditor may consider procedures (1) to test the reasonableness of the allocated charges under the accounting procedures supplement and (2) to test that the company was charged for its proper share of the expenses.

Revenues

5.125 Revenues from oil and gas producing activities are typically of two types: production revenues and property conveyances. The following are items that may be considered by the auditor in conducting an audit of these revenues:

- Sharing-in and accountability for oil and gas sales
- Pricing regulations and contractual agreements (including settlement of hedging contracts)
- Property conveyances

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Auditing

- Revenue accumulation
- Take-or-pay contracts

5.126 *Sharing-in and accountability for oil and gas sales.* Oil and gas sales may be recorded from purchase remittance advices received from oil and gas purchasers. The auditor may perform tests to determine if production quantities on which sales proceeds were received agree to independent production records that have been maintained by the operations department to substantiate that the company is receiving its proper share of revenues generated from a property or properties. The sharing of oil and gas production revenues by joint owners can be affected by a number of different arrangements. For instance, many joint interest drilling ventures call for joint interest owners to drill a free well or incur a higher percentage of the drilling costs (carried interest) than their permanent ownership interest in the property in return for contributions (for example, leasehold and exploration expenses) by other joint interest owners in the venture. Often these joint interest owners are entitled to all or to a proportionately higher interest in generated production revenues until they recover a specified amount of costs. When these costs are recovered, their revenue interest reverts to their permanent interest in the property.

5.127 Another common arrangement occurs when a joint interest owner declines participation (nonconsents) in drilling, deepening, completing, plugging back, or reworking a well. The consenting parties then incur proportionately higher costs to perform the specified task and, accordingly, are entitled to all of the nonconsenting parties' interest in generated revenues until they recover a predetermined percentage of their actual costs incurred. This percentage is commonly in excess of 100 percent of actual costs to compensate the consenting parties for their risk in the venture.

5.128 Various other such arrangements exist that can alter the sharing of revenues. The auditor may examine division orders and other substantive evidence to test the propriety of the company’s revenues. Testing oil and gas revenues may often be accomplished in conjunction with tests of oil and gas properties by determining that revenue recorded, if any, is reasonable in relation to the status of the property, the engineering reports, and the historical records.

5.129 *Pricing regulations and contractual agreements.* Oil and gas producing activities are subject to complex pricing and tax regulations governing oil and gas sales. In testing oil and gas revenue, the auditor may consider procedures to determine if the company is receiving maximum allowable prices (in some cases the market will not bear the maximum allowable price) or prices in excess of existing price ceilings, which may result in future refunds. In first-year audits, compliance procedures may assist in determining if potential refunds exist from excessive prices received from prior year oil and gas sales.

5.130 Natural gas producers may contract with purchasers to sell certain quantities of their production at specified prices. The auditor may test the prices received for natural gas to determine (a) if they agree with the terms of related contracts and (b) if they comply with applicable regulations.

5.131 *Property conveyances.* Accounting for oil and gas property conveyances is complex, and the auditor may review oil and gas property conveyances to determine if they are recorded in accordance with their underlying substance and applicable accounting pronouncements. From a revenue standpoint, the primary concern in testing conveyances is to determine that

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the company is immediately recognizing or deferring income, as appropriate. Although the accounting treatments are complex, audit procedures necessary to test conveyance transactions are not particularly unusual and will not be discussed further here. Future obligations that often accompany conveyance transactions may affect the accounting treatment and the possible need for footnote disclosure. It is important that the auditor obtain an understanding of the economics of the transaction to properly evaluate the accounting treatment.

5.132 Revenue accumulation. Oil and gas producing companies generally should accumulate revenue and expense data on a property-by-property basis. Financial data on a detail property basis are needed for several reasons, including royalty payments, percentage depletion computations, income tax obligations, and internal decision-making concerning the economics of individual properties. Since the auditor is concerned with this same data for auditing purposes, tests to determine that detail property data are properly accumulated may be considered. The auditor may then be able to rely on this financial data in other related audit areas.

5.133 Take-or-pay contracts. Sometimes gas producers and purchasers execute agreements whereby a purchaser agrees to take or pay for a minimum quantity of gas per year. Usually, any amount paid in excess of the price of gas taken is recoverable from future purchases in excess of minimum quantities. If the purchaser is not allowed to make up deficiencies, it is appropriate for the producer to record revenues to the extent of the minimum contracted quantity, assuming payment has been received or is reasonably assured. If deficiencies can be made up, receipts in excess of actual sales should be recorded as deferred revenues until production is actually taken or the right to make up deficiencies expires. The auditor should examine such contracts to determine the propriety of the accounting treatment and to identify possible contingencies. In addition, these contracts may impose an obligation on the producer to furnish a minimum amount of product. To the extent such product cannot be produced from the property, the producer may have a contingent liability to obtain the product from third parties. The auditor should evaluate such contingencies for possible losses or disclosure.

Auditing Fair Value Measurements

5.134 AU section 328, Auditing Fair Value Measurements and Disclosures (AICPA, Professional Standards, vol. 1), establishes standards and provides guidance on auditing fair value measurements and disclosures contained in financial statements. In particular, it addresses audit considerations relating to the measurement and disclosure of assets, liabilities, and specific components of equity presented or disclosed at fair value in financial statements. Fair value measurements of assets, liabilities, and components of equity may arise from both the initial recording of transactions and later changes in value.11 Auditing Interpretation No. 1, “Auditing Interests in Trusts Held by a Third-Party Trustee and Reported at Fair Value,” of AU section 328 (AICPA, Professional Standards, vol. 1, AU sec. 9328 par. 01–.04), provides additional guidance for auditing interests in trusts held by a third-party trustee. It states that

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11 FASB Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities—Including an amendment of FASB Statement No. 115, creates a fair value option under which an entity may irrevocably elect fair value as the initial and subsequent measurement attribute for certain financial assets and financial liabilities on a contract-by-contract basis, with changes in fair value recognized in earnings as those changes occur. See paragraphs 1.92–.94 of this guide for additional discussion of FASB Statement No. 159.
in circumstances in which the auditor determines that the nature and extent of auditing procedures should include verifying the existence and testing the measurement of investments held by a trust, simply receiving a confirmation from the trustee, either in aggregate or on an investment-by-investment basis, does not in and of itself constitute adequate audit evidence with respect to the requirements for auditing the fair value of the interest in the trust under AU section 328. In addition, receiving confirmation from the trustee for investments in aggregate does not constitute adequate audit evidence with respect to the existence assertion. Receiving confirmation from the trustee on an investment-by-investment basis, however, typically would constitute adequate audit evidence with respect to the existence assertion. In circumstances in which the auditor is unable to audit the existence or measurement of interests in trusts at the financial statement date, the auditor should consider whether that scope limitation requires the auditor to either qualify his or her opinion or to disclaim an opinion, as discussed in paragraphs .22–.26 of AU section 508, Reports on Audited Financial Statements (AICPA, Professional Standards, vol. 1).

5.135 The auditor should obtain sufficient competent audit evidence to provide reasonable assurance that the fair value measurements and disclosures are in conformity with GAAP, which requires that certain items be measured at fair value. FASB Statement of Financial Accounting Concepts No. 7, Using Cash Flow Information and Present Value in Accounting Measurements, defines the fair value of an asset (liability) as “the amount at which that asset (or liability) could be bought (or incurred) or sold (or settled) in a current transaction between willing parties, that is, other than in forced or liquidation sale.” Although GAAP may not prescribe the method for measuring the fair value of an item, it expresses a preference for the use of observable market prices to make that determination. In the absence of observable market prices, GAAP requires fair value to be based on the best information available in the circumstances.

5.136 Management is responsible for making the fair value measurements and disclosures included in the financial statements. As part of fulfilling its responsibility, management needs to establish an accounting and financial reporting process for determining the fair value measurements and disclosures, select appropriate valuation methods, identify and adequately support any significant assumptions used, prepare the valuation, and ensure that the presentation and disclosure of the fair value measurements are in accordance with GAAP.

5.137 Fair value measurements for which observable market prices are not available are inherently imprecise. That is because, among other things, those fair value measurements may be based on assumptions about future conditions, transactions, or events whose outcome is uncertain and will therefore be subject to change over time. The auditor is not responsible for predicting future conditions, transactions, or events that, had they been known at the time of the audit, may have had a significant effect on management’s actions or management’s assumptions underlying the fair value measurements and disclosures.

5.138 Assumptions used in fair value measurements are similar in nature to those required when developing other accounting estimates. However, if observable market prices are not available, GAAP requires that valuation

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12 FASB Statement No. 157, Fair Value Measurements, defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. See paragraphs 1.76–.91 of this guide for additional discussion of FASB Statement No. 157.

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Methods incorporate assumptions that marketplace participants would use in their estimates of fair value whenever that information is available without undue cost or effort. If information about market assumptions is not available, an entity may use its own assumptions as long as there are no contrary data indicating that marketplace participants would use different assumptions. These concepts generally are not relevant for accounting estimates made under measurement bases other than fair value. AU section 342 provides guidance on auditing accounting estimates in general. AU section 328 addresses considerations similar to those in AU section 342, as well as others in the specific context of fair value measurements and disclosures in accordance with GAAP.

5.139 The auditor should obtain an understanding of the entity’s process for determining fair value measurements and disclosures and of the relevant controls sufficient to develop an effective audit approach. AU section 328 paragraph .12 gives the auditor examples he or she considers when obtaining an understanding of the entity’s process.

5.140 AU section 328 paragraphs .20–.22 discusses that the auditor should consider whether to engage a specialist and use the work of that specialist as audit evidence in performing substantive tests to evaluate material financial statement assertions. The auditor may have the necessary skill and knowledge to plan and perform audit procedures related to fair values or may decide to use the work of a specialist. If the use of such a specialist is planned, the auditor should consider the guidance in AU section 336.

5.141 As stated in AU section 328 paragraph .23, based on the auditor’s assessment of the risks of material misstatement, the auditor should test the entity’s fair value measurements and disclosures. Substantive tests of the fair value measurements may involve (a) testing management’s significant assumptions, the valuation model, and the underlying data (see AU section 328 paragraphs .26–.39), (b) developing independent fair value estimates for corroborative purposes (see AU section 328 paragraph .40), or (c) reviewing subsequent events and transactions (see AU section 328 paragraphs .41–.42).

5.142 The auditor uses both the understanding of management’s process for determining fair value measurements and his or her assessment of the risks of material misstatement to determine the nature, timing, and extent of the audit procedures. The following is an example of a consideration in the development of audit procedures. In some situations in the oil and gas industry, additional procedures, such as the inspection of an asset by the auditor, may be necessary to obtain sufficient competent audit evidence about the appropriateness of a fair value measurement. For example, inspection of the asset may be necessary to obtain information about the current physical condition of the asset relevant to its fair value, or inspection of a security may reveal a restriction on its marketability that may affect its value.

5.143 Auditors should refer to AU section 328 paragraphs .43–.46 for disclosures about fair values. AU section 328 paragraphs .48–.49 discusses additional management representations about fair value measurements and disclosures the auditor may wish to include.

Other Audit Considerations

5.144 Other audit considerations in auditing oil and gas companies include nonoperators, joint ventures and partnerships, and reserve quantity and value disclosures.
5.145 Nonoperators. A company with direct investments in oil and gas producing activities generally should maintain its own controls and accountability for nonoperators’ properties. However, in some instances, particularly when the nonoperator is a passive investor with little or no industry experience, the company may not have the personnel or procedures to provide adequate oversight over costs and revenues related to nonoperated properties. In these instances, it may be necessary for the auditor to extend the audit tests to achieve the necessary level of assurance with respect to the recorded amounts.

5.146 The auditor may, in rare instances, encounter situations in which the nonoperator does not have sufficient documentation to establish the reasonableness of recorded amounts with respect to oil and gas producing activities. Normally, sufficient documentation may be obtained from the operator to provide the support for the recorded amounts or to enable the necessary adjustments to be made. As an alternative, it may be more efficient for the auditor to visit the operator and examine directly the accounting records related to the specific properties. Examples of some of the audit procedures that may be performed through requesting additional documentation or visiting the operators’ office include:

- examining third-party charges to support JIBs or revenue distributions to the nonoperator.
- examining land department records to ensure timely payments of delay rentals and timely receipt of title opinions and curatives.
- reviewing operating agreements to ensure that overhead and similar charges are in compliance with those documents.
- reviewing division orders and comparing with operators’ disbursements of revenues to the various interest owners to determine that revenues from production have been properly allocated and remitted to the royalty and working interest owners.

5.147 Joint ventures. The unincorporated joint venture is the most prevalent type of joint interest arrangement used by companies to share the risk of exploring for and developing oil and gas properties. An interpretation of Accounting Principles Board Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock, states that pro rata consolidation of the assets, liabilities, revenues, and expenses of unincorporated joint ventures is often used where it is established industry practice, as is the case in the oil and gas industry. The auditor may review and understand the structure of unincorporated joint ventures to determine if the company accounts for its investment in such joint ventures properly.

5.148 Reserve quantity and value disclosures. Public companies with oil and gas producing activities are required by the SEC and FASB to present certain supplementary reserve quantity and reserve value information outside of the basic financial statements. Although this supplementary information is not required to be audited, it is required to be disclosed by FASB Statement No. 69, Disclosures about Oil and Gas Producing Activities—an amendment of FASB Statements 19, 25, 33, and 39. The contents of the supplementary reserve quantity and reserve value disclosure information are defined in FASB Statement No. 69. AU section 558, Required Supplementary Information (AICPA, Professional Standards, vol. 1), and Auditing Interpretation No. 1, “Supplementary Oil and Gas Reserve Information,” of AU section 558 (AICPA, Professional Standards, vol. 1, AU sec. 9558 par. .01–.06), indicates that the auditor
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should perform certain procedures with respect to the reserve information. AU section 558 paragraph .09 states that in conjunction with the audit of the financial statements, the auditor may subject the supplementary information to certain auditing procedures. If the procedures are sufficient to enable the auditor to express an opinion on whether the information is fairly stated in all material respects in relation to the financial statements taken as a whole, the auditor may expand the audit report in accordance with paragraph .07 of AU section 550, Other Information in Documents Containing Audited Financial Statements (AICPA, Professional Standards, vol. 1).

5.149 The auditor’s objectives in applying procedures to supplementary reserve disclosures may include

- determining that the supplementary information prepared by the company is in conformity with prescribed guidelines and is presented in a manner consistent with prior year presentations
- determining that reserve quantity estimates are prepared by persons with appropriate qualifications
- determining that the reserve information is consistent with the information in the underlying financial statements

5.150 To meet these objectives, the auditor should apply the procedures specified in AU section 558 and AU section 9558 cited previously. Performing those limited procedures, along with any additional procedures the auditor considers necessary, may provide an adequate basis in determining whether the reserve quantity and reserve value information is presented in accordance with prescribed guidelines. However, an additional consideration may be appropriate. Independent reservoir engineers often use and rely on information, without corroboration, provided by the company in formulating their reserve quantity information. This information includes listings of the company’s properties, the company’s ownership interest in the properties, production data, prices, and so on. The auditor should consider appropriate tests to determine if the information provided to the reservoir engineer is complete. Because the supplementary information is unaudited, the auditor need not refer to the supplementary information in the auditor’s report on the financial statements, except in any of the following circumstances:

- The supplementary information that GAAP requires to be presented in the circumstances is omitted.
- The auditor has concluded that the measurement or presentation of the supplementary information departs materially from the prescribed guidelines.
- The auditor is unable to complete the prescribed procedures.
- The auditor is unable to remove substantial doubts about whether the supplementary information conforms to prescribed guidelines.

5.151 The auditor evaluates the reasonableness of the supplementary information based on the performance of the limited procedures and determines whether an appropriate expansion of the report is needed.

Attest Engagements on Greenhouse Gas Emissions Information

5.152 U.S. companies with operations in countries that have ratified the Kyoto Protocol may have to meet emission reduction targets in those countries once the Kyoto Protocol becomes effective. Consideration of alternative
strategies and related costs will enable those companies to find the lowest-cost alternative before triggering the imposition of requirements and any related fines. Emissions trading is considered to be an effective, cost-efficient way to meet limits imposed by regulators, especially toward the end of a compliance period.

5.153 In addition, there is a sense among many companies that even though they will not be subject to the Kyoto Protocol in the United States, at some point a regulatory framework that places a limit on greenhouse gases (GHG) emissions may be adopted. These companies take the view that it would be wise to start planning and preparing for a “carbon-constrained” future and eventually take advantage of the potential opportunities that GHG emissions trading presents.

5.154 In September 2003 the Auditing Standards Board issued Statement of Position (SOP) 03-2, Attest Engagements on Greenhouse Gas Emissions Information (AICPA, Technical Practice Aids, AUD sec. 14,400), which among other matters provides guidance to practitioners for engagements to examine and report on a schedule or an assertion relating to information about a GHG emission reduction in connection with (a) the recording of the reduction with a registry or (b) a trade of that reduction or credit.

5.155 As stated in SOP 03-2, such examination engagements should be performed pursuant to chapter 1, “Attest Engagements,” of Statement on Standards for Attestation Engagements (SSAE) No. 10, Attest Engagements (AICPA, Professional Standards, vol. 1, AT sec. 101), as amended.

5.156 Furthermore, SOP 03-2 explains that before accepting the engagement, the practitioner should consider guidance on engagement acceptance within chapter 1 of SSAE No. 10, as amended. Also, paragraph 17 of SOP 03-2 provides examples of specific matters that should be considered such as independence of the practitioner, the practitioner’s level of knowledge of the subject matter, use of a specialist, the existence of suitable criteria, materiality, any changes in the client’s method of measuring GHG emissions, and the availability of baseline data.

**Examination Engagement: GHG Emission Reduction Information**

5.157 The practitioner’s objective is to express an opinion about whether

a. the entity’s GHG emission reduction information related to a specific project or on an entity-wide basis is presented, in all material respects, in conformity with the criteria selected by management; or

b. the responsible party’s written assertion about the GHG emission reduction information related to a specific project or on an entity-wide basis is fairly stated, in all material respects, based on the criteria selected by management.

**Written Assertion by the Responsible Party**

5.158 A written assertion may be presented to a practitioner in a number of ways, such as in a narrative description, within a schedule, or as part of a representation letter appropriately identifying what is being presented and the point in time or period of time covered. An example of a written assertion on a GHG emission reduction project follows: “XYZ Company reduced GHG emissions in connection with project ABC by 50,000 tons of CO2 equivalents...”
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for the year ended December 31, 20XX, based on [identify criteria selected by management]."

5.159 An example of a GHG emission reduction project that relates to the oil and gas industry is the reduction in venting or flaring on offshore oil production platforms (installation of zero flare systems; rapid response to unplanned events).

5.160 Paragraphs 55–63 of SOP 03-2 provides requirements and guidance in planning the examination engagement.

5.161 The SOP also addresses consideration of subsequent events, adequacy of disclosure, representation letters (including an illustrative representation letter in appendix C), reporting, and attest documentation. Appendixes D–E include illustrative examination reports on GHG emissions information and GHG emission reduction information for general use.
Appendix A

Illustrative Financial Statements and Supplemental Information

The following financial statements illustrate oil and gas disclosures and highlight financial reporting differences between the successful efforts and the full cost methods of accounting. These statements do not represent a typical set of financial statements—nor are they necessarily complete because more or less detail in the financial statements or in the notes may be appropriate, depending on the circumstances. Footnote references are included to facilitate the locating of descriptive disclosures. Blanks in the financial statements indicate captions that are not applicable to the accounting method indicated. There is no intended correlation between the amounts in the successful efforts financial statements and the amounts in the full cost financial statements. The financial statements include certain disclosures that are required only for public companies. The notes to the financial statements are representative of the basic type of disclosure for an entity with oil and gas producing activities. Additional disclosures, such as information concerning subsequent events, pension plans, and postretirement benefits other than pensions, post employment benefits, lease commitments, accounting changes, share-based compensation, off-balance-sheet risks, concentrations of credit risk, and other matters not unique to entities with oil and gas producing activities may be required by generally accepted accounting principles (GAAP).

These illustrative financial statements do not and are not intended to include items that should be accounted for under the requirements of Financial Accounting Standards Board (FASB) Statement No. 133, Accounting for Derivative Instruments and Hedging Activities. Practitioners should refer to FASB

1 Financial Accounting Standards Board (FASB) Statement No. 158, Employers‘ Accounting for Defined Benefit Pension and Other Postretirement Plans, amends FASB Statement No. 87, Employers‘ Accounting for Pensions, No. 88, Employers‘ Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, No. 106, Employers‘ Accounting for Postretirement Benefits Other Than Pensions, and No. 132, Employers‘ Disclosures about Pensions and Other Postretirement Benefits—an amendment of FASB Statements No. 87, 88, and 106. The statement improves financial reporting by requiring an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity. The statement provides different effective dates for the recognition and related disclosure provisions and for the required change to a fiscal year-end measurement date. Also, the effective date of the recognition and disclosure provisions differs for an employer that is an issuer of publicly traded equity securities from one that is not. Readers should refer to the complete statement at www.fasb.org for applicability.

FASB Staff Position (FSP) FAS 158-1, Conforming Amendments to the Illustrations in FASB Statements No. 87, No. 88, and No. 106 and to the Related Staff Implementation Guides, updates the illustrations contained in appendix B of FASB Statement No. 87, appendix B of FASB Statement No. 88, and appendix C of FASB Statement No. 106. This FSP also amends the questions and answers contained in FASB Special Reports and makes conforming changes to other guidance and technical corrections to FASB Statement No. 158.

2 See FSP SOP 94-6-1, Terms of Loan Products That May Give Rise to a Concentration of Credit Risk, for additional guidance.

3 In March 2008, FASB issued FASB Statement No. 161, Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133. In response to constituents‘ concerns that FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, does not provide adequate information about how derivatives and hedging activities affect an entity’s financial position, financial performance, and cash flows, FASB issued FASB Statement (continued)
Entities With Oil and Gas Producing Activities

Statement No. 133 for guidance on reporting derivative instruments and hedging activities.

Independent Auditor’s Report

The Stockholders and Board of Directors
XYZ Oil Company

We have audited the accompanying consolidated balance sheet of XYZ Oil Company as of December 31, 20X7, and the related consolidated statements of income, retained earnings, and cash flows for the year then ended. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

No. 161 to enhance disclosures about an entity’s derivative and hedging activities and to improve financial transparency. This statement has the same scope as FASB Statement No. 133 and, accordingly, applies to all entities. FASB Statement No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Early adoption is encouraged. FASB Statement No. 161 encourages, but does not require, comparative disclosures for earlier periods at initial adoption. Refer to the FASB Web site at www.fasb.org for the full text of the statement.

For audits conducted in accordance with Public Company Accounting Oversight Board (PCAOB) standards, PCAOB Auditing Standard No. 1, References in Auditors’ Reports to the Standards of the Public Company Accounting Oversight Board (AICPA, PCAOB Standards and Related Rules, Rules of the Board, “Standards”), replaces this sentence with the following sentence, “We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States).”

Auditing Interpretation No. 18, “Reference to PCAOB Standards in an Audit Report on a Nonissuer,” of AU section 508, Reports on Audited Financial Statements (AICPA, Professional Standards, vol. 1, AU sec. 9508 par. .89–.92), provides reporting guidance for audits of nonissuers. Interpretation No. 18 provides guidance on the appropriate referencing of PCAOB auditing standards in audit reports when an auditor is engaged to perform the audit in accordance with both generally accepted auditing standards and PCAOB auditing standards. The Auditing Standards Board (ASB) also has undertaken a project to determine what amendments, if any, should be made to AU section 508. See the AICPA Web site at www.aicpa.org/members/div/auditstd/index.htm for more information.

An audit also includes assessing the accounting principles used and significant estimates made by management.
Illustrative Financial Statements and Supplemental Information

as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of XYZ Oil Company as of December 31, 20X7, and the consolidated results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

[Signature]
Certified Public Accountants

City, State
February 18, 20X8

Additional Guidance When Performing Integrated Audits of Financial Statements and Internal Control Over Financial Reporting

When performing an integrated audit of financial statements and internal control over financial reporting in accordance with the standards of the PCAOB, the auditor may choose to issue a combined report or separate reports on the company's financial statements and on internal control over financial reporting. Paragraphs 85–98 of PCAOB Auditing Standard No. 5, An Audit of Internal Control Over Financial Reporting That Is Integrated with An Audit of Financial Statements (AICPA, PCAOB Standards and Related Rules, Rules of the Board, "Standards"), and appendix C, "Special Reporting Situations," of PCAOB Auditing Standard No. 5 provide direction on reporting on internal control over financial reporting. In addition, see paragraphs 86–88 of PCAOB Auditing Standard No. 5, which include an illustrative combined audit report.

If the auditor issues separate reports on the company's financial statements and on internal control over financial reporting, the following paragraph should be added to the auditor's report on the company's financial statements:

"We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), X Company's internal control over financial reporting as of December 31, 20X7, based on [identify control criteria] and our report dated [date of report, which should be the same as the date of the report on the financial statements] expressed [include nature of opinion]."

When performing an integrated audit of financial statements and internal control over financial reporting in accordance with the standards of the PCAOB, the auditor's reports on the company's financial statements and on internal control over financial reporting should be dated the same date. Refer to paragraph 89 of PCAOB Auditing Standard No. 5 for direction about the report date in an audit of internal control over financial reporting.
Exhibit A-1

XYZ OIL COMPANY
Consolidated Balance Sheet
December 31, 20X7

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<th>Assets</th>
<th>Successful Efforts</th>
<th>Full Cost</th>
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<tbody>
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<td>Current assets</td>
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<td>Cash</td>
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<td>Receivables</td>
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<td>Affiliated partnerships</td>
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<tr>
<td>Materials and supplies</td>
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<td>500(a)</td>
</tr>
<tr>
<td>Oil and gas leases held for resale</td>
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<td></td>
</tr>
<tr>
<td>Total current assets</td>
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<td>6,200</td>
</tr>
</tbody>
</table>

Oil and gas properties, using successful efforts/full cost accounting\(^7\) (notes 5–7)

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<thead>
<tr>
<th>Assets</th>
<th>Success Efforts</th>
<th>Full Cost</th>
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</thead>
<tbody>
<tr>
<td>Proved properties</td>
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<tr>
<td>Unproved properties</td>
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<tr>
<td>Wells and related equipment and facilities</td>
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</tr>
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<td>Support equipment and facilities</td>
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<td>Drilling in progress</td>
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<td>Materials and supplies</td>
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<td>Properties being amortized</td>
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<td>40,800</td>
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<td>Properties not subject to amortization</td>
<td></td>
<td>9,500</td>
</tr>
<tr>
<td>Less accumulated depreciation, depletion,</td>
<td>4,800</td>
<td>10,700</td>
</tr>
<tr>
<td>amortization, and impairment</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net oil and gas properties</td>
<td>20,200</td>
<td>39,600</td>
</tr>
</tbody>
</table>

Other assets

<table>
<thead>
<tr>
<th>Assets</th>
<th>Successful Efforts</th>
<th>Full Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Other property and equipment, less</td>
<td>700(c)</td>
<td>700</td>
</tr>
<tr>
<td>accumulated depreciation of $300</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil and gas leases held for resale</td>
<td>1,500(b)</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>600</td>
<td>600</td>
</tr>
<tr>
<td>Total other assets</td>
<td>2,800</td>
<td>1,300</td>
</tr>
<tr>
<td></td>
<td>$30,000</td>
<td>$47,100</td>
</tr>
</tbody>
</table>

\(^7\) FSP FAS 19-1, *Accounting for Suspended Well Costs*, requires certain disclosures for exploratory well costs applicable to enterprises that use the successful efforts method of accounting.
### Illustrative Financial Statements and Supplemental Information

**Liabilities and Shareholders’ Equity**

<table>
<thead>
<tr>
<th></th>
<th>Successful Efforts</th>
<th>Full Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Current liabilities</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current portion of long-term debt (note 7)</td>
<td>$700</td>
<td>$700</td>
</tr>
<tr>
<td>Accounts payable</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Trade</td>
<td>3,850</td>
<td>3,850</td>
</tr>
<tr>
<td>Revenue distribution</td>
<td>800</td>
<td>800</td>
</tr>
<tr>
<td>Drilling advances (note 8)</td>
<td>900</td>
<td>900</td>
</tr>
<tr>
<td>Accrued expenses</td>
<td>850</td>
<td>850</td>
</tr>
<tr>
<td><strong>Total current liabilities</strong></td>
<td>7,100</td>
<td>7,100</td>
</tr>
<tr>
<td><strong>Long-term debt (note 7)</strong></td>
<td>6,700</td>
<td>6,700</td>
</tr>
<tr>
<td><strong>Deferred tax liability, net (note 9)</strong></td>
<td>2,500</td>
<td>6,500</td>
</tr>
<tr>
<td><strong>Deferred credit (note 5)</strong></td>
<td></td>
<td>1,400</td>
</tr>
<tr>
<td><strong>Asset retirement obligation liability (note 2)</strong></td>
<td>1000</td>
<td>1000</td>
</tr>
<tr>
<td><strong>Commitments and contingencies (note 10)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Shareholders’ equity</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Common stock, par value $1 per share; 10,000 shares authorized; 1,000 shares outstanding</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Additional paid-in capital</td>
<td>2,000</td>
<td>2,000</td>
</tr>
<tr>
<td>Retained earnings</td>
<td>8,300</td>
<td>22,800</td>
</tr>
<tr>
<td><strong>Total shareholders’ equity</strong></td>
<td>11,300</td>
<td>25,800</td>
</tr>
</tbody>
</table>

See notes to consolidated financial statements.

(a) Tubular goods inventories, as well as inventories of other oil field materials and supplies, may be classified as current assets or as oil and gas properties, depending on the intended use of the material.

(b) Oil and gas leases held for resale may be classified as current assets or as noncurrent assets. The criteria for classification of these leases are the same as for any other asset (for example, whether the leases will be sold for cash or contributed as an investment in an oil and gas limited partnership).

(c) FSP AUG AIR-1, *Accounting for Planned Major Maintenance Activities*, prohibits companies from recognizing planned major maintenance cost by accruing a liability over several reporting periods before the maintenance is performed or over interim-reporting periods within the annual period in which the cost is expected to be incurred. The FSP permits three alternative methods of accounting for planned major maintenance activities: direct expense method, built-in overhaul method, and the deferral method.
### Exhibit A-2

**XYZ OIL COMPANY**

**Consolidated Statement of Income**

**Year Ended December 31, 20X7**

<table>
<thead>
<tr>
<th></th>
<th>Successful Efforts</th>
<th>Full Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Revenue and other income items</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil and gas sales(^{c})</td>
<td>$14,000</td>
<td>$14,000</td>
</tr>
<tr>
<td>Management fees, net of related expenses of $200</td>
<td>100</td>
<td></td>
</tr>
<tr>
<td>Sale of oil and gas leases(^{a})</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td>Gain on sale of oil and gas properties (note 5)</td>
<td>2,000</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>400</td>
<td>400</td>
</tr>
<tr>
<td><strong>Total revenues and other income items</strong></td>
<td><strong>17,500</strong></td>
<td><strong>14,400</strong></td>
</tr>
</tbody>
</table>

|                      |                    |           |
| **Expenses**         |                    |           |
| Lease operating      | 1,000              | 1,000     |
| Production tax       | 1,000              | 1,000     |
| Exploration          | 5,000              |           |
| Depreciation, depletion, and amortization\(^{b}\) | 1,500             | 2,500     |
| Cost of oil and gas leases sold\(^{a}\) | 600               |           |
| Interest             | 1,500              | 1,700     |
| General and administrative (note 3) | 1,900             | 1,900     |
| **Total expenses**   | **12,500**         | **8,100** |

|                      |                    |           |
| **Income before provision for income taxes** | **5,000**         | **6,300** |
| Provision for income taxes (note 9)           | **1,750**         | **2,350** |
| **Net income**                                  | **$3,250**        | **$3,950**|

See notes to consolidated financial statements.

\(^{a}\) Some companies report the gain or loss from sales of oil and gas leases held for resale rather than the sales price and related cost.

\(^{b}\) If a write-down of oil and gas properties was recorded as a result of impairment or a capitalized cost ceiling limitation, the write-down may be reported as a separate expense item or included with depreciation, depletion, and amortization expense and separately disclosed.

\(^{c}\) Emerging Issues Task Force (EITF) Issue No. 06-3, “How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation),” requires that a company disclose its policy for recording taxes assessed by a governmental authority on a revenue-producing transaction between a seller and a customer. In addition, for any such taxes that are reported on a gross basis, a company is required to disclose the amounts of those taxes.

---

8 FASB Statement No. 130, *Reporting Comprehensive Income*, establishes standards for the reporting and display of comprehensive income and its components. The statement requires that all items that are required to be recognized under accounting standards as components of comprehensive income be reported in a financial statement that is displayed with the same prominence as other financial statements. The statement does not require a specific format for that financial statement but does require that an enterprise display an amount representing total comprehensive income for the period in that financial statement. The statement does not apply to an enterprise that has no items of other comprehensive income in any period presented.
Illustrative Financial Statements and Supplemental Information

Exhibit A-3

XYZ OIL COMPANY
Consolidated Statement of Cash Flows
Year Ended December 31, 20X7

<table>
<thead>
<tr>
<th>Successful Efforts</th>
<th>Full Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash flows from operating activities:</td>
<td></td>
</tr>
<tr>
<td>Net income</td>
<td>$ 3,250</td>
</tr>
<tr>
<td>Adjustments to reconcile net income to operating cash flow</td>
<td></td>
</tr>
<tr>
<td>Depreciation, depletion, and amortization</td>
<td>1,500</td>
</tr>
<tr>
<td>Gain on sale of oil and gas properties</td>
<td>(2,000)</td>
</tr>
<tr>
<td>Deferred income taxes</td>
<td>450</td>
</tr>
<tr>
<td>Increase in receivables</td>
<td>(1,500)</td>
</tr>
<tr>
<td>Decrease in materials and supplies</td>
<td>150</td>
</tr>
<tr>
<td>Increase in oil and gas leases held for resale</td>
<td>(200)</td>
</tr>
<tr>
<td>Increase in current portion of long-term debt</td>
<td>200</td>
</tr>
<tr>
<td>Increase in accounts payable</td>
<td>1,250</td>
</tr>
<tr>
<td>Increase in drilling advances</td>
<td>200</td>
</tr>
<tr>
<td>Increases in accrued expenses</td>
<td>150</td>
</tr>
<tr>
<td>Increase in income taxes payable</td>
<td>150</td>
</tr>
<tr>
<td>Net cash provided by operating activities</td>
<td>3,600</td>
</tr>
</tbody>
</table>

Cash flows from investing activities:

| Proceeds from sale of oil and gas properties | 5,600 | 6,600 |
| Purchase of oil and gas leases held for resale | (500) | |
| Capital expenditures for property and equipment | (8,600) | (14,600) |
| Net cash used for investing activities | (3,500) | (8,000) |

Cash flows from financing activities:

| Proceeds from additions to long-term debt | 4,300 | 4,300 |
| Payments to reduce long-term debt and other financing obligations | (4,000) | (4,000) |
| Net cash provided by financing activities | 300 | 300 |
| Net increase in cash and cash equivalents | 400 | 400 |
| Cash and cash equivalents at beginning of year | 800 | 800 |
| Cash and cash equivalents at end of year | $ 1,200 | $ 1,200 |

Supplemental disclosure of cash flow information:

| Cash paid during the year for income taxes | $ 1,150 | $ 1,150 |
| Cash paid during the year for interest | 700 | 1,100 |

See notes to consolidated financial statements.
1—Summary of Significant Accounting Policies

Nature of Operations and Summary of Significant Accounting Policies

Nature of Operations

The Company is engaged primarily in the acquisition, development, production, exploration for, and the sale of, oil, gas and natural gas liquids. The Company sells its oil and gas products primarily to domestic pipelines and refineries.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of XYZ Oil Company, its wholly owned subsidiaries, and its proportionate share of the assets, liabilities, revenues, and expenses of all affiliated oil and gas partnerships for which the Company is the general partner. All significant intercompany accounts and transactions have been eliminated in consolidation.

Materials and Supplies

Inventories, consisting primarily of tubular goods and oil field materials and supplies, are stated at the lower of cost or market, cost being determined by the average cost method.

Oil and Gas Properties

The Company uses the successful efforts method of accounting for oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, to drill and equip development wells and related asset retirement costs are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of carrying and retaining unproved properties are expensed.

9 FSP FAS No. 19-1 amends FASB Statement No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, to permit the continued capitalization of exploratory well costs beyond one year if the well found a sufficient quantity of reserves to justify its completion as a producing well and the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project.

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Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Other unproved properties are amortized based on the Company’s experience of successful drilling and average holding period. Capitalized costs of producing oil and gas properties, after considering estimated residual salvage values, are depreciated and depleted by the unit-of-production method. Support equipment and other property and equipment are depreciated over their estimated useful lives.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and the resultant gain or loss is recognized. On the retirement or sale of a partial unit of proved property, the cost is charged to accumulated depreciation, depletion, and amortization with a resulting gain or loss recognized in income.

On the sale of an entire interest in an unproved property for cash or cash equivalent, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

The Company follows the full cost method of accounting for oil and gas properties. Accordingly, all costs associated with acquisition, exploration, development of oil and gas reserves, including directly related overhead costs and related asset retirement costs, are capitalized.

All capitalized costs of oil and gas properties, including the estimated future costs to develop proved reserves, are amortized on the unit-of-production method using estimates of proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.

In addition, the capitalized costs are subject to a "ceiling test," which basically limits such costs to the aggregate of the "estimated present value," discounted at a 10 percent interest rate of future net revenues from proved reserves, based on current economic and operating conditions, plus the lower of cost or fair market value of unproved properties.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas, in which case the gain or loss is recognized in income.

Abandonments of properties are accounted for as adjustments of capitalized costs with no loss recognized.

---

10 FASB Statement No. 143, Accounting for Asset Retirement Obligations, amends FASB Statement No. 19. FASB Statement No. 143 requires that obligations for dismantlement, restoration, and abandonment costs shall be accounted for in accordance with the provisions of FASB Statement No. 143. Estimated residual values shall be taken into account in determining amortization and depreciation rates. A detailed discussion of the requirements of FASB Statement No. 143 is provided in paragraphs 2.127–137.
Entities With Oil and Gas Producing Activities

Oil and Gas Leases Held for Resale

The Company has acquired certain oil and gas leases for the purpose of contributing the leases to affiliated oil and gas partnerships or for the purpose of selling the leases to industry partners for cash consideration. Such leases held for resale are periodically reviewed to determine if they have been impaired. If impairment exists, a loss is recognized by providing an impairment allowance. Abandonments of oil and gas leases held for resale are charged to expense. With respect to leases transferred to affiliated oil and gas partnerships, the determination of recovery of total costs is made on a partnership-by-partnership basis.

Capitalized Interest

The Company capitalizes interest ($800 in 20X7) on expenditures for significant exploration and development projects while activities are in progress to bring the assets to their intended use.

Management Fees

In connection with the sponsorship of oil and gas partnerships, the Company receives a management fee of 3 percent from partnership subscriptions, which is credited to income as earned.

Cash and Cash Equivalents

Cash and cash equivalents include cash in banks and certificates of deposit that mature within three months of the date of purchase.

Long-Lived Assets

Long lived assets to be held and used or disposed of other than by sale are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. When required, impairment losses on assets to be held and used or disposed of other than by sale are recognized based on the fair value of the asset. Long-lived assets to be disposed of by sale are reported at the lower of their carrying amount or fair value less cost to sell.

Income Taxes

Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes on temporary differences between the amount

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Illustrative Financial Statements and Supplemental Information

of taxable income and pretax financial income and between the tax bases of assets and liabilities and their reported amounts in the financial statements. Deferred tax assets and liabilities are included in the financial statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled as prescribed in FASB Statement No. 109, Accounting for Income Taxes. As changes in tax laws or rates are enacted, deferred tax assets and liabilities are adjusted through the provision for income taxes.

2—Asset Retirement Obligations

XYZ Oil Company accounts for its asset retirement obligations in accordance with FASB Statement No. 143, Accounting for Asset Retirement Obligations. This statement requires that the fair value of an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement costs is capitalized as part of the carrying amount of the long-lived asset. For XYZ Oil Company, asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities.

While certain assets such as refineries, crude oil and product pipelines and marketing assets have retirement obligations covered by FASB Statement No. 143, those obligations have not been recognized since the fair value cannot be estimated due to the uncertainty of the settlement date of the obligation.

Effective January 1, 2003, XYZ Oil Company adopted FASB Statement No. 143, as required. The cumulative effect on net income of adopting FASB Statement No. 143 was a net favorable effect of approximately $XXX. At the time of adoption, total assets increased approximately $XXX, and total liabilities increased approximately $XXX. The amounts recognized upon adoption are based upon numerous estimates and assumptions, including future retirement costs, future recoverable quantities of oil and gas, future inflation rates and the credit-adjusted risk-free interest rate.11

* FASB Interpretation No. (FIN) 48, Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, clarifies the accounting for uncertainty in income taxes recognized in an enterprise’s financial statements in accordance with FASB Statement No. 109, Accounting for Income Taxes. Under FIN 48, a company will recognize a tax benefit in the financial statements for an uncertain tax position only if management’s assessment is that its position is “more likely than not” (a greater than 50 percent likelihood) to be upheld upon examination based only on the technical merits of the tax position. Under the transition guidance for implementing FIN 48, any required cumulative-effect adjustment will be recorded to retained earnings as of January 1, 2007.

FSP FIN 48-1, Definition of Settlement in FASB Interpretation No. 48, provides guidance on how an enterprise should determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits.

FSP FIN 48-2, Effective Date of FASB Interpretation No. 48 for Certain Nonpublic Enterprises. This FSP applies to nonpublic enterprises subject to the provisions of FIN 48 unless that nonpublic enterprise (a) is a consolidated entity of a public enterprise that applies U.S. generally accepted accounting principles (GAAP) or (b) has issued a full set of U.S. GAAP annual financial statements prior to the issuance of this FSP using the recognition, measurement, and disclosure requirements of FIN 48. This FSP defers the effective date of FIN 48 for nonissuing enterprises included within this FSP’s scope to the annual financial statements for fiscal years beginning after December 15, 2007. When effective, FIN 48 should be applied as of the beginning of the enterprise’s fiscal year.

11 FIN 47, Accounting for Conditional Asset Retirement Obligations—an interpretation of FASB Statement No. 143, clarifies the definition and treatment of conditional asset retirement obligations as discussed in FASB No. 143. A conditional asset retirement obligation is defined as an asset retirement activity in which the timing or method, or both, of settlement are conditional on a future event that

(continued)
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Entities With Oil and Gas Producing Activities

FASB Statement No. 143 requires depreciation of the capitalized asset retirement cost and accretion of the asset retirement obligation over time. The depreciation will generally be determined on a units-of-production basis, while the accretion to be recognized will escalate over the life of the producing assets, typically as production declines. The following table indicates the changes to the company’s before-tax asset retirement obligations in 20X7:

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balance at Jan. 1</td>
<td>$900</td>
</tr>
<tr>
<td>Liabilities incurred</td>
<td>10</td>
</tr>
<tr>
<td>Liabilities settled</td>
<td>(23)</td>
</tr>
<tr>
<td>Accretion expense</td>
<td>44</td>
</tr>
<tr>
<td>Revisions in estimated cash flows</td>
<td>69</td>
</tr>
<tr>
<td>Balance at December 31</td>
<td>$1000</td>
</tr>
</tbody>
</table>

3—Affiliated Oil and Gas Partnerships

The Company generally acquires, explores, and operates oil and gas properties for its own account; however, since 19X0 the Company has sponsored the formation of limited partnerships for the purpose of conducting oil and gas exploration, development, and production activities on certain oil and gas properties. The Company serves as general partner for these partnerships and, as such, has full and exclusive discretion in the management and control of the partnerships. The partnership agreements generally provide that the limited partners pay 99 percent of the cost of acquiring and operating the partnership properties, and of drilling, equipping, completing, and operating the partnership properties while the Company pays the remaining 1 percent of such costs. Revenues from partnership oil and gas properties are allocated 99 percent to the limited partners and 1 percent to the Company, until such time as the limited partners have recovered their investment in the partnership. Thereafter, partnership revenues are allocated 85 percent to the limited partners and 15 percent to the Company.

The Company is periodically reimbursed by the partnerships for certain overhead costs incurred on their behalf. In 20X7 these reimbursements totaled $750 and are reflected as a reduction in general and administrative expense in the accompanying consolidated financial statements.

4—Related Party Transactions

The Chairman of the Board of Directors of the Company owns a 25 percent interest in a drilling contractor and a 10 percent interest in an oil field tool rental company that provide services to the Company. Before engaging these

(footnote continued)

may or may not be within the control of the entity. FIN 47 states that an entity shall recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated.

12 Emerging Issues Task Force Issue No. 04-5, ‘Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights,’” states that the general partner in a limited partnership is presumed to control the partnership and must consolidate the entity on its financial statements. The presumption of control and consolidation requirement may be overcome if the limited partners have substantive participating rights or have the ability to effectively liquidate the partnership.

FASB issued FIN 46(R), Consolidation of Variable Interest Entities (revised December 2003)—an interpretation of ARB No. 51, which addresses consolidation by business enterprises of variable interest entities or potential variable interest entities commonly referred to as special purpose entities.
companies to perform services, the Company obtains competitive bids from independent companies offering similar services. During 20X7 the Company or its affiliated oil and gas partnerships paid $1,000 and $150 to each company, respectively, for services performed.

During 20X7 the Company purchased oil and gas leases from the president of the Company for an aggregate purchase price of $100. The prices paid for the leases represented market prices for similar leases in the areas.

5—Sale of Interests in Oil and Gas Properties

(successful efforts)

In 20X7, the Company completed the sale of the following oil and gas properties, which were not carried as oil and gas leases held for resale.

In February 20X7, the Company sold its entire interest in the ABC field, a proved property, for $3,000. The Company recorded a gain from this transaction of $2,000.

In July 20X7, the Company sold a partial interest in the DEF prospect, a block of unproved acreage, for $1,600. The Company's cost in the prospect totaled $200; however, since the Company anticipates incurring over $2,000 in exploration and development costs relating to the interest retained in the prospect, the Company has recorded a deferred credit of $1,400. As exploration and development costs are incurred on this prospect, they will be charged against the deferred credit.

In December 20X7, the Company sold a partial interest in the GHI prospect, a block of unproved acreage, for $1,000. The net book value of these properties totaled $1,500 at the time of the sale; consequently, the entire sales proceeds have been recorded as a reduction of the Company’s cost of the properties in the GHI area.

(full cost)

In 20X7, the Company completed the sale of the following oil and gas properties.

In February 20X7, the Company sold its entire interest in the ABC field, a proved property, for $3,000. Since the sale of this property did not significantly alter the relationship between capitalized costs and oil and gas reserves, the entire proceeds were credited to the full cost pool.

In July 20X7, the Company sold a partial interest in the DEF prospect, an unproved property, for $1,600, which was credited to the full cost pool.

In December 20X7, the Company sold a partial interest in the GHI prospect, an unproved property, for $1,000, which was credited to the full cost pool.

During 20X7, the Company sold several unproved leases for $1,000, which was credited to the full cost pool.

6—Oil and Gas Properties Not Subject to Amortization

(full cost)

The Company is currently participating in oil and gas exploration and development activities on an offshore block of acreage in the Gulf of Mexico. At December 31, 20X7, a determination cannot be made about the extent of
additional oil reserves that should be classified as proved reserves as a result of
this project. Consequently, the associated property costs and exploration costs
have been excluded in computing amortization of the full cost pool. The Com-
pany will begin to amortize these costs when the project is evaluated, which
is currently estimated to be 20X8. In addition, the cost of certain oil and gas
leases that the Company has acquired for the purpose of contributing to affili-
ated oil and gas partnerships or of selling to third parties has been excluded in
computing amortization of the full cost pool.

Costs excluded from amortization consist of the following at December 31,
20X7.

<table>
<thead>
<tr>
<th>Year</th>
<th>Acquisition Costs</th>
<th>Exploration Costs</th>
<th>Development Costs</th>
<th>Capitalized Interest</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>20X6</td>
<td>$2,600</td>
<td>$500</td>
<td>$400</td>
<td>$200</td>
<td>$3,700</td>
</tr>
<tr>
<td>20X7</td>
<td>1,500</td>
<td>3,200</td>
<td>500</td>
<td>600</td>
<td>5,800</td>
</tr>
<tr>
<td>Total</td>
<td>$4,100</td>
<td>$3,700</td>
<td>$900</td>
<td>$800</td>
<td>$9,500</td>
</tr>
</tbody>
</table>

7—Long-Term Debt

At December 31, 20X7, long-term debt and production payments consist of the
following items.

- Revolving credit agreement: $6,200
- Production payment: 1,200
- Less amounts due in one year: 700
- Long-term debt: $6,700

In 20X7, the Company renegotiated its $25,000 revolving credit agreement
with a group of banks. Indebtedness under the agreement bears interest at 5
percent above a bank’s prime lending rate (12 percent at December 31, 20X7)
and is repayable in quarterly installments of $350, beginning September 30,
20X8. This line of credit is secured by certain producing oil and gas properties
located in Texas and New Mexico. At December 31, 20X7, the unused available
line of credit was $18,800.

In November 20X7, the Company received a production payment of $1,200
relating to certain oil and gas properties in Utah that are presently shut in. The
Company is obligated to repay this advance plus interest at the rate of 15
percent per annum from 80 percent of the revenues received through oil and
gas production from these properties.

The Company’s aggregate long-term debt and production payments are es-
timated to be repayable annually in the following schedule.

<table>
<thead>
<tr>
<th>Year</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>20X8</td>
<td>$1,200&lt;sup&gt;(*)&lt;/sup&gt;</td>
</tr>
<tr>
<td>20X9</td>
<td>1,800</td>
</tr>
<tr>
<td>20X0</td>
<td>1,700</td>
</tr>
<tr>
<td>20X1</td>
<td>1,600</td>
</tr>
<tr>
<td>20X2</td>
<td>1,400</td>
</tr>
<tr>
<td>Thereafter</td>
<td>700</td>
</tr>
</tbody>
</table>
8—Drilling Advances

During 20X7 the Company received drilling advances from joint interest owners with a remaining balance of $900 at December 31, 20X7. These advances will be applied toward the payment of drilling costs to be incurred in 20X8.

9—Income Taxes 13

The provision (benefit) for income taxes includes income taxes currently payable and those deferred because of temporary differences between the financial statement and tax bases of assets and liabilities. The provision (benefit) for income taxes at December 31, 20X7 consists of the following:

<table>
<thead>
<tr>
<th></th>
<th>Successful</th>
<th>Full</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Efforts</td>
<td>Cost</td>
</tr>
<tr>
<td>Federal income taxes:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current</td>
<td>$1,125</td>
<td>$1,125</td>
</tr>
<tr>
<td>Deferred</td>
<td>400</td>
<td>850</td>
</tr>
<tr>
<td></td>
<td><strong>1,525</strong></td>
<td><strong>1,975</strong></td>
</tr>
<tr>
<td>State income taxes:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current</td>
<td>175</td>
<td>175</td>
</tr>
<tr>
<td>Deferred</td>
<td>50</td>
<td>200</td>
</tr>
<tr>
<td></td>
<td><strong>225</strong></td>
<td><strong>375</strong></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$1,750</strong></td>
<td><strong>$2,350</strong></td>
</tr>
</tbody>
</table>

Under FASB Statement No. 109, Accounting for Income Taxes, deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the company’s deferred tax assets (liabilities) as of December 31, 20X7 are as follows:

<table>
<thead>
<tr>
<th></th>
<th>Successful</th>
<th>Full</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Efforts</td>
<td>Cost</td>
</tr>
<tr>
<td>Noncurrent deferred tax assets (liabilities)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Exploration and development costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>capitalized for financial purposes, expensed for tax purposes</td>
<td>($1,200)</td>
<td>($4,300)</td>
</tr>
<tr>
<td>Exploration costs capitalized for tax purposes, expensed for financial purposes</td>
<td>(300)</td>
<td></td>
</tr>
<tr>
<td>Interest capitalized for financial purposes, expensed for tax purposes</td>
<td>400</td>
<td>300</td>
</tr>
<tr>
<td>Gain recognized on sales of oil and gas properties for tax purposes, not reported as a gain for financial purposes</td>
<td>(700)</td>
<td>(1,350)</td>
</tr>
<tr>
<td>Excess amortization of oil and gas properties for financial purposes over tax purposes</td>
<td>(700)</td>
<td>(1,150)</td>
</tr>
<tr>
<td>Deferred noncurrent tax liability, net</td>
<td>($2,500)</td>
<td>($6,500)</td>
</tr>
</tbody>
</table>

13 Pursuant to FASB Statement No. 109, deferred taxes shall be determined separately for each tax-paying component (an individual entity or group of entities that is consolidated for tax purposes) in each tax jurisdiction. The objective is to measure a deferred tax liability or asset using the enacted tax rate(s) expected to apply to taxable income in the periods in which the deferred tax liability or asset is expected to be settled or realized.
126  Entities With Oil and Gas Producing Activities

The reconciliation of income tax computed at statutory rates to income tax expense is as follows:

<table>
<thead>
<tr>
<th></th>
<th>Successful Efforts</th>
<th>Full Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Statutory rate</td>
<td>34.0%</td>
<td>34.0%</td>
</tr>
<tr>
<td>Excess statutory depletion</td>
<td>(10.0)</td>
<td>(5.0)</td>
</tr>
<tr>
<td>Minimum tax on tax preference depletion and capital gains</td>
<td>6.3</td>
<td>5.8</td>
</tr>
<tr>
<td>Other</td>
<td>4.7</td>
<td>2.5</td>
</tr>
<tr>
<td>Effective tax rate</td>
<td>35.0%</td>
<td>37.3%</td>
</tr>
</tbody>
</table>

10—Commitments and Contingencies (f)

As general partner in certain oil and gas limited partnerships, the Company is contingently liable for the repayment of loans made to the partnerships. At December 31, 20X7, the outstanding balance of these loans, which are secured by the partnerships’ oil and gas properties, is $5,000. The Company believes that the partnerships’ assets will be sufficient to satisfy these obligations without loss to the Company.

The Company is committed to purchase up to $1,000 in limited partnership interests of a certain oil and gas limited partnership, if tendered by the limited partners. During 20X7 no such interests were tendered and no purchases were made.

11—Fair Value of Financial Instruments

The Company values its financial instruments as required by FASB Statement No. 107, Disclosures about Fair Values of Financial Instruments. The carrying amounts of cash, short-term debt and long-term variable-rate debt approximate fair value. The Company estimates the fair value of its long-term, fixed-rate debt generally using discounted cash flow analysis based on the Company’s current borrowing rates for similar types of debt. The carrying amounts of the Company’s financial instruments generally approximate their fair values at December 31, 20X7.  

14 FASB Statement No. 126, Exemption from Certain Required Disclosures about Financial Instruments for Certain Nonpublic Entities—an amendment to FASB Statement No. 107, as amended by FASB Statement No. 133, amends FASB Statement No. 107, Disclosures about Fair Value of Financial Instruments, to make the disclosures about fair value of financial instruments prescribed in FASB Statement No. 107 optional for entities that meet all of the following criteria:

a. The entity is a nonpublic entity.

b. The entity’s total assets are less than $100 million on the date of the financial statements.

c. The entity has no instrument that, in whole or in part, is accounted for as a derivative instrument under FASB Statement No. 133 other than commitments related to the origination of mortgage loans to be held for sale during the reporting period.

† In September 2006, FASB issued Statement No. 157, Fair Value Measurements, which is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. See paragraphs 1.76–94 in chapter 1 of this guide for additional discussion on FASB Statement No. 157 and FASB Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities—including an amendment of FASB Statement No. 115.
12—Impairment of Long-Lived Assets

Recently adopted environmental legislation in a jurisdiction where the Company has undertaken major exploration and development activities has placed significant restrictions on the use of certain drilling equipment used by the Company. This circumstance has called into question the recoverability of the carrying amounts of these assets. As a result, pursuant to FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, an impairment loss of $X,XXX has been recognized for this equipment and included in income from continuing operations before income taxes under the caption “Exploration.” In calculating the impairment loss, fair value was determined by reviewing quoted market prices for current sales of similar equipment.

(a) It is also acceptable to account for investments in oil and gas partnerships using the equity method of accounting. In addition, the reader may wish to consider the applicability of Emerging Issues Task Force (EITF) Issue No. 00-1, “Investor Balance Sheet and Income Statement Display under the Equity Method for Investments in Certain Partnerships and Other Ventures.”

(b) In some cases it may be more appropriate to depreciate natural gas cycling and processing plants by the unit-of-production method; therefore, the costs of such plants may be included in the full cost pool.

(c) It is also acceptable, if economic circumstances (related to the effects of regulated prices) indicate, to use units of revenue as a basis for computing amortization.

(d) In certain circumstances, it may be required to record reimbursements as revenues. Companies should consider the guidance in EITF No. 99-19, “Reporting Revenue Gross as a Principal versus Net as an Agent,” and EITF No. 01-14, “Income Statement Characterization of Reimbursements Received for ‘Out-of-Pocket’ Expenses Incurred,” to determine the appropriate treatment.

(e) For guidance on the balance sheet classification of maturities of nonrecourse production payments, see Accounting Research Bulletin (ARB) No. 43 chapter 3A, Restatement and Revision of Accounting Research Bulletins, paragraph 8.

(f) If the Company has any unusually significant commitments for exploration and development costs, those commitments should be disclosed in the notes to the financial statements.
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Entities With Oil and Gas Producing Activities

Exhibit A-5

XYZ OIL COMPANY
Supplemental Information (Unaudited)(a)
Year Ended December 31, 20X7

<table>
<thead>
<tr>
<th>Successful Efforts</th>
<th>Full Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Capitalized Costs Relating to Oil and Gas Producing Activities at December 31, 20X7</strong></td>
<td></td>
</tr>
<tr>
<td>Unproved oil and gas properties</td>
<td>$10,000</td>
</tr>
<tr>
<td>Proved oil and gas properties</td>
<td>14,000</td>
</tr>
<tr>
<td>Support equipment and facilities</td>
<td>1,000</td>
</tr>
<tr>
<td></td>
<td><strong>25,000</strong></td>
</tr>
<tr>
<td>Less accumulated depreciation, depletion, amortization, and impairment</td>
<td>4,800</td>
</tr>
<tr>
<td>Net capitalized costs</td>
<td><strong>$20,200</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Costs Incurred in Oil and Gas Producing Activities for the Year Ended December 31, 20X7(b)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Property acquisition costs</td>
<td></td>
</tr>
<tr>
<td>Proved</td>
<td>$ 600</td>
</tr>
<tr>
<td>Unproved</td>
<td>1,500</td>
</tr>
<tr>
<td>Exploration costs</td>
<td>5,000</td>
</tr>
<tr>
<td>Development costs</td>
<td>1,500</td>
</tr>
<tr>
<td>Amortization rate per equivalent barrel of production</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Results of Operations for Oil and Gas Producing Activities for the Year Ended December 31, 20X7(b)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil and gas sales</td>
<td>$14,000</td>
</tr>
<tr>
<td>Gain on sale of oil and gas properties</td>
<td>2,000</td>
</tr>
<tr>
<td>Gain on sale of oil and gas leases</td>
<td>400</td>
</tr>
<tr>
<td>Production costs</td>
<td>(2,000)</td>
</tr>
<tr>
<td>Exploration expenses</td>
<td>(5,000)</td>
</tr>
<tr>
<td>Depreciation, depletion, and amortization</td>
<td>(1,400)</td>
</tr>
<tr>
<td>Income tax expense</td>
<td>(2,880)</td>
</tr>
<tr>
<td>Results of operations for oil and gas producing activities (excluding corporate overhead and financing costs)</td>
<td></td>
</tr>
</tbody>
</table>

The following estimates of proved and proved developed reserve quantities and related standardized measure of discounted net cash flow are estimates only, and do not purport to reflect realizable values or fair market values of the Company’s reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available. All of the Company’s reserves are located in the United States.

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Proved reserves are estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment, and operating methods.

The standardized measure of discounted future net cash flows is computed by applying year-end prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated) to be incurred on pretax net cash flows, less tax basis of the properties and available credits, and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10 percent a year to reflect the estimated timing of the future cash flows.
Entities With Oil and Gas Producing Activities

<table>
<thead>
<tr>
<th></th>
<th>Oil (Bbls)</th>
<th>Gas (Mcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proved developed and undeveloped reserves</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beginning of year</td>
<td>5,000</td>
<td>20,000</td>
</tr>
<tr>
<td>Revisions of previous estimates</td>
<td>(100)</td>
<td>(2,000)</td>
</tr>
<tr>
<td>Improved recovery</td>
<td>100</td>
<td></td>
</tr>
<tr>
<td>Purchases of minerals in place</td>
<td>80</td>
<td></td>
</tr>
<tr>
<td>Extensions and discoveries</td>
<td>2,500</td>
<td>2,300</td>
</tr>
<tr>
<td>Production</td>
<td>(325)</td>
<td>(1,400)</td>
</tr>
<tr>
<td>Sales of minerals in place</td>
<td>(375)</td>
<td></td>
</tr>
<tr>
<td>End of year</td>
<td>6,880</td>
<td>18,900</td>
</tr>
</tbody>
</table>

Proved developed reserves

|                     |            |           |
| Beginning of year   | 4,500      | 13,000    |
| End of year         | 6,200      | 16,000    |

Standardized Measure of Discounted Future Net Cash Flows at December 31, 20X7(b)

- Future cash inflows: $210,000
- Future production costs: (40,000)
- Future development costs: (10,000)
- Future income tax expenses: (70,000)
- Future net cash flows: 90,000

Future net cash flows:
- 10% annual discount for estimated timing of cash flows: (12,000)

Standardized measures of discounted future net cash flows relating to proved oil and gas reserves: $78,000

The following reconciles the change in the standardized measure of discounted future net cash flow during 20X7.

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Beginning of year</td>
<td>$66,000</td>
<td></td>
</tr>
<tr>
<td>Sales of oil and gas produced, net of production costs</td>
<td>(12,000)</td>
<td></td>
</tr>
<tr>
<td>Net changes in prices and production costs</td>
<td>(3,000)</td>
<td></td>
</tr>
<tr>
<td>Extensions, discoveries, and improved recovery, less related costs</td>
<td>29,000</td>
<td></td>
</tr>
<tr>
<td>Development costs incurred during the year which were previously estimated</td>
<td>2,500</td>
<td></td>
</tr>
<tr>
<td>Net change in estimated future development costs</td>
<td>2,000</td>
<td></td>
</tr>
<tr>
<td>Revisions of previous quantity estimates</td>
<td>(4,000)</td>
<td></td>
</tr>
<tr>
<td>Net change from purchases and sales of minerals in place</td>
<td>(5,500)</td>
<td></td>
</tr>
<tr>
<td>Accretion of discount</td>
<td>7,000</td>
<td></td>
</tr>
<tr>
<td>Net change in income taxes</td>
<td>(3,000)</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>(1,000)</td>
<td></td>
</tr>
<tr>
<td>End of year</td>
<td>$78,000</td>
<td></td>
</tr>
</tbody>
</table>
Illustrative Financial Statements and Supplemental Information

(a) If XYZ Oil Company had an investment in an enterprise that was accounted for on the equity method, the Company's share of the investee's net capitalized costs, costs incurred, results of operations for producing activities, reserve quantities, and standardized measure of discounted future net cash flows would be required to be disclosed separately.

(b) These disclosures are presented assuming that XYZ Oil Company has operations in only one reportable geographic area. If operations are conducted in two or more reportable geographic areas, this information would be required to be reported in total and by geographic area.
Appendix B

Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information by the Society of Petroleum Engineers of The American Institute of Mining, Metallurgical, and Petroleum Engineers (AIME)

The standards included in this appendix relating to auditing of oil and gas reserve information are applicable to petroleum engineers and not to certified public accountants performing audits in accordance with generally accepted auditing standards.
Standards by Society of Petroleum Engineers

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<table>
<thead>
<tr>
<th>Section</th>
<th>Article</th>
<th>Page</th>
</tr>
</thead>
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<td>1.1-1.4</td>
</tr>
<tr>
<td></td>
<td>II—Definitions of Selected Terms</td>
<td>2.1-2.2</td>
</tr>
<tr>
<td></td>
<td>III—Professional Qualifications of Reserves Estimators and Reserves Auditors</td>
<td>3.1-3.3</td>
</tr>
<tr>
<td></td>
<td>IV—Standards of Independence, Objectivity and Confidentiality for Reserves Estimators and Reserves Auditors</td>
<td>4.1-4.6</td>
</tr>
<tr>
<td></td>
<td>V—Standards for Estimating Reserves and Other Reserves Information</td>
<td>5.1-5.11</td>
</tr>
<tr>
<td></td>
<td>VI—Standards for Auditing Reserves and Other Reserves Information</td>
<td>6.1-6.6</td>
</tr>
</tbody>
</table>

AAG-OGP APP B
Standards by Society of Petroleum Engineers

Article I—The Basis and Purpose of Developing Standards Pertaining to the Estimating and Auditing of Petroleum Reserves Information

1.1 The Nature and Purpose of Estimating and Auditing Petroleum Reserves Information. Estimates of Reserves Information are made by or for entities as a part of their ongoing business practices. Such Reserves Information typically may include, among other things, estimates of (i) the reserves quantities, (ii) the future-producing rates from such reserves, (iii) the future net revenue from such reserves, and (iv) the present value of such future net revenue. The exact type and extent of Reserves Information must necessarily take into account the purpose for which such Reserves Information is being prepared and, correspondingly, statutory and regulatory provisions, if any, that are applicable to such intended use of the Reserves Information. Reserves Information may be limited to Proved Reserves.

1.2 Estimating and Auditing Reserves Information in Accordance With Generally Accepted Engineering and Evaluation Principles. The estimating and auditing of Reserves Information is predicated upon certain historically developed principles of geoscience, petroleum engineering, and evaluation methodologies, which are in turn based on principles of physical science, mathematics, and economics. Although these generally accepted geological, engineering, and evaluation principles are predicated on established scientific concepts, the application of such principles involves extensive judgments by qualified individuals and is subject to changes in (i) existing knowledge and technology; (ii) fiscal and economic conditions; (iii) applicable contractual, statutory, and regulatory provisions; and (iv) the purposes for which the Reserves information is to be used.

1.3 The Inherently Imprecise Nature of Reserve Information. The reliability of Reserves Information is considerably affected by several factors. Initially, it should be noted that Reserves Information is imprecise due to the inherent uncertainties in, and the limited nature of, the accumulation and interpretation of data upon which the estimating and auditing of Reserves Information is predicated. Moreover, the methods and data used in estimating Reserves Information are often necessarily indirect or analogical in character rather than direct or deductive. Furthermore, the persons estimating and auditing Reserves Information are required, in applying generally accepted petroleum engineering and evaluation principles, to make numerous unbiased judgments based upon their educational background, professional training, and professional experience. The extent and significance of the judgments to be made are, in themselves, sufficient to render Reserves Information inherently imprecise.

1.4 The Need for Standards Governing the Estimating and Auditing of Reserves Information. The Society of Petroleum Engineers (the "Society") has determined that the Society should adopt these Standards Pertaining to the Estimating and Auditing of Petroleum Reserves and Reserves

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1 These Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information (the "standards") are not intended to bind the members of the Society of Petroleum Engineers (the "society") or anyone else, and the society imposes no sanctions for the nonuse of these standards. Each person estimating and auditing oil and gas Reserve Information is encouraged to exercise his or her own judgment concerning the matters set forth in these standards. The society welcomes comments and suggested changes in regard to these standards.

2 Definitions are set forth in Section 2.2 for certain of the terms that are not textually defined in these standards.
Entities With Oil and Gas Producing Activities

Information (the "Standards"). The adoption of these Standards by the Society fulfills at least three useful objectives.

First, although some users of Reserves Information are cognizant of the general principles that are applied to databases in the estimation of Reserves Information, the judgments required in estimating and auditing Reserves Information, and the inherently imprecise nature of Reserves Information, many users of Reserves Information continue to fail to understand such matters. The adoption, publication, and distribution of these Standards should enable users of Reserves Information to understand these matters more fully and therefore place the appropriate level of confidence on Reserves Information.

Second, the wider dissemination of Reserves Information through public financial reporting, such as that required by various governmental authorities, makes it imperative that the users of Reserves Information have a general understanding of the methods of, and limitations on, estimating and auditing Reserves Information.

Third, as Reserves Information proliferates in terms of the types of information available and the broader dissemination thereof, it becomes increasingly important that Reserves Information be estimated and audited on a consistent basis by competent, well-trained professional geoscientists and engineers. Compliance with these Standards is a method of facilitating evaluation and comparisons of Reserves Information by the users thereof.

In order to accomplish the three above-discussed objectives, the Society has included in these Standards (i) definitions of selected terms pertaining to the estimation and evaluation of Reserves Information, (ii) qualifications for persons estimating and auditing Reserves Information, (iii) standards of independence and objectivity for such persons, (iv) standards for estimating reserves and other Reserves Information, and (v) standards for auditing reserves and other Reserves Information. Although these Standards are predicated on generally accepted geoscience, petroleum engineering, and economic evaluation principles, it may in the future become necessary, for the reasons set forth in Section 1.2, to clarify or amend certain of these Standards. Accordingly, the Society, as a part of its governance process, will periodically review these standards and determine whether to amend these Standards or publish clarifying statements.

Note that these Standards apply independently of the classification system and associated guidelines adopted by the entity; the reference system should be clearly identified.

Article II—Definitions of Selected Terms

2.1 Applicability of Definitions. In preparing a report or opinion, persons estimating and auditing Reserves Information shall ascribe, to reserves and other significant terms used therein, the current petroleum reserves and resources definitions and classification system promulgated by the Society or such other definitions as he or she may reasonably consider appropriate in accordance with generally accepted petroleum engineering and evaluation principles, provided, however, that (i) such report or opinion should define, or make reference to a definition of, each significant term that is used therein and (ii) the definitions used in any report or opinion must be consistent with statutory and regulatory provisions, if any, that apply to such report or opinion in accordance with its intended use.
Standards by Society of Petroleum Engineers

2.2 Defined Terms. The definitions set forth in this Section are applicable for all purposes of these standards:

(a) **Entity.** An Entity is a corporation, joint venture, partnership, trust, individual, principality, agency, or other person engaged directly or indirectly in (i) the exploration for, or production of, oil and gas; (ii) the acquisition of properties or interests therein for the purpose of conducting such exploration or production; or (iii) the ownership of properties or interests therein with respect to which such exploration or production is being, or will be, conducted.

(b) **Reserves Estimator.** A Reserves Estimator is a person who is designated to be in responsible charge for estimating and evaluating reserves and other Reserves Information. A Reserves Estimator either may personally make the estimates and evaluations of Reserves Information or may supervise and approve the estimation and evaluation thereof by others.

(c) **Entity Reserves Report.** An Entity Reserves Report may be prepared by an internal or external estimator for any of several purposes, all of which should be clearly disclosed in the report. Such report is to be considered valid for only those properties identified and included in the report as of the effective report date. To be termed an Entity Reserves Report, the report should represent all or at least 80% of an entity’s reserves, future production, and/or revenues. An Entity Reserves Report should clearly indicate the relative importance of the properties included and any properties excluded from the Entity Reserves Report. An Entity Reserves Report for any purpose should contain adequate disclosures to fully inform the user about the definitions and reserves classifications employed, qualifications and independence of the estimator, confidentiality restrictions, and any unusual circumstances or report qualifiers, and it should include, but not be limited to, authorization for the report, the sources and adequacy and reliability of the underlying geological and engineering data, assumptions employed, and any limitations imposed on the distribution and use of the Entity Reserves Report.

(d) **Property Reserves Report.** A Property Reserves Report may contain Reserves Information limited to one or more reservoirs, fields, and/or projects but is not sufficiently extensive to be considered an Entity Reserves Report. All of the other qualifications in (c) above apply.

(e) **Reserves Auditor.** A Reserves Auditor is a person who is designated to be in responsible charge for the conduct of an audit with respect to Reserves Information estimated by others. A Reserves Auditor either may personally conduct an audit of Reserves Information or may supervise and approve the conduct of an audit thereof by others. A Reserves Auditor may be an employee of the entity or an employee of an external independent firm.

(f) **Reserves Audit.** A Reserves Audit is the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed, (2) the adequacy and quality of the data relied upon, (3) the depth and thoroughness of the reserves estimation process, (4) the classification of reserves appropriate to the relevant definitions used, and (5) the reasonableness of the estimated reserves quantities and/or the Reserves Information. The term “reasonableness” cannot be defined with precision but should reflect a quantity and/or value difference of not more than plus or minus 10%, or the subject Reserves Information does not meet minimum recommended audit standards. This tolerance can be applied to any level of reserves or Reserves Informa-
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tion aggregation, depending upon the nature of the assignment, but is most often limited to Proved Reserves Information. A separate predetermined and disclosed tolerance may be appropriate for other reserves classifications. Often a reserves audit includes a detailed review of certain critical assumptions and independent assessments with acceptance of other information less critical to the reserves estimation. Typically, a reserves audit letter or report is prepared, clearly stating the assumptions made. A reserves audit should be of sufficient rigor to determine the appropriate reserves classification for all reserves in the property set evaluated and to clearly state the reserves classification system being utilized. In contrast to the term "audit" as used in a financial sense, a reserves audit is generally less rigorous than a reserves report.

(g) Financial Audit. A Financial Audit, as contrasted with a Reserves Audit, is typically described as a periodic examination of an organization's financial records and accounts, performed in an effort to verify that funds were used as they were intended and consistent with established financial management practices.

(h) Process Review. A Process Review is the result of an investigation by a person who is qualified by experience and training equivalent to that of a Reserves Auditor to address the adequacy and effectiveness of an entity's internal processes and controls relative to reserves estimation. These internal processes and controls most often include some form of an independent internal or external reserves audit system. The Process Review should not include an opinion relative to the reasonableness of the reserves quantities or Reserves Information and should be limited to the process and control system reviewed. The term process review includes reports that have also been termed "procedural audits" or "procedural reviews" in the industry. Although such reviews may provide value to the entity, an external or internal Process Review is not of sufficient rigor to establish appropriate classifications and quantities of reserves and should not be represented to the public as being equivalent to an audit of reserves.

(i) Reserves Information. Reserves Information consists of various estimates pertaining to the extent and value of petroleum properties. Reserves Information will include (i) estimates of petroleum reserves and may, but will not necessarily, include estimates of (ii) the future production rates from such reserves, (iii) the future net revenue from such reserves, and (iv) the present value of such future net revenue. All such Reserves Information should be estimated and classified as appropriate to stated reserves definitions.

Article III—Professional Qualifications of Reserves Estimators and Reserves Auditors

3.1 The Importance of Professionally Qualified Reserves Estimators and Reserves Auditors. Reserves Information is prepared and audited, respectively, by Reserves Estimators and Reserves Auditors, who are often assisted by other professionals and by paraprofessionals and clerical personnel. Reserves Estimators and Reserves Auditors may be (i) employees of an Entity itself or (ii) stockholders, proprietors, partners, or employees of an independent firm of petroleum consultants with which an arrangement has been made for the estimating or auditing of Reserves Information. Irrespective of the nature of their employment, however, Reserves Estimators and Reserves Auditors must
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(i) examine and interpret the available data necessary to estimate or audit Reserves Information; (ii) perform such tests, and consider such matters, as may be necessary to evaluate the sufficiency of the database; and (iii) make such calculations and estimates, and apply such tests and standards, as may be necessary to estimate or audit reserves and other Reserves Information. For the reasons discussed in Section 1.3, the proper determination of these matters is highly dependent upon the numerous judgments Reserves Estimators and Reserves Auditors are required to make based upon their educational background, professional training, integrity, and professional experience. Consequently, in order to assure that Reserves Information will be as reliable as possible given the limitations inherent in the estimating and auditing process, it is essential that those in responsible charge for estimating and auditing Reserves Information have adequate professional qualifications such as those set forth in this Article III.

3.2 Professional Qualifications of Reserves Estimators. A Reserves Estimator shall be considered professionally qualified in such capacity if he or she has sufficient educational background, professional training, and professional experience to enable him or her to exercise prudent professional judgment and to be in responsible charge in connection with the estimating of reserves and other Reserves Information. The determination of whether a Reserves Estimator is professionally qualified should be made on an individual-by-individual basis. A Reserves Estimator would normally be considered to be qualified if he or she (i) has a minimum of 3 years' practical experience in petroleum engineering or petroleum production geology, with at least 1 full year of such experience being in the estimation and evaluation of Reserves Information; and (ii) either (A) has obtained, from a college or university of recognized stature, a bachelor's or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (B) has received, and is maintaining in good standing, a registered or certified professional engineer's license or a registered or certified professional geologist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. In the context used herein, it is recommended that experience and competency levels should generally include a clear understanding of several areas of knowledge pertinent to the circumstances and conditions to which they are being applied, which could include industry accepted practices related to (1) the creation and understanding of geological maps and models, (2) the judicious selection of and reliance upon appropriate reservoir analogs, (3) appropriate application of and reliance upon seismic information in reserves estimation, (4) fundamentals and limitations of reservoir simulation, (5) basic knowledge and applicability of probabilistic and deterministic assessment methodologies, (6) the use of numerous performance evaluation techniques to confirm and/or refine geological interpretations, (7) the consequences of reliance on computer software without a full understanding of the internal calculation processes, (8) various forms of production licensing and fiscal systems, (9) ongoing training in the relevant or pertinent reserves definitions, and (10) ethics training—all of which should be refreshed periodically through some form of internally or externally provided continuing education. Reserves Estimators and Auditors are encouraged to recognize the professional obligation to secure ongoing training in the areas described above, whether or not this is provided or required by their employer. A Reserves Estimator should decline an assignment for which he or she is not qualified.
3.3 Professional Qualifications of Reserves Auditors. A Reserves Auditor shall be considered professionally qualified in such capacity if he or she has sufficient educational background, professional training (similar to that described above), and professional experience to enable him or her to exercise prudent professional judgment while acting in responsible charge for the conduct of an audit of Reserves Information estimated by others. The determination of whether a Reserves Auditor is professionally qualified should be made on an individual-by-individual basis and with the recognition and respect of his or her peers. A Reserves Auditor would normally be considered to be qualified if he or she (i) has a minimum of 10 years’ practical experience in petroleum engineering or petroleum production geology, with at least 5 years of such experience being in responsible charge of the estimation and evaluation of Reserves Information; and (ii) either (A) has obtained, from a college or university of recognized stature, a bachelor’s or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (B) has received, and is maintaining in good standing, a registered or certified professional engineer’s license or a registered or certified professional geologist’s license, or the equivalent thereof, from an appropriate governmental authority or professional organization. A Reserves Auditor should decline an assignment for which he or she is not qualified.

Article IV—Standards of Independence, Objectivity and Confidentiality for Reserves Estimators and Reserves Auditors

4.1 The Importance of Independent or Objective Reserves Estimators and Reserves Auditors. In order that users of Reserves Information may be assured that the Reserves Information has been estimated or audited in an unbiased and objective manner, it is important that Reserves Estimators and Reserves Auditors maintain, respectively, the levels of independence and objectivity set forth in this Article IV. The determination of the independence and objectivity of Reserves Estimators and Reserves Auditors should be made on a case-by-case basis. To facilitate such determination, the Society has adopted (i) standards of independence for consulting Reserves Estimators and consulting Reserves Auditors and (ii) standards of objectivity for Reserves Auditors internally employed by Entities to which the Reserves Information relates. To the extent that the applicable standards of independence and objectivity set forth in this Article IV are not met by Reserves Estimators and Reserves Auditors in estimating and auditing Reserves Information, such lack of conformity with this Article IV shall be disclosed in any report or opinion relating to Reserves Information which purports to have been estimated or audited in accordance with these Standards.

4.2 Requirement of Independence for Consulting Reserves Estimators and Consulting Reserves Auditors. Consulting Reserves Estimators and consulting Reserves Auditors, or any firm of petroleum consultants of which such individuals are stockholders, proprietors, partners, or employees, must be independent from any Entity with respect to which such Reserves Estimators, Reserves Auditors, or consulting firms estimate or audit Reserves Information which purports to have been estimated or audited in accordance with these Standards. A statement of such independence shall be made a part of any report containing Reserves Information.
4.3 Standards of Independence for Consulting Reserve Estimators and Consulting Reserve Auditors. Consulting Reserves Estimators and consulting Reserves Auditors, and any firm of petroleum consultants of which such individuals are stockholders, proprietors, partners, or employees, would not normally be considered independent with respect to an Entity if, during the term of their professional engagement, such Reserves Estimators, Reserves Auditors, or consulting firm:

(a) Investments. Either owned or acquired, or were committed to acquire, directly or indirectly, any material financial interest in (i) such Entity or any corporation or other person affiliated therewith or (ii) any property with respect to which Reserves Information is to be estimated or audited. Any such financial interest, stock, or other ownership in the properties held through direct ownership, trusts, partnerships, or incorporated entities should be disclosed in writing to the entity to determine materiality by the entity and maintained on file by the entity for review by financial auditors.

(b) Joint Business Venture. Either owned or acquired, or were committed to acquire, directly or indirectly, any material joint business investment with such Entity or any officer, director, principal stockholder, or other person affiliated therewith.

(c) Borrowings. Were indebted to such Entity or any officer, director, principal stockholder, or other person affiliated therewith, provided, however, that retainers, advances against work-in-progress, and trade accounts payable arising from the purchase of goods and services in the ordinary course of business shall not constitute indebtedness within the meaning of this Section 4.3(c).

(d) Guarantees of Borrowings. Were indebted to any individual, corporation, or other person under circumstances where the payment of such indebtedness was guaranteed by such Entity or any officer, director, principal stockholder, or other person affiliated therewith.

(e) Loans to Clients. Extended credit to (i) such Entity or any officer, director, principal stockholder, or other person affiliated therewith or (ii) any person having a material interest in any property with respect to which Reserves Information was estimated or audited, provided, however, that trade accounts receivable arising in the ordinary course of business from the performance of petroleum engineering and related services shall not constitute the extension of credit within the meaning of this Section 4.3(e).

(f) Guarantees for Clients. Guaranteed any indebtedness (i) owed by such Entity or any officer, director, principal stockholder, or other person affiliated therewith or (ii) payable to any individual, corporation, entity, or other person having a material interest in the Reserves Information pertaining to such Entity.

For purposes of this Section 4.3, the term “affiliated” shall, with respect to an Entity, describe the relationship of a person to such Entity under circumstances in which such person, directly or indirectly through one or more intermediaries, controls or is controlled by or is under common control with such Entity; provided, however, that commercial banks and other bona fide financial institutions shall not be considered to be affiliated with the Entity to which the Reserve Information relates unless such banks or institutions actively participate in the management of the properties of such Entity.

Unless the context requires otherwise, the term “material” shall, for purposes of this Section 4.3, be interpreted with reference to the net worth of the consulting Reserves Estimators or the consulting Reserves Auditors, or any firm of petroleum consultants of which such individuals are stockholders, proprietors, partners or employees.
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(g) Purchases and Sales of Assets. Purchased any material asset from, or sold any material asset to, such Entity or any officer, director, principal stockholder, or other person affiliated therewith.

(h) Certain Relationships With Client. Were directly or indirectly connected with such Entity as a promoter, underwriter, officer, director, or principal stockholder, or in any capacity equivalent thereto, or were otherwise not separate and independent from the operating and investment decision making process of such Entity.

(i) Trusts and Estates. Were trustees, participants, or beneficial owners in any trust, or executors, administrators, or beneficiaries of any estate, if such trust or estate had any direct or indirect interest material to it in such Entity or in any property with respect to which Reserves Information was estimated or audited.

(j) Contingent Fee. Were engaged by such Entity to estimate or audit Reserves Information pursuant to any agreement, arrangement, or understanding whereby the remuneration or fee paid by such Entity was contingent upon, or related to, the results or conclusions reached in estimating or auditing such Reserves Information.

The independence of consulting Reserves Estimators and consulting Reserves Auditors, and the independence of any firm of petroleum consultants of which such individuals are stockholders, proprietors, partners, or employees, shall not be considered impaired merely because other petroleum engineering and related services were performed (i) for such Entity or any officer, director, principal stockholder, or other person affiliated therewith or (ii) in regard to any property with respect to which Reserves Information was estimated or audited, provided, however, that such other services must have been of a type normally rendered by the petroleum engineering profession and should be clearly disclosed in all reports relating to independent audits of, or reports containing, Reserves Information.

4.4 Requirement of Objectivity for Reserve Auditors Internally Employed by Entities. Reserve Auditors who are internally employed by an Entity should be empowered by the Entity to be objective with respect to such Entity if such Reserve Auditors audit Reserves Information relating to such Entity which purports to have been estimated or audited in accordance with these Standards.

4.5 Standards of Objectivity for Reserve Auditors Internally Employed by Entities. Reserve Auditors internally employed by an Entity would normally be considered to be in a position of objectivity with respect to such Entity if, during the time period in which Reserves Information was audited, such Reserve Auditors:

(a) Accountability to Management. Were assigned to an internal-audit group which was (i) accountable to Senior level management and/or the board of directors of such Entity and (ii) separate and independent from the operating and investment decision-making process of such Entity.

(b) Freedom to Report Irregularities. Were granted complete and unrestricted freedom to report, to one or more of the principal executives and/or the board of directors of such Entity, any substantive or procedural irregularities of which such Reserve Auditors became aware during their audit of Reserves Information pertaining to such Entity. Certain regulatory guidelines may require, or at least suggest, that such reporting by an internal auditor or auditing
group be routinely made directly and exclusively to a board of directors, a board committee, or one or more of the members of the entity management team. It may further be appropriate to consider that internal reserves auditors and their supervisors, if any, be excluded from any reserves-based compensation incentive plans or the budget allocation processes of the entity. If reserves-based compensation incentive plans for internal reserves evaluators or auditors, supervisors, or management exist within the entity, then such incentive plans should be clearly disclosed in any reserves reporting external to the entity. Further disclosures may be appropriate in any circumstance(s) where an internal Reserves Auditor and the Entity Reserves Estimator(s) have been unable to reach agreement within the prescribed tolerances for a single property or group of properties.

4.6 Requirement of Confidentiality. Reserves Estimators and Reserves Auditors, and any firm of petroleum consultants of which such individuals are stockholders, proprietors, partners, or employees, should retain in strictest confidence Reserves Information and other data and information furnished by, or pertaining to, an Entity, and such Reserves Information, data, and information should not be disclosed to others without the prior consent of such Entity. This practice should be followed whether or not a confidentiality agreement has been executed.

Article V—Standards for Estimating Reserves and Other Reserves Information

5.1 General Considerations in Estimating Reserves Information. Reserves Information may be estimated through the use of generally accepted geological and engineering methods that are consistent with both these Standards and any statutory and regulatory provisions that are applicable to such Reserves Information, in accordance with its intended use. In estimating Reserves Information for a property or group of properties, Reserves Estimators will determine the geological and engineering methods to be used in estimating Reserves Information by considering (i) the sufficiency and reliability of the database; (ii) the stage of development; (iii) the performance history; (iv) their experience with respect to such property or group of properties, and with respect to similar properties; and (v) the significance of such property or group of properties to the aggregate oil and gas properties and interests being estimated or evaluated. The report as to Reserves Information should set forth information regarding the manner in which, and the assumptions pursuant to which, such report was prepared. Such disclosure should include, where appropriate, definitions of the significant terms used in such report; the geological and engineering methods and measurement base used in preparing the Reserve Information and the source of the data used with regard to ownership interests, oil and gas production and other performance data; costs of development, operations, and abandonment; product prices; and agreements relating to current and future operations, transportation, and sales of production. Reference is made herein to the Petroleum Reserves and Resources Classification, Definitions and Guidelines jointly published in 2007 by SPE, the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE), hereinafter denoted as the SPE 2007 Definitions. However, these Standards apply regardless of the specified system being employed in the evaluation.
5.2 Adequacy of Data Base in Estimating Reserves Information. The sufficiency and reliability of the database is of primary importance in the estimation of reserves and other Reserves Information. The type and extent of the data required will necessarily vary in accordance with the methods employed to estimate reserves and other Reserves Information. In this regard, information must be available with respect to each property or group of properties as to ownership and fiscal terms, marketing arrangements (including product prices), operating interests, and expense interests and revenue interests and future changes in any of such interests that, based on current circumstances, are expected to occur. Additionally, if future net revenue from reserves, or the present value of such future net revenue, is to be estimated, the database should include, with respect to each property or group of properties, estimated future expenditures for capital required in field development, capital for continued production maintenance, including but not limited to workovers and compression costs, operating costs, taxes, fees, transportation charges, and ultimate dismantlement costs, if appropriate. The foregoing is not intended as a complete listing of all items required for consideration in the estimation of reserves and reserves information.

5.3 Estimating Reserves. The acceptable methods for estimating reserves include (i) the volumetric method, (ii) evaluation of the performance history, (iii) development of a mathematical model through consideration of material balance and computer simulation techniques, and (iv) analogy to other reservoirs if geographic location, formation characteristics, or similar factors render such analogy appropriate. In estimating reserves, Reserves Estimators should utilize the particular methods, and, if possible, combinations of a number of methods which, in their professional judgment, are most appropriate given (i) the geographic location, reservoir rock and fluid characteristics, and nature of the property or group of properties with respect to which reserves are being estimated; (ii) the amount and quality of available data; and (iii) the significance of such property or group of properties in relation to the oil and gas properties with respect to which reserves are being estimated. For all methodologies, the current reservoir conditions, such as pressures and fluid contacts, must be given consideration, as these may vary with time over the producing life of the property. Any or all of the methods identified above may need adaptation to conform to the reserves definitions that are applicable to the purpose of the estimate. In no event should the result of two or more methodologies be averaged to provide an estimate of reserves.

5.4 Estimating Reserves by the Volumetric Method. Estimating reserves in accordance with the volumetric method involves estimation of petroleum in place based upon review and analysis of such documents and information as (i) ownership and development maps; (ii) geological maps and models; (iii) openhole and cased-hole well logs and formation tests; (iv) relevant reservoir, fluid, and core data; (v) relevant seismic data and interpretations; and (v) information regarding the existing and planned completion of oil and gas wells and any production performance thereof. An appropriately estimated recovery efficiency is applied to the resulting oil and gas in place quantities in order to derive estimated original reserves. The unmodified term “reserves” is applicable to remaining quantities of petroleum, net of cumulative production, at any effective reporting date. The estimated recovery efficiency may also vary as a function of the appropriate reserves classification.
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5.5 Estimating Reserves by Analyzing Performance Data. For reservoirs with respect to which performance has disclosed reliable production trends, reserves may be estimated by analysis of performance histories and projections of such trends. These estimates may be primarily predicated on an analysis of the rates of decline in production and on appropriate consideration of other performance parameters including, but not limited to, reservoir pressures, oil/water ratios, gas/oil ratios, and gas/liquid ratios. Particular attention should be given to the utilization of proprietary or commercial software programs that employ various types of mathematical routines to assist in the projection of future production rates or pressure trends. Professional judgment and experience, perhaps derived from appropriate analogies, should always be used in confirming mathematically derived projections.

5.6 Estimating Reserves by Using Mathematical Models (Reservoir Simulation). Reserves and future production performance can be estimated through a combination of detailed geological and reservoir engineering studies and mathematical or computer simulation models. The validity of the mathematical simulation models is enhanced by the degree to which the calculated history matches the performance history, particularly at individual well locations. Where performance history is unavailable, special consideration should be given to determining the sensitivity of the calculated ultimate recoveries to the data that are the most uncertain. After making such sensitivity determinations, the ultimate recovery should be based on computed results using a combination of input parameters appropriate for the classification of reserves assigned. Again, the user is advised to exercise caution in accepting results produced through use of proprietary or commercial software without a full understanding of the internal mathematical algorithms and correlations.

5.7 Estimating Reserves by Analogy to Comparable Reservoirs. If performance trends have not been established with respect to oil and gas production, future production rates and reserves may be estimated by analogy to reservoirs in the same formation and in the same geological environment having similar reservoir rock and fluid characteristics, drive mechanisms, and established performance trends. Care should be taken to recognize current reservoir rock and fluid characteristics and conditions (particularly the stage of depletion), since these can vary substantially during the producing life of any property and could affect the validity of the analogy employed. The choice and selection of acceptable analogs for reserves classification may be described in certain regulatory reporting applications.

5.8 Categorization of Reserves. Reserves must be categorized according to the level of certainty that they will be recovered. To guide the categorization of reserves, Reserves and Resource Definitions have been promulgated by various regulatory bodies and professional organizations throughout the world. Most such Definitions allow for different categories of reserves depending on the level of certainty associated with the reserves estimate. The highest category of reserves in many systems is “Proved Reserves,” which require the highest degree of confidence. Lower categories of unproved reserves, such as “Probable” or “Possible,” imply decreasing standards of certainty. Proved plus Probable reserves (2P) may represent the best estimate for many purposes, including regulatory reporting in some countries. When presenting a set of reserves quantities, the Reserves Estimator should always identify the Definitions under which those reserves were determined.
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Different categories of reserves are used for different purposes. Proved reserves are always included in reports used for financial reporting and lending; however, the incorporation of both Proved and Probable reserves is increasingly becoming common in regulatory and financial reporting. Many, if not most, Entities and other users of Reserves Information routinely rely upon a recognition of all reserves categories for virtually all related business decisions.

The SPE 2007 Definitions contain a general requirement that Proved reserves have a “reasonable certainty” of being recovered. Other, more specific, criteria must also be met for reserves to be classified as Proved. The definition for Probable reserves is less stringent, requiring that a general test of “more likely than not” be satisfied. Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than Probable reserves.

5.9 Deterministic and Probabilistic Methods of Estimating Reserves. Under the SPE 2007 Definitions, reserves estimates may be prepared using either deterministic or probabilistic methods. With the deterministic method, the Reserves Estimator selects a single value for each parameter to be used in the calculation of reserves. The discrete value for each parameter is selected based on the estimator’s opinion of the value that is most appropriate for the corresponding reserves classification.

With the probabilistic method, the full range of possible values is described for each parameter. A mathematical technique, such as Monte Carlo Simulation (being one of several techniques), is then employed to perform a large number of random, repetitive calculations to generate a range of possible outcomes for the reserves and their associated probability of occurrence. Care should be given to all parameter values chosen but particularly for the endpoints of the relevant parameters to ensure that the possible outcomes generated are reasonable.

In principle, the two methods employ comparable calculation techniques. Conceptually, a deterministic estimate is a single value taken from a range of possible reserves values that can be expressed by a probabilistic analysis. For proved reserves, the SPE 2007 Definitions specify that there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate if probabilistic methods are used. Similarly, the definitions specify that 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. And finally, 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.

It should be noted that the probability distribution of reserves values associated with the aggregation of a number of individual entities may be different from the arithmetic sum of the probability distributions for those entities. As the number of entities increases, the spread between the tails of the aggregated probability distribution decreases with respect to the spread observed for the arithmetic sum. In general, however, the arithmetic sum of a set of mean estimates will equal the mean of a probabilistic sum of such estimates. The aggregation method employed should be appropriate to the use of the results. Without specific regulatory guidance, the SPE 2007 Definitions recommends that reported reserves should not be based on probabilistic models beyond the field, property, or project level and that further aggregation be by arithmetic summation by reserves category. In all cases, the aggregation method and any additional conditions should be clearly stated.
5.10 Estimated Future Rates of Production. Future rates of oil and gas production may be estimated by extrapolating production trends where such trends have been established. If production trends have not been established, future rates of production may be estimated by analogy to the respective rates of production of reservoirs in the same geographic area having similar geological features, reservoir rock, drive mechanism, and fluid characteristics. If there are not available either (i) production trends from the property or group of properties with respect to which reserves are being estimated or (ii) rates of production from similar reservoirs, the estimates of future rates of production may be predicated on an assumed future decline rate that takes into proper consideration the cumulative oil and gas production that is estimated to occur prior to the predicted decline in such production in relation to the estimated ultimate production. Reservoir simulation is also an accepted method of estimating future rates of production. Irrespective of the method used, however, proper consideration should be given to (i) the producing capacities of the wells; (ii) the number of wells to be drilled in the future, together with the proposed times when such are to be drilled and the structural positions of such wells; (iii) the energy inherent in, or introduced to, the reservoir; (iv) the estimated ultimate recovery; (v) future remedial work to be performed; (vi) the scheduling of future well abandonments; (vii) normal downtime which may be anticipated; and (viii) artificial restriction of future production rates that is attributable to statutory and regulatory provisions, purchaser proration, marketing limitations, and other factors.

5.11 Estimating Other Reserves Information. A Reserves Estimator often estimates Reserves Information other than reserves and future rates of production in order to make his or her report more useful. Reserves net to the interests appraised are estimated using the Entity's ownership interest in the property or group of properties, or in the production therefrom, with respect to which reserves were estimated. The nature of the ownership interest of the Entity may be established or affected by any number of arrangements, which the Reserve Estimator must take into account. Estimated future revenues are calculated from the estimated future rates of production by applying the appropriate sales prices furnished by the Entity or by using such other pricing levels as may be required by statutory and regulatory provisions that are applicable to such report in accordance with its intended use. Where appropriate, the Reserves Estimator deducts from such future revenues items such as (i) any existing production or severance taxes; (ii) taxes levied against property or production; (iii) estimates of future operating costs; (iv) estimates of any future development; equipment, or other significant capital expenditures required for the production of the reserves; and (v) net costs of abandonment. Such deductions normally include various overhead and management charges. For some purposes, it is desirable to subtract income taxes and other governmental levies in estimating future net revenues.

The foregoing may need to be modified to employ the "economic interest" method in the estimation of reserves (and reserves information) owned or controlled by an entity through a Production Sharing Agreement or other various forms of contracts or licensing agreements, as may be applicable. Legal advice may be critical to the full understanding of specific contract language affecting the right to report reserves in compliance with various regulatory bodies.

In estimating future net revenues, the Reserves Estimator should consider, where appropriate, any known or likely changes (i) from historical operating
costs, (ii) from current estimates of future capital expenditures, and (iii) in other factors which may affect estimated limits of economic production.

**Article VI—Standards for Auditing Reserves and Other Reserves Information**

6.1 **The Concept of Auditing Reserves and Other Reserves Information.** An audit is an examination of Reserves Information that is conducted for the purpose of expressing an opinion as to whether such Reserves Information, in the aggregate, is reasonable and has been estimated by qualified individuals and presented in conformity with generally accepted petroleum engineering and evaluation principles and in compliance with the relevant reserves definitions. (See expanded definition of a reserves audit and types of Reserves Reports in Section 2.2).

As discussed in Section 1.3, the estimation of reserves and other Reserves Information is an imprecise science due to the many unknown geological and reservoir factors that can only be estimated through sampling techniques. Since reserves are therefore only estimates, they cannot be audited for the purpose of verifying exactness. Instead, Reserves Information is audited for the purpose of reviewing in sufficient detail the policies, procedures, methods, and data used by an Entity in estimating its Reserves Information so that the Reserves Auditors may express an opinion as to whether, in the aggregate, the Reserves Information furnished by such Entity is reasonable within established and predetermined tolerances and has been estimated and presented in conformity with generally accepted petroleum engineering and evaluation principles and the controlling reserves definitions.

The methods and procedures used by an Entity, and the Reserves Information it furnishes, must be reviewed in sufficient detail to permit the Reserves Auditor, in his or her professional judgment, to express an opinion as to the reasonableness of such Entity's Reserves Information. In some cases, the auditing procedure may require independent estimates of Reserves Information for some or all properties. The desirability of such re-estimation will be determined by the Reserves Auditor exercising his or her professional judgment in arriving at an opinion as to the reasonableness of the Entity's Reserves Information.

There may be some instances in which the Reserves Auditor cannot issue an unqualified report attesting to ‘reasonable’ agreement in the aggregated Reserves Information compiled by the Entity. In such circumstances, the Entity may be requested to review and revise certain portions of its Reserves Information in a joint effort to produce an aggregated result within the predetermined tolerances comprising ‘reasonableness.’ Failure to do so may result in a qualified report containing full disclosure of the inability to reach the desired result.

6.2 **Limitations on Responsibility of Reserve Auditors.** Since the primary responsibility for estimating and presenting Reserves Information pertaining to an Entity is with the management of such Entity, the responsibility of Reserves Auditors is necessarily limited to any opinion they express with respect to such Reserves Information. In discharging such responsibility, Reserves Auditors may accept, generally without independent verification, information and data furnished by the Entity with respect to ownership terms and interests, oil and gas production, historical costs of operation and development, product prices, agreements relating to current and future operations and sales of production, and other specified matters. If during the course of the audit,
however, questions arise as to the accuracy or sufficiency of any information or data furnished by the Entity, the Reserves Auditor should not rely on such information or data unless such questions are resolved or the information or data are independently verified. If Reserves Information is used for financial accounting purposes, certain basic data would ordinarily be tested by an Entity's independent public accountants in connection with their examination of the Entity's financial statements. Such basic data would include information such as the property interests owned by the Entity, historical production data, and the prices, costs, and discount factors used in valuations of reserves. Reserves Auditors should, however, review estimates of major expenditures for development and equipment and any major differences between historical operating costs and estimated future operating costs.

6.3 Understanding Among an Entity, Its Independent Public Accountants (Where Applicable), and the Reserves Auditors. An understanding should exist among an Entity, its independent public accountants, where applicable, and the Reserves Auditors with respect to the nature of the work to be performed by the Reserves Auditors. Irrespective of whether the Reserves Auditors are consultants or internally employed by the Entity, the understanding between the Entity and the Reserves Auditors should include at least the following:

(a) Availability of Reserves Information. The Entity will provide the Reserves Auditors with (i) all existing Reserves Information prepared by such Entity, (ii) access to all basic data and documentation pertaining to the oil and gas properties of such Entity, (iii) access to all personnel of such Entity who might have information relevant to the audit of such Reserves Information, and (iv) the right to use additional nonconfidential information available to the auditor from other reliable sources.

(b) Performance of Audit. The Reserves Auditors will (i) study and evaluate the appropriateness of the methods and procedures used by the Entity in estimating and documenting its Reserves Information; (ii) review the reserves definitions and classifications used by such Entity; (iii) test and evaluate the Reserves Information of such Entity and the underlying data to the extent considered necessary by the Reserves Auditors; and (iv) express an opinion as to the reasonableness, in the aggregate, of such Entity's Reserves Information.

(c) Availability of Audit Report to Independent Public Accountants. The Reserves Auditors will, upon written request, (i) permit their audit report to be provided to the independent public accountants of the Entity, when appropriate, for use in their examination of its financial statements and (ii) be available to discuss their audit report with such independent public accountants or others as authorized by the Entity.

(d) Coordination Between Reserves Auditors and Independent Public Accountants. The Reserves Auditors and the Entity's independent public accountants will coordinate their efforts and agree on the records and data of the Entity to be reviewed by each, where such coordination is necessary.

In the case of an audit to be conducted by consulting Reserves Auditors, it is preferable that such understanding be documented, such as through an engagement letter between the Entity and the consulting Reserves Auditors.

6.4 Procedures for Auditing Reserves Information. Irrespective of whether the Reserves Information pertaining to an Entity is being audited by consulting Reserves Auditors or Reserves Auditors internally employed by
such Entity, the audit should be conducted in accordance with the following procedures:

(a) **Proper Planning and Supervision.** The audit should be adequately planned, and assistants, if any, should be properly supervised. Clear paths of communication by the Reserves Auditors with all relevant individuals shall be established along with unrestricted access to pertinent data, work papers, and Reserves Information to be audited during normal business hours.

(b) **Early Appointment of Reserves Auditors.** Where appropriate, early appointment of Reserves Auditors is advantageous to both the Entity and the Reserves Auditors. Early appointment enables the Reserves Auditors to plan their work so that it may be done expeditiously and to determine the extent to which such can be completed prior to the balance sheet date. Preliminary work by the Reserves Auditors benefits the Entity by facilitating the efficient and expeditious completion of the audit of such Entity’s Reserves Information.

(c) **Disclosure of the possibility of a Qualified Audit Opinion.** Before accepting an engagement, Reserves Auditors should ascertain whether circumstances are likely to permit an unqualified opinion with respect to an Entity’s Reserves Information and, if such will not, they should discuss with such Entity (i) the possible necessity of their rendering a qualified opinion and (ii) the possible remedies to the circumstances giving rise to the potential qualification of such opinion.

(d) **Interim Audit Procedures.** Many audit tests can be conducted at almost any time during the year. In the course of interim work, the Reserves Auditors make tests of the Entity’s methods, procedures, and controls to determine the extent to which such are reliable. It is acceptable practice for the Reserves Auditors to complete substantial parts of an audit examination at interim dates.

When a significant part of an audit is completed during the year and the Entity’s methods, procedures, and controls are found to be effective, the year-end audit procedure may primarily consist of an evaluation of the impact of new data. The Reserves Auditors must nevertheless be satisfied that the procedures and controls are still effective at the year’s end and that new discoveries, recent oil and gas production, and other recent information and data have been taken into account. Reserve Auditors would not be required to retest the database pertaining to an Entity’s properties and interests unless their inquiries and observations indicate that conditions have changed significantly.

(e) **General Matters To Be Reviewed With Respect to Reserves Information.** An audit of the Reserves Information pertaining to an Entity generally should include a review of (i) the policies, procedures, controls, documentation, and guidelines of such Entity with respect to the estimation, review, and approval of its Reserves Information; (ii) the qualifications and independence of Reserves Estimators internally employed by such Entity; (iii) ratios of such Entity’s reserves to annual production for, respectively, oil, gas, and natural gas liquids; (iv) historical reserves and revision trends with respect to the oil and gas properties and interests of such Entity; (v) the ranking by size of properties or groups of properties with respect to estimates of reserves or the future net revenue from such reserves; (vi) the percentages of reserves estimated by each of the various methods set forth in Section 5.3 for estimating reserves; and (vii) the significant changes occurring in such Entity’s reserves, other than from production, during the year with respect to which the audit is being prepared.
Standards by Society of Petroleum Engineers

(f) Evaluation of Internal Policies, Procedures, Controls, and Documentation. Reserves Auditors should review and evaluate the internal policies, procedures, controls, and documentation of an Entity to establish an understanding of the internal processes which such Entity uses in its reviews of existing Reserves Information. The internal policies, procedures and documentation to be reviewed with respect to an Entity should include (i) reserves definitions and classifications used by such Entity; (ii) such Entity’s policies pertaining to, and management involvement in, the review and approval of Reserves Information and changes therein; (iii) the frequency with which such Entity reviews existing Reserves Information and documentation of the Reserves Information of such Entity, together with such Entity’s internal distribution thereof; (iv) the form, content, and basis for reliance thereon in determining the nature, extent, and timing of the audit tests to be applied in the examination of such Entity’s Reserves Information and other data and matters; and (v) the flow of data to and from such Entity’s reserves inventory system.

(g) Testing for Compliance. Reserves Auditors should conduct tests and spot checks to confirm that (i) there is adherence on the part of an Entity’s internal Reserves Estimators and other employees to the policies, procedures, and controls established by such Entity and (ii) the data flowing into the reserves inventory system of such Entity is complete and consistent with other available records.

(h) Substantive Testing. In conducting substantive tests, Reserves Auditors should give priority to each property or group of properties of an Entity having (i) a large reserves value in relation to the aggregate properties of such Entity; (ii) a relatively large reserves value and major changes during the audit year in the Reserves Information pertaining to such property or group of properties; and (iii) a relatively large reserves value and a high degree of uncertainty in the Reserves Information pertaining thereto. The selection of properties for substantive testing shall be made independently by the Reserves Auditors. The amount of substantive testing performed with respect to particular Reserves Information of an Entity should depend on the assessment of (i) the general degree of uncertainty with respect to such Reserves Information, (ii) the evaluation of the internal policies, procedures, and documentation of such Entity, and (iii) the results of the compliance testing with respect to such Entity. Such substantive testing could therefore appropriately range from a limited number of tests selected by the Reserves Auditor to the complete estimation of Reserves Information with respect to a majority of an Entity’s reserves.

6.5 Records and Documentation With Respect to Audit. The Reserves Auditor should document, and maintain records with respect to, each audit of the Reserves Information of an Entity. Such documentation and records should include, among other things, a description of (i) the Reserves Information audited; (ii) the review and evaluation of such Entity’s policies, procedures, and documentation; (iii) the compliance testing performed with respect to such Entity; and (iv) the substantive tests performed in the course of such audit.

6.6 Forms of Unqualified Audit Opinions. Acceptable forms of unqualified audit opinions for consulting Reserves Auditors and Reserves Auditors internally employed by Entities are attached to these standards as, respectively, Exhibits “A” and “B.”
Exhibit “A-1”—Illustrative Unqualified Audit Opinion of Consulting Reserve Auditor

[Date]

Entity
Address

Independent Public Accountants of Entity
Address

Gentlemen:

At your request, we have examined the estimates as of [dates] set forth in the accompanying table with respect to (i) the proved reserves of Entity, (ii) changes in such proved reserves during the period indicated, (iii) the future net revenue from such proved reserves, and (iv) the present value of such future net revenue. Our examination included such tests and procedures as we considered necessary under the circumstances to render the opinion set forth herein.

[A detailed description of the audit should be set forth.]

We are independent with respect to Entity as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

It should be understood that our above-described audit does not constitute a complete reserves study of the oil and gas properties of Entity. In the conduct of our report, we have not independently verified the accuracy and completeness of information and data furnished by Entity with respect to ownership interests, oil and gas production, historical costs of operation and development, product prices, agreements relating to current and future operations and sales of production, and [specify other information, data and matters upon which reliance was placed]. We have, however, specifically identified to you the information and data upon which we so relied so that you may subject such to those procedures that you consider necessary. Furthermore, if, in the course of our examination, something came to our attention which brought into question the validity or sufficiency of any of such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data.

Please be advised that, based upon the foregoing, in our opinion the above-described estimates of Entity’s proved reserves and other Reserves Information are, in the aggregate, reasonable within the established audit tolerance guidelines of (+ or -)[%] and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

[Insert, where appropriate and to the extent warranted by the Reserves Auditor’s examination, whether the Reserves Information is in conformity with specified governmental regulations.]

[Optional: This letter is solely for the information of Entity and for the information and assistance of its independent public accountants in connection

4 If a Reserves Auditor is unable to give an unqualified opinion as to an Entity’s Reserves Information, the Reserves Auditor should set forth in his or her opinion the nature and extent of the qualifications to such opinion and the reasons therefore.

AAG-OGP APP B
Standards by Society of Petroleum Engineers

with their review of, and report upon, the financial statements of Entity. This letter should not be used, circulated or quoted for any other purpose without the express written consent of the undersigned or except as required by law.

Very truly yours,
RESERVES AUDITOR
By ________
Exhibit “B-1”—Illustrative Unqualified Audit Opinion of Reserve Auditor Internally Employed by an Entity

[Date]

Entity
[Address]
Independent Public Accountants of Entity
[Address]

Gentlemen:

I have examined the estimates as of [dates] set forth in the accompanying table with respect to (i) the proved reserves of Entity, (ii) changes in such proved reserves during the period indicated, (iii) the future net revenue from such proved reserves, and (iv) the present value of such future net revenue. My examination included such tests and procedures as I considered necessary under the circumstances to render the opinion set forth herein.

[A detailed description of the audit tests and procedures may be set forth.]

I meet the requirements of objectivity for Reserves Auditors internally employed by Entities as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

It should be understood that my above-described audit does not constitute a complete reserves study of the oil and gas properties of Entity. In the conduct of my report, I have not independently verified the accuracy and completeness of information and data furnished by other employees of Entity with respect to ownership interests, oil and gas production, historical costs of operation and development, development, product prices, agreements relating to current and future operations and sales of production, and [specify other information, data and matters upon which reliance was placed]. I have, however, specifically identified to you the information and data upon which I so relied so that you may subject such to those procedures that you consider necessary. Furthermore, if, in the course of my examination, something came to my attention which brought into question the validity or sufficiency of any of such information or data, I did not rely on such information or data until I had satisfactorily resolved my questions relating thereto or had independently verified such information or data.

Please be advised that, based upon the foregoing, in my opinion the above-described estimates of Entity’s proved reserves and other Reserves Information are, in the aggregate, reasonable within the established audit tolerance guidelines of (+ or -)[%] and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

[Insert, where appropriate and to the extent warranted by the Reserves Auditor's examination, whether the Reserves Information is in conformity with specified governmental regulations.]

Very truly yours
RESERVES AUDITOR
By ________

5 If a Reserves Auditor is unable to give an unqualified opinion as to an Entity's Reserves Information, the Reserves Auditor should set forth in his or her opinion the nature and extent of the qualifications to such opinion and the reasons therefore.
Appendix C

Information Sources

Further information on matters addressed in this guide is available through various publications and services listed in the table that follows. Many non-government and some government publications and services involve a charge or membership requirement.

Fax services allow users to follow voice cues and request that selected documents be sent by fax machine. Some fax services require the user to call from the handset of the fax machine, others allow the user to call from any phone. Most fax services offer an index document, which lists titles and other information describing available documents.

Electronic bulletin board services allow users to read, copy, and exchange information electronically. Most are available using a modem and standard communications software. Some bulletin board services are also available using one or more Internet protocols.

Recorded announcements allow users to listen to announcements about a variety of recent or scheduled actions or meetings.

All telephone numbers listed are voice lines, unless otherwise designated as fax (f) or data (d) lines. Required modem speeds, expressed in bauds per second, are listed for data lines.

General information, including electronic versions of documents and email alerts, may also be obtained by visiting an organization’s Web site.
<table>
<thead>
<tr>
<th>Organization</th>
<th>General Information</th>
<th>Fax Services</th>
<th>Internet Web Site</th>
<th>Recorded Announcements</th>
</tr>
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<tr>
<td>American Institute of Certified Public Accountants (AICPA)</td>
<td>Order Department&lt;br&gt;220 Leigh Farm Road&lt;br&gt;Durham, NC 27707–8110&lt;br&gt;(888) 777-7077</td>
<td><a href="http://www.aicpa.org">www.aicpa.org</a>&lt;br&gt;Copies of AICPA publications referred to in this document may also be obtained from the online AICPA store at <a href="http://www.cpa2biz.com">www.cpa2biz.com</a>.</td>
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<tr>
<td>Financial Accounting Standards Board (FASB)</td>
<td>Order Department&lt;br&gt;401 Merritt 7&lt;br&gt;P.O. Box 5116&lt;br&gt;Norwalk, CT 06856-5116&lt;br&gt;(800) 748-0659</td>
<td>24 Hour Access&lt;br&gt;(203) 847-0700</td>
<td><a href="http://www.fasb.org">www.fasb.org</a></td>
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<tr>
<td>Organization</td>
<td>General Information</td>
<td>Fax Services</td>
<td>Internet Web Site</td>
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| U.S. Securities and Exchange Commission (SEC) | Publications Unit  
100 F Street, NE  
Washington, DC 20549  
(202) 551-4040  
SEC Public Documents Request  
(202) 551-8090  
(800) SEC-0330 |                              | www.sec.gov       | Information Line  
(202) 942-8088  
(202) 551-6020 (tty) |
| Institute of Petroleum Accounting     | University of North Texas  
Marquis Hall, Room 315  
P.O. Box 305460  
Denton, Texas 76203-5460  
General Information  
(940) 565-3170  
E-mail: ipa@unt.edu | Fax (940) 369-8839 | www.unt.edu/ipa     |                              |
| American Petroleum Institute          | 1220 L Street, NW  
Washington, DC 20005-4070  
General Information  
(202) 682-8000 |                              | www.api.org        |                              |
| Gas Technology Institute              | 1700 South Mount Prospect Road  
Des Plaines, IL 60018-1804  
General Information  
(847) 768-0500 | Fax (847) 768-0501 | www.gastechnology.org |                              |
Appendix D

Major Existing Differences Between AICPA Standards and PCAOB Standards

At the time of this writing, the following major differences existed between AICPA standards and final Public Company Accounting Oversight Board (PCAOB) standards approved by the Securities and Exchange Commission (SEC):

- **Risk Assessment Standards.** In March 2006, the Auditing Standards Board (ASB) issued eight Statements on Auditing Standards (SAS) Nos. 104–111, collectively referred to as the risk assessment standards. These standards are applicable to nonissuers and are effective for audits of financial statements for periods beginning on or after December 15, 2006. These standards provide extensive guidance concerning the auditor’s assessment of the risks of material misstatement in a financial statement audit, and the design and performance of audit procedures whose nature, timing, and extent are responsive to the assessed risks. Additionally, the SASs establish standards and provide guidance on planning and supervision, the nature of audit evidence, and evaluating whether the audit evidence obtained affords a reasonable basis for an opinion regarding the financial statements under audit. SAS Nos. 104–111 make significant changes to numerous AU sections in the auditing literature. These standards and their changes do not apply to audits conducted in accordance with PCAOB standards.

- **Audit of Internal Control.** In connection with the requirement of section 404(b) of the Sarbanes-Oxley Act that an issuer’s independent auditor attest to and report on management’s assessment of the effectiveness of internal control, PCAOB Auditing Standard No. 5, *An Audit of Internal Control Over Financial Reporting That is Integrated With an Audit of Financial Statements* (AICPA, *PCAOB Standards and Related Rules*, Rules of the Board, “Standards”), establishes requirements and provides direction that apply when an auditor is engaged to audit the internal control over financial reporting and to perform that audit in conjunction with the audit of an issuer’s financial statements. There were also several conforming amendments to PCAOB Auditing Standards resulting from the adoption of PCAOB Auditing Standard No. 5.

Entities With Oil and Gas Producing Activities

more restrictive—or less restrictive—than the PCAOB’s interim independence standards, a registered public accounting firm shall comply with the more restrictive requirement.

- **Independence Matters.** The PCAOB has adopted ethics and independence rules concerning independence, tax services, and contingent fees. See PCAOB Rules 3501, 3502, 3520, 3521, 3522, 3523, and 3524.

- **Audit Committee Preapproval of Nonaudit Services.** Rule 3525 requires registered public accounting firms who are performing a nonaudit service related to internal control over financial reporting to (1) describe to the audit committee of the issuer the scope of the service, (2) discuss with the audit committee the potential effects of the service on independence, and (3) document the substance of these discussions.

- **Concurring Partner.** Rule 3400T requires the establishment of policies and procedures for a concurring review (generally the SEC Practice Section [SECPS] membership rule).\(^1\)

- **Communication of Firm Policy.** Rule 3400T requires registered firms to communicate through a written statement to all professional firm personnel the broad principles that influence the firm’s quality control and operating policies and procedures on, at a minimum, matters that relate to the recommendation and approval of accounting principles, present and potential client relationships, and the types of services provided, and inform professional firm personnel periodically that compliance with those principles is mandatory (generally the SECPS membership rule).

- **Affiliated Firms.** Rule 3400T requires registered firms that are part of an international association to seek adoption of policies and procedures by the international organization or individual foreign associated firms consistent with PCAOB standards.

- **Partner Rotation.** Rule 3600T requires compliance with the SEC’s independence rules which include partner rotation.

- **Continuing Professional Education (CPE) Requirements.** Rule 3400T requires registered accounting firms to ensure that all of their professionals participate in at least 20 hours of qualifying CPE every year (generally the SECPS membership rule).

Please note that in the time since publication, these differences might have been eliminated and others might have arisen.

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\(^1\) Firms that were not members of the AICPA’s Securities and Exchange Commission (SEC) Practice Section (SECPS) as of April 16, 2003 do not have to comply with this requirement.
Appendix E

Comparison of Key Provisions of the Risk Assessment Standards to Previous Standards

This appendix discusses the key provisions of each of the risk assessment related Statements on Auditing Standards (SASs) and provides a summary of how each of the SASs differs, if at all, from the previous AICPA generally accepted audit standards.
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SAS No. 104, Amendment to Statement on Auditing Standards No. 1, Codification of Auditing Standards and Procedures ("Due Professional Care in the Performance of Work")

<table>
<thead>
<tr>
<th>Key Provisions</th>
<th>How the SAS Differs From Previous Standards</th>
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<tbody>
<tr>
<td>• SAS No. 104 defines reasonable assurance as a &quot;high level of assurance.&quot;</td>
<td>• SAS No. 104 clarifies the meaning of reasonable assurance.</td>
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</table>
Comparison of Key Provisions of the Risk Assessment Standards

**SAS No. 105, Amendment to Statement on Auditing Standards No. 95, Generally Accepted Auditing Standards**

<table>
<thead>
<tr>
<th>Key Provisions</th>
<th>How the SAS Differs From Previous Standards</th>
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<tr>
<td>– SAS No. 105 expands the scope of the understanding that the auditor must obtain in the second standard of field work from “internal control” to “the entity and its environment, including its internal control.”</td>
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<tr>
<td>– The quality and depth of the understanding to be obtained is emphasized by amending its purpose from “planning the audit” to “assessing the risks of material misstatement of the financial statements whether due to error or fraud and to design the nature, timing, and extent of further audit procedures.”</td>
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<tr>
<td>– Previous guidance considered the understanding of the entity to be a part of audit planning, and emphasized that the understanding of internal control also was primarily part of audit planning.</td>
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<tr>
<td>– By stating that the purpose of your understanding of the entity and its internal control is part of assessing the risks of material misstatement, SAS No. 105 essentially considers this understanding to provide audit evidence that ultimately supports your opinion on the financial statements.</td>
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<tr>
<td>– SAS No. 105 emphasizes the link between understanding the entity, assessing risks, and the design of further audit procedures. It is anticipated that “generic” audit programs will not be an appropriate response for all engagements because risks vary between entities.</td>
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<tr>
<td>– The term <em>further audit procedures</em>, which consists of test of controls and substantive tests, replaces the term <em>tests to be performed</em> in recognition that risk assessment procedures are also performed.</td>
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<tr>
<td>– The term <em>audit evidence</em> replaces the term <em>evidential matter.</em></td>
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### SAS No. 106, Audit Evidence

**Key Provisions** | **How the SAS Differs From Previous Standards**
---|---
- SAS No. 106 defines *audit evidence* as "all the information used by the auditor in arriving at the conclusions on which the audit opinion is based."
- Previous guidance did not define audit evidence.
- SAS No. 106 also describes basic concepts of audit evidence.
- The term *sufficient, appropriate audit evidence*, defined in SAS No. 106, replaces the term *sufficient, competent evidential matter.*

- SAS No. 106 recategorizes assertions by classes of transactions, account balances, and presentation and disclosure; expands the guidance related to presentation and disclosure; and describes how the auditor uses relevant assertions to assess risk and design audit procedures.
- SAS No. 106 recategorizes assertions to add clarity.
- *Assertion relating to presentation and disclosure* has been expanded and includes a new assertion that information in disclosures should be "expressed clearly" (understability).

- SAS No. 106 defines *relevant assertions* as those assertions that have a meaningful bearing on whether the account is fairly stated.
- The term *relevant assertions* is new, and it is used repeatedly throughout SAS No. 106.

- SAS No. 106 provides additional guidance on the reliability of various kinds of audit evidence.
- The previous standard included a discussion of the competence of evidential matter and how different types of audit evidence may provide more or less valid evidence. SAS No. 106 expands on this guidance.

- SAS No. 106 identifies "risk assessment procedures" as audit procedures performed on all audits to obtain an understanding of the entity and its environment, including its internal control, to assess the risks of material misstatement at the financial statement and relevant assertion levels.
- SAS No. 106 introduces the concept of risk assessment procedures, which are necessary to provide a basis for assessing the risks of material misstatement. The results of risk assessment procedures, along with the results of further audit procedures, provide audit evidence that ultimately supports the auditor’s opinion on the financial statements.
Comparison of Key Provisions of the Risk Assessment Standards

<table>
<thead>
<tr>
<th>Key Provisions</th>
<th>How the SAS Differs From Previous Standards</th>
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<tbody>
<tr>
<td>• SAS No. 106 provides that evidence obtained by performing risk assessment procedures, as well as that obtained by performing tests of controls and substantive procedures, is part of the evidence the auditor obtains to draw reasonable conclusions on which to base the audit opinion, although such evidence is not sufficient in and of itself to support the audit opinion.</td>
<td></td>
</tr>
<tr>
<td>• SAS No. 106 describes the types of audit procedures that the auditor may use alone or in combination as risk assessment procedures, tests of controls, or substantive procedures, depending on the context in which they are applied by the auditor.</td>
<td>• Risk assessment procedures include:</td>
</tr>
<tr>
<td>• SAS No. 106 includes guidance on the uses and limitations of inquiry as an audit procedure.</td>
<td>— Inquiries of management and others within the entity</td>
</tr>
<tr>
<td></td>
<td>— Analytical procedures</td>
</tr>
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<td></td>
<td>— Observation and inspection</td>
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<td></td>
<td>• Inquiry alone is not sufficient to evaluate the design of internal control and to determine whether it has been implemented.</td>
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### Entities With Oil and Gas Producing Activities

**SAS No. 107, Audit Risk and Materiality in Conducting an Audit**

<table>
<thead>
<tr>
<th><strong>Key Provisions</strong></th>
<th><strong>How the SAS Differs From Previous Standards</strong></th>
</tr>
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</table>
| • The auditor must consider audit risk and must determine a materiality level for the financial statements taken as a whole for the purpose of:  
  1. Determining the extent and nature of risk assessment procedures.  
  2. Identifying and assessing the risk of material misstatement.  
  3. Determining the nature, timing, and extent of further audit procedures.  
  4. Evaluating whether the financial statements taken as a whole are presented fairly, in conformity with generally accepted accounting principles. | • Previous guidance said that auditors "should consider" audit risk and materiality for certain specified purposes. SAS No. 107 states that the auditor "must" consider.  
• New guidance explicitly states that audit risk and materiality are used to identify and assess the risk of material misstatement. |
| • Combined assessment of inherent and control risks is termed the risk of material misstatement. | • SAS No. 107 consistently uses the term risk of material misstatement, which often is described as a combined assessment of inherent and control risk. However, auditors may make separate assessment of inherent risk and control risks. |
| • The auditor should assess the risk of material misstatement as a basis for further audit procedures. Although that risk assessment is a judgment rather than a precise measurement of risk, the auditor should have an appropriate basis for that assessment.  
• Assessed risks and the basis for those assessments should be documented. | • SAS No. 107 states that the auditor should have and document an appropriate basis for the audit approach.  
• These two provisions of the risk assessment standards effectively eliminate the ability of the auditor to assess control risk "at the maximum" without having a basis for that assessment. In other words, it is no longer acceptable to "default" to maximum control risk. |
## Comparison of Key Provisions of the Risk Assessment Standards

<table>
<thead>
<tr>
<th>Key Provisions</th>
<th>How the SAS Differs From Previous Standards</th>
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<tr>
<td>• The auditor must accumulate all known and likely misstatements identified during the audit, other than those that the auditor believes are trivial, and communicate them to the appropriate level of management.</td>
<td>• SAS No. 107 provides additional guidance on communicating misstatements to management.</td>
</tr>
<tr>
<td>• The auditor should request management to respond appropriately when misstatements (known or likely) are identified during the audit.</td>
<td>• The concept of not accumulating misstatements below a certain threshold is included in the previous standards, but SAS No. 107 provides additional specific guidance on how to determine this threshold.</td>
</tr>
<tr>
<td>• SAS No. 107 provides specific guidance regarding the appropriate auditor’s responses to the types of misstatements (known or likely) identified by the auditor.</td>
<td></td>
</tr>
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</table>
Entities With Oil and Gas Producing Activities

SAS No. 108, Planning and Supervision

<table>
<thead>
<tr>
<th>Key Provisions</th>
<th>How the SAS Differs From Previous Standards</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAS No. 108 provides guidance on:</td>
<td>• Much of the guidance provided in SAS No. 108 has been consolidated from several existing standards.</td>
</tr>
<tr>
<td>• Appointment of the independent auditor.</td>
<td>• However, SAS No. 108 provides new guidance on preliminary engagement activities, including the development of an overall audit strategy and an audit plan.</td>
</tr>
<tr>
<td>• Establishing an understanding with the auditee.</td>
<td>— The overall audit strategy is what previously was commonly referred to as the audit approach. It is a broad approach to how the audit will be conducted, considering factors such as the scope of the engagement, deadlines for performing the audit and issuing the report, and recent financial reporting developments.</td>
</tr>
<tr>
<td>• Preliminary engagement activities.</td>
<td>— The audit plan is more detailed than the audit strategy and is commonly referred to as the audit program. The audit plan describes in detail the nature, timing, and extent of risk assessment and further audit procedures you perform in an audit.</td>
</tr>
<tr>
<td>• The overall audit strategy.</td>
<td>• SAS No. 108 states that you should establish a written understanding with your auditee regarding the services to be performed for each engagement.</td>
</tr>
<tr>
<td>• The audit plan.</td>
<td></td>
</tr>
<tr>
<td>• Determining the extent of involvement of professionals possessing specialized skills.</td>
<td></td>
</tr>
<tr>
<td>• Using a professional possessing IT skills to understand the effect of IT on the audit.</td>
<td></td>
</tr>
<tr>
<td>• Additional considerations in initial audit engagements.</td>
<td></td>
</tr>
<tr>
<td>• Supervision of assistants.</td>
<td></td>
</tr>
</tbody>
</table>
## Comparison of Key Provisions of the Risk Assessment Standards

### SAS No. 109, *Understanding the Entity and Its Environment and Assessing the Risks of Material Misstatement*

<table>
<thead>
<tr>
<th>Key Provisions</th>
<th>How the SAS Differs From Previous Standards</th>
</tr>
</thead>
<tbody>
<tr>
<td>• SAS No. 109 describes audit procedures that the auditor should perform to obtain the understanding of the entity and its environment, including its internal control.</td>
<td>• The auditor should perform “risk assessment procedures” to gather information and gain an understanding of the entity and its environment. These procedures include inquiries, observation, inspection, and analytical procedures. Previous standards did not describe the procedures that should be performed to gain an understanding of the auditee.</td>
</tr>
<tr>
<td>• The audit team should discuss the susceptibility of the entity’s financial statements to material misstatement.</td>
<td>• Information about the entity may be provided by a variety of sources, including knowledge about the entity gathered in previous audits (provided certain conditions are met), and the results of auditee acceptance and continuance procedures.</td>
</tr>
<tr>
<td>• The purpose of obtaining an understanding of the entity and its environment, including its internal control, is to identify and assess “the risks of material misstatement” and design and perform further audit procedures responsive to the assessed risks.</td>
<td>• SAS No. 109 directs the auditor to perform a variety of risk assessment procedures, and it describes the limitations of inquiry.</td>
</tr>
</tbody>
</table>

(continued)

• SAS No. 109 directly links the understanding of the entity and its internal control with the assessment of risk and design of further audit procedures. Thus, the understanding of the entity and its environment, including its internal control, provides the audit evidence necessary to support the auditor’s assessment of risk.
<table>
<thead>
<tr>
<th>Key Provisions</th>
<th>How the SAS Differs From Previous Standards</th>
</tr>
</thead>
</table>
| • SAS No. 109 states the auditor should assess the risks of material misstatement at both the financial statement and relevant assertion levels. | • The previous standard included the concept of assessing risk at the financial statement level, but SAS No. 109 provides expanded and more explicit guidance.  
• SAS No. 109 also directs the auditor to determine how risks at the financial statement level may result in risks at the assertion level. |
| • SAS No. 109 provides directions on how to evaluate the design of the entity’s controls and determine whether the controls are adequate and have been implemented. | • Under the previous standard, the primary purpose of gaining an understanding of internal control was to plan the audit. Under SAS No. 109, your understanding of internal control is used to assess risks. Thus, the understanding of internal control provides audit evidence that ultimately supports the auditor’s opinion on the financial statements.  
• The previous standard directs the auditor to obtain an understanding of internal control as part of obtaining an understanding of the entity and its environment. SAS No. 109 requires auditors to evaluate the design of controls and determine whether they have been implemented. Evaluating the design of a control involves considering whether the control, individually or in combination with other controls, is capable of effectively preventing or detecting and correcting material misstatements. It is anticipated that this phase of the audit will require more work than simply gaining understanding of internal control. |
| • SAS No. 109 directs the auditor to consider whether any of the assessed risks are significant risks that require special audit consideration or risks for which substantive procedures alone do not provide sufficient appropriate audit evidence. | • Previous standard did not include the concept of "significant risks."  
• Significant risks exist on most engagements.  
• The auditor should gain an understanding of internal control and also perform substantive procedures for all identified significant risks. Substantive analytical procedures alone are not sufficient to test significant risks. |

Entities With Oil and Gas Producing Activities
Comparison of Key Provisions of the Risk Assessment Standards

<table>
<thead>
<tr>
<th>Key Provisions</th>
<th>How the SAS Differs From Previous Standards</th>
</tr>
</thead>
<tbody>
<tr>
<td>• SAS No. 109 provides extensive guidance on the matters that should be documented.</td>
<td>• The guidance provided by SAS No. 109 relating to documentation is significantly greater than that provided by previous standards.</td>
</tr>
</tbody>
</table>
## SAS No. 110, Performing Audit Procedures in Response to Assessed Risks and Evaluating the Audit Evidence Obtained

<table>
<thead>
<tr>
<th>Key Provisions</th>
<th>How the SAS Differs From Previous Standards</th>
</tr>
</thead>
<tbody>
<tr>
<td>• SAS No. 110 provides guidance on determining overall responses to address the risks of material misstatement at the financial statement level and the nature of those responses.</td>
<td>• The concept of addressing the risks of material misstatement at the financial statement level and developing an appropriate overall response is similar to the requirement in previous standards relating to the consideration of audit risk at the financial statement level. However, that guidance was placed in the context of audit planning. SAS No. 110 &quot;restores&quot; your consideration of risk at the financial statement level so you make this assessment as a result of and in conjunction with your performance of risk assessment procedures. In some cases, this assessment may not be able to be made during audit planning.</td>
</tr>
<tr>
<td>• Further audit procedures, which may include tests of controls, or substantive procedures should be responsive to the assessed risks of material misstatement at the relevant assertion level.</td>
<td>• SAS No. 110 requires you to consider how your assessment of risks at the financial statement level affects individual financial statement assertions, so you may design and perform tailored further audit procedures (substantive tests or tests of controls).</td>
</tr>
<tr>
<td>• Although the previous standards included the concept that audit procedures should be responsive to assessed risks, this idea was embedded in the discussion of the audit risk model. The SASs repeatedly emphasize the need to provide a clear linkage between your understanding of the entity, your risk assessments, and the design of further audit procedures.</td>
<td>• The list of possible overall responses to the risks of material misstatement at the financial statement level also has been expanded.</td>
</tr>
<tr>
<td>• SAS No. 110 requires you to document the linkage between assessed risks and further audit procedures, which was not a requirement under the previous standards.</td>
<td></td>
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</table>
### Comparison of Key Provisions of the Risk Assessment Standards

<table>
<thead>
<tr>
<th>Key Provisions</th>
<th>How the SAS Differs From Previous Standards</th>
</tr>
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<tbody>
<tr>
<td>• SAS No. 110 provides guidance on matters the auditor should consider in</td>
<td>• The new guidance on determining the nature, timing, and extent of tests of controls and substantive tests</td>
</tr>
<tr>
<td>determining the nature, timing, and extent of such audit procedures.</td>
<td>has been expanded greatly and addresses issues that previously were not included in the authoritative</td>
</tr>
<tr>
<td></td>
<td>literature.</td>
</tr>
<tr>
<td>• SAS No. 110 states that the nature of further audit procedures is of most</td>
<td>• SAS No. 110 states that the nature of further audit procedures is of most importance in responding to your</td>
</tr>
<tr>
<td>importance in responding to your assessed risks of material misstatement.</td>
<td>assessed risks of material misstatement. That is, increasing the extent of your audit procedures will</td>
</tr>
<tr>
<td></td>
<td>not compensate for procedures that do not address the specifically identified risks of misstatement.</td>
</tr>
<tr>
<td>• SAS No. 110 states that you should perform certain substantive procedures on</td>
<td>• SAS No. 110 states that you should perform certain substantive procedures on all engagements. These</td>
</tr>
<tr>
<td>all engagements. These procedures include:</td>
<td>procedures include:</td>
</tr>
<tr>
<td></td>
<td>— Performing substantive tests for all relevant assertions related to each material class of transactions,</td>
</tr>
<tr>
<td></td>
<td>account balance, and disclosure regardless of the assessment of the risks of material misstatements.</td>
</tr>
<tr>
<td></td>
<td>— Agreeing the financial statements, including their accompanying notes, to the underlying accounting</td>
</tr>
<tr>
<td></td>
<td>records</td>
</tr>
<tr>
<td></td>
<td>— Examining material journal entries and other adjustments made during the course of preparing the</td>
</tr>
<tr>
<td></td>
<td>financial statements</td>
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</tbody>
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AAG-OGP APP E
## Key Provisions

- SAS No. 111 provides guidance relating to the auditor's judgment about establishing tolerable misstatement for a specific audit procedure and on the application of sampling to tests of controls.

## How the SAS Differs From Previous Standards

- SAS No. 111 provides enhanced guidance on tolerable misstatement. In general, tolerable misstatement in an account should be less than materiality to allow for aggregation in final assessment.
- Ordinarily sample sizes for non-statistical samples are comparable to sample sizes for an efficient and effectively designed statistical sample with the same sampling parameters.
Schedule of Changes

Appendix F

Schedule of Changes Made to the Text From the Previous Edition

As of May 1, 2008

This schedule of changes identifies areas in the text and footnotes of this guide that have changed since the previous edition. Entries in the table of this appendix reflect current numbering, lettering (including that in appendix names), and character designations that resulted from the renumbering or reordering that occurred in the updating of this guide.

Terms Used to Define Professional Requirements

The 2008 editions of the AICPA Audit and Accounting Guides, including this guide, have been updated to conform with AU section 120, Defining Professional Requirements in Statements on Auditing Standards, AT section 20, Defining Professional Requirements in Statements on Standards for Attestation Engagements (AICPA, Professional Standards, vol. 1), and AR section 20, Defining Professional Requirements in Statements on Standards for Accounting and Review Services (AICPA, Professional Standards, vol. 2), in which professional requirements are categorized as either unconditional requirements or presumptively mandatory requirements, each of which is associated with specific wording such as “must” or “is required” or “should.” These standards distinguish professional requirements set forth in the standards from explanatory material contained in the standards, the latter of which requires only the auditor’s, practitioner’s, or accountant’s “attention and understanding.” Whether the auditor, practitioner, or accountant performs the suggested procedures or actions in the engagement (as stated in the explanatory material) depends on the exercise of professional judgment in the circumstances consistent with the objective of the standard.

Because interpretive publications (including AICPA Audit and Accounting Guides, for example) are recommendations, the publications cannot establish requirements. Paragraph .06 of AU section 150, Generally Accepted Auditing Standards (AICPA, Professional Standards, vol. 1), states, “The auditor should be aware of and consider interpretive publications applicable to his or her audit. If the auditor does not apply the auditing guidance included in an interpretive publication, the auditor should be prepared to explain how he or she complied with the SAS provisions addressed by such auditing guidance.”

An interpretive publication, such as this guide, should state the requirement of the standard, and then give recommendations on the application of the requirement in the specific circumstances. The terms must, is required, or should may be used in an interpretive publication only when it is clear that the requirement originated in a standard. Otherwise, the user may be uncertain whether a requirement or a recommendation is intended. The following conventions were used to conform the AICPA Audit and Accounting Guides to these standards, which define professional requirements:

- Terms to replace the use of must, should, and is required consist only of those explanatory material terms included in AU section 120, AT section 20, and AR section 20: could, may, and might, and these variations of those terms: could consider, may consider, and might consider.
Entities With Oil and Gas Producing Activities

- When referring guide users to interpretive publications (which consist of interpretations of the Statements on Auditing Standards [SASs], appendices to the SASs, auditing guidance in AICPA Audit and Accounting Guides, and AICPA auditing Statements of Position) or to nonauthoritative knowledge sources, if an auditor can perform an adequate risk assessment without the recommended knowledge, explanatory material terms are used; if not, should or should consider is used.

- Specific auditing procedures generally are explanatory in nature (the standards generally do not include specific audit procedures). As such, explanatory material terms (could, may, might, could consider, may consider, or might consider) are used, unless the specific audit procedure is the established way or only way of achieving a generally accepted auditing standard objective for this industry, in which case should is used.

- If the recommendation is that the auditor consult or familiarize himself or herself with other sources of information, such as Securities and Exchange Commission (SEC) regulations, income tax laws, and industry developments including regulatory, economic, and legislative developments, then the following considerations were used in developing which terms to use in the guides:
  - If the purpose of the recommendation is for the auditor, practitioner, or accountant to develop the required understanding of the entity and its environment for risk assessment purposes, and an auditor can perform an adequate risk assessment without the recommended knowledge, explanatory material terms are used within the recommendation; if not, should or must is used depending upon the associated standard requirement.
  - If the purpose of the recommendation is for the auditor, practitioner, or accountant to perform the engagement in accordance with AICPA Professional Standards, and the knowledge is available only from the source cited (such as SEC regulations, income tax law, and the like), then should is used. If the knowledge is available from other sources as well, explanatory material terms are used.

- The guides contain guidance for management which includes best practices for the industry. Because the recommendations are best practices, the terms ordinarily should or generally should are used.
## Schedule of Changes

<table>
<thead>
<tr>
<th>Reference</th>
<th>Change</th>
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</thead>
<tbody>
<tr>
<td>Notice to Readers and Preface</td>
<td>Updated.</td>
</tr>
<tr>
<td>Paragraph 1.26</td>
<td>Revised to reflect the appropriate use of terms used to define the professional requirements of auditors, practitioners, and accountants in AU section 120, AT section 20, and AR section 20 of AICPA Professional Standards. Subsequently, these changes are referred to as defining professional requirements in the schedule of changes.</td>
</tr>
<tr>
<td>Former footnote 1 in paragraph 1.26</td>
<td>Deleted due to the passage of time.</td>
</tr>
<tr>
<td>Footnote 1 in heading before paragraph 1.30</td>
<td>Revised to reflect the issuance of FASB Interpretation No. 46(R).</td>
</tr>
<tr>
<td>Paragraphs 1.35</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Paragraph 1.40</td>
<td>Revised for clarification; footnote 2 added for clarification.</td>
</tr>
<tr>
<td>Paragraph 1.41</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Footnote 3 in paragraph 1.51</td>
<td>Revised for clarification.</td>
</tr>
<tr>
<td>Paragraph 1.52</td>
<td>Revised for clarification; footnote 4 revised to define professional requirements; footnote 5 revised for clarification.</td>
</tr>
<tr>
<td>Paragraph 1.53 and footnote 6 in heading before paragraph 1.55</td>
<td>Revised for clarification.</td>
</tr>
<tr>
<td>Paragraph 1.55</td>
<td>Footnote 7 revised for clarification; footnote 8 revised to define professional requirements.</td>
</tr>
<tr>
<td>Paragraph 1.56, footnote 11 in paragraph 1.58, paragraph 1.60, and footnote 12 in paragraph 1.61</td>
<td>Revised for clarification.</td>
</tr>
<tr>
<td>Paragraph 1.65</td>
<td>Revised for clarification; footnote 15 added to reflect the issuance of FASB FSP 142-3.</td>
</tr>
<tr>
<td>Former footnote ‡ in paragraph 1.67</td>
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</tr>
<tr>
<td>Paragraph 1.70</td>
<td>Revised for clarification; former footnote # deleted.</td>
</tr>
<tr>
<td>Paragraph 1.71</td>
<td>Added for clarification.</td>
</tr>
<tr>
<td>Footnote * in heading before paragraph 1.72</td>
<td>Added to reflect the issuance of FASB Statement Nos. 141(R) and 160.</td>
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</table>

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<table>
<thead>
<tr>
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<th>Change</th>
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<tbody>
<tr>
<td>Paragraphs 1.76–.83 and heading</td>
<td>Added to reflect the issuance of FASB Statement No. 157, FSP FAS 157-1, and FSP FAS 157-2.</td>
</tr>
<tr>
<td>Paragraphs 1.84–.86 and heading</td>
<td>Added to reflect the issuance of FASB Statement No. 157, FSP FAS 157-1, and FSP FAS 157-2.</td>
</tr>
<tr>
<td>Footnote 16 in paragraph 1.84</td>
<td>Added for clarification.</td>
</tr>
<tr>
<td>Paragraphs 1.87–.90 and heading</td>
<td>Added to reflect the issuance of FASB Statement No. 157, FSP FAS 157-1, and FSP FAS 157-2.</td>
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<td>Paragraph 1.91 and heading</td>
<td>Added to reflect the issuance of FASB Statement No. 157, FSP FAS 157-1, and FSP FAS 157-2.</td>
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<tr>
<td>Paragraphs 1.92–.94 and heading</td>
<td>Added to reflect the issuance of FASB Statement No. 157.</td>
</tr>
<tr>
<td>Paragraph 1.92</td>
<td>Footnote 17 added to reflect the issuance of FASB Statement No. 161; footnote † added for clarification.</td>
</tr>
<tr>
<td>Paragraph 2.18</td>
<td>Former footnote * deleted; footnote 2 added for clarification.</td>
</tr>
<tr>
<td>Paragraph 2.20</td>
<td>Revised for clarification.</td>
</tr>
<tr>
<td>Paragraph 2.26</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Footnote 4 in paragraph 2.33</td>
<td>Added for clarification.</td>
</tr>
<tr>
<td>Paragraphs 2.63, 2.66, 2.72, 2.78–.79, and 2.88</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Paragraph 2.89</td>
<td>Revised for clarification.</td>
</tr>
<tr>
<td>Paragraphs 2.92–.93 and 2.96–.97</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Footnote 9 in paragraph 2.114</td>
<td>Revised for clarification.</td>
</tr>
<tr>
<td>Footnote 10 in paragraph 2.118</td>
<td>Added for clarification.</td>
</tr>
<tr>
<td>Paragraphs 2.120 and 2.122</td>
<td>Revised for clarification.</td>
</tr>
<tr>
<td>Heading before paragraph 2.125</td>
<td>Former footnote # deleted; footnote 12 added for clarification.</td>
</tr>
<tr>
<td>Paragraph 2.127</td>
<td>Former footnote * deleted; footnote 13 added for clarification.</td>
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<tr>
<td>Paragraph 2.147</td>
<td>Former footnote ‡‡ deleted.</td>
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## Schedule of Changes

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<td>Paragraph 2.148</td>
<td>Revised for clarification; former footnote * deleted.</td>
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<td>Paragraph 2.149</td>
<td>Former footnote † deleted; footnote 15 added to reflect the issuance of FASB Statement No. 161; footnote 16 revised to define professional requirements.</td>
</tr>
<tr>
<td>Paragraph 2.150</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Paragraph 2.153</td>
<td>Added for clarification.</td>
</tr>
<tr>
<td>Paragraph 3.08</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Footnote 2 in chapter 4 title</td>
<td>Revised for clarification.</td>
</tr>
<tr>
<td>Paragraph 4.02</td>
<td>Revised to define professional requirements; revised for clarification.</td>
</tr>
<tr>
<td>Paragraphs 4.03–.04</td>
<td>Revised for clarification.</td>
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<tr>
<td>Paragraph 4.16</td>
<td>Revised to define professional requirements.</td>
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<tr>
<td>Heading before paragraph 4.17</td>
<td>Former footnote † deleted; footnote 3 added for clarification.</td>
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<tr>
<td>Former footnote * in chapter 5 title</td>
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<tr>
<td>Paragraph 5.02</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Paragraph 5.03</td>
<td>Revised for clarification.</td>
</tr>
<tr>
<td>Paragraph 5.05</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Paragraph 5.06</td>
<td>Revised for clarification.</td>
</tr>
<tr>
<td>Paragraph 5.08</td>
<td>Revised to define professional requirements; former footnote 1 deleted for clarification.</td>
</tr>
<tr>
<td>Paragraphs 5.11–.12</td>
<td>Revised for clarification.</td>
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<tr>
<td>Paragraphs 5.15–.18 and 5.22</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Paragraphs 5.27, 5.29–.31, 5.36–.37, 5.40–.41, 5.44, 5.53, 5.55, 5.59–.60, 5.62, footnote 2 in heading before paragraph 5.72, 5.72, 5.75, footnote 3 in heading before paragraph 5.77, and 5.84</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Heading before paragraph 5.83 and paragraph 5.83</td>
<td>Updated for the issuance of SAS No. 114.</td>
</tr>
<tr>
<td>Heading before paragraph 5.86 and former footnote 7 to heading before paragraph 5.86</td>
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### Entities With Oil and Gas Producing Activities

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<th>Reference</th>
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<tr>
<td>Paragraph 5.86</td>
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</tr>
<tr>
<td>Footnote 7 in paragraph 5.89</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Paragraph 5.90</td>
<td>Revised to define professional requirements; revised for clarification.</td>
</tr>
<tr>
<td>Heading before former paragraph 5.91, former footnote ‡ in paragraph 5.91, and former paragraphs 5.91–.94</td>
<td>Deleted for clarification.</td>
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<td>Paragraphs 5.91–.94, 5.99, footnote 8 in paragraph 5.101, and 5.101–.102</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Footnote 9 in paragraph 5.103</td>
<td>Revised for clarification.</td>
</tr>
<tr>
<td>Paragraphs 5.104–.106, 5.108–.109, 5.111–.113, 5.117–.120, 5.122–.124, and 5.126–.134</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Footnote 11 in paragraph 5.134, 5.135, and footnote 12 in paragraph 5.135</td>
<td>Revised for clarification.</td>
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<tr>
<td>Paragraphs 5.139–.140 and 5.144–.149</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Paragraph 5.150</td>
<td>Revised to define professional requirements; revised for clarification.</td>
</tr>
<tr>
<td>Paragraph 5.160</td>
<td>Revised to define professional requirements.</td>
</tr>
<tr>
<td>Appendix A</td>
<td>Footnote 1 revised for clarification and to reflect the issuance of FSP FAS 158-1; footnote 3 added to reflect the issuance of FASB Statement No. 161; footnotes 4–6 revised for clarification; material under the heading “Additional Guidance When Performing Integrated Audits of Financial Statements and Internal Control Over Financial Reporting” revised to reflect the issuance of PCAOB Auditing Standard No. 5; former footnote 5 deleted; footnote * revised to reflect the issuance of FSP FIN 48-2; footnote 11 revised to define professional requirements; footnote 12 revised to reflect the issuance of FIN 46(R); footnote ‡ revised for clarification; financial statement note 12 former item (d) deleted.</td>
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## Schedule of Changes

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<tr>
<td>Appendix B</td>
<td>Revised to reflect the updated <em>Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information</em>.</td>
</tr>
<tr>
<td>Appendix C</td>
<td>Updated.</td>
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<td>Appendix D</td>
<td>Updated.</td>
</tr>
<tr>
<td>Glossary</td>
<td>Footnote * added in the definition of <em>goodwill</em> to reflect the issuance of FASB Statement No. 141(R).</td>
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</table>
**Glossary**

**AFE.** Authorization for expenditure.

**barrel.** A standard measurement in the oil industry. One barrel equals 42 U.S. gallons. On the average, 7.33 barrels of crude oil weigh one metric ton; 7.5 barrels weigh one long ton; and 6.65 barrels weigh one short ton.

**bottom hole contribution.** A defined cash contribution by a noninterest owner to the working interest owners upon the drilling of a well, regardless of the outcome, to a specific geological formation or to a specified depth.

**carried interest.** An arrangement in which one party agrees to develop and operate a property at its cost but with the right to recapture its costs or a defined greater amount from the proceeds of production.

**casing.** Heavy steel pipe that lines the hole of a well. Initially, casing is used near the surface and is cemented into place to guide the drill pipe. Later, if oil or gas is found, production casing is set near the bottom of the hole. Surface casings protect any fresh water supplies from contamination during drilling operations. Lower casings keep loose earth, rock, salt water, and other material out of the well, protect the producing reservoir, and serve as conduits for the tubing that brings oil and gas to the surface.

**casing point.** The point at which the operator decides whether or not it will be profitable enough to set production casing and complete the well.

**completion.** The process of attempting to bring an oil or gas well into production. The process begins only after the well has reached the depth where oil or gas is thought to exist and generally involves cleaning out the material the drill bit has ground up. Casing is run to protect the producing formation. Completion also may include perforating the casing so the oil or gas can flow into the well. Sometimes the flow rate can be improved by an acid treatment or by fracturing the oil formation to open channels for the oil to flow into the well.

**condensate.** A mixture of liquid hydrocarbons at atmospheric (surface) conditions that occur as a vapor in underground gas reservoirs. The liquids (condensate) are separated from the gas in field separators or gas processing plants. These liquids generally include propane, butane, and heavier hydrocarbons used in making gasoline.

**condition value.** The application of a percentage of replacement cost for new materials to used equipment at the time when taken out of service.

**coring.** A technique for cutting samples of subsurface rocks as a well is being drilled. A hollow bit or cutting tool at the bottom of the drill pipe cuts a cylindrical length of rock, or core, as the drill pipe rotates. The core is pushed up into a hollow tube, or core barrel, attached to the bit. The core barrel is brought to the surface and the core sample removed for study. The average core is about 30 feet long.

**crude oil.** Liquid petroleum that has not been refined. Sour crude oils have relatively large amounts of sulfur (1 percent or more). Sweet crude oils have less sulfur and are more valuable. Most U.S. crudes tend to be sweet, while Middle East crudes tend to be sour. Crude oil is generally sold on a volume basis. The volume is corrected for any basic sediment and water (BS&W) present.
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and adjusted to the standard base temperature of 60 degrees Fahrenheit. Light crude oils have a lower specific gravity than do heavy crudes, which may be thick and viscous.

**DD&A.** Depreciation, depletion, and amortization.

**delay rental.** Payments to the lessor for the privilege of delaying drilling on a lease for a period of time, usually one year.

**development well.** A well drilled within the proved area of an oil or gas reservoir to a depth of a stratigraphic horizon known to be productive.

**division order.** A legal document signed by each owner of a revenue interest specifying the percent ownership of each owner.

**dry hole.** A well that either finds no oil or gas or finds too little to make it financially worthwhile to produce.

**dry hole contribution.** A defined cash contribution by a noninterest owner to the working interest owners, payable only if the well is unsuccessful.

**exploratory well.** A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well.

**farm-out.** A sharing of oil or gas exploration activities and costs. A company with the right to explore more potential acreage than it can or wishes to handle may invite others to explore portions of the tract in return for a share of whatever oil or gas is found.

**financial asset.** Cash, evidence of an ownership interest in an entity, or a contract that conveys to a second entity a contractual right (a) to receive cash or another financial instrument from a first entity or (b) to exchange other financial instruments on potentially favorable terms with the first entity.

**fracturing.** A method of increasing the flow of oil or gas into a well. Production of individual wells often decreases because the underground formation is not sufficiently permeable to allow the oil to move freely toward the well.

**free wells.** An assignment of an individual fraction of the working interest to a second party in consideration for an undertaking by the second party to drill and equip a well at no cost to the first party.

**G&G.** Geological and geophysical.

**goodwill.** The excess if the cost of an acquired entity over the net of the amounts assigned to assets acquired and liabilities assumed. The amount recognized as goodwill includes acquired intangible assets that do not meet the criteria in FASB Statement No. 141, *Business Combinations,* for recognition as an asset apart from goodwill.

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* In December 2007, Financial Accounting Standards Board (FASB) issued Statement No. 141 (revised 2007), *Business Combinations.* The effective date of FASB Statement No. 141(R) is for fiscal years beginning on or after December 15, 2008, with early adoption prohibited. Once effective, the following original wording: "The excess cost of an acquired entity over the net of the amounts assigned to assets acquired and liabilities assumed." will be replaced with the following: "An asset representing
improved recovery. Man made methods as opposed to natural methods of increasing the flow of oil or gas from underground reservoirs.

injection well. A well that is used to pump water, gas, or chemicals into the underground reservoir of a producing field. The object is to maintain the pressure needed to drive oil and gas to the surface or to sweep more oil out of the reservoir. Sometimes the salt water produced with oil is pumped back into the reservoir. This serves two purposes: It helps to extend the life of the oil field, and it gets rid of a potential pollutant.

intangible assets. Assets (not including financial assets) that lack physical substance.

intangible drilling costs (IDC). Expenses for labor, fuel, repair, hauling, rig rental, and supplies used in the drilling of a well. These expenses differ from the cost of tangibles, which include anything that has inherent salvage value.

joint interest billings (JIB). The process of the operator’s billing costs of joint exploration, development, and operations to the various working interest owners.

joint interests. Ownership of individual fractions or percentages of the working interests held by two or more parties.

lease bonus. The initial consideration paid by the lessee to the lessor to acquire the mineral rights.

LOE. Lease operating expenses.

mcf. Thousand cubic feet. The standard volume measure of natural gas at a standard pressure and temperature.

natural gas. Consists largely of the hydrocarbon methane. It is found in underground formations either by itself or with crude oil. It is the cleanest burning of all fossil fuels. Once virtually a waste product, natural gas provides about one-third of the total energy used in the United States.

net profits interest. An interest that entitles the owner to a specified share of net profits from production of hydrocarbons.

overriding royalty. An interest in production similar to a royalty. It differs from a royalty, however, in that it is created out of the working interest.

payout. The defined point in many drilling arrangements and partnerships at which one party has recovered its costs and revenue sharing may change.

percentage depletion. A provision of the U.S. income tax law that applies to producers of some seventy-five minerals, including some oil and gas producers. The U.S. income tax law allows a mineral producer a percentage depletion deduction based on the gross income from mineral properties.

pooled interests. The combination of two or more working and nonoperating interests in several properties to form a new economic unit.

(footnote continued)

the future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. See footnote * in the heading before paragraph 1.72 of this guide for additional information regarding FASB Statement No. 141(R).
posted prices. In the petroleum industry, the price lists posted for various types of crude by the buyer in the United States, and the seller in foreign countries.

production payments. A nonoperating interest payable from a specific portion of production expressed either as a certain amount of money (with or without interest) or a certain number of units of hydrocarbons.

proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

proved reserves. The estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economics and operating conditions.

proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for repletion.

recompletions. Work-overs that entail completion of the well in a productive structure, either shallower or deeper, that has not previously been produced through the well.

reserves. Defined as proved, probable, and possible and as developed or undeveloped.

reservoir. An underground formation where oil or gas has accumulated. The formation consists of porous rock that holds droplets of oil and gas. If the rock pores are interconnected to allow oil or gas to move through it, it is called permeable rock.

revenue interest. The interest of each owner of an economic interest in production of hydrocarbons from a specified property. The revenue interest normally differs from the percentage working interest because of nonworking interests in each property.

reversionary interest. A revenue interest that increases upon the attainment of certain specified objectives, often at payout.

royalty. The right to a share of production retained by the lessor free and clear of exploration, development, and operating costs.

stratigraphic test well. A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells are customarily drilled without the intention of being completed for production.

tangible equipment. Equipment such as casing, tubing, pumps, tanks, and other equipment installed on a well.

top leasing. The practice of obtaining a new lease on a property prior to the expiration of the existing lease. The new lease becomes effective at the expiration of the old lease.

windfall profit taxes (WPT). The WPT is an excise tax assessed on the removal of domestic crude oil. WPT liabilities are limited by a statutory provision based on defined net income from a property. For WPT purposes, domestic crude oil is divided into two principal categories, exempt and taxable. Exempt is defined by law and includes oil applicable to certain...
governmental and charitable entities, certain front-end incentive oil, exempt stripper well oil, exempt royalty oil, and exempt Indian oil. WPT was repealed August 23, 1988.

**work-over.** Major remedial operations required to maintain or increase production rates. *See recompletions.*
Bibliography

Books—Accounting and Reporting


A research study sponsored by the Accounting Principles Board in its effort to develop oil and gas accounting standards.


Discusses aspects that the investor, sponsor, and accountant involved in a drilling fund must consider, with an emphasis on tax aspects.

Brock, Horace R.; Jones, Donald M.; and Klingstedt, John P. *Accounting for Oil and Gas Producing Companies, Part 1: Exploration, Acquisition, Development and Production*. Denton, Texas: Professional Development Institute, North Texas State University, 1981.

Serves as a practical reference guide on financial accounting and reporting for oil and gas producing companies. Covers the following: the economic aspects of the industry; company organization; general principles of oil and gas accounting; accounting for expenditures incurred in exploration, leasing, and development activities; revenue accounting; and accounting for lifting costs. Emphasizes the successful efforts method of accounting.

*Accounting for Oil and Gas Producing Companies, Part 2: Amortization, Full Costing and Disclosures*. Denton, Texas: Professional Development Institute, North Texas State University, 1982.

A continuation of Part 1 above. Topics covered include the following: depreciation, depletion, and amortization; the full cost method; sales and subleases; production payments; poolings of capital; deferred income taxes; supplemental disclosures; joint operations; gas production.

Burke, Kenneth M., and Durand, Francis L. *Oil and Gas Limited Partnerships, Accounting, Reporting and Taxation*. Denton, Texas: Professional Development Institute, North Texas State University, 1984.

Topics include federal income tax, windfall profit tax, and accounting and reporting matters. Illustrates several different types of limited partnerships. Exhibits include detailed computations of taxable income distribution, investor cash flow, depreciation, depletion and amortization, windfall profit tax, allowable depletion, tax liability, and deferred taxes.


Two-volume publication covering oil and gas taxation. Revised annually.


Articles are grouped in five subject areas of interest to the petroleum industry. Areas covered are the following: full cost, successful efforts, and discovery value; FASB and SEC releases; empirical studies; profitability in the oil industry; and accounting for inflation.
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Provides a review of the basic successful efforts and full cost rules. It is written from the perspective of a nonaccountant, although it provides the general rules for practicing accountants. Also included are sample annual reports and the complete successful efforts and full cost rules.


Reference guide for the explanation of standards and regulations promulgated by the FASB and SEC. Contains numerous practical examples. Successful efforts and full cost methods are both discussed with overview of development of current standards and regulations.


Provides a general introduction to the various accounting practices followed by companies engaged in oil and gas exploration and production in the United Kingdom. While describing various alternative accounting practices followed in the industry, the book also serves as a practical handbook for those in financial management and provides the theoretical background required by those involved in the financial reporting of the industry.


A general reference book on oil and gas accounting. Accounting principles for exploration, development, and production are covered. In addition, the book includes chapters on tank car operations, pipeline operations, marine operations, crude oil purchasing and storage, refining operations, petrochemical operations, and marketing operations.


A research study sponsored by the API on methods to compute value of oil and gas reserves.

Books—General


A good description of physical activities in selecting drilling sites, carrying on drilling activities, completing wells, and performing special drilling operations. Includes a description of drilling rig components.


Coverage includes not only petroleum industry terms but abbreviations used in drilling reports and abbreviations used for scientific and engineering terms.
Bibliography


Designed to serve as a basic guide on the practical aspects of the petroleum industry. Gives a basic discussion of the petroleum industry from geology and reservoirs through exploration, drilling, production, pipelining, refining, and marketing.


Principally discusses the equipment and methods used to solve problems encountered in offshore operations.


Designed for the person unfamiliar with production practices. Gives an elementary understanding of the day-to-day workings of an oil and gas field.


Scope includes equipment and procedures used in oil well service. Specific chapters include well completion, remedial well work, well cleanout and work-over, well stimulation and analysis, planning, and economics. Contains glossary of terms used.


Comprehensive listing of oil and gas terms with short, concise definitions that often include references to statutes, cases, books, and law review articles. Revised annually.

Books—Taxation


A general coverage of oil and gas taxation. Revised annually.


A general coverage of oil and gas taxation. Revised frequently.

COPAS Bulletins

COPAS Bulletins are issued by the Council of Petroleum Accountants Societies. The bulletins provide accounting guidance in matters related to joint operations. They may be purchased from Kraftbilt Products, P.O. Box 800, Tulsa, Okla. 74101.

COPAS Interpretations

Interpretations of portions of COPAS Bulletins that are subject to debate.
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Periodicals

*Journal of Extractive Industries Accounting.* Denton, Texas: Professional Development Institute, North Texas State University.

Published three times a year. Articles deal primarily with financial accounting and reporting problems in the petroleum industry.

*Oil and Gas Tax Quarterly.* New York: Matthew Bender & Co., Inc.

Published quarterly. Most articles are related to oil and gas taxation, with a few articles on financial accounting and reporting in the petroleum industry.
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